EXHIBIT 51

UNITED STATES OF AMERICA
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order TransAlta Centralia Generation	Order No. 202-25-11

DECLARATION OF JOEL NIGHTINGALE
IN SUPPORT OF
MOTION TO INTERVENE, REQUEST FOR REHEARING,
AND MOTION TO STAY BY STATE OF WASHINGTON

I, Joel Nightingale, declare under penalty of perjury under the laws of the state of Washington that the following is true and correct:

Background and Qualifications

1. I am now and at all times mentioned have been a citizen of the United States, over the age of 18 years, and competent to make this declaration. I have personal knowledge of the matters set forth below or have knowledge based on my review of information and records gathered by my staff. I submit this declaration in support of Washington State's Motion to Intervene, Request Rehearing, and Motion to Stay. The statements contained herein are my own, and not binding on the Washington Utilities and Transportation Commission in a future proceeding.

2. I am currently employed as a Section Manager at the Washington State Utilities and Transportation Commission ("WUTC" or "Commission") in the Energy Planning Section of the Regulatory Services Division. I have held this position since 2025 and served at the Commission as a Regulatory Analyst from 2021 to 2025. Prior to joining the Commission, I served as the Sustainability Coordinator for Prairie State College in the Chicago area.

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3. My educational background includes a Master of Science degree in Sustainable Engineering from Villanova University and a Bachelor of Science degree in Mechanical Engineering from the University of Portland. I have more than seven (7) years of professional experience related to renewable energy and sustainability.

4. The Commission is an independent three-member board appointed by the Governor of Washington. The Commission's role is to regulate the rates, services, and practices of privately owned utilities and transportation services. Its mission is to protect the people of Washington by ensuring that investor-owned utility and transportation services are safe, equitable, available, reliable, and fairly priced.

5. In my current role as section manager, I oversee the work of Energy Planning Regulatory Analysts who review planning documents from regulated investor-owned utilities ("IOUs"), such as Integrated Resource Plans ("IRPs"), Clean Energy Action Plans ("CEAPs"), Clean Energy Implementation Plans ("CEIPs"), Biennial Conservation Plans ("BCPs"), Transportation Electrification Plans ("TEPs"), and Requests for Proposals ("RFPs"), and other long-term planning documents. I have worked for the WUTC on energy planning issues for over four years. I have also been involved in long-term regional planning, serving on advisory committees for the Northwest Power and Conservation Council, and supporting statewide resource adequacy meetings.

6. The purpose of this declaration is to attest to the impact that the Department of Energy's emergency order will have on investor-owned electric utility customers in Washington and long-term grid planning for Washington.

Long-term Planning and Reliability Considerations Guide Transition of Centralia Coal Plant

7. Washington's electric IOUs are required to submit IRPs to the WUTC every four years, with a progress report two years after each IRP. WAC 480-100-625. These plans project electricity demand for the next twenty (20) or more years and identify the "lowest

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reasonable cost" portfolio of resources to meet that demand. The brains of this exercise are the models that the IOUs use to optimize for the lowest cost. The IOUs feed the models a menu of resource options that include new resources (solar, wind, thermal, storage, etc.), retirements of existing resources, energy efficiency, demand response, etc. With this information, the model selects which resources would minimize the cost of the system while still meeting regulatory requirements (including resource adequacy standards).

8. Washington's largest IOU, serving more than 1.2 million electric customers in the state, is Puget Sound Energy (PSE). Besides being the state's largest utility, Puget Sound Energy is especially relevant in this case as it has an agreement with TransAlta for exclusive access to energy, capacity and ancillary services from the Centralia plant after Unit 2 has been converted from coal to gas. Ex. 20 (*TransAlta Signs Long-Term Agreement for 700 MW at Centralia Facility Enabling Coal to Natural Gas Conversion*, TransAlta (Jan. 5, 2026)). PSE has filed seven long-term plans (IRPs or IRP progress reports) since 2010. These plans are available at https://www.utc.wa.gov/documents-and-proceedings/dockets, by searching by docket number and date of document filed:

- *Puget Sound Energy 2011 Electric and Gas Integrated Resource Plan*, Docket Nos. UE-100961 & UG-100960, 2011 Integrated Resource Plan (May 27, 2011);
- *Puget Sound Energy's 2013 Electric and Gas Integrated Resource Plan*, Docket Nos. UE-120767 & UG-120768, 2013 Integrated Resource Plan (May 31, 2013);
- *Puget Sound Energy's 2015 Electric and Gas Integrated Resource Plan*, Docket Nos. UE-141169 & UG-141170, 2015 Integrated Resource Plan (Nov. 25, 2015);
- *Puget Sound Energy 2017 Electric and Gas Integrated Resource Plan*, Docket Nos. UE-160918 & UG-180607, 2017 Integrated Resource Plan (Nov. 14, 2017);
- *Puget Sound Energy 2019 Electric and Gas Integrated Resource Plan*, Docket Nos. UE-180607 & UG-180608, 2019 Integrated Resource Plan Work Plan Revision Pursuant to Order 01 (Feb. 28, 2019);

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- *2021 Integrated Resource Plan*, Docket Nos. UE-200304 & UG-200305, 2021 Final Integrated Resource Plan (Apr. 1, 2021);
- *2023 Electric Progress Report on the 2021 Electric IRP UE-200304*, Docket No. UE-200304, 2023 Electric Progress Report (Mar. 31, 2023)).

None of these plans have included continued or new long-term contracts with coal-fired plants (including the Centralia coal plant) beyond the end of 2025. This means that for well over a decade, the largest utility in the state has been planning to meet its customers' energy and peak capacity needs (including during seasonal peaks) at the lowest reasonable cost in the absence of coal-fired generation.

9. For well over a decade, TransAlta, in coordination with the State, has been planning for the retirement of its coal-fired plant in Centralia. After retirement of the coal-fired units, TransAlta plans to convert the facility to a gas plant. As I understand it, the Department of Energy's December 16, 2025, Emergency Order, 202-25-11 ("Order"), seeks to delay the retirement of the coal facility. *See* Ex. 1.

10. In its 2024 General Rate Case (GRC), PSE witness Ronald J. Roberts describes in testimony the IOU's approach to addressing resource adequacy challenges by: (1) reducing reliance on wholesale spot market transactions by securing near- and intermediate-term PPAs, (2) participating in regional resource adequacy programs, (3) exploring new day-ahead market options, and (4) maintaining availability of PSE's gas-fired generation fleet to mitigate projected capacity shortfalls. Ex. 51-1 (*Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket Nos. UE-240004 & UG-240005, Testimony of Ronald J. Roberts Exh. RJR-1T, at 10:17-11:4 (Feb. 15, 2024)).

11. Witness Roberts goes on to say that "PSE expects to use its existing gas-fired generation fleet to meet reliability and resource adequacy requirements and fill a region-wide deficit of baseload generation resulting from the removal of coal-fired generation." Ex. 51-1 at 19:2-4.

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12. While the transition to meeting future energy and capacity needs using only clean resources, as with any change, presents challenges, Washington's largest utility has been planning this transition for over a decade including by using gas as a bridge resource.

Order Misinterprets Key Cited Studies

13. Two key reports cited as motivating the Order do not support its conclusion.

14. The North American Electric Reliability Corporation (NERC) conducts an annual Winter Reliability Assessment (WRA). The WRA for this winter (2025-2026) is one of two key reports that the Order cites to support the conclusion that the Centralia plant should continue its coal-fired operations through March 2026. While the assessment does identify certain challenges in the "WECC NW" subregion (of which Washington is a part), it also finds that "the results of the probabilistic assessment reveal no EUE (Expected Unserved Energy – a measure of the magnitude of a resource adequacy event) or LOLH (Loss of Load Hours – a measure of the duration of a resource adequacy event) for Winter 2025–2026." Ex. 2 at 15, Table 5 (*2025-2026 Winter Reliability Assessment*, NERC (November 2025)). In other words, this analysis showed zero hours and zero energy going unserved this winter.

15. The scenario from the WRA that the Order apparently relies on to conclude there is an emergency this winter is one that was specifically designed to stress test the electric system, and not one that appears likely to occur this year. In that scenario, wind resources are derated by 91 percent, solar by 18 percent, thermal resources by 9 percent, and hydro resources are derated by 36 percent. Ex. 51-2 at 12 (*In re Resource Adequacy Discussion Pursuant to RCW 19.280.065*, Docket No. UE-210096, Winter Reliability and Electric-Gas Coordination (Nov. 4, 2025)). The hydro derate specifically appears especially unlikely to describe conditions in winter 2025-2026. As shown in the table below, the U.S. Energy Information Administration's (EIA) Short-Term Energy Outlook published on December 9, 2025, forecasts a *better* hydro resource in winter 2025-2026 than winter 2024-2025. Solar and wind are also forecasted to be better this winter than last.

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Table 1 Conventional Hydropower Generation (billion kilowatthours)

	Q1	Q2	Q3	Q4
2024	26.9	30.8	26.6	25.4
2025	30.1	32.0	24.5	**25.9**
2026	**31.1**	37.3	28.8	26.4

See Ex. 51-3 at Table 7d (*Short-Term Energy Outlook*, U.S. Energy Information Administration, (Dec. 9, 2025)).

16. The order cites the WRA estimate of a 9.3 percent increase in winter peak demand as justification for delaying the retirement of the Centralia coal plant. Ex. 1. However, the WRA also estimates a 12.2 percent increase in prospective resources. Ex. 2 at 40 (*2025-2026 Winter Reliability Assessment*, NERC). This suggests that the increased demand and retirements are *more than made up for* by the resources newly available to the region since last winter's WRA. This is reflected in the 3.3 percent *increase* in the region's reserve margin. Ex. 2 at 37, 49. And these estimates include the planned retirement of large coal units like TransAlta Centralia. Ex. 2 at 37, fourth bullet point.

17. The second source the Executive Order cites is a slide deck from Energy + Environmental Economics (E3) which reports its analysis of the state of resource adequacy in the Pacific Northwest. *See* Ex. 3 (Energy + Environmental Economics, *Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results*, Power Point (Sept. 22, 2025)). These slides do point to the retirement of existing coal resources as part of the wider energy transition that contributes to the resource adequacy conversation. However, coal–whether new or extended-life–is absent from any of E3's slides related to solutions. In fact, to the degree the slides do point to solutions in meeting the region's resource adequacy challenges, the alternatives discussed include demand response, battery storage, and natural gas–natural gas being the very resource that this Order would risk delaying coming online. Ex. 3 at 19-22. The E3 slides also state that "Natural gas is the only viable near-term firm

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capacity option, yet siting new gas plants is extremely challenging and may create stranded asset risks." Ex. 3 at 22. The existing plan to build a new natural gas plant at the same location as the retiring coal plant represents an opportunity for the region to benefit from the capacity of gas while avoiding some of these siting challenges.

18. In addition to the E3's analysis pointing to a conclusion not consistent with the Order's directive, in several places the E3 slides point to "federal headwinds" as a challenge to meeting resource adequacy requirements. Ex. 3 at 2, 21, 23. The language in the slides is vague, but suggests that at least some policies at the federal level are hindering, rather than supporting, the region in meeting its resource adequacy priorities.

Coal Plant Operational Characteristics Not As Supportive Of Resource Adequacy As Gas Plant's

19. Washington is in a transition that involves meeting an increasing amount of its electric demand with renewable and non-emitting resources. This is partly driven by the state's Clean Energy Transformation Act (CETA), but even absent CETA's mandates, recent analysis from the U.S. EIA shows that wind and solar are among the cheapest sources of energy even when accounting for the recent sunsetting of federal tax credits. Ex. 51-4 at 9 (*Levelized Costs of New Generation Resources in the Annual Energy Outlook 2025*, U.S. Energy Information Administration, (Jan. 5, 2026)). While these technologies provide cheap and clean energy, their increased penetration results in capacity challenges when their production does not align well with periods of highest demand.

20. As mentioned above, the very E3 slides that the Order cites point to several currently available resources that can help with this issue: demand response, battery storage, and natural gas. Ex. 3. These resources are especially valuable because they are agile enough to ramp up and down as demand and resource availability changes. Conversely, coal resources lack this agility in their operations. Table 2, below, shows this operational difference between

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coal and other resources quantitatively. Clearly, even a gas combined cycle combustion turbine (CCCT) – the less-flexible of the two general types of gas plants – is much more agile than a coal plant. CCCTs start up faster (up to 1 hour vs. up to 10 hours) and can change output to meet load faster (5-10 percent per minute vs. 1-5 percent per minute) than coal plants, making them better suited for the needs of a grid with a higher penetration of variable energy resources. The Northwest Power and Conservation Council says the following in describing gas CCCTs: "This increasingly versatile technology can be used both as a replacement to retiring baseload coal power, and as a complementary firming power source to hydropower and renewable generation." Ex. 51-5 at 1 (*Generating Resource Reference Plants: Natural Gas*, Northwest Power and Conservation Council).

Table 22 Capability of Different Power Generating Technologies to Provide Flexibility

Plant Type	**Start-up time**	**Max Change in 30 secs (%)**	**Max ramp rate (%/min)**
Simple Cycle CT	10-20 min	20-30	20
Combined Cycle CT	30-60 min	10-20	5-10
Coal Plant	1-10 h	5-10	1-5
Nuclear Plant	2h-2d	<5	1-5

Ex. 51-6 at 10 (Phillip Graeter and Seth Schwartz, *Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices*, Nat'l Ass'n of Regul. Utility Comm'rs (Jan. 2020)).

21. Further, since the Order's concern appears to be about winter reliability, it is important also to consider the likelihood of different resource types being out of service unexpectedly. A metric that captures this is the weighted equivalent forced outage rate (WEFOR), and gas plants are considerably better in this metric than coal plants as well. Below is a figure from a recent NERC report that shows coal plants having the worst WEFOR of the four resource types analyzed. While these are averages and not specific to the Centralia

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plant, coal's higher forced outage rate suggests it is more likely than a gas plant to be offline unexpectedly when needed.

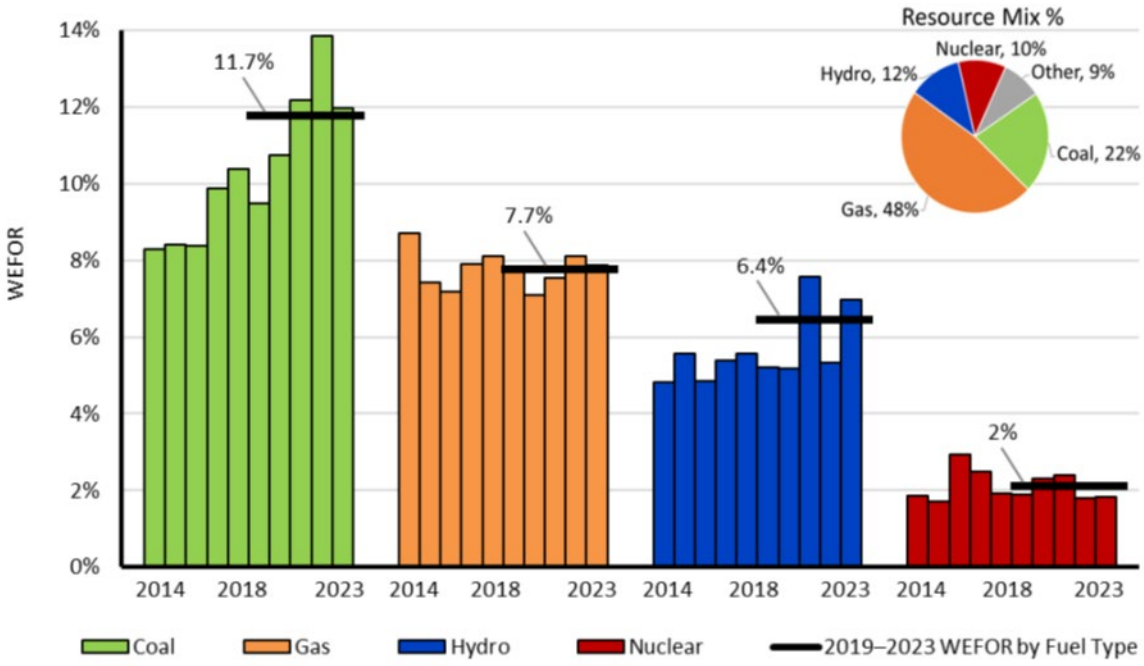


Figure 1 - 10-year Annual Weighted Equivalent Forced Outage Rates by Fuel Type and 2023 Resource Mix by Net Maximum Capacity Ex. 51-7 at 59 Figure 45 (*2024 State of Reliability*, North American Reliability Corporation (June 2024)).

Delaying Conversion May Exacerbate Potential Resource Adequacy Issues

22. The Order points to rising demand for electricity as a reason to extend the life of the existing Centralia coal plant's operations for three months (from December 2025 to March 2026), but for at least two reasons that logic does not hold up.

23. First, a three-month extension of the plant's coal operations will not help cover the long-term load growth the Order describes. Ex. 1. Insofar as new industry, data centers, and other drivers of load growth materialize, the Order points to no evidence that they will go away after the three-month term of the order. In fact, it says the opposite: that "increasing demand and accelerated retirement of generation facilities will continue in the near term and also are likely to continue into subsequent years." Ex. 1. As described above, Washington's

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largest electric utility has been planning to meet its rising load with a lowest reasonable cost mix of resources for over a decade, and–based on its recent agreement with TransAlta–appears to believe conversion of the Centralia plant to gas will support that growth. *See* Ex. 20. TransAlta is an old coal facility that has been slated for retirement for years. Confronting potential future increases in load growth requires new resources that can more adequately meet the capacity and response needs of these potential new demands.

24. Second, conversion will require some amount of down-time for construction to take place at the Centralia plant, converting the facility from burning coal to gas. The timeline outlined in TransAlta's press release indicates that the Centralia plant will cease coal-fired generation at the end of 2025 with a targeted commercial operation date for the converted facility in late-2028. Ex. 20. While PSE indicated in its 2024 general rate case that it has a plan to accommodate this transition on its current schedule, increases in load each year would likely make the transition more difficult the further the transition is pushed back in time.

Conclusion

25. Running this coal resource three months beyond its scheduled retirement date does not support long-term resource adequacy. Washington's utilities have planned for this retirement for over a decade and have identified strategies to meet their customers' needs in its absence. This order may exacerbate the region's resource adequacy issues if it delays the addition of planned resources that better suit the needs of the system.

DATED this 13 day of January, in White Salmon, Washington.

JOEL NIGHTINGALE

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EXHIBIT 51-1

EXH. RJR-1T
DOCKETS UE-240004/UG-240005
2024 PSE GENERAL RATE CASE
WITNESS: RONALD J. ROBERTS

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**Docket UE-240004** **Docket UG-240005**

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF

RONALD J. ROBERTS

ON BEHALF OF PUGET SOUND ENERGY

FEBRUARY 15, 2024

PUGET SOUND ENERGY

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF RONALD J. ROBERTS

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PUGET SOUND ENERGY

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF RONALD J. ROBERTS

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PUGET SOUND ENERGY

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF RONALD J. ROBERTS

I. INTRODUCTION

Q. Please state your name, business address, and position with Puget Sound Energy.

A. My name is Ronald J. Roberts, and my business address is 355 110th Avenue NE, Bellevue, Washington 98004. I am the Senior Vice President of Energy Resources for Puget Sound Energy ("PSE").

Q. Have you prepared an exhibit describing your education, relevant employment experience, and other professional qualifications?

A. Yes, I have. Please see the First Exhibit to the Prefiled Direct Testimony of Ronald J. Roberts, Exh. RJR-2, which describes my education, relevant employment experience, and other professional qualifications.

Q. What are your duties as Senior Vice President of Energy Resources?

A. As Senior Vice President of Energy Resources, I am responsible for all electric generation facilities and natural gas storage facilities owned by PSE, long-term resource planning, utility-scale resource acquisition, and the energy supply merchant function – which is responsible for PSE's wholesale energy supply activities including dispatch of electric generation assets and contracts, merchant

transmission acquisition and optimization, wholesale power and gas trading and commodity hedging programs, resource adequacy, and integrating new generation assets.

Q. Please summarize the purpose of this prefiled direct testimony.

A. The purpose of this testimony is to provide an overview of how PSE is adapting its energy supply portfolio to meet statewide decarbonization requirements under the Clean Energy Transformation Act of 2019 ("CETA") while delivering reliable and cost-effective energy to serve customer demand.

Section II of this prefiled direct testimony presents an update to PSE's resource mix and the challenges PSE faces to continue delivering safe, reliable, and affordable energy in light of the requirements of CETA and changing regional energy market dynamics.

Section III describes actions taken by PSE's energy supply function to address a near-term capacity deficit and reduce reliance on increasingly volatile wholesale energy markets to meet peak demand.

II. PSE IS ADAPTING ITS ENERGY SUPPLY TO ACHIEVE CLEAN ENERGY TARGETS WHILE PROVIDING SAFE, RELIABLE AND AFFORDABLE SERVICE TO MEET CUSTOMER DEMAND

A. Overview

Q. Will PSE need to acquire new electric resources to reliably serve demand and achieve the state's decarbonization goals codified in CETA?

A. Yes. PSE must acquire an unprecedented volume of new electric resources to meet CETA requirements, serve projected growth in customer demand, and continue to provide reliable electric service. As outlined in the Prefiled Direct Testimony of Joshua J. Jacobs, Exh. JJJ-1T, in March 2023 PSE filed its 2023 Electric Progress Report[1] ("2023 Report") with the Commission. In that report, PSE projected that it must acquire resources with combined nameplate capacity of over 6,700 megawatts ("MW") by 2030 and nearly 15,000 MW by 2045. In the shorter-term, PSE is working to meet immediate capacity needs, achieve interim clean energy targets, and replace approximately 750 MW of baseload capacity from Colstrip Units 3 & 4 and the Centralia Coal Transition Power Purchase Agreement which will be removed from PSE's portfolio at the end of 2025.

[1] Puget Sound Energy, *2023 Electric Progress Report* (Mar. 31, 2023), https://www.pse.com/-/media/PDFs/IRP/2023/electric/chapters/00_EPR23_ChapterBook_Final.pdf?modified=20230331180618).

Q. How much clean energy does PSE project it will need to procure in the coming years to stay on course to meet CETA goals?

A. To meet CETA goals, PSE's need will grow from 1.5 million MWh in 2024 to 6.3 million MWh in 2030, as discussed in more detail in the Prefiled Direct Testimony of Joshua J. Jacobs, Exh. JJJ-1T. This represents an unprecedented volume of resources that PSE will need to acquire over the next two decades, more generation resources than PSE has amassed in its 100-plus year history. These staggering numbers underscore the speed and scale of the change facing PSE as it works to meet the goals codified in CETA.

Q. How much capacity is PSE projecting it needs to meet resource adequacy requirements between now and 2030?

A. PSE's capacity needs are seasonal in nature (i.e., peak capacity needs are identified separately for summer and winter seasons). As discussed in the Prefiled Direct Testimony of Joshua J. Jacobs, Exh. JJJ-IT, PSE must also procure electric resources to fill PSE's currently open transmission capacity.[2]

In the near and intermediate-terms,[3] PSE projects that it will need to acquire:

- 174 MW in winter peak capacity by 2024, plus 1,069 MW open transmission capacity for a total of 1,243 MW,
- 465 MW in winter peak capacity by 2025, plus 855 MW open transmission capacity for a total of 1,320 MW,

[2] *See also* 2023 Report, *supra* note 1.

[3] PSE generally defines "near-term" as a period less than 12 months and "intermediate-term" as less than five years when referring to electricity transactions.

- 1,336 MW in winter peak capacity by 2026, plus 642 MW open transmission capacity for a total of 1,978 MW,
- 1,848 MW in winter peak capacity by 2027, plus 428 MW open transmission capacity for a total of 2,275 MW,
- 2,096 MW in winter peak capacity by 2028, plus 214 MW open transmission capacity for a total of 2,310 MW, and
- 2,340 MW in winter peak capacity by 2029.[4]

PSE also projects that it will need to acquire:

- 167 MW in summer peak capacity by 2024, plus 1,048 MW of open transmission capacity for a total of 1,216 MW,
- 534 MW in summer peak capacity by 2025, plus 839 MW of open transmission capacity for a total of 1,372 MW,
- 1,415 MW in summer peak capacity by 2026, plus 629 MW of open transmission capacity for a total of 2,044 MW,
- 1,906 MW in summer peak capacity by 2027, plus 419 MW of open transmission capacity for a total of 2,325 MW,
- 2,177 MW in summer peak capacity by 2028, plus 210 MW of open transmission capacity for a total of 2,387 MW, and
- 2,770 MW in summer peak capacity by 2029.[5]

The electric resource supply needs discussed above directly inform PSE's Energy Supply function on the type and volume of electric resources it pursues for acquisition in the near- and intermediate-term periods.

[4] Prefiled Direct Testimony of Joshua J. Jacobs, Exh. JJJ-IT.
[5] 2023 Report, *supra* note 1.

Q. What is PSE doing to meet these needs?

A. PSE is pursuing a resource acquisition strategy that focuses on long-term acquisitions and relies upon near- and intermediate-term resource acquisitions to bridge capacity and renewable needs. The near- and intermediate-term resource acquisitions are complementary to the long-term acquisition process and meet capacity and renewable needs during the period before the long-term resources achieve commercial operations.

Please see the Prefiled Direct Testimony of Craig J. Pospisil, Exh. CJP-1T, for a discussion of PSE's bridging and long-term electric resource acquisition strategy. Please see the Prefiled Direct Testimony of Joshua J. Jacobs, Exh. JJJ-1T, for a discussion of why these near-, intermediate-, and long-term resource acquisitions are necessary for PSE to continue providing safe and reliable electric service.

Q. Please elaborate on the steps PSE is taking to meet long-term resource acquisition needs.

A. PSE is pursuing and evaluating long-term resource acquisition opportunities to meet projected new resource needs. These include power purchase agreements ("PPAs"), new PSE-owned resources, and demand side solutions. Please see the Prefiled Direct Testimony of Colin P. Crowley, Exh. CPC-1HCT, for a discussion of certain PSE long-term resource acquisitions, such as the Vantage Wind PPA, the Beaver Creek Wind Project, and other proposed projects that may commence operation during the multiyear rate plan period. Additionally, please see the

Prefiled Direct Testimony of Zacarias C. Yanez, Exh. ZCY-1CT, for a discussion of a new long-term power sales agreement that secures clean, hydroelectric generation from Public Utility District No. 1 of Chelan County, Washington ("Chelan PUD").

The Prefiled Direct Testimony of James P. Hogan, Exh. JPH-1CT, discusses construction and execution of major capital projects scheduled to commence operations during the multiyear rate plan period that will support PSE's long-term need.

Q. Please elaborate on steps PSE is taking to meet near-term and intermediate-term electric resource needs.

A. PSE's Energy Supply Merchant function generally fulfills PSE's resource acquisition activities to fill near-term and intermediate-term electric resource needs. The Prefiled Direct Testimony of Philip A. Haines, Exh. PAH-1CT, addresses near-term and intermediate-term electric supply resources and transmission contracts that will be effective during some or all of the multiyear rate plan period. The Prefiled Direct Testimony of Steve J. St. Clair, Exh. SJS-1CT, addresses an intermediate-term contract intended to bridge capacity need ahead of long-term acquisitions.

Q. Does PSE's resource acquisition strategy include demand response and distributed energy resources?

A. Yes. The Prefiled Direct Testimony of Gilbert Archuleta, Exh. GA-1T, discusses demand response contracts that PSE has entered to address resource adequacy needs via demand side programs.

The Prefiled Direct Testimony of Aaron A. August, Exh. AAA-1T, provides an update on PSE's pursuit of thirty-four shortlisted distributed energy resources resulting from PSE's 2022 Distributed Solar and Storage Request for Proposals. The Prefiled Direct Testimony of Brennan D. Mueller, Exh BDM-1T, addresses PSE's proposal for cost recovery for distributed energy resources that achieve commercial operations during some or all of the multiyear rate plan period.

Q. What actions is PSE's Energy Supply function taking to decarbonize generation resources and maintain reliable electric service?

A. PSE's Energy Supply function participates in the effort to decarbonize operations by managing the transition away from coal-fired resources, procuring renewable and nonemitting electric generation resources and reliable capacity through near- and intermediate-term PPAs and market transactions, and coordinating with PSE's long-term resource acquisition function to integrate new electric generation resources into PSE's electric supply operations.

Q. How are decarbonization efforts affecting electricity generation and reliability?

A. PSE faces both market and resource adequacy challenges as it works to expand the acquisition and implementation of new resources to meet CETA goals. As discussed in the Prefiled Direct Testimony of Joshua J. Jacobs, Exh. JJJ-1T, these goals include serving at least 60 percent of PSE's retail electric load with renewable and nonemitting electric generation resources by 2025.[6] For the first compliance period under CETA (calendar years 2030-2033), PSE must plan to serve at least 80 percent of PSE's retail electric load with renewable and nonemitting electric generation resources, and PSE must plan to serve all retail electric load with renewable and nonemitting electric generation resources by calendar year 2045.

Similar efforts across the region to replace baseload fuel supplies with renewable and nonemitting electric generation resources have contributed to an increase in regional electric market price volatility, capacity shortfalls, and scarcity of firm transmission rights. These developments add to uncertainty regarding implementation costs associated with achievement of the state's decarbonization goals.

[6] Prefiled Direct Testimony of Joshua J. Jacobs, Exh. JJJ-1T.

Q. How is PSE continuing to provide safe and reliable electric service to meet customer demand?

A. PSE is taking several steps to continue to provide safe, reliable, and affordable service for retail customers, but challenges remain. As presented in the Prefiled Direct Testimony of Joshua J. Jacobs, Exh. JJJ-1T, PSE's projected resource need provided in the 2023 Report already includes an increase in projected need relative to the 2021 Integrated Resource Plan ("2021 IRP") and the 2021 Clean Energy Implementation Plan (the "2021 CEIP"). Factors that influence this increased need include implementation of CETA requirements, an approximately seven percent increase in forecasted demand relative to earlier forecasts,[7] a regional capacity deficit, variability in renewable energy production, and longer lead-times associated with the development and procurement of new resources. Compounding PSE's long-term resource planning challenges, a shift in fundamentals of regional electricity market supply and demand limits PSE's ability to secure reliable supply via wholesale market purchases during periods of high demand.

PSE's Energy Supply function is proactively addressing these market and resource adequacy challenges by:

(i) reducing reliance on wholesale spot market transactions by securing near- and intermediate-term PPAs,

[7] *See* Puget Sound Energy, *2023 Biennial Clean Energy Implementation Plan Update* (Nov. 20, 2023), at 2.10-2.11, https://www.pse.com/-/media/PDFs/CEIP/2023/001_BU23_Chapters_Final.pdf.

(ii) participating in regional resource adequacy programs,

(iii) exploring new day-ahead market options, and

(iv) maintaining availability of PSE's gas-fired generation fleet to mitigate projected capacity shortfalls.

The Prefiled Direct Testimony of Philip A. Haines, Exh. PAH-1CT, discusses in more detail how PSE's Energy Supply function is addressing near- and intermediate-term energy and resource adequacy needs and managing its evolving resource portfolio. And the Prefiled Direct Testimony of Mark A. Carlson, Exh. MAC-1CT, discusses operation and maintenance of PSE's gas-fired generation fleet in more detail.

B. PSE's Resource Mix and Path to a Decarbonized Portfolio

Q. What is PSE's existing supply-side resource mix and portfolio?

A. PSE owns supply-side resources that include 1,742 MW of renewable resources, including 773 MW of wind generation, 244 MW of hydroelectric power, 0.5 MW of solar generation, and 2 MW of battery storage power.[8] Thermal resources owned by PSE total 2,275 MW, which includes 1,663 MW of baseload thermal resources and 612 MW of combustion turbine peaking resources.[9] PSE will lose 370 MW of company-owned baseload thermal capacity at the end of 2025 when Colstrip Units 3 & 4 are removed from the resource portfolio.

[8] *See* 2023 Report, *supra* note 1, at Appx. C (Existing Resource Inventory), at Table C.4: Total Renewable Resources.

[9] *See id*. at Table C.9: Total Thermal Resources.

PSE's supply-side resources also include long-term PPAs with independent power producers and other utilities. Approximately 1,880 MW of electric capacity is supplied to PSE pursuant to long-term PPAs. These include over 1,375 MW from renewable and nonemitting generation resources and 380 MW from the Centralia Coal Transition PPA. The Centralia Coal Transition PPA expires at the end of 2025.

Q. What challenges does PSE face as it works to meet both its clean energy and resource adequacy requirements?

A. PSE is rapidly transforming its business model and developing the expertise necessary to support the development and acquisition of renewable and non-emitting electric generation resources and carbon-free, dispatchable resources. Many electric generation technologies that could meet both CETA and resource adequacy requirements are not yet mature and will likely not be commercially available for some time. In addition, there are limited options in terms of existing dispatchable resources that PSE can add to its near-term portfolio, which adds to the complexity of an accelerated clean energy transformation.

Q. What new resources is PSE adding during the proposed multiyear rate plan period that would contribute to CETA and resource adequacy requirements?

A. Although meeting PSE's CETA and resource adequacy requirements will be a challenge, PSE is moving forward with new utility-scale assets scheduled to become operational during the multiyear rate plan period. The Prefiled Direct Testimony of Colin P. Crowley, Exh. CPC-1HCT, discusses PSE's acquisition of

the Beaver Creek Wind project located in Stillwater County, Montana, with an expected nameplate capacity of 248 MW, projected to be in service August 2025. He also discusses the Vantage Wind Power Purchase Agreement, which is a 15-year PPA beginning in October 2025. The Prefiled Direct Testimony of Philip A. Haines, Exh. PAH-1CT, discusses several new power supply resources as well as new and renewed transmission contracts. The Prefiled Direct Testimony of Zacarias C. Yanez, Exh. ZCY-1CT, discusses PSE's renewal and extension of the power sales agreement with Chelan PUD, which provides PSE with a 25 percent share of the output of the Rocky Reach and the Rock Island Hydroelectric Projects. And, as previously discussed, the Prefiled Direct Testimony of Gilbert Archuleta, GA-IT, presents several demand response PPAs.

C. Energy Supply Challenges

1. Policy Drivers

Q. How are decarbonization policies adding complexity to the wholesale electricity sector?

A. Decarbonization efforts are transforming the regional resource supply stack, adding complexity and uncertainty in the wholesale electricity sector. Additions of variable renewable resources combined with retirements of traditional coal and gas-fired resources are contributing to increased volatility in market electricity prices and generally higher net power supply costs, at least in the near term. Limited availability of and competition for CETA-compliant renewable and nonemitting electric generation resources drive up the cost for these resources.

The cost to acquire flexible, dispatchable renewable resources, such as hydroelectric products in the Pacific Northwest, have increased markedly over the past few years.

The "Cap-and-Invest" program established under the state's Climate Commitment Act ("CCA") adds additional challenges for power supply operations in the region and likely increases the net cost of power supply for PSE's retail electric customers. Details regarding Cap-and-Invest program rules are still evolving, but PSE understands that the program will only provide no-cost allowances for emissions from electric generation resources used to serve PSE's retail electric demand. This means that PSE will have to purchase allowances for any emissions associated with wholesale market sales and/or reduce the volume of power sold into the wholesale markets. Because wholesale sales revenue is a reduction to the net power supply costs paid by retail customers, any loss of wholesale sales revenue increases these net costs. Other potential CCA risks include uncertainty and volatility in the price of compliance instruments (allowances), complex reporting requirements, and how the rules will be reflected in the operation of organized markets like the Western Energy Imbalance Market or potential day-ahead market structures.

Q. How is PSE's Energy Supply function addressing the CCA Cap-and-Invest program in its power supply operations?

A. Despite uncertainty regarding the Department of Ecology's implementation of the CCA Cap-and-Invest program, PSE has adjusted its operations in order to

minimize the likely impact of Washington's CCA on retail electric rates. Please see the Prefiled Direct Testimony of Brennan D. Mueller, Exh. BDM-1T, for a discussion of how PSE's Energy Supply function is addressing the CCA Cap-and-Invest program in its power supply operations and the impacts to forecasted power supply costs in this proceeding.

2. Market Challenges

Q. What are the market challenges currently facing PSE?

A. A region-wide transition toward carbon-free electric energy supply has accelerated the deployment of intermittent resources, namely wind and solar resources. The rapid expansion of intermittent resources coupled with widespread divestment and decommissioning of traditional baseload resources, like coal, in conjunction with more frequent, climate change-related extreme weather events, have resulted in tightened and more volatile energy supplies and a sharp rise in electric market price volatility.

For many years, the western energy market had enjoyed a capacity surplus, and reliance on short-term market purchases to meet peak demand proved a cost-effective way for PSE to plan and operate. With the rapid expansion of intermittent renewable resources and decrease in dispatchable, baseload generation, however, the western energy market faces unprecedented resource scarcity and significant capacity shortfalls. As discussed in PSE's 2023 Electric Progress Report, recent studies about resource adequacy in the Northwest

conducted by respected industry-based organizations are consistent and aligned in finding that near-term risks to grid reliability are growing as loads drastically increase and baseload, dispatchable resources retire.[10] The Western Electricity Coordinating Council ("WECC") put it most directly, stating: "As early as 2025, all subregions (of the WECC) will be unable to maintain 99.98 percent reliability because they will not be able to reduce the hours at risk for loss of load enough, even if they build all planned resource additions and import power."[11] And the most recent study by the Pacific Northwest Utilities Conference Committee ("PNUCC") finds that if no new resources are built beyond those already under construction as of publication of the study, there is a 46 percent loss-of-load probability by 2027, as compared to the 5 percent loss-of-load probability that PNUCC sets as the threshold for power supply adequacy. In other words, this change in regional market supply and demand fundamentals both increases energy prices and threatens reliability for PSE and other regional load-serving entities seeking to meet electric load demand.

[10] 2023 Report, supra note 1, at 7.16-7.18; *see also* North American Electric Reliability Corporation ("NERC"), *2021 Long-term Reliability Assessment*, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf; Western Electricity Coordinating Council, *2021 Western Assessment of Resource Adequacy*, https://www.wecc.org/Administrative/WARA%202021.pdf; Pacific Northwest Utilities Conference Committee ("PNUCC"), *Pacific Northwest Power Supply Adequacy Assessment for 2027*, https://www.nwcouncil.org/fs/18158/2023-1_adequacyassessment.pdf.

[11] WECC, *2021 Western Assessment of Resource Adequacy*, *supra* note 10, at 4.

Q. Have any recent events resulted from the changes to regional supply and demand fundamentals described above?

A. Yes. In January 2024, the Pacific Northwest experienced sustained record cold weather that triggered extreme spot market electricity prices and threatened electric system reliability, with PSE and three other load serving entities declaring Energy Emergency Alerts ("EEA"). The most significant impact to PSE occurred between January 11 and January 16, with peak electric demand reaching nearly 5,000 MW and exceeding the previous historical peak.

Limited energy supply relative to demands drove prices up to and even above the $1,000 price cap for much of the seven day period. PSE was able to secure sufficient energy supply to meet January's record customer demand, but at a high cost. This latest severe weather event emphasizes the necessity of acquiring new capacity and regional coordination programs like the Western Resource Adequacy Program ("WRAP") as well as the risk of relying on the wholesale spot market during periods of peak demand.

3. Capacity and Resource Adequacy Shortfalls

Q. Is PSE currently facing a capacity and resource adequacy shortfall?

A. Yes. After 2025, PSE's resource portfolio used to provide electricity to retail electricity customers will no longer include nearly 750 MW of coal-fired baseload generation from Colstrip Units 3 & 4 and the Centralia Coal Transition PPA. The

loss of these baseload resources compounds existing market capacity and resource adequacy challenges faced by the region in general and PSE in particular.

Q. Is the projected capacity and resource adequacy shortfall unique to PSE?

A. No. As discussed above, in PSE's 2023 Electric Progress Report,[12] and in recent regional planning assessments by WECC, NERC, and PNUCC,[13] PSE's capacity needs and projected capacity shortfalls reflect a broader, regional trend stemming from a shift to a higher concentration of intermittent resources in the energy supply mix and simultaneous phasing out of traditional baseload generation resources, which directly and indirectly contributes to market price volatility.

Q. Is PSE investigating utility-scale carbon-free dispatchable, baseload generation technologies?

A. Yes. PSE is investigating utility-scale carbon-free dispatchable, baseload generation technologies, such as electric generation fueled by renewable hydrogen. This class of resource, however, is not yet commercially available. Until carbon-free technologies can replace traditional baseload generation resources, PSE is supplementing a near- and intermediate-term regional baseload generation deficit with its existing gas-fired generation fleet. Please see the Prefiled Direct Testimony of John Mannetti, Exh. JM-1CT, for an overview of PSE's investigation of emerging carbon-free technologies.

[12] 2023 Report, *supra* note 1, at 7.16-7.18.

[13] NERC, *2021 Long-term Reliability Assessment*, *supra* note 10; WECC, *2021 Western Assessment of Resource Adequacy*, *supra* note 10; PNUCC, *2022 Northwest Regional Forecast*, *supra* note 10.

Q. How does PSE plan to address these near- and intermediate-term needs?

A. PSE expects to use its existing gas-fired generation fleet to meet reliability and resource adequacy requirements and to fill a region-wide deficit of baseload generation resulting from the removal of coal-fired generation. Without an adequate supply of dispatchable generation, PSE and load serving entities throughout the region will not be able to serve customer demand reliably. Please see the Prefiled Direct Testimony of Brennan D. Mueller, Exh BDM-1T, for a discussion of the forecast of increased near- and intermediate-term use of PSE's owned gas-fired generation resources.

This projected near-term reliance on existing dispatchable, baseload gas-fired resources will subsequently increase operations and maintenance ("O&M") costs for these resources. Please see the Prefiled Direct Testimony of Mark A. Carlson, Exh. MAC-1CT, for a discussion of O&M costs associated with PSE-owned gas-fired generation.

4. Need for Timely Recovery of Costs

Q. How do capacity constraints and CETA and CCA compliance requirements affect PSE's power supply costs?

A. The complexities of changing market fundamentals involve myriad resource need issues, such as climate change related extreme weather events, reduced baseload capacity, transmission constraints, increased deployment of intermittent renewable resources, and uncertainty of costs related to CETA and CCA

compliance. All of these factors contribute to broad electricity market challenges, diminished reliability in multi-year supply cost forecasts, and a resulting increase in power cost variability for PSE.

Q. Why do market volatility and policy implementation challenges validate the need for a continued annual power cost update?

A. PSE's need to acquire significant new resources and clean energy, coupled with power cost under-recoveries, necessitates timely recovery of investment and O&M costs. PSE is working to realize the state's decarbonization goals codified in CETA. This work represents an unprecedented clean energy transformation and is a large, accelerated, and costly undertaking. Continuation of the annual power cost update approved by the Commission in the settlement of PSE's 2022 multiyear rate plan[14] is necessary for PSE to continue its work to meet the state's decarbonization goals. Aligning customer rates with the timely recovery of power costs is essential for PSE to meet the decarbonization goals in CETA and continue to provide safe and reliable energy to meet customer demand. The Prefiled Direct Testimony of Brennan D. Mueller, Exh. BDM-1T, discusses a proposal for routine annual updates to the power cost forecast included in customer rates. The proposal seeks to ensure that customer rates reflect the most current estimate of the costs and benefits of PSE's actual resource supply portfolio, given the rapid

[14] *See WUTC v. Puget Sound Energy*, Docket UE-220066 et al., Order 24/10, Appx. A at ¶¶ 28-30 (Dec. 22, 2022).

evolution of that portfolio combined with increasingly volatile wholesale market conditions.

Please see the Prefiled Direct Testimony of Daniel A. Doyle, Exh. DAD-1CT, for an overview of PSE's financial fitness and proposals to improve PSE's position and cash-flow necessary to supply customers with clean, reliable energy.

III. PSE'S EFFORTS TO REDUCE RELIANCE ON SHORT-TERM MARKET TRANSACTIONS

Q. How is PSE's Energy Supply function reducing its reliance on short-term market transactions through increased market coordination?

A. PSE is shifting away from its reliance on short-term bilateral market purchases, in-part, through participation in regional coordinating opportunities. PSE aims to reduce price volatility risk and address capacity and transmission constraints by exploring participation in a day-ahead market and the WRAP.

Q. Which day-ahead markets is PSE considering?

A. Currently, PSE is considering both the California ISO Extended-Day Ahead Market (the "CAISO EDAM") and the Southwest Power Pool ("SPP") Markets+ program. The CAISO EDAM program would extend participation in the day-ahead market to participants in the CAISO Energy Imbalance Market in a framework that does not require full integration into the California ISO balancing

area.[15] The SPP Markets+ program would offer services to centralize day-ahead and real-time unit commitment and dispatch and seek to integrate renewable generation reliably.[16]

The CAISO EDAM and SPP Markets+ programs are currently under development, and PSE has not yet committed to participation in either. Indeed, PSE does not anticipate that it would begin participation in either day-ahead market program before or during the proposed multiyear rate plan period. Much work remains to be done in the development of these day-ahead market programs, and PSE will continue investigating these developing programs.

Q. Has PSE joined the WRAP?

A. Yes. PSE has joined the WRAP, which allows the Northwest Power Pool ("NWPP") d/b/a Western Power Pool ("WPP") to implement a regional resource adequacy planning and compliance program in the Western Interconnection. The intent of the WRAP is to ensure that participants, such as PSE, have sufficient capacity resources available to serve their loads and that excess capacity is held back for potential use by participants who do not have sufficient resources to serve their loads in real-time.[17] The WRAP should help address the resource adequacy trends and challenges faced in the west by allowing for a coordinated, regional framework to enhance reliability tailored to the western electricity

[15] *See generally* California ISO, *Initiative: Extended Day-Ahead Market*, https://stakeholdercenter.caiso.com/StakeholderInitiatives/Extended-day-ahead-market.
[16] *See generally* Southwest Power Pool, Markets+, https://www.spp.org/western-services/marketsplus/.
[17] *See generally Northwest Power Pool*, 182 FERC ¶ 61,063 (Feb. 10, 2023).

markets. In approving the WRAP Tariff, the Federal Energy Regulatory Commission found that

> the WRAP has the potential to enhance resource adequacy planning, provide for the benchmarking of resource adequacy standards, and more effectively encourage the use of western regional resource diversity compared to the status quo.[18]

Q. How does increased market coordination strengthen PSE's capacity and resource adequacy position?

A. Regional coordination, required for both a day-ahead market and the WRAP, would offer a cost-effective method for PSE to acquire resources necessary to meet the state's decarbonization goals in CETA and PSE's preexisting capacity needs. Please see the Prefiled Direct Testimony of Philip A. Haines, Exh. PAH-1CT, for a discussion of PSE's decision to join the WRAP and an update on PSE's investigation of day-ahead market programs.

IV. CONCLUSION

Q. Does that conclude your prefiled direct testimony?

A. Yes, it does.

[18] *Id*. at ¶ 28.

EXHIBIT 51-2



Winter Reliability and Electric-Gas Coordination

Matthew Zapotocky
Senior Reliability Assessments Engineer

Electric Reliability & Security for the West

November 4, 2025



- Western Interconnection
- Reliability Concerns
- Extreme Cold
- Extreme Cold Weather Study
- Gas-Electric Coordination in the West
- Winter Reliability Assessment

Western Interconnection at a Glance



158,332 TOTAL
Miles of transmission lines

90+ MILLION
People living in the Western Interconnection

168.2 GW
Interconnection peak demand

448	329	52	37	4
Registered Entities	Generation Owners	Transmission Operators	Balancing Authorities	Reliability Coordinators

Reliability Concerns

Top Reliability Concerns in the West		
Season	**Reliability Concern**	**% of WECC Members**
Summer	Extreme Heat Events	**60%**
Winter	Extreme Cold Events	**58%**
Summer	Wildfires	**49%**
Year-Round*	Solar Variability	**35%**
Year-Round	Wind Variability	**33%**
Year-Round	Hydro Variability	**27%**
Year-Round	Aging Thermal Fleet	**23%**
Winter*	Outage Coordination	**23%**
Summer	Delays in Resource Completion	**23%**
Summer	BTM/DER Variability	**23%**

*Solar variability followed by outage coordination are the most prevalent concerns during the shoulder seasons.

"Brace yourself, winter is coming...."

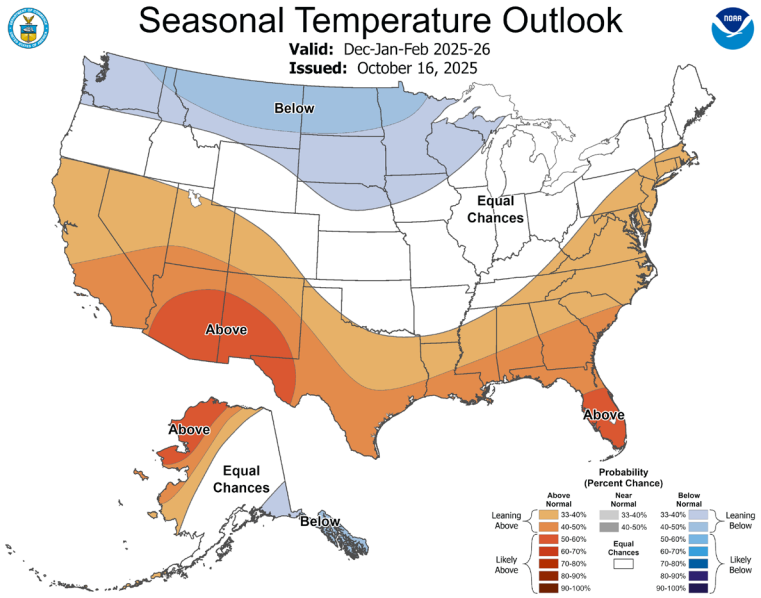
Extreme Cold

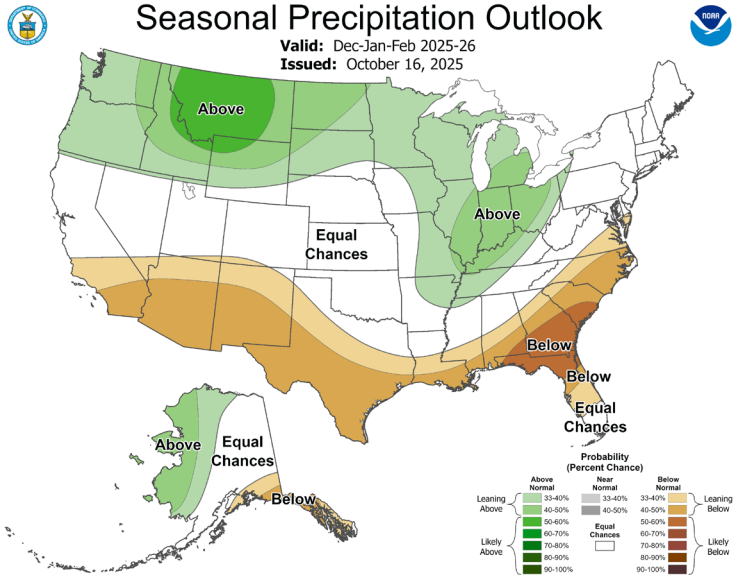
Primarily cited as a concern in the Northwest and Canada

Winter Storms Gerri/Heather:

- Low temperatures—elevated demand
- Turbine blade icing—wind derates
- Minimal solar availability
- Gas delivery constraints
- Unplanned transmission outages
- Unplanned generator outages
- Bilateral market exhaustion

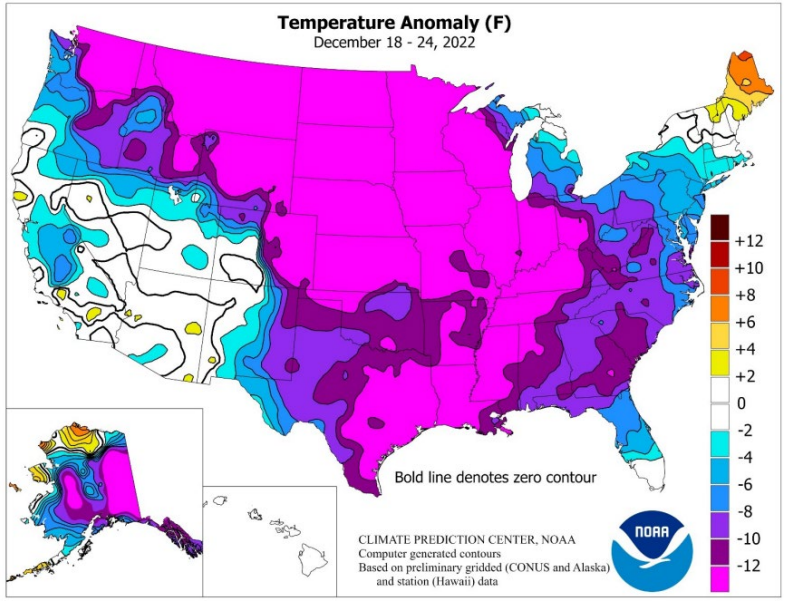
- **5 Energy Emergency Alerts during the same event across different BAs (63 hours of EEAs over four days)**

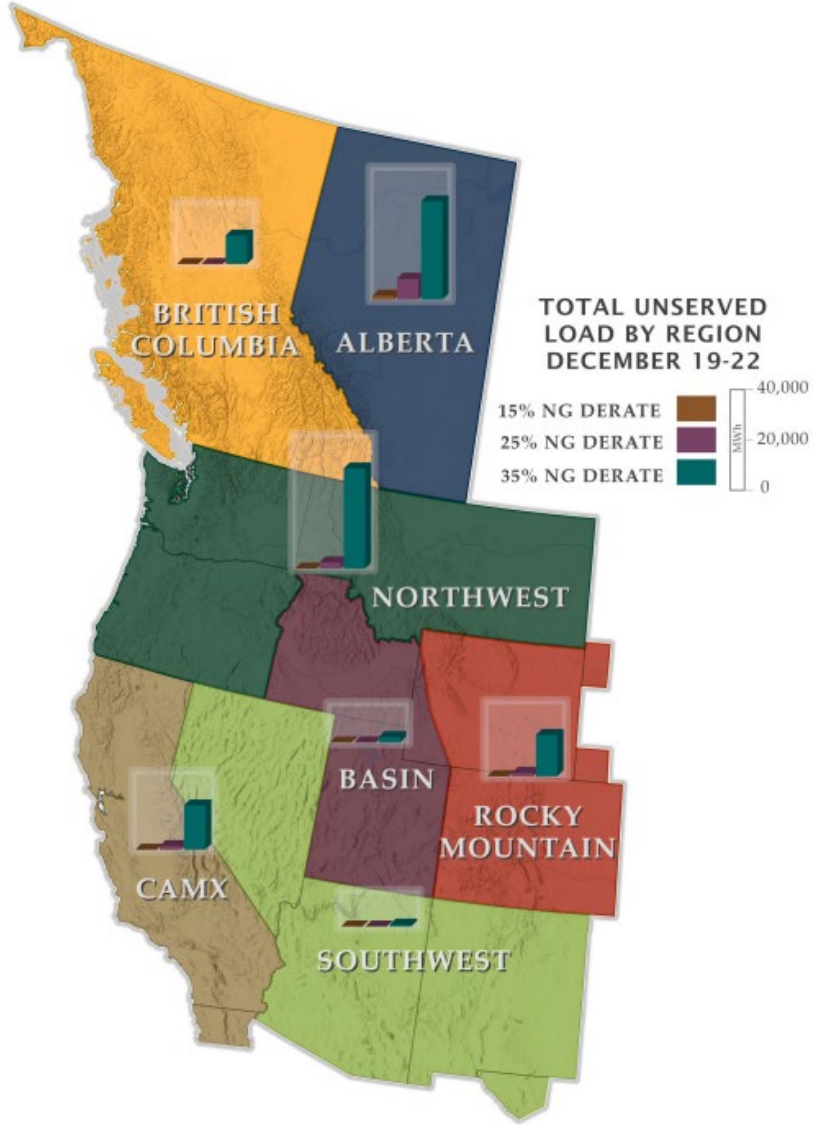




2032 Extreme Cold Weather Study

- Winter Storm Elliott load shape and incremental demand
- Doubled forced outage rates
- Historic lows for wind and solar output
- Reduced natural gas availability by 15%, 25%, & 35%





Link to extreme cold weather studies: StS | Western Electricity Coordinating Council

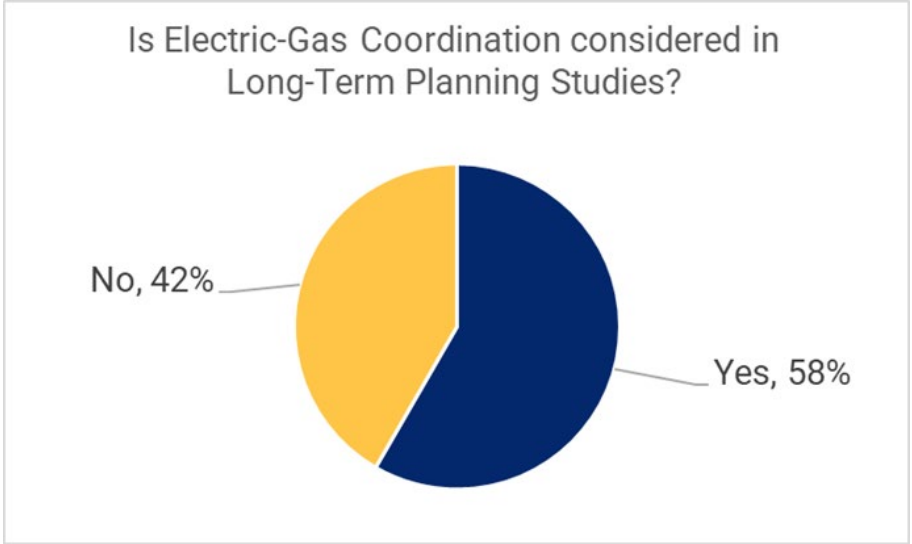
Gas-Electric Coordination

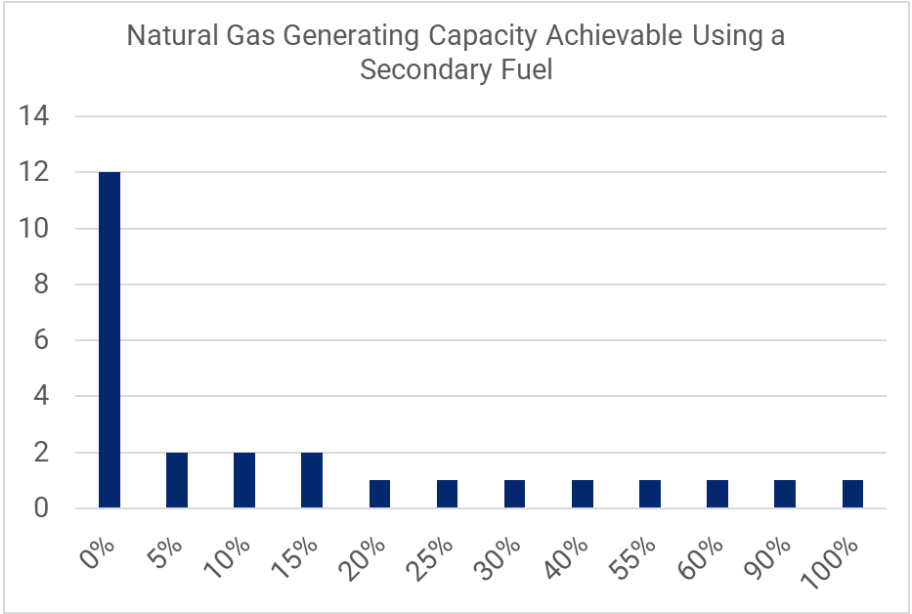
Long-Term Planning

- Pipeline constraints
- Contract terms
- LDC and generation analyzed in tandem to determine contract needs

Operations

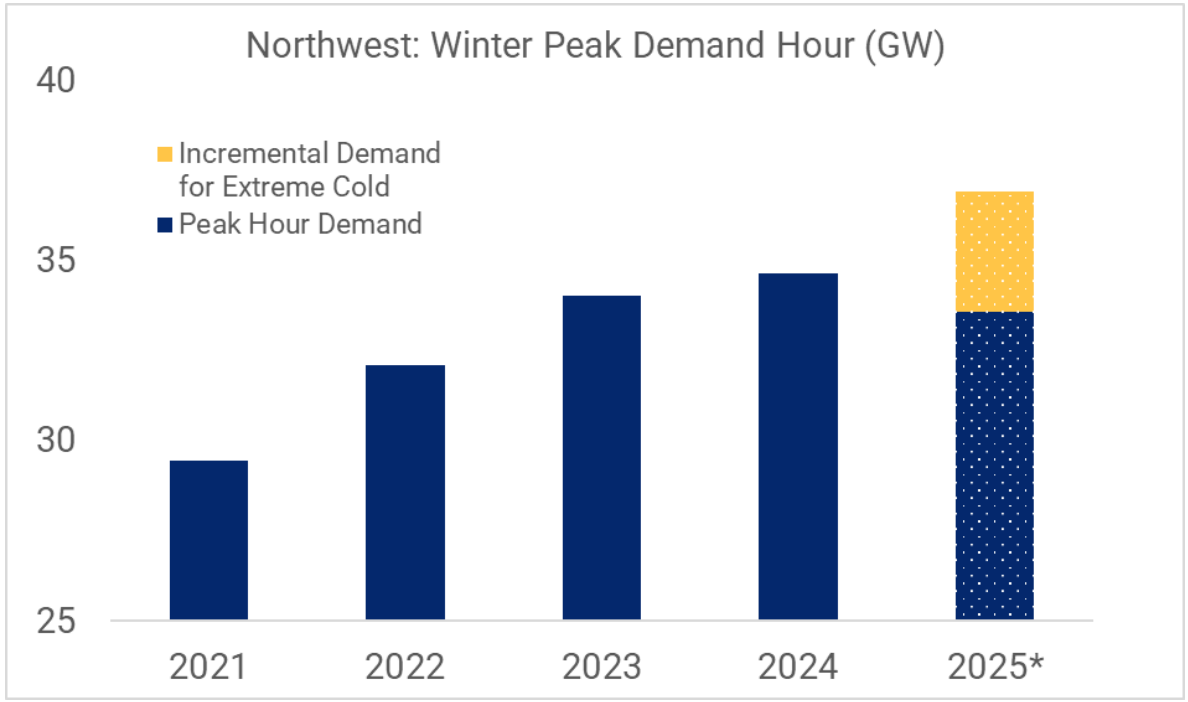
- Mutual assistance agreements
- Daily communication between gas suppliers and system operators
- Emergency scenario simulations
- Secondary fuel (e.g. fuel oil)
- Working groups

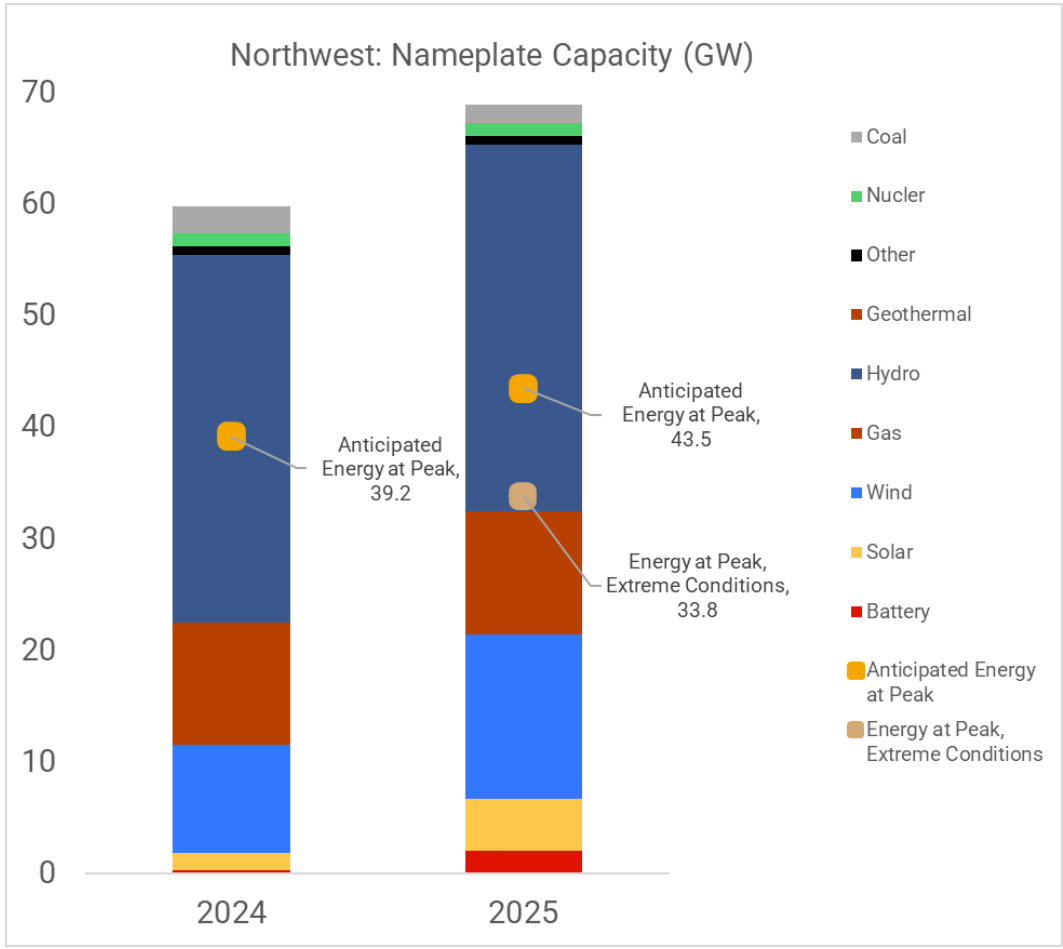




Winter Reliability Assessment (Preliminary)

- Reports on areas with reliability concern this winter (Dec 2025 –Feb 2026)
- Existing + Tier 1 Resources (under construction, operable in WRA timeframe)
- Focused on peak demand hour
- Nameplate capacity ≠ energy at peak





WECC

WWW.WECC.ORG | (801) 582-0353

155 N 400 W, Salt Lake City, UT 84103, USA

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC's Winter Reliability Assessment

Preliminary Findings for Winter Readiness

Gerad M. Freeman, Ph.D., Senior Engineer, Reliability Assessment

Washington Utilities and Transportation Commission Winter Resource Adequacy Meeting
November 4, 2025

2025-2026 Winter Reliability Assessment

- NERC and the six Regional Entities began collecting data and inputs for the 2025-2026 Winter Reliability Assessment in July
- Capacity and energy risk assessment for 23 North American BPS areas based on both deterministic scenarios and probabilistic evaluations of all risk periods
- Added focus this winter on rapid increases in demand and fuel supply concerns

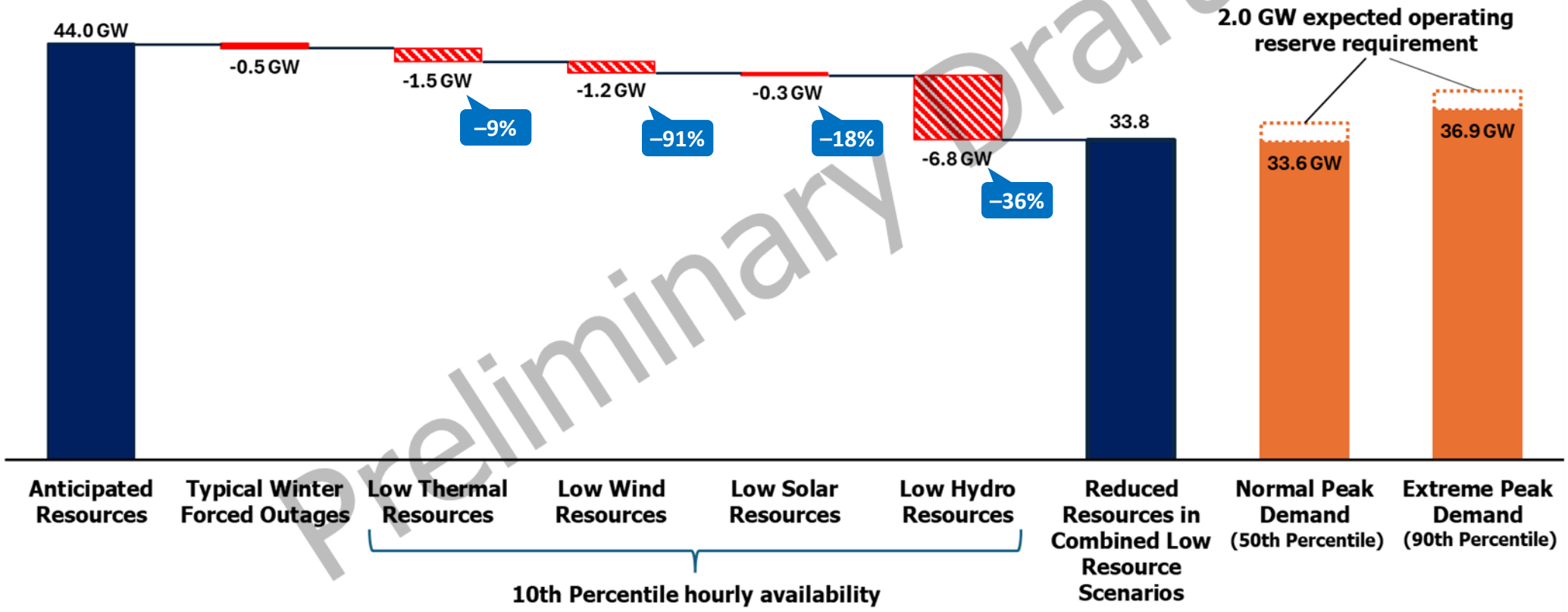
Seasonal Risk Assessment Criteria		
Risk Level	Deterministic	Probabilistic
High Indication of insufficient operating reserves or energy shortfalls in normal peak conditions	• Planning reserve margin does not meet reference margin level, **or** • Risk period analysis indicates resources will not be able to sustain operating reserve requirements under **normal peak-day demand and typical resource outage scenarios**	• Seasonal Normalized Expected Unserved Energy **is greater than 0.002%** (20 ppm), **or** • Seasonal Loss of Load Hours **is greater than 2.4 hours**

Elevated
Indication of insufficient operating reserves or energy shortfalls in above-normal conditions
	• Risk period analysis indicates resources will not be able to sustain operating reserves under:
	  • **above-normal peak-day demand and normal resource outage levels, or**
	  • **normal peak-day demand and above-normal resource outage levels**
		• Seasonal Normalized Expected Unserved Energy is **greater than zero and less than 0.002%** (20 ppm), **or**
		• Seasonal Loss of Load Hours **is greater than 0.1 hours and less than 2.4 hours**

Normal Indication of sufficient operating reserves and energy shortfalls not expected	• Risk period analysis indicates resources will be sufficient to meet operating reserves under normal **and** above-normal peak-day demand and resource outage scenarios	• Seasonal Normalized Expected Unserved Energy **is negligible, and** • Seasonal Loss of Load Hours is **less than 0.1 hours**

Deterministic Risk Period Analysis for WECC-Northwest

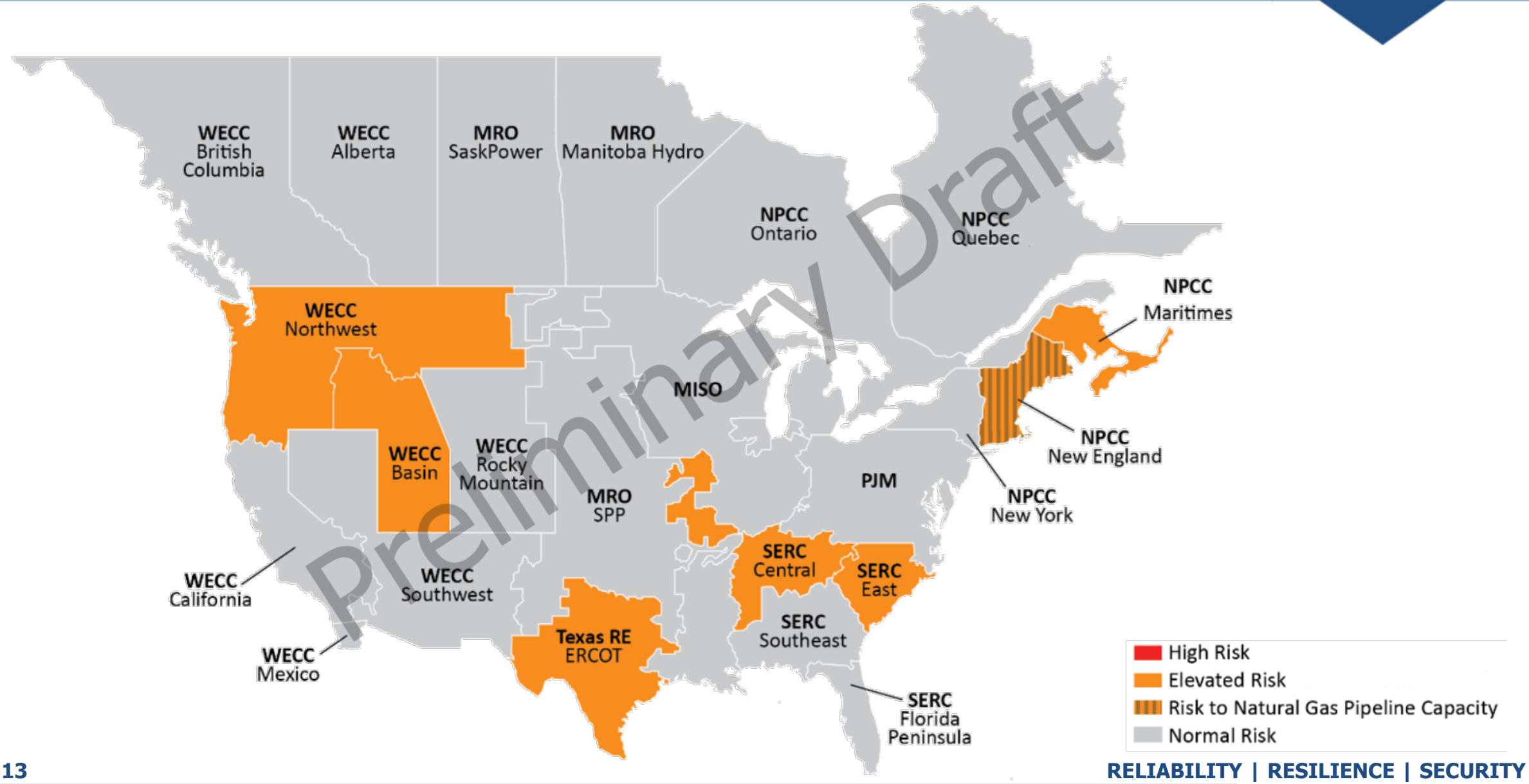
Winter reliability assessment examines each NERC Assessment Area's ability to meet operating reserve requirements under stressed conditions



Preliminary Draft

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Multiple regions face an elevated risk of operating reserve or energy shortfalls during the upcoming winter season



Preliminary Draft

<Limited-Disclosure>

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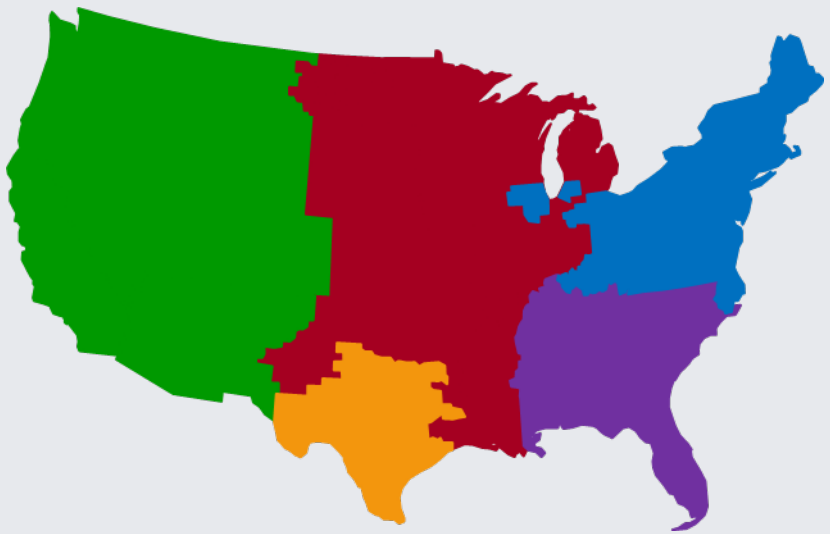
2025-2026 NERC Winter Reliability Assessment: Key Gas-Electric Themes

Continent-Wide Gas-Electric Winter Risk Themes

- Increased variable energy resources have led to higher dependence on gas-fired resources, especially in the winter
- Many areas express a concern about extended cold-snaps and the effect they would have on fuel availability for the gas-fired generator fleet
- Potential risks related to natural gas transportation capacity in areas with high pipeline utilization, competition for delivered gas/firm supply, and ratable flow requirements that could affect combustion turbine operations

Focus on awareness and coordination

- **Increased importance of gas-electric coordination when faced with accelerated coal-fired retirements**
- **Regional tabletop exercises with gas and electric operators to simulate emergency scenarios and improve readiness**
- **Increased participation by natural gas industry in BPS regional planning and coordination organizations**
- **Weekly/sub-weekly monitoring and BPS alerting of regional fuel adequacy during times of natural gas pipeline constraint and real-time coordination with the gas industry**



Mitigations are being implemented

- **Updated pipeline operation logic and expedited emergency protocols**
- **Limited duration support from battery energy storage system capacity increases**
- **Increased focus on winterization and inspection of key gas and electric system elements**
- **Electric market service to ensure preparedness for potential winter gas restrictions**
- **Entities updating internal protocols, securing third-party gas supply options, and dual-fuel capability to strengthen winter readiness.**
- **Pre-event unit cycling minimization, early unit startup, unit commitment adjustments based on anticipated reliability, congestion, and capacity needs**

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Questions and Answers

EXHIBIT 51-3

Independent Statistics and Analysis
U.S. Energy Information Administration

Short-Term Energy Outlook

STEO

December 2025



December 2025

The U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy (DOE), prepared this report. By law, our data, analyses, and forecasts are independent of approval by any other officer or employee of the U.S. Government. The views in this report do not represent those of DOE or any other federal agencies.

Short-Term Energy Outlook

Overview

U.S. energy market indicators	2024	2025	2026
Brent crude oil spot price (dollars per barrel)	**$81**	**$69**	**$55**
Retail gasoline price (dollars per gallon)	**$3.31**	**$3.11**	**$3.00**
U.S. crude oil production (million barrels per day)	**13.2**	**13.6**	**13.5**
Natural gas price at Henry Hub (dollars per million British thermal units)	**$2.19**	**$3.56**	**$4.01**
U.S. liquefied natural gas gross exports (billion cubic feet per day)	**12**	**15**	**16**
Shares of U.S. electricity generation			
Natural gas	42%	40%	40%
Coal	16%	17%	16%
Nuclear	19%	18%	18%
Conventional hydropower	6%	6%	6%
Wind	11%	11%	11%
Solar	5%	7%	8%
Other energy sources	1%	1%	1%
U.S. GDP (percentage change)	**2.8%**	**2.0%**	**2.2%**
U.S. CO_2 emissions (billion metric tons)	**4.8**	**4.9**	**4.8**

Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook,* November 2025
Note: Values in this table are rounded and may not match values in other tables in this report.

- **Global oil prices.** We expect global oil inventories to continue to rise through 2026, putting downward pressure on oil prices in the coming months. We forecast the Brent crude oil price will fall to an average of $55 per barrel (b) in the first quarter of 2026 (1Q26) and remain near that price for the rest of next year. Although we expect crude oil prices to continue to fall in the coming months, we assess that both the OPEC+ production policy and China's continued inventory builds will limit price declines.

- **Natural gas prices.** The Henry Hub natural gas spot price in our forecast rises to an average of almost $4.30 per million British thermal units (MMBtu) this winter (November–March), more than 40 cents/MMBtu higher than we forecast in our November STEO. The revision is driven primarily by colder-than-expected weather in December which we expect will increase space heating demand. However, we expect milder-than-normal weather in early 2026 and rising production will help moderate natural gas prices following the winter, with the Henry Hub price averaging about $4.00/MMBtu next year.

- **Electricity generation.** Forecast U.S. electricity generation by the power sector grows by 2.4% in 2025 and by 1.7% in 2026. This growth is in contrast to relatively flat generation from 2010 to 2020 and is primarily driven by increasing demand from large customers, including data centers,

concentrated in regions managed by the Electric Reliability Council of Texas and the PJM Interconnection. We reduced our forecast for generation growth in 2026 compared with last month's STEO based on how much large load electricity demand has come online so far this year and its implications for near-term growth.

- **Coal consumption.** We expect coal consumption to increase by 9% in 2025 driven by an 11% increase in coal consumption in the electric power sector this year as both natural gas costs and electricity demand increased. Coal consumption is expected to fall in 2026 as electric power generation from renewable sources increases. However, coal production falls by less than consumption next year, supporting a small increase in coal exports and rising coal inventories.

Notable forecast changes

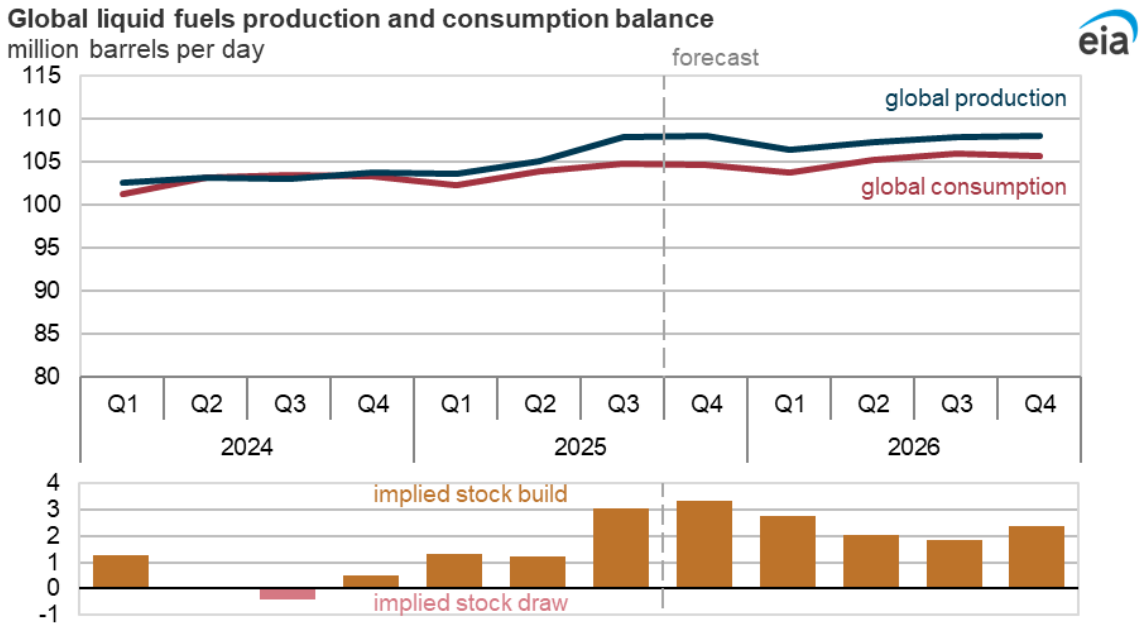
Current forecast: December 9, 2025; previous forecast: November 12, 2025	**2025**	**2026**
U.S. secondary coal inventories (million short tons)	**110**	**117**
Previous forecast	111	106
Percentage change	-1.3%	10.7%

Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook*
Note: Percentages and changes are calculated from unrounded values.

Global Oil Markets

Global oil prices

The Brent crude oil spot price averaged $64 per barrel (b) in November, which is $11/b lower than in November 2024. Crude oil prices continue to fall as growing crude oil production outweighs the effect of increased drone attacks on Russia's oil infrastructure, and the latest sanctions on Russia's oil sector. We forecast that growing global oil production and lower demand over the winter will accelerate the accumulation of oil inventories, resulting in further crude oil price declines in the coming months. We forecast that the Brent price will drop to an average of $55/b in the first quarter of 2026 (1Q26) and will stay near that price for the rest of the year.



Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook*, December 2025

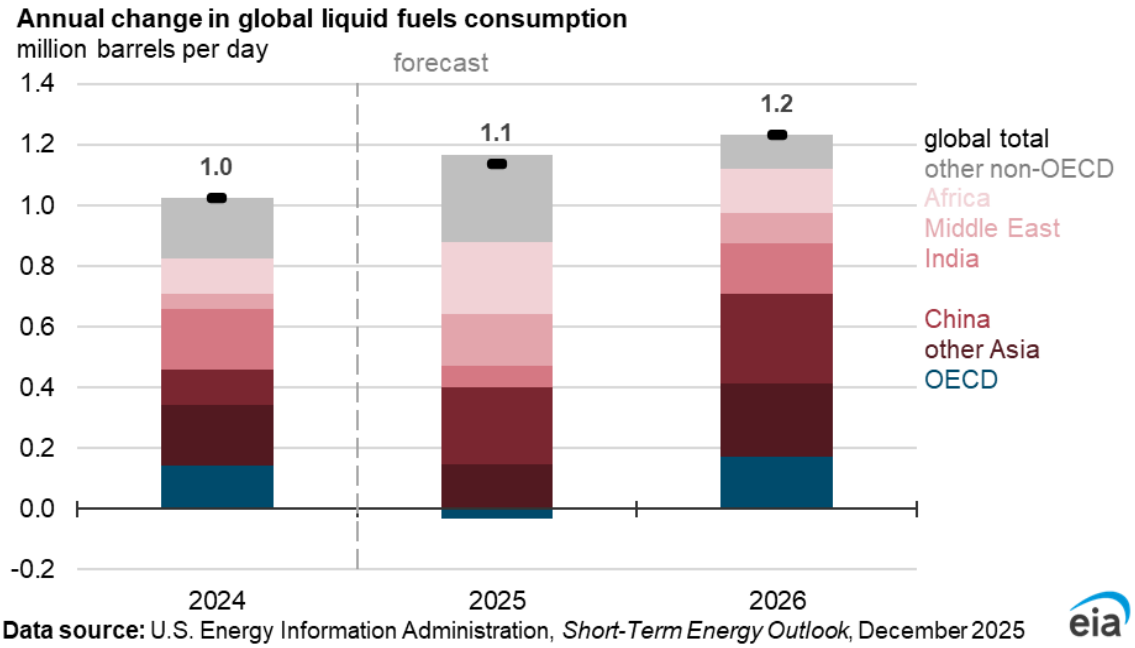
Strong global oil production growth has outpaced consumption in recent months, driving our assessment that global oil inventories have risen quickly in the second half of 2025. In 2026, we expect production and consumption to grow at similar rates, but production levels will continue to exceed consumption, further adding to inventories. We forecast that global oil inventory builds will exceed 2 million barrels per day (b/d) in 2026, which is similar to this year's increase. Persistent inventory builds could fill commercial storage options on land, which may prompt market participants to increasingly seek other, more expensive options for storing crude oil, such as floating storage. As a result, some of the crude oil price declines will likely reflect the higher marginal cost of storage.

Although we expect prices to fall in 2026, we assess that both OPEC+ policy and China's continued inventory builds will limit declines. Given our expectation of substantial global oil inventory builds, we forecast OPEC+ will produce about 1.3 million b/d less than targeted production in 2026. On November 30, OPEC+ reaffirmed plans to keep production flat in the first quarter, but left open the potential for future adjustments. A large portion of oil inventory builds this year have been in strategic stockpiles in

China, which has limited downward price pressures. We expect that China will continue building strategic stockpiles into 2026.

Global oil consumption and production

Forecast global liquid fuels consumption increases by 1.1 million b/d in 2025 and by 1.2 million b/d in 2026. Global liquid fuels consumption growth is driven almost entirely by non-OECD countries.



Most non-OECD growth is concentrated in Asia. We forecast total liquid fuels consumption in China increases by 250,000 b/d in 2025 and by an additional 300,000 b/d in 2026. We raised our forecast of 2026 oil consumption in China by 50,000 b/d from last month's STEO due to upward revisions to expected GDP growth. We expect India will increase its liquid fuels consumption by 70,000 b/d this year and 170,000 b/d next year.

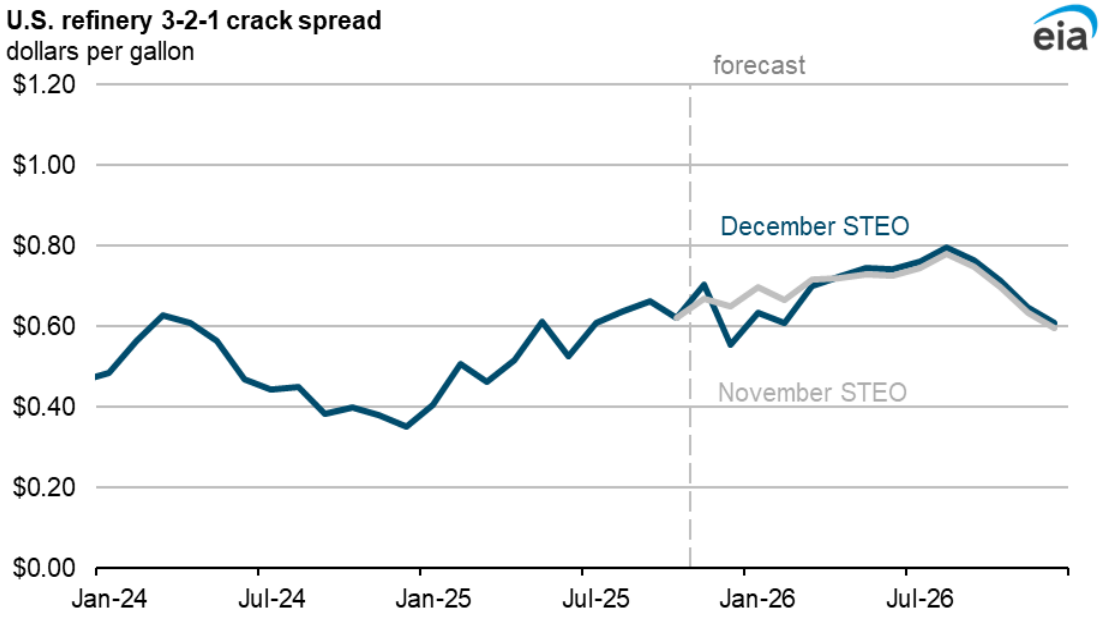
The Middle East is also a significant source of non-OECD demand growth, increasing by 170,000 b/d in 2025 and 100,000 b/d in 2026. We forecast total liquid fuels consumption in Africa increases by 240,000 b/d in 2025 and 150,000 b/d in 2026, led by strong growth in Sub-Saharan Africa.

Global liquid fuels production in our forecast increases by 3.0 million b/d in 2025 and by more than 1.2 million b/d in 2026. Along with OPEC+, the United States, Brazil, Guyana, and Canada drive production growth in the forecast. Together these four countries contribute more than 50% (1.5 million b/d) of total global growth this year and about 60% (0.8 million b/d) in 2026. Production in South America has been the leading source of growth in 2025 as new offshore vessels have started up ahead of schedule in Brazil and Guyana, with additional projects still in development.

U.S. Petroleum Products

U.S. refinery margins

We expect to see lower crack spreads, broadly a measure of refining profitability, in December and the first quarter of 2026 (1Q26) compared with our previous forecast. In November, crack spreads increased in response to constrained global refinery production. However, refinery margins at the end of November and in early December decreased as some global refinery maintenance comes to an end. In our December STEO, we estimate U.S. average 3-2-1 crack spreads in the month of December will be 10 cents per gallon lower than we estimated in our November STEO. We do not expect much of a change to the rest of our forecast as we still expect global petroleum product market tightness and lower crude oil prices to continue to contribute to higher refinery margins in 2026.



The 3-2-1 crack spread is calculated by subtracting the price of a gallon of crude oil from two thirds the price of a gallon of gasoline and one third the price of a gallon of diesel. It is also an indicator of the relative value of refining crude oil, particularly for U.S. refiners that tend to produce higher yields of gasoline relative to diesel-focused refineries like many in Europe .

High November crack spreads reflected tight global market conditions, partly brought on by the United States' and European Union's October 2025 implementation of new sanctions on petroleum from Russia. They also reflected reduced refinery production from European and Middle Eastern refineries during the fall maintenance season. Spreads decreased at the end of November as maintenance comes to an end.

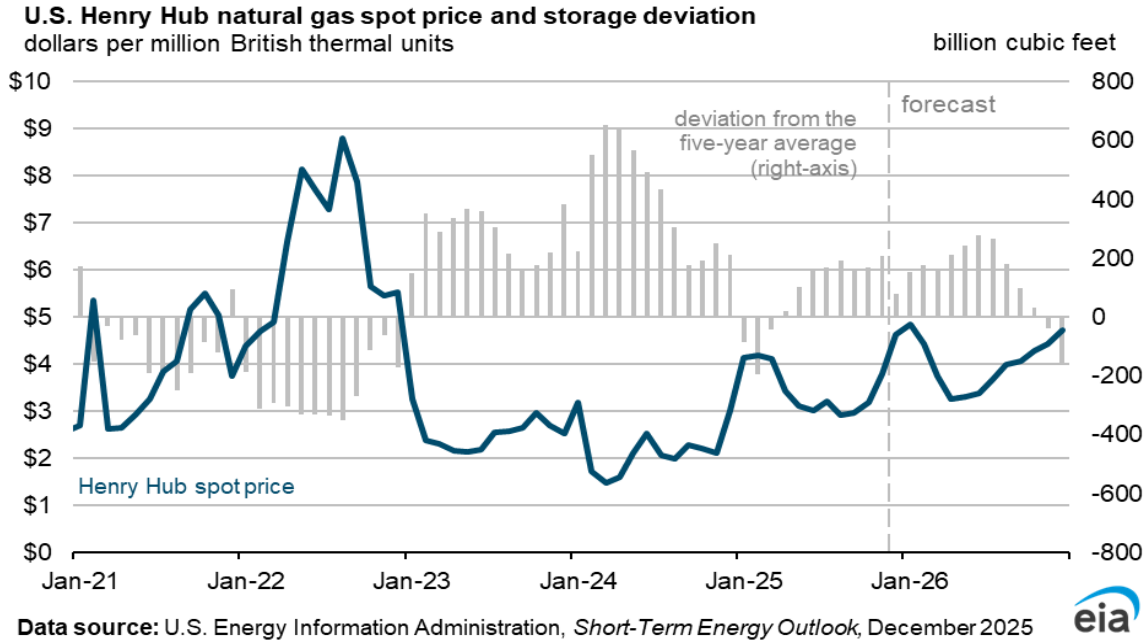
Despite lower gasoline and diesel prices in late November and early December, we still estimate crack spreads will be more than 10 cents per gallon higher, on average, in 2026 than they were in 2025. Attacks on Russian refineries, shifting crude oil trade flows, and sanctions on Russia's petroleum sector

present an ongoing source of upward price pressure for global petroleum product markets. We assume global refiners using crude oil from Russia will find replacement volumes in an increasingly oversupplied global crude market. Nonetheless, the potential for a more prolonged and permanent impact on global refinery margins resulting from these risks is a source of uncertainty and upside price risk for our forecast.

Natural Gas

Natural gas prices and storage

An early December cold snap is putting upward pressure on natural gas prices. The Henry Hub spot price in our forecast averages around $4.30 per million British thermal units (MMBtu) this winter heating season (November–March), 22% higher than last winter. We raised our forecast for prices this winter by more than 40 cents/MMBtu on average compared with last month's STEO, largely because early December has been colder than we assumed in last month's STEO, leading us to raise our estimate of natural gas used for space heating.



Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook*, December 2025

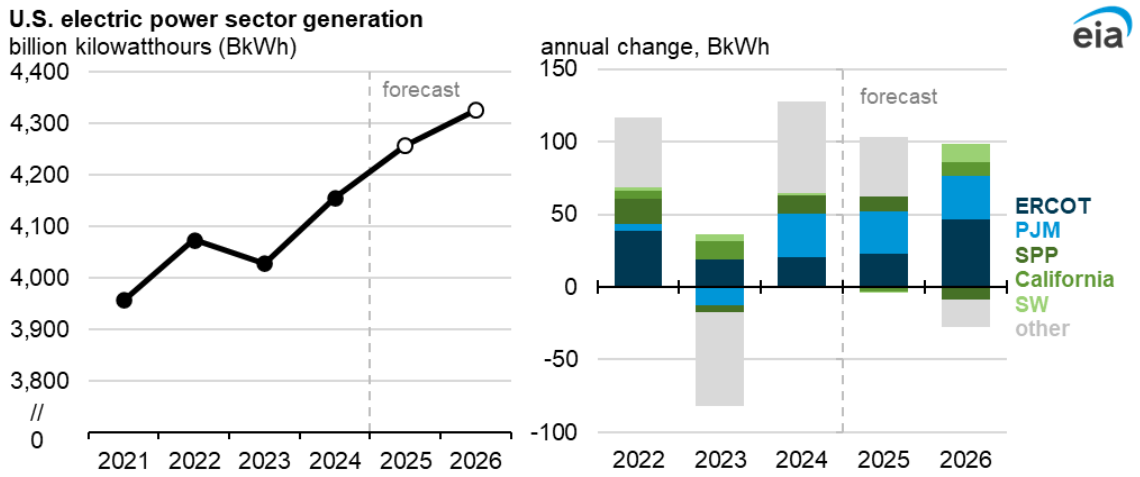
Based on data from the National Oceanic and Atmospheric Administration, we assume December will have 8% more heating degree days (HDDs) than the 10-year average, and 7% more HDDs than we assumed in last month's forecast. Because of the colder weather, we now forecast the residential and commercial sectors will consume 6% more natural gas in December than we forecast last month, reducing the amount of natural gas held in storage. The United States entered the winter heating season with 4% more working natural gas in storage than the previous five-year (2020–2024) average. We expect inventory withdrawals will be 580 billion cubic feet (Bcf) this December, 28% more than the five-year average withdrawal for the month. We forecast U.S. natural gas stocks will end the winter at 2,000 Bcf, 9% above the five-year average.

Rising production helps moderate natural gas prices next year. We expect the Henry Hub spot price to average almost $4.50/MMBtu in 4Q26, down 5% from last month's forecast. U.S dry natural gas production in our forecast averages 109 billion cubic feet per day (Bcf/d) in 2026, up 1% from this year. We raised our forecast for U.S. natural gas production compared with the November STEO after we updated our assumptions about natural gas-to-oil ratios (GORs). Specifically, we raised our expectations of GORs in the Permian region based on recent production trends, leading to more overall natural gas production in our forecast for 2026.

Electricity, Coal, and Renewables

Electricity generation

Electricity generation has been trending upwards in recent years after a decade of relatively flat growth. Between 2010 and 2020, U.S. electricity generation fell by an average of 0.3% per year. Since 2021, electricity generation has grown about 2% per year. We forecast U.S. generation will grow by 2.4% in 2025 and by 1.7% in 2026.



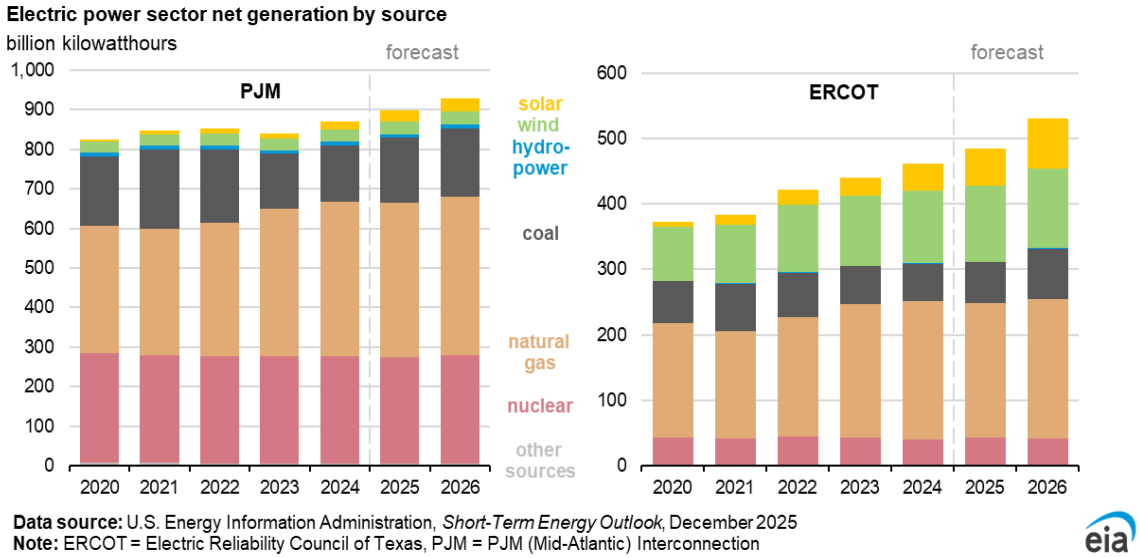
Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook*, December 2025
Note: ERCOT = Electric Reliability Council of Texas, PJM = PJM (Mid-Atlantic) Interconnection, SPP = Southwest Power Pool, SW = Southwest

Much of the recent growth in generation has been driven by increasing demand for electricity from data centers and other large customers in Texas where the grid is managed by the Electric Reliability Council of Texas (ERCOT) and in the Mid-Atlantic/Ohio Valley region where the grid is managed by the PJM Interconnection.

We expect that electricity demand in PJM will grow by 3.3% in both 2025 and 2026, while demand in ERCOT grows by 5.0% in 2025 and 9.6% in 2026. We have revised our forecast of ERCOT's growth rates down from the November STEO (which were 6.0% and 15.7%, respectively) based on how much large load electricity demand has come online so far this year and its implications for near-term growth.

Changes in the mix of energy sources used for electricity generation are expected for these two fastest-growing regions. The largest source in both regions is natural gas, which we forecast will grow by 2% in both regions between 2024 and 2026. We expect most of the growing electricity demand in the PJM

region will be met by growing generation from coal and solar, up 23% and 63%, respectively, between 2024 and 2026. In ERCOT, the fastest growing energy source is solar, which we forecast will grow by 92% between 2024 and 2026.

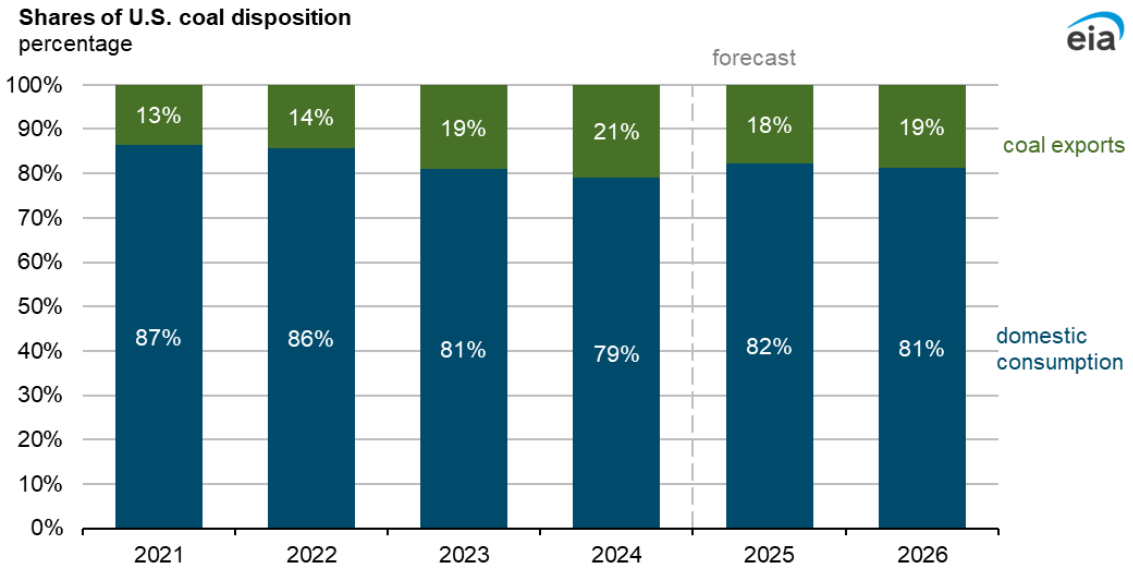


Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook*, December 2025
Note: ERCOT = Electric Reliability Council of Texas, PJM = PJM (Mid-Atlantic) Interconnection

Coal markets

We expect coal consumption to total 448 million short tons (MMst) in 2025, a 9% increase compared with 2024. The increase is mostly driven by an 11% increase in electric power consumption in the United States, which accounts for approximately 90% of total coal consumption. The power sector's consumption of coal has increased this year as the average cost of natural gas in the electric power sector increased over 40% compared with 2024. More overall electricity demand has also supported coal consumption this year. As domestic demand for coal increased, exports decreased in absolute terms and as a share of total U.S. coal disposition. We estimate that both steam and metallurgical exports will fall 11% in 2025, decreasing the share of exports in total U.S. coal disposition from 21% in 2024 to 18% in 2025. The drop in coal exports reflects relatively weak global prices driven by oversupply and soft demand.

We expect this trend to reverse in 2026, as domestic coal consumption falls by 5%, due to lower coal consumption in the U.S. electric power sector, while exports rise 1%. The rise in exports reflects an 8% increase in metallurgical exports due to the long wall expansion at the Blue Creek mine in Alabama and the reopening of the Leer South and Longview mines in West Virginia. We expect supply reductions among other metallurgic coal exporters next year will help support prices and an increase in U.S. exports. Steam coal exports, which are subject to lower global prices and typically sell at a high discount relative to metallurgical coal exports, are forecast to fall by 6% in 2026.



Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook*, December 2025
Note: Domestic consumption = U.S. coke plants + U.S. electric power + U.S. retail, commercial and industrial consumption

Economy, CO_2, and Weather

U.S. macroeconomics

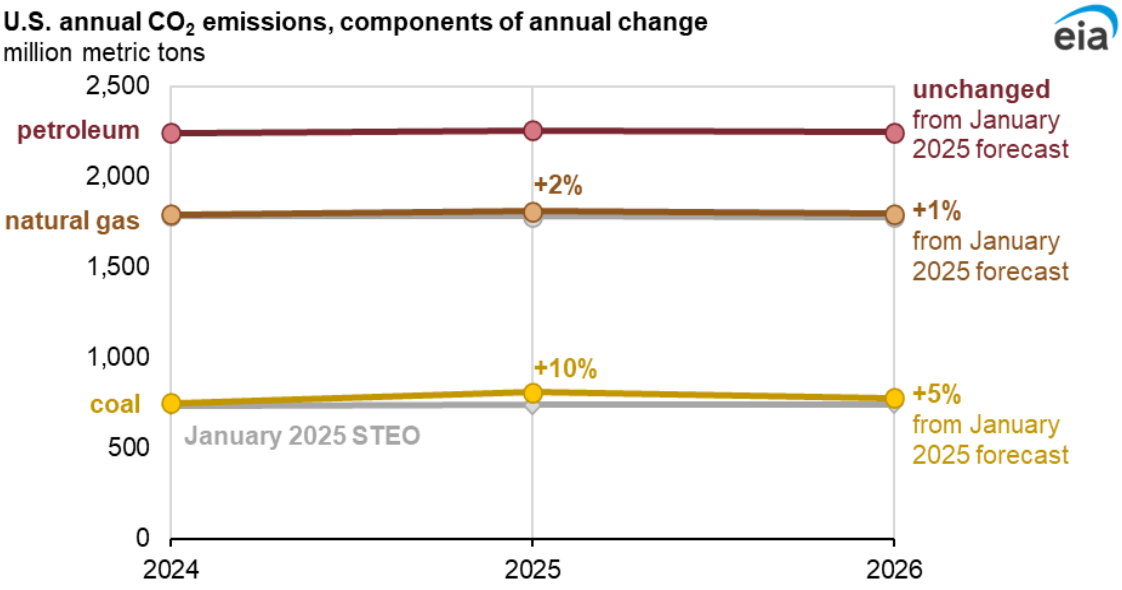
This month's forecast assumes that real GDP will grow at an annualized rate of 2.0% in 2025 and 2.2% in 2026, both of which are the same as assumed last month.

The macroeconomic assumptions in the STEO are based on S&P Global's macroeconomic model. We incorporate STEO energy price forecasts into the model to obtain the final macroeconomic assumptions.

Emissions

We forecast U.S. energy-related CO_2 emissions to increase by 1.9% in 2025, followed by a decrease of 1.2% in 2026. This is a change from our November forecast, when we forecast CO_2 emissions to decrease by 0.5% in 2026. The lower 2026 emissions estimate in the current forecast is a result of relatively lower anticipated natural gas-fired electricity generation next year.

Our current CO_2 emissions forecast for 2025 and 2026 is slightly higher than our initial January 2025 estimates. We expect total CO_2 emissions in 2025 and 2026 to be 1.9% and 0.9% higher, respectively, than our January 2025 outlook because coal-fired electricity generation was higher than we expected due to additional electricity demand and natural gas prices. We also now forecast CO_2 emissions from natural gas to be higher in both 2025 and 2026 compared with our January forecast. Relative increases in 2025 natural gas emissions are a result of higher natural gas consumption across all sectors except electric power, most notably for industrial use and building space heating in the first quarter. Emissions increases in 2026 are associated with relatively higher natural gas-fired electricity generation, associated with rising electricity demand for data centers and cryptocurrency mining. CO_2 emissions from petroleum products have remained unchanged, overall, relative to our January forecast.



Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook* (STEO), December 2025

Weather

Based on current forecasts and data from the National Oceanic and Atmospheric Administration, we expect a colder-than-average December, with 765 heating degree days (HDDs) across the United States, 9% more than in December 2024 and 8% more than the 10-year monthly average. Milder weather in the first quarter of 2026 (1Q26) more than offsets the cooler start to the winter in 4Q25. As a result, with a total of 3,194 HDDs overall, we expect the 2025–2026 winter heating season (November—March) will be milder than both last winter (1% fewer HDDs) and the previous 10-year winter average (1% fewer HDDs).

Short-Term Energy Outlook

Chart Gallery

December 9, 2025

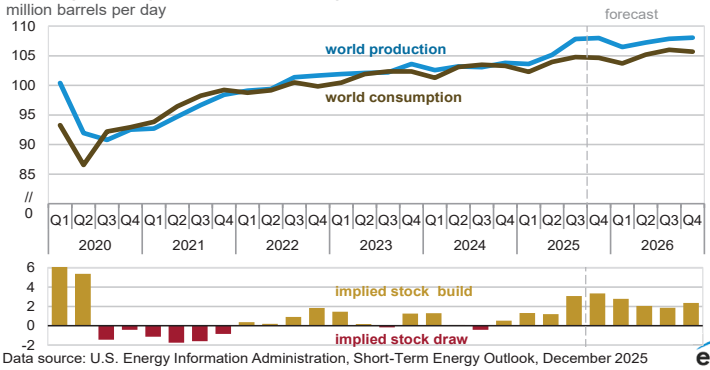
U.S. Energy Information Administration | *Independent Statistics and Analysis* | www.eia.gov

West Texas Intermediate (WTI) crude oil price and NYMEX futures price
dollars per barrel



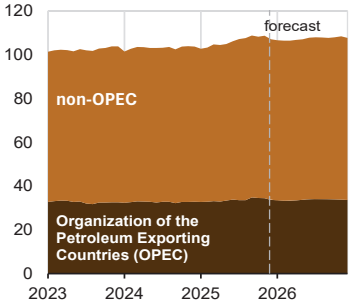
Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025, Bloomberg, L.P., and Refinitiv an LSEG Business
Note: Futures curve is the average settlement price for five trading days ending December 4, 2025.

World liquid fuels production and consumption balance
million barrels per day

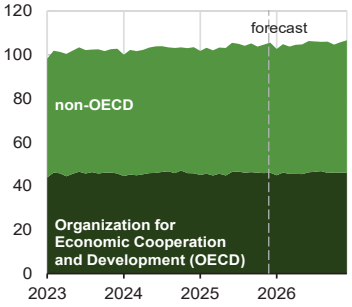


Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

World liquid fuels production
million barrels per day

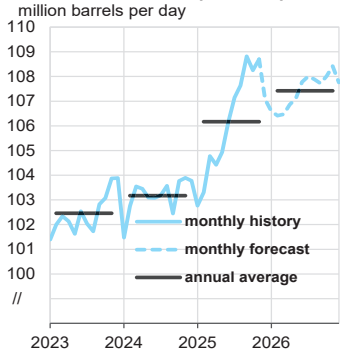


World liquid fuels consumption
million barrels per day

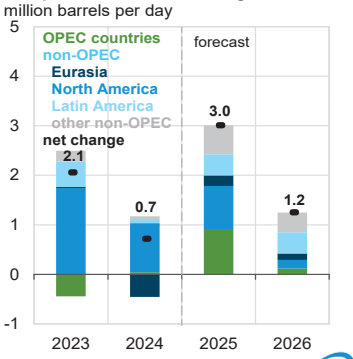


Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

World crude oil and liquid fuels production
million barrels per day

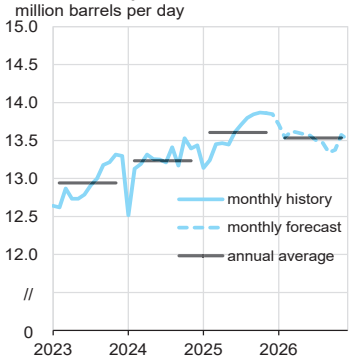


Components of annual change
million barrels per day

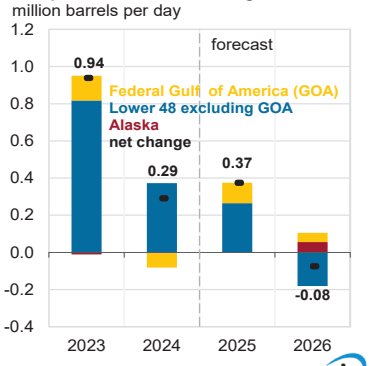


Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

U.S. crude oil production
million barrels per day

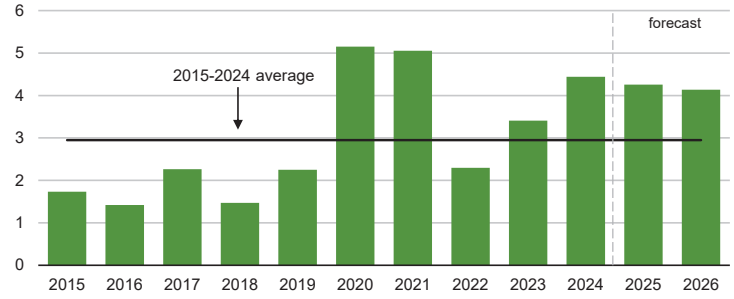


Components of annual change
million barrels per day



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

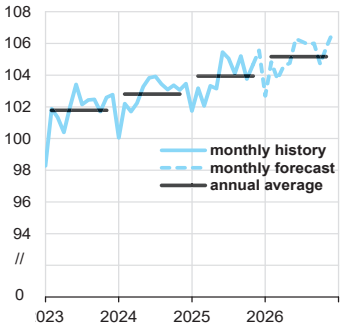
Organization of the Petroleum Exporting Countries (OPEC) surplus crude oil production capacity
million barrels per day



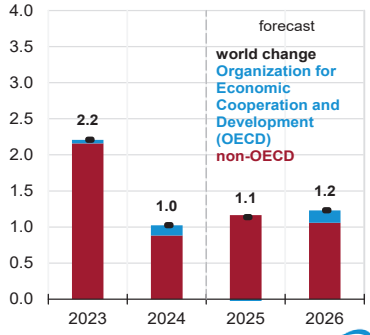
Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

Note: Black line represents 2015-2024 average (2.9 million barrels per day).

World liquid fuels consumption
million barrels per day

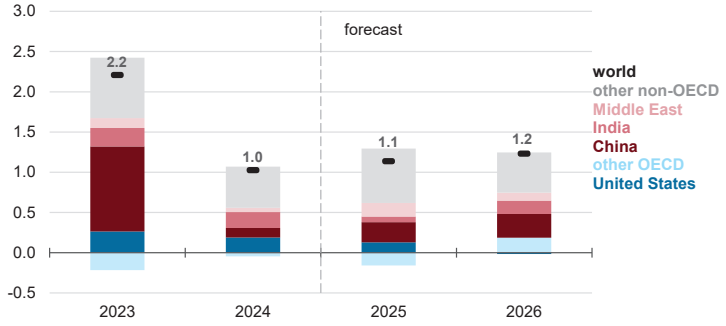


Components of annual change
million barrels per day



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

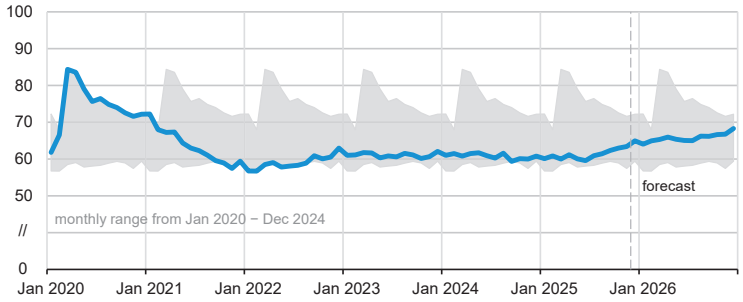
Annual change in world liquid fuels consumption
million barrels per day



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

Organization for Economic Cooperation and Development (OECD) commercial inventories of crude oil and other liquids

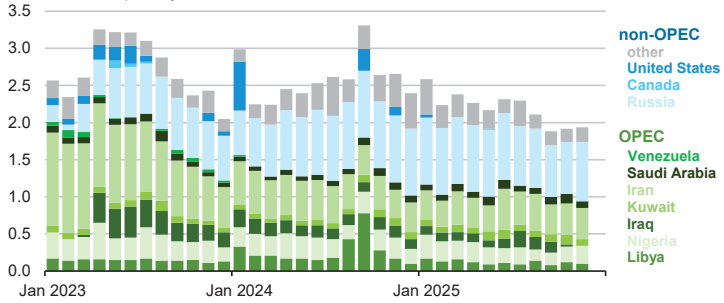
days of supply



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

Estimated unplanned liquid fuels production outages among OPEC and non-OPEC producers

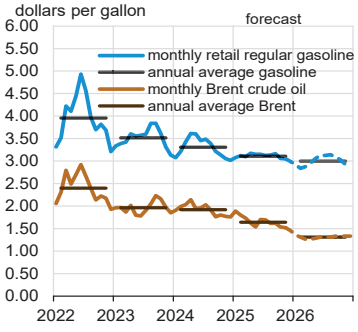
million barrels per day



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

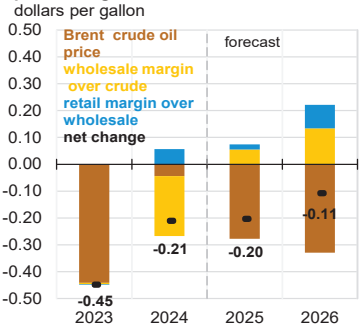
U.S. gasoline and crude oil prices

dollars per gallon



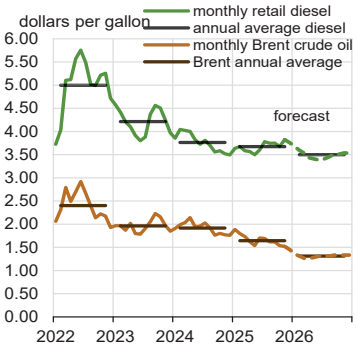
Components of annual gasoline price changes

dollars per gallon

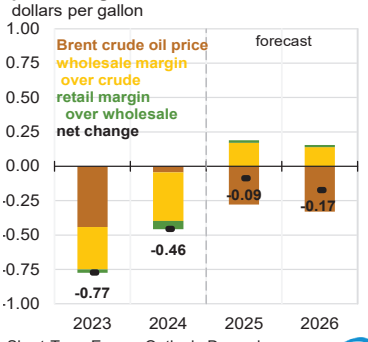


Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025, and Refinitiv an LSEG Business

U.S. diesel and crude oil prices

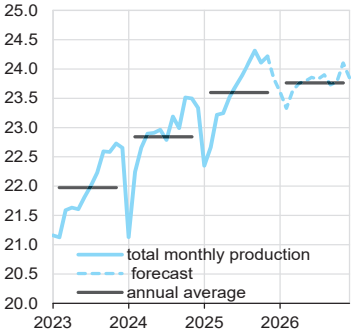


Components of annual diesel price changes

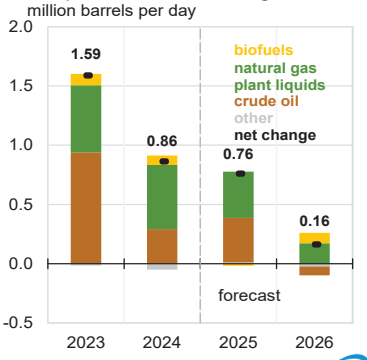


Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025, and Refinitiv an LSEG Business

U.S. crude oil and liquid fuels production

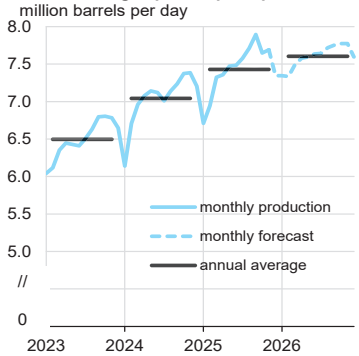


Components of annual change

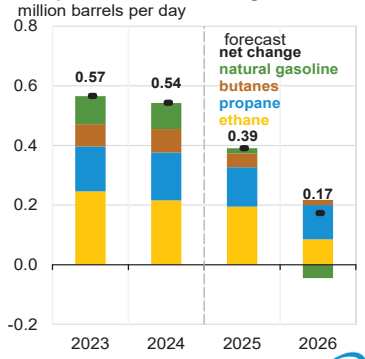


Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

U.S. natural gas plant liquids production



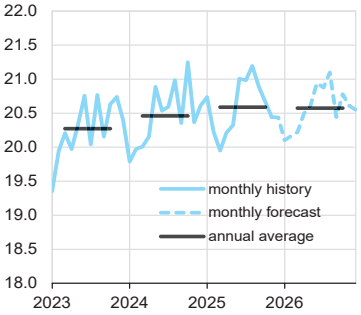
Components of annual change



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

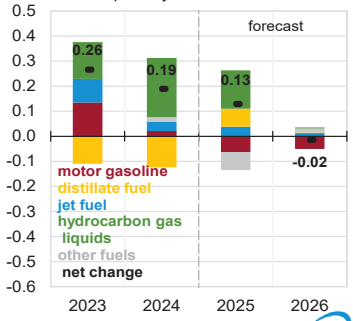
U.S. liquid fuels product supplied (consumption)

million barrels per day



Components of annual change

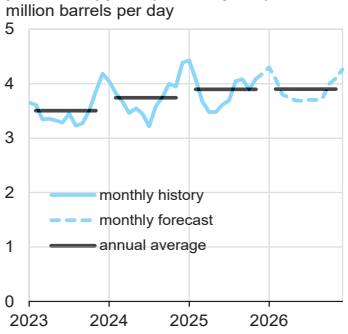
million barrels per day



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

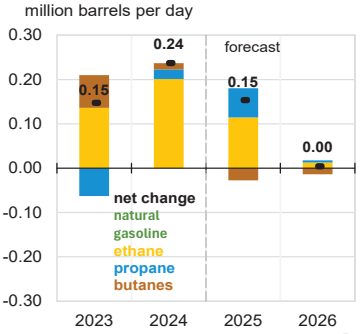
U.S. hydrocarbon gas liquids product supplied (consumption)

million barrels per day



Components of annual change

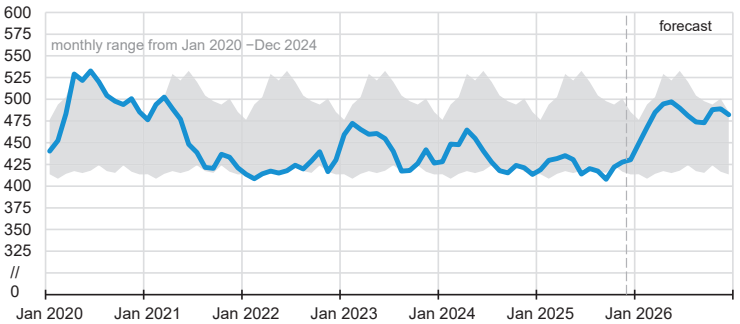
million barrels per day



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

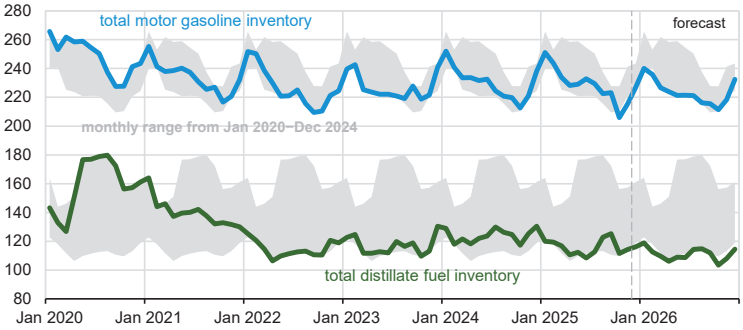
U.S. commercial crude oil inventories

million barrels



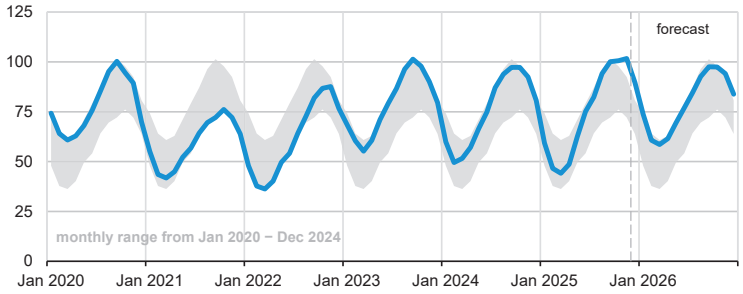
Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

U.S. gasoline and distillate inventories
million barrels



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

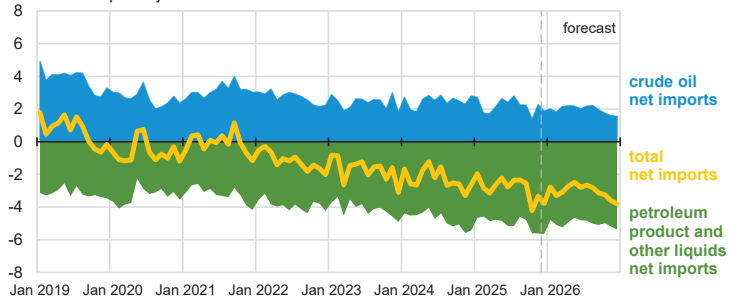
U.S. commercial propane inventories
million barrels



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

Note: Excludes propylene.

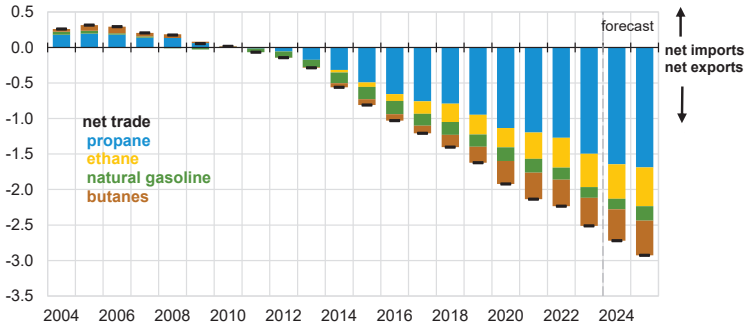
U.S. net imports of crude oil and liquid fuels
million barrels per day



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

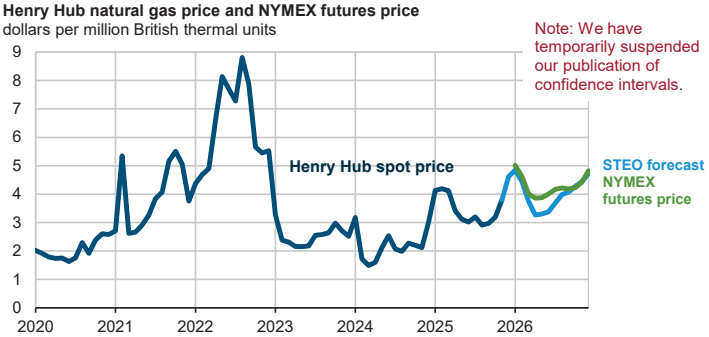
Note: Petroleum product and other liquids include: gasoline, distillate fuels, hydrocarbon gas liquids, jet fuel, residual fuel oil, unfinished oils, other hydrocarbons/oxygenates, and other oils.

U.S. net trade of hydrocarbon gas liquids (HGL)
million barrels per day



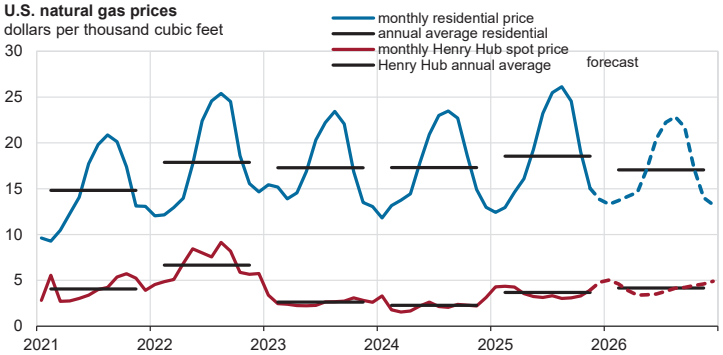
Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

Henry Hub natural gas price and NYMEX futures price
dollars per million British thermal units



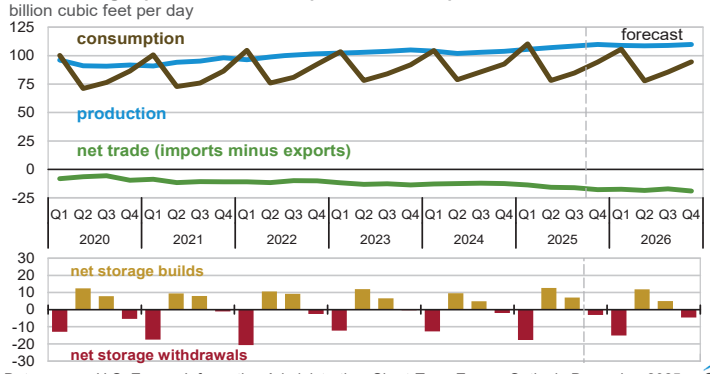
Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025, Bloomberg L.P., and Refinitiv an LSEG Business
Note: Futures curve is the average settlement price for five trading days ending November 6, 2025.

U.S. natural gas prices
dollars per thousand cubic feet



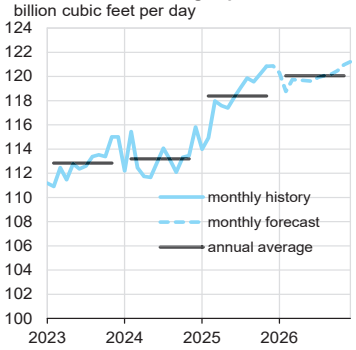
Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025, and Refinitiv an LSEG Business

U.S. natural gas production, consumption, and net imports
billion cubic feet per day

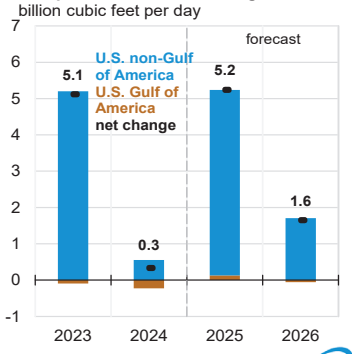


Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

U.S. marketed natural gas production
billion cubic feet per day

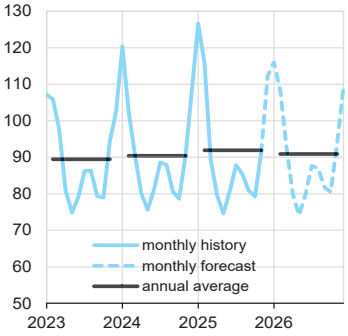


Components of annual change
billion cubic feet per day

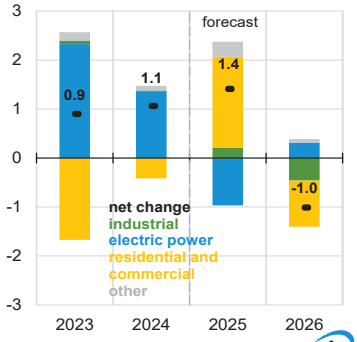


Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

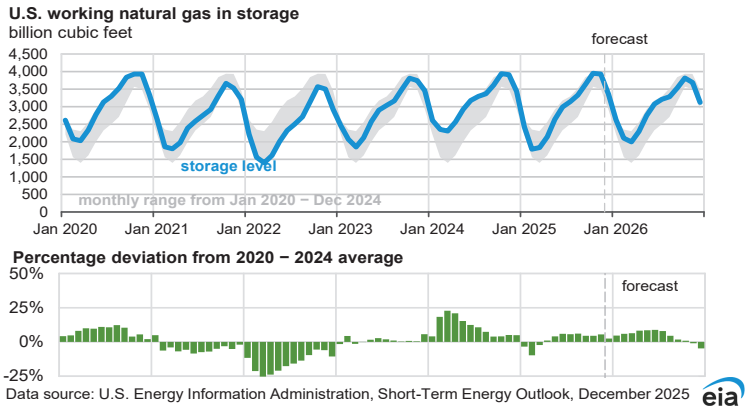
U.S. natural gas consumption
billion cubic feet per day



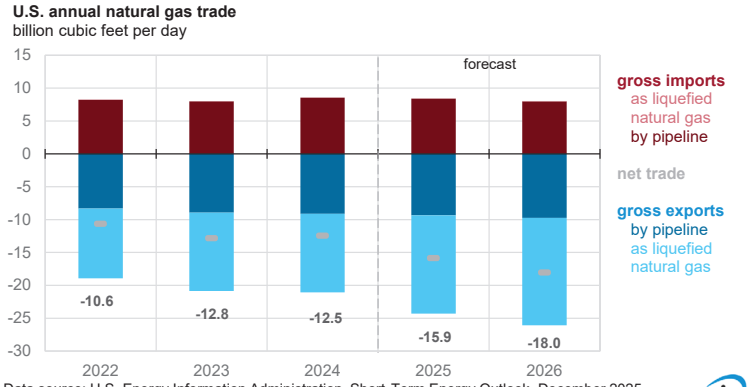
Components of annual change
billion cubic feet per day



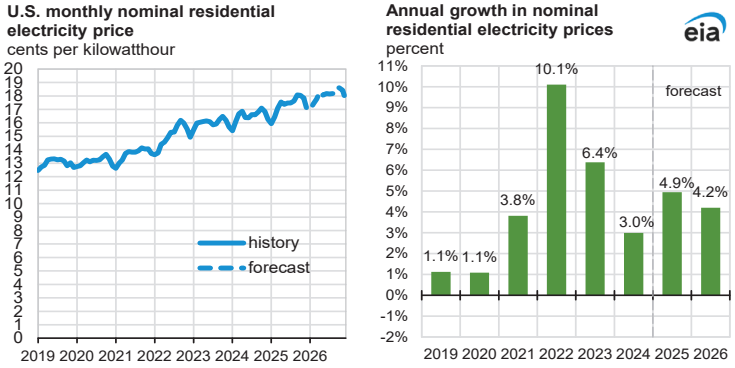
Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

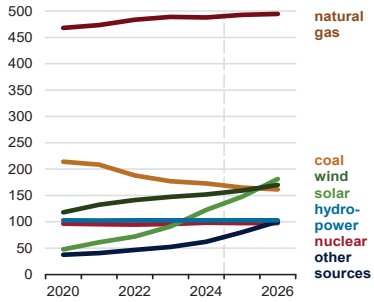


Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

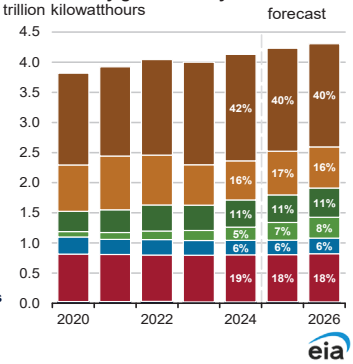


Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

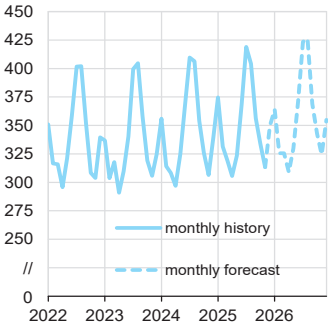
U.S. electric power sector generating capacity
gigawatts at end of period forecast



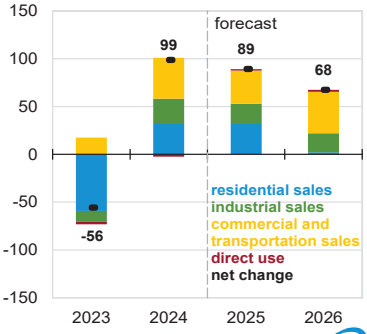
U.S. electricity generation by source
trillion kilowatthours



U.S. electricity consumption
billion kilowatthours

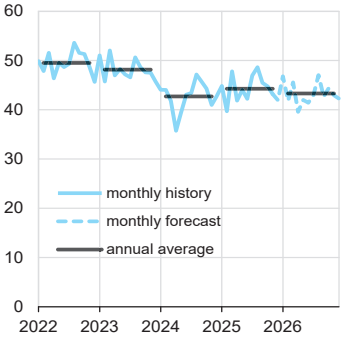


Components of annual change
billion kilowatthours

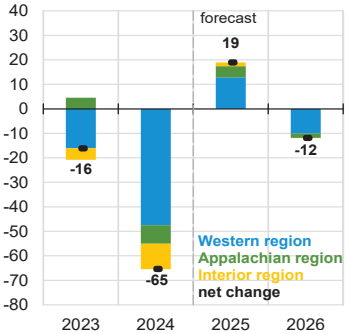


Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

U.S. coal production
million short tons

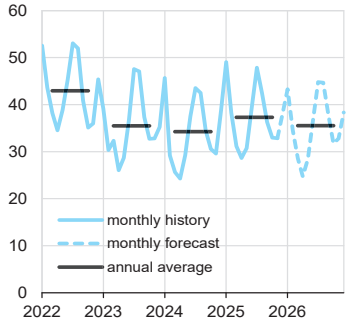


Components of annual change
million short tons

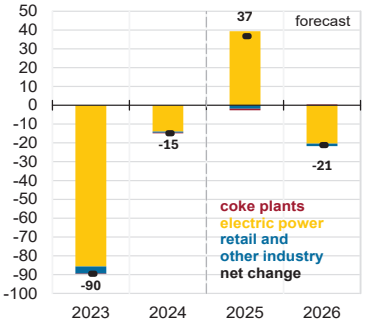


Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

U.S. coal consumption
million short tons

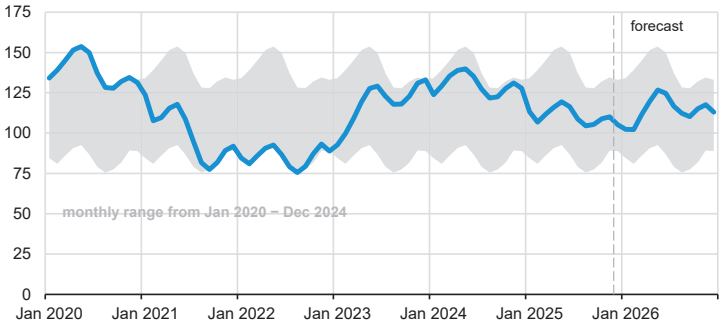


Components of annual change
million short tons



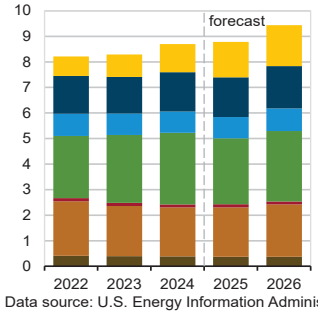
Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

U.S. electric power coal inventories
million short tons

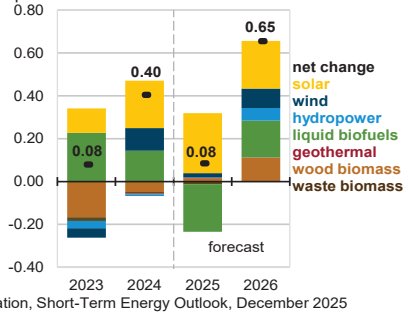


Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

U.S. renewable energy supply
quadrillion British thermal units



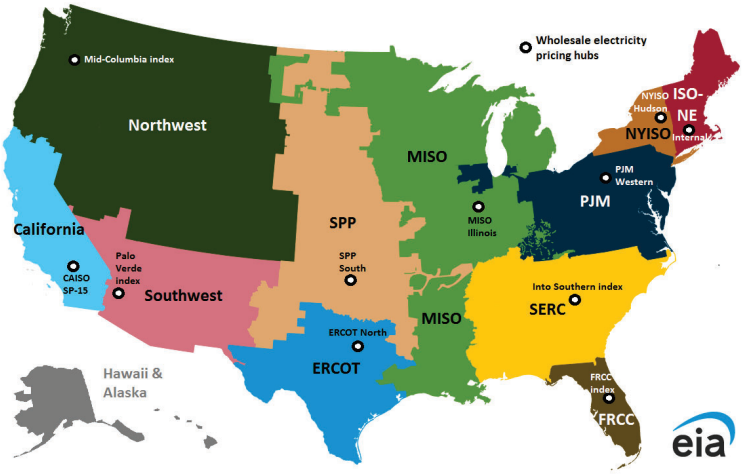
Components of annual change
quadrillion British thermal units



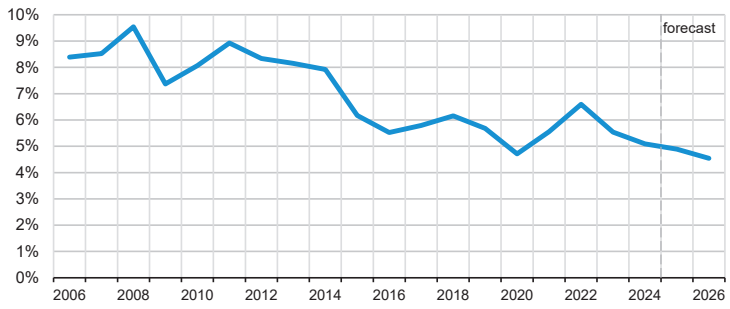
Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

Note: Hydropower excludes pumped storage generation. Liquids include ethanol, biodiesel, renewable diesel, other biofuels, and biofuel losses and coproducts.Waste biomass includes municipal waste from biogenic sources, landfill gas, and non-wood waste.

Short-Term Energy Outlook electricity supply regions

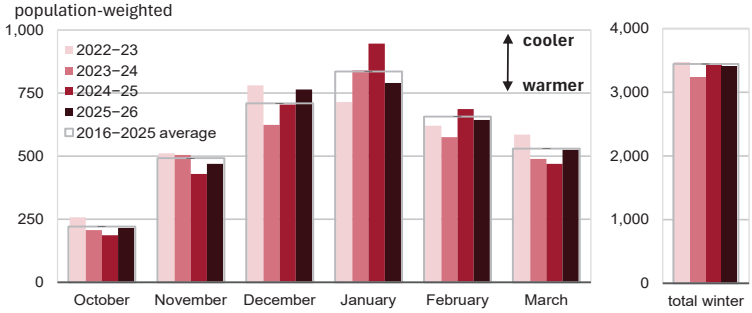


U.S. annual energy expenditures
share of gross domestic product



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

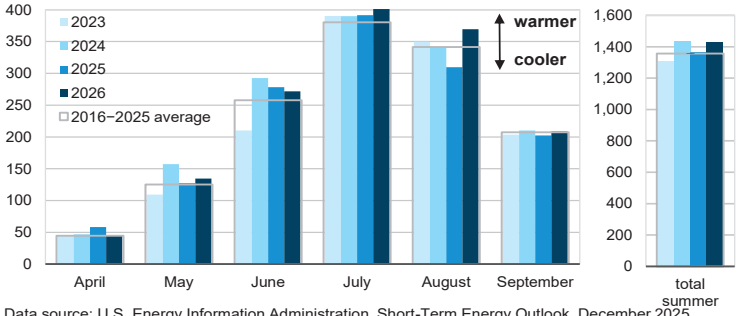
U.S. winter heating degree days
population-weighted



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December

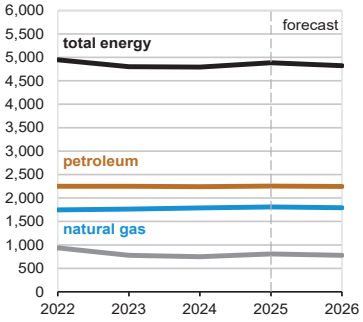
Note: EIA calculations based on National Oceanic and Atmospheric Administration (NOAA) data.

U.S. summer cooling degree days
population-weighted

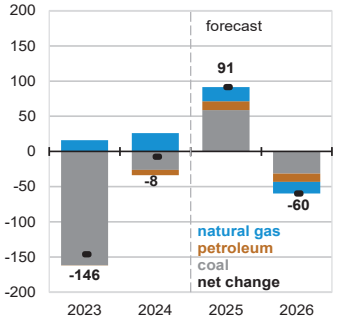


Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025
Note: EIA calculations based on National Oceanic and Atmospheric Administration (NOAA) data.

U.S. annual CO_2 emissions by source
million metric tons

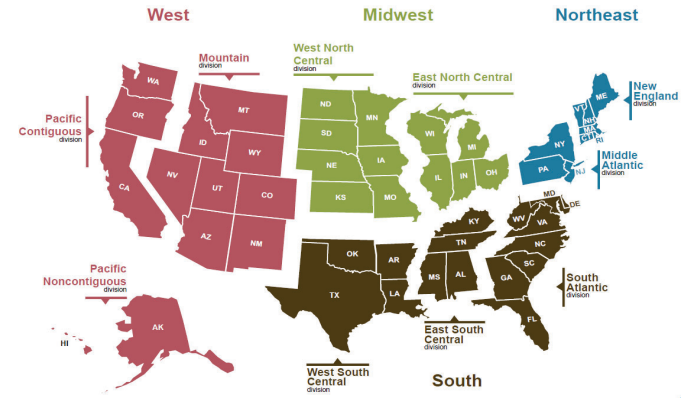


Components of annual change
million metric tons



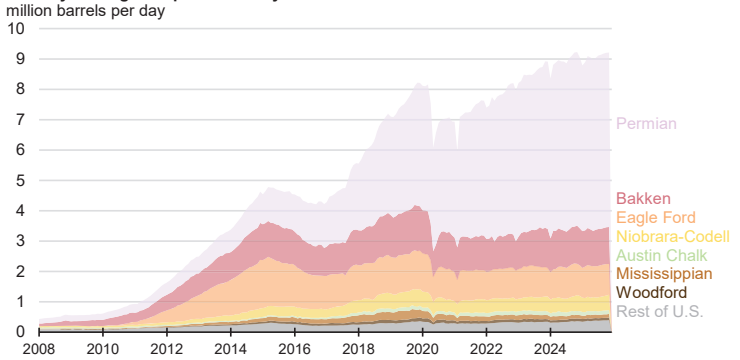
Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

U.S. Census regions and divisions



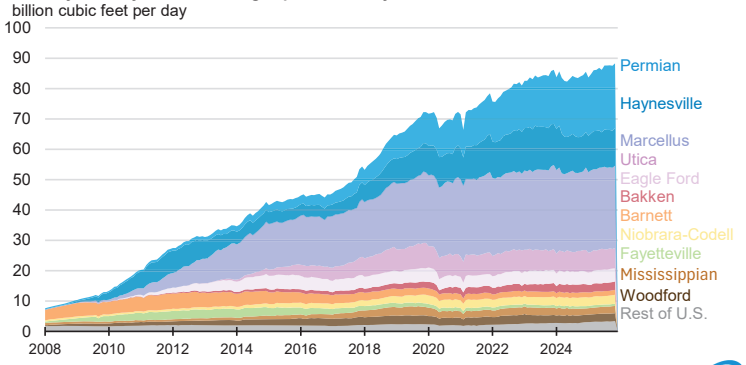
Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook*

Monthly U.S. tight oil production by formation
million barrels per day



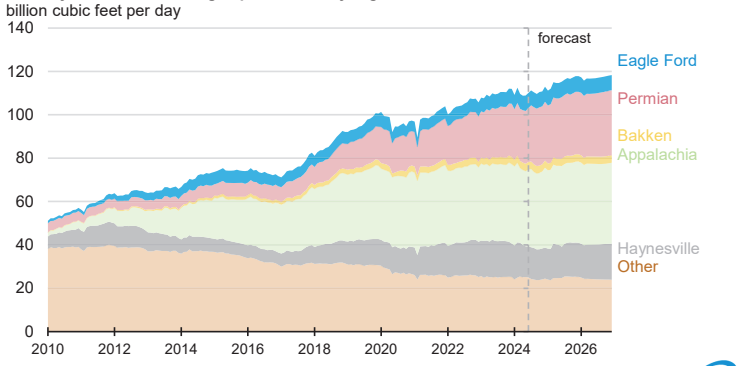
Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

Monthly U.S. dry shale natural gas production by formation
billion cubic feet per day



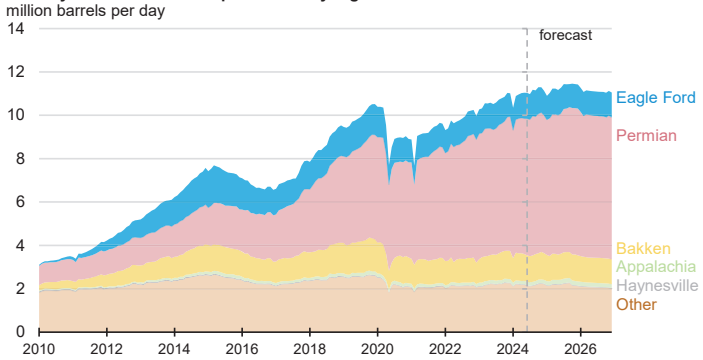
Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

Monthly Lower 48 natural gas production by region
billion cubic feet per day



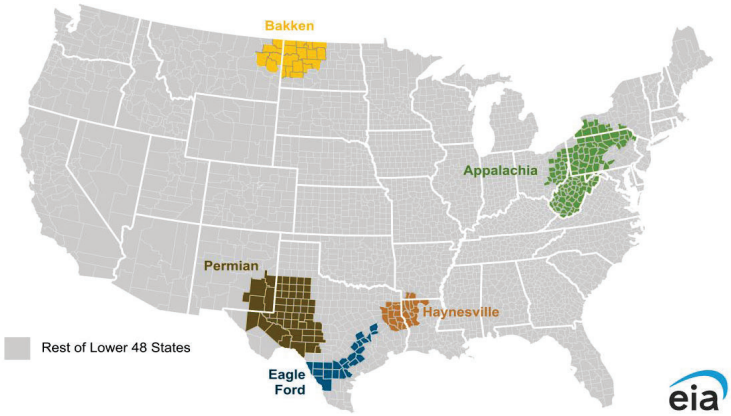
Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

Monthly Lower 48 crude oil production by region
million barrels per day



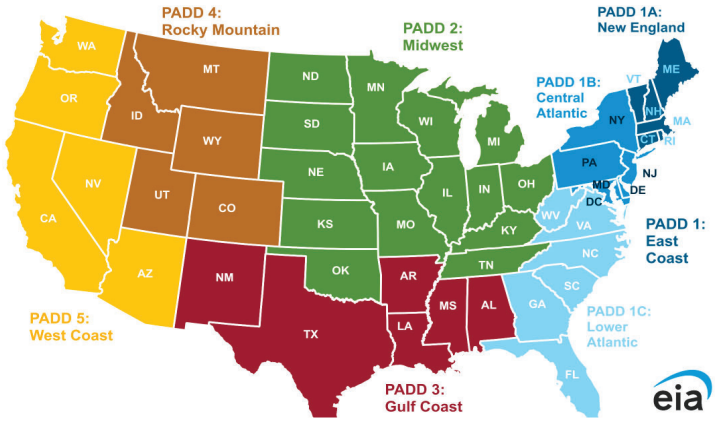
Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2025

U.S. production regions



Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook*, and the U.S. Census Bureau

U.S. Petroleum Administration for Defense Districts (PADD) regions



Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook*

Table 1. U.S. Energy Markets Summary

U.S. Energy Information Administration | Short-Term Energy Outlook - December 2025

	2024				2025				2026				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
Energy Production															
Crude Oil Production (a)															
(million barrels per day)	12.94	13.27	13.27	13.45	13.28	13.51	13.78	13.86	13.63	13.58	13.44	13.49	13.23	13.61	13.53
Dry Natural Gas Production															
(billion cubic feet per day)	103.9	102.0	103.0	103.8	105.6	107.1	108.4	109.8	109.0	108.7	109.0	109.8	103.2	107.7	109.1
Coal Production															
(million short tons)	130	118	136	128	132	128	141	130	134	123	133	130	513	531	520
Energy Consumption															
Liquid Fuels															
(million barrels per day)	19.92	20.53	20.65	20.75	20.31	20.51	21.02	20.52	20.16	20.68	20.81	20.65	20.46	20.59	20.58
Natural Gas															
(billion cubic feet per day)	104.5	78.9	85.8	92.6	110.3	78.2	84.7	94.3	105.6	77.9	85.5	94.4	90.4	91.8	90.8
Coal (b)															
(million short tons)	100	91	120	99	118	99	127	104	106	90	127	103	411	448	426
Electricity															
(billion kilowatt hours per day)	10.75	10.87	12.72	10.57	11.39	10.96	12.82	10.84	11.28	11.11	13.25	11.11	11.23	11.50	11.69
Renewables (c)															
(quadrillion Btu)	2.12	2.28	2.16	2.13	2.16	2.28	2.17	2.17	2.26	2.48	2.38	2.31	8.70	8.78	9.43
Total Energy Consumption (d)															
(quadrillion Btu)	24.52	22.35	23.82	23.85	25.45	22.45	23.87	24.07	24.79	22.48	24.19	24.22	94.54	95.85	95.68
Energy Prices															
Crude Oil West Texas Intermediate Spo															
(dollars per barrel)	77.50	81.77	76.43	70.74	71.85	64.63	65.78	59.31	50.93	50.68	52.00	52.00	76.60	65.32	51.42
Natural Gas Henry Hub Spot															
(dollars per million Btu)	2.13	2.09	2.11	2.44	4.15	3.19	3.03	3.87	4.35	3.32	3.91	4.48	2.19	3.56	4.01
Coal															
(dollars per million Btu)	2.49	2.53	2.44	2.43	2.43	2.48	2.40	2.39	2.41	2.40	2.40	2.38	2.47	2.42	2.40
Macroeconomic															
Real Gross Domestic Product															
(billion chained 2017 dollars - SAAR)	23,082	23,287	23,479	23,587	23,548	23,771	23,953	24,006	24,141	24,284	24,432	24,559	23,358	23,820	24,354
Percent change from prior year	2.9	3.1	2.8	2.4	2.0	2.1	2.0	1.8	2.5	2.2	2.0	2.3	2.8	2.0	2.2
GDP Implicit Price Deflator															
(Index, 2017=100)	124.4	125.2	125.7	126.5	127.6	128.3	129.2	130.4	131.5	132.3	133.0	133.9	125.4	128.9	132.7
Percent change from prior year	2.5	2.7	2.3	2.5	2.6	2.5	2.8	3.1	3.1	3.1	2.9	2.6	2.5	2.7	2.9
Real Disposable Personal Income															
(billion chained 2017 dollars - SAAR)	17,596	17,701	17,755	17,843	17,943	18,082	18,098	18,141	18,424	18,569	18,712	18,859	17,724	18,066	18,641
Percent change from prior year	3.5	3.0	2.8	2.4	2.0	2.2	1.9	1.7	2.7	2.7	3.4	4.0	2.9	1.9	3.2
Manufacturing Production Index															
(Index, 2017=100)	99.5	99.8	99.6	99.3	100.1	100.7	100.9	100.6	100.4	100.7	101.1	101.5	99.5	100.6	100.9
Percent change from prior year	-0.6	-0.3	-0.4	-0.4	0.7	0.9	1.3	1.4	0.3	0.0	0.2	0.9	-0.4	1.0	0.3
Weather															
U.S. Heating Degree-Days	1,905	414	50	1,321	2,103	436	54	1,449	1,960	464	73	1,424	3,690	4,042	3,921
U.S. Cooling Degree-Days	54	496	942	141	54	464	904	116	51	451	979	107	1,634	1,537	1,589

(a) Includes lease condensate.

(b) Total consumption includes Independent Power Producer (IPP) consumption.

(c) Renewable energy includes minor components of non-marketed renewable energy that is neither bought nor sold, either directly or indirectly, as inputs to marketed energy. EIA does not estimate or project end-use consumption of non-marketed renewable energy.

(d) The conversion from physical units to Btu is calculated using a subset of conversion factors used in the calculations of gross energy consumption in EIA's *Monthly Energy Review* (MER). Consequently, the historical data may not precisely match those published in the MER.

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

- = no data available

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

Prices are not adjusted for inflation.

Sources:

Historical data: Latest data available from Energy Information Administration databases supporting the following reports: Petroleum Supply Monthly; *Petroleum Supply Annual; Weekly Petroleum Status Report; Petroleum Marketing Monthly; Natural Gas Monthly; Electric Power Monthly; Quarterly Coal Report; and International Petroleum Monthly*.

Minor discrepancies with published historical data are due to independent rounding.

Forecasts: EIA Short-Term Integrated Forecasting System. U.S. macroeconomic forecasts are based on the S&P Global model of the U.S. Economy.

Table 2. Energy Prices

U.S. Energy Information Administration | Short-Term Energy Outlook - December 2025

	2024				2025				2026				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
Crude Oil (dollars per barrel)															
West Texas Intermediate Spot Average	77.50	81.77	76.43	70.74	71.85	64.63	65.78	59.31	50.93	50.68	52.00	52.00	76.60	65.32	51.42
Brent Spot Average	82.96	84.72	80.03	74.65	75.83	68.01	69.00	63.10	54.93	54.02	55.32	56.00	80.56	68.91	55.08
U.S. Imported Average	72.22	79.62	74.83	69.36	70.83	64.13	65.35	56.47	48.20	47.88	49.25	49.25	74.14	64.41	48.62
U.S. Refiner Average Acquisition Cost	76.42	81.76	76.98	71.39	72.63	65.58	66.78	59.54	51.24	50.93	52.25	52.25	76.63	66.07	51.67
U.S. Liquid Fuels (dollars per gallon)															
Wholesale Petroleum Product Prices															
Gasoline	2.46	2.58	2.34	2.11	2.20	2.17	2.22	2.01	1.85	2.01	2.05	1.89	2.37	2.15	1.95
Diesel Fuel	2.70	2.51	2.31	2.23	2.39	2.18	2.38	2.35	2.17	2.03	2.16	2.19	2.43	2.33	2.14
Fuel Oil	2.64	2.42	2.09	2.07	2.31	2.08	2.26	2.25	2.11	1.95	2.02	2.08	2.30	2.23	2.04
Jet Fuel	2.68	2.52	2.27	2.15	2.29	2.07	2.19	2.21	2.11	1.89	1.99	2.03	2.40	2.19	2.00
No. 6 Residual Fuel Oil (a)	1.98	2.06	2.00	1.84	1.88	1.70	1.72	1.60	1.43	1.34	1.39	1.40	1.97	1.73	1.39
Propane Mont Belvieu Spot	0.84	0.75	0.74	0.78	0.90	0.78	0.69	0.61	0.57	0.59	0.62	0.64	0.78	0.74	0.61
Retail Prices Including Taxes															
Gasoline Regular Grade (b)	3.24	3.56	3.37	3.07	3.10	3.16	3.14	3.03	2.88	3.05	3.12	2.94	3.31	3.11	3.00
Gasoline All Grades (b)	3.36	3.68	3.48	3.19	3.22	3.28	3.27	3.16	3.01	3.17	3.25	3.07	3.43	3.23	3.13
On-highway Diesel Fuel	3.97	3.85	3.69	3.54	3.63	3.55	3.76	3.75	3.60	3.41	3.46	3.53	3.76	3.67	3.50
Heating Oil	3.79	3.66	3.54	3.43	3.75	3.47	3.60	3.59	3.49	3.25	3.23	3.33	3.60	3.60	3.32
Propane Residential	2.58	2.48	2.38	2.48	2.71	0.00	0.00	2.48	2.63	0.00	0.00	2.31	2.48	0.00	0.00
Natural Gas															
Henry Hub Spot (dollars per thousand cubic feet)	2.21	2.17	2.19	2.54	4.30	3.31	3.14	4.01	4.51	3.44	4.06	4.65	2.28	3.69	4.17
Henry Hub Spot (dollars per million Btu)	2.13	2.09	2.11	2.44	4.15	3.19	3.03	3.87	4.35	3.32	3.91	4.48	2.19	3.56	4.01
U.S. Retail Prices (dollars per thousand cubic feet)															
Industrial Sector	4.54	3.40	3.33	4.31	5.69	4.69	4.29	4.88	5.61	4.19	4.55	5.40	3.93	4.93	4.97
Commercial Sector	9.84	10.34	10.99	10.13	10.28	11.73	12.41	10.37	10.35	10.59	11.10	10.03	10.14	10.76	10.37
Residential Sector	12.71	16.69	23.05	14.37	13.09	18.46	25.37	14.93	13.67	16.51	22.25	14.13	14.55	15.21	14.84
U.S. Electricity															
Power Generation Fuel Costs (dollars per million Btu)															
Coal	2.49	2.53	2.44	2.43	2.43	2.48	2.40	2.39	2.41	2.40	2.40	2.38	2.47	2.42	2.40
Natural Gas	3.41	2.37	2.38	3.03	5.03	3.39	3.26	4.18	4.88	3.45	3.91	4.71	2.76	3.91	4.22
Residual Fuel Oil (c)	18.85	18.54	17.84	16.16	16.29	15.22	15.89	13.43	12.37	11.83	11.32	11.39	17.79	15.31	11.73
Distillate Fuel Oil	20.09	19.70	18.67	17.89	18.59	17.49	18.12	18.14	17.26	15.93	16.58	16.99	19.11	18.19	16.78
Prices to Ultimate Customers (cents per kilowatthour)															
Industrial Sector	7.84	8.03	8.62	7.98	8.25	8.44	9.13	8.50	8.55	8.64	9.32	8.58	8.13	8.59	8.78
Commercial Sector	12.50	12.53	13.25	12.63	13.07	13.21	14.08	13.19	13.46	13.60	14.45	13.42	12.75	13.42	13.76
Residential Sector	15.99	16.52	16.67	16.71	16.43	17.46	17.69	17.59	17.35	18.18	18.30	18.19	16.48	17.29	18.02

(a) Average for all sulfur contents.

(b) Average self-service cash price.

(c) Includes fuel oils No. 4, No. 5, No. 6, and topped crude.

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

- = no data available

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

Prices are not adjusted for inflation; prices exclude taxes unless otherwise noted.

Sources:

Historical data: Latest data available from Energy Information Administration databases supporting the following reports: Petroleum Marketing Monthly; *Weekly Petroleum Status Report; Natural Gas Monthly; Electric Power Monthly; Monthly Energy Review; Heating Oil and Propoane Update.*

WTI and Brent crude oil spot prices, the Mt. Belvieu propane spot price, and the Henry Hub natural gas spot price are from Refinitiv,an LSEG company, via EIA (https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm).

Retail heating oil prices are from the Bureau of Labor Statistics, *Consumer Price Index.*

Minor discrepancies with published historical data are due to independent rounding.

Forecasts: EIA Short-Term Integrated Forecasting System.

Table 3a. World Petroleum and Other Liquid Fuels Production, Consumption, and Inventories

U.S. Energy Information Administration | Short-Term Energy Outlook - December 2025

	2024				2025				2026				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
Production (million barrels per day) (a)															
World total	**102.59**	**103.21**	**103.07**	**103.81**	**103.62**	**105.17**	**107.85**	**108.00**	**106.50**	**107.25**	**107.87**	**108.06**	**103.17**	**106.18**	**107.43**
Crude oil	76.97	76.48	76.14	76.71	77.21	77.97	79.93	80.43	79.37	79.34	79.62	79.85	76.57	78.90	79.55
Other liquids	25.62	26.73	26.93	27.11	26.41	27.19	27.92	27.57	27.13	27.90	28.26	28.22	26.60	27.28	27.88
World total	**102.59**	**103.21**	**103.07**	**103.81**	**103.62**	**105.17**	**107.85**	**108.00**	**106.50**	**107.25**	**107.87**	**108.06**	**103.17**	**106.18**	**107.43**
OPEC total (b)	32.72	32.77	32.65	32.77	32.91	33.41	34.00	34.21	33.40	33.77	34.01	33.84	32.73	33.64	33.76
Crude oil	27.10	27.13	27.00	27.12	27.21	27.71	28.30	28.47	27.60	27.93	28.14	27.93	27.09	27.92	27.90
Other liquids	5.62	5.63	5.64	5.65	5.71	5.70	5.71	5.74	5.80	5.83	5.88	5.91	5.64	5.72	5.86
Non-OPEC total	**69.87**	**70.44**	**70.43**	**71.04**	**70.71**	**71.75**	**73.85**	**73.79**	**73.10**	**73.48**	**73.86**	**74.22**	**70.45**	**72.54**	**73.67**
Crude oil	49.87	49.35	49.14	49.59	50.01	50.26	51.64	51.96	51.77	51.41	51.48	51.91	49.48	50.97	51.64
Other liquids	20.00	21.10	21.29	21.45	20.70	21.49	22.21	21.83	21.33	22.07	22.38	22.30	20.96	21.56	22.02
Consumption (million barrels per day) (c)															
World total	**101.29**	**103.12**	**103.48**	**103.29**	**102.30**	**103.96**	**104.78**	**104.66**	**103.71**	**105.20**	**106.03**	**105.70**	**102.80**	**103.94**	**105.17**
OECD total (d)	**44.94**	**45.79**	**46.41**	**46.28**	**45.19**	**45.68**	**46.38**	**46.04**	**45.53**	**45.78**	**46.49**	**46.17**	**45.86**	**45.83**	**46.00**
Canada	2.36	2.30	2.44	2.37	2.39	2.37	2.45	2.40	2.38	2.35	2.46	2.40	2.37	2.40	2.40
Europe	12.81	13.60	14.01	13.47	12.92	13.66	13.73	13.53	13.17	13.59	14.00	13.55	13.47	13.46	13.58
Japan	3.43	2.95	2.91	3.27	3.35	2.87	2.85	3.18	3.37	2.77	2.82	3.12	3.14	3.06	3.02
United States	19.92	20.53	20.65	20.75	20.31	20.51	21.02	20.52	20.16	20.68	20.81	20.65	20.46	20.59	20.58
U.S. Territories	0.12	0.13	0.14	0.14	0.12	0.12	0.13	0.13	0.12	0.12	0.13	0.13	0.13	0.13	0.12
Other OECD	6.28	6.29	6.26	6.28	6.11	6.14	6.18	6.28	6.33	6.26	6.27	6.32	6.28	6.18	6.30
Non-OECD total	**56.36**	**57.33**	**57.07**	**57.01**	**57.10**	**58.29**	**58.41**	**58.62**	**58.18**	**59.42**	**59.54**	**59.52**	**56.94**	**58.11**	**59.17**
China	16.27	16.47	16.14	16.36	16.39	16.65	16.41	16.77	16.78	16.94	16.69	17.00	16.31	16.56	16.85
Eurasia	4.87	4.97	5.27	5.13	4.85	5.00	5.32	5.21	4.87	5.03	5.35	5.24	5.06	5.10	5.12
Europe	0.76	0.80	0.82	0.82	0.77	0.80	0.82	0.82	0.77	0.80	0.82	0.82	0.80	0.80	0.80
Other Asia	15.10	14.95	14.27	14.71	15.17	15.17	14.71	15.32	15.49	15.62	15.17	15.61	14.76	15.09	15.47
Other non-OECD	19.35	20.14	20.58	20.01	19.92	20.66	21.15	20.50	20.27	21.02	21.51	20.85	20.02	20.56	20.91
Total crude oil and other liquids inventory net withdrawals (million barrels per day)															
World total	**-1.29**	**-0.09**	**0.41**	**-0.52**	**-1.33**	**-1.20**	**-3.07**	**-3.34**	**-2.78**	**-2.05**	**-1.85**	**-2.36**	**-0.37**	**-2.24**	**-2.26**
United States	0.12	-0.63	0.02	0.22	0.31	-0.51	-0.54	0.20	-0.33	-0.49	-0.16	0.26	-0.06	-0.13	-0.18
Other OECD	-0.15	-0.29	0.30	0.22	-0.33	0.02	-0.54	-0.75	-0.41	-0.14	-0.18	-0.46	0.02	-0.40	-0.30
Other inventory draws and balance	-1.26	0.82	0.09	-0.96	-1.31	-0.71	-1.99	-2.79	-2.04	-1.43	-1.51	-2.16	-0.33	-1.71	-1.79
End-of-period commercial crude oil and other liquids inventories (million barrels)															
OECD total	**2,760**	**2,834**	**2,795**	**2,743**	**2,741**	**2,780**	**2,875**	**2,919**	**2,979**	**3,030**	**3,056**	**3,075**	**2,743**	**2,919**	**3,075**
United States	1,232	1,279	1,267	1,236	1,205	1,245	1,290	1,265	1,288	1,327	1,336	1,312	1,236	1,265	1,312
Other OECD	1,529	1,555	1,527	1,507	1,537	1,535	1,585	1,654	1,691	1,703	1,720	1,763	1,507	1,654	1,763

(a) Includes crude oil, lease condensate, natural gas plant liquids, other liquids, refinery processing gain, and other unaccounted-for liquids. Differences in the reported historical production data across countries could result in some inconsistencies in the delineation between crude oil and other liquid fuels.

(b) OPEC = Organization of the Petroleum Exporting Countries: Algeria, Congo (Brazzaville), Equatorial Guinea, Gabon, Iran, Iraq, Kuwait, Libya, Nigeria, Saudi Arabia, United Arab Emirates, and Venezuela.

(c) Consumption of petroleum by the OECD countries is the same as "petroleum product supplied," defined in the glossary of the EIA Petroleum Supply Monthly (DOE/EIA-0109). Consumption of petroleum by the non-OECD countries is "apparent consumption," which includes internal consumption, refinery fuel and loss, and bunkering.

(d) OECD = Organization for Economic Cooperation and Development: Australia, Austria, Belgium, Canada, Chile, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Japan, Latvia, Lithuania, Luxembourg, Mexico, Netherlands, New Zealand, Norway, Poland, Portugal, Slovakia, Slovenia, South Korea, Spain, Sweden, Switzerland, Turkiye, United Kingdom, and United States.

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

- = no data available

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

Minor discrepancies with published historical data are due to independent rounding.

Sources:

Historical data: Energy Information Administration *International Energy Statistics* (https://www.eia.gov/international/data/world).

Forecasts: EIA Short-Term Integrated Forecasting System.

Table 3b. Non-OPEC Petroleum and Other Liquid Fuels Production (million barrels per day)

U.S. Energy Information Administration | Short-Term Energy Outlook - December 2025

	2024				2025				2026				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
Petroleum and other liquid fuels production (a)															
Non-OPEC total (b)	**69.87**	**70.44**	**70.43**	**71.04**	**70.71**	**71.75**	**73.85**	**73.79**	**73.10**	**73.48**	**73.86**	**74.22**	**70.45**	**72.54**	**73.67**
North America total	**30.00**	**30.75**	**30.95**	**31.69**	**30.89**	**31.31**	**32.33**	**32.33**	**31.77**	**31.71**	**31.91**	**32.19**	**30.85**	**31.72**	**31.90**
Canada	5.95	5.82	5.92	6.29	6.28	5.96	6.35	6.45	6.42	6.11	6.31	6.52	6.00	6.26	6.34
Mexico	2.05	2.00	2.04	1.95	1.87	1.86	1.88	1.82	1.82	1.80	1.78	1.76	2.01	1.86	1.79
United States	22.01	22.92	22.99	23.45	22.75	23.49	24.10	24.05	23.53	23.80	23.82	23.91	22.84	23.60	23.77
Central and South America total	**7.01**	**7.50**	**7.74**	**7.33**	**7.14**	**7.71**	**8.51**	**8.28**	**8.00**	**8.55**	**8.89**	**8.54**	**7.39**	**7.91**	**8.50**
Argentina	0.86	0.87	0.91	0.94	0.93	0.94	1.02	1.01	1.03	1.04	1.04	1.07	0.89	0.98	1.05
Brazil	3.90	4.39	4.67	4.15	3.99	4.57	5.21	4.81	4.54	5.09	5.43	5.03	4.28	4.65	5.03
Colombia	0.80	0.82	0.80	0.79	0.79	0.77	0.78	0.77	0.77	0.76	0.76	0.76	0.80	0.78	0.76
Guyana	0.64	0.62	0.57	0.64	0.63	0.65	0.81	0.89	0.88	0.88	0.88	0.91	0.62	0.75	0.89
Europe total	**3.94**	**3.85**	**3.72**	**3.90**	**3.95**	**3.89**	**3.98**	**4.01**	**4.04**	**3.94**	**3.84**	**3.96**	**3.85**	**3.96**	**3.95**
Norway	2.06	2.01	1.95	2.01	1.97	1.96	2.14	2.14	2.17	2.09	2.06	2.11	2.01	2.05	2.11
United Kingdom	0.77	0.74	0.68	0.77	0.82	0.77	0.69	0.75	0.76	0.74	0.67	0.74	0.74	0.76	0.73
Eurasia total	**13.79**	**13.40**	**13.20**	**13.19**	**13.53**	**13.59**	**13.65**	**13.69**	**13.82**	**13.77**	**13.62**	**13.83**	**13.39**	**13.61**	**13.76**
Azerbaijan	0.60	0.59	0.59	0.60	0.57	0.57	0.56	0.56	0.55	0.54	0.53	0.53	0.60	0.57	0.54
Kazakhstan	2.00	1.90	1.90	1.82	2.16	2.18	2.21	2.13	2.23	2.20	2.15	2.22	1.90	2.17	2.20
Russia	10.83	10.55	10.34	10.42	10.44	10.47	10.50	10.62	10.66	10.64	10.56	10.70	10.53	10.51	10.64
Middle East total	**3.13**	**3.15**	**3.14**	**3.15**	**3.16**	**3.21**	**3.24**	**3.26**	**3.25**	**3.27**	**3.33**	**3.36**	**3.14**	**3.22**	**3.30**
Oman	1.01	1.00	1.00	1.00	1.00	1.00	1.02	1.03	1.04	1.05	1.05	1.05	1.00	1.01	1.05
Qatar	1.84	1.85	1.86	1.86	1.88	1.88	1.90	1.91	1.91	1.91	1.96	2.00	1.85	1.89	1.94
Africa total	**2.63**	**2.50**	**2.55**	**2.56**	**2.56**	**2.54**	**2.68**	**2.66**	**2.64**	**2.64**	**2.67**	**2.70**	**2.56**	**2.61**	**2.66**
Angola	1.20	1.16	1.17	1.13	1.08	1.01	1.09	1.07	1.07	1.07	1.11	1.14	1.16	1.06	1.10
Egypt	0.66	0.65	0.63	0.62	0.61	0.61	0.60	0.62	0.60	0.60	0.60	0.60	0.64	0.61	0.60
Asia and Oceania total	**9.36**	**9.29**	**9.14**	**9.22**	**9.48**	**9.49**	**9.48**	**9.56**	**9.58**	**9.61**	**9.60**	**9.63**	**9.25**	**9.50**	**9.61**
China	5.39	5.36	5.29	5.30	5.51	5.48	5.42	5.42	5.45	5.48	5.47	5.51	5.33	5.46	5.48
India	0.96	0.96	0.94	0.96	1.02	1.01	1.01	1.03	1.05	1.05	1.05	1.06	0.95	1.02	1.06
Indonesia	0.83	0.85	0.83	0.85	0.85	0.85	0.86	0.85	0.85	0.85	0.85	0.84	0.84	0.85	0.85
Malaysia	0.60	0.58	0.53	0.57	0.57	0.60	0.63	0.62	0.59	0.60	0.59	0.59	0.57	0.61	0.59
Unplanned production outages															
Non-OPEC total	**1.08**	**1.15**	**1.37**	**1.36**	**1.28**	**1.15**	**1.01**	**-**	**-**	**-**	**-**	**-**	**1.24**	**-**	**-**

(a) Includes crude oil, lease condensate, natural gas plant liquids, other liquids, refinery processing gain, and other unaccounted-for liquids.

(b) OPEC = Organization of the Petroleum Exporting Countries: Algeria, Congo (Brazzaville), Equatorial Guinea, Gabon, Iran, Iraq, Kuwait, Libya, Nigeria, Saudi Arabia, United Arab Emirates, and Venezuela.

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

- = no data available

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

Minor discrepancies with published historical data are due to independent rounding.

Sources:

Historical data: Energy Information Administration *International Energy Statistics* (https://www.eia.gov/international/data/world).

Forecasts: EIA Short-Term Integrated Forecasting System.

Table 3c. World Petroleum and Other Liquid Fuels Production (million barrels per day)

U.S. Energy Information Administration | Short-Term Energy Outlook - December 2025

	2024				2025				2026				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
Petroleum and other liquid fuels production (a)															
World total	**102.59**	**103.21**	**103.07**	**103.81**	**103.62**	**105.17**	**107.85**	**108.00**	**106.50**	**107.25**	**107.87**	**108.06**	**103.17**	**106.18**	**107.43**
OPEC+ total (b)	43.67	43.00	42.86	42.62	42.88	43.43	44.18	44.45	44.03	44.34	44.40	44.39	43.04	43.74	44.29
United States	22.01	22.92	22.99	23.45	22.75	23.49	24.10	24.05	23.53	23.80	23.82	23.91	22.84	23.60	23.77
Non-OPEC+ excluding United States	36.91	37.28	37.23	37.74	38.00	38.24	39.57	39.50	38.94	39.11	39.65	39.76	37.29	38.83	39.37
OPEC total (c)	**32.72**	**32.77**	**32.65**	**32.77**	**32.91**	**33.41**	**34.00**	**34.21**	**33.40**	**33.77**	**34.01**	**33.84**	**32.73**	**33.64**	**33.76**
Algeria	1.38	1.37	1.38	1.38	1.38	1.39	1.41	-	-	-	-	-	1.38	-	-
Congo (Brazzaville)	0.26	0.26	0.25	0.24	0.25	0.24	0.25	-	-	-	-	-	0.25	-	-
Equatorial Guinea	0.10	0.09	0.10	0.10	0.09	0.09	0.09	-	-	-	-	-	0.10	-	-
Gabon	0.21	0.22	0.21	0.22	0.23	0.24	0.24	-	-	-	-	-	0.21	-	-
Iran	4.55	4.58	4.66	4.71	4.74	4.69	4.69	-	-	-	-	-	4.63	-	-
Iraq	4.54	4.57	4.56	4.35	4.45	4.45	4.47	-	-	-	-	-	4.51	-	-
Kuwait	2.77	2.81	2.76	2.76	2.72	2.77	2.79	-	-	-	-	-	2.78	-	-
Libya	1.20	1.28	0.99	1.26	1.34	1.39	1.39	-	-	-	-	-	1.18	-	-
Nigeria	1.57	1.52	1.59	1.57	1.64	1.68	1.72	-	-	-	-	-	1.56	-	-
Saudi Arabia	10.79	10.68	10.71	10.66	10.68	10.97	11.19	-	-	-	-	-	10.71	-	-
United Arab Emirates	4.49	4.47	4.51	4.59	4.41	4.49	4.73	-	-	-	-	-	4.51	-	-
Venezuela	0.86	0.90	0.93	0.92	0.98	1.01	1.03	-	-	-	-	-	0.90	-	-
OPEC+ total (b)	**43.67**	**43.00**	**42.86**	**42.62**	**42.88**	**43.43**	**44.18**	**44.45**	**44.03**	**44.34**	**44.40**	**44.39**	**43.04**	**43.74**	**44.29**
OPEC members subject to OPEC+ agreements (d)	**26.11**	**26.00**	**26.07**	**25.87**	**25.86**	**26.32**	**26.89**	**27.19**	**26.68**	**27.04**	**27.27**	**27.09**	**26.01**	**26.57**	**27.02**
OPEC+ other participants total	**17.56**	**17.00**	**16.79**	**16.75**	**17.02**	**17.11**	**17.29**	**17.26**	**17.35**	**17.30**	**17.13**	**17.31**	**17.02**	**17.17**	**17.27**
Azerbaijan	0.60	0.59	0.59	0.60	0.57	0.57	0.56	0.56	0.55	0.54	0.53	0.53	0.60	0.57	0.54
Bahrain	0.18	0.20	0.17	0.19	0.20	0.19	0.20	0.19	0.17	0.18	0.18	0.18	0.19	0.19	0.18
Brunei	0.10	0.08	0.11	0.11	0.11	0.10	0.11	0.11	0.11	0.10	0.11	0.11	0.10	0.11	0.11
Kazakhstan	2.00	1.90	1.90	1.82	2.16	2.18	2.21	2.13	2.23	2.20	2.15	2.22	1.90	2.17	2.20
Malaysia	0.60	0.58	0.53	0.57	0.57	0.60	0.63	0.62	0.59	0.60	0.59	0.59	0.57	0.61	0.59
Mexico	2.05	2.00	2.04	1.95	1.87	1.86	1.88	1.82	1.82	1.80	1.78	1.76	2.01	1.86	1.79
Oman	1.01	1.00	1.00	1.00	1.00	1.00	1.02	1.03	1.04	1.05	1.05	1.05	1.00	1.01	1.05
Russia	10.83	10.55	10.34	10.42	10.44	10.47	10.50	10.62	10.66	10.64	10.56	10.70	10.53	10.51	10.64
South Sudan	0.13	0.06	0.06	0.06	0.07	0.10	0.15	0.14	0.15	0.15	0.15	0.15	0.08	0.12	0.15
Sudan	0.06	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.03	0.03

(a) Includes crude oil, lease condensate, natural gas plant liquids, other liquids, refinery processing gain, and other unaccounted-for liquids.

(b) OPEC+ total = OPEC members subject to OPEC+ agreements plus Azerbaijan, Bahrain, Brunei, Kazakhstan, Malaysia, Mexico, Oman, Russia, South Sudan, and Sudan.

(c) OPEC = Organization of the Petroleum Exporting Countries: Algeria, Congo (Brazzaville), Equatorial Guinea, Gabon, Iran, Iraq, Kuwait, Libya, Nigeria, Saudi Arabia, United Arab Emirates, and Venezuela.

(d) Iran, Libya, and Venezuela are not sbuject to the OPEC+ agreements.

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

- = no data available

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

Minor discrepancies with published historical data are due to independent rounding.

Sources:

Historical data: Energy Information Administration *International Energy Statistics* (https://www.eia.gov/international/data/world).

Forecasts: EIA Short-Term Integrated Forecasting System.

Table 3d. World Crude Oil Production (million barrels per day)

U.S. Energy Information Administration | Short-Term Energy Outlook - December 2025

	2024				2025				2026				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
Crude oil production (a)															
World total	**76.97**	**76.48**	**76.14**	**76.71**	**77.21**	**77.97**	**79.93**	**80.43**	**79.37**	**79.34**	**79.62**	**79.85**	**76.57**	**78.90**	**79.55**
OPEC+ total (b)	36.63	36.07	35.93	35.49	35.70	36.33	37.20	37.32	36.84	37.20	37.34	37.14	36.03	36.64	37.13
United States	12.94	13.27	13.27	13.45	13.28	13.51	13.78	13.86	13.63	13.58	13.44	13.49	13.23	13.61	13.53
Non-OPEC+ excluding United States	27.39	27.13	26.95	27.77	28.23	28.14	28.95	29.25	28.90	28.56	28.84	29.22	27.31	28.65	28.88
OPEC total (c)	**27.10**	**27.13**	**27.00**	**27.12**	**27.21**	**27.71**	**28.30**	**28.47**	**27.60**	**27.93**	**28.14**	**27.93**	**27.09**	**27.92**	**27.90**
Algeria	0.91	0.90	0.91	0.91	0.91	0.92	0.94	-	-	-	-	-	0.91	-	-
Congo (Brazzaville)	0.25	0.25	0.24	0.23	0.24	0.23	0.24	-	-	-	-	-	0.24	-	-
Equatorial Guinea	0.06	0.05	0.06	0.06	0.06	0.05	0.06	-	-	-	-	-	0.06	-	-
Gabon	0.21	0.22	0.21	0.22	0.23	0.24	0.24	-	-	-	-	-	0.22	-	-
Iran	3.24	3.26	3.34	3.39	3.40	3.37	3.35	-	-	-	-	-	3.31	-	-
Iraq	4.43	4.46	4.45	4.25	4.31	4.30	4.34	-	-	-	-	-	4.40	-	-
Kuwait	2.46	2.49	2.44	2.44	2.43	2.48	2.49	-	-	-	-	-	2.46	-	-
Libya	1.10	1.19	0.89	1.17	1.25	1.29	1.30	-	-	-	-	-	1.09	-	-
Nigeria	1.28	1.24	1.31	1.30	1.37	1.42	1.47	-	-	-	-	-	1.28	-	-
Saudi Arabia	9.12	9.00	9.02	8.95	8.94	9.21	9.43	-	-	-	-	-	9.02	-	-
United Arab Emirates	3.25	3.23	3.27	3.35	3.17	3.25	3.49	-	-	-	-	-	3.27	-	-
Venezuela	0.79	0.83	0.86	0.85	0.91	0.94	0.96	-	-	-	-	-	0.83	-	-
OPEC+ total (b)	**36.63**	**36.07**	**35.93**	**35.49**	**35.70**	**36.33**	**37.20**	**37.32**	**36.84**	**37.20**	**37.34**	**37.14**	**36.03**	**36.64**	**37.13**
OPEC members subject to OPEC+ agreements (d)	**21.97**	**21.85**	**21.91**	**21.71**	**21.65**	**22.11**	**22.69**	**22.95**	**22.41**	**22.73**	**22.92**	**22.70**	**21.86**	**22.35**	**22.69**
OPEC+ other participants total	**14.66**	**14.22**	**14.02**	**13.78**	**14.05**	**14.22**	**14.51**	**14.37**	**14.44**	**14.47**	**14.42**	**14.44**	**14.17**	**14.29**	**14.44**
Azerbaijan	0.47	0.47	0.48	0.48	0.47	0.45	0.44	-	-	-	-	-	0.48	-	-
Bahrain	0.17	0.18	0.16	0.18	0.19	0.18	0.18	-	-	-	-	-	0.17	-	-
Brunei	0.08	0.06	0.09	0.08	0.09	0.08	0.08	-	-	-	-	-	0.08	-	-
Kazakhstan	1.58	1.52	1.53	1.39	1.73	1.78	1.83	-	-	-	-	-	1.50	-	-
Malaysia	0.37	0.36	0.31	0.34	0.34	0.36	0.39	-	-	-	-	-	0.34	-	-
Mexico	1.60	1.56	1.57	1.49	1.42	1.43	1.43	-	-	-	-	-	1.55	-	-
Oman	0.76	0.76	0.76	0.76	0.75	0.76	0.78	-	-	-	-	-	0.76	-	-
Russia	9.44	9.19	9.03	8.97	8.97	9.05	9.18	-	-	-	-	-	9.16	-	-
South Sudan	0.13	0.06	0.06	0.06	0.07	0.10	0.15	-	-	-	-	-	0.08	-	-
Sudan	0.06	0.03	0.03	0.03	0.03	0.03	0.03	-	-	-	-	-	0.04	-	-
Crude oil production capacity															
OPEC total	**31.29**	**31.53**	**31.49**	**31.79**	**32.10**	**32.19**	**32.19**	**32.24**	**32.02**	**32.04**	**32.04**	**32.05**	**31.53**	**32.18**	**32.04**
Middle East	26.59	26.74	26.91	26.95	27.05	27.02	26.93	27.04	26.96	26.96	26.96	26.96	26.80	27.01	26.96
Other	4.70	4.79	4.58	4.84	5.05	5.17	5.26	5.20	5.07	5.08	5.08	5.10	4.73	5.17	5.08
Surplus crude oil production capacity															
OPEC total	**4.19**	**4.40**	**4.49**	**4.67**	**4.89**	**4.48**	**3.90**	**3.77**	**4.43**	**4.11**	**3.90**	**4.12**	**4.44**	**4.26**	**4.14**
Middle East	4.09	4.29	4.39	4.58	4.80	4.40	3.84	3.73	4.39	4.07	3.86	4.08	4.34	4.19	4.10
Other	0.10	0.11	0.10	0.10	0.09	0.08	0.06	0.04	0.04	0.04	0.04	0.04	0.10	0.07	0.04
Unplanned production outages															
OPEC total	**1.42**	**1.31**	**1.46**	**1.20**	**1.13**	**1.10**	**1.09**	**-**	**-**	**-**	**-**	**-**	**1.35**	**-**	**-**

(a) Differences in the reported historical production data across countries could result in some inconsistencies in the delineation between crude oil and other liquid fuels.

(b) OPEC+ total = OPEC members subject to OPEC+ agreements plus Azerbaijan, Bahrain, Brunei, Kazakhstan, Malaysia, Mexico, Oman, Russia, South Sudan, and Sudan.

(c) OPEC = Organization of the Petroleum Exporting Countries: Algeria, Congo (Brazzaville), Equatorial Guinea, Gabon, Iran, Iraq, Kuwait, Libya, Nigeria, Saudi Arabia, United Arab Emirates, and Venezuela.

(d) Iran, Libya, and Venezuela are not sbuject to the OPEC+ agreements.

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

- = no data available

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

Minor discrepancies with published historical data are due to independent rounding.

Sources:

Historical data: Energy Information Administration *International Energy Statistics* (https://www.eia.gov/international/data/world).

Forecasts: EIA Short-Term Integrated Forecasting System.

Table 3e. World Petroleum and Other Liquid Fuels Consumption (million barrels per day)

U.S. Energy Information Administration | Short-Term Energy Outlook - December 2025

	2024				2025				2026						
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
Petroleum and other liquid fuels consumption (a)															
World total	**101.29**	**103.12**	**103.48**	**103.29**	**102.30**	**103.96**	**104.78**	**104.66**	**103.71**	**105.20**	**106.03**	**105.70**	**102.80**	**103.94**	**105.17**
OECD total (b)	44.94	45.79	46.41	46.28	45.19	45.68	46.38	46.04	45.53	45.78	46.49	46.17	45.86	45.83	46.00
Non-OECD total	56.36	57.33	57.07	57.01	57.10	58.29	58.41	58.62	58.18	59.42	59.54	59.52	56.94	58.11	59.17
World total	**101.29**	**103.12**	**103.48**	**103.29**	**102.30**	**103.96**	**104.78**	**104.66**	**103.71**	**105.20**	**106.03**	**105.70**	**102.80**	**103.94**	**105.17**
North America total	**24.13**	**24.73**	**24.98**	**24.92**	**24.45**	**24.71**	**25.31**	**24.73**	**24.37**	**24.91**	**25.14**	**24.86**	**24.69**	**24.80**	**24.82**
Canada	2.36	2.30	2.44	2.37	2.39	2.37	2.45	2.40	2.38	2.35	2.46	2.40	2.37	2.40	2.40
Mexico	1.83	1.89	1.88	1.79	1.75	1.83	1.82	1.81	1.82	1.87	1.86	1.80	1.85	1.80	1.84
United States	19.92	20.53	20.65	20.75	20.31	20.51	21.02	20.52	20.16	20.68	20.81	20.65	20.46	20.59	20.58
Central and South America total	**6.66**	**6.84**	**6.98**	**6.94**	**6.80**	**6.95**	**7.08**	**7.05**	**6.91**	**7.08**	**7.21**	**7.16**	**6.86**	**6.97**	**7.09**
Brazil	3.16	3.24	3.33	3.34	3.25	3.32	3.41	3.41	3.32	3.38	3.48	3.47	3.27	3.35	3.41
Europe total	**13.58**	**14.39**	**14.82**	**14.29**	**13.68**	**14.47**	**14.55**	**14.35**	**13.94**	**14.40**	**14.82**	**14.37**	**14.27**	**14.27**	**14.38**
Eurasia total	**4.87**	**4.97**	**5.27**	**5.13**	**4.85**	**5.00**	**5.32**	**5.21**	**4.87**	**5.03**	**5.35**	**5.24**	**5.06**	**5.10**	**5.12**
Russia	3.61	3.70	4.00	3.85	3.61	3.73	4.03	3.87	3.62	3.74	4.05	3.89	3.79	3.81	3.83
Middle East total	**8.73**	**9.35**	**9.72**	**9.10**	**8.91**	**9.49**	**9.97**	**9.20**	**9.00**	**9.59**	**10.08**	**9.30**	**9.23**	**9.40**	**9.49**
Africa total	**4.65**	**4.66**	**4.60**	**4.67**	**4.91**	**4.91**	**4.79**	**4.94**	**5.06**	**5.05**	**4.93**	**5.09**	**4.65**	**4.89**	**5.03**
Asia and Oceania total	**38.68**	**38.18**	**37.10**	**38.24**	**38.68**	**38.43**	**37.77**	**39.19**	**39.57**	**39.14**	**38.50**	**39.68**	**38.05**	**38.52**	**39.22**
China	16.27	16.47	16.14	16.36	16.39	16.65	16.41	16.77	16.78	16.94	16.69	17.00	16.31	16.56	16.85
India	5.73	5.68	5.23	5.68	5.70	5.74	5.36	5.79	5.84	5.94	5.56	5.93	5.58	5.65	5.82
Japan	3.43	2.95	2.91	3.27	3.35	2.87	2.85	3.18	3.37	2.77	2.82	3.12	3.14	3.06	3.02
Real gross domestic product (c)															
World index, 2015 Q1 = 100	130.5	131.6	132.8	134.2	135.0	136.2	137.1	138.0	138.9	140.2	141.5	142.8	132.3	136.6	140.9
Percent change from prior year	3.3	3.1	3.2	3.5	3.4	3.5	3.3	2.8	2.9	2.9	3.1	3.5	3.3	3.3	3.1
OECD index, 2015 = 100	-	-	-	-	-	-	-	-	-	-	-	-	119.1	121.1	123.2
Percent change from prior year	-	-	-	-	-	-	-	-	-	-	-	-	1.8	1.7	1.8
Non-OECD index, 2015 = 100	-	-	-	-	-	-	-	-	-	-	-	-	141.6	147.9	154.1
Percent change from prior year	-	-	-	-	-	-	-	-	-	-	-	-	4.5	4.5	4.2
Nominal U.S. Dollar index (d)															
Index, 2015 Q1 = 100	114.8	116.6	116.6	119.6	121.3	116.4	114.4	115.2	116.1	116.4	116.5	116.5	116.9	116.8	116.4
Percent change from prior year	0.6	2.8	2.3	3.5	5.7	-0.2	-1.8	-3.7	-4.3	0.0	1.8	1.2	2.3	-0.1	-0.4

(a) Consumption of petroleum by the OECD countries is the same as "petroleum product supplied," defined in the glossary of the EIA Petroleum Supply Monthly (DOE/EIA-0109). Consumption of petroleum by the non-OECD countries is "apparent consumption," which includes internal consumption, refinery fuel and loss, and bunkering.

(b) OECD = Organization for Economic Cooperation and Development: Australia, Austria, Belgium, Canada, Chile, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Japan, Latvia, Lithuania, Luxembourg, Mexico, Netherlands, New Zealand, Norway, Poland, Portugal, Slovakia, Slovenia, South Korea, Spain, Sweden, Switzerland, Turkiye, United Kingdom, and United States.

(c) GDP values for the individual countries in the indexes are converted to U.S. dollars at purchasing power parity and then summed to create values for the world, OECD, and non-OECD. Historical and forecast data are from Oxford Economics, and quarterly values are reindexed to 2015 Q1 by EIA.

(d) An increase in the index indicates an appreciation of the U.S. dollar against a basket of currencies, and a decrease in the index indicates a depreciation of the U.S. dollar against a basket of currencies. Historical data source is the Board of Governors of the U.S. Federal Reserve System Nominal Broad Trade-Weighted Dollar Index accessed via Oxford Economics. Forecast data are from Oxford Economics, and quarterly values are reindexed to 2015 Q1 by EIA.

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

- = no data available

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

Minor discrepancies with published historical data are due to independent rounding.

Sources:

Historical data: Energy Information Administration *International Energy Statistics* (https://www.eia.gov/international/data/world) and Oxford Economics.

Forecasts: EIA Short-Term Integrated Forecasting System.

Table 4a. U.S. Petroleum and Other Liquids Supply, Consumption, and Inventories

U.S. Energy Information Administration | Short-Term Energy Outlook - December 2025

	2024				2025				2026				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
Supply (million barrels per day)															
U.S. total crude oil production (a)	**12.94**	**13.27**	**13.27**	**13.45**	**13.28**	**13.51**	**13.78**	**13.86**	**13.63**	**13.58**	**13.44**	**13.49**	**13.23**	**13.61**	**13.53**
Alaska	0.43	0.42	0.40	0.43	0.44	0.43	0.39	0.43	0.46	0.48	0.45	0.52	0.42	0.42	0.48
Federal Gulf of America (b)	1.78	1.82	1.76	1.78	1.79	1.85	1.96	1.99	2.00	2.00	1.90	1.89	1.79	1.90	1.95
Lower 48 States (excl GOA) (c)	10.73	11.03	11.10	11.24	11.06	11.23	11.44	11.44	11.17	11.11	11.09	11.07	11.03	11.29	11.11
Appalachia region	0.15	0.15	0.16	0.17	0.18	0.20	0.21	0.20	0.18	0.18	0.18	0.18	0.16	0.20	0.18
Bakken region	1.22	1.24	1.22	1.24	1.20	1.19	1.21	1.21	1.17	1.16	1.16	1.15	1.23	1.20	1.16
Eagle Ford region	1.08	1.18	1.20	1.17	1.16	1.18	1.11	1.11	1.11	1.12	1.13	1.14	1.16	1.14	1.12
Haynesville region	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Permian region	6.08	6.26	6.36	6.40	6.33	6.44	6.63	6.75	6.58	6.57	6.54	6.55	6.28	6.54	6.56
Rest of Lower 48 States	2.17	2.17	2.14	2.22	2.15	2.19	2.25	2.14	2.09	2.07	2.06	2.03	2.17	2.18	2.06
Total Supply	**19.92**	**20.53**	**20.65**	**20.75**	**20.30**	**20.51**	**21.02**	**20.52**	**20.16**	**20.68**	**20.81**	**20.65**	**20.46**	**20.59**	**20.58**
Crude oil input to refineries	**15.39**	**16.47**	**16.55**	**16.48**	**15.65**	**16.64**	**16.81**	**15.99**	**15.56**	**16.21**	**16.29**	**15.63**	**16.23**	**16.27**	**15.92**
U.S. total crude oil production (a)	12.94	13.27	13.27	13.45	13.28	13.51	13.78	13.86	13.63	13.58	13.44	13.49	13.23	13.61	13.53
Transfers to crude oil supply	0.52	0.62	0.63	0.69	0.67	0.55	0.69	0.56	0.60	0.59	0.60	0.58	0.61	0.62	0.59
Crude oil net imports (d)	2.18	2.65	2.62	2.53	2.07	2.40	2.44	1.85	2.00	2.13	2.12	1.63	2.49	2.19	1.97
SPR net withdrawals (e)	-0.10	-0.10	-0.11	-0.12	-0.03	-0.07	-0.04	-0.07	-0.07	-0.06	-0.06	0.00	-0.11	-0.05	-0.05
Commercial inventory net withdrawals	-0.23	0.08	0.28	0.02	-0.20	0.20	0.07	-0.25	-0.60	-0.06	0.18	-0.10	0.04	-0.05	-0.14
Crude oil adjustment (f)	0.09	-0.05	-0.13	-0.09	-0.13	0.06	-0.12	0.04	0.01	0.02	0.01	0.03	-0.05	-0.04	0.02
Refinery processing gain	**0.91**	**0.98**	**0.97**	**1.02**	**0.94**	**1.01**	**1.01**	**1.01**	**0.94**	**0.97**	**0.99**	**0.98**	**0.97**	**0.99**	**0.97**
Natural Gas Plant Liquids Production	**6.60**	**7.11**	**7.13**	**7.32**	**6.99**	**7.44**	**7.73**	**7.56**	**7.39**	**7.60**	**7.70**	**7.71**	**7.04**	**7.43**	**7.60**
Renewables and oxygenate production (g)	**1.34**	**1.34**	**1.41**	**1.43**	**1.33**	**1.33**	**1.37**	**1.41**	**1.36**	**1.43**	**1.47**	**1.52**	**1.38**	**1.36**	**1.44**
Fuel ethanol production	1.05	1.02	1.07	1.09	1.07	1.04	1.07	1.08	1.06	1.06	1.07	1.10	1.06	1.07	1.08
Petroleum products adjustment (h)	**0.21**	**0.22**	**0.22**	**0.22**	**0.21**	**0.21**	**0.21**	**0.22**	**0.21**	**0.21**	**0.22**	**0.22**	**0.22**	**0.21**	**0.21**
Petroleum products transfers to crude oil supply	**-0.52**	**-0.62**	**-0.63**	**-0.69**	**-0.67**	**-0.55**	**-0.69**	**-0.56**	**-0.60**	**-0.59**	**-0.60**	**-0.58**	**-0.61**	**-0.62**	**-0.59**
Petroleum product net imports (d)	**-4.47**	**-4.37**	**-4.86**	**-5.36**	**-4.71**	**-4.93**	**-4.85**	**-5.63**	**-5.04**	**-4.79**	**-4.98**	**-5.18**	**-4.77**	**-5.03**	**-5.00**
Hydrocarbon gas liquids	-2.59	-2.67	-2.74	-2.88	-2.84	-2.91	-2.86	-3.09	-3.20	-3.21	-3.23	-3.28	-2.72	-2.93	-3.23
Unfinished oils	0.09	0.17	0.11	0.13	0.14	0.05	0.30	0.08	0.13	0.12	0.14	0.07	0.12	0.14	0.11
Other hydrocarbons and oxygenates	-0.05	-0.07	-0.07	-0.11	-0.15	-0.19	-0.19	-0.18	-0.17	-0.18	-0.17	-0.18	-0.08	-0.18	-0.17
Total motor gasoline	-0.32	0.03	-0.08	-0.45	-0.31	0.00	-0.20	-0.44	-0.25	0.17	0.04	-0.20	-0.21	-0.24	-0.06
Jet fuel	-0.10	-0.08	-0.11	-0.13	-0.11	-0.10	-0.09	-0.08	-0.09	0.02	0.05	0.01	-0.11	-0.09	0.00
Distillate fuel oil	-0.85	-1.18	-1.32	-1.22	-0.87	-1.17	-1.22	-1.25	-0.84	-1.06	-1.16	-0.99	-1.14	-1.13	-1.01
Residual fuel oil	-0.02	-0.03	-0.06	0.00	0.03	-0.04	-0.03	-0.02	0.00	0.01	-0.01	0.05	-0.03	-0.02	0.01
Other oils (i)	-0.62	-0.54	-0.58	-0.69	-0.59	-0.57	-0.56	-0.65	-0.61	-0.67	-0.65	-0.66	-0.61	-0.59	-0.65
Petroleum product inventory net withdrawals	**0.45**	**-0.61**	**-0.15**	**0.32**	**0.55**	**-0.63**	**-0.56**	**0.52**	**0.35**	**-0.37**	**-0.28**	**0.36**	**0.01**	**-0.03**	**0.01**
Consumption (million barrels per day)															
U.S. total petroleum products consumption	**19.92**	**20.53**	**20.65**	**20.75**	**20.31**	**20.51**	**21.02**	**20.52**	**20.16**	**20.68**	**20.81**	**20.65**	**20.46**	**20.59**	**20.58**
Hydrocarbon gas liquids	3.85	3.49	3.52	4.11	4.06	3.52	3.94	4.05	4.06	3.71	3.71	4.12	3.74	3.89	3.90
Other hydrocarbons and oxygenates	0.30	0.33	0.34	0.33	0.22	0.21	0.22	0.26	0.24	0.30	0.34	0.35	0.33	0.23	0.31
Motor gasoline	8.63	9.16	9.19	8.89	8.64	9.08	9.11	8.78	8.59	9.06	9.02	8.74	8.97	8.90	8.85
Jet fuel	1.58	1.73	1.76	1.70	1.60	1.79	1.79	1.73	1.61	1.82	1.81	1.72	1.69	1.73	1.74
Distillate fuel oil	3.81	3.74	3.76	3.85	3.98	3.88	3.78	3.81	3.94	3.84	3.83	3.86	3.79	3.86	3.87
Residual fuel oil	0.29	0.30	0.27	0.31	0.32	0.26	0.32	0.25	0.27	0.28	0.27	0.29	0.29	0.29	0.28
Other oils (i)	1.47	1.78	1.82	1.56	1.48	1.77	1.86	1.63	1.45	1.68	1.83	1.58	1.65	1.68	1.64
Total petroleum and other liquid fuels net imports (d)	**-2.29**	**-1.72**	**-2.24**	**-2.83**	**-2.64**	**-2.54**	**-2.41**	**-3.78**	**-3.04**	**-2.66**	**-2.86**	**-3.55**	**-2.27**	**-2.84**	**-3.03**
End-of-period inventories (million barrels)															
Total commercial inventory	**1231.5**	**1279.3**	**1267.4**	**1236.1**	**1204.7**	**1244.6**	**1290.2**	**1264.7**	**1288.0**	**1326.8**	**1335.8**	**1312.0**	**1236.1**	**1264.7**	**1312.0**
Crude oil (excluding SPR)	447.8	440.5	415.2	413.4	431.7	413.9	407.9	430.4	484.9	490.0	473.0	482.3	413.4	430.4	482.3
Hydrocarbon gas liquids	170.2	234.8	276.9	225.7	173.5	252.6	304.6	261.6	214.0	260.9	302.3	252.6	225.7	261.6	252.6
Unfinished oils	91.2	87.4	79.8	76.5	87.5	83.2	85.4	81.7	90.6	88.8	86.3	81.3	76.5	81.7	81.3
Other hydrocarbons and oxygenates	38.3	33.6	33.5	35.0	37.2	33.5	33.2	34.4	37.1	34.1	33.1	35.4	35.0	34.4	35.4
Total motor gasoline	233.5	232.5	219.8	238.2	233.8	232.8	223.2	227.0	226.6	221.4	215.6	232.4	238.2	227.0	232.4
Jet fuel	41.9	44.5	45.4	43.7	41.7	44.4	44.1	43.6	43.5	42.2	42.9	40.2	43.7	43.6	40.2
Distillate fuel oil	121.5	123.6	124.6	130.4	116.8	108.4	125.2	116.2	109.7	108.6	111.9	114.5	130.4	116.2	114.5
Residual fuel oil	29.9	27.3	24.0	22.7	24.8	22.7	20.6	22.0	23.7	23.9	22.0	22.2	22.7	22.0	22.2
Other oils (i)	57.2	55.1	48.3	50.4	57.6	53.0	46.0	47.8	57.9	57.0	48.7	51.1	50.4	47.8	51.1
Crude oil in SPR (e)	**363.9**	**373.1**	**382.9**	**393.6**	**396.7**	**403.0**	**407.0**	**413.6**	**420.0**	**425.3**	**430.7**	**430.7**	**393.6**	**413.6**	**430.7**

(a) Includes lease condensate.

(b) Crude oil production from U.S. Federal leases in the Gulf of America (GOA).

(c) Regional production in this table is based on geographic regions and not geologic formations.

(d) Net imports equal gross imports minus gross exports.

(e) SPR: Strategic Petroleum Reserve

(f) The crude oil adjustment equals the sum of disposition items (e.g. refinery inputs) minus the sum of supply items (e.g. production).

(g) Renewables and oxygenate production includes pentanes plus, oxygenates (excluding fuel ethanol), and renewable fuels. Beginning in January 2021, renewable fuels includes biodiesel, renewable diesel, renewable jet fuel, renewable heating oil, renewable naphtha and gasoline, and other renewable fuels. For December 2020 and prior, renewable fuels includes only biodiesel.

(h) Petroleum products adjustment includes hydrogen/oxygenates/renewables/other hydrocarbons, motor gasoline blending components, and finished motor gasoline.

(i) Other oils includes aviation gasoline blending components, finished aviation gasoline, kerosene, petrochemical feedstocks, special naphthas, lubricants, waxes, petroleum coke, asphalt and road oil, still gas, and miscellaneous products.

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

- = no data available

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

Minor discrepancies with published historical data are due to independent rounding.

Sources:

Historical data: Latest data available from Energy Information Administration databases supporting the following reports: Petroleum Supply Monthly; Petroleum Supply Annual; and Weekly Petroleum Status Report.
Forecasts: EIA Short-Term Integrated Forecasting System.

Table 4b. U.S. Hydrocarbon Gas Liquids (HGL) and Petroleum Refinery Balances (million barrels per day, except inventories and utilization factor)

U.S. Energy Information Administration | Short-Term Energy Outlook - December 2025

	2024				2025				2026				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
HGL production, consumption, and inventories															
Total HGL production	**7.02**	**7.91**	**7.83**	**7.63**	**7.41**	**8.21**	**8.44**	**7.88**	**7.81**	**8.38**	**8.40**	**8.02**	**7.60**	**7.99**	**8.15**
Natural gas processing plant production	**6.60**	**7.11**	**7.13**	**7.32**	**6.99**	**7.44**	**7.73**	**7.56**	**7.39**	**7.60**	**7.70**	**7.71**	**7.04**	**7.43**	**7.60**
Ethane	2.66	2.95	2.84	3.03	2.87	3.09	3.18	3.10	2.98	3.15	3.21	3.26	2.87	3.06	3.15
Propane	2.08	2.17	2.21	2.26	2.19	2.27	2.36	2.43	2.43	2.42	2.43	2.44	2.18	2.31	2.43
Butanes	1.08	1.14	1.17	1.18	1.13	1.19	1.24	1.20	1.20	1.21	1.21	1.21	1.14	1.19	1.21
Natural gasoline (pentanes plus)	0.78	0.86	0.91	0.86	0.80	0.89	0.95	0.83	0.79	0.83	0.86	0.81	0.85	0.87	0.82
Refinery and blender net production	**0.44**	**0.82**	**0.73**	**0.34**	**0.44**	**0.79**	**0.73**	**0.33**	**0.44**	**0.80**	**0.72**	**0.33**	**0.58**	**0.57**	**0.57**
Ethane/ethylene	0.00	-0.01	-0.01	-0.01	-0.02	-0.02	-0.02	-0.01	-0.01	-0.02	-0.02	-0.01	-0.01	-0.02	-0.01
Propane	0.27	0.28	0.28	0.27	0.27	0.29	0.28	0.27	0.26	0.28	0.28	0.27	0.27	0.28	0.28
Propylene (refinery-grade)	0.24	0.27	0.26	0.28	0.25	0.26	0.25	0.27	0.27	0.27	0.26	0.27	0.26	0.26	0.27
Butanes/butylenes	-0.07	0.28	0.21	-0.20	-0.06	0.26	0.22	-0.19	-0.08	0.26	0.19	-0.19	0.05	0.06	0.04
Renewable/oxygenate plant net production of natural gasoli	**-0.02**	**-0.02**	**-0.02**	**-0.02**	**-0.02**	**-0.02**	**-0.02**	**-0.02**	**-0.02**	**-0.02**	**-0.02**	**-0.02**	**-0.02**	**-0.02**	**-0.02**
Total HGL consumption	**3.85**	**3.49**	**3.52**	**4.11**	**4.06**	**3.52**	**3.94**	**4.05**	**4.06**	**3.71**	**3.71**	**4.12**	**3.74**	**3.89**	**3.90**
Ethane/Ethylene	2.25	2.30	2.32	2.56	2.37	2.38	2.64	2.50	2.40	2.50	2.50	2.53	2.36	2.47	2.48
Propane	1.05	0.57	0.58	0.97	1.21	0.57	0.73	0.96	1.12	0.64	0.67	1.00	0.79	0.87	0.86
Propylene (refinery-grade)	0.26	0.28	0.27	0.29	0.26	0.27	0.26	0.28	0.29	0.29	0.28	0.28	0.28	0.27	0.28
Butanes/butylenes	0.29	0.33	0.35	0.29	0.23	0.30	0.32	0.31	0.24	0.29	0.26	0.30	0.32	0.29	0.27
HGL net imports	**-2.59**	**-2.67**	**-2.74**	**-2.88**	**-2.84**	**-2.91**	**-2.86**	**-3.09**	**-3.20**	**-3.21**	**-3.23**	**-3.28**	**-2.72**	**-2.93**	**-3.23**
Ethane	-0.48	-0.46	-0.49	-0.52	-0.57	-0.50	-0.54	-0.58	-0.59	-0.62	-0.68	-0.70	-0.49	-0.55	-0.65
Propane/propylene	-1.60	-1.60	-1.66	-1.72	-1.66	-1.64	-1.63	-1.83	-1.90	-1.85	-1.80	-1.85	-1.64	-1.69	-1.85
Butanes/butylenes	-0.41	-0.47	-0.46	-0.43	-0.44	-0.55	-0.50	-0.47	-0.50	-0.56	-0.55	-0.51	-0.44	-0.49	-0.53
Natural gasoline (pentanes plus)	-0.11	-0.13	-0.14	-0.20	-0.18	-0.22	-0.19	-0.21	-0.23	-0.19	-0.19	-0.21	-0.15	-0.20	-0.21
HGL inventories (million barrels)	**170.2**	**234.8**	**276.9**	**225.7**	**173.5**	**252.6**	**304.6**	**261.6**	**214.0**	**260.9**	**302.3**	**252.6**	**225.7**	**261.6**	**252.6**
Ethane	59.6	75.3	77.2	71.6	63.9	81.6	80.7	81.2	78.5	80.1	81.2	81.6	71.6	81.2	81.6
Propane	51.59	74.9	97.3	80.7	44.1	75.2	100.1	89.7	58.5	76.9	97.6	83.8	80.7	89.7	83.8
Propylene (at refineries only)	0.89	1.3	1.3	1.4	1.1	1.2	1.2	1.2	1.1	1.4	1.6	1.5	1.4	1.2	1.5
Butanes/butylenes	35.0	59.2	76.5	49.1	42.8	67.6	92.5	60.9	50.0	74.9	93.3	58.8	49.1	60.9	58.8
Natural gasoline (pentanes plus)	23.2	24.1	24.6	23.0	21.6	27.1	30.1	28.6	25.8	27.5	28.6	27.0	23.0	28.6	27.0
Refining															
Total refinery and blender net inputs	**17.58**	**19.04**	**19.06**	**18.53**	**17.52**	**18.86**	**19.06**	**18.13**	**17.47**	**18.59**	**18.67**	**17.83**	**18.56**	**18.39**	**18.14**
Crude oil	15.39	16.47	16.55	16.48	15.65	16.64	16.81	15.99	15.56	16.21	16.29	15.63	16.23	16.27	15.92
HGL	0.67	0.56	0.59	0.77	0.60	0.50	0.59	0.76	0.66	0.50	0.55	0.73	0.65	0.61	0.61
Other hydrocarbons/oxygenates	1.13	1.21	1.20	1.18	1.11	1.17	1.17	1.15	1.13	1.20	1.20	1.17	1.18	1.15	1.17
Unfinished oils	-0.02	0.09	0.09	-0.09	-0.16	-0.05	0.07	-0.01	-0.15	-0.01	0.03	-0.03	0.02	-0.04	-0.04
Motor gasoline blending components	0.41	0.72	0.64	0.19	0.31	0.60	0.42	0.25	0.27	0.69	0.61	0.33	0.49	0.39	0.47
Refinery Processing Gain	**0.91**	**0.98**	**0.97**	**1.02**	**0.94**	**1.01**	**1.01**	**1.01**	**0.94**	**0.97**	**0.99**	**0.98**	**0.97**	**0.99**	**0.97**
Total refinery and blender net production	**18.50**	**20.02**	**20.03**	**19.55**	**18.46**	**19.87**	**20.07**	**19.14**	**18.41**	**19.57**	**19.66**	**18.80**	**19.53**	**19.39**	**19.11**
HGL	0.44	0.82	0.73	0.34	0.44	0.79	0.73	0.33	0.44	0.80	0.72	0.33	0.58	0.57	0.57
Finished motor gasoline	9.24	9.81	9.73	9.70	9.16	9.63	9.60	9.46	9.10	9.50	9.50	9.41	9.62	9.46	9.38
Jet fuel	1.70	1.84	1.87	1.81	1.69	1.92	1.88	1.80	1.71	1.78	1.77	1.68	1.81	1.82	1.73
Distillate fuel oil	4.57	4.95	5.09	5.14	4.70	4.96	5.19	4.96	4.70	4.88	5.02	4.88	4.94	4.95	4.87
Residual fuel oil	0.37	0.30	0.29	0.29	0.32	0.28	0.33	0.29	0.29	0.26	0.26	0.24	0.32	0.30	0.26
Other oils (a)	2.17	2.29	2.33	2.28	2.15	2.28	2.34	2.30	2.18	2.34	2.39	2.26	2.27	2.27	2.29
Refinery distillation inputs	**15.78**	**16.94**	**16.92**	**16.79**	**15.94**	**16.97**	**17.21**	**16.36**	**16.01**	**16.66**	**16.78**	**16.10**	**16.61**	**16.62**	**16.39**
Refinery operable distillation capacity	**18.36**	**18.33**	**18.34**	**18.36**	**18.32**	**18.14**	**18.16**	**18.02**	**18.02**	**17.90**	**17.88**	**17.88**	**18.35**	**18.16**	**17.92**
Refinery distillation utilization factor	**0.86**	**0.92**	**0.92**	**0.91**	**0.87**	**0.94**	**0.95**	**0.91**	**0.89**	**0.93**	**0.94**	**0.90**	**0.91**	**0.92**	**0.91**

(a) Other oils include aviation gasoline blending components, finished aviation gasoline, kerosene, petrochemical feedstocks, special naphthas, lubricants, waxes, petroleum coke, asphalt and road oil, still gas, and miscellaneous products.

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

- = no data available

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

Minor discrepancies with published historical data are due to independent rounding.

Sources:

Table 4c. U.S. Regional Motor Gasoline Prices and Inventories

U.S. Energy Information Administration | Short-Term Energy Outlook - December 2025

	2024				2025				2026				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
Wholesale price (dollars per gallon)															
United States average	2.46	2.58	2.34	2.11	2.20	2.17	2.22	2.01	1.85	2.01	2.05	1.89	2.37	2.15	1.95
Retail prices (dollars per gallon) (a)															
All grades United States average	**3.36**	**3.68**	**3.48**	**3.19**	**3.22**	**3.28**	**3.27**	**3.16**	**3.01**	**3.17**	**3.25**	**3.07**	**3.43**	**3.23**	**3.13**
Regular grade United States average	**3.24**	**3.56**	**3.37**	**3.07**	**3.10**	**3.16**	**3.14**	**3.03**	**2.88**	**3.05**	**3.12**	**2.94**	**3.31**	**3.11**	**3.00**
PADD 1	3.19	3.45	3.29	3.01	3.01	3.00	3.01	2.93	2.77	2.88	2.95	2.82	3.23	2.99	2.86
PADD 2	3.07	3.39	3.28	2.93	2.95	3.02	3.01	2.82	2.67	2.82	2.89	2.68	3.17	2.95	2.77
PADD 3	2.86	3.12	2.94	2.65	2.69	2.74	2.72	2.59	2.43	2.59	2.60	2.40	2.89	2.68	2.51
PADD 4	2.91	3.38	3.40	3.03	2.98	3.13	3.15	2.91	2.68	2.91	3.05	2.88	3.19	3.05	2.88
PADD 5	4.13	4.59	4.11	3.91	4.01	4.21	4.10	4.11	3.90	4.20	4.35	4.17	4.19	4.11	4.16
End-of-period inventories (million barrels) (b)															
Total U.S. gasoline inventories	**233.5**	**232.5**	**219.8**	**238.2**	**233.8**	**232.8**	**223.2**	**227.0**	**226.6**	**221.4**	**215.6**	**232.4**	**238.2**	**227.0**	**232.4**
PADD 1	54.9	56.8	61.0	60.7	59.5	63.6	57.2	53.9	56.4	55.5	57.4	59.0	60.7	53.9	59.0
PADD 2	54.9	48.5	45.4	52.0	56.1	48.1	46.8	49.1	53.0	47.2	44.6	51.6	52.0	49.1	51.6
PADD 3	85.7	86.4	79.2	87.3	81.8	83.6	81.8	86.7	81.8	84.2	79.8	86.2	87.3	86.7	86.2
PADD 4	8.6	8.0	6.8	8.4	8.7	7.1	7.2	8.4	8.2	7.4	7.0	7.6	8.4	8.4	7.6
PADD 5	29.4	32.8	27.3	29.8	27.6	30.4	30.3	28.9	27.3	27.0	26.9	28.0	29.8	28.9	28.0

(a) Retail prices include all federal, state, and local taxes.

(b) Inventories include both finished motor gasoline and motor gasoline blending components

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

- = no data available

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

Minor discrepancies with published historical data are due to independent rounding.

Prices are not adjusted for inflation.

PADD = Petroleum Administration for Defense District (PADD).

See “Petroleum for Administration Defense District” in EIA’s Energy Glossary (http://www.eia.gov/glossary/index.html) for a list of States in each region.

Sources:

Historical data: Latest data available from Energy Information Administration databases supporting the following reports: Petroleum Marketing Monthly; *Petroleum Supply Monthly; Petroleum Supply Annual; and Weekly Petroleum Status Report.*

Forecasts: EIA Short-Term Integrated Forecasting System.

Table 4d. U.S. Biofuel Supply, Consumption, and Inventories

U.S. Energy Information Administration | Short-Term Energy Outlook - December 2025

	2024				2025				2026				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
Supply (million barrels per day)															
Total biofuels supply	**1.24**	**1.33**	**1.35**	**1.32**	**1.17**	**1.21**	**1.21**	**1.23**	**1.18**	**1.30**	**1.33**	**1.34**	**1.31**	**1.20**	**1.29**
Fuel ethanol production	1.05	1.02	1.07	1.09	1.07	1.04	1.07	1.08	1.06	1.06	1.07	1.10	1.06	1.07	1.08
Biodiesel production	0.10	0.11	0.11	0.11	0.07	0.08	0.08	0.08	0.08	0.10	0.11	0.11	0.11	0.08	0.10
Renewable diesel production	0.19	0.21	0.22	0.22	0.17	0.19	0.20	0.22	0.20	0.25	0.27	0.29	0.21	0.19	0.25
Other biofuel production (a)	0.02	0.02	0.02	0.03	0.04	0.03	0.04	0.04	0.04	0.04	0.04	0.05	0.02	0.04	0.04
Fuel ethanol net imports	-0.12	-0.13	-0.12	-0.14	-0.14	-0.14	-0.14	-0.15	-0.14	-0.15	-0.14	-0.16	-0.13	-0.14	-0.15
Biodiesel net imports	0.03	0.02	0.00	0.01	0.00	-0.01	-0.01	0.00	0.00	-0.01	0.00	0.00	0.02	0.00	0.00
Renewable diesel net imports (b)	0.03	0.04	0.04	0.02	-0.01	-0.04	-0.04	-0.04	-0.02	-0.03	-0.03	-0.03	0.03	-0.03	-0.03
Other biofuel net imports (b)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biofuel stock draw	-0.06	0.05	0.00	-0.02	-0.02	0.04	0.00	-0.01	-0.03	0.03	0.01	-0.02	-0.01	0.00	0.00
Total distillate fuel oil supply (c)	**4.10**	**4.06**	**4.09**	**4.16**	**4.18**	**4.06**	**3.97**	**4.03**	**4.14**	**4.10**	**4.13**	**4.17**	**4.10**	**4.06**	**4.13**
Distillate fuel production	4.57	4.95	5.09	5.14	4.70	4.96	5.19	4.96	4.70	4.88	5.02	4.88	4.94	4.95	4.87
Biodiesel production	0.10	0.11	0.11	0.11	0.07	0.08	0.08	0.08	0.08	0.10	0.11	0.11	0.11	0.08	0.10
Renewable diesel production	0.19	0.21	0.22	0.22	0.17	0.19	0.20	0.22	0.20	0.25	0.27	0.29	0.21	0.19	0.25
Distillate fuel oil net imports	-0.85	-1.18	-1.32	-1.22	-0.87	-1.17	-1.22	-1.25	-0.84	-1.06	-1.16	-0.99	-1.14	-1.13	-1.01
Biodiesel net imports	0.03	0.02	0.00	0.01	0.00	-0.01	-0.01	0.00	0.00	-0.01	0.00	0.00	0.02	0.00	0.00
Renewable diesel net imports	0.03	0.04	0.04	0.02	-0.01	-0.04	-0.04	-0.04	-0.02	-0.03	-0.03	-0.03	0.03	-0.03	-0.03
Total distillate fuel stock draw	0.08	-0.02	0.00	-0.07	0.16	0.09	-0.19	0.09	0.06	0.02	-0.03	-0.04	0.00	0.04	0.00
Consumption (million barrels per day)															
Total biofuels consumption	**1.24**	**1.33**	**1.35**	**1.32**	**1.17**	**1.21**	**1.20**	**1.23**	**1.18**	**1.30**	**1.33**	**1.34**	**1.31**	**1.20**	**1.29**
Fuel ethanol blended into motor gasoline	0.89	0.93	0.95	0.94	0.90	0.95	0.94	0.93	0.89	0.94	0.94	0.93	0.93	0.93	0.93
Biodiesel consumption	0.13	0.13	0.12	0.12	0.07	0.08	0.07	0.08	0.07	0.10	0.11	0.10	0.13	0.07	0.09
Biodiesel product supplied (d)	0.09	0.08	0.07	0.08	0.04	0.04	0.04	0.05	0.04	0.06	0.06	0.06	0.08	0.04	0.06
Biodiesel net inputs (e)	0.04	0.05	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.03	0.04
Renewable diesel consumption	0.21	0.25	0.27	0.24	0.16	0.15	0.16	0.18	0.18	0.22	0.25	0.26	0.24	0.16	0.23
Renewable diesel product supplied	0.20	0.24	0.25	0.22	0.15	0.13	0.15	0.17	0.17	0.21	0.23	0.25	0.23	0.15	0.21
Renewable diesel net inputs	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Other biofuel consumption	0.02	0.02	0.02	0.03	0.03	0.04	0.03	0.04	0.04	0.04	0.04	0.05	0.02	0.04	0.04
Total motor gasoline consumption	**8.63**	**9.16**	**9.19**	**8.89**	**8.64**	**9.08**	**9.11**	**8.78**	**8.59**	**9.06**	**9.02**	**8.74**	**8.97**	**8.90**	**8.85**
Petroleum-based gasoline	7.74	8.22	8.24	7.96	7.74	8.13	8.17	7.85	7.70	8.12	8.08	7.80	8.04	7.98	7.93
Fuel ethanol blended into motor gasoline	0.89	0.93	0.95	0.94	0.90	0.95	0.94	0.93	0.89	0.94	0.94	0.93	0.93	0.93	0.93
Total distillate fuel oil consumption (f)	**4.10**	**4.06**	**4.09**	**4.16**	**4.18**	**4.06**	**3.97**	**4.03**	**4.14**	**4.10**	**4.13**	**4.17**	**4.10**	**4.06**	**4.13**
Distillate fuel oil	3.81	3.74	3.76	3.85	3.98	3.88	3.78	3.81	3.94	3.84	3.83	3.86	3.79	3.86	3.87
Petroleum-based distillate	3.76	3.68	3.70	3.80	3.94	3.83	3.74	3.77	3.89	3.78	3.77	3.81	3.74	3.82	3.82
Biodiesel net inputs (g)	0.04	0.05	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.03	0.04
Renewable diesel net inputs	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Biodiesel product supplied (h)	0.09	0.08	0.07	0.08	0.04	0.04	0.04	0.05	0.04	0.06	0.06	0.06	0.08	0.04	0.06
Renewable diesel product supplied (h)	0.20	0.24	0.25	0.22	0.15	0.13	0.15	0.17	0.17	0.21	0.23	0.25	0.23	0.15	0.21
End-of-period inventories (million barrels)															
Total biofuels inventories	**38.30**	**33.63**	**33.47**	**34.99**	**37.20**	**33.47**	**33.17**	**34.35**	**37.10**	**34.10**	**33.11**	**35.34**	**34.99**	**34.35**	**35.34**
Fuel ethanol	26.74	22.65	23.46	24.42	27.38	23.61	22.74	23.33	25.40	22.91	22.20	23.39	24.42	23.33	23.39
Biodiesel	4.39	3.72	3.16	3.56	3.03	2.65	3.12	3.56	4.06	3.31	2.89	3.56	3.56	3.56	3.56
Renewable diesel	6.59	6.52	6.20	6.11	6.30	5.51	6.27	6.46	6.77	6.90	7.12	7.38	6.35	6.13	7.04
Other biofuels	0.44	0.48	0.60	0.52	0.85	0.79	0.81	0.84	0.84	0.84	0.84	0.84	0.51	0.82	0.84
Total distillate fuel oil inventories	**132.61**	**134.07**	**133.91**	**140.51**	**125.71**	**117.67**	**134.82**	**126.33**	**120.54**	**118.97**	**121.97**	**125.63**	**140.51**	**126.33**	**125.63**
Distillate fuel oil	121.54	123.63	124.65	130.42	116.83	108.43	125.24	116.15	109.67	108.62	111.91	114.51	130.42	116.15	114.51
Biodiesel	4.39	3.72	3.16	3.56	3.03	2.65	3.12	3.56	4.06	3.31	2.89	3.56	3.56	3.56	3.56
Renewable diesel	6.59	6.52	6.20	6.11	6.30	5.51	6.27	6.46	6.77	6.90	7.12	7.38	6.35	6.13	7.04

(a) Includes renewable heating oil, renewable jet fuel (sustainable aviation fuel, alternative jet fuel, and biojet), renewable naphtha, renewable gasoline, and other emerging biofuels that are in various stages of development and commercialization

(b) Renewable diesel net imports and other biofuel net imports equal imports because we do not collect or receive export data for those fuels.

(c) Total distillate fuel oil supply equals the sum of the seven components shown minus refiner and blender net inputs of biodiesel and renewable diesel, which are listed in rows 44 and 45 of this table.

(d) The volumes of renewable fuels that are not reported as blended with petroleum fuels.

(e) The volumes of renewable fuels that are reported as blended with petroleum fuels.

(f) Equals the sum of distillate fuel oil, biodiesel product supplied, and renewable diesel product supplied.

(g) Prior to 2021, we did not publish biodiesel product supplied and instead included it as part of distillate fuel oil product supplied.

(h) Prior to 2021, we did not publish renewable diesel product supplied, and STEO values for that period are taken from the U.S. Environmental Protection Agency's Moderated Transaction System.

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

- = no data available

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

Minor discrepancies with published historical data are due to independent rounding.

Sources:

Historical data: Latest data available from Energy Information Administration databases supporting the following reports: Petroleum Supply Monthly; Petroleum Supply Annual; and Weekly Petroleum Status Report.
Forecasts: EIA Short-Term Integrated Forecasting System.

Table 5a. U.S. Natural Gas Supply, Consumption, and Inventories

U.S. Energy Information Administration | Short-Term Energy Outlook - December 2025

	2024				2025				2026				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
Supply (billion cubic feet per day)															
U.S. total marketed natural gas production	**113.3**	**112.1**	**113.1**	**114.2**	**115.6**	**117.8**	**119.5**	**120.6**	**119.6**	**119.7**	**120.1**	**120.9**	**113.2**	**118.4**	**120.1**
Alaska	1.1	1.0	0.9	1.0	1.1	1.0	0.9	1.0	1.0	1.0	0.9	1.1	1.0	1.0	1.0
Federal Gulf of America (a)	1.8	1.8	1.8	1.8	1.8	1.8	2.0	2.0	2.0	1.9	1.8	1.8	1.8	1.9	1.9
Lower 48 States (excl GOA) (b)	110.4	109.3	110.4	111.4	112.8	114.9	116.6	117.6	116.6	116.7	117.3	118.0	110.4	115.5	117.2
Appalachia region	35.9	34.9	35.5	35.9	36.3	36.7	36.7	37.2	37.3	37.3	37.1	37.2	35.6	36.7	37.2
Bakken region	3.2	3.4	3.4	3.3	3.2	3.3	3.4	3.4	3.4	3.4	3.4	3.5	3.3	3.3	3.4
Eagle Ford region	6.8	6.9	6.8	6.9	7.0	7.2	7.1	7.3	7.1	7.0	7.0	7.0	6.9	7.2	7.0
Haynesville region	15.8	14.4	14.4	14.2	14.9	15.1	15.5	15.7	15.6	15.9	16.2	16.5	14.7	15.3	16.0
Permian region	23.8	24.5	26.2	26.9	27.1	27.9	28.4	28.7	28.7	28.9	29.5	29.9	25.4	28.0	29.3
Rest of Lower 48 States	24.8	25.1	24.0	24.1	24.2	24.7	25.4	25.3	24.6	24.2	24.1	24.0	24.5	24.9	24.2
Total primary supply	**104.5**	**78.9**	**85.8**	**92.6**	**110.3**	**78.2**	**84.7**	**94.3**	**105.6**	**77.9**	**85.5**	**94.4**	**90.4**	**91.8**	**90.8**
Balancing item (c)	0.3	-1.3	-0.5	-1.0	0.3	-0.7	-0.8	-1.1	-1.3	-0.9	-1.5	-1.1	-0.6	-0.6	-1.2
Total supply	**104.2**	**80.2**	**86.3**	**93.6**	**110.0**	**79.0**	**85.5**	**95.5**	**107.0**	**78.8**	**87.0**	**95.6**	**91.1**	**92.4**	**92.0**
U.S. total dry natural gas production	103.9	102.0	103.0	103.8	105.6	107.1	108.4	109.8	109.0	108.7	109.0	109.8	103.2	107.7	109.1
Net inventory withdrawals	12.7	-9.6	-4.9	1.9	17.7	-12.7	-7.0	3.1	15.1	-11.8	-5.1	4.5	0.0	0.2	0.6
Supplemental gaseous fuels	0.4	0.3	0.3	0.3	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Net imports	-12.8	-12.5	-12.2	-12.5	-13.7	-15.7	-16.2	-17.8	-17.5	-18.4	-17.2	-19.1	-12.5	-15.9	-18.0
LNG gross imports (d)	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.1
LNG gross exports (d)	12.4	11.3	11.4	12.6	14.2	14.2	14.6	16.7	16.5	16.0	15.3	17.7	11.9	14.9	16.3
Pipeline gross imports	8.9	7.8	8.4	9.0	9.9	7.9	7.8	8.0	8.8	7.5	7.7	8.0	8.5	8.4	8.0
Pipeline gross exports	9.4	8.9	9.2	8.9	9.4	9.5	9.5	9.1	9.9	10.0	9.7	9.5	9.1	9.4	9.8
Consumption (billion cubic feet per day)															
Total consumption	**104.5**	**78.9**	**85.8**	**92.6**	**110.3**	**78.2**	**84.7**	**94.3**	**105.6**	**77.9**	**85.5**	**94.4**	**90.4**	**91.8**	**90.8**
Residential	23.0	6.7	3.6	14.8	26.2	7.1	3.6	16.0	23.9	7.2	3.6	15.8	12.0	13.2	12.6
Commercial	14.4	6.4	4.9	10.8	16.3	6.7	5.0	11.4	15.0	6.7	4.9	11.3	9.1	9.8	9.5
Industrial	24.9	22.5	22.3	24.1	25.8	22.6	22.2	24.1	25.0	22.1	21.8	24.0	23.4	23.7	23.2
Electric power (e)	32.6	34.8	46.2	33.6	32.1	33.1	44.8	33.3	31.7	33.1	46.0	33.7	36.8	35.9	36.2
Lease and plant fuel	5.4	5.4	5.4	5.5	5.5	5.6	5.7	5.8	5.7	5.7	5.7	5.8	5.4	5.7	5.7
Pipeline and distribution	4.0	3.0	3.3	3.5	4.2	3.0	3.2	3.6	4.1	3.0	3.3	3.6	3.4	3.5	3.5
Vehicle	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
End-of-period working natural gas inventories (billion cubic feet) (f)															
United States total	**2,306**	**3,175**	**3,615**	**3,438**	**1,836**	**2,990**	**3,637**	**3,354**	**1,996**	**3,073**	**3,539**	**3,120**	**3,438**	**3,354**	**3,120**
East region	369	670	862	747	294	610	851	743	320	639	827	713	747	743	713
Midwest region	507	781	1,022	893	365	691	988	885	424	745	996	867	893	885	867
South Central region	1,007	1,172	1,121	1,215	778	1,139	1,183	1,204	899	1,217	1,195	1,125	1,215	1,204	1,125
Mountain region	168	238	282	259	170	232	276	238	141	182	223	178	259	238	178
Pacific region	231	286	296	295	205	289	303	257	189	262	265	208	295	257	208
Alaska	24	28	33	28	25	28	36	28	24	28	33	28	28	28	28

(a) Marketed production from U.S. Federal leases in the Gulf of America.

(b) Regional production in this table is based on geographic regions and not geologic formations.

(c) The balancing item is the difference between total natural gas consumption (NGTCPUS) and total natural gas supply (NGPSUPP).

(d) LNG: liquefied natural gas

(e) Natural gas used for electricity generation and (a limited amount of) useful thermal output by electric utilities and independent power producers.

(f) For a list of states in each inventory region refer to *Weekly Natural Gas Storage Report, Notes and Definitions (http://ir.eia.gov/ngs/notes.html)* .

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

- = no data available

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

Minor discrepancies with published historical data are due to independent rounding.

Sources:

Historical data: Latest data available from Energy Information Administration databases supporting the following reports: Natural Gas Monthly; and Electric Power Monthly.

Forecasts: EIA Short-Term Integrated Forecasting System.

Table 5b. U.S. Regional Natural Gas Prices (dollars per thousand cubic feet)

U.S. Energy Information Administration | Short-Term Energy Outlook - December 2025

	2024				2025				2026				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
Wholesale price															
Henry Hub spot price	2.21	2.17	2.19	2.54	4.30	3.31	3.14	4.01	4.51	3.44	4.06	4.65	2.28	3.69	4.17
Residential retail (a)															
United States average	12.71	16.69	23.05	14.37	13.09	18.46	25.37	14.93	13.67	16.51	22.25	14.13	14.55	15.21	14.84
New England	19.13	20.47	23.85	20.88	21.48	22.00	27.63	22.45	22.50	22.98	25.92	21.06	20.19	22.22	22.40
Middle Atlantic	13.38	15.90	21.47	15.41	13.95	18.70	25.33	16.46	14.71	16.46	21.31	14.92	14.91	16.03	15.50
East North Central	9.24	14.56	23.30	10.83	9.59	15.31	25.21	11.57	10.16	14.17	23.30	11.43	11.27	11.82	11.92
West North Central	10.72	14.49	22.84	11.98	11.01	15.22	23.73	12.27	11.49	14.57	21.88	11.52	12.32	12.59	12.51
South Atlantic	14.59	21.83	31.84	17.02	14.83	24.79	32.85	16.32	15.08	21.01	28.73	16.08	17.55	17.67	17.25
East South Central	11.29	16.31	24.90	14.12	11.57	19.34	25.84	13.96	11.81	16.16	22.43	13.22	13.51	13.84	13.41
West South Central	12.55	22.10	28.89	20.36	13.57	24.68	33.68	18.56	14.14	20.15	25.89	15.39	17.25	17.76	16.36
Mountain	12.56	13.84	17.53	10.75	10.37	12.65	16.91	11.60	11.50	13.51	18.28	12.33	12.56	11.58	12.57
Pacific	17.71	17.23	19.09	18.51	19.98	20.74	22.08	19.20	19.06	17.23	18.30	17.38	18.02	20.12	18.13
Commercial retail (a)															
United States average	9.84	10.34	10.99	10.13	10.28	11.73	12.41	10.37	10.35	10.59	11.10	10.03	10.14	10.76	10.37
New England	12.89	12.95	12.33	12.86	13.67	13.76	14.19	13.10	13.35	13.52	13.46	12.76	12.83	13.56	13.22
Middle Atlantic	10.63	10.33	9.30	10.85	11.83	12.43	11.85	10.73	11.01	9.85	9.11	9.66	10.49	11.60	10.19
East North Central	7.42	8.94	11.09	8.26	8.01	10.42	12.08	8.40	8.49	9.22	10.96	8.33	8.19	8.78	8.74
West North Central	8.55	8.99	11.25	8.65	9.15	10.03	11.66	9.23	9.51	10.10	11.22	9.17	8.86	9.50	9.63
South Atlantic	10.38	10.33	10.65	10.44	10.88	12.07	11.44	10.88	10.97	11.29	11.50	10.94	10.42	11.12	11.08
East South Central	9.80	10.02	11.55	10.73	10.10	12.39	12.98	10.86	10.38	11.05	11.84	10.78	10.32	10.96	10.78
West South Central	9.27	9.80	10.37	10.76	9.83	11.49	12.55	11.10	10.24	10.49	10.95	10.13	9.92	10.83	10.37
Mountain	10.26	10.21	10.39	8.18	8.06	8.32	9.14	8.16	8.43	9.07	10.13	9.07	9.64	8.25	8.91
Pacific	14.00	12.48	13.95	13.83	15.16	15.03	16.07	14.47	14.82	13.58	13.71	13.36	13.63	15.06	13.97
Industrial retail (a)															
United States average	4.54	3.40	3.33	4.31	5.69	4.69	4.29	4.88	5.61	4.19	4.55	5.40	3.93	4.93	4.97
New England	11.14	9.59	7.03	9.43	11.69	10.71	8.40	9.61	10.99	10.03	8.67	9.91	9.59	10.49	10.05
Middle Atlantic	9.92	9.01	8.17	9.59	11.18	11.12	10.40	10.13	10.57	9.47	9.12	9.86	9.50	10.90	10.04
East North Central	6.34	6.16	5.95	6.25	6.88	7.47	6.86	6.61	7.28	7.15	7.13	7.30	6.24	6.90	7.25
West North Central	5.36	3.50	3.58	4.88	6.47	5.07	4.94	5.68	6.73	5.33	5.24	6.11	4.38	5.62	5.92
South Atlantic	5.22	4.54	4.66	5.19	6.40	6.03	5.88	6.03	6.90	5.68	5.90	6.61	4.93	6.10	6.32
East South Central	4.55	3.76	3.89	4.64	5.94	5.11	4.88	5.34	6.24	4.95	5.25	6.02	4.24	5.35	5.65
West South Central	2.52	2.05	2.23	2.87	4.01	3.34	3.17	4.23	4.75	3.50	4.07	4.78	2.42	3.75	4.28
Mountain	7.96	6.83	6.26	5.98	6.25	6.39	6.94	6.73	7.04	6.94	7.26	7.24	6.85	6.53	7.11
Pacific	8.82	7.26	7.56	8.50	9.06	8.19	8.39	8.39	9.06	7.82	7.75	8.13	8.13	8.59	8.26

(a) For a list of states in each region see "Census division" in EIA's Energy Glossary (http://www.eia.gov/glossary/index.html).

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

- = no data available

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

Minor discrepancies with published historical data are due to independent rounding.

Prices are not adjusted for inflation.

Regions refer to U.S. Census divisions.

Sources:

Historical data: Latest data available from Energy Information Administration databases supporting the Natural Gas Monthly. Henry Hub spot price is from Refinitiv,an LSEG company, via EIA (https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm).

Forecasts: EIA Short-Term Integrated Forecasting System.

Table 6. U.S. Coal Supply, Consumption, and Inventories (million short tons)

U.S. Energy Information Administration | Short-Term Energy Outlook - December 2025

	2024				2025				2026				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
Supply															
Total supply	**103.9**	**95.3**	**124.4**	**97.6**	**126.9**	**102.9**	**134.1**	**105.6**	**106.4**	**89.8**	**127.4**	**102.8**	**421.2**	**469.6**	**426.4**
Secondary inventory withdrawals	-2.4	0.0	12.4	-5.2	16.4	-5.0	11.6	0.1	-5.6	-13.3	14.1	-2.8	4.8	23.2	-7.6
Waste coal (a)	2.3	2.1	2.1	1.8	2.3	1.6	1.6	1.6	1.6	1.6	1.6	1.6	8.3	7.0	6.3
Total primary supply	**103.9**	**93.2**	**109.9**	**101.0**	**108.2**	**106.4**	**120.9**	**103.9**	**110.5**	**101.5**	**111.7**	**104.0**	**408.1**	**439.4**	**427.7**
U.S. total coal production	**129.9**	**118.3**	**136.3**	**128.1**	**132.3**	**128.1**	**141.1**	**129.9**	**134.2**	**123.1**	**132.7**	**129.6**	**512.5**	**531.5**	**519.6**
Appalachia	39.6	40.0	39.9	38.6	39.7	40.4	43.9	38.5	45.1	40.3	37.3	38.1	158.1	162.6	160.9
Interior	22.3	20.3	21.7	19.0	22.9	19.5	22.3	20.1	22.7	20.8	20.9	20.3	83.3	84.8	84.8
Western	68.1	58.0	74.7	70.4	69.7	68.2	74.9	71.3	66.4	62.0	74.4	71.2	271.2	284.0	274.0
Net imports	**-26.4**	**-25.5**	**-26.9**	**-27.5**	**-23.8**	**-21.7**	**-21.7**	**-25.9**	**-23.3**	**-21.4**	**-22.6**	**-25.4**	**-106.3**	**-93.1**	**-92.7**
Gross imports	0.3	0.5	0.7	0.4	0.6	0.7	0.8	1.1	1.0	1.4	1.4	1.2	2.0	3.2	4.9
Gross exports	26.8	26.1	27.6	27.9	24.4	22.4	22.5	27.0	24.3	22.8	24.0	26.6	108.3	96.3	97.6
Metallurgical coal	14.1	13.8	13.4	15.3	12.7	11.6	12.6	13.2	12.8	13.9	13.5	13.8	56.6	50.1	54.0
Steam coal	12.7	12.2	14.2	12.6	11.7	10.8	9.9	13.8	11.4	8.9	10.5	12.8	51.7	46.2	43.6
Primary inventory withdrawals	**0.5**	**0.5**	**0.5**	**0.5**	**-0.4**	**-0.1**	**1.6**	**-0.1**	**-0.5**	**-0.1**	**1.5**	**-0.1**	**1.9**	**1.0**	**0.8**
Consumption															
U.S. total coal consumption	**100.5**	**91.0**	**120.5**	**99.0**	**118.5**	**98.8**	**126.6**	**103.8**	**106.4**	**89.8**	**127.4**	**102.8**	**410.9**	**447.6**	**426.4**
Coke plants	3.9	3.7	3.9	4.0	3.6	3.7	3.6	3.7	3.7	3.8	3.8	3.9	15.5	14.7	15.2
Electric power sector (b)	90.9	81.9	111.4	89.1	109.2	90.4	118.3	94.7	97.5	81.6	119.2	93.9	373.3	412.6	392.2
Retail and other industry	5.7	5.3	5.2	5.9	5.7	4.7	4.6	5.3	5.3	4.3	4.3	5.1	22.2	20.3	19.0
Residential and commercial	0.2	0.1	0.1	0.2	0.2	0.1	0.1	0.2	0.3	0.1	0.1	0.2	0.6	0.7	0.8
Other industrial	5.5	5.2	5.1	5.7	5.4	4.6	4.5	5.1	5.0	4.2	4.2	4.9	21.5	19.6	18.2
Discrepancy (c)	**3.4**	**4.3**	**3.9**	**-1.4**	**8.5**	**4.1**	**7.6**	**1.8**	**0.0**	**0.0**	**0.0**	**0.0**	**10.2**	**22.0**	**0.0**
End-of-period inventories	**164.4**	**163.9**	**151.0**	**155.8**	**139.8**	**144.8**	**136.6**	**131.6**	**137.7**	**151.1**	**135.5**	**138.4**	**155.8**	**131.6**	**138.4**
Primary inventories (d)	24.4	23.9	23.5	23.0	23.4	23.5	21.9	22.0	22.5	22.6	21.1	21.2	23.0	22.0	21.2
Secondary inventories	140.0	140.0	127.5	132.8	116.4	121.4	109.7	109.6	115.2	128.5	114.4	117.2	132.8	109.6	117.2
Electric power sector	135.5	135.2	122.6	127.8	111.7	116.4	105.4	105.3	111.6	124.7	110.3	113.0	127.8	105.3	113.0
Retail and general industry	2.8	3.1	3.2	3.1	2.9	3.0	2.8	2.8	2.4	2.5	2.7	2.8	3.1	2.8	2.8
Coke plants	1.4	1.6	1.7	1.7	1.6	1.8	1.3	1.3	1.1	1.2	1.2	1.2	1.7	1.3	1.2
Commercial & institutional	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.2	0.1
Coal market indicators															
Coal miner productivity (tons per hour)	6.56	6.56	6.56	6.56	6.27	6.27	6.27	6.27	5.76	5.76	5.76	5.76	6.56	6.27	5.76
Total raw steel production (million short tons)	22.22	22.36	22.72	21.62	21.34	22.59	23.34	23.39	23.22	24.02	24.50	23.89	88.91	90.66	95.63
Cost of coal to electric utilities (dollars per million Btu)	2.49	2.53	2.44	2.43	2.43	2.48	2.40	2.39	2.41	2.40	2.40	2.38	2.47	2.42	2.40

(a) Waste coal includes waste coal and cloal slurry reprocessed into briquettes.

(b) Coal used for electricity generation and (a limited amount of) useful thermal output by electric utilities and independent power producers.

(c) The discrepancy reflects an unaccounted-for shipper and receiver reporting difference, assumed to be zero in the forecast period.

(d) Primary stocks are held at the mines and distribution points.

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

- = no data available

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

Sources:

Historical data: Latest data available from Energy Information Administration databases supporting the following reports: Quarterly Coal Report; and Electric Power Monthly.

Table 7a. U.S. Electricity Industry Overview

U.S. Energy Information Administration | Short-Term Energy Outlook - December 2025

	2024				2025				2026				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
Electricity supply (billion kilowatthours)															
Total utility-scale power supply	**1,030**	**1,052**	**1,219**	**1,022**	**1,080**	**1,065**	**1,242**	**1,048**	**1,064**	**1,077**	**1,283**	**1,073**	**4,322**	**4,434**	**4,497**
Electricity generation (a)	**1,028**	**1,051**	**1,212**	**1,018**	**1,074**	**1,057**	**1,234**	**1,044**	**1,062**	**1,074**	**1,276**	**1,071**	**4,309**	**4,410**	**4,483**
Electric power sector	990	1,014	1,172	981	1,036	1,021	1,194	1,005	1,023	1,036	1,235	1,032	4,157	4,256	4,327
Industrial sector	35	33	35	33	35	33	35	35	34	33	36	34	137	138	138
Commercial sector	4	4	4	4	4	4	4	4	4	4	5	4	15	16	18
Net imports	**2**	**1**	**7**	**5**	**5**	**8**	**8**	**4**	**3**	**3**	**7**	**2**	**14**	**25**	**15**
Small-scale solar generation (c)	**17**	**25**	**25**	**17**	**19**	**27**	**27**	**19**	**21**	**31**	**30**	**21**	**84**	**93**	**102**
Residential sector	12	17	17	12	13	19	19	13	14	21	20	14	58	63	69
Commercial sector	4	6	6	4	5	7	7	5	6	8	8	6	22	25	28
Industrial sector	1	1	1	1	1	1	2	1	1	2	2	1	5	5	6
Losses and Unaccounted for (b)	51	63	48	50	55	68	62	51	49	66	64	51	213	235	231
Electricity consumption (billion kilowatthours)															
Total consumption	**978**	**989**	**1,170**	**972**	**1,025**	**997**	**1,180**	**997**	**1,015**	**1,011**	**1,219**	**1,022**	**4,110**	**4,199**	**4,267**
Sales to ultimate customers	**944**	**956**	**1,135**	**940**	**991**	**965**	**1,144**	**963**	**981**	**977**	**1,182**	**987**	**3,975**	**4,063**	**4,129**
Residential sector	360	341	451	330	390	339	451	336	372	341	470	335	1,483	1,516	1,518
Commercial sector	339	355	407	350	350	361	413	362	355	368	427	380	1,451	1,486	1,530
Industrial sector	244	258	275	258	249	263	279	263	252	267	284	271	1,035	1,055	1,075
Transportation sector	2	2	2	2	2	2	2	2	2	2	2	2	7	7	6
Direct use (d)	**34**	**33**	**35**	**33**	**34**	**32**	**35**	**34**	**34**	**33**	**36**	**34**	**135**	**136**	**138**
Average residential electricity usage per customer (kWh)	2,515	2,384	3,153	2,308	2,698	2,345	3,117	2,325	2,555	2,337	3,224	2,300	10,359	10,485	10,416
End-of-period fuel inventories held by electric power sector															
Coal (million short tons)	135.5	135.2	122.6	127.8	111.7	116.4	105.4	105.3	111.6	124.7	110.3	113.0	127.8	105.3	113.0
Residual fuel (million barrels)	6.1	6.0	5.5	5.3	4.9	4.9	4.7	4.6	4.3	4.3	3.5	3.6	5.3	4.6	3.6
Distillate fuel (million barrels)	17.4	17.3	16.8	17.0	16.2	15.9	15.9	16.2	16.2	16.1	16.1	16.4	17.0	16.2	16.4
Prices															
Power generation fuel costs (dollars per million Btu)															
Coal	2.49	2.53	2.44	2.43	2.43	2.48	2.40	2.39	2.41	2.40	2.40	2.38	2.47	2.42	2.40
Natural gas	3.41	2.37	2.38	3.03	5.03	3.39	3.26	4.18	4.88	3.45	3.91	4.71	2.76	3.91	4.22
Residual fuel oil	18.85	18.54	17.84	16.16	16.29	15.22	15.89	13.43	12.37	11.83	11.32	11.39	17.79	15.31	11.73
Distillate fuel oil	20.09	19.70	18.67	17.89	18.59	17.49	18.12	18.14	17.26	15.93	16.58	16.99	19.11	18.19	16.78
Prices to ultimate customers (cents per kilowatthour)															
Residential sector	15.99	16.52	16.67	16.71	16.43	17.46	17.69	17.59	17.35	18.18	18.30	18.19	16.48	17.29	18.02
Commercial sector	12.50	12.53	13.25	12.63	13.07	13.21	14.08	13.19	13.46	13.60	14.45	13.42	12.75	13.42	13.76
Industrial sector	7.84	8.03	8.62	7.98	8.25	8.44	9.13	8.50	8.55	8.64	9.32	8.58	8.13	8.59	8.78
Wholesale electricity prices (dollars per megawatthour)															
ERCOT North hub	32.53	39.94	33.54	28.54	35.72	37.33	41.00	36.35	38.51	38.26	60.87	40.41	33.64	37.60	44.51
CAISO SP15 zone	33.41	7.97	43.12	35.32	26.46	16.85	36.34	33.79	33.69	27.94	36.91	37.56	29.96	28.36	34.02
ISO-NE Internal hub	47.50	34.50	45.87	58.50	108.83	45.85	62.77	61.45	83.21	55.19	74.56	71.41	46.59	69.72	71.09
NYISO Hudson Valley zone	43.48	33.82	42.06	50.80	99.75	48.08	63.99	60.60	79.97	56.17	67.72	70.80	42.54	68.10	68.67
PJM Western hub	35.76	37.75	49.70	39.81	60.16	52.75	61.48	59.63	68.68	56.13	66.20	63.76	40.75	58.51	63.69
Midcontinent ISO Illinois hub	32.52	30.38	37.95	31.57	45.87	41.64	56.56	43.23	50.46	43.95	51.62	47.49	33.11	46.83	48.38
SPP ISO South hub	31.66	33.95	47.92	46.52	38.41	36.01	41.13	38.97	38.97	37.00	45.75	39.34	40.01	38.63	40.26
SERC index, Into Southern	27.96	29.20	31.53	29.85	43.28	40.13	41.66	40.98	42.16	38.75	43.94	41.85	29.64	41.51	41.68
FRCC index, Florida Reliability	30.01	31.81	33.26	30.89	46.10	42.43	44.63	45.65	45.19	43.72	50.48	46.48	31.49	44.70	46.47
Northwest index, Mid-Columbia	99.74	32.91	60.98	45.09	53.72	35.11	53.10	47.14	53.39	38.12	51.30	55.26	59.68	47.27	49.52
Southwest index, Palo Verde	29.62	11.22	50.17	34.98	27.88	23.45	39.11	35.93	36.77	30.14	43.69	39.87	31.50	31.59	37.62

(a) Generation supplied by utility-scale power plants with capacity of at least one megawatt.

(b) Includes transmission and distribution losses, data collection time-frame differences, and estimation error.

(c) Solar photovoltaic systems smaller than one megawatt such as those installed on rooftops.

(d) Direct use represents commercial and industrial facility use of onsite net electricity generation; and electrical sales or transfers to adjacent or colocated facilities for which revenue information is not available. See Table 7.6 of the EIA Monthly Energy Review.

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

kWh = kilowatthours. Btu = British thermal units.

Prices are not adjusted for inflation.

Sources:

Historical data: Latest data available from EIA databases supporting the following reports: Electric Power Monthly and Electric Power Annual (electricity supply and consumption, fuel inventories and costs, and retail electricity prices); S&P Global Market Intelligence (wholesale electricity prices).

Table 7b. U.S. Regional Electricity Sales to Ultimate Customers (billion kilowatthours)

U.S. Energy Information Administration | Short-Term Energy Outlook - December 2025

	2024				2025				2026				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
All sectors (a)	**944.3**	**956.1**	**1,135.1**	**939.9**	**990.7**	**965.1**	**1,144.5**	**962.8**	**981.2**	**977.4**	**1,182.5**	**987.5**	**3,975.4**	**4,063.1**	**4,128.6**
New England	28.6	26.4	30.3	26.5	29.3	26.6	31.3	27.1	28.7	26.5	32.4	26.8	111.9	114.3	114.4
Middle Atlantic	87.3	83.8	101.9	83.2	91.9	82.5	101.0	84.9	91.4	84.2	104.5	87.4	356.2	360.4	367.5
E. N. Central	135.8	133.8	152.9	131.0	141.8	134.6	158.5	136.2	143.4	137.4	159.3	141.1	553.4	571.2	581.1
W. N. Central	78.8	75.4	86.6	76.3	83.3	76.2	89.7	79.4	83.2	78.1	92.4	80.8	317.1	328.7	334.4
S. Atlantic	205.1	215.8	252.2	204.4	215.8	216.9	251.8	207.1	208.3	215.9	260.5	210.7	877.5	891.6	895.4
E. S. Central	76.7	74.7	89.8	72.4	80.2	75.3	91.3	74.3	77.6	75.7	92.1	74.0	313.6	321.1	319.4
W. S. Central	162.6	176.1	212.2	171.8	176.0	181.3	216.1	177.5	176.3	186.8	230.6	187.8	722.8	750.9	781.4
Mountain	69.9	76.3	94.3	72.0	71.1	77.4	93.9	73.1	71.6	78.5	96.4	74.5	312.5	315.5	321.0
Pacific contiguous	95.7	90.2	111.1	98.4	97.6	90.6	107.0	99.3	97.1	90.7	110.5	100.4	395.4	394.4	398.7
AK and HI	3.7	3.6	3.8	3.9	3.7	3.6	3.9	3.9	3.8	3.7	3.9	3.9	15.0	15.2	15.3
Residential sector	**360.0**	**341.2**	**451.3**	**330.4**	**390.1**	**339.0**	**450.5**	**336.1**	**372.4**	**340.5**	**469.9**	**335.1**	**1,482.9**	**1,515.7**	**1,517.9**
New England	12.6	10.8	13.4	11.1	13.4	10.8	13.8	11.6	13.1	10.9	14.7	11.5	48.0	49.6	50.1
Middle Atlantic	33.6	30.5	41.1	29.7	36.9	29.2	40.9	30.0	35.6	29.5	42.6	29.5	134.8	137.0	137.1
E. N. Central	46.6	43.2	54.3	41.5	50.8	42.2	55.9	42.3	48.9	41.8	55.5	41.5	185.6	191.1	187.6
W. N. Central	28.2	23.7	29.9	24.2	31.1	23.4	31.4	25.4	30.3	24.1	32.8	25.9	106.1	111.3	113.1
S. Atlantic	91.3	91.9	116.0	86.4	99.9	91.7	114.5	86.6	92.0	90.8	119.7	86.0	385.6	392.7	388.5
E. S. Central	31.5	27.0	36.9	26.0	34.0	26.6	37.2	27.3	31.8	27.1	37.9	27.0	121.4	125.1	123.8
W. S. Central	52.8	56.5	79.1	50.5	59.3	57.3	79.5	52.4	56.4	58.1	85.1	51.6	238.9	248.6	251.2
Mountain	24.4	26.8	38.0	24.2	24.8	26.5	36.9	24.0	24.6	27.0	38.3	24.8	113.4	112.2	114.7
Pacific contiguous	37.7	29.6	41.5	35.4	38.8	30.1	39.2	35.2	38.5	30.2	42.2	36.3	144.2	143.3	147.1
AK and HI	1.2	1.1	1.2	1.3	1.2	1.1	1.2	1.2	1.2	1.1	1.2	1.2	4.7	4.7	4.8
Commercial sector	**338.6**	**354.8**	**407.4**	**350.1**	**349.7**	**360.9**	**412.9**	**362.1**	**354.7**	**368.2**	**427.0**	**379.7**	**1,450.9**	**1,485.6**	**1,529.7**
New England	12.4	11.9	13.0	11.7	12.3	12.0	13.6	11.8	12.1	11.9	13.9	11.7	49.0	49.7	49.6
Middle Atlantic	35.4	34.5	41.3	35.4	37.2	35.0	40.7	36.9	38.0	36.3	42.3	39.2	146.7	149.9	155.9
E. N. Central	43.3	43.9	49.8	43.2	45.2	45.5	52.9	46.9	48.1	48.1	54.1	51.4	180.2	190.5	201.7
W. N. Central	26.5	26.7	29.9	26.9	27.9	27.1	31.1	27.8	28.1	27.8	32.0	28.3	109.9	114.0	116.3
S. Atlantic	81.1	89.5	100.7	84.5	83.0	90.1	101.0	86.3	82.9	89.6	104.1	89.6	355.8	360.4	366.3
E. S. Central	21.3	23.0	27.2	21.8	21.8	23.1	27.4	22.0	21.4	23.0	27.7	22.0	93.3	94.2	94.1
W. S. Central	50.9	55.1	64.4	54.7	53.8	57.8	66.3	57.1	55.6	60.6	71.5	63.5	225.1	235.1	251.2
Mountain	25.6	27.5	32.5	26.9	26.4	28.4	32.6	27.6	26.7	28.8	33.5	28.1	112.5	114.9	117.0
Pacific contiguous	40.7	41.3	47.3	43.6	40.7	40.6	45.9	44.2	40.5	40.7	46.6	44.4	172.9	171.4	172.1
AK and HI	1.3	1.3	1.4	1.4	1.3	1.3	1.4	1.4	1.4	1.4	1.4	1.4	5.4	5.5	5.6
Industrial sector	**243.9**	**258.4**	**274.6**	**257.7**	**249.0**	**263.4**	**279.2**	**263.1**	**252.4**	**267.1**	**284.0**	**271.0**	**1,034.6**	**1,054.7**	**1,074.5**
New England	3.5	3.6	3.8	3.5	3.5	3.6	3.9	3.5	3.4	3.6	3.8	3.5	14.4	14.5	14.2
Middle Atlantic	17.4	17.9	18.6	17.1	16.7	17.3	18.5	17.2	16.9	17.6	18.8	18.0	71.0	69.7	71.3
E. N. Central	45.7	46.5	48.7	46.2	45.5	46.9	49.5	47.0	46.2	47.5	49.6	48.1	187.1	188.9	191.3
W. N. Central	24.1	25.0	26.8	25.2	24.3	25.7	27.2	26.2	24.8	26.1	27.6	26.6	101.1	103.4	105.1
S. Atlantic	32.4	34.1	35.1	33.2	32.7	34.7	35.9	33.9	33.1	35.2	36.5	34.9	134.8	137.2	139.6
E. S. Central	23.8	24.7	25.8	24.5	24.4	25.7	26.7	25.1	24.5	25.6	26.5	24.9	98.8	101.8	101.5
W. S. Central	58.8	64.5	68.8	66.6	62.9	66.2	70.2	67.9	64.2	68.0	73.9	72.7	258.7	267.2	278.8
Mountain	19.9	21.9	23.7	20.9	20.0	22.4	24.3	21.5	20.3	22.7	24.5	21.6	86.4	88.2	89.1
Pacific contiguous	17.1	19.1	22.1	19.1	17.9	19.7	21.7	19.6	17.9	19.6	21.5	19.6	77.4	78.8	78.7
AK and HI	1.2	1.2	1.3	1.3	1.2	1.2	1.3	1.3	1.2	1.2	1.3	1.3	4.8	5.0	4.9

(a) Total includes sales of electricity to ultimate customers in transportation sector (not shown), as well as residential, commercial, and industrial sectors.

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

Electricity sales to ultimate customers are sold by electric utilities and power marketers for direct consumption by the customer and not available for resale. Includes electric sales to end users by third-party owners of behind-the-meter solar photovoltaic systems.

Regions refer to U.S. Census divisions (https://www.eia.gov/tools/glossary/index.php?id=C#census_division).

Sources:

Historical data: Latest data available from EIA databases supporting the following reports: Electric Power Monthly and Electric Power Annual.

Table 7c. U.S. Regional Electricity Prices to Ultimate Customers (Cents per Kilowatthour)

U.S. Energy Information Administration | Short-Term Energy Outlook - December 2025

	2024				2025				2026				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
All sectors (a)															
United States average ...	12.63	12.74	13.49	12.79	13.18	13.40	14.30	13.44	13.67	13.84	14.75	13.71	12.94	13.61	14.03
New England	23.12	21.97	23.21	23.78	25.39	24.28	24.58	24.73	26.58	25.42	25.62	25.87	23.03	24.75	25.87
Middle Atlantic	15.54	15.73	17.03	15.96	17.28	17.43	19.21	17.55	18.33	18.21	19.88	17.96	16.11	17.92	18.66
E. N. Central	11.99	12.27	12.49	12.09	12.78	13.07	13.82	13.04	13.43	13.63	14.36	13.37	12.22	13.20	13.72
W. N. Central	9.89	10.59	11.51	9.97	10.14	10.96	12.10	10.25	10.32	11.09	12.20	10.35	10.52	10.89	11.03
S. Atlantic	11.93	11.82	12.00	11.91	12.34	12.46	12.92	12.74	12.97	13.09	13.55	13.14	11.92	12.62	13.21
E. S. Central	10.93	10.86	11.07	11.07	11.51	11.71	11.84	11.72	11.93	11.98	12.09	11.98	10.99	11.70	12.00
W. S. Central	9.30	9.45	10.05	9.39	9.62	9.92	10.54	9.73	9.73	10.05	10.77	9.75	9.58	9.98	10.12
Mountain	10.70	11.28	11.88	10.85	10.87	11.43	12.18	11.16	11.22	11.79	12.52	11.39	11.23	11.46	11.79
Pacific	19.16	20.41	23.19	19.99	19.50	20.74	23.40	20.38	19.93	21.38	24.14	21.00	20.79	21.07	21.69
Residential sector															
United States average ...	15.99	16.52	16.67	16.71	16.43	17.46	17.69	17.59	17.35	18.18	18.30	18.19	16.48	17.29	18.02
New England	27.72	26.66	27.83	28.45	29.27	28.92	28.75	28.92	30.13	29.79	29.71	30.47	27.68	28.97	30.01
Middle Atlantic	19.89	20.48	21.19	20.82	21.15	22.68	23.70	23.10	22.83	23.84	24.56	24.07	20.62	22.66	23.85
E. N. Central	15.99	16.86	16.46	16.66	16.60	18.16	18.19	18.03	17.70	19.17	19.15	18.87	16.48	17.73	18.71
W. N. Central	12.21	13.92	14.68	12.98	12.41	14.55	15.33	13.24	12.75	14.72	15.40	13.35	13.47	13.88	14.08
S. Atlantic	14.41	14.56	14.42	14.69	14.69	15.39	15.63	15.82	15.77	16.35	16.49	16.53	14.51	15.38	16.29
E. S. Central	13.12	13.53	13.21	13.85	13.68	14.66	14.13	14.51	14.41	14.95	14.40	14.94	13.40	14.20	14.64
W. S. Central	13.52	13.95	14.12	14.56	13.84	14.76	14.86	15.13	14.54	15.23	15.14	15.69	14.04	14.65	15.14
Mountain	13.55	14.36	14.34	14.10	13.78	14.41	14.70	14.60	14.36	14.97	15.24	14.93	14.12	14.41	14.92
Pacific	22.09	25.29	26.11	23.41	22.48	25.54	26.12	23.63	22.87	26.27	26.57	23.89	24.23	24.40	24.88
Commercial sector															
United States average ...	12.50	12.53	13.25	12.63	13.07	13.21	14.08	13.19	13.46	13.60	14.45	13.42	12.75	13.42	13.76
New England	20.43	19.75	20.55	21.50	23.20	22.29	22.39	22.80	24.84	23.69	23.40	23.74	20.55	22.66	23.90
Middle Atlantic	14.93	15.49	16.66	15.53	16.94	17.18	18.94	16.97	17.93	18.01	19.59	17.40	15.69	17.55	18.26
E. N. Central	12.00	12.23	12.26	12.01	12.58	12.88	13.36	12.67	13.12	13.37	13.80	12.92	12.13	12.89	13.31
W. N. Central	9.71	10.29	11.19	9.71	9.82	10.66	11.69	10.02	9.95	10.70	11.68	10.06	10.25	10.58	10.63
S. Atlantic	10.88	10.59	10.54	10.77	11.23	11.18	11.42	11.52	11.83	11.75	11.92	11.87	10.69	11.34	11.85
E. S. Central	12.44	12.26	12.23	12.55	13.09	13.21	13.07	13.29	13.64	13.60	13.31	13.52	12.36	13.16	13.51
W. S. Central	8.76	8.80	9.11	8.81	8.96	9.08	9.49	8.71	8.59	8.98	9.64	8.79	8.88	9.08	9.03
Mountain	10.48	11.16	11.60	10.73	10.67	11.31	11.99	11.02	10.94	11.57	12.13	11.16	11.03	11.29	11.49
Pacific	18.93	19.47	23.25	19.41	19.39	20.37	23.93	19.85	19.75	20.88	24.72	20.62	20.36	20.95	21.59
Industrial sector															
United States average ...	7.84	8.03	8.62	7.98	8.25	8.44	9.13	8.50	8.55	8.64	9.32	8.58	8.13	8.59	8.78
New England	16.38	15.41	16.37	16.98	18.52	17.48	17.78	17.79	19.59	18.33	18.37	18.30	16.28	17.88	18.63
Middle Atlantic	8.46	8.26	8.78	8.57	9.66	9.18	10.02	9.24	9.89	9.34	10.11	9.28	8.52	9.53	9.66
E. N. Central	7.92	8.04	8.29	8.07	8.74	8.70	9.38	8.93	9.25	9.03	9.63	9.13	8.08	8.94	9.26
W. N. Central	7.38	7.77	8.34	7.35	7.59	8.00	8.85	7.60	7.77	8.14	9.01	7.74	7.72	8.03	8.18
S. Atlantic	7.58	7.64	8.18	7.61	7.99	8.03	8.47	8.01	8.05	8.09	8.62	8.06	7.76	8.13	8.21
E. S. Central	6.68	6.64	6.77	6.80	7.06	7.29	7.38	7.30	7.21	7.39	7.53	7.40	6.72	7.26	7.38
W. S. Central	5.97	6.06	6.23	5.95	6.21	6.44	6.65	6.41	6.50	6.59	6.83	6.36	6.06	6.43	6.58
Mountain	7.50	7.67	8.32	7.24	7.54	8.05	8.60	7.48	7.80	8.29	8.78	7.64	7.70	7.95	8.16
Pacific	13.29	14.93	17.65	15.05	13.38	14.22	17.42	15.81	14.10	14.96	18.25	16.57	15.38	15.31	16.07

(a) Average price to all sectors is weighted by sales of electricity to ultimate customers in the residential, commercial, industrial and transportation (not shown) sectors.

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

consumers by the corresponding sales of electricity.

Prices are not adjusted for inflation.

Regions refer to U.S. Census divisions (https://www.eia.gov/tools/glossary/index.php?id=C#census_division).

Sources:

Historical data: Latest data available from EIA databases supporting the following reports: Electric Power Monthly and Electric Power Annual.

Table 7d part 1. U.S. Regional Electricity Generation, Electric Power Sector (billion kilowatthours), *continues on Table 7d part 2*

U.S. Energy Information Administration | Short-Term Energy Outlook - December 2025

	2024				2025				2026				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
United States															
Total generation	**989.6**	**1,013.9**	**1,172.3**	**980.9**	**1,035.7**	**1,020.7**	**1,194.4**	**1,005.5**	**1,023.3**	**1,036.0**	**1,235.2**	**1,032.4**	**4,156.6**	**4,256.2**	**4,326.9**
Natural gas	398.3	409.7	551.1	406.9	379.9	389.4	535.6	402.0	373.3	383.6	545.7	407.4	1,766.0	1,706.9	1,709.9
Coal	157.1	143.4	193.7	153.5	193.5	157.7	207.3	166.6	170.6	140.9	205.6	164.4	647.7	725.1	681.5
Nuclear	197.0	190.7	202.3	191.9	196.0	186.3	206.9	192.0	197.2	195.7	209.5	197.9	781.9	781.3	800.3
Renewable energy sources:	233.4	266.6	222.3	225.3	260.7	283.9	241.3	241.5	278.8	314.1	272.4	261.1	947.7	1,027.3	1,126.4
Conventional hydropower	65.4	67.5	57.6	51.4	63.1	69.0	55.0	54.3	65.6	75.0	62.5	56.4	241.8	241.5	259.6
Wind	120.8	124.9	86.7	119.2	133.5	118.5	84.7	121.0	139.0	126.8	90.6	127.9	451.7	457.7	484.3
Solar (a)	37.9	65.7	69.0	46.1	54.8	87.6	92.2	57.2	65.0	103.9	109.8	67.7	218.7	291.8	346.4
Biomass	5.2	4.8	5.3	4.8	5.2	4.9	5.4	4.9	5.1	4.8	5.4	4.9	20.1	20.5	20.1
Geothermal	4.1	3.7	3.6	4.0	4.0	3.8	3.9	4.1	4.0	3.6	4.2	4.2	15.4	15.9	16.0
Pumped storage hydropower	-1.2	-1.2	-2.1	-1.4	-1.3	-0.9	-1.5	-1.6	-1.4	-1.7	-2.1	-2.0	-5.9	-5.4	-7.1
Petroleum (b)	3.6	3.4	3.8	3.6	5.8	3.6	4.3	4.2	4.1	3.1	3.9	3.5	14.4	17.9	14.6
Other fossil gases	0.8	0.8	0.8	0.7	0.8	0.5	0.5	0.8	0.8	0.7	0.7	0.8	3.0	2.6	3.0
Other nonrenewable fuels (c)	0.7	0.5	0.4	0.3	0.3	0.2	0.0	-0.1	-0.2	-0.4	-0.6	-0.7	1.9	0.4	-1.8
New England (ISO-NE)															
Total generation	**25.6**	**25.0**	**29.9**	**25.0**	**25.8**	**24.6**	**30.5**	**27.1**	**26.6**	**24.4**	**30.6**	**24.6**	**105.5**	**108.0**	**106.2**
Natural gas	13.2	12.6	18.5	15.3	12.7	12.9	18.1	14.2	12.9	12.8	18.2	12.6	59.7	57.9	56.5
Coal	0.0	0.0	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.0	0.1	0.1	0.3	0.4	0.4
Nuclear	7.0	7.3	6.9	5.4	7.2	6.1	7.2	7.0	7.0	5.4	7.2	6.1	26.5	27.6	25.7
Conventional hydropower	2.3	2.0	1.4	1.1	1.7	1.8	1.5	1.8	2.0	2.2	1.2	1.8	6.8	6.7	7.3
Wind	1.1	0.8	0.5	1.2	1.3	0.9	0.6	1.7	1.9	1.3	0.8	2.1	3.6	4.5	6.1
Solar (a)	0.8	1.4	1.5	0.9	1.1	1.8	1.9	1.1	1.2	1.7	1.9	0.9	4.6	5.9	5.7
Other energy sources (d)	1.1	0.9	1.1	1.1	1.5	1.0	1.2	1.2	1.3	1.0	1.1	1.1	4.1	5.0	4.5
Net energy for load (e)	29.6	27.0	32.0	28.1	30.7	26.7	31.3	28.0	29.7	27.5	34.2	28.9	116.8	116.7	120.2
New York (NYISO)															
Total generation	**32.5**	**32.0**	**35.9**	**31.9**	**32.6**	**31.9**	**37.5**	**31.2**	**30.9**	**30.7**	**37.9**	**32.1**	**132.4**	**133.2**	**131.6**
Natural gas	15.7	15.3	20.8	15.9	15.3	14.7	21.3	14.7	14.0	13.6	21.4	14.3	67.6	66.0	63.3
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	6.5	7.2	6.4	7.0	6.8	7.2	7.2	7.2	6.3	6.9	6.9	7.2	27.1	28.4	27.3
Conventional hydropower	7.9	7.1	6.6	6.3	6.5	6.8	6.3	6.5	6.6	6.7	6.8	7.0	27.9	26.0	27.2
Wind	1.7	1.4	1.0	2.0	2.3	1.7	0.9	1.8	2.5	1.8	1.0	2.4	6.0	6.7	7.8
Solar (a)	0.4	0.9	1.0	0.6	0.9	1.4	1.5	0.6	0.9	1.5	1.7	0.9	2.9	4.5	5.0
Other energy sources (d)	0.3	0.2	0.2	0.2	0.9	0.2	0.2	0.4	0.5	0.1	0.2	0.2	0.9	1.7	1.1
Net energy for load (e)	37.0	35.7	42.4	35.9	38.2	35.0	41.7	35.3	37.4	36.1	45.3	36.8	150.9	150.2	155.5
Mid-Atlantic (PJM)															
Total generation	**218.8**	**207.9**	**239.0**	**204.4**	**230.3**	**209.0**	**248.8**	**210.7**	**226.7**	**212.1**	**255.3**	**234.0**	**870.1**	**898.8**	**928.1**
Natural gas	95.8	91.0	116.1	88.3	95.1	86.7	117.7	90.2	93.8	87.9	119.9	99.1	391.1	389.7	400.7
Coal	36.3	34.8	39.9	30.9	46.6	36.1	45.0	37.3	43.8	35.8	47.6	46.7	141.8	165.0	174.0
Nuclear	68.9	64.3	70.4	68.8	68.2	65.7	69.9	65.4	67.6	66.6	71.2	68.6	272.4	269.2	274.0
Conventional hydropower	3.2	2.4	1.5	1.6	2.3	2.6	1.7	2.1	2.7	2.6	1.7	2.1	8.7	8.7	9.2
Wind	9.8	7.8	3.8	9.3	10.6	7.5	3.7	9.3	11.0	8.0	3.6	10.3	30.7	31.2	32.8
Solar (a)	3.5	6.3	6.4	4.2	5.6	9.1	9.6	5.1	6.4	10.2	10.5	6.2	20.5	29.3	33.4
Other energy sources (d)	1.3	1.2	1.0	1.2	2.0	1.2	1.2	1.3	1.4	1.0	0.8	0.9	4.9	5.7	4.2
Net energy for load (e)	207.4	199.3	227.4	197.5	220.1	199.4	232.0	211.2	223.4	206.3	244.7	226.9	831.6	862.8	901.4
Southeast (SERC)															
Total generation	**154.6**	**157.8**	**179.2**	**150.1**	**159.1**	**157.0**	**183.0**	**149.3**	**150.3**	**154.5**	**183.2**	**145.1**	**641.7**	**648.4**	**633.1**
Natural gas	59.0	62.5	82.5	62.5	64.9	61.9	78.4	57.3	58.3	58.0	77.5	55.4	266.5	262.4	249.2
Coal	23.3	24.4	28.7	22.1	27.6	25.1	29.9	22.1	19.6	21.5	28.9	17.7	98.6	104.7	87.6
Nuclear	55.9	56.8	55.6	53.5	52.2	53.0	59.7	56.2	55.5	57.3	60.0	57.1	221.8	221.1	229.9
Conventional hydropower	10.9	6.4	5.5	6.5	7.9	8.2	6.5	7.6	10.5	8.2	7.6	8.2	29.4	30.2	34.6
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar (a)	4.8	7.2	6.7	5.1	5.8	8.4	8.3	5.8	5.8	9.5	9.2	6.4	23.7	28.3	30.9
Other energy sources (d)	0.7	0.4	0.2	0.5	0.8	0.4	0.2	0.4	0.6	0.1	-0.1	0.3	1.7	1.7	0.8
Net energy for load (e)	140.0	141.8	161.8	134.5	146.7	141.6	163.0	133.7	136.2	138.4	164.5	131.8	578.2	585.1	570.9
Florida (FRCC)															
Total generation	**55.1**	**68.7**	**79.0**	**58.5**	**55.6**	**69.5**	**78.4**	**59.5**	**55.5**	**66.8**	**77.7**	**59.8**	**261.4**	**263.0**	**259.8**
Natural gas	41.9	52.3	63.0	45.9	40.2	50.7	59.8	44.6	39.8	48.1	57.6	43.2	203.0	195.3	188.7
Coal	1.4	2.3	3.0	1.1	1.7	2.7	3.2	2.1	1.9	2.9	4.5	2.5	7.8	9.7	11.8
Nuclear	7.5	7.5	7.3	6.8	7.5	7.9	7.7	7.3	7.2	7.0	7.5	8.1	29.1	30.4	29.7
Conventional hydropower	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.2	0.2	0.2
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar (a)	3.7	5.8	4.8	4.0	5.3	7.2	6.6	4.7	5.8	7.9	7.2	5.2	18.4	23.8	26.0
Other energy sources (d)	0.6	0.8	0.9	0.6	0.9	0.9	1.1	0.7	0.8	0.8	1.0	0.7	2.9	3.6	3.4
Net energy for load (e)	54.7	70.2	80.3	59.6	56.3	71.2	79.6	59.9	55.9	69.3	80.9	60.8	264.8	267.0	267.0

(a) Generation from utility-scale solar photovoltaic and solar thermal power plants. Excludes generation from small-scale solar photovoltaic systems (see Table 7a).

(b) Residual fuel oil, distillate fuel oil, petroleum coke, and other petroleum liquids.

(c) Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, nonrenewable waste, and miscellaneous technologies.

(d) Pumped storage hydroelectric, biomass, geothermal, petroleum, other fossil gases, batteries, and other nonrenewable fuels. See notes (b) and (c).

(e) Includes regional generation from power plants operated by electric power sector, plus net energy receipts from neighboring regions (see Figure 36 for STEO electricity supply regions).

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

The electric power sector includes utility-scale generating power plants (total capacity is larger than 1 megawatt) operated by electric utilities and independent power producers.

Sources:

Historical data: Latest data available from EIA databases supporting the following reports: Electric Power Monthly and Electric Power Annual.

Minor discrepancies with published historical data are due to independent rounding and possible revisions not yet reflected in the STEO.

Forecast data: EIA Short-Term Integrated Forecasting System.

Table 7d part 2. U.S. Regional Electricity Generation, Electric Power Sector (billion kilowatthours), *continued from Table 7d part 1*

U.S. Energy Information Administration | Short-Term Energy Outlook - December 2025

	2024				2025				2026				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
Midwest (MISO)															
Total generation	**147.2**	**150.0**	**169.6**	**149.1**	**159.7**	**149.7**	**176.0**	**156.4**	**157.1**	**149.7**	**175.2**	**150.0**	**615.9**	**641.7**	**631.9**
Natural gas	48.7	54.0	67.9	49.1	41.0	47.9	66.7	49.8	43.7	49.0	68.2	47.8	219.6	205.4	208.7
Coal	42.8	38.1	51.3	42.1	53.3	43.2	55.9	45.7	45.9	34.3	49.7	39.8	174.3	198.1	169.7
Nuclear	20.9	21.7	25.0	22.7	23.3	20.2	24.2	22.5	23.3	25.0	25.9	23.4	90.4	90.2	97.4
Conventional hydropower	2.3	3.0	2.0	1.6	2.4	2.6	2.1	1.9	2.2	2.7	2.1	2.1	8.9	9.0	9.1
Wind	28.6	27.2	16.5	28.6	32.6	24.9	14.6	29.0	33.2	25.6	14.7	29.0	100.9	101.1	102.7
Solar (a)	2.5	4.8	5.8	3.6	5.6	9.5	11.0	5.7	7.3	11.8	13.0	6.4	16.7	31.8	38.4
Other energy sources (d)	1.4	1.2	1.2	1.2	1.6	1.3	1.5	1.7	1.5	1.3	1.6	1.5	5.0	6.1	5.9
Net energy for load (e)	159.9	160.1	182.5	158.1	166.4	160.1	188.7	163.0	164.4	161.7	189.9	161.0	660.6	678.3	677.0
Central (Southwest Power Pool)															
Total generation	**75.9**	**76.1**	**89.1**	**73.6**	**81.2**	**76.2**	**90.1**	**77.1**	**76.8**	**76.3**	**90.3**	**72.8**	**314.7**	**324.7**	**316.2**
Natural gas	21.1	22.8	31.4	19.4	18.5	20.7	29.6	20.0	16.7	19.6	29.8	18.8	94.6	88.8	84.9
Coal	17.7	15.6	25.7	18.0	23.4	18.1	29.0	21.8	20.3	15.7	27.1	16.6	77.0	92.2	79.6
Nuclear	4.3	3.2	4.1	3.8	4.4	4.4	4.4	3.0	4.2	4.2	4.2	3.6	15.3	16.1	16.2
Conventional hydropower	2.7	3.6	3.1	2.7	3.3	3.6	2.8	2.5	3.2	4.1	3.7	3.0	12.1	12.2	14.0
Wind	29.5	30.2	24.0	29.1	30.9	28.3	23.3	29.1	31.5	31.2	24.1	29.8	112.8	111.7	116.6
Solar (a)	0.3	0.5	0.6	0.3	0.4	0.7	0.9	0.5	0.7	1.1	1.3	0.8	1.7	2.5	3.9
Other energy sources (d)	0.3	0.4	0.3	0.2	0.4	0.4	0.3	0.2	0.3	0.4	0.2	0.2	1.2	1.2	1.0
Net energy for load (e)	75.1	75.2	88.7	73.1	79.6	75.3	90.1	76.5	76.8	75.3	90.6	72.2	312.1	321.5	314.9
Texas (ERCOT)															
Total generation	**102.4**	**117.1**	**133.3**	**108.5**	**110.9**	**121.5**	**138.4**	**113.6**	**116.3**	**131.8**	**156.2**	**126.9**	**461.2**	**484.4**	**531.1**
Natural gas	43.0	52.8	69.3	46.2	42.6	48.8	67.5	47.2	40.8	51.6	72.0	50.3	211.2	206.1	214.7
Coal	12.0	12.4	18.2	14.9	15.4	14.2	18.1	15.5	17.6	15.5	22.9	20.8	57.6	63.2	76.8
Nuclear	10.0	9.1	10.6	9.0	10.8	10.2	10.8	9.9	10.7	8.8	10.9	10.2	38.6	41.6	40.6
Conventional hydropower	0.1	0.2	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.2	0.1	0.1	0.5	0.6	0.6
Wind	29.8	31.9	21.7	28.5	31.3	32.2	23.6	28.4	33.0	33.7	25.3	29.5	111.9	115.5	121.5
Solar (a)	7.1	10.4	13.0	9.6	10.4	15.8	18.2	12.4	14.0	22.1	24.9	16.0	40.1	56.7	77.0
Other energy sources (d)	0.3	0.4	0.3	0.3	0.3	0.1	0.1	0.1	0.1	0.0	-0.1	-0.1	1.3	0.7	-0.1
Net energy for load (e)	101.0	117.8	134.8	107.8	109.9	122.8	141.2	113.6	116.3	131.8	156.2	126.9	461.5	487.6	531.1
Northwest															
Total generation	**93.5**	**89.8**	**101.9**	**92.3**	**98.2**	**91.5**	**99.8**	**91.8**	**97.2**	**94.0**	**107.3**	**95.3**	**377.5**	**381.4**	**393.8**
Natural gas	28.0	19.9	32.2	26.4	23.5	20.1	31.5	25.1	22.6	16.0	32.6	26.2	106.4	100.3	97.4
Coal	17.5	11.1	19.1	18.1	19.6	14.2	19.7	17.2	17.1	11.0	18.4	15.8	65.7	70.6	62.3
Nuclear	2.5	2.5	2.5	2.5	2.4	0.3	2.5	2.5	2.4	2.4	2.4	2.4	10.0	7.7	9.7
Conventional hydropower	26.9	30.8	26.6	25.4	30.1	32.0	24.5	25.9	31.1	37.3	28.8	26.4	109.7	112.6	123.6
Wind	13.0	16.2	12.2	13.9	15.9	14.6	11.3	14.8	16.8	16.3	13.7	17.5	55.3	56.5	64.3
Solar (a)	3.8	8.0	8.1	4.5	5.1	8.8	9.0	4.9	5.7	9.8	9.9	5.5	24.4	27.9	30.9
Other energy sources (d)	1.8	1.4	1.3	1.5	1.6	1.4	1.4	1.5	1.5	1.3	1.4	1.5	6.0	5.8	5.7
Net energy for load (e)	92.1	85.3	96.8	89.5	94.2	86.4	97.5	89.5	93.3	88.4	101.3	92.6	363.7	367.5	375.6
Southwest															
Total generation	**34.3**	**37.1**	**45.9**	**36.4**	**33.5**	**36.8**	**47.3**	**36.0**	**35.8**	**40.0**	**51.2**	**39.2**	**153.7**	**153.5**	**166.2**
Natural gas	12.3	15.3	22.8	16.5	11.3	14.3	22.5	15.3	11.3	14.5	23.0	15.9	66.9	63.5	64.6
Coal	5.1	4.0	5.6	3.7	3.7	3.3	5.3	4.1	4.1	3.7	6.0	3.9	18.2	16.5	17.7
Nuclear	8.7	7.4	8.7	7.5	8.5	7.3	8.7	6.9	8.4	7.5	8.6	7.5	32.4	31.4	32.0
Conventional hydropower	1.6	2.3	1.6	1.4	1.8	2.2	1.6	1.1	1.4	2.1	2.0	1.4	7.0	6.7	6.9
Wind	3.8	3.6	2.5	3.7	4.1	3.2	2.5	3.7	4.4	3.6	2.8	4.1	13.5	13.5	15.0
Solar (a)	2.1	3.7	3.9	2.8	3.2	5.7	5.8	4.2	5.4	8.1	8.0	5.7	12.5	18.8	27.2
Other energy sources (d)	0.8	0.8	0.8	0.8	0.8	0.7	0.8	0.7	0.8	0.6	0.8	0.7	3.2	3.0	2.8
Net energy for load (e)	23.1	29.5	38.9	25.5	24.4	30.4	39.4	26.7	25.3	31.4	40.0	26.2	117.0	120.9	122.9
California															
Total generation	**46.1**	**48.8**	**65.5**	**47.3**	**45.3**	**49.6**	**60.5**	**48.8**	**46.4**	**51.9**	**66.5**	**48.9**	**207.7**	**204.2**	**213.8**
Natural gas	18.8	10.7	25.9	20.7	14.3	10.3	21.4	22.8	18.5	11.9	24.9	23.1	76.2	68.8	78.4
Coal	0.7	0.6	2.0	2.3	1.9	0.6	0.9	0.3	0.0	0.0	0.0	0.0	5.7	3.8	0.0
Nuclear	4.9	3.6	4.9	4.9	4.8	3.9	4.8	4.1	4.6	4.7	4.7	3.6	18.4	17.6	17.7
Conventional hydropower	7.1	9.1	8.8	4.2	6.5	8.6	7.6	4.4	5.2	8.4	8.0	3.9	29.2	27.1	25.4
Wind	3.3	5.8	4.4	2.7	4.3	4.9	4.0	3.0	4.4	5.0	4.3	2.9	16.2	16.2	16.6
Solar (a)	8.9	16.4	17.0	10.2	11.2	18.9	19.1	12.1	11.9	20.0	21.9	13.4	52.4	61.3	67.1
Other energy sources (d)	2.4	2.5	2.6	2.2	2.3	2.4	2.7	2.2	1.9	1.9	2.7	2.0	9.7	9.5	8.5
Net energy for load (e)	58.6	61.9	80.2	64.7	59.3	64.5	78.5	62.5	60.8	66.2	83.7	64.6	265.4	264.8	275.3

(a) Generation from utility-scale solar photovoltaic and solar thermal power plants. Excludes generation from small-scale solar photovoltaic systems (see Table 7a).

(b) Residual fuel oil, distillate fuel oil, petroleum coke, and other petroleum liquids.

(c) Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, nonrenewable waste, and miscellaneous technologies.

(d) Pumped storage hydroelectric, biomass, geothermal, petroleum, other fossil gases, batteries, and other nonrenewable fuels. See notes (b) and (c).

(e) Includes regional generation from power plants operated by electric power sector, plus net energy receipts from neighboring regions (see Figure 36 for STEO electricity supply regions).

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

The electric power sector includes utility-scale generating power plants (total capacity is larger than 1 megawatt) operated by electric utilities and independent power producers.

Sources:

Historical data: Latest data available from EIA databases supporting the following reports: Electric Power Monthly and Electric Power Annual.

Minor discrepancies with published historical data are due to independent rounding and possible revisions not yet reflected in the STEO.

Forecast: EIA Short-Term Integrated Forecasting System.

Table 7e. U.S. Electricity Generating Capacity (gigawatts at end of period)

U.S. Energy Information Administration | Short-Term Energy Outlook - December 2025

	2024				2025				2026				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
Electric power sector (power plants larger than one megawatt)															
Fossil fuel energy sources															
Natural gas	488.4	486.8	487.6	487.9	489.2	490.4	491.1	492.9	493.9	495.5	494.9	494.8	487.9	492.9	494.8
Coal	175.9	174.6	174.4	172.8	170.5	170.4	170.4	165.1	165.1	164.6	164.6	161.6	172.8	165.1	161.6
Petroleum	27.3	27.2	27.2	27.2	27.2	26.5	26.6	26.6	26.6	26.6	26.6	26.6	27.2	26.6	26.6
Other fossil gases	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Renewable energy sources															
Wind	148.1	149.3	150.5	152.0	153.7	154.7	155.1	159.5	160.2	164.2	164.8	169.9	152.0	159.5	169.9
Solar photovoltaic	96.6	103.2	107.8	121.3	128.2	133.5	138.5	146.4	152.2	158.4	162.6	179.9	121.3	146.4	179.9
Solar thermal	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Geothermal	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Waste biomass	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Wood biomass	2.3	2.3	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Conventional hydroelectric	79.6	79.6	79.6	79.6	79.6	79.6	79.6	79.7	79.7	79.7	79.7	79.7	79.6	79.7	79.7
Pumped storage hydroelectric	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2
Nuclear	97.3	98.4	98.4	98.4	96.8	96.9	96.9	97.6	97.6	97.6	97.6	97.6	98.4	97.6	97.6
Battery storage	17.3	20.4	23.2	27.0	28.8	33.1	36.8	45.6	49.0	55.0	57.0	65.6	27.0	45.6	65.6
Other nonrenewable sources (a)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Industrial and commercial sectors (combined heat and power plants larger than one megawatt)															
Fossil fuel energy sources															
Natural gas	18.8	18.7	18.7	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.6	18.5	18.5	18.6
Coal	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Petroleum	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Other fossil gases	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Renewable energy sources															
Wood biomass	5.2	5.2	5.2	5.2	5.2	5.2	5.1	5.1	5.1	5.1	5.1	5.1	5.2	5.1	5.1
Waste biomass	1.4	1.4	1.4	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Solar	0.7	0.7	0.7	0.7	0.7	0.8	1.0	1.1	1.1	1.1	1.1	1.1	0.7	1.1	1.1
Wind	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Geothermal	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Conventional hydroelectric	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Battery storage	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.3	0.1	0.2	0.3
Other nonrenewable sources (a)	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Small-scale solar photovoltaic capacity (systems smaller than one megawatt)															
All sectors total	**48.7**	**50.1**	**51.6**	**53.2**	**54.6**	**55.9**	**57.3**	**58.9**	**60.5**	**62.0**	**63.6**	**65.1**	**53.2**	**58.9**	**65.1**
Residential sector	33.6	34.4	35.5	36.5	37.4	38.2	39.2	40.3	41.3	42.4	43.4	44.5	36.5	40.3	44.5
Commercial sector	12.5	13.0	13.4	14.0	14.5	14.9	15.3	15.7	16.1	16.6	17.0	17.5	14.0	15.7	17.5
Industrial sector	2.6	2.6	2.7	2.7	2.8	2.8	2.9	2.9	3.0	3.0	3.1	3.2	2.7	2.9	3.2

(a) Other sources include hydrogen, pitch, chemicals, sulfur, purchased steam, nonrenewable waste, and miscellaneous technologies.

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

Capacity values represent the amount of generating capacity that is operating (or expected to be operating) at the end of each period.

Changes in capacity reflect various factors including new generators coming online, retiring generators, capacity uprates and derates, delayed planned capacity projects, cancelled projects, and other

Sources:

Historical data: Utility-scale capacity (power plants larger than one megawatt): EIA-860 Annual Survey and EIA-860M Preliminary Monthly Electric Generator Inventory, September 2025.

Small-scale solar capacity (systems smaller than one megawatt): Form EIA-861M Monthly Electric Power Industry Report.

Historical capacity data may differ from other EIA publications due to frequent updates to the Preliminary Monthly Electric Generator Inventory.

Table 8. U.S. Renewable Energy Consumption (quadrillion Btu)

U.S. Energy Information Administration | Short-Term Energy Outlook - December 2025

	2024				2025				2026				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
All Sectors	**2.118**	**2.282**	**2.164**	**2.132**	**2.163**	**2.277**	**2.170**	**2.169**	**2.262**	**2.479**	**2.384**	**2.311**	**8.696**	**8.779**	**9.435**
Biodiesel, renewable diesel, and other (g)	0.175	0.198	0.203	0.194	0.132	0.128	0.132	0.153	0.138	0.177	0.197	0.202	0.770	0.545	0.714
Biofuel losses and co-products (d)	0.210	0.205	0.218	0.221	0.213	0.210	0.217	0.221	0.211	0.214	0.218	0.225	0.854	0.860	0.868
Ethanol (f)	0.281	0.296	0.303	0.299	0.281	0.299	0.300	0.295	0.278	0.297	0.299	0.297	1.179	1.175	1.171
Geothermal	0.030	0.029	0.028	0.030	0.029	0.029	0.029	0.030	0.029	0.028	0.030	0.030	0.116	0.118	0.118
Hydroelectric power (a)	0.224	0.231	0.197	0.176	0.216	0.237	0.191	0.186	0.225	0.257	0.214	0.193	0.829	0.830	0.889
Solar (b)(f)	0.202	0.329	0.340	0.229	0.266	0.412	0.428	0.274	0.307	0.480	0.499	0.316	1.100	1.380	1.602
Waste biomass (c)	0.100	0.095	0.094	0.098	0.096	0.091	0.091	0.096	0.093	0.091	0.093	0.096	0.387	0.374	0.373
Wood biomass	0.483	0.473	0.485	0.479	0.475	0.466	0.493	0.502	0.505	0.502	0.524	0.516	1.920	1.936	2.047
Wind	0.412	0.426	0.296	0.407	0.455	0.404	0.289	0.413	0.474	0.433	0.309	0.436	1.541	1.562	1.652
Electric power sector	**0.863**	**0.970**	**0.823**	**0.829**	**0.953**	**1.026**	**0.890**	**0.883**	**1.012**	**1.129**	**0.994**	**0.949**	**3.485**	**3.753**	**4.084**
Geothermal	0.014	0.013	0.012	0.014	0.014	0.013	0.013	0.014	0.014	0.012	0.014	0.014	0.053	0.054	0.054
Hydroelectric power (a)	0.223	0.230	0.196	0.175	0.215	0.236	0.190	0.185	0.224	0.256	0.213	0.192	0.825	0.827	0.886
Solar (b)	0.129	0.224	0.235	0.157	0.187	0.299	0.314	0.195	0.222	0.355	0.375	0.231	0.746	0.996	1.182
Waste biomass (c)	0.041	0.038	0.040	0.040	0.039	0.037	0.037	0.039	0.038	0.037	0.039	0.039	0.158	0.152	0.153
Wood biomass	0.044	0.038	0.043	0.036	0.042	0.037	0.046	0.037	0.041	0.036	0.044	0.036	0.162	0.163	0.156
Wind	0.412	0.426	0.296	0.407	0.455	0.404	0.289	0.413	0.474	0.433	0.309	0.436	1.541	1.562	1.652
Industrial sector (e)	**0.593**	**0.584**	**0.600**	**0.606**	**0.588**	**0.580**	**0.603**	**0.628**	**0.617**	**0.621**	**0.639**	**0.647**	**2.383**	**2.398**	**2.524**
Biofuel losses and co-products (d)	0.210	0.205	0.218	0.221	0.213	0.210	0.217	0.221	0.211	0.214	0.218	0.225	0.854	0.860	0.868
Geothermal	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.004	0.004	0.004
Hydroelectric power (a)	0.001	0.001	0.000	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.003	0.003	0.003
Solar (b)	0.004	0.005	0.005	0.004	0.004	0.006	0.006	0.005	0.005	0.006	0.006	0.004	0.018	0.020	0.022
Waste biomass (c)	0.041	0.039	0.037	0.040	0.040	0.038	0.037	0.040	0.038	0.037	0.037	0.039	0.156	0.154	0.152
Wood biomass	0.332	0.328	0.333	0.334	0.324	0.320	0.336	0.357	0.357	0.357	0.370	0.372	1.328	1.337	1.456
Commercial sector (e)	**0.063**	**0.070**	**0.071**	**0.063**	**0.064**	**0.072**	**0.074**	**0.066**	**0.067**	**0.076**	**0.077**	**0.068**	**0.268**	**0.276**	**0.288**
Geothermal	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.020	0.020	0.020
Solar (b)	0.015	0.023	0.023	0.015	0.018	0.026	0.026	0.018	0.021	0.030	0.030	0.020	0.076	0.088	0.100
Waste biomass (c)	0.018	0.018	0.018	0.018	0.017	0.016	0.017	0.018	0.017	0.016	0.017	0.017	0.072	0.068	0.068
Wood biomass	0.018	0.018	0.018	0.018	0.018	0.018	0.019	0.018	0.018	0.018	0.019	0.018	0.072	0.072	0.072
Residential sector	**0.152**	**0.176**	**0.176**	**0.153**	**0.157**	**0.183**	**0.183**	**0.156**	**0.160**	**0.191**	**0.190**	**0.160**	**0.658**	**0.679**	**0.701**
Geothermal	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.040	0.040	0.040
Solar (f)	0.053	0.077	0.076	0.053	0.057	0.082	0.082	0.056	0.060	0.089	0.089	0.061	0.260	0.276	0.299
Wood biomass	0.089	0.089	0.090	0.090	0.090	0.091	0.091	0.090	0.090	0.091	0.091	0.090	0.358	0.363	0.363
Transportation sector	**0.445**	**0.482**	**0.494**	**0.481**	**0.401**	**0.416**	**0.420**	**0.436**	**0.405**	**0.462**	**0.484**	**0.486**	**1.901**	**1.673**	**1.837**
Biodiesel, renewable diesel, and other (g)	0.175	0.198	0.203	0.194	0.132	0.128	0.132	0.153	0.138	0.177	0.197	0.202	0.770	0.545	0.714
Ethanol (g)	0.270	0.284	0.291	0.287	0.269	0.287	0.288	0.283	0.267	0.285	0.287	0.285	1.131	1.128	1.124

(a) Energy consumption for conventional hydroelectric power only. Hydroelectricity generated by pumped storage is not included in renewable energy.

(b) Solar energy consumption by utility-scale power plants (capacity greater than or equal to 1 megawatt) in the electric power, commercial, and industrial sectors and energy consumption by small-scale solar photovoltaic systems (less than 1 megawatts in size).

(c) Municipal solid waste from biogenic sources, landfill gas, sludge waste, agricultural byproducts, and other biomass.

(d) Losses and co-products from the production of fuel ethanol and biomass-based diesel

(e) Subtotals for the industrial and commercial sectors might not equal the sum of the components. The subtotal for the industrial sector includes ethanol consumption that is not shown separately. The subtotal for the commercial sector includes ethanol and hydroelectric consumption that are not shown separately.

(f) Solar consumption in the residential sector includes energy from small-scale solar photovoltaic systems (<1 megawatt), and it includes solar heating consumption in all sectors.

(g) Fuel ethanol and biodiesel, renewable diesel, and other biofuels consumption in the transportation sector includes production, stock change, and imports less exports.
Some biomass-based diesel may be consumed in the residential sector in heating oil.

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

Sources:

Monthly Energy Review, and Petroleum Supply Monthly.

Minor discrepancies with published historical data are due to independent rounding and possible revisions not yet reflected in the STEO.

Forecasts: EIA Short-Term Integrated Forecasting System.

Table 9a. U.S. Macroeconomic Indicators and CO_2 Emissions

U.S. Energy Information Administration | Short-Term Energy Outlook - December 2025

	2024				2025				2026				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
Macroeconomic															
Real Gross Domestic Product															
(billion chained 2017 dollars - SAAR)	23,082	23,287	23,479	23,587	23,548	23,771	23,953	24,006	24,141	24,284	24,432	24,559	23,358	23,820	24,354
Real Personal Consumption Expend.															
(billion chained 2017 dollars - SAAR)	15,858	16,010	16,166	16,321	16,346	16,446	16,572	16,623	16,710	16,806	16,903	16,984	16,088	16,497	16,851
Real Private Fixed Investment															
(billion chained 2017 dollars - SAAR)	4,250	4,265	4,281	4,260	4,334	4,380	4,386	4,352	4,353	4,370	4,393	4,415	4,264	4,363	4,383
Business Inventory Change															
(billion chained 2017 dollars - SAAR)	15	98	83	18	212	-46	-45	23	15	16	41	77	54	36	37
Real Government Expenditures															
(billion chained 2017 dollars - SAAR)	3,887	3,919	3,971	4,004	3,994	3,993	3,998	3,971	4,031	4,039	4,046	4,050	3,945	3,989	4,041
Real Exports of Goods & Services															
(billion chained 2017 dollars - SAAR)	2,604	2,608	2,664	2,658	2,660	2,647	2,652	2,661	2,680	2,720	2,761	2,794	2,634	2,655	2,739
Real Imports of Goods & Services															
(billion chained 2017 dollars - SAAR)	3,568	3,640	3,729	3,727	4,040	3,705	3,621	3,614	3,644	3,656	3,692	3,734	3,666	3,745	3,682
Real Disposable Personal Income															
(billion chained 2017 dollars - SAAR)	17,596	17,701	17,755	17,843	17,943	18,082	18,098	18,141	18,424	18,569	18,712	18,859	17,724	18,066	18,641
Non-Farm Employment															
(millions)	157.3	157.8	158.1	158.6	159.2	159.4	159.6	159.6	159.9	160.2	160.5	160.8	158.0	159.4	160.3
Civilian Unemployment Rate															
(percent)	3.8	4.0	4.2	4.1	4.1	4.2	4.3	4.4	4.4	4.5	4.4	4.4	4.0	4.2	4.4
Housing Starts															
(millions - SAAR)	1.42	1.34	1.34	1.39	1.40	1.35	1.36	1.31	1.31	1.31	1.31	1.31	1.37	1.36	1.31
Industrial Production Indices (Index, 2017=100)															
Total Industrial Production	102.2	102.9	102.7	102.4	103.4	103.8	103.9	103.5	103.2	103.1	103.4	103.6	102.6	103.7	103.3
Manufacturing	99.5	99.8	99.6	99.3	100.1	100.7	100.9	100.6	100.4	100.7	101.1	101.5	99.5	100.6	100.9
Food	101.8	102.2	101.9	102.3	103.1	103.1	103.2	103.4	103.5	103.7	103.9	104.2	102.0	103.2	103.8
Paper	86.6	86.7	87.1	87.4	86.6	85.9	86.4	86.3	86.1	86.6	86.7	87.0	86.9	86.3	86.6
Petroleum and coal products	93.0	92.4	93.3	94.8	93.4	93.2	94.5	95.4	95.7	95.7	95.3	94.9	93.4	94.1	95.4
Chemicals	103.0	104.9	106.6	108.4	108.4	108.9	109.7	110.3	110.6	111.6	112.1	112.5	105.7	109.3	111.7
Nonmetallic mineral products	100.7	99.8	100.4	101.5	102.8	99.4	98.5	97.2	96.4	96.1	95.7	95.5	100.6	99.5	95.9
Primary metals	93.7	93.5	93.7	92.5	94.1	94.8	96.8	96.9	96.3	97.0	96.8	96.9	93.3	95.6	96.7
Coal-weighted manufacturing (a)	94.4	94.3	94.6	95.4	95.2	94.6	95.4	95.3	94.8	95.1	94.8	94.7	94.7	95.2	94.8
Distillate-weighted manufacturing (a)	96.7	96.6	96.7	97.3	97.7	97.0	97.2	96.8	96.3	96.4	96.3	96.4	96.8	97.2	96.4
Electricity-weighted manufacturing (a)	96.3	96.7	96.4	96.8	96.7	97.0	97.6	97.3	96.8	97.1	97.1	97.2	96.5	97.2	97.1
Natural Gas-weighted manufacturing (a)	93.9	94.7	94.6	96.1	94.9	95.0	95.7	95.5	94.9	95.3	95.0	94.9	94.8	95.3	95.0
Price Indexes															
Consumer Price Index (all urban consumers)															
(index, 1982-1984=1.00)	3.11	3.13	3.14	3.17	3.19	3.21	3.23	3.26	3.28	3.30	3.32	3.34	3.14	3.22	3.31
Producer Price Index: All Commodities															
(index, 1982=1.00)	2.55	2.54	2.54	2.55	2.60	2.57	2.57	2.57	2.56	2.55	2.57	2.59	2.55	2.58	2.57
Producer Price Index: Petroleum															
(index, 1982=1.00)	2.79	2.84	2.67	2.43	2.47	2.41	2.50	2.36	2.19	2.18	2.27	2.19	2.68	2.44	2.21
GDP Implicit Price Deflator															
(index, 2017=100)	124.4	125.2	125.7	126.5	127.6	128.3	129.2	130.4	131.5	132.3	133.0	133.9	125.4	128.9	132.7
Miscellaneous															
Vehicle Miles Traveled (a)															
(million miles/day)	8,374	9,327	9,305	8,829	8,513	9,416	9,446	8,877	8,517	9,483	9,421	8,869	8,959	9,065	9,074
Raw Steel Production															
(million short tons per day)	22.216	22.362	22.716	21.620	21.341	22.586	23.338	23.394	23.221	24.017	24.497	23.894	88.913	90.658	95.630
Carbon Dioxide (CO_2) Emissions (million metric tons)															
Total Energy (c)	**1,247**	**1,120**	**1,216**	**1,208**	**1,310**	**1,133**	**1,215**	**1,224**	**1,259**	**1,113**	**1,229**	**1,223**	**4,792**	**4,883**	**4,823**
Petroleum	546	564	568	565	554	566	571	564	548	564	569	563	2,243	2,256	2,244
Natural gas	515	388	427	461	538	385	418	469	515	383	426	470	1,790	1,810	1,794
Coal	184	166	220	181	216	180	223	189	194	164	232	187	750	809	778

(a) Fuel share weights of individual sector indices based on EIA *Manufacturing Energy Consumption Survey*.

(b) Total highway travel includes gasoline and diesel fuel vehicles.

(c) Includes electric power sector use of geothermal energy and non-biomass waste.

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

- = no data available

SAAR = Seasonally-adjusted annual rate

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

Sources:

Historical data: Latest data available from U.S. Department of Commerce, Bureau of Economic Analysis; Federal Reserve System, Statistical release G17; Federal Highway Administration; and Federal Aviation Administration.

Table 9b. U.S. Regional Macroeconomic Data

U.S. Energy Information Administration | Short-Term Energy Outlook - December 2025

	2024				2025				2026				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
Real Gross State Product (billion $2017)															
New England	1,177	1,186	1,192	1,191	1,197	1,208	1,215	1,217	1,222	1,228	1,235	1,240	1,187	1,209	1,231
Middle Atlantic	3,275	3,310	3,336	3,347	3,354	3,385	3,417	3,424	3,444	3,464	3,485	3,502	3,317	3,395	3,474
E. N. Central	2,923	2,945	2,958	2,965	2,956	2,984	3,011	3,019	3,034	3,051	3,067	3,082	2,947	2,993	3,058
W. N. Central	1,397	1,408	1,414	1,416	1,409	1,423	1,434	1,438	1,447	1,457	1,466	1,474	1,409	1,426	1,461
S. Atlantic	4,299	4,327	4,368	4,399	4,401	4,431	4,457	4,456	4,480	4,504	4,534	4,560	4,348	4,436	4,520
E. S. Central	1,036	1,047	1,057	1,059	1,057	1,063	1,073	1,077	1,083	1,090	1,096	1,102	1,050	1,067	1,093
W. S. Central	2,788	2,824	2,856	2,871	2,851	2,891	2,918	2,927	2,946	2,965	2,985	3,003	2,835	2,897	2,975
Mountain	1,631	1,649	1,664	1,676	1,667	1,682	1,693	1,698	1,708	1,719	1,730	1,740	1,655	1,685	1,724
Pacific	4,366	4,397	4,438	4,467	4,461	4,505	4,536	4,550	4,576	4,604	4,631	4,653	4,417	4,513	4,616
Industrial Output, Manufacturing (index, year 2017=100)															
New England	94.1	94.1	93.8	93.4	94.2	94.4	94.8	94.6	94.4	94.7	95.2	95.5	93.9	94.5	95.0
Middle Atlantic	94.5	94.8	94.8	94.4	95.4	95.9	96.5	96.2	95.9	96.2	96.6	96.9	94.6	96.0	96.4
E. N. Central	95.6	95.8	95.4	95.2	96.0	96.6	97.0	96.6	96.2	96.4	96.6	96.9	95.5	96.5	96.5
W. N. Central	100.8	101.1	100.5	100.2	100.8	101.5	102.0	101.6	101.2	101.5	102.0	102.4	100.6	101.5	101.8
S. Atlantic	102.9	103.4	103.4	102.8	103.9	104.5	104.7	104.5	104.4	104.8	105.3	105.8	103.1	104.4	105.1
E. S. Central	100.2	100.7	100.6	100.7	101.9	102.4	102.6	102.4	102.1	102.5	102.8	103.2	100.6	102.3	102.6
W. S. Central	106.4	107.0	107.3	107.3	108.1	109.2	109.4	109.1	108.9	109.2	109.8	110.3	107.0	109.0	109.5
Mountain	110.9	111.5	111.1	111.5	113.0	113.3	113.4	113.1	113.0	113.4	114.1	114.6	111.2	113.2	113.8
Pacific	94.1	94.1	93.7	92.4	93.1	93.0	93.1	92.8	92.6	92.8	93.3	93.7	93.6	93.0	93.1
Real Personal Income (billion $2017)															
New England	1,045	1,050	1,053	1,055	1,064	1,074	1,074	1,076	1,083	1,091	1,098	1,106	1,051	1,072	1,094
Middle Atlantic	2,616	2,631	2,645	2,648	2,670	2,689	2,698	2,705	2,726	2,746	2,768	2,789	2,635	2,690	2,757
E. N. Central	2,727	2,743	2,744	2,756	2,775	2,798	2,805	2,812	2,833	2,855	2,873	2,893	2,742	2,797	2,864
W. N. Central	1,320	1,325	1,328	1,334	1,347	1,359	1,360	1,361	1,371	1,382	1,392	1,403	1,327	1,357	1,387
S. Atlantic	3,928	3,952	3,981	4,008	4,038	4,075	4,080	4,086	4,122	4,155	4,188	4,223	3,967	4,070	4,172
E. S. Central	1,054	1,063	1,068	1,073	1,082	1,088	1,091	1,095	1,103	1,113	1,122	1,130	1,065	1,089	1,117
W. S. Central	2,466	2,482	2,495	2,505	2,528	2,550	2,554	2,560	2,578	2,599	2,623	2,647	2,487	2,548	2,612
Mountain	1,508	1,519	1,525	1,537	1,546	1,562	1,564	1,569	1,582	1,597	1,611	1,626	1,522	1,560	1,604
Pacific	3,263	3,293	3,314	3,354	3,363	3,386	3,386	3,393	3,419	3,446	3,472	3,499	3,306	3,382	3,459
Households (thousands)															
New England	6,133	6,146	6,152	6,168	6,179	6,189	6,200	6,208	6,217	6,226	6,234	6,242	6,168	6,208	6,242
Middle Atlantic	16,153	16,167	16,180	16,220	16,248	16,270	16,296	16,315	16,332	16,347	16,361	16,372	16,220	16,315	16,372
E. N. Central	19,117	19,161	19,188	19,243	19,281	19,316	19,350	19,377	19,401	19,425	19,448	19,466	19,243	19,377	19,466
W. N. Central	8,788	8,814	8,827	8,855	8,876	8,897	8,918	8,936	8,954	8,971	8,987	9,002	8,855	8,936	9,002
S. Atlantic	27,706	27,819	27,887	27,995	28,079	28,160	28,242	28,314	28,384	28,454	28,525	28,596	27,995	28,314	28,596
E. S. Central	7,992	8,016	8,028	8,054	8,074	8,095	8,118	8,139	8,158	8,178	8,196	8,213	8,054	8,139	8,213
W. S. Central	16,172	16,232	16,265	16,324	16,370	16,416	16,464	16,506	16,549	16,593	16,637	16,678	16,324	16,506	16,678
Mountain	10,024	10,075	10,100	10,143	10,179	10,214	10,249	10,280	10,313	10,346	10,379	10,410	10,143	10,280	10,410
Pacific	19,229	19,276	19,290	19,334	19,364	19,394	19,426	19,453	19,477	19,501	19,527	19,548	19,334	19,453	19,548
Total Non-farm Employment (millions)															
New England	7.6	7.6	7.6	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.6	7.7	7.7
Middle Atlantic	20.3	20.4	20.5	20.5	20.6	20.6	20.7	20.7	20.7	20.8	20.8	20.8	20.4	20.7	20.8
E. N. Central	22.6	22.6	22.7	22.7	22.8	22.8	22.8	22.9	22.9	22.9	22.9	22.9	22.6	22.8	22.9
W. N. Central	11.0	11.1	11.1	11.1	11.1	11.1	11.1	11.2	11.2	11.2	11.2	11.2	11.1	11.1	11.2
S. Atlantic	31.2	31.4	31.5	31.5	31.7	31.8	31.8	31.7	31.8	31.9	31.9	32.0	31.4	31.7	31.9
E. S. Central	8.8	8.8	8.8	8.9	8.9	8.9	8.9	8.9	8.9	9.0	9.0	9.0	8.8	8.9	9.0
W. S. Central	19.2	19.3	19.3	19.4	19.5	19.6	19.6	19.6	19.7	19.7	19.8	19.8	19.3	19.6	19.7
Mountain	12.1	12.1	12.1	12.2	12.2	12.3	12.2	12.3	12.3	12.3	12.4	12.4	12.1	12.2	12.3
Pacific	24.6	24.6	24.6	24.7	24.8	24.8	24.7	24.8	24.8	24.9	24.9	25.0	24.6	24.8	24.9

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

- = no data available

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

Regions refer to U.S. Census divisions.

See "Census division" in EIA's Energy Glossary (http://www.eia.gov/glossary/index.html) for a list of States in each region.

Sources:

Historical data: Latest data available from U.S. Department of Commerce, Bureau of Economic Analysis; Federal Reserve System, Statistical release G17.

Table 9c. U.S. Regional Weather Data

U.S. Energy Information Administration | Short-Term Energy Outlook - December 2025

	2024				2025				2026				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
Heating Degree Days															
United States average	1,905	414	50	1,321	2,103	436	54	1,449	1,960	464	73	1,424	3,690	4,042	3,921
New England	2,764	751	112	2,051	3,115	769	120	2,180	2,920	812	129	2,012	5,678	6,185	5,873
Middle Atlantic	2,523	567	71	1,859	2,864	626	69	1,985	2,698	648	85	1,841	5,021	5,543	5,272
E. N. Central	2,656	546	67	1,916	3,109	719	86	2,181	2,943	687	118	2,088	5,185	6,095	5,836
W. N. Central	2,838	598	88	2,049	3,273	674	98	2,216	3,112	693	151	2,307	5,572	6,261	6,263
South Atlantic	1,244	136	10	842	1,397	131	11	941	1,247	175	12	860	2,231	2,480	2,294
E. S. Central	1,662	169	11	1,041	1,839	177	13	1,246	1,653	228	19	1,199	2,883	3,274	3,099
W. S. Central	1,074	50	2	509	1,191	53	2	681	1,061	82	5	741	1,635	1,927	1,889
Mountain	2,246	694	100	1,635	2,231	649	115	1,676	2,152	704	152	1,826	4,675	4,671	4,833
Pacific	1,567	613	68	1,087	1,532	538	62	1,108	1,445	584	95	1,160	3,336	3,240	3,283
Heating Degree Days, Prior 10-year average															
United States average	2,103	483	58	1,444	2,048	476	55	1,422	2,023	475	56	1,441	4,088	4,001	3,996
New England	3,111	856	98	2,057	3,031	843	95	2,054	2,957	838	101	2,092	6,122	6,022	5,989
Middle Atlantic	2,889	685	63	1,878	2,799	672	61	1,868	2,728	673	64	1,912	5,516	5,399	5,377
E. N. Central	3,159	735	91	2,113	3,031	717	81	2,068	2,973	723	82	2,112	6,098	5,896	5,889
W. N. Central	3,295	729	120	2,303	3,192	714	111	2,256	3,182	716	111	2,281	6,447	6,273	6,290
South Atlantic	1,357	188	9	895	1,310	182	9	875	1,282	179	9	903	2,448	2,375	2,374
E. S. Central	1,756	248	14	1,205	1,695	242	13	1,168	1,665	241	13	1,205	3,224	3,119	3,124
W. S. Central	1,164	90	3	730	1,123	86	2	697	1,103	85	2	703	1,987	1,909	1,893
Mountain	2,210	697	128	1,801	2,222	696	123	1,789	2,255	690	123	1,769	4,837	4,830	4,838
Pacific	1,471	539	77	1,129	1,501	553	78	1,139	1,545	554	76	1,129	3,215	3,271	3,305
Cooling Degree Days															
United States average	54	496	942	141	54	464	904	116	51	451	979	107	1,634	1,537	1,589
New England	0	147	476	0	0	120	428	0	0	102	523	1	623	548	626
Middle Atlantic	0	240	611	7	0	192	597	4	0	186	667	5	858	793	858
E. N. Central	3	312	571	15	3	250	608	15	1	247	603	7	900	876	857
W. N. Central	11	332	674	31	11	280	708	32	5	298	735	11	1,049	1,030	1,048
South Atlantic	149	764	1,249	270	136	770	1,188	229	142	722	1,299	263	2,431	2,323	2,425
E. S. Central	40	619	1,102	107	39	571	1,106	78	34	548	1,133	68	1,868	1,794	1,783
W. S. Central	126	1,052	1,588	384	130	958	1,547	337	107	950	1,672	217	3,151	2,973	2,946
Mountain	9	489	1,083	128	23	462	1,002	92	21	462	1,041	85	1,708	1,580	1,608
Pacific	20	197	730	103	27	204	608	61	28	204	718	78	1,050	900	1,028
Cooling Degree Days, Prior 10-year average															
United States average	53	414	909	111	55	424	926	116	56	428	929	114	1,488	1,522	1,527
New England	0	83	482	2	0	90	495	2	0	95	490	2	567	588	587
Middle Atlantic	0	154	623	9	0	162	640	9	0	162	638	9	785	811	809
E. N. Central	1	231	566	10	1	239	586	11	2	242	597	12	808	837	852
W. N. Central	4	301	680	12	5	308	694	14	6	309	698	16	997	1,021	1,030
South Atlantic	153	674	1,212	271	157	686	1,231	278	157	687	1,234	268	2,310	2,353	2,346
E. S. Central	41	519	1,077	85	44	531	1,095	89	46	530	1,104	87	1,721	1,759	1,766
W. S. Central	109	872	1,585	228	118	900	1,599	244	126	910	1,597	251	2,793	2,861	2,884
Mountain	22	447	971	88	19	452	992	91	17	455	1,000	92	1,527	1,554	1,564
Pacific	32	202	678	88	30	199	682	88	27	197	675	82	1,000	998	981

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

- = no data available

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

Regional degree days for each period are calculated by EIA as contemporaneous period population-weighted averages of state degree day data published by the National Oceanic and Atmospheric Administration (NOAA).

See *Change in Regional and U.S. Degree-Day Calculations* (http://www.eia.gov/forecasts/steo/special/pdf/2012_sp_04.pdf) for more information.

The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Regions refer to U.S. Census divisions. See "Census division" in EIA's Energy Glossary (http://www.eia.gov/tools/glossary/) for a list of states in each region.

Sources:

Table 10a. Drilling Productivity Metrics

U.S. Energy Information Administration | Short-Term Energy Outlook - December 2025

	2024				2025				2026				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
Active rigs															
Appalachia region	42	39	35	34	35	36	36	-	-	-	-	-	37	-	-
Bakken region	34	34	35	35	34	32	30	-	-	-	-	-	34	-	-
Eagle Ford region	57	56	52	52	52	51	50	-	-	-	-	-	54	-	-
Haynesville region	43	36	35	33	31	36	44	-	-	-	-	-	37	-	-
Permian region	312	313	305	304	302	282	258	-	-	-	-	-	308	-	-
Rest of Lower 48 States, excluding GOA	104	96	96	105	112	114	103	-	-	-	-	-	100	-	-
New wells drilled															
Appalachia region	238	217	194	188	192	203	201	-	-	-	-	-	837	-	-
Bakken region	203	206	210	212	202	191	183	-	-	-	-	-	831	-	-
Eagle Ford region	296	300	296	308	314	311	309	-	-	-	-	-	1,200	-	-
Haynesville region	124	103	99	93	91	102	121	-	-	-	-	-	419	-	-
Permian region	1,404	1,410	1,386	1,396	1,410	1,370	1,284	-	-	-	-	-	5,596	-	-
Rest of Lower 48 States, excluding GOA	613	562	566	597	613	614	564	-	-	-	-	-	2,338	-	-
New wells drilled per rig															
Appalachia region	5.6	5.6	5.6	5.6	5.6	5.6	5.6	-	-	-	-	-	22.4	-	-
Bakken region	6.0	6.0	6.0	6.0	6.0	6.0	6.1	-	-	-	-	-	24.1	-	-
Eagle Ford region	5.2	5.4	5.7	6.0	6.1	6.1	6.2	-	-	-	-	-	22.2	-	-
Haynesville region	2.9	2.9	2.9	2.9	2.9	2.8	2.7	-	-	-	-	-	11.5	-	-
Permian region	4.5	4.5	4.5	4.6	4.7	4.9	5.0	-	-	-	-	-	18.1	-	-
Rest of Lower 48 States, excluding GOA	5.9	5.9	5.9	5.7	5.5	5.4	5.5						23.3		
New wells completed															
Appalachia region	210	188	163	175	223	223	213	-	-	-	-	-	736	-	-
Bakken region	164	232	234	181	204	228	223	-	-	-	-	-	811	-	-
Eagle Ford region	402	383	374	272	375	355	298	-	-	-	-	-	1,431	-	-
Haynesville region	114	115	96	91	105	131	140	-	-	-	-	-	416	-	-
Permian region	1,560	1,561	1,606	1,496	1,548	1,520	1,385	-	-	-	-	-	6,223	-	-
Rest of Lower 48 States, excluding GOA	558	553	605	517	586	653	606	-	-	-	-	-	2,233	-	-
Cumulative drilled but uncompleted wells															
Appalachia region	715	745	776	789	760	740	727	-	-	-	-	-	789	-	-
Bakken region	372	346	322	353	351	315	275	-	-	-	-	-	353	-	-
Eagle Ford region	534	452	373	410	349	305	315	-	-	-	-	-	410	-	-
Haynesville region	733	721	723	725	710	681	662	-	-	-	-	-	725	-	-
Permian region	1,737	1,586	1,366	1,267	1,129	979	878	-	-	-	-	-	1,267	-	-
Rest of Lower 48 States, excluding GOA	2,205	2,213	2,173	2,254	2,283	2,244	2,203	-	-	-	-	-	2,254	-	-
Crude oil production from newly completed wells, one-year trend (thousand barrels per day) (a) (c)															
Appalachia region	12	13	15	15	14	14	15	-	-	-	-	-	14	-	-
Bakken region	54	56	63	59	52	56	60	-	-	-	-	-	58	-	-
Eagle Ford region	70	84	84	77	73	74	73	-	-	-	-	-	79	-	-
Haynesville region	0	0	0	0	0	0	0	-	-	-	-	-	0	-	-
Permian region	449	461	456	432	431	440	438	-	-	-	-	-	450	-	-
Rest of Lower 48 States, excluding GOA	78	78	87	87	78	75	80	-	-	-	-	-	83	-	-
Crude oil production from newly completed wells per rig, one-year trend (thousand barrels per day) (a)															
Appalachia region	0.3	0.3	0.4	0.4	0.4	0.4	0.4	-	-	-	-	-	0.4	-	-
Bakken region	1.6	1.6	1.8	1.7	1.5	1.7	1.9	-	-	-	-	-	1.7	-	-
Eagle Ford region	1.3	1.5	1.6	1.5	1.4	1.4	1.5	-	-	-	-	-	1.4	-	-
Haynesville region	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	0.0	-	-
Permian region	1.4	1.5	1.5	1.4	1.4	1.5	1.6	-	-	-	-	-	1.5	-	-
Rest of Lower 48 States, excluding GOA	0.7	0.8	0.9	0.9	0.7	0.7	0.7	-	-	-	-	-	0.8	-	-
Existing crude oil production change, one-year trend (thousand barrels per day) (a) (c)															
Appalachia region	-12.5	-11.7	-12.2	-12.2	-12.7	-12.4	-12.5	-	-	-	-	-	-12.1	-	-
Bakken region	-60.0	-59.5	-70.0	-65.0	-56.5	-53.5	-55.8	-	-	-	-	-	-63.6	-	-
Eagle Ford region	-66.0	-67.7	-80.8	-77.6	-70.6	-68.8	-73.6	-	-	-	-	-	-73.1	-	-
Haynesville region	-0.7	-0.6	-0.4	-0.4	-0.7	-0.7	-0.6	-	-	-	-	-	-0.5	-	-
Permian region	-421.0	-431.2	-428.5	-416.2	-416.2	-415.9	-425.7	-	-	-	-	-	-424.2	-	-
Rest of Lower 48 States, excluding GOA	-86.2	-82.3	-84.2	-89.8	-89.7	-84.3	-85.9	-	-	-	-	-	-85.6	-	-
Natural gas production from newly completed wells, one-year trend (million cubic feet per day) (a) (d)															
Appalachia region	1,043.3	926.9	933.5	971.6	1,040.9	1,040.9	1,004.8	-	-	-	-	-	968.7	-	-
Bakken region	59.1	62.3	69.6	62.5	55.1	61.1	63.8	-	-	-	-	-	63.4	-	-
Eagle Ford region	342.2	314.0	292.7	299.0	328.4	347.4	342.1	-	-	-	-	-	311.9	-	-
Haynesville region	672.6	556.2	497.7	509.0	559.3	624.2	653.8	-	-	-	-	-	558.6	-	-
Permian region	876.7	956.1	937.8	863.5	877.2	910.3	892.5	-	-	-	-	-	908.5	-	-
Rest of Lower 48 States, excluding GOA	330.0	285.3	311.8	380.7	403.1	363.2	365.0	-	-	-	-	-	327.1	-	-
Natural gas production from newly completed wells per rig, one-year trend (million cubic feet per day) (a) (d)															
Appalachia region	25.7	21.9	25.0	28.9	30.6	29.2	28.2	-	-	-	-	-	25.4	-	-
Bakken region	1.8	1.8	2.0	1.8	1.6	1.9	2.0	-	-	-	-	-	1.9	-	-
Eagle Ford region	6.1	5.5	5.5	5.7	6.5	6.6	6.8	-	-	-	-	-	5.7	-	-
Haynesville region	14.7	14.0	13.6	15.1	17.7	19.3	16.8	-	-	-	-	-	14.3	-	-
Permian region	2.8	3.0	3.0	2.8	2.9	3.1	3.3	-	-	-	-	-	2.9	-	-
Rest of Lower 48 States, excluding GOA	3.1	2.8	3.3	3.8	3.8	3.2	3.4	-	-	-	-	-	3.3	-	-
Existing natural gas production change, one-year trend (million cubic feet per day) (a) (c) (d)															
Appalachia region	-1,135.3	-1,047.2	-833.0	-892.7	-963.8	-1,047.8	-986.0	-	-	-	-	-	-976.4	-	-
Bakken region	-51.7	-32.0	-67.4	-77.6	-62.2	-50.7	-57.9	-	-	-	-	-	-57.2	-	-
Eagle Ford region	-340.1	-319.1	-287.6	-272.8	-274.9	-268.4	-271.7	-	-	-	-	-	-304.8	-	-
Haynesville region	-930.3	-823.2	-651.8	-510.6	-482.0	-581.4	-624.9	-	-	-	-	-	-728.2	-	-
Permian region	-687.4	-681.0	-658.1	-628.6	-665.7	-681.8	-679.9	-	-	-	-	-	-663.7	-	-
Rest of Lower 48 States, excluding GOA	-462.1	-403.5	-385.5	-401.7	-394.1	-362.5	-367.7	-	-	-	-	-	-413.1	-	-

(a) The Production From Newly Completed Wells and the Existing Production Change data series are reported as smoothed monthly data over a twelve-month period. The smoothing is done using the Locally Weighted Scatterplot Smoothing (LOWESS) function. LOWESS calculates a locally weighted average for each point, giving more weight to nearby monthly data and less weights to distant data. The smoothed data may change each month according to updated data.

(b) The most recent six months of well-level data is incomplete due to known lags in reporting. For these months, the values are imputed based on historical reporting patterns and other relevant factors.

(c) The sum of "Production from Newly Completed Wells" and "Existing Production Change" may not equal the month-over-month crude oil or natural gas production changes reported in tables 4a and 5a, respectively. This discrepancy arises from the statistical smoothing techniques applied to aggregated basin level data, variations in data imputation methodologies, and utilizing different data sources.

(d) Natural gas production in this table is marketed natural gas production.

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

- = no data available

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

Minor discrepancies with published historical data are due to independent rounding.

Sources:

Historical data: Latest data available from Baker Hughes, Enervus, FracFocus.org.

Table 10b. Crude Oil and Natural Gas Production from Shale and Tight Formations

U.S. Energy Information Administration | Short-Term Energy Outlook

	2024				2025				2026				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2024	2025	2026
Total U.S. tight oil production (million barrels per day) (a)	**8.68**	**8.93**	**8.99**	**9.16**	**8.93**	**9.02**	**9.14**	-	-	-	-	-	**8.94**	-	-
Austin Chalk formation	0.12	0.14	0.13	0.13	0.12	0.12	0.12	-	-	-	-	-	0.13	-	-
Bakken formation	1.21	1.23	1.21	1.23	1.21	1.19	1.21	-	-	-	-	-	1.22	-	-
Eagle Ford formation	0.94	1.03	1.04	1.04	1.02	1.03	1.04	-	-	-	-	-	1.01	-	-
Mississippian formation	0.13	0.12	0.11	0.12	0.11	0.12	0.11	-	-	-	-	-	0.12	-	-
Niobrara Codell formation	0.47	0.46	0.46	0.51	0.47	0.45	0.47	-	-	-	-	-	0.47	-	-
Permian formations	5.42	5.55	5.61	5.69	5.55	5.66	5.73	-	-	-	-	-	5.57	-	-
Woodford formation	0.08	0.08	0.08	0.09	0.09	0.08	0.08	-	-	-	-	-	0.08	-	-
Other U.S. formations	0.31	0.33	0.35	0.35	0.36	0.37	0.38	-	-	-	-	-	0.33	-	-
Total U.S. shale dry natural gas production (billion cubic feet per day) (a)	**84.3**	**82.7**	**83.8**	**84.6**	**84.9**	**86.4**	**87.6**	-	-	-	-	-	**83.8**	-	-
Bakken formation	2.5	2.7	2.7	2.6	2.6	2.7	2.7	-	-	-	-	-	2.6	-	-
Barnett formation	1.7	1.6	1.6	1.7	1.6	1.6	1.6	-	-	-	-	-	1.7	-	-
Eagle Ford formation	4.3	4.4	4.3	4.3	4.2	4.4	4.4	-	-	-	-	-	4.3	-	-
Fayetteville formation	0.8	0.8	0.8	0.8	0.8	0.8	0.7	-	-	-	-	-	0.8	-	-
Haynesville formation	13.5	12.0	12.0	11.7	12.2	12.1	12.3	-	-	-	-	-	12.3	-	-
Marcellus formation	26.8	25.8	26.2	26.3	26.7	26.9	26.9	-	-	-	-	-	26.3	-	-
Mississippian formation	2.3	2.3	2.2	2.2	2.1	2.2	2.3	-	-	-	-	-	2.2	-	-
Niobrara Codell formation	2.8	2.8	2.8	2.9	2.8	2.8	2.8	-	-	-	-	-	2.8	-	-
Permian formations	17.7	18.5	19.3	19.8	19.6	20.5	21.2	-	-	-	-	-	18.9	-	-
Utica formation	6.5	6.6	6.5	6.8	6.6	6.7	6.7	-	-	-	-	-	6.6	-	-
Woodford formation	2.5	2.6	2.5	2.5	2.5	2.6	2.6	-	-	-	-	-	2.5	-	-
Other U.S. formations	2.8	2.7	2.7	2.9	3.1	3.2	3.2	-	-	-	-	-	2.8	-	-

(a) These production estimates are based on geologic formations, not geographic regions

Notes:

EIA completed modeling and analysis for this report on December 4, 2025.

- = no data available

The approximate break between historical and forecast values is shown with historical data with no shading; estimates and forecasts are shaded gray.

Minor discrepancies with published historical data are due to independent rounding.

Sources:

Historical data: Latest data available from Enverus state administrative data.

Appendix to the December 2025 *Short-Term Energy Outlook*

This appendix is prepared in fulfillment of section 1245(d)(4)(A) of the National Defense Authorization Act (NDAA) for Fiscal Year 2012, as amended. The law requires the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy, to submit to Congress a report on the availability and price of petroleum and petroleum products produced in countries other than Iran in the two-month period preceding the submission of the report. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the U.S. Government. The data in this appendix, therefore, should not be construed as representing those of the U.S. Department of Energy or other federal agencies.

EIA consulted with the U.S. Department of the Treasury, the U.S. Department of State, and the intelligence community in the process of developing the NDAA report, which was previously published as a stand-alone report. Detailed background and contextual information not repeated here can be found in early editions of the NDAA report.

This appendix is published in the *Short-Term Energy Outlook* in even numbered months.

Table a1. Summary of Estimated Petroleum and Other Liquids Quantities

	Oct 2025	Nov 2025	Oct 2025 – Nov 2025 Average	Oct 2024 – Nov 2024 Average	2022 – 2024 Average
Global Petroleum and Other Liquids (million barrels per day)					
Global Petroleum and Other Liquids Production (a)	108.3	108.7	108.5	103.8	102.0
Global Petroleum and Other Liquids Consumption (b)	103.7	104.6	104.1	103.2	101.4
Biofuels Production (c)	3.1	2.8	2.9	2.9	2.8
Biofuels Consumption (c)	2.8	2.8	2.8	2.8	2.7
Iran Liquid Fuels Production	4.7	4.7	4.7	4.7	4.1
Iran Liquid Fuels Consumption	2.0	2.0	2.0	2.0	2.0
Petroleum and Petroleum Products Produced and Consumed in Countries Other Than Iran (million barrels per day)					
Production (d)	100.4	101.2	100.8	96.3	99.3
Consumption (d)	98.9	99.9	99.4	98.4	96.7
Production minus Consumption	1.5	1.4	1.5	-2.2	2.6
World Inventory Net Withdrawals Including Iran	-4.6	-4.1	-4.3	-0.6	-0.6
Estimated OECD Inventory Level (e) (million barrels)	2892	2925	2909	2754	2759
Surplus Production Capacity (million barrels per day)					
OPEC Surplus Crude Oil Production Capacity (f)	3.6	3.6	3.6	4.6	3.4

Note: The term "petroleum and other liquids" encompasses crude oil, lease condensate, natural gas liquids, biofuels, coal-to-liquids, gas-to-liquids, and refinery processing gains, which are important to consider in concert due to the inter-related supply, demand, and price dynamics of petroleum, petroleum products, and related fuels.

(a) Production includes crude oil (including lease condensates), natural gas liquids, other liquids, and refinery processing gains.

(b) Consumption of petroleum by the OECD countries is synonymous with "products supplied," defined in the glossary of the EIA Petroleum Supply Monthly, DOE/EIA-0109. Consumption of petroleum by the non-OECD countries is "apparent consumption," which includes internal consumption, refinery fuel, and loss, and bunkering.

(c) Biofuels production and consumption are based on EIA estimates as published in the International Energy Statistics. Biofuels production in the third quarter tends to be at its highest level in the year as ethanol production in Brazil reaches its seasonal peak and is typically lowest in the first quarter as seasonal production falls in the South/South-Central region of Brazil.

(d) Global production of petroleum and petroleum products outside of Iran is derived by subtracting biofuels production and Iran liquid fuels production from global liquid fuels production. The same method is used to calculate global consumption outside of Iran.

(e) Estimated inventory level is for OECD countries only.

(f) EIA defines surplus oil production capacity as potential oil production that could be brought online within 90 days and sustained for at least 90 days, consistent with sound business practices. EIA calculates surplus crude oil production capacity for producers as the difference between their effective production capacity and actual production. This does not include oil production increases that could not be sustained without degrading the future production capacity of a field.
Data source: U.S. Energy Information Administration.

Table a2. Crude Oil and Petroleum Product Price Data

Item	Oct 2025	Nov 2025	Oct 2025 – Nov 2025 Average	Oct 2024 – Nov 2024 Average	2022 – 2024 Average
Brent Front Month Futures Price ($ per barrel)	63.95	63.66	63.82	74.46	87.03
WTI Front Month Futures Price ($ per barrel)	60.07	59.48	59.80	70.62	82.57
Dubai Front Month Futures Price ($ per barrel)	64.94	64.47	64.73	79.50	85.98
Brent 1st - 13th Month Futures Spread ($ per barrel)	0.61	0.96	0.77	1.73	7.42
WTI 1st - 13th Month Futures Spread ($ per barrel)	0.50	0.37	0.44	2.86	7.46
RBOB Front Month Futures Price ($ per gallon)	1.88	1.94	1.91	2.03	2.59
Heating Oil Front Month Futures Price ($ per gallon)	2.29	2.48	2.37	2.24	2.93
RBOB - Brent Futures Crack Spread ($ per gallon)	0.36	0.42	0.39	0.26	0.52
Heating Oil - Brent Futures Crack Spread ($ per gallon)	0.76	0.96	0.85	0.46	0.86

(a) Brent refers to Brent crude oil traded on the Intercontinental Exchange (ICE).
(b) WTI refers to West Texas Intermediate crude oil traded on the New York Mercantile Exchange (NYMEX), owned by Chicago Mercantile Exchange (CME) Group.
(c) RBOB refers to reformulated blendstock for oxygenate blending traded on the NYMEX.
Data source: U.S. Energy Information Administration, based on Chicago Mercantile Exchange (CME), Intercontinental Exchange (ICE), and Dubai Mercantile Exchange (DME).

EXHIBIT 51-4

Levelized Costs of New Generation Resources in the Annual Energy Outlook 2025



U.S. Energy Information Administration

#AEO2025

April 2025
www.eia.gov/aeo

Introduction

- This paper presents average values of levelized costs for new generation resources as represented in the National Energy Modeling System (NEMS) for our *Annual Energy Outlook 2025* (AEO2025) Reference case. The estimates include only resources owned by the electric power sector, not those owned in the residential or commercial sector.
- Levelized cost of electricity (LCOE) and levelized cost of storage (LCOS) represent the estimated costs required to build and operate a generator and diurnal storage, respectively, over a specified cost recovery period.
- Levelized avoided cost of electricity (LACE) is an estimate of the revenue available to that generator during the same period.
- Although LCOE, LCOS, and LACE do not fully capture all factors contributing to the capacity expansion decisions as modeled, when used together as a value-cost ratio (the ratio of LACE-to-LCOE or LACE-to-LCOS), they provide a reasonable comparison of first-order economic competitiveness among a wider variety of technologies than is possible using LCOE, LCOS, or LACE individually.
- We included both a capacity-weighted average reflecting as-built regional cost variation and a simple average (unweighted) of the regional values across the 25 U.S. supply regions[1] of the Electricity Market Module (EMM).
- We included only laws and regulations effective as of December 2024.

[1] *U.S. supply regions of Electricity Market Module, https://www.eia.gov/outlooks/aeo/pdf/nerc_map.pdf*

Technology-specific assumption of tax incentives

The provisions of the Inflation Reduction Act (IRA) of 2022 qualify eligible technologies for either the PTC or the ITC. We choose the credit that is most economically beneficial to the technology.

Technology	Credit type	Prevailing wage	Apprenticeship	Domestic content	Tax value[a] (percentage or 1992 cents/kWh)	Advanced manufacturing	Energy communities
Battery storage	ITC	✓	✓		30%		
Geothermal	ITC	✓	✓		30%		
Hydroelectric	ITC	✓	✓		30%		
Wind, offshore	ITC	✓	✓	✓	30% through 2031 40% 2032 forward		
Advanced nuclear	PTC	✓	✓	✓	1.65 cents/kWh		
Biomass	PTC	✓	✓	✓	1.65 cents/kWh		
PV-battery hybrid	PTC	✓	✓		1.50 cents/kWh		✓
Solar PV	PTC	✓	✓		1.50 cents/kWh		✓
Wind, onshore	PTC	✓	✓	✓	1.65 cents/kWh	✓	✓

[a]Tax value represents the total value of the production tax credit (PTC) or investment tax credit (ITC) as represented in the Levelized Tax Credit component of the LCOE. Tax value consists of the base credit as well as the prevailing wage, apprenticeship, and domestic content bonus credits. Advanced manufacturing and energy communities bonus credits are converted into cost multipliers and applied to the overall capital cost, and they are not estimated as a part of the Levelized Tax Credit component of the LCOE.

Note: kWh=kilowatthour

Carbon capture and sequestration

Starting in AEO2025, we estimate the levelized captured carbon credit that represents the revenue (negative cost) at a power plant with a carbon capture and sequestration (CCS) system.

The price of CO_2 is determined in NEMS, and it includes the cost to transport CO_2 for either saline formation storage or enhanced oil recovery (EOR) for oil wells, net policy revenue, and revenue from selling CO_2 to EOR sites.

The 45Q tax credits are under the IRA of 2022 and available for the first 12 years of plant's operation with construction start date before 2033. In addition, we assume the prevailing wage and apprenticeship requirements are met for the additional bonus credit.

In April 2024, the U.S. Environmental Protection Agency (EPA) finalized its rule for Section 111 of the Clean Air Act regulating CO_2 emissions from existing coal, oil, and natural gas-fired steam generating units and new natural gas-fired combustion turbines.[1]

Part of the ruling requires that new natural gas-fired combustion turbines intended to run as base load (greater than 40% capacity factor) must operate with at least a 90% CO_2 removal rate CCS system by 2032. In AEO2025, we represent this operating restriction on any new natural gas-fired combined-cycle plants that are built without CCS.

We consider combustion turbines operating at or below a 40% capacity factor to be consistent with current efficient designs and the use of low-emitting fuel.

[1] *U.S. Environmental Protection Agency, Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants, April 25, 2024*

General assumptions

The costs presented in the report are for generation facilities entering service in 2030, which is the first feasible online year for all technologies given the long construction lead time for some technologies. For AEO2025, ultra-supercritical coal technology is not represented in this report, and we added natural gas-fired combined-cycle with a 95% CO_2 removal rate CCS system in its place.

The levelized costs are calculated based on a 30-year cost recovery period, using an after-tax weighted average cost of capital (WACC) of 6.65% for the 2030 online year.

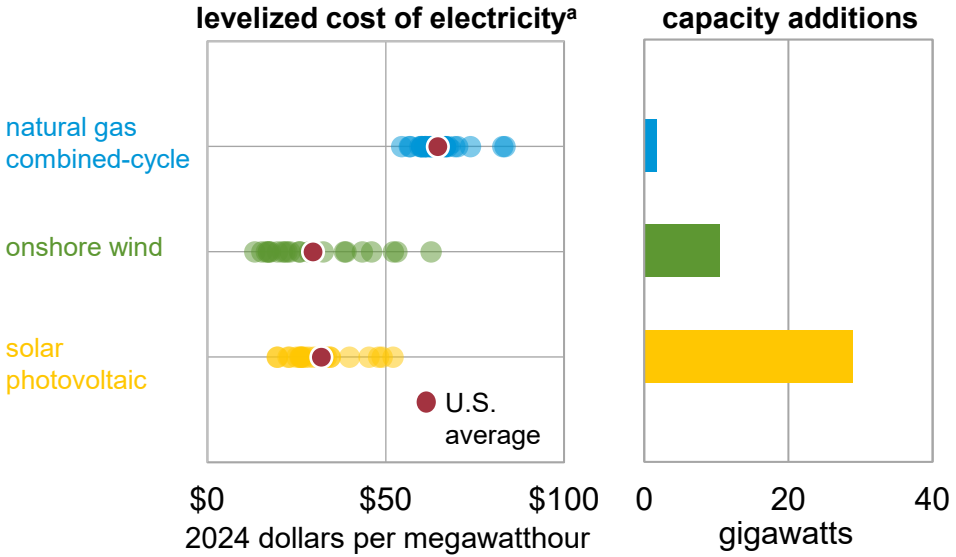
The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region in 2030, excluding planned capacity additions. Technologies for which no capacity additions are projected do not have a capacity-weighted average.

We assume the solar technology is photovoltaic (PV) with single-axis tracking. A solar PV-battery (PV-battery) hybrid system is a single-axis PV system coupled with a four-hour battery storage system. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

As modeled, we assume that hydroelectric generating assets are seasonal because generation is a function of seasonal rainfall. Similarly, PV-battery hybrid generating assets are used at specific times of the day, depending on the number of daylight hours.

Direct comparisons of LCOE or LCOS across technologies are misleading as a method to assess the economic competitiveness

Regional and U.S. average levelized cost of electricity and capacity additions in AEO2025 Reference case



LCOE does not capture all factors that contribute to investment decisions. The inherent uncertainty about future fuel prices, changing policies, or local considerations to ensure system reliability can place a value on portfolio diversification or other risk-related concerns.

In AEO2025, we project higher solar PV capacity additions compared with that of onshore wind in 2030, even though the LCOE, on average, is higher. In this case, adding solar PV capacity to the grid provides value in certain regions that LCOE may not fully capture.

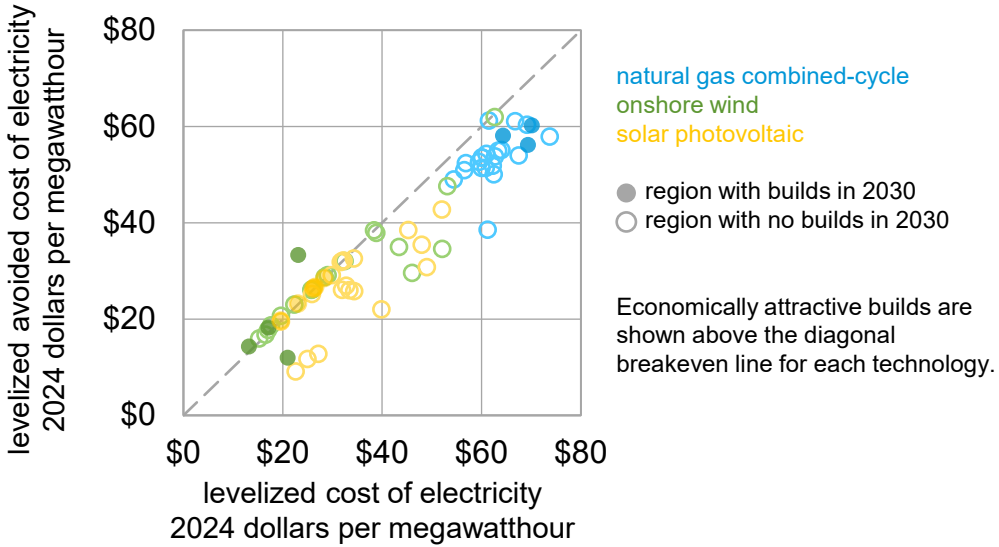
Data source: U.S. Energy Information Administration, Annual Energy Outlook 2025

Note: Each solid circle on the figure represents an electricity market region as modeled.

[a]Levelized cost includes tax credits available for plants entering service during the projection period.

LCOE is limited because it only reflects the *cost* to build and operate a plant, not the *value* of the plant to the grid

Levelized cost of electricity[a] and levelized avoided cost of electricity by region for online year 2030, AEO2025 Reference case



We use LACE as a companion metric to LCOE. This method improves comparisons of different generation technologies by providing the value of the plant serving the electric grid.

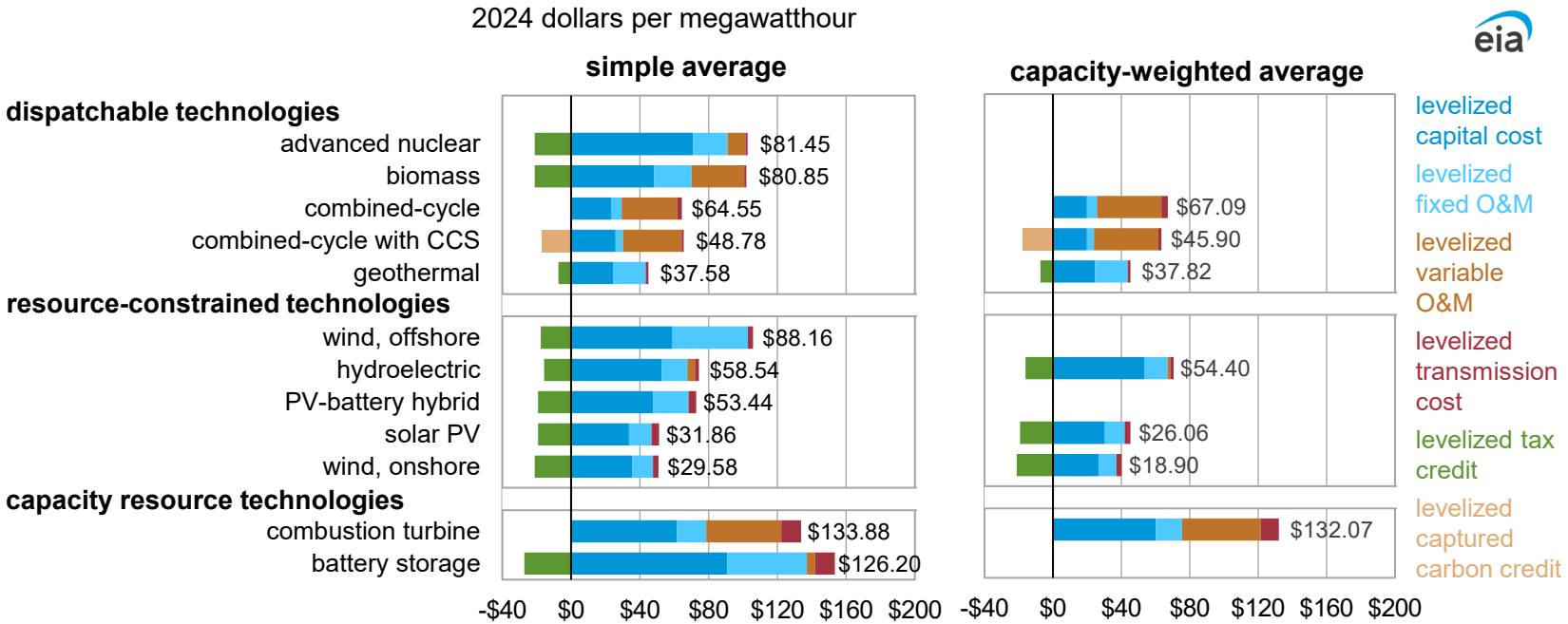
The LACE (value) provides a proxy measure for potential revenues (or avoided costs) from the sales of electricity or other ancillary services produced from a candidate project displacing another marginal asset.

Projects with LACE (value) greater than LCOE or LCOS (cost) are more economically attractive to build than those with a value-cost ratio less than one (that is, LACE is less than LCOE or LCOS).

Data source: U.S. Energy Information Administration, Annual Energy Outlook 2025

[a]Levelized cost includes tax credits available for plants entering service during the projection period.

Estimated levelized cost of electricity (LCOE) and levelized cost of storage (LCOS) for new resources entering service in 2030

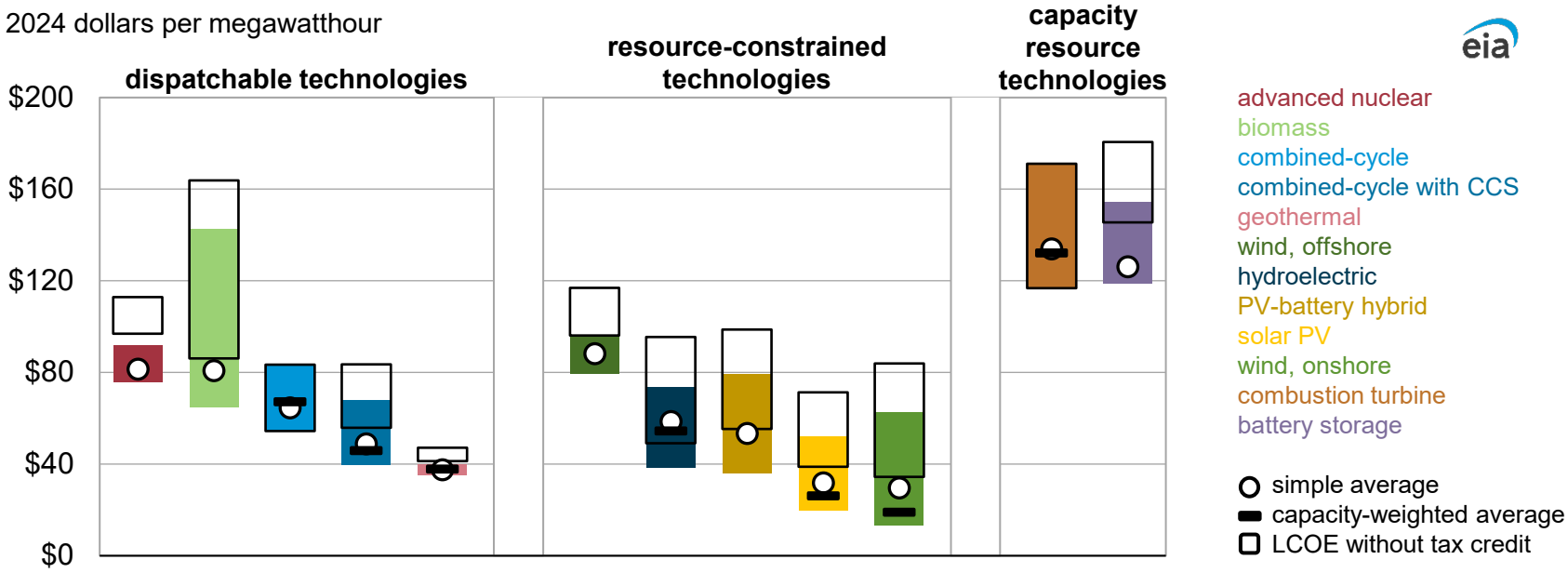


Data source: U.S. Energy Information Administration, Annual Energy Outlook 2025

Note: Technologies with no additions in 2030 do not have a capacity-weighted average. The stated LCOE values include the levelized tax credit component for eligible technologies. CCS=carbon capture & sequestration, PV=photovoltaic, O&M=operations and maintenance

Solar PV LCOE is lower than natural gas combined-cycle LCOE on average and, in most regions, even without the tax credit

Regional variation in levelized cost of electricity (LCOE) and levelized cost of storage (LCOS) for new resources entering service in 2030 by technology, AEO2025 Reference case

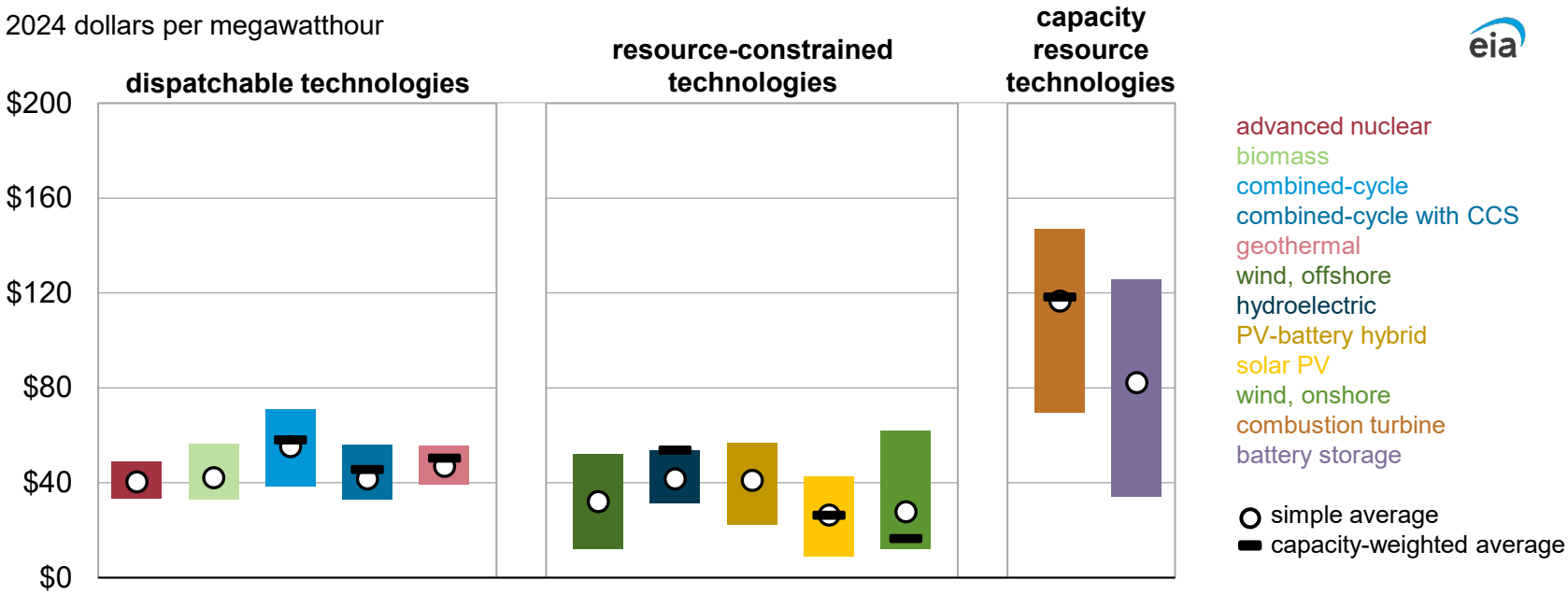


Data source: U.S. Energy Information Administration, Annual Energy Outlook 2025

Note: Technologies with no additions in 2030 do not have a capacity-weighted average. CCS=carbon capture & sequestration, PV=photovoltaic

LACE for resource-constrained technologies is generally lower because of their lower contribution for energy, capacity, and spinning reserve to the grid

Regional variation in levelized avoided cost of electricity (LACE) for new resources entering service in 2030 by technology, AEO2025 Reference case

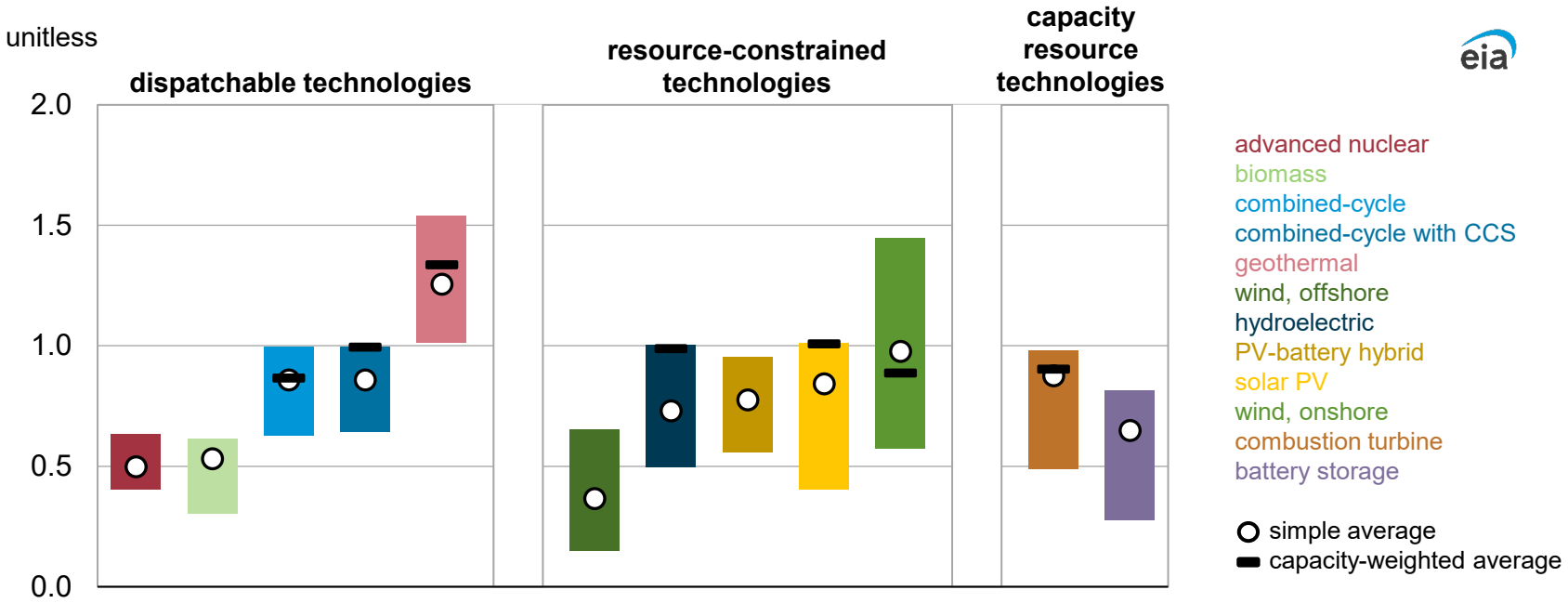


Data source: U.S. Energy Information Administration, Annual Energy Outlook 2025

Note: Technologies with no additions in 2030 do not have a capacity-weighted average. CCS=carbon capture & sequestration, PV=photovoltaic

Capacity-weighted value-cost ratio stays above simple average value-cost ratio, indicating capacity is added in regions where it is most economical

Regional variation in value-cost ratio (VCR) for new resources entering service in 2030 by technology, AEO2025 Reference case

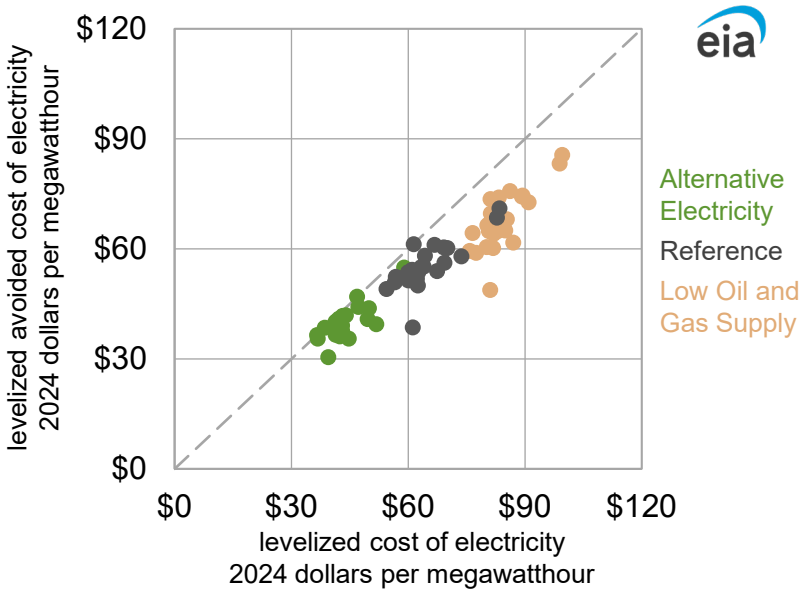


Data source: U.S. Energy Information Administration, Annual Energy Outlook 2025

Note: Technologies with no additions in 2030 do not have a capacity-weighted average. CCS=carbon capture & sequestration, PV=photovoltaic

Multiple factors affect LCOE, LACE, and value-cost ratio differently at regional level, making the context of projection scenarios important

Levelized cost of electricity and levelized avoided cost of electricity for combined-cycle plants entering service in 2030, AEO2025 select cases



In the Alternative Electricity case, we assume the final Clean Air Act's Section 111 rule is not implemented. The LCOE is lower because the combined-cycle plants without CCS are assumed to operate at an 87% capacity factor and are not limited at 40%, like in the Reference case, distributing the same costs over higher generation. LACE is also lower because less hours are available to contribute toward spinning reserves. Although capacity revenue is the same in both cases, the Alternative Electricity case has higher expected annual generation, which leads to lower capacity payment per megawatthour compared with the Reference case.

Higher natural gas prices assumed in the Low Oil and Gas Supply case lead to higher fuel cost and higher LCOE compared with the Reference case. Higher natural gas prices, however, also lead to higher realized electricity prices and subsequently higher revenue that also increase LACE when compared with the Reference case.

Data source: U.S. Energy Information Administration, Annual Energy Outlook 2025

For more information

U.S. Energy Information Administration home page | www.eia.gov

Annual Energy Outlook | www.eia.gov/aeo

Levelized Cost of New Generation Resources Methodology | https://www.eia.gov/outlooks/electricity_generation.php

EXHIBIT 51-5

Generating Resource Reference Plants

Natural Gas

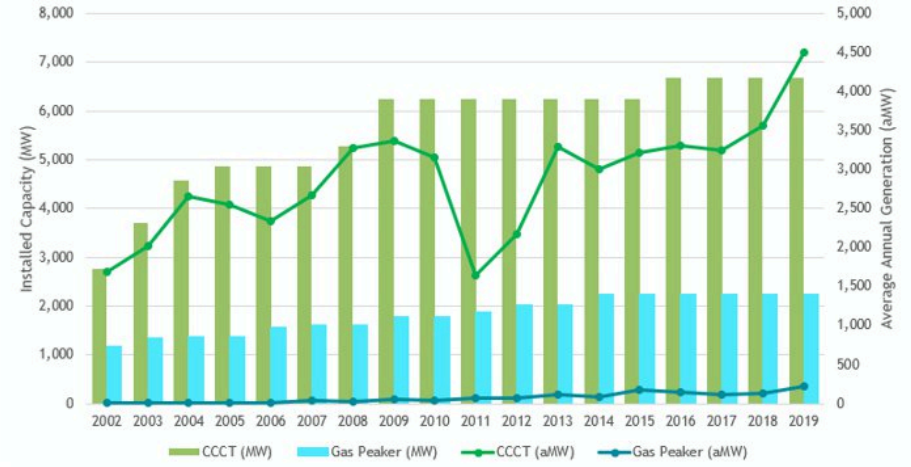
Jump to: Trends, Considerations, and Resource Potential | Description of Reference Plant

Natural gas technologies are proven and mature, yet also evolving to adapt to the needs of the new power system. As more must-run variable energy resources have entered the grid, it has become less important for gas resources to provide consistent, baseload generation. Rather, it has become increasingly important for gas resources to provide flexibility (fast start, ramping abilities) and greater efficiency (less fuel is combusted to generate more electricity). There are two major types of natural gas resources that the Council assessed for the 2021 Power Plan – combined cycle combustion turbines (CCCT) and gas peakers (which include various simple cycle combustion turbine (SCCT) technologies and reciprocating engines).

Combined cycle combustion turbines (CCCT) are highly efficient generating resources that can provide baseload and dispatchable power. A CCCT plant consists of one or more gas turbine generators each exhausting to a heat recovery steam generator (HRSG). The HRSG captures the exhaust heat and produces steam that is supplied to a steam turbine generator and condenser to produce additional electricity. The productive use of the gas turbine exhaust energy greatly increases the efficiency and output of CCCT plants as compared to simple-cycle gas turbines. This increasingly versatile technology can be used both as a replacement to retiring baseload coal power, and as a complementary firming power source to hydropower and renewable generation. The high efficiency of combined cycle plants coupled with the low carbon content of natural gas fuel results in the lowest carbon dioxide production rate of any fossil fuel generating technology. In the Northwest, operation of existing CCCT plants depends largely on the variability in annual hydro generation. During low water years, when hydro conditions are below average, thermal resources (primarily natural gas CCCT and coal units) tend to run at higher capacity factors to make up for the lower amount of hydroelectric power. During high water years, utilization of CCCT plants may decline. There are many other factors that may impact regional CCCT utilization, such as load, renewable power generation levels, plant outages, fuel prices, and wholesale electricity prices.

Gas peakers are generating units that can ramp up and down quickly to meet sharp spikes in demand. Newer, more flexible and efficient models can be used to follow the variable output of wind and solar resources. Because of the availability and abundance of hydropower, relatively few gas peakers have been constructed in the Northwest, compared to regions with a predominance of thermal electric capacity. In general, gas peakers produce at a much lower capacity factor when compared to CCCTs, running only when needed. Over the last twenty years, the capacity factor of the region's gas peaker fleet has increased – averaging around 6% in recent years as compared to 1% in the early 2000's.

PNW Natural Gas Fleet: Annual Generation vs. Installed Capacity



	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CCCT Capacity Factor	61%	54%	58%	52%	48%	55%	62%	54%	50%	26%	35%	53%	48%	52%	49%	49%	53%	67%
Gas Peaker Capacity Factor	1%	1%	1%	0%	1%	2%	1%	3%	2%	4%	4%	6%	4%	8%	6%	5%	6%	10%

* Data source: Council's project database

Simple-cycle gas turbines have been used for decades to help serve peak loads. A simple-cycle gas turbine generator plant consists of a combustion gas turbine (sometimes multiples) driving an electric power generator. The three primary simple cycle gas turbine technologies available today are frame, aeroderivative, and intercooled.

- **Frame** turbines are heavy-duty machines that are rugged and reliable. In the past, they have tended to have lower efficiency and less operational flexibility than other simple cycle technologies. However, as increased importance is placed on operational flexibility and ramping, newer classes of frame units are being developed to meet this need.
- **Aeroderivative** turbines are based on engines developed for aircraft propulsion and are characterized as light weight, highly efficient, and flexible. Aeroderivative are generally more expensive than frame turbines.
- **Intercooled gas turbines** are a hybrid of frame and aeroderivative technologies, designed for operational flexibility and high efficiency. They include an intercooler between compression stages to improve thermodynamic efficiency. The intercooler requires an external cooling water supply.

Reciprocating engine generating units consist of modular compression spark or spark-ignition reciprocating engines driving a generator. These engines can run on many different fuels, including natural gas, biogas, and oil. The technology has been widely used for biogas energy recovery, remote baseload power, and for emergency backup purposes. More recently, reciprocating engine generator plants have been used for peak load-following, and for shaping the output of wind and solar variable energy resources. These large internal combustion engines offer rapid response and quick start-up capability. Reciprocating engine generators also offer the best efficiency of the simple cycle gas technologies, especially during part-load conditions, and as a result they may run more often.

Natural gas as a fuel emits about half the carbon dioxide at combustion that coal does, and with natural gas being relied on more over coal, overall emissions from the generation of electricity are beginning to decline in the region. For more information on the Council's strategy to account for carbon emission damages in the 2021 Power Plan, see the Greenhouse Gas Parameters here. In addition, the Council analyzed upstream emissions from methane during natural gas extraction and processing. For more information, see the upstream methane emissions analysis as well as the Council's natural gas fuel price forecast.

Natural Gas Technologies Trends, Considerations, and Resource Potential

Jump to: Technology Trends | Cost Trends | Development Trends | Environmental Effects | Resource Potential in Region | Opportunities and Challenges

The following section describes high level trends in technology, cost, and development for natural gas technologies. In addition, it identifies resource potential in the region, opportunities and challenges, and environmental effects.

Technology Trends

Manufacturers of natural gas technologies are chasing greater performance (net output), efficiency (lower heat rates), and greater flexibility (ability to ramp up and down quickly, for example). This has led to the phase out of older more traditional simple cycle gas turbines - that were primarily used on occasion to meet peak load - in favor of technologies that can react, adapt, and provide additional ancillary services and value to the grid.

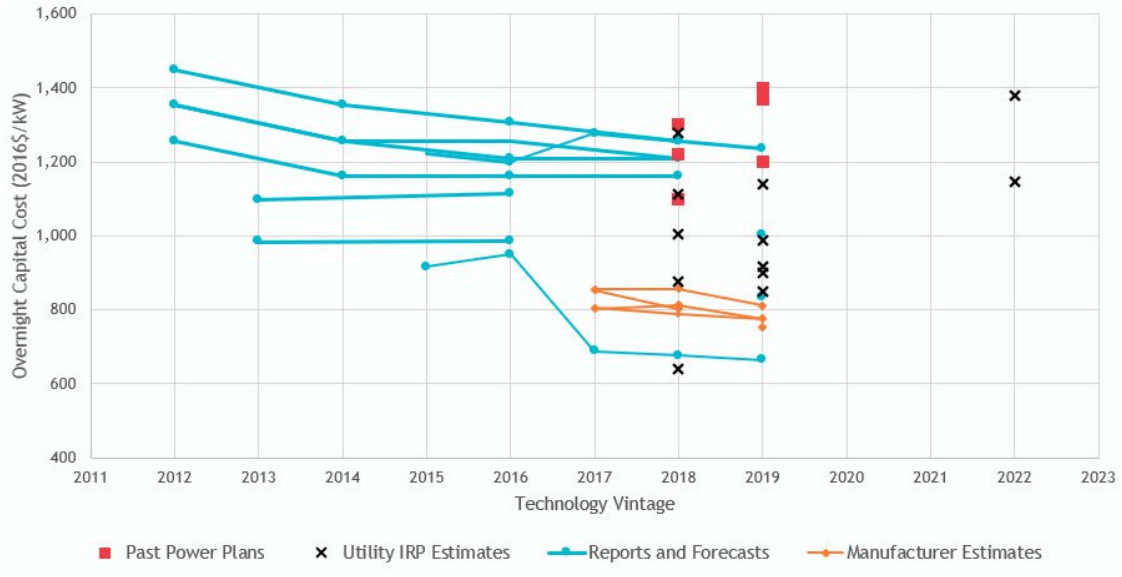
Cost Trends

Overall, gas technology costs have largely remained the same over the past several years with the exception of simple cycle frame units. There have been significant cost declines in natural gas frame units - operated in simple cycle mode as a gas peaker – which can be attributed to greater nameplate capacities and performance (output), lower equipment costs, and increased competition among engineering, procurement, and construction (EPC) contractors for the limited amount of new builds (thus contractors bid low in order to secure contracts).

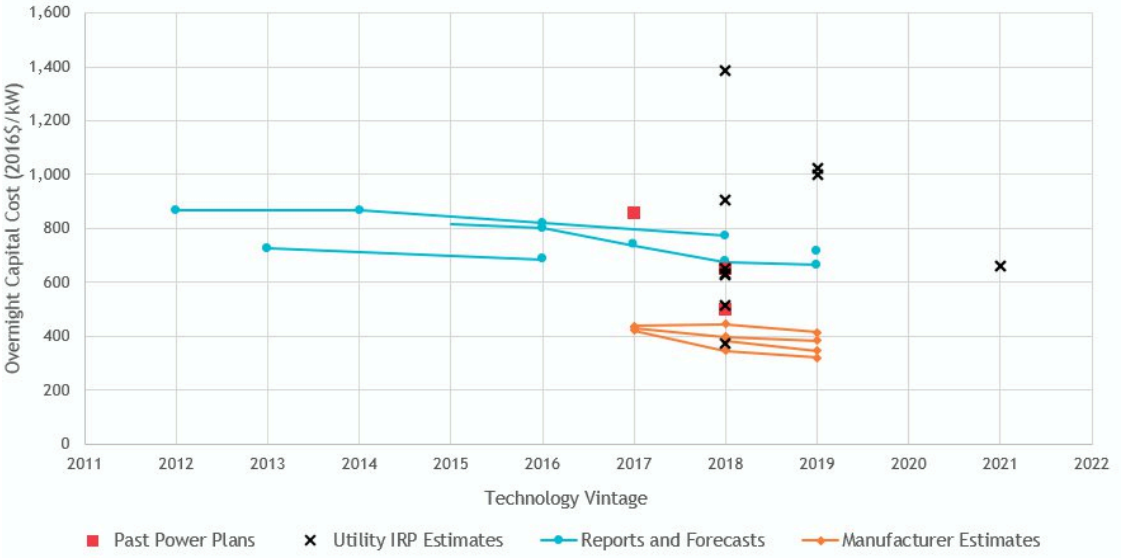
There are sizable variations in the cost estimates for each technology, as evidenced by the figures below that capture cost estimates from utilities, manufacturers, and reports. This is largely due to equipment choices (selecting wet vs. dry cooling, adding oil back-up capability, fuel compressors, inlet air chilling for plants operating at high temperatures, bypass stacks to run a CCCT independent of the HRSG, clutches on gas peakers to provide voltage support and reactive power to the grid, and supplemental duct firing, as a few examples) that can have a considerable effect on the capital cost of a project – sometimes up to 30% - but also the overall performance and capability of the project. In addition, for frame turbines, there are large differences in capacity when you move from one class to another. For example, in the Seventh Power Plan, the Council's reference plant was based off of an F-class frame turbine. For the 2021 Power Plan, the reference plant is based off of the more advanced (more flexible) H-class frame turbine which has a much greater capacity. The H-class is much less expensive in terms of capital cost ($/kW) because it is capable of producing significantly more electricity. It is incumbent on the utility or project owner to assess the needs of their respective balancing area or customer(s), while complying with mandated regulations, and make the most cost-effective equipment selections for their system.

The figures below show the data plots and analysis that was used to develop the 2021 Power Plan reference plant cost estimates for natural gas. Note that these figures capture data from various project capacities, configurations, and technology vintages. See the cost workbooks for more details.

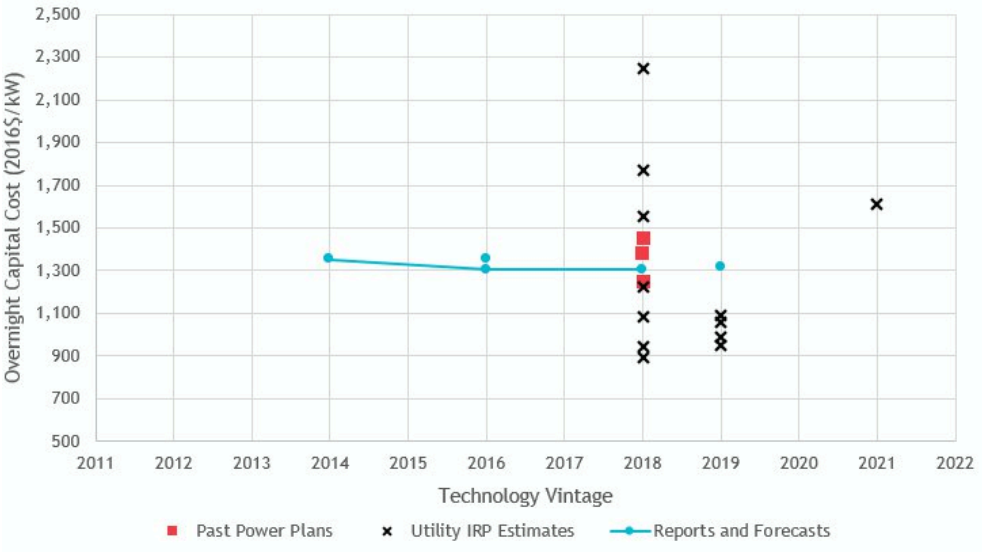
Overnight Capital Cost of Natural Gas Combined Cycle Combustion Turbines



Overnight Capital Cost of Natural Gas Simple Cycle Combustion Turbines – Frame



Overnight Capital Cost of Natural Gas Reciprocating Engines

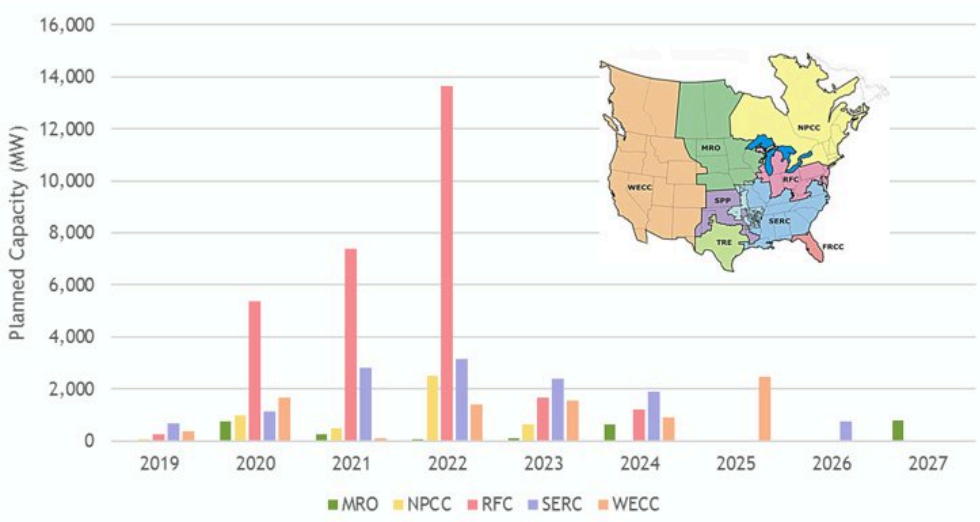


Development Trends

Across the entire United States, from 2016 to the end of 2019, roughly 48,000 megawatts (nameplate capacity) of new natural gas resources were developed and placed in service. The majority of this new capacity – by far – were combined cycle combustion turbines (CCCT). However, the story is very different in the west, with only about 5% (2,400 megawatts) of this new capacity located across the western interconnect. Contrary to the trends elsewhere in the nation, the majority of new development in the west were gas peakers in California and Arizona, with only one CCCT in the Pacific Northwest (Carty Generating Station).

Through 2027, about 80,000 megawatts of new natural gas nameplate capacity were planned across the United States (based on data pulled in 2019 from S&P Global). Only 10% of that planned potential is located within the western interconnect (WECC) and the majority are in the eastern United States in the RFC and SERC regions of NERC. While planned resources do not mean that these projects will proceed, they can provide a general idea of what the future could look like. While there are renewable portfolio standards in some of the eastern states in the RFC and SERC, they tend to be less aggressive than the west and there are no clean energy regulations. This definitely plays a role in future generating resource options in these areas.

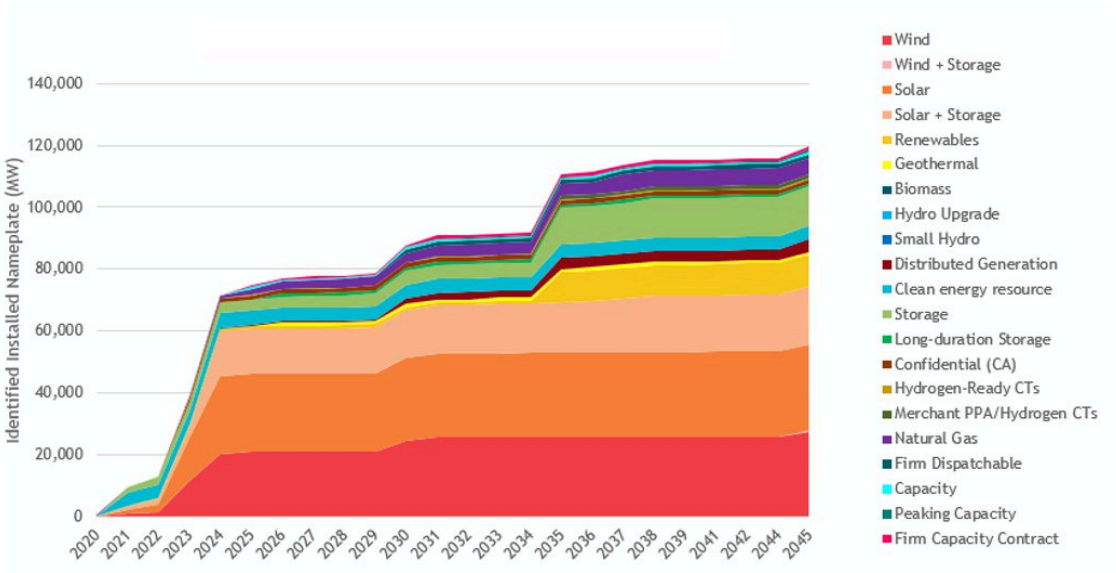
Planned New Natural Gas Additions, by NERC Region



* Data sourced from S&P Global, 2019

In the latest round of utility integrated resource plans (IRPs) throughout the WECC (see Council analysis and presentation from June 2021), it is clear that utilities are grappling over the future role of new natural gas plants as coal plants retire and many states and utilities have adopted clean energy policies and goals. Of the data compiled from the IRPs (which covered about 70% of the US portion of WECC), only a small portion of the future new resources identified is natural gas (the purple shaded area towards the top). While IRPs represent a moment in time and are subject to change as they are analyzed every two years, it definitely shows a heavy preference for renewable and carbon-free new resources. Of the new natural gas identified, about 30% were combined cycle combustion turbines and 70% were gas peakers. Several utilities are exploring dual-fuel CCCTs and peaking units, with the idea that the plants can combust natural gas for the near future and then switch to alternative fuels (hydrogen, biodiesels) down the road.

Identified Potential New Resources - ~70% of the U.S. portion of WECC IRPs



Environmental Effects

See the Environmental Effects of Generating Resources for a high-level summary of some of the primary environmental effects of natural gas technologies. For an in-depth description of the lifecycle impacts associated with electricity generation, see Appendix I of the Seventh Power Plan.

All of the new natural gas technologies considered and assessed by the Council for the 2021 Power Plan are assumed to comply with existing environmental regulations governing air and water emissions, siting regulations, waste disposal, fuel use (extraction and production), and fish and wildlife protection and mitigation costs when quantifiable and directly attributable to the new resource. For natural gas technologies, this is most obviously captured and quantified in the cost of equipment and therefore accounted for in the reference plant cost estimates. For more information, see the section on Federal Statutes and Regulation Updates and the Methodology for Determining Quantifiable Environmental Costs and Benefits and Due Consideration.

Resource Potential in the Region

With the Clean Energy Transformation Act (CETA) in Washington and the House Bill 2021 in Oregon mandating 100% clean energy supplies by 2045 and 2040, respectively, it could be difficult to license and develop new gas plants within those states. However, in Idaho and Montana, there are no regulations prohibiting new natural gas development. In response to a competitive solicitation process for long-term capacity resources, Northwestern Energy announced in April 2021 plans to develop a 175-megawatt natural gas reciprocating engine plant in Laurel, Montana. If constructed, it could be in operation in 2023.

Opportunities and Challenges:

There are significant coal unit retirements occurring and planned across the region and the western interconnect over the next decade – to what extent will natural gas be a part of the replacement resources that help play a role in the new dynamic, carbon-constrained energy system? The future role – and the extent of it - of new natural gas plants within the region's power system is yet to be determined. With clean energy policies enacted in Oregon and Washington, new natural gas development may only be realistic in Idaho and Montana.

Natural gas technologies are able to provide consistent energy generation as well as flexible capacity, two attractive attributes to any power system. Costs for some technologies are competitive with other resource alternatives – though not as cheap as solar and wind. There may be opportunities for manufacturers to explore dual fuel technologies to enable the combustion of natural gas in the near-term and alternative less-carbon intensive fuels (like hydrogen and biodiesel) in the future.

Description of Natural Gas Reference Plants

For the 2021 Power Plan, the Council developed three natural gas reference plants, all located east of the Cascades – a combined cycle combustion turbine (CCCT), simple cycle combustion turbine (SCCT), and a reciprocating engine (recip). There are several options for a simple cycle combustion turbine technology. After discussions with the GRAC, the Council settled on the frame technology because it is the least expensive option. While it may not be *as* flexible as the other gas peakers, there are similar enough operating characteristics between them all. Though the Council only included the frame SCCT in its modeling, staff did provide analysis and reference plant attributes for a SCCT aeroderivative and intercooled unit as well. See the workbook for data on these options. All natural gas reference plants utilize technologies and equipment that comply with federal environmental regulations.

The CCCT natural gas reference plant is based off of the General Electric 7HA.02 frame unit in a configuration that includes one gas turbine and heat recovery steam generator (HRSG) to one steam turbine (1x1). This reference plant utilizes dry cooling (as opposed to wet cooling) and is a single fuel only (not dual fueled to allow for oil back-up or alternative fuel). The nameplate capacity is 545 megawatts, taking into account altitude and ambient temperatures in an eastern location. The reference plant assumes all surrounding infrastructure and necessary equipment are included in the cost, for example all buildings, step-up transformers, switchgear and interconnection facilities, and security, control, and maintenance facilities. While some CCCTs utilize duct firing to increase output from the steam generator, this reference plant does not assume this feature. Emission controls in compliance with federal regulations include dry low-nitrogen oxide burners and selective catalytic reduction for nitrogen oxide control and an oxidation catalyst for carbon dioxide and volatile organic compound control.

The SCCT natural gas reference plant is based off of the General Electric 7HA.02 frame unit with one turbine generator (1x0 configuration). The nameplate capacity is 360 megawatts, taking into account altitude and ambient temperatures in an eastern location. The reference plant assumes all surrounding infrastructure and necessary equipment are included in the cost, for example all buildings, step-up transformers, switchgear and interconnection facilities, and security, control, and maintenance facilities. Emission controls in compliance with federal regulations include dry low-nitrogen oxide burners and selective catalytic reduction for nitrogen oxide control and an oxidation catalyst for carbon dioxide and volatile organic compound control.

The reciprocating engine natural gas reference plant is based off of the Wärtsilä 18V50SG gensets. The reference plant includes 12 gensets at about 18 megawatts each, for a plant nameplate capacity of about 220 megawatts. Emission controls in compliance with federal regulations include selective catalytic reduction for nitrogen oxide control and an oxidation catalyst for carbon dioxide and volatile organic compound control. The reference plant assumes all surrounding infrastructure and necessary equipment are included in the cost, for example all buildings, step-up transformers, switchgear and interconnection facilities, and security, control, and maintenance facilities.

Natural Gas Technologies: 2021 Power Plan Reference Plants

Reference Plant	Natural Gas – CCCT East	Natural Gas – SCCT East	Natural Gas – Recip East
Technology Type	GE 7HA.02, Dry-cool, Single fuel	GE 7HA.02 Frame	Wartsila 18V50SG gensets
Configuration	1 x 1	1 x 360 MW	12 x 18MW
Nameplate Capacity (MW)	545 MW	360 MW	220 MW

Location	East of the Cascades	East of the Cascades	East of the Cascades
Technology Vintage Year	2019	2019	2019
Average Capacity Factor	–	–	–
Round-trip Efficiency	–	–	–
Heat Rate – HHV (Btu/kWh)	5973	8890	8176
Economic Life (Years)	30	30	30
Tax Benefits	–	–	–
Financial Sponsor	IOU	IOU	IOU
Development Period (Yrs)	2	2	1
Construction Period (Yrs)	2	1	1
Earliest In-Operation Date	2021	2021	2021
Overnight Capital Cost ($/kW)	$1,150/kW	$550/kW	$1,250/kW
All-in Capital Cost ($/kW)	$1,272/kW	$580/kW	$1,315/kW
Fixed O&M Cost ($/kW-yr)	$10/kW-yr	$5.50/kW-yr	$5/kW-yr
Variable O&M Cost ($/MWh)	$3/MWh	$6.50/MWh	$5/MWh
Transmission	BPA P2P Long-term Firm	BPA P2P Long-term Firm	BPA P2P Long-term Firm
Deferred Transmission and Distribution ($/kW-yr)	–	–	–
Maximum buildout (MW)	5,450 MW (10 ref plants)	3,650 MW (10 ref plants)	2,200 MW (10 ref plants)

*All costs in 2016 year dollars. For more details and definitions of resource attributes, see Definitions of Reference Plant Components.

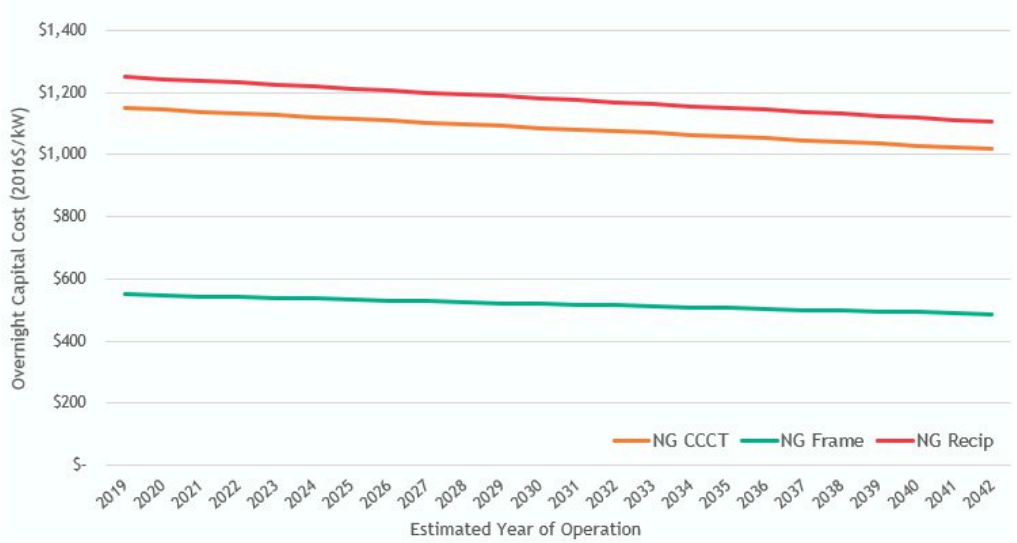
Fuel: When calculating the levelized cost of energy, fixed and variable fuel costs are included for each natural gas reference plant. The fixed-fuel cost estimates for new natural gas power plants are expressed in a $/kW nameplate capacity basis. It is assumed that a new plant would contract for firm capacity on the long-haul pipeline that is delivering its gas. The cost represents the cost to reserve incremental firm capacity on the

pipeline and is calculated using the specific pipeline tariff. The variable fuel cost ($/MMBtu) is primarily the commodity cost for the product itself – the cost to purchase the gas far upstream plus some variable pipeline charges to move it to the plant. For data on the fixed and variable fuel costs applied to the reference plants in a LCOE calculation, see the MicroFin workbook. For information on the derivation of the cost estimates, see the natural gas price forecast and fixed fuel cost estimate for new gas power plants.

Maximum buildout: The maximum buildout potential for natural gas reference plants in the 2021 Power Plan aligns with a rough judgment of gas pipeline capacity on the eastside.

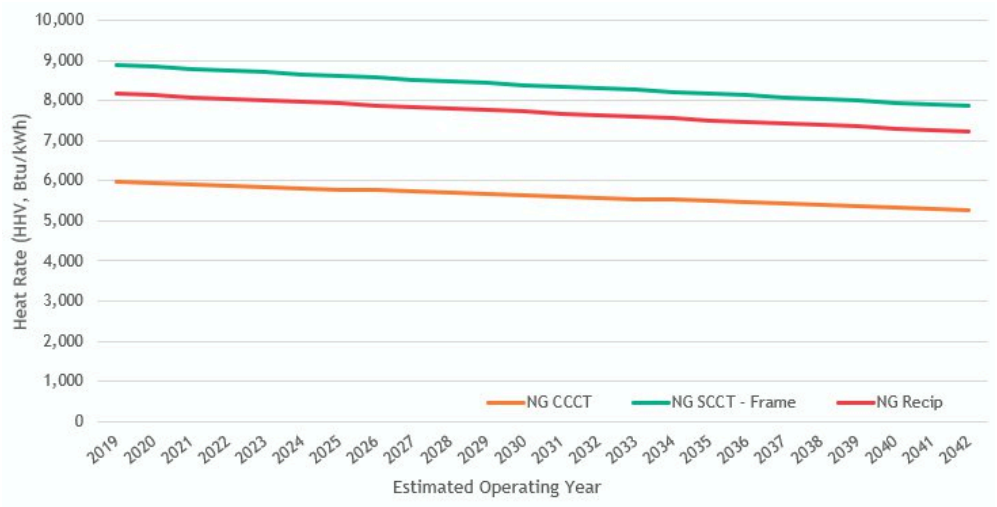
Forward capital cost curves: Each of the natural gas reference points utilize mature technologies and therefore there are not any major cost improvements anticipated over the course of the power plan. A forward capital cost de-escalation rate of 0.05% annually has been applied to the costs of all natural gas reference plants to reflect modest gradual price improvements. By the end of the planning horizon in 2042, all natural gas reference plant capital, fixed O&M, and variable O&M costs are estimated to have improved (decreased) by 12%.

Natural Gas Reference Plants – Capital Cost (2016$/kW)



Forward heat rate improvements: A modest 0.05% annual heat rate multiplier is applied to each of the natural gas reference plants. This assumes gradual improvements to the efficiency of the gas plant technologies over the course of the power plan. By the end of the planning horizon in 2042, all natural gas reference plants are estimated to have improved (decreased) heat rates by 12%.

Natural Gas Reference Plants Forward Heat Rate Improvement



More information: For background analysis, see the initial presentation on onshore wind reference plants from the October 2019 GRAC meeting. Please note that some of the material in the presentation may have been updated between that meeting and the draft plan. In addition, see the capital/FOM/VOM cost workbooks for all resource reference plants as well as MicroFin for supplementary inputs and analysis.

EXHIBIT 51-6



Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices

National Association of Regulatory Utility Commissioners | January 2020

Phillip Graeter, Energy Ventures Analysis, Inc.

Seth Schwartz, Energy Ventures Analysis, Inc.

Acknowledgments and Disclaimers

The report you are reading was developed under the project: "Carbon Capture Storage and Utilization Partnership between NARUC and the United States Department of Energy," an initiative of the National Association of Regulatory Utility Commissioners (NARUC) Center for Partnerships and Innovation. This material is based upon work supported by the U.S. Department of Energy under Award Number DE-FE0027486.

This report was authored by Phillip Graeter and Seth Schwartz of Energy Ventures Analysis, Inc., under subcontract to NARUC. Throughout the preparation process, NARUC staff and members provided the authors with editorial comments and suggestions. However, the views and opinions expressed herein are strictly those of the authors and may not necessarily agree with positions of NARUC or those of the U.S. Department of Energy.

Special thanks to:

- Joseph Giove, U.S. Department of Energy
- Tom Sarkus, National Energy Technology Laboratory
- Venkat Venkataraman, National Energy Technology Laboratory
- Martin J. Webler, National Energy Technology Laboratory
- Hon. Jeremy Oden, Alabama Public Service Commission
- Hon. Kara B. Fornstrom, Wyoming Public Service Commission
- Hon. ToNola Brown-Bland, North Carolina Utilities Commission
- Hon. Ethan Kimbrel, Illinois Commerce Commission
- Hon. Brian Kroshus, North Dakota Public Service Commission
- Hon. Talina Mathews, Kentucky Public Service Commission
- Hon. Tony O'Donnell, Montana Public Service Commission
- Jim Zolnierek, Illinois Commerce Commission
- Danielle Sass Byrnett, NARUC Center for Partnerships & Innovation
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Executive Summary

Over the last decade, the U.S. electric power sector has gone through one of the most dramatic changes in its existence. The combination of low natural gas prices as a result of the shale gas revolution and significant reduction in construction and operating costs for renewable resources, in part due to federal tax credits such as the production tax credit and investment tax credit mainly benefitting wind and solar, respectively, has resulted in a significant shift away from coal-fired generation, and instead towards natural gas and renewable generation.

Furthermore, the operating profile of existing coal-fired electric generating units has changed significantly. As new natural gas combined cycle plants have become increasingly more efficient and cheaper to operate than older existing coal-fired power plants, coal units continue to lose baseload generation share and more frequently operate as load-following, or cycling, resources. These trends are of particular importance to state public utility commissions (commissions). Functioning as economic regulators, commissions oversee investments in a reliable, efficient system while balancing emissions goals, customer demands, and other policy objectives. Changes to coal plant operations as a result of increased competition from other fuel sources may have a bearing on system reliability and economics, and therefore constitute an important area for commissions to monitor.

Increased cycling operations of coal plants, including more frequent startups and shutdowns, as well as faster changes in unit output, have a considerable impact on the reliability and cost of the plant. More frequent cycling increases wear-and-tear of plant equipment and can lead to shorter equipment lifespan due to thermal fatigue, thermal expansion, increased corrosion, and increased cost of start-up fuel. Without proper maintenance of the plant during these operations, unexpected plant outages become more frequent.

Despite the increase in plant operating costs due to cycling, there exist numerous options for plant operators to minimize the financial impact and optimize the plant's operation. One option for mitigating the effects of flexible operation is for plants to implement system modifications that recover plant efficiency lost to continuous cycling operation. Examples include sliding pressure operation, variable-speed drives for the primary cycle and auxiliary equipment, and boiler draft control schemes and operating philosophy.

Other options include establishing and following cycle chemistry guidelines for flexible operations, accurate damage estimation, flexible operation studies, and plant operator coaching. Additionally, areas to minimize coal plant cycling costs, outside the control of coal plant operators, include the increased deployment of energy storage and demand-side management resources and curtailing wind and solar generation during times of high generation or low demand.

Most of the cycling cost mitigation strategies require significant capital investment. However, recent market developments have undercut the profitability of existing coal-fired power plants and reduced the amount of working capital plant owners are able or willing to spend on the maintenance necessary to ensure plant reliability.

While they are currently being discussed, no specific market mechanisms to compensate unit flexibility provided by fossil fuel power plants exist in the Electric Reliability Council of Texas (ERCOT) and Southwest Power Pool (SPP) power markets, the two independent system operators (ISO) with the largest share of intermittent renewable energy resources in their generation mix. However, without any additional source of revenue for coal plants (e.g., for providing necessary operational flexibility for these power markets), more coal retirements due to poor economics

are likely, increasing the risk of potential power outages in states like Texas. In areas with regulated utilities, the increased cost of coal plant cycling is being passed on to utility customers. Any market mechanisms that financially reward the flexibility of coal-fired generating units will arguably result in lower overall system costs while ensuring the reliable operation of the electric power grid.

Thoughtful market mechanisms that financially compensate coal-fired generating units for providing essential market balancing attributes, such as short-term generation flexibility, could arguably result in lower electric retail rates for end-use customers while equally, if not more importantly, helping to ensure reliable operation of the nation's electric power grid.

Introduction

Over the last ten years, the U.S. electric power system has gone through significant changes, creating new challenges for various stakeholders, including state public utility commissions (commissions). Following the Great Recession from 2007 to 2009, demand for electricity has mostly remained flat due to changes in consumer behavior and a heightened focus on energy efficiency and conservation. Additionally, technical advancements in hydraulic fracturing and horizontal drilling have revolutionized the U.S. natural gas and oil industry, resulting in record domestic production of natural gas and crude oil.

Subsequently, pricing for both commodities has decreased substantially. The shale gas revolution has created an environment where natural gas-fired power plants in the U.S. are becoming increasingly more cost-competitive with their coal-fired counterparts, resulting in a major shift from coal to natural gas generation.

Additionally, climate change has arguably been one of the most discussed topics of this decade and will likely be a leading global issue going forward. Societal pressure to move to zero-emissions energy sources, combined with renewable energy mandates, tax incentives for renewable development, and significant cost reductions for wind and solar technologies, have resulted in the continued addition of new wind and solar generating facilities across the country. With intermittent resources accounting for over one-third of total generation in some states, traditional baseload generators have been forced to be more flexible in their operating profile and complement fluctuations in generation from intermittent renewable sources.

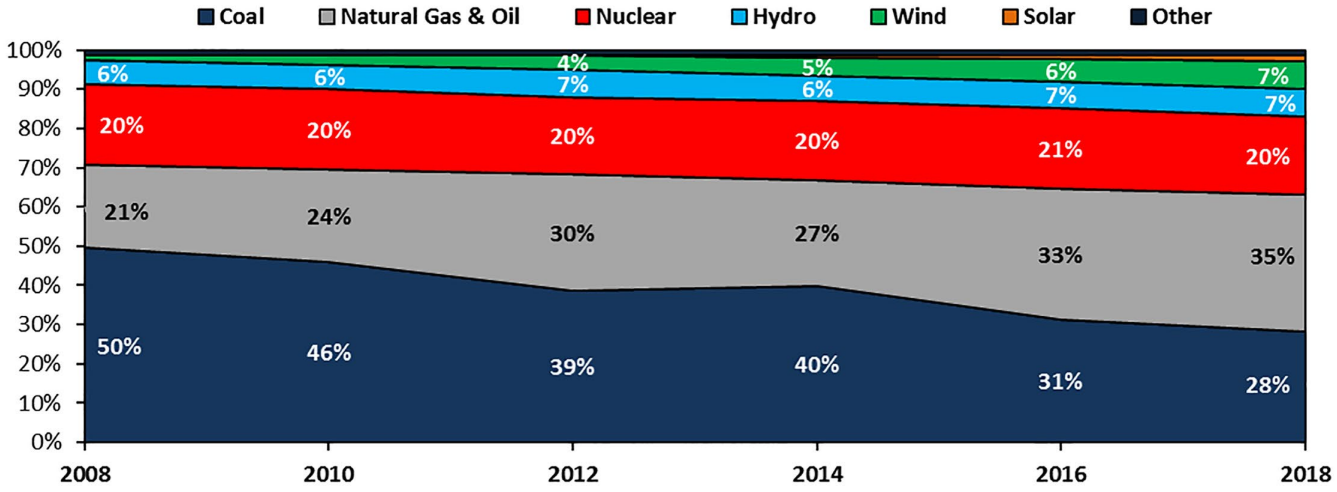
These conditions have resulted in new challenges for commissions. As economic regulators, they are charged with overseeing the reliable, safe, and affordable operation of the electricity generation and delivery system. The asset life for electric generation can span decades, making today's decisions impactful for customers well into the future. Similarly, commissioners inherit a system of assets at various stages in their operating lifespans. As new generation sources become competitive with coal — a fuel that was, for much of the twentieth century, one of the cheapest sources of electricity — commissions can benefit from two things: (1) a more complete understanding of how coal generation is or can be responding to competition, and (2) a discussion of an important attribute of the electricity system: flexibility. This paper focuses on operational changes experienced by U.S. coal-fired power plants as a result of high renewable penetration. The report also explores how fossil fuel plant flexibility is currently procured and compensated. Future research in this area may consider options for states to maintain flexible, reliable, and affordable electricity.

Overview of the Changes in the U.S. Electric Power System between 2008 and 2018

Over the last decade, the U.S. electric generating fleet has experienced some significant changes. Cheap natural gas, as a result of the shale gas revolution and falling construction and production costs for new wind and solar generation, in conjunction with public policy initiatives supporting renewables, have caused a shift from coal-fired power generation to natural gas and renewable generation.

As shown in **Exhibit 1,** in 2008, electric generation from coal-fired power plants accounted for 50% of total U.S. electric generation. Natural gas and oil generation accounted for 21%, and non-hydro renewable generation accounted for less than 2% of total generation. A decade later, the generation mix has changed dramatically. In 2018, coal-fired power plants accounted for just 28% of the total electricity produced in the U.S., while natural gas and oil's share increased to 35% and non-hydro renewable's share to 10%. This shift, which shows little sign of slowing, is creating both new opportunities and challenges for stakeholders.

EXHIBIT 1: U.S. ELECTRIC GENERATION[1] MIX – 2008 TO 2018[2]



In 2018, U.S. coal generation dropped by more than 40% from 2001 levels, while natural gas and renewable generation more than doubled their combined generation during the same period. Since renewable generation from wind and solar is generally considered non-dispatchable and is widely perceived as a nominally zero marginal cost resource, any available generation from these resources is on a "take-when-available" agreement and is displacing baseload coal generation at the bottom of the dispatch stack.[3]

In addition, the fall of natural gas prices and the resulting wave of new natural gas combined cycle power plants (CCGTs) have increased the competition between coal-fired and natural gas-fired generation for meeting baseload power needs. As a result of the shift from coal to natural gas and non-hydro renewables and resulting change in the

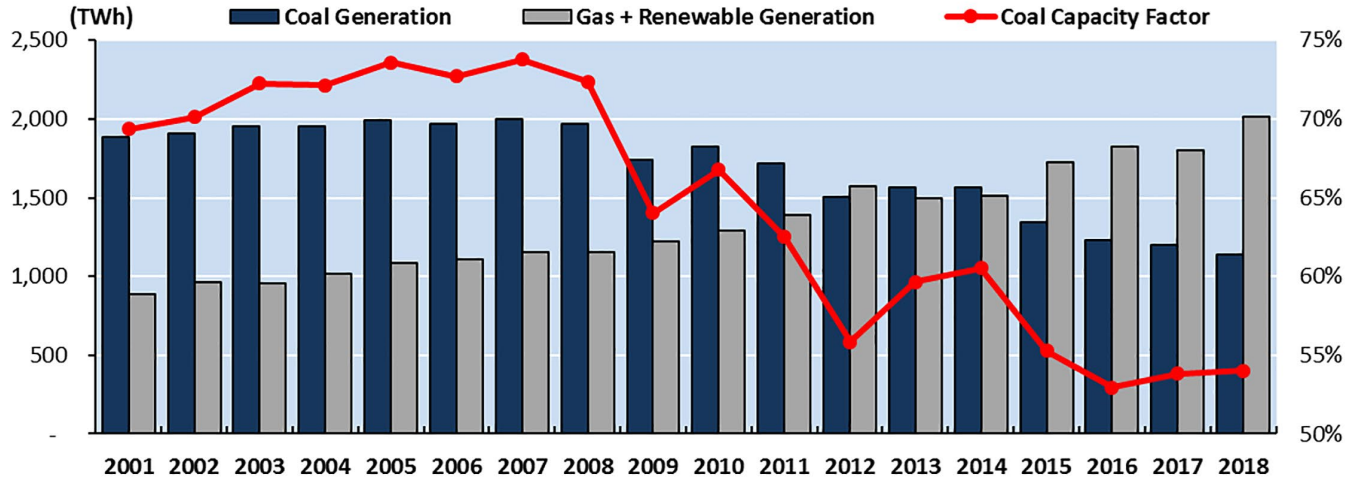
1 Generation throughout this report refers to the amount of electricity generated in a certain period measured MWh. Capacity refers to the maximum generation output a unit can generate in one hour, measured in MW.

2 Source: Department of Energy - Energy Information Administration (EIA) Annual Form-923 data

3 Some power markets have experienced times when renewable generation was greater than the total electricity demand at that time, forcing the system operator to curtail (i.e., stop from generating electricity) renewable generation.

economic dispatch order, coal plant utilization rates, also referred to as capacity factors,[4] have dropped from a high of 74% in 2007 to just 54% in 2018, as shown in **Exhibit 2.**

EXHIBIT 2: U.S. COAL GENERATION AND CAPACITY FACTOR VS. COMBINED NATURAL GAS & RENEWABLE GENERATION[5]



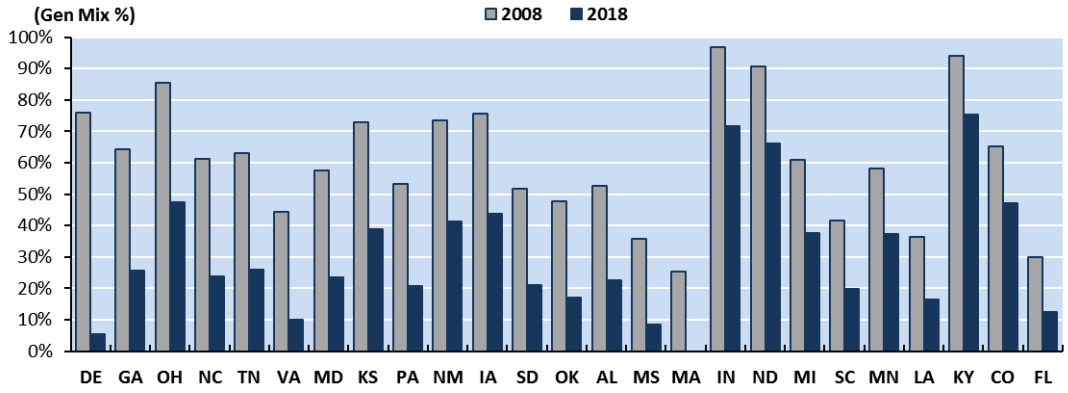
It should be noted that the magnitude of this shift from coal to natural gas and non-hydro renewable generation varies from state to state. From 2008 to 2018, all but one state (Alaska) experienced a drop in their coal generation share. **Exhibit 3** shows the top 25 states with the largest reduction in coal generation share between 2008 and 2018. Some states have seen their in-state coal generation share drop from the most dominant to just a minor role in 2018. For example, Virginia's coal fleet accounted for more than half of the total in-state generation in 2003. By 2018, that share dropped below 10%, while natural gas generation increased from 14% to 55% over the same period.

Other states with significant coal generation declines include Delaware (-71% generation share decline between 2008 and 2018), Georgia (-39%), and Ohio (-38%). On the other hand, states like Washington, Arkansas, and Nebraska, have seen only modest declines (<4%) of coal generation over the same period.

4 Capacity factor measures the utilization of a generating unit over time. For example, an electric generating unit with a generating capacity of 100 MW is capable of generating 100 MW per hour, or 876,000 MWh per year. If the same unit only generated 438,000 MWh during the year, it only generated 50% of the electricity it is theoretically capable of. Therefore, its capacity factor is 50%.

5 Source: Annual EIA Form-923 and Form 860 Data

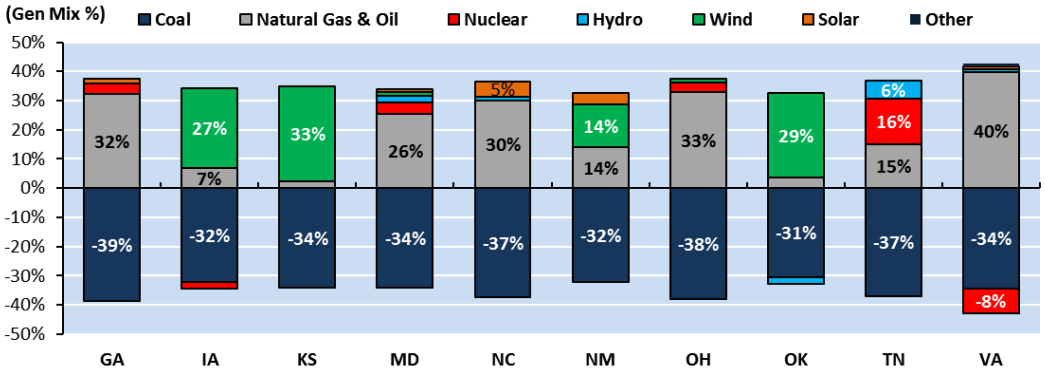
EXHIBIT 3: TOP 25 DECLINES IN COAL GENERATION SHARE BY STATE – 2008 VS. 2018[6]



While the magnitude of coal displacement varies from state to state, so does the source of replacement energy, as shown in **Exhibit 4.** For example, in Georgia, the vast majority of the 39% loss in coal generation over the last 11 years has been replaced by natural gas generation. In states like Iowa, Kansas, and Oklahoma, which have substantial wind resources, coal has been displaced predominantly by wind generation.

Lastly, another group of states has used falling costs of natural gas and renewable generation to diversify their in-state generation mix significantly. For example, New Mexico replaced the loss of 32% of coal generation share with equal parts natural gas and wind generation (14% each), as well as 4% from new solar generation. Tennessee, which is home to the recently-completed Watts Bar 2 nuclear reactor, also added significant amounts of natural gas and hydro generation to displace coal generation.

EXHIBIT 4: REPLACEMENT OF COAL GENERATION MIX SHARE BY OTHER FUELS FOR VARIOUS STATES – 2008 VS. 2018[7]



6 Source: Annual EIA Form-923 Data

7 Source: Annual EIA Form-923 Data

Operational Changes at Coal Plants between 2008 and 2018

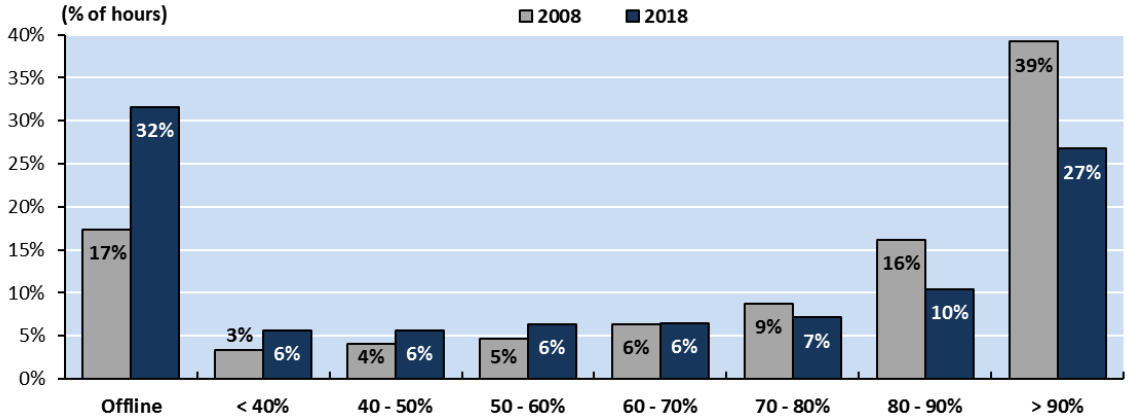
These dramatic changes in the generation mix have significant impacts on the operation of the remaining coal-fired generating fleet. To highlight these differences, this report presents an in-depth analysis of hourly gross generation data from EPA's Continuous Emission Monitoring System (EPA CEMS) for all operating coal-fired electric generating units (EGUs) in 2008 and 2018. Plants with only partial-year data (due to reporting requirements, in-year retirements, or online dates) and glaring reporting errors were excluded. In total, the hourly generation dataset included 8.1 million observations for 927 EGUs across 43 states in 2008 and 4.7 million observations for 531 EGUs across 42 states in 2018. 2008 marked the last year of historically "normal" coal plant operation (as indicated by the 72% capacity factor for the U.S. coal fleet shown in **Exhibit 2**) and was, therefore, chosen as comparison to current market conditions.

The analysis focused on four key metrics for coal plant operations: (1) gross capacity factor by segment, (2) number of hot, warm, and cold starts, and average duration that the coal unit was offline, (3) maximum turndown rate, defined as the *lowest* safe power output level, and (4) hourly ramping rates. Differences in these metrics were analyzed on a state level, in addition to the age and size of the coal plant. Highlights of the results are presented below.

As shown in **Exhibit 5,** the distribution of hourly capacity factors for the U.S. coal fleet has changed dramatically over the last decade. As described earlier, the annual capacity factor for the U.S. coal fleet dropped from 72% in 2008 to 54% in 2018. However, annual capacity factors do not provide sufficient detail on the actual operation of individual coal-fired EGUs. For example, an EGU that operates at a 100% capacity factor for half of the year, while offline the other half, has the same capacity factor as an EGU cycling equally between 30% and 70% capacity factors for the entire year. Exhibit 5 highlights a few significant shifts in operations for the U.S. coal fleet.

First, as a result of higher wind penetration, increased competition with natural gas-fired EGUs, and overall higher ramping and startup and shutdown costs (as described later in this report), coal plant operators in 2018 more often chose to keep the EGU offline and only brought it online when favorable market conditions persisted over a more extended period of time, such as high wholesale power prices during elevated demand periods. Therefore, coal units were offline an additional 14% of the time compared to 2008. Second, when online, coal-fired EGUs in 2018 operated at much lower capacity factors than their 2008 counterparts. Coal units operated only 37% of the time above 80% of their gross capacity, which is considered the highest efficiency range for most coal-fired EGUs. In 2008, the U.S. coal fleet operated during more than 55% of all hours in that same range. Additionally, coal plants in 2018 operated more often at lower capacity factors near maximum turndown levels, the utilization level at which boiler temperatures and pressures are being maintained so that the unit can ramp up more quickly in response to changes (increased demand) in electric load and/or decreased wind output. In 2018, coal plants operated more than 18% of the time at capacity factors below 60%, compared to just 12% of the time in 2008.

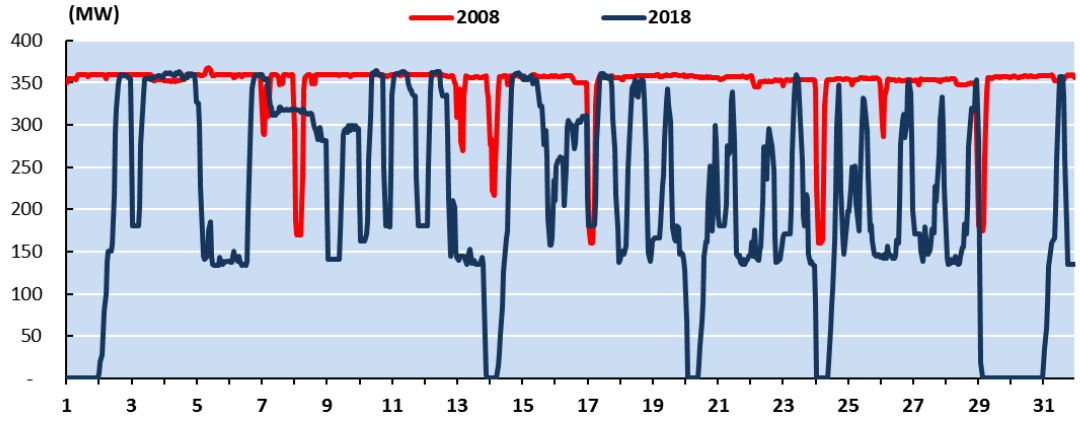
EXHIBIT 5: DISTRIBUTION OF HOURLY CAPACITY FACTOR FOR U.S. COAL-FIRED EGUS – 2008 VS. 2018[8]



An example of such an operation change is presented in **Exhibit 6.** Exhibit 6 shows the hourly gross generation profile of Xcel Energy's 350-MW Harrington unit 1, located in Texas, for the months of December 2008 and December 2018. As mentioned earlier (and in greater detail below), Texas has added a significant amount of wind generation and natural gas-fired generating capacity over the last decade. During December 2008, Harrington 1 remained relatively steady output near its maximum capacity throughout the month, with just eight turndowns, and it never fell below 150 MW.

Conversely, in December 2018, Harrington 1's gross generation output varied significantly. First, the unit was offline five times during the month of December. Second, when online, the unit cycled almost continuously between the maximum and minimum unit output, depending on current load requirements. The data also shows that plant operators turned down the unit to much lower levels than in 2008, with output falling below 150 MW on multiple occasions. Examples like these are much more frequent in 2018 than in previous years and are likely to become more numerous as more wind and solar resources are added to the generation mix.

EXHIBIT 6: XCEL ENERGY'S HARRINGTON UNIT 1 HOURLY GROSS GENERATION DURING DECEMBER[9]



8 Source: EVA Analysis of Environmental Protection Agency (EPA) Continuous Emissions Monitoring System (CEMS) Hourly Data

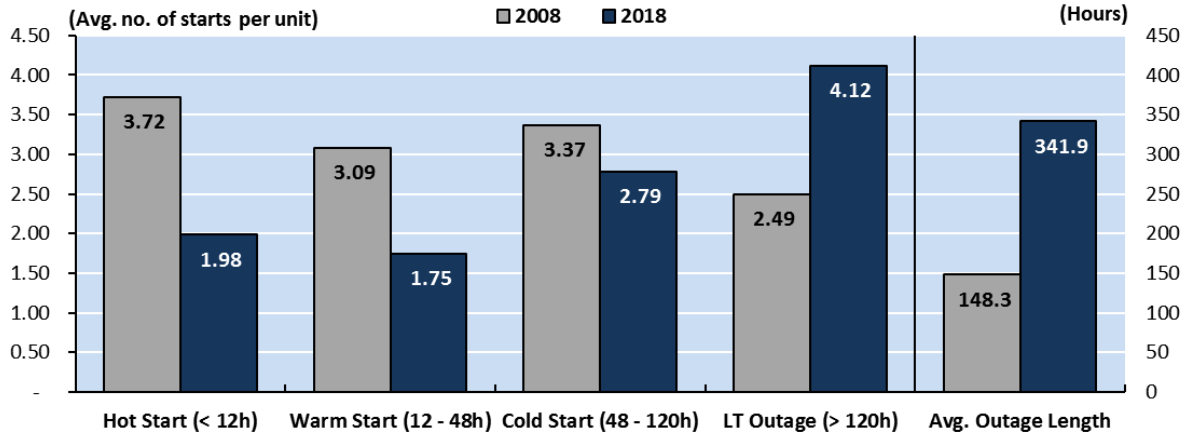
9 Source: EPA CEMS Hourly Data

Operating a coal-fired EGU below its optimal boiler design utilization rate has adverse effects on both the efficiency of the unit and its structural integrity. At lower utilization rates, coal units consume more fuel to produce the same amount of electricity, resulting in both higher fuel costs and emissions of SO_2, NO_x, and CO_2. Additionally, more frequent and faster load changes increase the stress on the boiler equipment and shorten the time between maintenance outages for the unit. The impacts are described in more detail in the next section.

Another metric to consider when assessing the flexibility of coal-fired EGUs and the impacts of unit cycling are its number of hot, warm, and cold starts. Hot starts are typically defined to have very high (700°F to 900°F) boiler and turbine temperatures and occur after 8 to 12 hours offline. Warm starts generally have boiler and turbine temperatures between 250°F and 700°F and occur after the unit has been offline for 12 to 48 hours. Starts at ambient temperatures are considered cold starts after the boiler was offline for 48 to 120 hours.[10] These definitions vary from unit to unit based on design, unit size, and manufacturer.

Generally, the colder the temperature of the boiler and turbine, the higher the startup cost of the unit. **Exhibit 7** shows the comparison between the average number of hot, warm, and cold starts for all U.S. coal-fired EGUs, as well as the average number of long-term outages and the average length of outages between starts in 2008 and 2018. Although the total average amount of starts per unit is similar between 2008 and 2018 (12.67 vs. 10.64 total starts per year respectively), Exhibit 7 clearly shows a shift away from more frequent starts at various temperature levels to longer-term outages (greater than 120 hours, or five days). On average, coal-fired EGUs in 2018 experienced less than four hot and warm starts (starts after being offline for less than 48 hours), compared to almost eight such starts in 2008. Conversely, coal units in 2018 have experienced long-term outages (greater than five days) more frequently, with over four such outages per year compared to just 2.5 per year in 2008. Finally, the average outage length for U.S. coal units in 2018 has more than doubled from less than 150 hours (approximately six days) per outage to over 340 hours per outage (approximately 14 days).

EXHIBIT 7: AVERAGE NUMBER OF STARTS PER COAL-FIRED EGU – 2008 VS. 2018[11]



10 Source: Lefton S A, Besuner P M, Grimsrud G P, Kuntz T A (2010) *Experience in cycling cost analysis of power plants in North America and Europe.*

11 Source: EVA Analysis of EPA CEMS Data

A third metric to consider when analyzing the operational changes the U.S. coal fleet experienced over the previous decade is the rate of change of generation output over a period of time, also known as ramp rates. Ramp rates can vary significantly between plant and fuel types. **Exhibit 8** shows various flexibility capabilities by technology type, according to IEA.

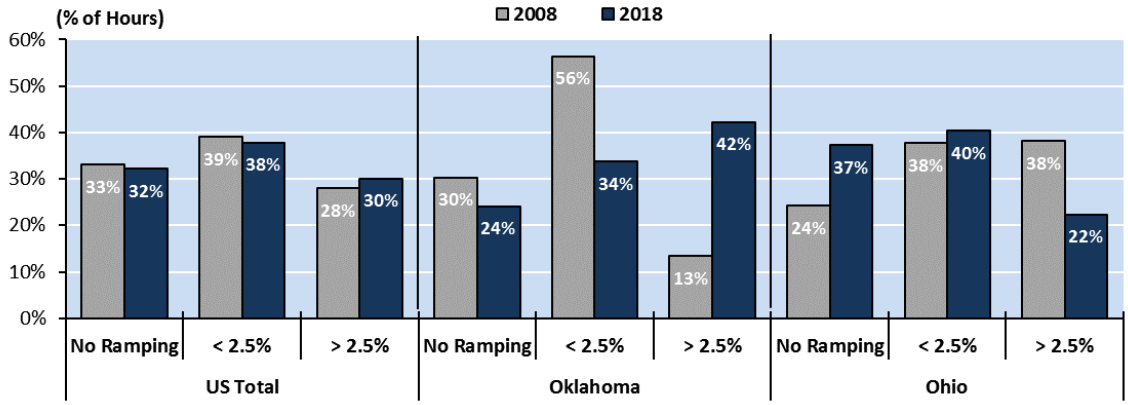
EXHIBIT 8: CAPABILITY OF DIFFERENT POWER GENERATING TECHNOLOGIES TO PROVIDE FLEXIBILITY[12]

Plant Type	Start-up time	Max Change in 30secs, %	Max ramp rate, %/min
Simple Cycle CT	10 - 20 min	20 - 30	20
Combined Cycle CT	30 - 60 min	10 - 20	5 - 10
Coal Plant	1 - 10 h	5 - 10	1 - 5
Nuclear Plant	2 h - 2 d	< 5	1 - 5

Although coal plants are far more flexible than nuclear power plants, they are generally less flexible than their natural gas-fired competition. Simple cycle and combined cycle natural gas-fired combustion turbines (CTs) have much shorter start-up times than coal-fired units as well as faster ramp rates and spinning capabilities. (For this report, ramp rates refer to the hourly change in gross electric output.) The ramp rates listed above are maximum ramp rates that also depend on the unit's specific design characteristics. Frequent ramping of a unit at these maximum ramp rates can significantly shorten the life of the unit before certain parts need to be replaced. The analysis in this report focuses on hourly changes in output for the coal units in 2008 and 2018 and does not make any inference on the maximum ramping capabilities of these units.

Exhibit 9 shows the average distribution of hourly ramp rates (when online) for the U.S. coal fleet in 2008 and 2018 in three categories: no ramping (i.e., no change in output from the previous hour), less than 2.5% change in output, and greater than 2.5% change in gross electric output.

EXHIBIT 9: AVERAGE DISTRIBUTION OF HOURLY RAMP RATES FOR THE U.S. COAL FLEET AND TWO SPECIFIC STATES – 2008 VS. 2018[13]



12 Source: International Energy Agency – Clean Coal Centre (2016) *Levelling the intermittency of renewables with coal.*

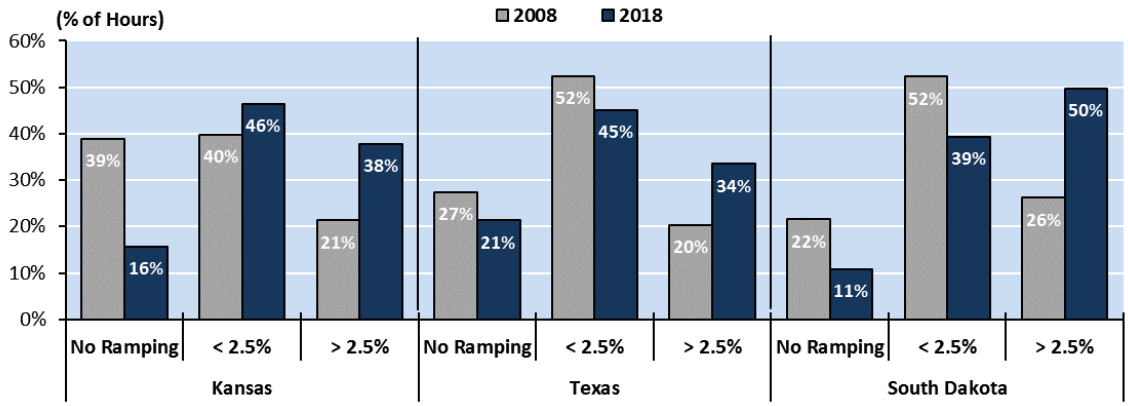
13 Source: EVA Analysis of EPA CEMS Data

As shown in **Exhibit 9,** there is little change in ramp rates for the average coal unit when comparing the ramp rates on a national level between 2008 and 2018. For all three categories, the 2018 values are within two percentage points of its 2008 counterparts, indicating little change on a national level. However, there are significant differences on a regional level.

Between 2008 and 2018, Oklahoma's coal fleet lost more than 30% of generation share, mostly to new wind resources in the state. Since little to no new peaking units have come online in the state since 2008, the responsibility of balancing the possible sudden loss of wind generation fell on the remaining Oklahoma coal units. As a result, Oklahoma's coal units have significantly increased their share of output changes greater than 2.5%, from 13% in 2008 to over 42% in 2018. Conversely, the percentage of ramping at less than 2.5% has fallen tremendously, from 56% in 2008 to 34% in 2018.

As shown in **Exhibit 10,** other states where coal generation was mainly displaced by wind with almost no new peaking capacity have seen similar developments. For example, in Kansas, the number of times an average coal unit in the state ramped up or down at rates greater than 2.5% increased from 21% in 2008 to 36% in 2018.

EXHIBIT 10: AVERAGE DISTRIBUTION OF HOURLY RAMP RATES COAL FLEET IN WIND STATES – 2008 VS. 2018[14]

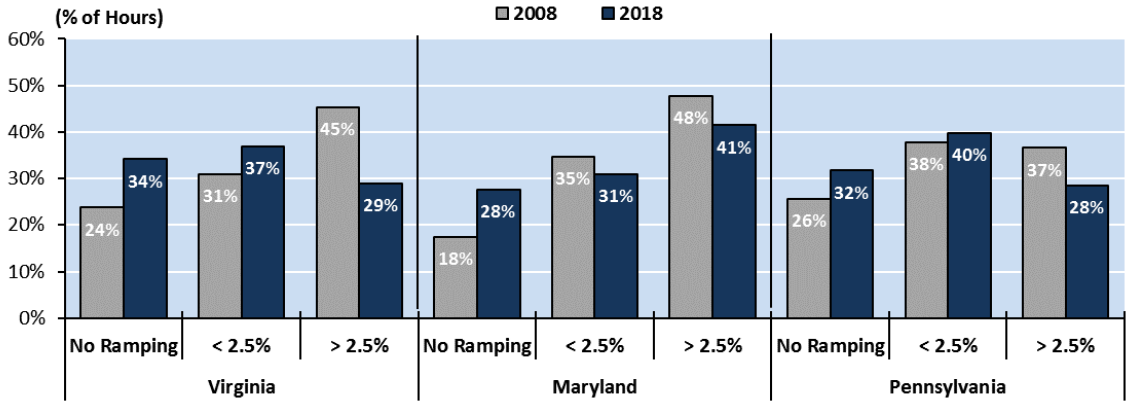


On the other hand, coal units in states where coal has been displaced mainly by new natural gas simple cycle and combined cycle power plants have been subject to less ramping at higher percentages. In Ohio, coal's generation share fell by 38 percentage points between 2008 and 2018, while natural gas's share increased by 33 percentage points over the same period. With cheap natural gas supply in the region, Ohio's new and highly efficient natural gas power plants are more economical to operate than most of the remaining in-state coal fleet. As a result, Ohio natural gas plants are being dispatched ahead of most of the Ohio coal fleet, while also providing flexibility support. Ohio coal plants are mainly called upon during times of high electricity demand to provide additional baseload generation, while the new natural gas plants provide load-following support. As a result, as seen in Exhibit 9, coal's ramp rates above 2.5% have fallen between 2008 and 2018, from 38% to 22%, respectively. Conversely, hours during which coal plants did not ramp at all increased from 24% in 2008 to 37% in 2018.

14 Source: EVA Analysis of EPA CEMS Data

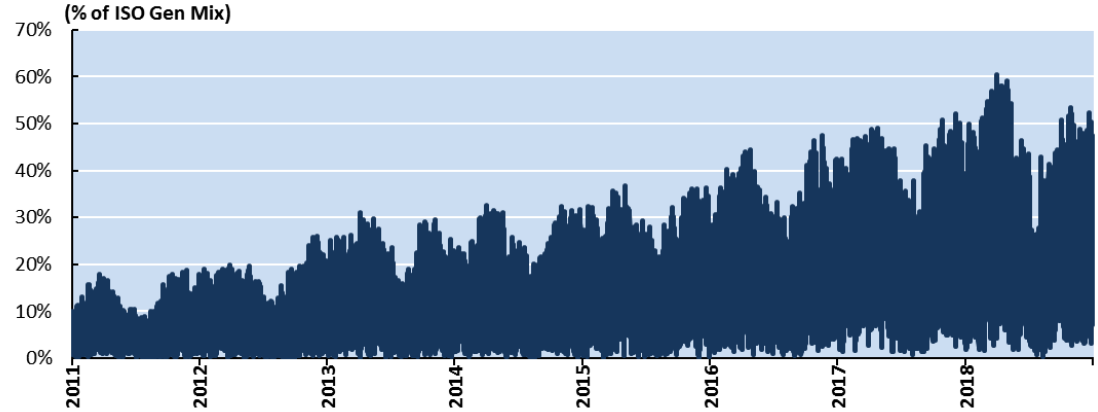
Again, states where electric generation shifted predominantly from coal to natural gas have seen similar developments, as shown in **Exhibit 11.** For example, in Virginia, another state where coal has been displaced mainly by natural gas, the share of ramp rates for coal units greater than 2.5% has fallen since 2008, from 45% to just 29% in 2018.

EXHIBIT 11: AVERAGE DISTRIBUTION OF HOURLY RAMP RATES COAL FLEET IN NATURAL GAS STATES – 2008 VS. 2018[15]



High ramp rate requirements for coal units in states with a significant share of wind generation already will continue to increase as more wind resources are added to the generation mix. **Exhibit 12** shows the hourly wind generation share in the SPP, the ISO for states with some of the highest percentages of wind generation in 2018, including Kansas, Oklahoma, and both of the Dakotas. In 2018, the generation share of wind rose to 60% on March 31 and fell to almost zero on August 8, with fluctuations of more than 9 GWh of generation in six hours on February 17. With coal still accounting for more than two-thirds of fossil fuel generation in SPP, that variation in wind generation is being balanced mostly by coal-fired EGUs.

EXHIBIT 12: HOURLY WIND GENERATION SHARE IN SPP – 2011 TO 2018[16]

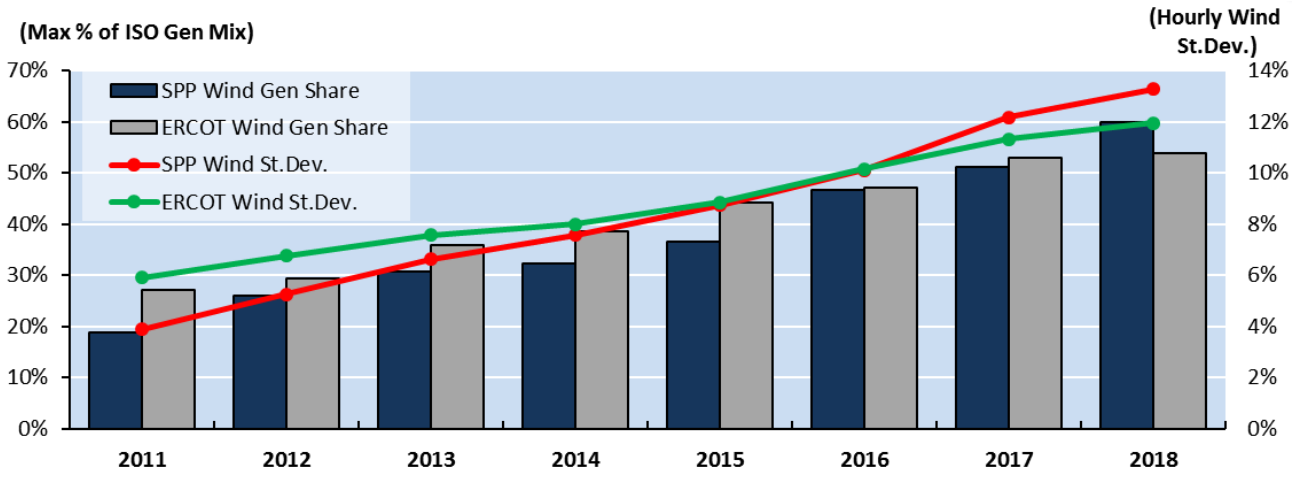


15 Source: EVA Analysis of EPA CEMS Data

16 Source: Southwest Power Pool (SPP) Hourly Generation Mix Data

As more wind generation is being added to the electric power system, utilities and ISOs, such as ERCOT and SPP, have to balance more considerable amounts of the variable generation with dispatchable generating units such as coal and natural gas. **Exhibit 13** shows the trend since 2011 in annual wind generation share for ERCOT and SPP, as well as the standard deviation for hourly wind generation for the two ISOs. Although wind developers and ISOs attempt to diversify wind farms locationally to minimize the variability of wind output, wind variability has continued to increase significantly in both ISOs. In 2011, when hourly wind output peaked at just 20% of SPP's generation, the standard deviation for the hourly generation mix share from wind was below 4%. In 2018, however, when the peak hourly generation share of wind increased to 60%, the standard deviation more than tripled to over 13%. As more wind is added to the ISO's generation mix, flexibility from dispatchable resources such as coal and natural gas has become more critical.

EXHIBIT 13: MAX HOURLY WIND GENERATION SHARE & STANDARD DEVIATION FOR ERCOT & SPP ISO – 2011 TO 2018[17]

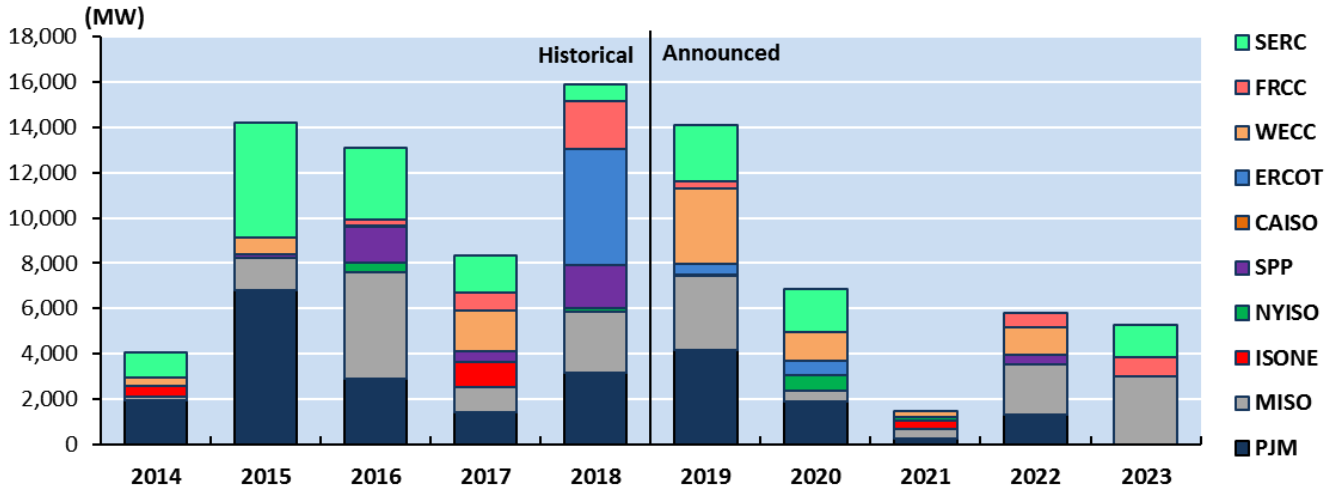


Despite the increased importance of flexible and dispatchable generation to balance the variability of a growing renewable fleet, more and more coal plants are being retired in power markets with an ever-increasing share of renewable generation. **Exhibit 14** shows historical and announced coal retirements by power market. In 2018, a record 16 GW of coal-fired generation retired, more than in any other previous year. 2019 follows close behind with another 14 GW of coal capacity either already retired or scheduled to retire. More than 30 GW of additional coal capacity have already retired or are announced to retire by 2023 in MISO, ERCOT, and SPP alone, the three power markets with the highest share of wind generation in 2018. Unlike the massive amounts of coal retirements in 2015 and 2016 due to the compliance deadline for the EPA Mercury and Air Toxics Standard (MATS), these coal retirements are mainly due to reduced revenues as a result of lower utilization rates. The next section discusses the structural and financial implications of increased cycling of coal-fired power plants and

17 Source: EVA Analysis of SPP and ERCOT Hourly Generation Mix Data

how coal plant owners are, or are not, currently compensated for providing much needed operational flexibility to the grid.

EXHIBIT 14: HISTORICAL COAL RETIREMENTS BY POWER MARKET – 2008 TO 2018[18]



18 Source: EVA Power Plant Tracking System Database

The Costs and Implications of Coal Plant Cycling

As described in the previous section, coal-fired power plants are operating less frequently in baseload operation, where they provide a constant level of electric output with minimal variation. Instead, they are asked to provide more operational flexibility in response to higher shares of intermittent generating resources, such as wind and solar entering the market.

There are two main types of coal plant cycling practices to facilitate changes in output, as mentioned previously: completely shutting down the coal unit or changing its electric output to follow load. As both types imply a diversion from designed operating practices, operating costs for coal-fired power plants are expected to increase (substantially in some cases) as revenue from decreased energy market payments falls. These operational changes and other factors associated with more flexible operation can have the following effects on coal-fired EGUs:

- Increased wear-and-tear on high-temperature and high-pressure plant components and associated costs
- Increased wear-and-tear on balance-of-plant components and related costs
- Shorter periods between maintenance time but more prolonged outages
- Decreased thermal efficiency at high turndown levels
- Increased fuel costs due to more frequent and inefficient unit starts, which require start-up fuel
- Difficulties in maintaining optimal steam chemistry leading to accelerated corrosion
- Potential for catalyst fouling on NO_x control equipment
- Long-term loss of critical equipment life
- Efficiency losses during startup through synchronization and loading to zero load
- Increased risk of human error in plant operations

Exhibit 15 shows the typical costs for a medium-sized coal-fired power plant during various types of operation, based on previous studies analyzing the financial implications of the increased wear-and-tear and associated maintenance and capital costs listed above.

EXHIBIT 15: TYPICAL STARTUP AND CYCLING COSTS FOR A MEDIUM-SIZED COAL-FIRED POWER PLANT ($2019)[19]

Type of Start	Cost category	Cost estimates ($/MW)		
		Expected	Low	High
Hot Start (1–23 h offline)	Maintenance and capital	$ 128	$ 102	$ 162
	Forced outage	$ 60	$ 48	$ 76
	Start-up fuel	$ 20	$ 14	$ 30
	Auxiliary power	$ 11	$ 8	$ 13
	Efficiency loss from low and variable load operation	$ 5	$ 4	$ 8
	Water chemistry cost and support	$ 1	$ 1	$ 2
	Total cycling cost	**$ 225**	**$ 178**	**$ 291**
Warm Start (24 - 120 h offline)	Maintenance and capital	$ 137	$ 109	$ 170
	Forced outage	$ 65	$ 51	$ 80
	Start-up fuel	$ 43	$ 30	$ 57
	Auxiliary power	$ 23	$ 18	$ 28
	Efficiency loss from low and variable load operation	$ 6	$ 5	$ 9
	Water chemistry cost and support	$ 6	$ 4	$ 9
	Total cycling cost	**$ 277**	**$ 217**	**$ 351**
Cold Start (> 120 h offline)	Maintenance and capital	$ 205	$ 162	$ 255
	Forced outage	$ 96	$ 76	$ 120
	Start-up fuel	$ 64	$ 45	$ 24
	Auxiliary power	$ 29	$ 23	$ 36
	Efficiency loss from low and variable load operation	$ 6	$ 5	$ 10
	Water chemistry cost and support	$ 17	$ 13	$ 21
	Total cycling cost	**$ 417**	**$ 325**	**$ 465**
Load follow down to 36% of Capacity	Maintenance and capital	$ 20	$ 12	$ 31
	Forced outage	$ 9	$ 6	$ 15
	Efficiency loss from low and variable load operation	$ 1	$ 1	$ 2
	Mill cycle gas	$ 2	$ 19	$ 50
	Total cycling cost	**$ 32**	**$ 19**	**$ 50**

As shown in **Exhibit 15,** expected costs for cold starts can be almost double the startup cost for a hot start when the remaining temperature in the boiler and turbine system are still significantly higher. However, even hot starts can range from $89,000 to $145,500 per start for a 500 MW coal-fired EGU. These costs can also vary significantly between coal units based on differences in boiler size and design (subcritical vs. supercritical). The highest cost

19 Source: Lefton S A, Hilleman D (2011). *Make your plant ready for cycling operations.* http://www.powermag.com/make-your-plant-ready-for-cycling-operations/

category for all four operation types above is "maintenance and capital." According to a previous study from the National Renewable Energy Laboratory (NREL), there is a trade-off between high capital and maintenance costs and corresponding lower equipment-forced outage rates (EFORd).

According to a study by the Electric Power Research Institute (EPRI)[20], some of the **damage mechanisms** that occur due to increased load-following and on/off operations include:

- **Thermal fatigue.** This phenomenon, caused by frequent changes in equipment temperature, can produce cracking in thick-walled components, especially castings such as turbine valves and casings. Also affected are boiler superheater and reheater headers, where ligament cracking is commonly seen between tube stubs. These headers are expensive, thick-walled vessels operating under high steam pressure, making this damage of particular concern to plant owners.

- **Thermal expansion.** Several systems in a coal plant consist of components that undergo high thermal growth relative to surrounding components. The most notable example of this phenomenon is the enormous movement of boiler structures relative to the cooler support framework. These support ties are designed to accommodate growth, but are subject to accelerated life consumption if the frequency of thermal cycling increases.

- **Corrosion-related Issues.** Two-shifting, or any other operation that challenges the ability of a plant to maintain water chemistry, can lead to increased corrosion and accelerated component failure. Increased levels of dissolved oxygen in feedwater can be the result of condenser leaks, aggravated by more frequent shutdowns.

- **Fireside corrosion.** Load cycling and relatively quick ramp rates under staged conditions will hurt both fireside corrosion and circumferential cracking.

- **Rotor bore cracking.** When subjected to transients in the temperature of the admitted steam, the high-pressure and intermediate-pressure steam turbine rotors can suffer thermo-mechanical stress excursions, resulting in low-cycle fatigue damage. This damage can result either from introducing hot steam to a relatively cold rotor exterior, or the opposite.

The more accurately costs to repair or replace the issues described above can be predicted and included in the current unit dispatch operation methodology, the lower the risk for a particular coal-fired EGU to experience an unexpected equipment failure and unit outage, and miss out on potentially significant energy revenues.

Numerous studies have explored how to mitigate flexible operation damage. Some of the suggested **mitigation strategies** to reduce the damage and associated costs extensive cycling has on coal plants include:

- **Efficiency improvements.** One option for mitigating the effects of flexible operation is for plants to implement system modifications that recover plant efficiency lost to continuous cycling operation. Mitigation examples

20 Source: Hesler S (2011) *Mitigating the effects of flexible operation on coal-fired power plants.* http://www.powermag.com/mitigating-the-effects-of-flexible-operation-on-coal-fired-powerplants/

include: sliding pressure operation, variable-speed drives for the primary cycle and auxiliary equipment, and changes to boiler draft control schemes and operating philosophy. However, many plants today do not have sufficient capital, whether internally or through the investment community, available to undertake these major system modifications.

- **Establishing and following cycle chemistry guidelines for flexible operations.** An area of particular concern for plants under cycling duty is following appropriate cycle chemistry guideline limits during plant startup, shutdown, and layup. Proper protection of the entire steam circuit (boiler, piping, feedwater, and turbine) is critical during these modes of flexible operation. Correct layup procedures, combined with appropriate chemical treatment during shutdown and startup, will significantly reduce corrosion and deposits in the steam cycle equipment, including the boiler, steam-touched tubing, and the turbine.

- **Accurate damage estimation.** Estimates can be made of damage costs per start to inform the plant's trading position. Cost estimates are based on increased routine maintenance costs, damage to major components, and estimated cost of consumables per start.

- **Flexible operation studies.** These studies reduce component damage through procedure optimization and design modification. Included in the reviews are: an initial appraisal of plant-specific risk areas, installation of additional instrumentation, flexible operation trials, assessment of thermal transients, changes to operating procedures and design to address issues identified, repeat tests to confirm success, and detailed stress analysis to inform strategy going forward.

- **Operator coaching.** Simplified damage algorithms for creep and fatigue are also developed for operator coaching. Plant data for critical components are screened to identify and understand the most damaging operational conditions. Operators can then seek to minimize the extent of such conditions during future unit starts. Proper operator training can reduce the risk of human error during increased coal plant cycling operations.

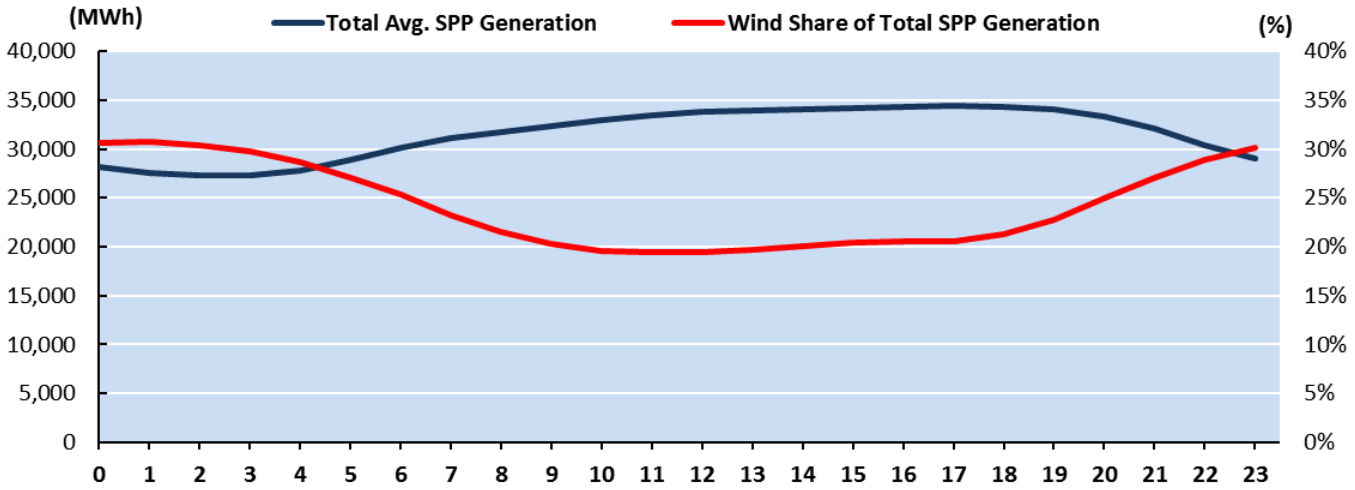
Other areas to minimize coal plant cycling costs, outside the control of coal plant owners, include increased deployment of energy storage and demand-side management resources to shift some of the renewable generation from wind and solar to peak demand hours or reduce the demand fluctuations over the course of the day. A more drastic approach is to curtail wind and solar generation during times of high generation or low demand to minimize the requirement for fossil fuel plant cycling.

Current Financial Compensation Practices for Plant Flexibility Operation

The previous section described various mitigation strategies to counteract the increased maintenance and capital costs due to increased coal plant cycling and shutdowns/startups. Most of these mitigation strategies require significant amounts of additional capital investments by coal plant owners. Recent market developments described previously, including increased renewable generation from wind and solar and low natural gas prices due to the shale gas revolution, have eroded the revenue stream of coal plants significantly. Still, maintaining a flexible baseload fleet is vital to complement the variability of wind generation and keep electricity reliable and affordable, especially during times when new natural gas power plants face additional regulatory hurdles.

One issue with wind generation in SPP is shown in **Exhibit 16.** Exhibit 16 shows the average hourly total generation for SPP during a 24-hour cycle in 2018 along with the wind generation share during those same hours. In 2018, wind supplied over 30% of the generation between 11 pm and 3 am, while dropping to just 20% between 10 am and 5 pm. Conversely, demand for electricity in SPP reaches its low point at 3 am and starts to climb throughout the day, before beginning to decline again around 6 pm. Therefore, during peak electricity demand times, wind generation in SPP is generally at its lowest, requiring other generating resources such as coal and natural gas to increase generation accordingly.

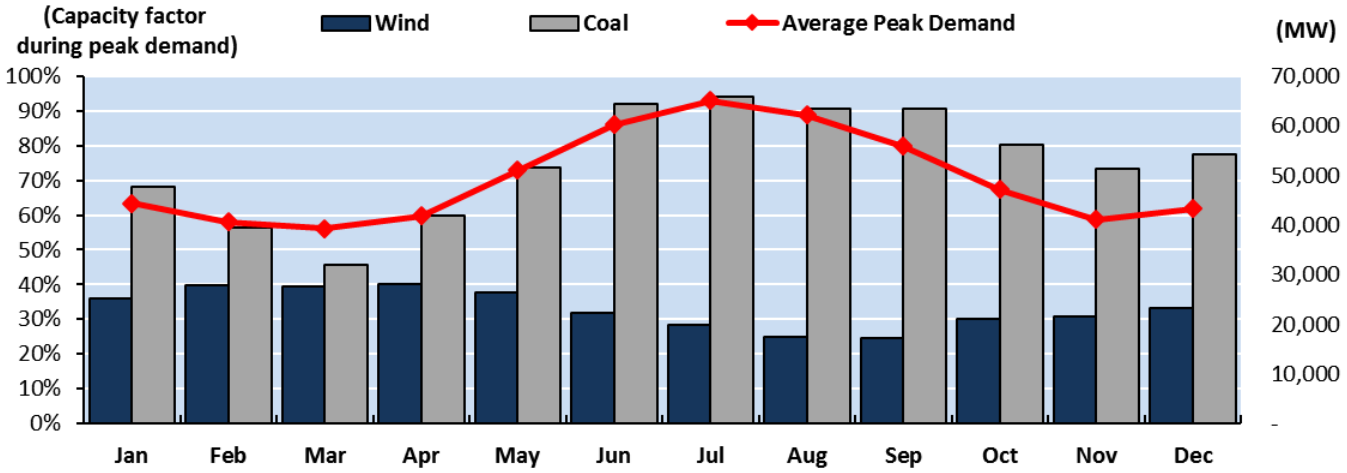
EXHIBIT 16: 2018 AVERAGE HOURLY SPP GENERATION VS. WIND GENERATION SHARE[21]



Additionally, wind generation varies significantly from month to month. Exhibit 17 shows the average capacity factors for both coal and wind and during peak demand hours by month for ERCOT for the years 2016 through 2018. Wind generation tends to achieve its highest capacity factors during the spring and fall seasons while being at its lowest during the hot summer months. On the other hand, demand for electricity reaches its peak during the hot summer months when the use of air conditioning drives up demand. Again, due to the seasonality of wind, additional generating resources are needed to increase generation to ensure reliable electricity delivery.

21 Source: SPP Hourly Generation Mix Data

EXHIBIT 17: AVERAGE CAPACITY FACTOR OF WIND AND COAL GENERATION DURING PEAK DEMAND HOURS IN ERCOT BY MONTH – 2016 TO 2018[22]



Historically, as shown in **Exhibit 17,** coal-fired EGUs operated at full capacity during high demand seasons, such as summer and winter, while frequently cycling between minimum load and full load during the shoulder months when online. During shoulder months, power prices during off-peak hours (late night to early morning hours) would sometimes drop below the coal unit's operating costs, therefore losing money during those hours. However, coal unit operators would accept the overnight losses to be available during peak demand hours, subsequently having the opportunity to recoup lost revenue.

The shale gas revolution and the increased development of renewable generating resources have changed this equation dramatically. As a review, power prices in deregulated power markets are set by the EGU that provides the marginal MWh to meet electricity demand at that time. As the dispatch cost for wind is essentially zero, the increased share of wind generation has caused off-peak power prices to decline in recent years. Additionally, on-peak power prices have fallen at even higher rates, as natural gas prices have plummeted, reducing the dispatch costs for combustion turbines which historically used to be the marginal resources and set the on-peak power prices. In some regions, dispatch costs for combustion turbines and combined cycle power plants have dropped well below coal-fired power plants, leaving an increasing number of coal plants "out-of-the-money."

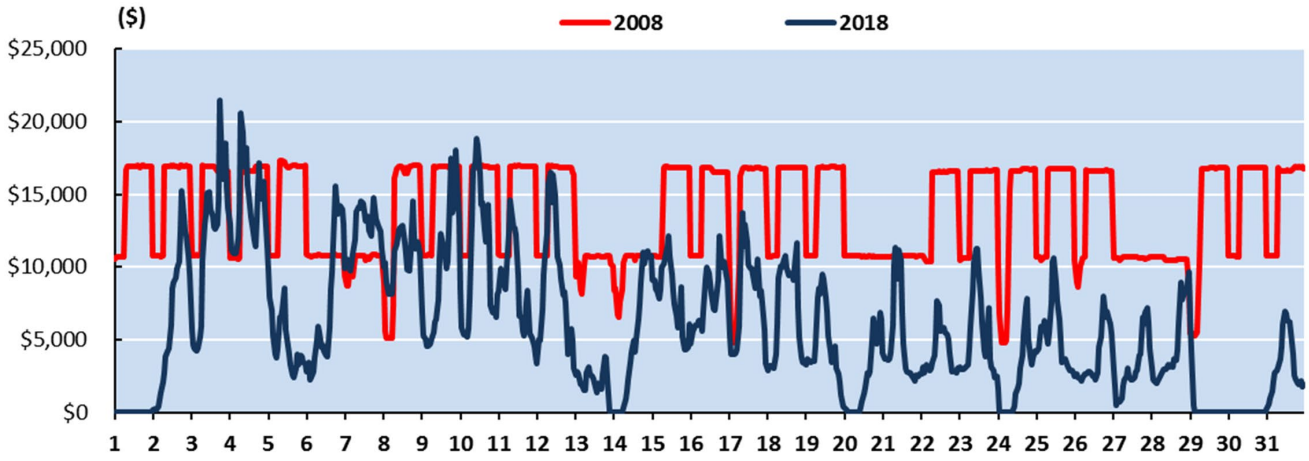
As a result, coal plants frequently find themselves in a vicious cycle. Due to the low revenue expectation during on-peak hours and to minimize losses during off-peak hours, coal plants more often shut down operations for longer periods and only return to service when more extended periods of profitability are expected. However, the longer coal-fired EGUs remain offline, the more expensive it becomes to return them to service. In fact, cold starts are often more than three times more expensive than hot starts, increasing the capital and maintenance costs associated with operating the unit. On the other hand, lower revenues due to lower wholesale power prices and lower plant utilization rates have reduced the working capital for many coal plant operators, therefore limiting the amount of available capital to spend on maintenance or to make significant improvements to reduce the overall cycling cost of the unit.

22 Source: ERCOT Hourly Generation Mix Data

Consequently, the combination of falling on-peak and off-peak power prices and increased cycling operations have significantly eroded the economic viability of many coal-fired power plants across the country, even though they can provide essential reliability and flexibility services.

Xcel's Harrington 1 coal-fired unit in Texas, the example from earlier, provides a useful case study of this issue. In December 2008, the EGU operated at a capacity factor of 94.7%, had zero shutdowns over the course of the month, and its average hourly ramp rate was 1.1%. In December 2018, these numbers were drastically different. Harrington 1's capacity factor dropped to 57.1%. It experienced five different startups (three hot starts and two warm starts), and its average hourly ramp rate increased to 4.9%. Additionally, on-peak and off-peak power prices for SPP-South, where Harrington is located, dropped 38% and 23% between December 2008 and 2018, respectively. **Exhibit 18** shows Harrington's estimated hourly energy revenue for the month of December in 2008 and 2018.

EXHIBIT 18: ESTIMATED ENERGY REVENUE FOR XCEL ENERGY'S HARRINGTON 1 COAL UNIT – DECEMBER 2008 & 2018[23]



As shown in **Exhibit 6,** Harrington 1 operated at full capacity almost all of December 2008 and generated over $10 million in energy revenue as a result. In December 2018, however, as power prices collapsed and Harrington 1 operated at much lower utilization rates, its energy revenue fell to $4.5 million. Including the additional costs of approximately $500,000 for the two warm starts and three hot starts, Harrington 1 generated more than $6 million less in net revenue in December 2018 compared to 2008. This does not include any additional O&M requirements to offset the greater stress on plant equipment due to the more frequent cycling operations.

As is recognized by market participants in both regulated and deregulated power markets, it is of utmost importance to retain a significant amount of electric generating capacity above peak electricity demand to account for unexpected losses in variable energy generation from wind and solar, unscheduled fossil plant outages, and under-forecasts of load. This amount of excess capacity is referred to as the reserve margin. Because wind resources tend to be at lower generation levels during peak demand hours as described previously, wind resources are rated at lower capacity

23 Source: S&P Global Platts Megawatt Daily Power Price Data

values than other resources. While some power markets such as PJM provide capacity payments to generating resources to provide capacity when needed, the two markets with the highest share of intermittent renewable generation, SPP and ERCOT, do not have capacity markets. Both markets are considered energy-only markets (although SPP does have a resource adequacy requirement tariff).

Both ERCOT and SPP acknowledged in their latest State of the Market Reports[24] that it is in the best interest for the market to develop compensation mechanisms or products to pay for capacity to cover uncertainties, such as the loss of the significant amount of generation during high demand times, as was the case in ERCOT this summer. The independent market monitor for ERCOT acknowledged that in 2018, coal units in ERCOT received just enough revenue from energy and ancillary services to cover operating costs.[25]

The other two major independent power markets with significant coal generation, PJM and MISO, are also in the process of developing new market mechanisms to better support and compensate the coal plants in their markets for the reliability and flexibility they provide. MISO, for example, is currently exploring the introduction of a so-called multi-day operating margin forecast. The forecast provides key power market metrics such as expected renewable generation, forecasted load, and scheduled plant outages for the next seven days to allow plant operators to make commitment decisions well ahead of the day-ahead market auction. PJM, on the other hand, tries to minimize the financial losses coal plants incur overnight. As mentioned previously, many coal plants cannot turn off completely overnight as they have to be available during peak demand hours in the morning. However, with the rise in renewable generation and drop in natural gas prices, off-peak power prices during the late night/early morning hours have dropped well below the operating costs of many of these coal plants, forcing them to incur huge losses these plants are struggling to recoup during the day. PJM is working on a pricing tool that allows certain baseload power plants to receive higher prices during off-peak hours to ensure they provide flexible and reliable generation during the day.

Regulated Utilities

Regulatory mechanisms minimize the financial exposure regulated utilities face compared to their merchant counterparts. However, they do experience their own unique struggles. Regulated utilities generally have two options to recover the costs for operating their generating fleet.

First, every few years, regulated utilities forecast their expenditures for maintaining affordable and reliable electricity supply, and request an electric rate adjustment through a "rate case" to recoup their expected capital expenditures and guarantee a set rate of return. However, there is generally no true-up to previous rate cases. If a utility greatly underestimated the costs to operate its generation fleet during its last rate case, the utility incurs these costs with no possibility to recoup those losses. Regulated utilities do use past projections versus performance measures to inform their next rate adjustment.

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24 Southwest Power Pool. "State of the Market 2018" (May 2019) https://www.spp.org/documents/59861/2018%20annual%20state%20of%20the%20market%20report.pdf

25 Potomac Economics. "State of the Market Report for ERCOT Electricity Markets" (June 2019) https://www.potomaceconomics.com/wp-content/uploads/2019/06/2018-State-of-the-Market-Report.pdf

The second option for utilities to recoup their investments in their generating fleet is through short-term adjustments. Based on the state, these adjustments vary in name and frequency. For example, in Alabama, regulated utilities can recover increased fuel or purchased power expenditures through the Energy Cost Recovery Rider. In other states, such as Wyoming, utilities are also allowed to recover some of their increased O&M costs through annual adjustment riders. However, in states where capital expenditures for increased O&M caused by operational changes at coal-fired power plants discussed throughout this report can only be recovered through projected going-forward costs as part of a rate case, some utilities have likely incurred some unexpected losses over the last decade.

As the example in Texas this summer has shown, sufficient backup flexible capacity is needed to ensure reliable electricity supply during peak demand times, coupled with a higher-than-expected loss of variable generation from wind or solar. Without any other market mechanisms incentivizing new capacity entry into the market, keeping existing fossil generation from retiring becomes paramount. Even in regulated states, continued operation of and investment in existing coal-fired power plants can oftentimes be the more economical choice than building a new natural gas plant. Besides the technology options discussed in this report to make existing coal plants more flexible and efficient, new technologies begin to emerge and provide viable alternatives to natural gas peaking resources in the near future. According to a recent report from Bloomberg New Energy Finance, lithium-ion battery prices have dropped faster than projected, from over $1,100/kWh in 2010 to $156/kWh in 2019.[26] As the industry focuses on bringing new energy storage and flexible generation to commercial operation, utilities focus on maintaining the existing fleet of fossil resources to bridge that timing gap.

Regulators in California are now pursuing a similar strategy. In order to achieve its aggressive GHG emission reduction goal, California required utilities to invest in new non-hydro renewable generation heavily, mainly solar and, to a lesser extent, wind, while also banning new natural gas generation from entering the market. As older fossil plants have retired over the last few years due to the loss of energy revenue and increased operating costs, California's reserve margin began to shrink, and the risk of a potential loss of load increased. Now, regulators in California required existing natural gas generation to continue operating and provide much-needed backup flexible generation while new non-GHG emitting energy storage resources such as battery storage enter the market.[27]

26 BNEF. "Battery Pack Prices Fall As Market Ramps Up With Market Average At $156/kWh In 2019" (December 2019) https://about.bnef.com/blog/battery-pack-prices-fall-as-market-ramps-up-with-market-average-at-156-kwh-in-2019/?sf113554299=1

27 http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M312/K522/312522263.PDF

Conclusion

In summary, it is worth highlighting the following points:

- Coal plant operations have changed dramatically over the last decade, forced by changing market dynamics due to low natural gas prices and increased generation from intermittent renewable energy resources such as wind and solar.

- While not originally designed to be load-following, many coal plants are capable of providing flexible generation at efficient and cost-effective levels to complement increased renewable generation. Additionally, technology improvements exist to increase the efficiency and flexibility of existing coal plants that are oftentimes more economical than building new generation capacity.

- However, the current market and regulatory mechanisms are not sufficient to offset some or all of the increased one-time and ongoing costs for coal-fired power plant operators to support this change in plant operations. Power markets and regulatory commissions provide different options to help mitigate the issue and are focusing on developing new mechanisms or making changes to existing ones.

- Recent examples in Texas and California have shown the necessity of maintaining existing generating resources to provide much-needed flexible and reliable generation while new energy storage technologies are being developed and deployed.

Appendix

EXHIBIT 19: GENERATION MIX BY STATE – 2008 VS. 2018

	2008							2018						
	Coal	Natural Gas & Oil	Nuclear	Hydro	Wind	Solar	Other	Coal	Natural Gas & Oil	Nuclear	Hydro	Wind	Solar	Other
US Total	**50%**	**21%**	**20%**	**6%**	**1%**	**0%**	**1%**	**28%**	**35%**	**20%**	**7%**	**7%**	**2%**	**1%**
Alaska	6%	76%	0%	18%	0%	0%	0%	9%	64%	0%	24%	2%	0%	0%
Alabama	53%	15%	28%	4%	0%	0%	0%	23%	41%	28%	8%	0%	0%	0%
Arkansas	49%	15%	27%	9%	0%	0%	0%	46%	29%	19%	5%	0%	0%	0%
Arizona	37%	33%	25%	6%	0%	0%	0%	27%	33%	28%	6%	1%	5%	0%
California	1%	56%	17%	13%	3%	0%	9%	0%	44%	10%	14%	8%	15%	9%
Colorado	65%	25%	0%	3%	6%	0%	0%	47%	30%	0%	3%	18%	2%	0%
Connecticut	15%	28%	51%	2%	0%	0%	5%	1%	50%	44%	1%	0%	0%	3%
District Of Columbia	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Delaware	76%	22%	0%	0%	0%	0%	2%	6%	92%	0%	0%	0%	1%	1%
Florida	30%	53%	15%	0%	0%	0%	2%	13%	72%	12%	0%	0%	1%	2%
Georgia	64%	10%	24%	1%	0%	0%	0%	26%	42%	28%	2%	0%	2%	1%
Hawaii	15%	79%	0%	0%	2%	0%	3%	14%	71%	0%	1%	6%	2%	7%
Iowa	76%	4%	10%	2%	8%	0%	0%	44%	12%	8%	2%	35%	0%	0%
Idaho	0%	15%	0%	82%	2%	0%	1%	0%	18%	0%	62%	15%	3%	1%
Illinois	48%	2%	48%	0%	1%	0%	0%	31%	8%	53%	0%	7%	0%	0%
Indiana	97%	3%	0%	0%	0%	0%	0%	72%	22%	0%	0%	5%	0%	0%
Kansas	73%	5%	18%	0%	4%	0%	0%	39%	7%	17%	0%	36%	0%	0%
Kentucky	94%	4%	0%	2%	0%	0%	0%	75%	18%	0%	6%	0%	0%	0%
Louisiana	36%	39%	23%	2%	0%	0%	0%	17%	58%	24%	1%	0%	0%	0%
Massachusetts	25%	55%	14%	1%	0%	0%	5%	0%	68%	16%	2%	1%	5%	7%
Maryland	58%	5%	31%	4%	0%	0%	1%	23%	31%	35%	7%	1%	1%	2%
Maine	1%	47%	0%	32%	1%	0%	18%	1%	22%	0%	35%	26%	0%	17%
Michigan	61%	9%	28%	0%	0%	0%	2%	38%	28%	27%	1%	5%	0%	2%
Minnesota	58%	6%	25%	1%	8%	0%	2%	37%	15%	24%	2%	18%	2%	2%
Missouri	81%	6%	10%	3%	0%	0%	0%	73%	8%	13%	2%	4%	0%	0%
Mississippi	36%	44%	20%	0%	0%	0%	0%	9%	80%	11%	0%	0%	1%	0%
Montana	62%	2%	0%	34%	2%	0%	0%	48%	3%	0%	39%	8%	0%	1%
North Carolina	61%	4%	32%	2%	0%	0%	0%	24%	34%	32%	4%	0%	5%	1%
North Dakota	91%	0%	0%	4%	5%	0%	0%	66%	2%	0%	6%	26%	0%	0%
Nebraska	66%	2%	29%	1%	1%	0%	0%	63%	3%	15%	4%	14%	0%	0%
New Hampshire	15%	31%	41%	7%	0%	0%	5%	4%	18%	58%	9%	2%	0%	9%
New Jersey	14%	33%	51%	0%	0%	0%	2%	2%	52%	43%	0%	0%	2%	2%
New Mexico	74%	21%	0%	1%	4%	0%	0%	41%	35%	0%	1%	19%	4%	0%
Nevada	22%	68%	0%	5%	0%	0%	4%	6%	67%	0%	5%	1%	12%	9%
New York	13%	34%	31%	19%	1%	0%	2%	1%	38%	33%	23%	3%	0%	2%
Ohio	86%	3%	11%	0%	0%	0%	0%	47%	35%	15%	0%	1%	0%	0%
Oklahoma	48%	44%	0%	5%	3%	0%	0%	17%	48%	0%	3%	32%	0%	0%
Oregon	7%	29%	0%	59%	4%	0%	1%	2%	27%	0%	57%	11%	1%	1%
Pennsylvania	53%	9%	36%	1%	0%	0%	1%	21%	36%	39%	1%	2%	0%	1%
Rhode Island	0%	98%	0%	0%	0%	0%	2%	0%	93%	0%	0%	2%	1%	3%
South Carolina	42%	6%	52%	0%	0%	0%	0%	20%	23%	54%	2%	0%	1%	1%
South Dakota	52%	4%	0%	42%	2%	0%	0%	21%	9%	0%	46%	24%	0%	0%
Tennessee	63%	1%	31%	6%	0%	0%	0%	26%	16%	46%	12%	0%	0%	0%
Texas	40%	44%	11%	0%	4%	0%	0%	26%	46%	10%	0%	18%	1%	0%
Utah	82%	16%	0%	1%	0%	0%	1%	66%	21%	0%	3%	2%	6%	2%
Virginia	44%	15%	40%	0%	0%	0%	1%	10%	54%	32%	0%	0%	1%	3%
Vermont	0%	0%	72%	22%	0%	0%	6%	0%	0%	0%	59%	17%	6%	18%
Washington	8%	9%	8%	71%	3%	0%	1%	5%	9%	8%	71%	6%	0%	0%
Wisconsin	66%	9%	20%	2%	1%	0%	1%	50%	26%	15%	4%	3%	0%	1%
West Virginia	98%	0%	0%	1%	0%	0%	0%	94%	2%	0%	2%	3%	0%	0%
Wyoming	96%	0%	0%	2%	2%	0%	0%	87%	1%	0%	2%	9%	0%	0%

EXHIBIT 20: AVERAGE UTILIZATION DISTRIBUTION BY STATE – 2008 VS. 2018

	2008						2018					
	Offline	< 40%	40 - 60%	60 - 80%	> 80%	Avg. Turndown	Offline	< 40%	40 - 60%	60 - 80%	> 80%	Avg. Turndown
US Total	**17%**	**3%**	**9%**	**15%**	**55%**	**52%**	**32%**	**6%**	**12%**	**14%**	**37%**	**43%**
Alabama	13%	3%	11%	16%	58%	50%	34%	9%	17%	11%	29%	43%
Arkansas	15%	2%	5%	9%	70%	53%	20%	4%	9%	12%	55%	43%
Arizona	7%	1%	2%	9%	81%	70%	15%	8%	13%	29%	36%	44%
Colorado	11%	1%	5%	12%	71%	63%	20%	0%	12%	27%	41%	57%
Connecticut	7%	6%	3%	3%	81%	36%	85%	4%	1%	2%	8%	12%
Delaware	18%	13%	15%	19%	34%	35%	85%	2%	7%	2%	4%	10%
Florida	19%	3%	12%	15%	52%	52%	33%	11%	14%	14%	28%	35%
Georgia	11%	5%	23%	16%	44%	46%	54%	8%	13%	9%	15%	34%
Iowa	21%	3%	12%	24%	40%	50%	30%	7%	12%	10%	42%	35%
Illinois	14%	3%	10%	15%	57%	53%	28%	5%	13%	16%	39%	46%
Indiana	18%	3%	8%	13%	59%	52%	30%	4%	12%	13%	41%	46%
Kansas	12%	1%	6%	19%	62%	61%	29%	9%	11%	14%	38%	41%
Kentucky	13%	3%	8%	16%	60%	52%	24%	4%	12%	17%	43%	43%
Louisiana	13%	2%	3%	8%	75%	57%	28%	6%	13%	19%	33%	43%
Maryland	22%	8%	13%	18%	39%	40%	71%	8%	6%	5%	11%	19%
Michigan	16%	3%	11%	22%	48%	51%	35%	3%	15%	20%	26%	43%
Minnesota	21%	3%	9%	20%	47%	52%	20%	2%	21%	16%	42%	49%
Missouri	14%	2%	5%	14%	66%	58%	21%	2%	10%	13%	54%	51%
Mississippi	15%	2%	5%	7%	71%	53%	49%	29%	17%	4%	1%	35%
Montana	12%	2%	4%	11%	72%	55%	30%	4%	4%	19%	42%	46%
North Carolina	31%	7%	13%	11%	38%	39%	54%	12%	9%	7%	19%	33%
North Dakota	10%	0%	1%	8%	80%	75%	11%	0%	7%	13%	67%	69%
Nebraska	9%	1%	11%	33%	47%	56%	16%	5%	20%	14%	44%	42%
New Hampshire	14%	2%	2%	6%	77%	73%	68%	1%	2%	5%	23%	47%
New Jersey	48%	6%	9%	15%	22%	40%	98%	0%	1%	0%	1%	7%
New Mexico	15%	1%	2%	4%	78%	71%	26%	4%	9%	17%	45%	56%
Nevada	19%	2%	3%	7%	69%	57%	36%	19%	10%	13%	22%	38%
New York	10%	1%	5%	14%	70%	59%	88%	3%	2%	2%	6%	24%
Ohio	24%	5%	11%	17%	44%	42%	42%	5%	11%	9%	33%	30%
Oklahoma	12%	2%	4%	10%	72%	57%	43%	6%	11%	9%	30%	39%
Oregon	18%	1%	1%	1%	80%	87%	63%	3%	2%	3%	28%	26%
Pennsylvania	19%	6%	11%	18%	46%	47%	47%	3%	13%	7%	30%	42%
South Carolina	22%	3%	8%	20%	47%	52%	45%	5%	10%	19%	22%	44%
South Dakota	4%	0%	4%	12%	79%	60%	23%	2%	22%	17%	36%	42%
Tennessee	8%	1%	6%	18%	67%	55%	48%	1%	14%	11%	26%	45%
Texas	10%	1%	2%	7%	79%	68%	17%	10%	12%	10%	51%	41%
Utah	6%	1%	2%	7%	85%	75%	8%	16%	12%	16%	48%	37%
Virginia	32%	7%	8%	15%	38%	40%	64%	4%	8%	6%	17%	38%
Washington	23%	1%	2%	2%	72%	71%	43%	3%	7%	11%	37%	40%
Wisconsin	23%	5%	13%	22%	37%	40%	21%	6%	13%	20%	41%	43%
West Virginia	28%	4%	7%	13%	48%	45%	29%	3%	12%	12%	44%	53%
Wyoming	7%	1%	3%	6%	83%	70%	9%	4%	11%	13%	63%	55%

EXHIBIT 21: AVERAGE NUMBER OF STARTS & AVG. OUTAGE LENGTH BY STATE – 2008 VS. 2018

	2008					2018				
	Hot Start (< 12h)	Warm Start (12 - 48h)	Cold Start (48 - 120h)	LT Outage (> 120h)	Avg. Outage Length	Hot Start (< 12h)	Warm Start (12 - 48h)	Cold Start (48 - 120h)	LT Outage (> 120h)	Avg. Outage Length
US Total	**3.7**	**3.1**	**3.4**	**2.5**	**148.3**	**2.0**	**1.7**	**2.8**	**4.1**	**341.9**
Alabama	3.2	2.5	1.5	2.0	147.6	2.7	0.8	1.5	3.5	407.5
Arkansas	2.8	0.8	2.2	2.0	186.8	1.1	1.4	0.4	2.1	542.0
Arizona	4.0	1.5	2.5	0.8	76.8	2.4	1.0	3.1	2.5	170.2
Colorado	2.3	1.6	2.3	1.5	140.7	2.1	0.7	1.0	2.3	372.7
Connecticut	5.0	5.0	3.0	1.0	47.2	3.0	-	2.0	9.0	532.8
Delaware	2.3	3.7	5.0	3.3	114.0	2.0	3.0	7.0	10.0	339.5
Florida	3.9	2.9	2.0	2.5	180.3	2.7	1.6	2.2	3.8	303.7
Georgia	1.9	2.5	1.1	1.6	160.2	1.7	1.4	1.6	2.9	870.1
Iowa	3.8	1.9	3.6	2.3	183.7	2.2	3.5	3.6	3.0	402.1
Illinois	2.7	3.6	3.4	2.1	122.6	2.3	2.9	5.0	4.8	176.4
Indiana	2.9	3.6	3.7	2.6	131.7	1.6	2.0	3.2	4.4	262.3
Kansas	2.8	3.7	2.3	1.1	129.0	1.1	1.7	5.1	3.6	242.6
Kentucky	3.0	4.2	2.7	1.5	120.1	1.7	1.6	2.4	3.6	258.8
Louisiana	2.8	3.3	1.8	1.8	114.1	1.3	2.1	2.6	4.3	268.6
Maryland	7.1	4.4	4.7	3.3	131.8	0.9	0.2	2.6	10.6	536.6
Michigan	2.5	2.8	5.0	2.2	156.9	1.5	0.8	1.3	4.1	597.0
Minnesota	2.5	3.7	3.7	2.5	167.0	2.6	3.9	4.4	4.3	126.8
Missouri	2.9	2.8	2.3	1.7	138.8	1.9	1.9	3.3	3.3	199.8
Mississippi	2.8	1.2	1.0	2.0	296.9	4.0	1.7	1.0	4.7	758.6
Montana	5.0	3.3	1.7	2.4	84.1	3.0	1.7	4.0	2.7	267.3
North Carolina	4.8	5.0	6.0	5.0	145.7	1.1	0.8	3.2	7.1	473.3
North Dakota	2.0	3.2	2.6	1.0	126.7	1.1	2.6	3.2	2.0	131.0
Nebraska	2.5	1.2	1.6	1.7	145.4	1.7	1.6	1.9	3.1	207.1
New Hampshire	1.0	1.2	2.8	2.0	174.3	12.0	5.8	6.0	11.0	221.5
New Jersey	1.9	5.1	6.4	6.0	301.5	3.0	-	-	4.0	1,229.3
New Mexico	6.6	2.5	4.2	1.5	88.4	2.4	3.4	2.8	2.6	280.7
Nevada	6.0	3.0	5.5	2.3	106.2	5.0	1.3	-	2.0	391.4
New York	2.2	1.4	2.5	1.8	127.4	1.5	0.5	3.0	7.5	622.7
Ohio	7.0	3.2	5.2	3.5	234.0	1.3	2.3	4.9	5.9	287.8
Oklahoma	5.0	2.2	2.2	1.8	105.9	3.5	2.7	5.3	8.7	217.6
Oregon	4.0	3.0	3.0	1.0	143.6	1.0	1.0	2.0	4.0	694.4
Pennsylvania	2.0	2.8	3.7	3.6	134.0	1.6	1.1	2.7	6.8	502.4
South Carolina	2.3	3.8	2.7	2.8	176.0	1.0	1.5	3.2	6.2	495.9
South Dakota	-	4.0	1.0	1.0	66.3	1.0	3.0	2.0	2.0	253.5
Tennessee	0.5	0.8	2.2	1.6	131.5	0.4	0.4	0.8	3.7	978.7
Texas	2.2	2.2	1.9	1.3	139.2	2.4	1.7	1.6	2.3	214.9
Utah	3.6	4.4	3.1	0.2	52.3	3.1	1.8	1.5	1.4	111.7
Virginia	13.0	4.0	5.6	5.5	130.1	0.5	0.8	3.7	7.7	462.9
Washington	2.0	3.5	3.0	2.5	191.0	2.0	3.0	3.5	1.0	404.4
Wisconsin	9.8	3.0	3.3	3.3	171.3	1.1	1.6	2.1	3.3	226.3
West Virginia	1.9	4.0	5.2	4.3	165.6	1.0	2.1	4.1	4.3	253.5
Wyoming	4.7	4.0	2.4	0.6	65.9	4.0	2.7	2.2	1.1	88.7

EXHIBIT 22: AVERAGE DISTRIBUTION OF HOURLY RAMP RATES BY STATE – 2008 VS. 2018

	2008			2018		
	No Ramping	< 2.5%	> 2.5%	No Ramping	< 2.5%	> 2.5%
US Total	**33%**	**39%**	**28%**	**32%**	**38%**	**30%**
Alabama	37%	37%	26%	49%	27%	24%
Arkansas	24%	43%	33%	20%	42%	38%
Arizona	44%	37%	19%	37%	27%	35%
Colorado	48%	39%	14%	32%	39%	30%
Connecticut	68%	14%	18%	19%	32%	49%
Delaware	47%	24%	28%	33%	24%	43%
Florida	31%	39%	29%	41%	29%	29%
Georgia	30%	35%	35%	39%	32%	29%
Iowa	35%	34%	31%	29%	38%	33%
Illinois	25%	43%	31%	30%	41%	29%
Indiana	30%	43%	27%	32%	36%	32%
Kansas	39%	40%	21%	16%	46%	38%
Kentucky	32%	40%	28%	32%	38%	29%
Louisiana	22%	57%	21%	19%	49%	32%
Maryland	18%	35%	48%	28%	31%	41%
Michigan	45%	32%	23%	44%	31%	24%
Minnesota	40%	36%	24%	27%	38%	35%
Missouri	38%	40%	22%	24%	46%	30%
Mississippi	30%	44%	26%	46%	27%	27%
Montana	48%	43%	9%	43%	36%	21%
North Carolina	39%	27%	34%	29%	32%	39%
North Dakota	35%	53%	12%	36%	50%	14%
Nebraska	40%	37%	23%	27%	40%	33%
New Hampshire	64%	28%	8%	46%	22%	32%
New Jersey	33%	35%	31%	20%	32%	48%
New Mexico	40%	45%	14%	28%	47%	25%
Nevada	38%	47%	15%	48%	27%	25%
New York	38%	39%	23%	24%	35%	41%
Ohio	24%	38%	38%	37%	40%	22%
Oklahoma	30%	56%	13%	24%	34%	42%
Oregon	32%	65%	3%	30%	46%	24%
Pennsylvania	26%	38%	37%	32%	40%	28%
South Carolina	33%	38%	29%	22%	44%	34%
South Dakota	22%	52%	26%	11%	39%	50%
Tennessee	40%	39%	21%	43%	35%	22%
Texas	27%	52%	20%	21%	45%	34%
Utah	35%	52%	13%	23%	38%	38%
Virginia	24%	31%	45%	34%	37%	29%
Washington	22%	70%	7%	19%	59%	21%
Wisconsin	34%	30%	36%	31%	36%	33%
West Virginia	25%	37%	38%	27%	43%	30%
Wyoming	31%	59%	9%	35%	39%	25%


NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS
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EXHIBIT 51-7

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION



2024 State of Reliability

June 2024

[2024 SOR Infographic]

[2024 SOR Overview]

[2024 SOR Video]

Technical Assessment of 2023 Bulk Power System Performance

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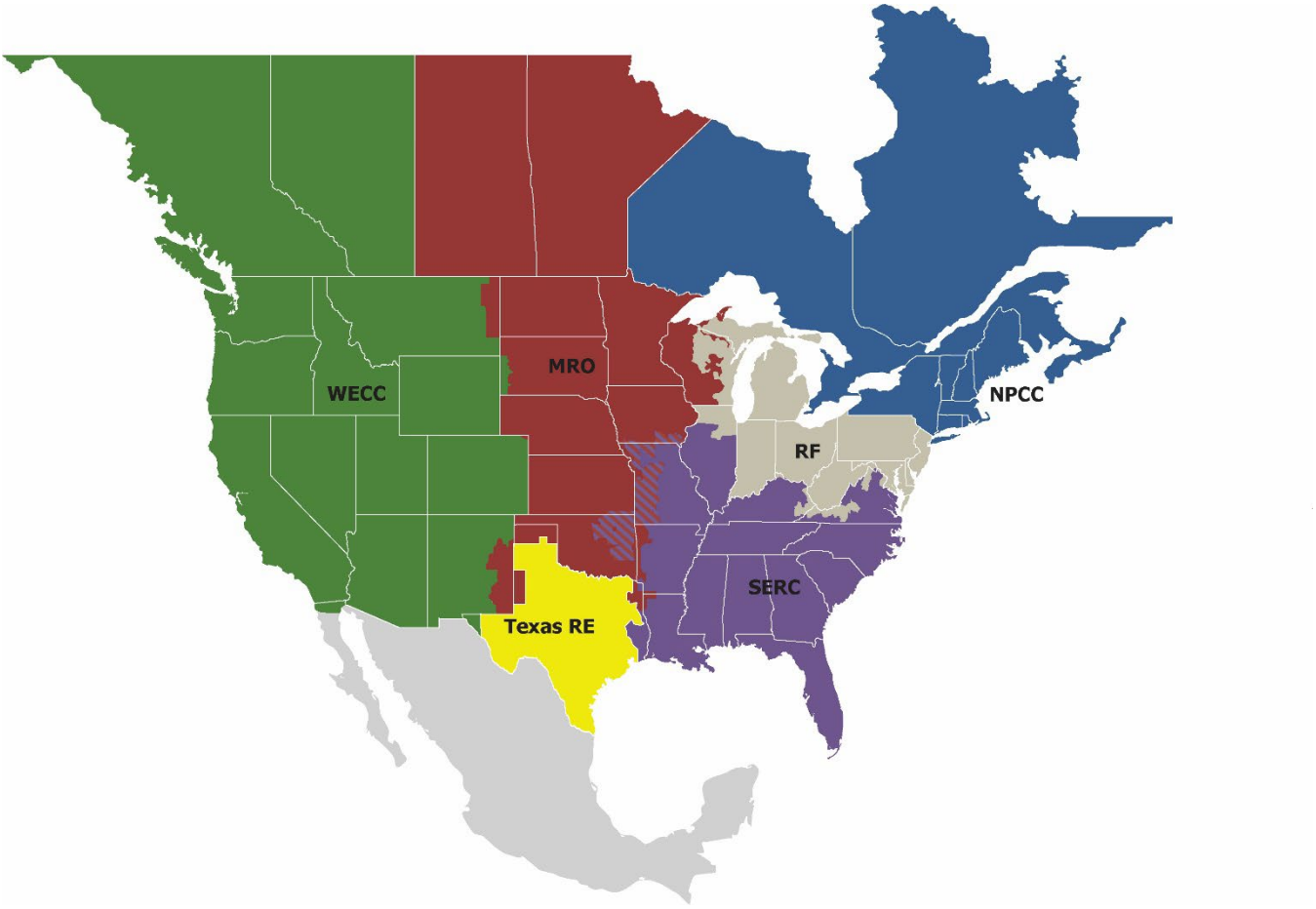
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Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Transmission Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About This Technical Assessment

Introduction

The *State of Reliability* (*SOR*) report seeks to inform regulators, policymakers, and industry leaders on the most significant reliability risks facing the BPS and describe the actions that the ERO Enterprise has taken and will take to address them. This year's *SOR* report is comprised of two publications: this *2024 SOR Technical Assessment*, which provides NERC's comprehensive annual technical review of BPS reliability for the 2023 operating (calendar) year, and the *2024 SOR Overview*,[1] which is a high-level summary of the Technical Assessment, summarized by important findings.

- The *2024 SOR Overview* replaces the key findings previously found in the Technical Assessment.
- This *2024 SOR Technical Assessment* provides key occurrences and highlights major reports released in 2023, along with in-depth analysis of risks and resilience, grid transformation and performance, and related performance metrics.

Purpose of the *SOR*

Both the Overview and the Technical Assessment provide objective and concise information for policymakers, industry leaders, and regulators on issues that affect the reliability and resilience of the North American BPS. Specifically, the *SOR* report does the following:

- Analyzes performance trends and emerging reliability risks based on past performance
- Reports on the relative health of the interconnected system
- Measures the success of mitigation activities deployed

NERC, as the ERO, works to assure the effective and efficient reduction of reliability and security risks to the North American BPS. Annual and seasonal risk assessments look to the future, and special reports on emergent risks serve to identify and mitigate potential risks. This assessment document identifies performance trends and provides strong technical support for those interested in the underlying data and detailed analytics.

NERC defines the reliability[2] of the interconnected BPS in terms of the following two basic and functional aspects:

- Adequacy
- Operating Reliability

The *2024 SOR* report focuses on BPS[3] performance during the prior calendar year as measured by an established set of performance metrics, other reliability indicators, and more detailed analysis performed by ERO staff and technical committee participants. Data used in the analysis comes from the Transmission Availability Data System (TADS), the Generating Availability Data System (GADS), the Misoperation Information Data Analysis System (MIDAS), voluntary reporting into the Event Analysis Management System (TEAMS), Bulk Power System Awareness monitoring and processes, and the Institute of Electrical and Electronics Engineers (IEEE) Distribution Reliability Working Group. ERO staff developed this independent assessment with support from the Performance Analysis Subcommittee (PAS).

[1] https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2024_Overview.pdf

[2] **Learn About NERC** provides background information about NERC, the definition of reliability, and the electric grid.

[3] The term BPS is defined in Section 215 of the Federal Power Act as facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. 16 U.S.C. § 824o(a)(1). Bulk Electric System (BES) is a subset of the BPS and is a defined term under the NERC Glossary as approved by the Federal Energy Regulatory Commission (FERC). As the Electric Reliability Organization, NERC is responsible for developing and enforcing Reliability Standards to ensure an adequate level of reliability of the BPS and assessing reliability of the BPS. NERC's regulatory model is designed to ensure that entities capable of affecting the reliability of the BPS are registered and subject to Reliability Standards. North Am. Elec. Reliability Corp., 187 FERC ¶ 61,196, P 53 (2024).

NERC also produces the following regular assessments to evaluate BPS security as well as present and future BPS reliability:

- *Long-Term Reliability Assessment* (*LTRA*)
- Summer and Winter Assessments
- Electricity Information Sharing and Analysis Center (E-ISAC) *End-of-Year Report*[4]

Considerations

- Data in the *SOR* report represents the performance for the January–December 2023 operating year unless otherwise noted.
- Analysis in this report is based on data from 2019–2023 that was available in Spring 2024, and it provides a basis to evaluate 2023 performance relative to performance over the last five years. All dates and times shown are in Coordinated Universal Time (UTC).
- To properly demonstrate key trending information, this year's report evaluates generation data dating back to 2014.
- The *SOR* report is a review of industry-wide trends and not the performance of individual entities.
- When analysis is presented by Interconnection, the Québec Interconnection is combined with the Eastern Interconnection unless specific analysis for the Québec Interconnection is shown.

[4] 2023 E-ISAC *End-of-Year Report*

Chapter 1: Major Occurrences and Report Releases for 2023

This chapter highlights major occurrences and reports that were issued in 2023. These occurrences and reports did not constitute a key finding but had a notable impact on the BPS.

Figure 1.1 highlights important numbers and facts about the North American BPS. Table 1.1 shows the five-year trend of these numbers.

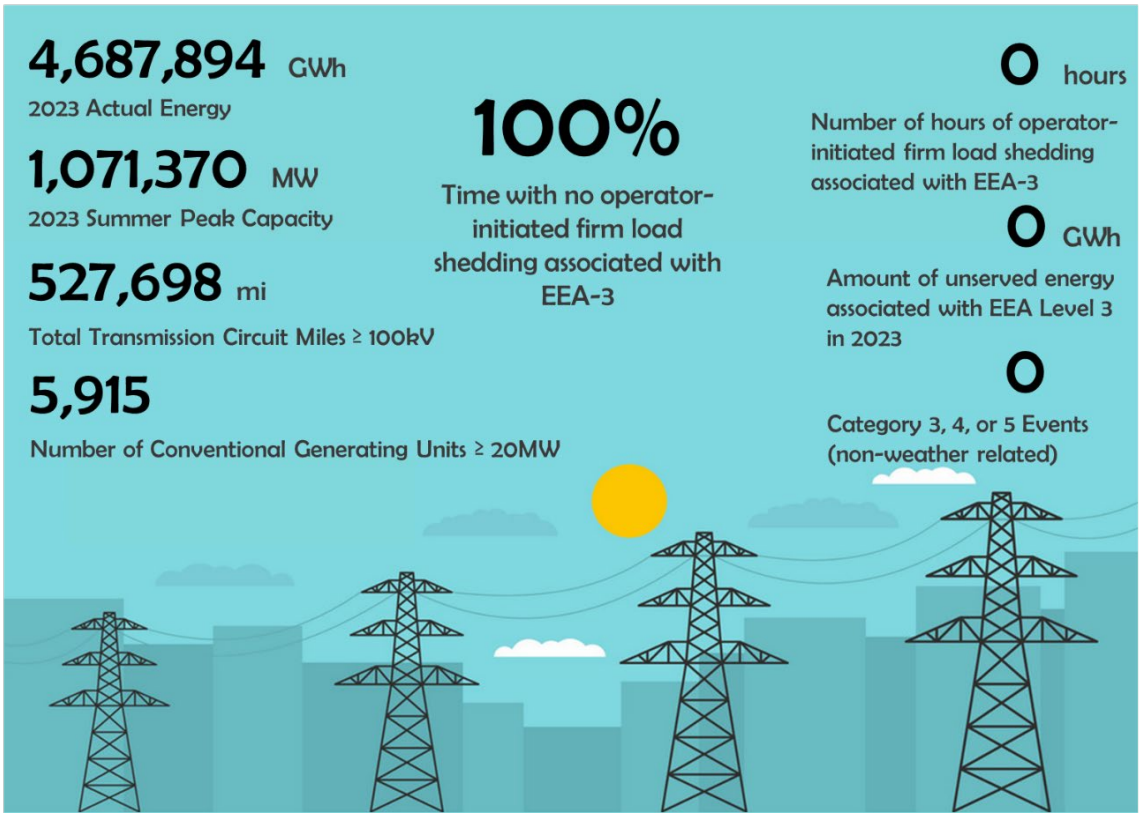


Figure 1.1: 2023 BPS Inventory and Performance Statistics

Table 1.1: Five-Year BPS Inventory and Performance Statistics

Rank	2019	2020	2021	2022	2023
Actual Energy (GWh)	4,639,653	4,588,062	4,585,939	4,674,290	4,687,894
Summer Peak Capacity (MW)	N/A	1,048,944	1,056,980	1,057,455	1,071,370
Total Transmission Circuit Miles > 100 kV miles	492,463	503,551	511,099	522,665	527,698
Number of Conventional Generating Units > 20 MW	6,064	6,009	5,966	5,910	5,915
Portion of hours in the year with no operator-initiated firm load shedding associated with EEA Level 3	99.9%	99.7%	99.2%	99.4%	100%
Category 3, 4, 5 Events (non-weather related)	0	0	0	1	0
Amount of unserved energy associated with EEA Level 3 (GWh)	5.85	828.1	1,015.5	96.2	0
Number of hours with operator-initiated load shed	>1	22	71	56.5	0

Québec Wildfires

In Québec, the 2023 wildfire season began in May when La Société de Protection des Forêts Contre le Feu (SOPFEU),[5] a nonprofit responsible for forest fire prevention in Québec, provided the provincial power grid operator, Hydro-Québec, with its first notification of a critical situation from the threat from increased wildfire activity. This wildfire season escalated to become the worst such season in Québec's history, quickly breaking records set during the 1923 wildfire season.[6] According to SOPFEU, 4,318,538.6 hectares (ha), the equivalent of 16,673.97 square miles, were burned by active fires across the province (see Figure 1.2).[7] The size of the impacted area is approximately equal to the cumulative area in the province that burned over the previous 20 years combined (equal to the area of Massachusetts and New Hampshire). The smoke from the Québec wildfires reached New York City during Summer 2023, briefly causing hazy skies and hazardous air quality.

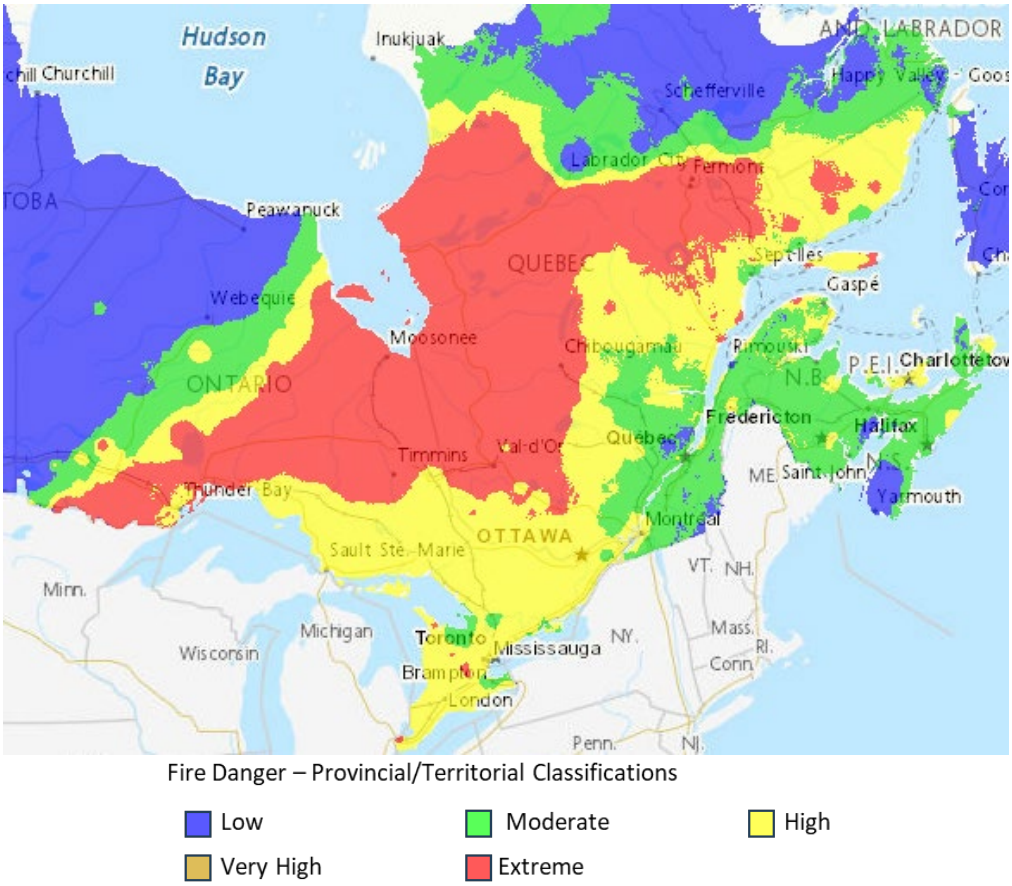


Figure 1.2: Map from Natural Resources Canada, June 20, 2023[8]

Hydro-Québec is a public corporation utility owned by the government of Québec that manages the generation, transmission, and distribution of electricity across the province. Hydro-Québec coordinates power exchanges through interconnections with three Canadian provinces (Newfoundland and Labrador, New Brunswick, and Ontario) and portions of the United States, including New York and the New England states. As a direct result of the dense smoke caused by increased wildfire activity throughout the province, Hydro-Québec experienced multiple transmission power line outages from the operation of protection systems. To address the situation, specific operating strategies were used to manage these challenging system conditions. During a period of increased intensity and proximity to wildfires in the northern portion of the province, Hydro-Québec staff and personnel had to be evacuated from critical generating and transmission facilities. The two most significant events during this period were the load-shedding

[5] SOPFEU | Organization
[6] *The 2023 wildfire season in Québec: an overview of extreme conditions, impacts, lessons learned and considerations for the future* (biorxiv.org)
[7] SOPFEU | 2023 Season Review | A record-breaking season for SOPFEU
[8] Natural Resources Canada, June 20, 2023

actions by the remedial action scheme (RAS) that operated to ensure system stability, shedding approximately 600 and 1,200 MW, respectively.[9] However, the outages were short-lived, with an average customer outage duration of less than an hour. The wildfires also impacted high-voltage direct current (HVdc) facilities and equipment exporting power from the province to the New England power grid operator, Independent System Operator New England, Inc. (ISO-NE); this subsequently caused a temporary capacity deficiency event for the ISO-NE footprint.[10]

Through enhanced coordination and real-time communication among neighboring Reliability Coordinators (RC), including New York Independent System Operator (NYISO), ISO-NE, Independent Electricity System Operator (IESO), and New Brunswick Power System Operator (NBP-SO) along with the NPCC situation awareness team, the grid across northeastern North America remained stable throughout the 2023 Québec wildfires. This collaborative effort maintained the reliability of the Québec Interconnection and the entire region.

This year's severity risk index (SRI), extreme days for transmission, and transmission outage severity (TOS) analyses all indicated that these wildfires had a disproportionately high impact on the BPS. The fires rose in prominence due to somewhat frequent and brief outages on very high-voltage transmission lines. These analyses highlighted a deficiency with the current definition of a formula that sums up transmission capacity affected by the outages started on a given day without consideration for their durations or whether repeat outages occur on the same equipment. This leads to a systematic overestimation of the contribution of much shorter outages while conversely underestimating the contribution of longer outages. The PAS is evaluating the calculations to incorporate and adequately account for outage duration.

Utah Solar Photovoltaic (PV) Performance Improvement

On April 10, 2023, at 08:51 Pacific, a single-line-to-ground fault occurred on a 345 kV transmission circuit in the southern Nevada/southwest Utah area (see Figure 1.3)**.** The fault was normally cleared in 58 ms. While no conventional generation tripped because of the transmission line outage, supervisory control and data acquisition (SCADA) data for the area showed that aggregate solar PV output dropped significantly. The abnormal active power reduction for each facility was due to inverters tripping for a variety of causes, including loss of synchronization, ac overvoltage, and ac overcurrent.

Fifteen solar sites were connected to the system with the majority on 138 kV transmission lines. The total solar loss was approximately 929 MW, ranging anywhere from 3 MW to 234 MW per site. Most of the generation was automatically restored within 1–11 minutes and the remainder was manually restored within 120 minutes. A joint NERC, WECC, and BA investigative team recommended that the plant owners work with their inverter manufacturers to apply known improvements to ride-through settings.

[9] Remedial action schemes are designed to detect abnormal or predetermined system conditions and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. These schemes are independent of firm load shed reported through an energy emergency alert.

[10] *2023 Summer Quarterly Markets Report* (iso-ne.com)

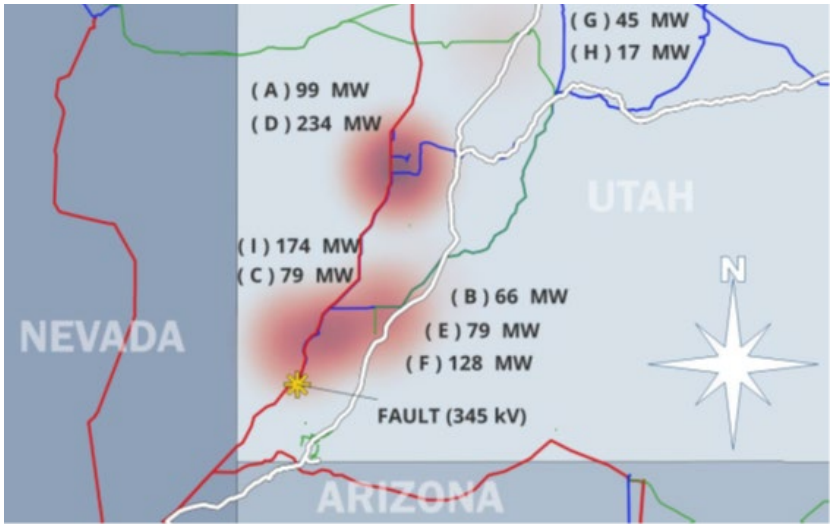


Figure 1.3: Map of Fault Location and Affected Solar PV Facilities, April 10, 2023, Event

On September 29, 2023, at 14:32:40 Pacific, a trip with no reclosing occurred on another 345 kV transmission circuit in southern Utah due to a line-to-line fault that lasted approximately 66 ms and was cleared as intended. At the same time, roughly 537 MW of solar generation (about 90% of which was from the same facilities involved in the April 10, 2023, event) experienced a sudden cessation of generation output while remaining connected to the grid. All but 5.3 MW of generation were restored within seven minutes.

After the April 10, 2023, event, the Generator Owners (GOs) of some of the larger facilities worked with their inverter manufacturers to set the inverters to not trip on the same behaviors seen during that event. These changes allowed their IBR generation to reduce active power injection but not trip, resulting in significantly improved recovery times of two to three minutes. GOs also provided updated models to the Transmission Planner for all but two of the sites.

Although these IBR facilities exhibited improved performance, recovery time still has room to improve. The investigative team is working with the inverter manufacturers and the GOs to identify the settings that need to be altered to optimize performance.

Winter Storm Elliott Report

In November 2023, FERC and the ERO Enterprise released a 167-page report on Winter Storm Elliott,[11] the late December 2022 storm that contributed to power outages for millions of electricity customers in the eastern half of the United States. During this extreme cold weather event, over 90,000 MW of coincident unplanned generation outages occurred that rendered 18% of the U.S. portion of anticipated resources in the Eastern Interconnection unavailable along with generation already on outage at that time.[12] As temperatures rapidly decreased across the event area and electricity demand correspondingly increased, balancing area operators in SERC-East and SERC-Central were faced with energy deficiencies that required 5,400 MW of firm load shed to maintain system balance, the largest controlled firm load shed recorded in the history of the Eastern Interconnection (see Figure 1.4).[13]

[11] *Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022*
[12] FERC/NERC/RE WS Elliott Report at 18.
[13] FERC/NERC/RE WS Elliott Report at 6.

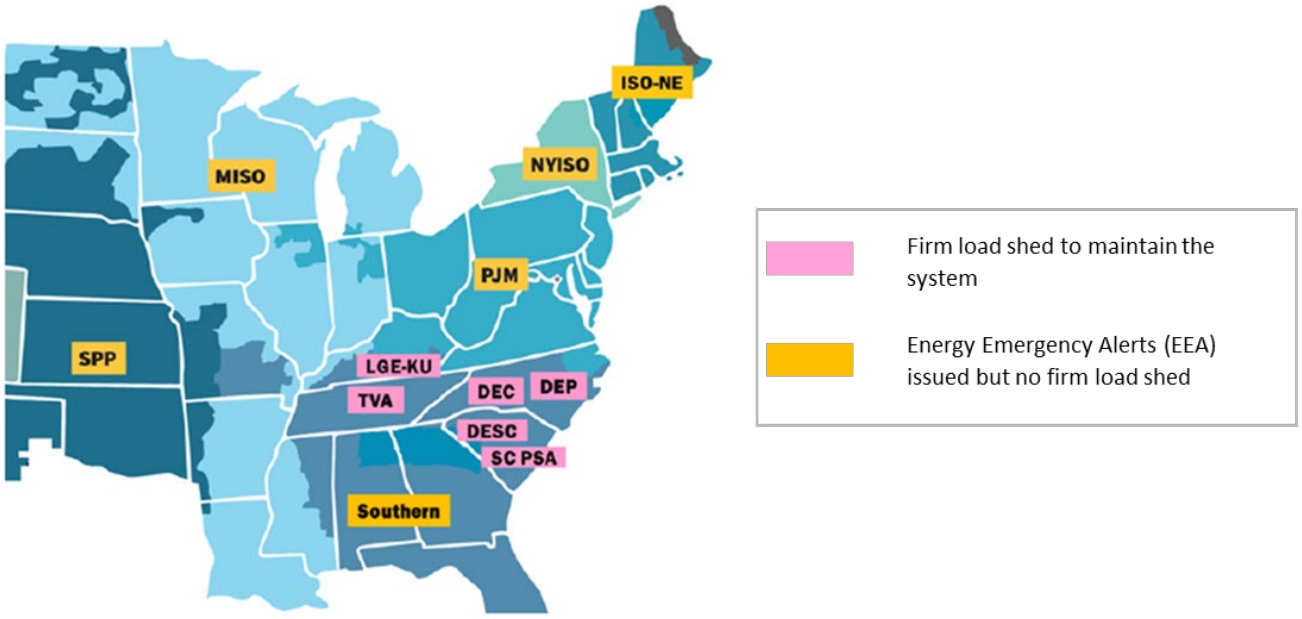


Figure 1.4: Bulk Electric System Map of Entities in the U.S. Eastern Interconnection Affected by Winter Storm Elliott

During the 2022 event, domestic U.S. natural gas production experienced its greatest decline since 2021's Winter Storm Uri. In the Marcellus and Utica shale regions, production dropped by 23–54%. Wellhead freeze-offs, the freezing of other natural gas supply chain equipment, and weather-related poor road conditions that prevented necessary maintenance were reported as the top causes.[14] The combination of reduced natural gas production and record consumption[15] forced some pipelines in the event area to declare force majeure and curtail deliveries even to firm gas transportation customers. While natural gas availability and delivery issues accounted for 20% of unplanned generating unit MW outages, mechanical/electrical issues comprised 41% and freezing issues comprised 31%[16] (see Figure 1.5).[17]

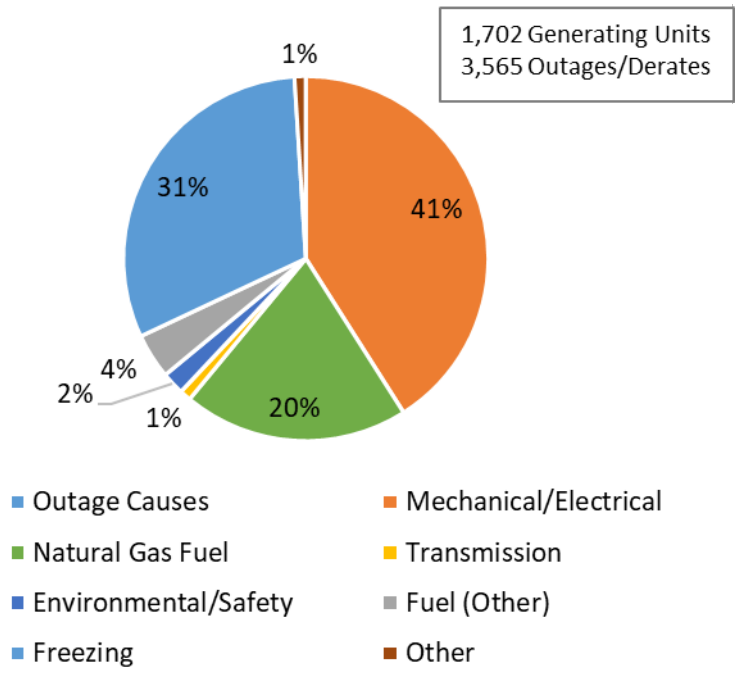


Figure 1.5: Incremental Unplanned Generating Unit MW Outages, Derates, and Failures to Start; Winter Storm Elliott Event Area by Cause

[14] FERC/NERC/RE WS Elliott Report at 19.
[15] FERC/NERC/RE WS Elliott Report at 112.
[16] "Natural Gas Fuel Issues include the combined effects of decreased natural gas production; cold weather impacts and mechanical problems at production, gathering, processing and pipeline facilities resulting in gas quality issues and low pipeline pressure; supply and transportation interruptions; curtailments and failure to comply with contractual obligations. Additionally, it includes shippers' inability to procure natural gas due to tight supply, prohibitive, scarcity-induced market prices, or mismatches between the timing of the natural gas and energy markets." (Footnote 58 of FERC/NERC/RE WS Elliott Report)
17 FERC/NERC/RE WS Elliott Report Fig 7.

CAISO Battery Energy Storage System (BESS) Disturbance Report[18]

On March 9 (Figure 1.6) and April 6, 2022 (Figure 1.7), the Southern California area experienced normally cleared transmission faults of less than 5 cycles, resulting in solar PV and BESS generation losses. The March 9 fault was due to a circuit breaker failure on a 694 MW natural gas unit; it cleared in 4.5 cycles and led to 1,102 MW of generation loss: a 694 MW natural gas unit, initiating the loss of 124 MW BESS and 284 MW of other IBRs. The second fault cleared in about 4 cycles on April 6 and led to about 500 MW of generation loss and all IBRs.

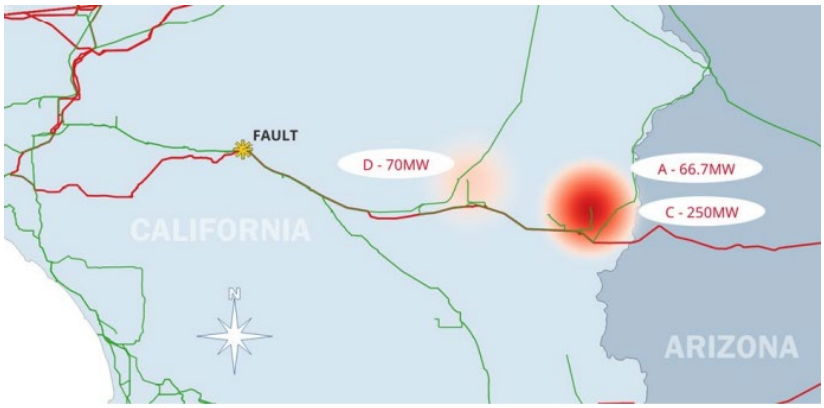


Figure 1.6: Map of the Fault Location and Affected IBR Facilities, March 9, 2022

The March 9 event is unique in that it occurred after sunset with no solar resources on-line. It was noted that, in this event, "most of the affected BESS facilities were located in the vicinity of solar PV facilities." Of the 1,102 MW of generation lost in this event, 124 MW was attributed to BESS and the remainder to synchronous generation.

A single phase-to-ground fault on a 220 kV bus caused the April 6 event at 15:06 Pacific. In this event, 498 MW of IBRs were lost. Because of poor or no metering at the BESS facilities, the report was not able to indicate the exact MW impact of the BESS lost. None of the facilities involved in these two events met CAISO's 10 ms data resolution requirement, making it difficult or impossible to verify the behavior of the plants during the disturbance.

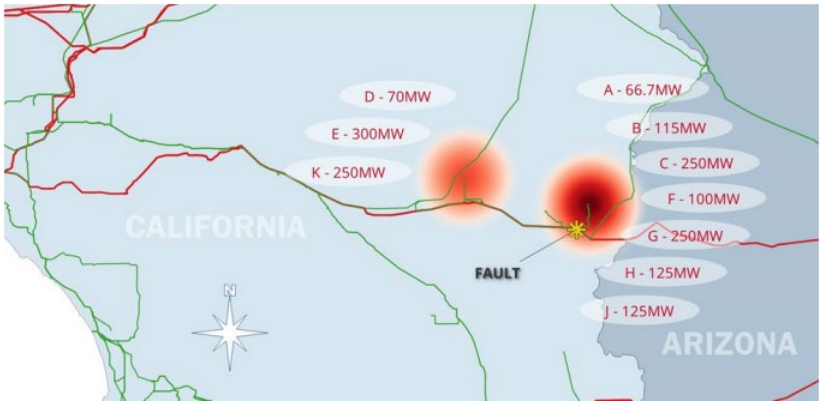


Figure 1.7: Map of the Fault Location and Affected IBR Facilities, April 6, 2022

The causes and problems that have been traditionally seen in IBR events within the Western Interconnection were seen in these events as well. Key observations and recommendations from the report are as follows:

- BESS may have the same system performance problems as solar PV resources.
- BESS ride-through performance is not adequately assessed during the interconnection process.
- Poor commissioning practices are a significant contributor to the unreliable performance of IBRs.
- NERC will be conducting a model quality assessment of this event and subsequently issue an alert as needed.
- Inadequate monitoring hinders performance and event analysis.

Based on the analysis of the events, including a finding that the affected entities did not meet the performance requirements of the Generator Interconnection Agreement, CAISO worked with affected GOs to develop and implement mitigation plans to eliminate the unexpected causes of tripping and make changes to recording capabilities to meet the Interconnection agreement requirements.

[18] *2022 California Battery Energy Storage System Disturbances*

Chapter 2: Severe Risks, Impact, and Resilience

This chapter identifies and examines the highest-stress days on the BPS in 2023 using established measures.

Severity Risk Index[19]

The SRI provides a quantitative measure that assesses the relative severity of the combined impact of load, generation, and transmission loss on the BPS daily and offers a comprehensive picture of the performance of the BPS, allowing NERC to assess year-on-year reliability trends. For 2023, load-loss data voluntarily reported to the IEEE Distribution Reliability Working Group was used to estimate the daily load-loss component; generation and transmission components are calculated from data collected by NERC.

By comparing the daily SRI scores in descending order for each of the past five years, the overall performance of the BPS can be evaluated (see Figure 2.1). The inset chart in the upper right of Figure 2.1 provides a detailed comparison of the top 10 SRI days for each year. The annual cumulative SRI shown in Table 2.1 sums each day's SRI for the year by component. Three of these cumulative measures for 2023 were the lowest in the past five years (Cumulative Weighted Load Loss, Annual Cumulative SRI, and Average Daily SRI) and Cumulative Weighted Generation was the second lowest.

The cumulative performance of the BPS is calculated by summing each day's SRI for the year. Table 2.1 and Figure 2.1 show the annual cumulative SRI for the five-year period of 2019–2023.

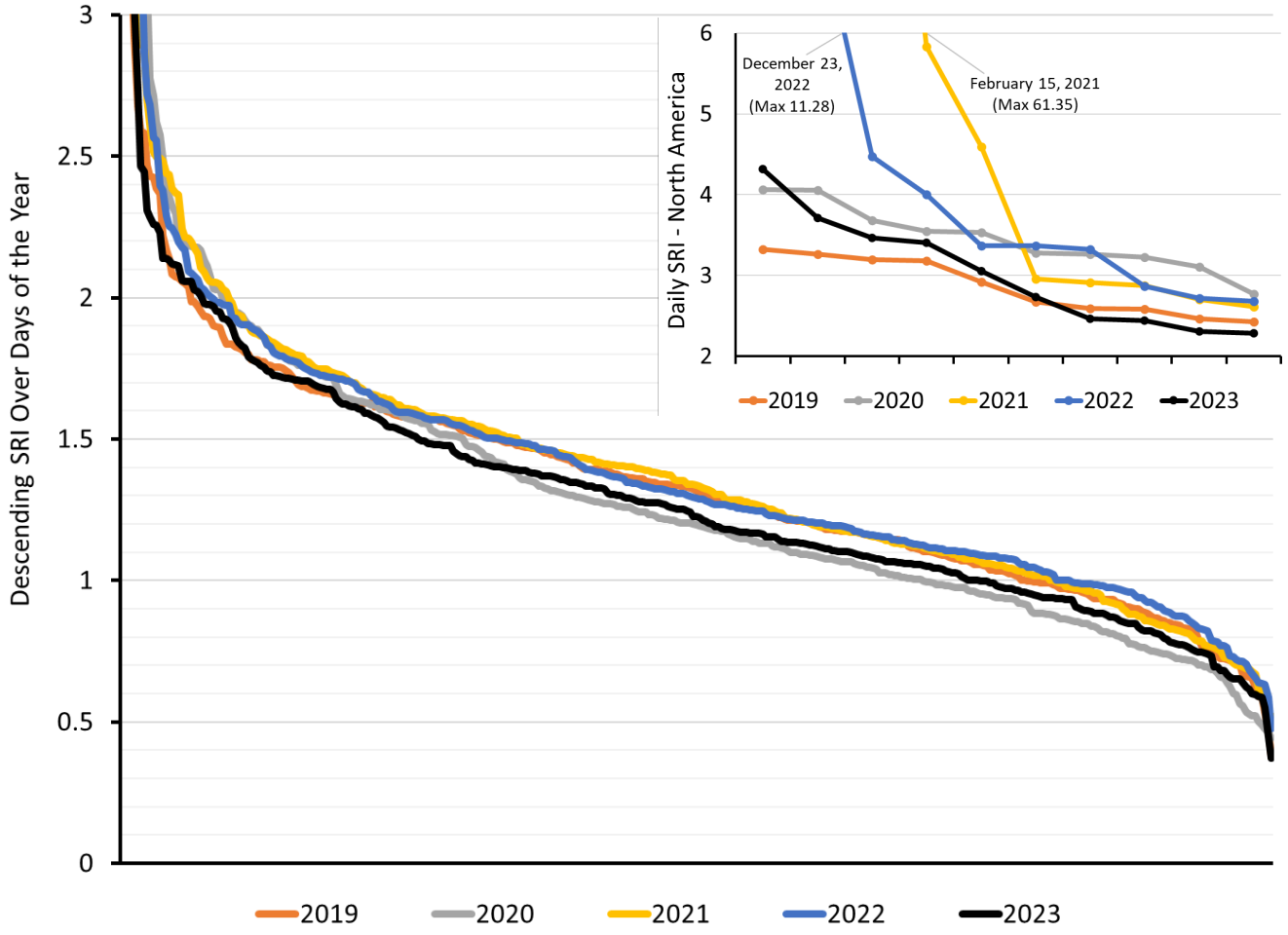


Figure 2.1: NERC Descending SRI by Day of the Year

[19] Severity Risk Index

Table 2.1: Annual Cumulative SRI					
Year	Cumulative Weighted Generation	Cumulative Weighted Transmission	Cumulative Weighted Load Loss	Annual Cumulative SRI	Average Daily SRI
2019	368.9	67.4	57.0	493.3	1.35
2020	339.0	67.7	72.5	479.2	1.31
2021	375.8	65.3	152.1	593.2	1.63
2022	404.2	61.1	55.2	520.4	1.43
2023	356.8	65.9	53.2	475.9	1.30

Figure 2.2 plots the daily SRI scores for 2023 against control limits that were calculated by using 2019–2022 seasonal daily performance and identifies the 10 highest SRI days. A general normal range of performance is represented by the gray-colored band, showing the daily seasonal 90% control limits.[20] Days that extend above the seasonal control limit indicate irregularities for the season but may not have a high enough SRI to rank in the top 10.

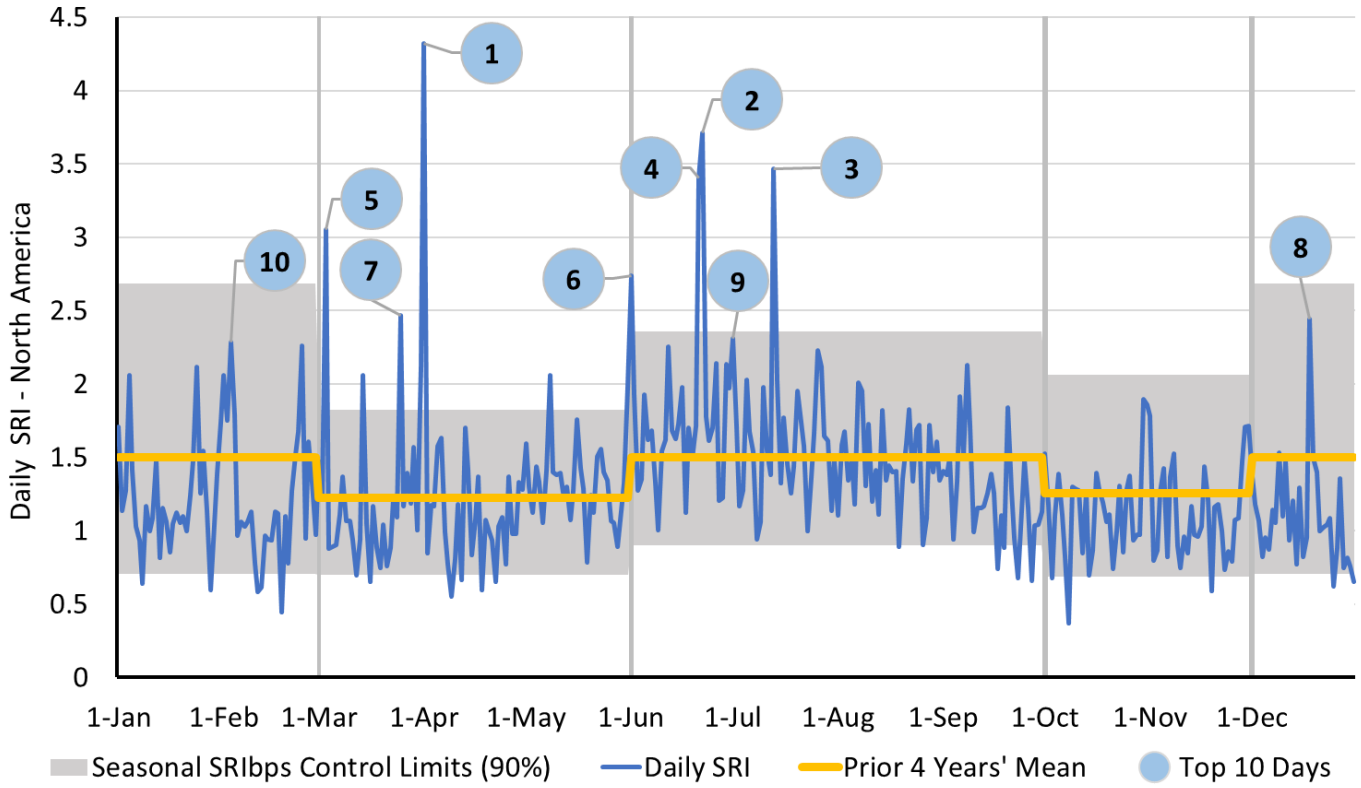


Figure 2.2: 2023 Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

Table 2.2 details the scores for the top 10 SRI days during 2023. The table identifies where atypical weather conditions were ongoing during the day and the general location by Regional Entity. Four of the top 10 SRI days in 2023 were driven by relatively short high-voltage transmission outages resulting from the wildfires in Québec. As noted in other areas of this report, although the wildfires did have some impact on reliability, they have disproportionately increased transmission indicators. Five of the six remaining top days were coincident with major thunderstorms, leading to higher load loss than usual. Due to the relatively calm weather in 2023, the final remaining day was a result of several coincident large fossil generator outages.

[20] The shaded area reflects the 90% confidence interval (CI) of the historic values between the 5th and 95th percentiles.

Table 2.2: 2023 Top 10 SRI Days							
Rank	Date	SRI and Weighted Components 2023				Atypical Weather Conditions	Regional Entities
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	1-Apr	4.32	1.10	0.45	2.77	Widespread storms and tornadoes	MRO, RF, SERC
2	22-Jun	3.71	1.39	2.18	0.14	Québec Wildfires	NPCC
3	13-Jul	3.47	1.01	2.18	0.28	Québec Wildfires	NPCC
4	21-Jun	3.40	1.36	1.80	0.24	Québec Wildfires	NPCC
5	3-Mar	3.05	1.40	0.57	1.08	Severe Storms	RF, SERC, Texas RE
6	1-Jun	2.74	1.78	0.77	0.19	Québec Wildfires	NPCC
7	25-Mar	2.46	0.71	0.30	1.46	Widespread storms	RF, SERC
8	18-Dec	2.45	1.26	0.15	1.04	East Coast thunderstorms and coincident generation outages	NPCC, SERC
9	1-Jul	2.31	1.68	0.51	0.12	Three high-voltage lines out < 30 minutes due to lightning	NPCC
10	3-Feb	2.28	2.00	0.14	0.15	Coincident large coal and gas generator outages	N/A

SRI Performance Trends

To put the severity of days in 2023 into context with historic BPS performance, the top 10 days over the five-year period are updated annually. Table 2.3 identifies the top 10 SRI days occurring for 2019–2023 with the contribution of the generation, transmission, and load-loss components to the SRI for each day; contributing event information; and the Regional Entities impacted by the event. Only April 1, 2023, was severe enough to be added to the top 10 SRI days of the past five years.

Table 2.3: 2019–2023 Top 10 SRI Days							
Rank	Date	SRI and Weighted Components				Atypical Weather Conditions	Regional Entity
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	February 15, 2021	61.35	5.54	0.79	55.02	Cold Weather Event	MRO, RF, SERC, TRE
2	February 16, 2021	18.34	5.02	0.54	12.78	Cold Weather Event	MRO, RF, SERC, TRE
3	February 17, 2021	12.04	2.49	0.29	9.26	Cold Weather Event	MRO, RF, SERC, TRE
4	December 23, 2022	11.28	8.17	0.86	2.26	Winter Storm Elliott	All
5	December 24, 2022	7.46	6.44	0.97	0.05	Winter Storm Elliott	All

Table 2.3: 2019–2023 Top 10 SRI Days							
Rank	Date	SRI and Weighted Components				Atypical Weather Conditions	Regional Entity
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
6	February 18, 2021	5.83	2.20	0.33	3.30	Cold Weather Event	MRO, RF, SERC, TRE
7	February 14, 2021	4.59	1.91	0.86	1.83	Cold Weather Event	MRO, RF, SERC, TRE
8	June 14, 2022	4.47	1.52	0.39	2.57	High Temperatures and Derecho	MRO, NPCC, RF, SERC, TRE
9	April 1, 2023	4.32	1.10	0.45	2.77	Hurricane Florence	SERC
10	August 27, 2020	4.06	1.52	0.94	1.60	Winter Storm Riley	NPCC

Major Weather Events

The typical major weather systems that have been analyzed for 2023, such as severe thunderstorms, hurricanes, tornadoes, and winter storms, had less of an impact on the BPS than seen in the past. Six of the 28 events highlighted in Figure 2.3[21] were identified as large transmission events in the resilience analysis. By far the largest natural disaster event that impacted the BPS transmission metrics was the Québec wildfires; however, the impact of this event does not align with the metrics (see **Major Occurrences**, **Resilience Curves,** and **TADS Reliability Indicators** sections).

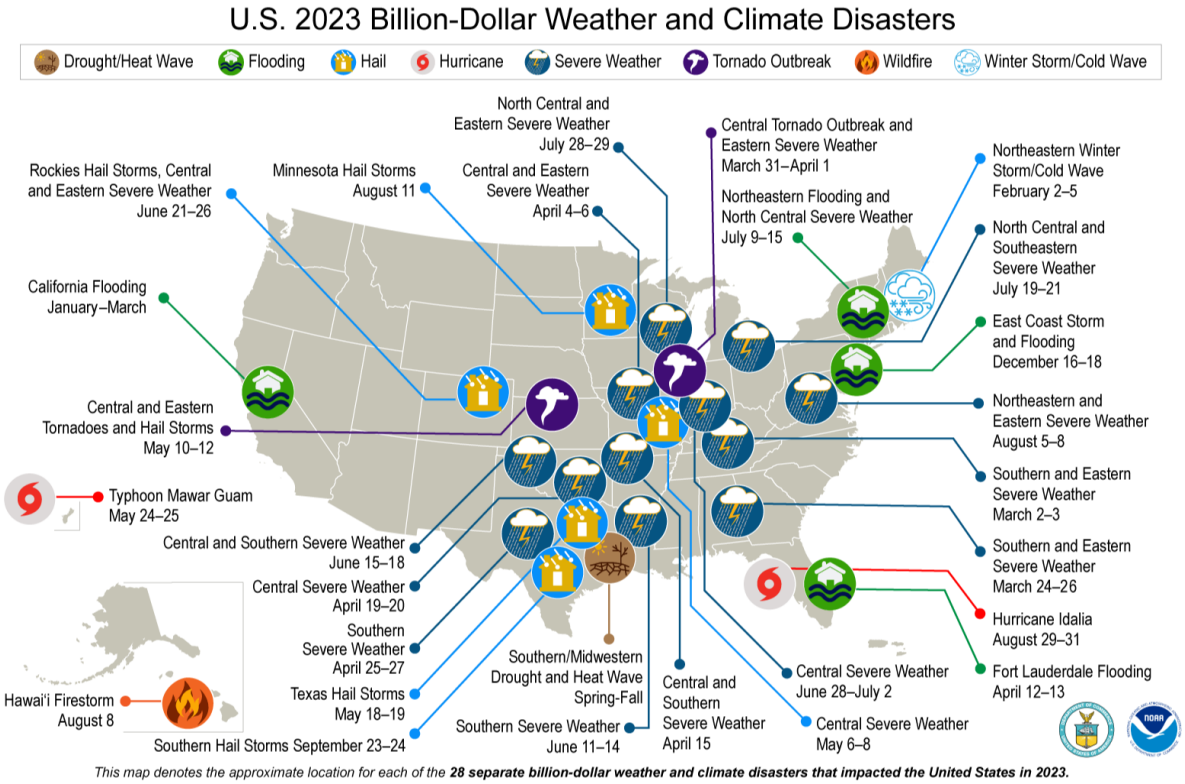


Figure 2.3: 2023 U.S. Billion-Dollar Weather and Climate Disasters[22]

[21] NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2023). https://https://www.ncei.noaa.gov/access/billions/, DOI: 10.25921/stkw-7w73

[22] NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2023). https://https://www.ncei.noaa.gov/access/billions/, DOI: 10.25921/stkw-7w73

Impact of Extreme Event Days

Extreme Event Days

Extreme event days are identified as event days above the 95th percentile upper bound relative to the past four years' severity measures for any season within North America or a specified Interconnection. This analysis expands on the transmission and generation components that contribute to the SRI reported in the previous **SRI Performance Trends** section to explore the causes of the extreme days.

The impacts of extreme days on BPS resources are characterized by the amount of transmission or generation reporting immediate forced outages or derates starting on a given day. By analyzing the impact and causes of extreme event days, it is possible to identify which conditions pose the highest risk to the BPS. While this analysis does not address every potential scenario, learning from performance during extreme events helps provide insight into how the system may respond to a range of conditions and events.

Extreme-day outages for transmission and generation by Interconnection are presented in **Appendix A**, Supplemental Analysis by Interconnection.[23] The analysis provided in the following subsections is reported separately for transmission and generation. The total estimated MVA transfer capacity[24] reported in TADS or net maximum capacity reported to GADS for all Regional Entities or by Interconnection is shown at the top of each figure in this chapter.

Transmission Impacted

In 2023, 22 days met the criteria of extreme transmission days for the BPS as compared to 11 in 2022. Of the 22 extreme days in 2023, 14 were associated with the Québec wildfires. The most extreme transmission-impacting day was June 22, primarily due to the Québec wildfires (see Figure 2.4), followed closely by July 13, also due to the Québec wildfires. On these days, the potential MVA capacity impacted due to automatic transmission outages was 10.4 times as high as the associated season's average.

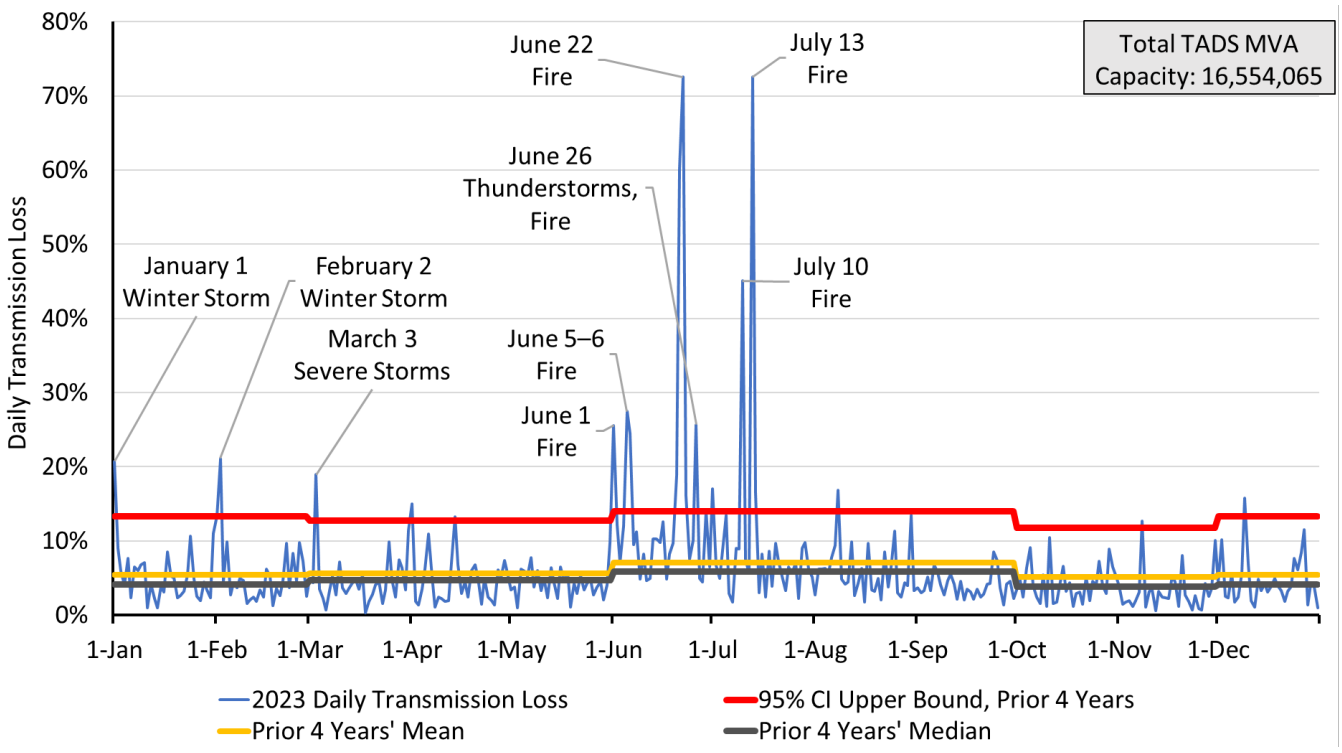


Figure 2.4: 2023 Transmission Outages during Extreme Days

[23] For extreme day Interconnection-level analysis, the Québec Interconnection is included in the analysis labeled as Eastern Interconnection–Québec Interconnection.

[24] Severity Risk Index

The top causes reported for outages that occurred on extreme days are shown in rank order for North America and each Interconnection (Table 2.4).

Table 2.4: Top Transmission Initiating Outage Causes on Extreme Days Ranked by MVA Capacity

Area	Cause #1	Cause #2	Cause #3	Cause #4	Cause #5
All NERC Regional Entities	Fire (568,311)	Weather (Excluding Lightning) (112,908)	Lightning (59,365)	Failed AC Circuit Equipment (32,329)	Unknown (31,075)
Eastern–Québec Interconnections	Fire (568,392)	Weather (Excluding Lightning) (91,274)	Lightning (49,745)	Failed AC Circuit Equipment (31,732)	Failed Protection System Equipment (29,606)
Texas Interconnection	Weather (Excluding Lightning) (55,125)	Lightning (27,487)	Failed AC Circuit Equipment (18,963)	Unknown (6,895)	Other (5,952)
Western Interconnection	Weather (Excluding Lightning) (24,675)	Unknown (16,615)	Power System Condition (8,739)	Lightning (8,475)	Human Error (6,668)

Conventional Generation Impacted

Based on analysis of GADS data, a total of 14 days in 2023 qualified as extreme for North America's BPS (see Figure 2.5) compared to 22 in 2022. The two highest-impact days for generation loss were July 27 (severe storms) and February 3 (winter storm). On these days, conventional generating units experienced outages that were 1.8–1.9 times as severe as the associated season's average. Two of the extreme generation loss days coincided with extreme days identified for transmission (early February winter storms and June 1). The days on which generation outages were slightly above the seasonal bounds (**red** line) do not have a specific cause listed and have been investigated; they either coincided with severe thunderstorms (i.e., May 8, June 1, June 12, and July 27) or saw many coincident outages that were not a result of adverse weather conditions.

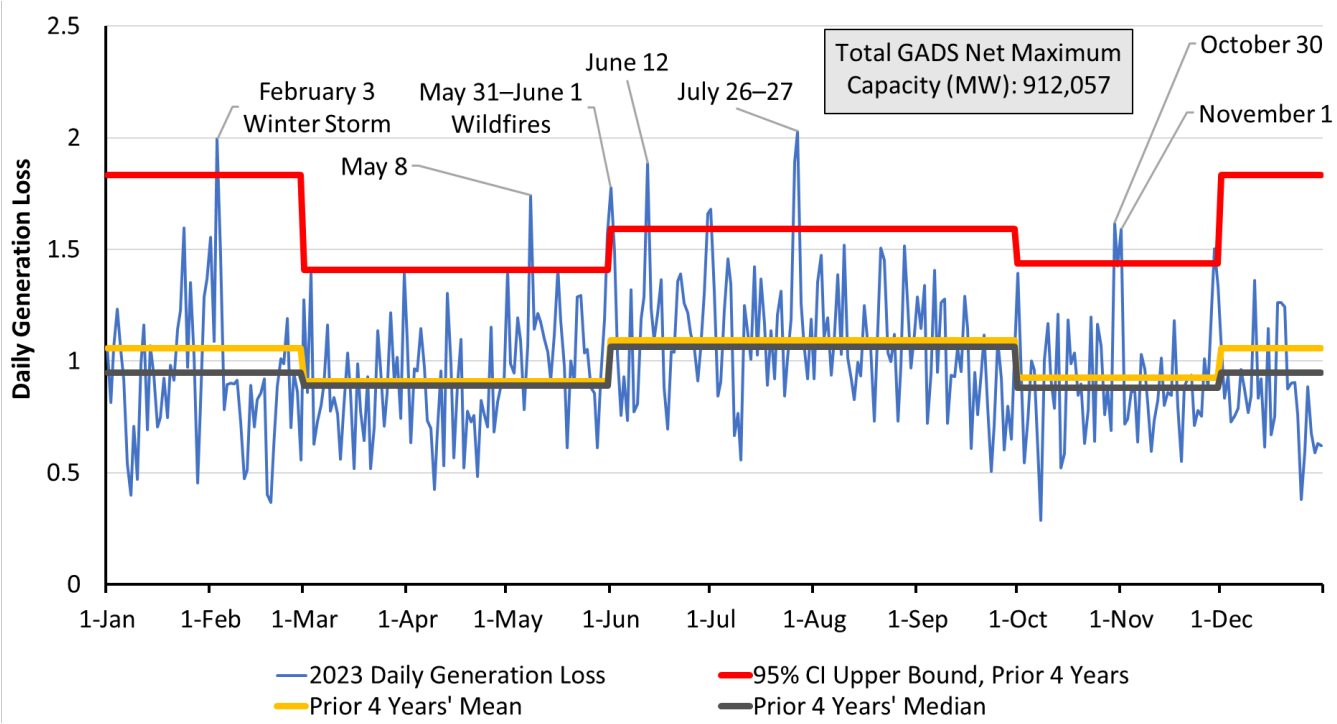


Figure 2.5: 2023 Generation Impacted during Extreme Days

The top causes reported for outages that occurred on extreme days are shown in rank order for North America and each Interconnection (Table 2.5).

Table 2.5: Top Generation Outage Causes on Extreme Days Ranked by Unavailable Net Maximum Capacity

Area	Cause #1	Cause #2	Cause #3	Cause #4	Cause #5
All Regional Entities	Electrical (17,851)	Fuel, Ignition, and Combustion Systems (14,130)	Auxiliary Systems (13,876)	Boiler Tube Leaks (13,008)	Controls (11,341)
Eastern–Québec Interconnections	Fuel, Ignition, and Combustion Systems (11,086)	Boiler Tube Leaks (10,758)	Electrical (9,073)	Auxiliary Systems (7,126)	Lack of Fuel (Hydro, gas, coal) (6,746)
Texas Interconnection	Electrical (5,784)	Controls (4,933)	Boiler Tube Leaks (4,868)	Fuel, Ignition, and Combustion Systems (4,471)	Boiler Piping System (4,444)
Western Interconnection	Feedwater System (2,136)	Electrical (1,579)	Fuel, Ignition, and Combustion Systems (1,470)	Controls (1,397)	Condensing System (1,373)

Analysis of Transmission System Resilience

The analysis of large transmission events evaluates transmission outages related to severe weather events that involve 20 or more automatic outages. Outage and restoration processes for transmission elements are analyzed, not the disruption and restoration of distribution customer load. Restoration of the transmission system to serve customer load is always the priority.

The analysis of the 2023 transmission outages identified 11 large transmission events that were caused by weather and quantified the resilience and restoration statistics for them. The resilience statistics enable the measurement and tracking of some abilities of the transmission system to withstand, adapt, protect against, and recover during and after major weather events.[25]

This section provides a detailed description of the March 31 winter storm and tornado event as the largest outage event on the transmission system in 2023 and the Québec wildfires as a composite event due to the impact on other transmission metrics. Multiyear statistics by associated weather type and changes in the severity and duration of these events as measured by the number of transmission outages reported for each cause are compared for two five-year periods: 2018–2022 and 2019–2023.

TADS Outage Grouping and 2023 Large Weather Events

The outage grouping algorithm[26] considers automatic outages reported in TADS based on Interconnection and associated start and end times. The resulting transmission outage events are determined to be weather-related if at least one outage in the event is initiated or sustained by one of the following TADS cause codes: Weather (excluding lighting), Lightning, Fire, or Environmental. The procedure produces groupings of outages that are further reviewed and compared with the weather information from external sources to confirm or refine the events. The TADS data was supplemented by Velocity Suite as a source to identify utility company footprints, and weather sources like National Oceanic and Atmosphere Administration (NOAA) and Ventusky were used to visualize the weather events. Matching the data from these sources provides a much clearer picture of outages within the event. This combination of automatic and manual procedures results in a set of transmission events that can cross boundaries of different utilities and Regional Entities to capture significant events caused by major weather occurrences, such as hurricanes and severe winter storms.

Table 2.6 lists these events in chronological order and shows the severe weather type for each event with statistics that quantify the impact of the event on the transmission system. In 2023, the largest event was the Québec wildfire composite event with 180 outages between June 20 and July 16, which consisted of 101 small non-overlapping events and as such was not captured by the algorithm as one single event. The combination of all events affected 600,635 of MVA capacity. This composite event is shown in **blue** in Table 2.6.

The second largest event, the March 31 winter storm/tornado event (with 119 transmission outages reported), occurred in the Eastern Interconnection, shown in **red** in Table 2.6. In terms of impact to the overall system, the February 1 ERCOT winter storm event had the highest transmission capacity affected (48,761 MVA out) for any single event in 2023. The two events taking place on June 25 were reported as two separate events due to the large time gap and geographical distance between them.

[25] Resilience Framework, Methods, and Metrics for the Electricity Sector | IEEE Power & Energy Society Resource Center (ieee-pes.org)

[26] Impact of Extreme Weather on North American Transmission System Outages | IEEE Conference Publication | IEEE Xplore

Table 2.6: 2023 Large Transmission Weather-Related Events

Event Start	Event Outage Count			Interconnection	Extreme/Severe Weather Event	Transmission Capacity Affected (MVA)	Miles Affected	Final Restoration Duration (Days)	Element-Days[27] Lost	Most Simultaneous Unavailable Capacity (MVA)
	All Automatic	Sustained Automatic	Momentary Auto.							
February 1	66	61	5	Texas	Winter Storm, Ice	48,105	1,270	61.5	115	35,593
March 3	88	75	13	Eastern	Severe / High Winds	39,100	2,609	5.6	50	13,676
March 25	29	23	6	Eastern	Thunderstorm	16,401	920	2.3	15	4,706
March 31	**119**	**99**	**20**	**Eastern**	**Winter Storm, Tornadoes**	**47,097**	**3,091**	**22.8**	**164**	**16,788**
June 15	85	72	13	Eastern	Thunderstorm, Tornadoes	26,747	2,034	11.3	127	14,388
June 18	32	29	3	Eastern	Thunderstorm, Tornadoes	9,406	859	9	60	6,620
June 20-July 14	**180**	**143**	**37**	**Québec**	**Wildfires (composite event)**	**600,635**	**25,710**	**N/A**	**9**	**17,482**
June 25	22	19	3	Eastern	South Central Thunderstorm, Tornadoes	5,038	587	6.9	29	3,121
June 25	21	19	2	Eastern	Thunderstorms	6,472	503	2.2	10	3,686
June 29	58	50	8	Eastern	Derecho, Thunderstorms	23,781	1,520	11.7	51	10,983
July 20	52	42	10	Eastern	Thunderstorm, High Winds	18,147	1,365	4.9	33	7,055
August 30	58	56	2	Eastern	Hurricane Idalia	15,170	1,439	9.2	106	11,132

[27]The definition for element-days is provided in Appendix B of the NERC *2022 SOR*.

Outage, Restore, and Performance Curves

Table 2.6 illustrates the variability in event sizes and duration. However, these statistics do not completely explain what happened during the events; the outage, restore, and performance curves of the events provide more details on how he events unfolded.[28] Figure 2.6 serves as an example to describe transmission outages during an event. These curves track the number of elements out or the MVA transmission capacity impact on the vertical axis versus time on the horizontal axis.

The outage curve is the cumulative number of elements or cumulative equivalent MVA capacity impact at the time shown on the horizontal axis.

The restore curve is the cumulative number of elements restored or cumulative equivalent MVA restored at the time shown on the horizontal axis.

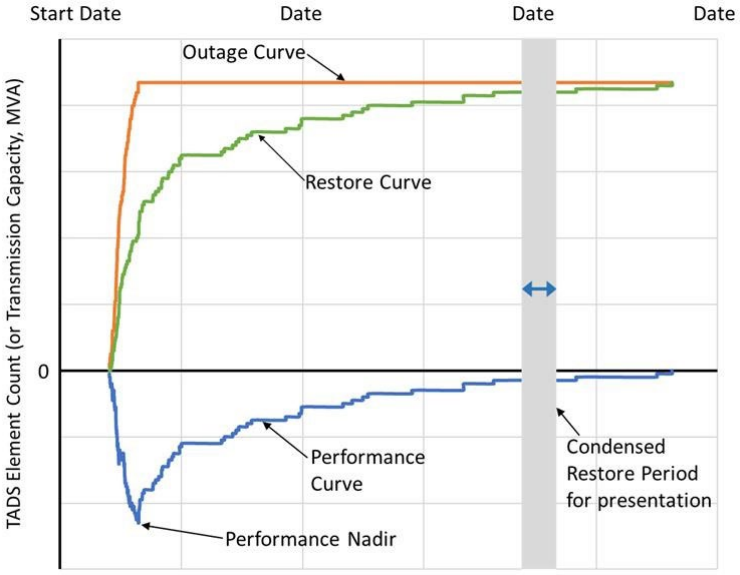


Figure 2.6: Example of Outage, Restore, and Performance Curves for a Large Transmission Outage Event

Lastly, the performance curve is the number of elements or equivalent MVA capacity impact out simultaneously at the time shown on the horizontal axis. The value is equal to elements or MVA capacity restored minus the elements or MVA capacity (i.e., the performance curve is the restore curve minus the outage curve). The performance curve combines information on degradation and recovery during the event.

The curves enable the calculation of several resilience metrics.[29] These metrics help quantify the abilities of a resilient power system to effectively absorb, withstand, adapt, protect against major weather events (event size, outage process duration and outage rate, time to first restore, the most degraded state in the event, the total element-days and MVA capacity-days lost), and recover from and reduce the durations and impacts of major weather events (event duration, time to first restore, time to substantial restoration, instantaneous restore rate).

Resilience Curves and Statistics for Two Largest Transmission Events in 2023

Québec Wildfires (June 20–July 14, 2023)

The Québec wildfire outages were combined into one composite event that consisted of 101 non-overlapping small outage events that are grouped together to better assess the overall impact between June 20 and July 26, 2023. These small events together contained 180 automatic outages. It should be noted that the creation of this composite event is only possible due to the specificity of the "Fire" cause code. With current data, it would be impossible to perform a similar, accurate methodology for other types of weather, making for limited comparability.

Out of the 180 outages, 37 were momentary (< 1 minute) and the remaining were sustained. The event included 11 dc circuit outages and 169 ac circuit outages. A total of 180 automatic outages occurred on 2 distinct dc circuits and 26 distinct ac circuits. The affected dc circuits were from the 400–499 kV voltage class and the ac circuits from the 300–399 kV and 600–799 kV voltage classes. Because of the high voltages and large estimated MVA capacity of the dc and ac circuits and because the wildfires were considered as one composite event, the total affected transmission capacity summed up to 600,635 MVA. Outage durations were short (1.2 hours on average) and generally not overlapping, reducing the simultaneous stress on the transmission system. The total duration analyzed from the first outage to final restoration was 26.1 days. The element- and MVA-based performance curves for the Québec wildfires

[28] S. Ekisheva, I. Dobson, R. Rieder, and J. Norris, "Assessing transmission resilience during extreme weather with outage and restore processes," 2022 17th International Conference on Probabilistic Methods Applied to Power Systems

[29] Resilience statistics are defined in Appendix B in the *2022 SOR*.

composite event are shown in Figure 2.7 and Figure 2.8, respectively. The outage and restore curves for the composite event are not shown because they do not provide valuable information since regular resilience statistics cannot be properly applied.

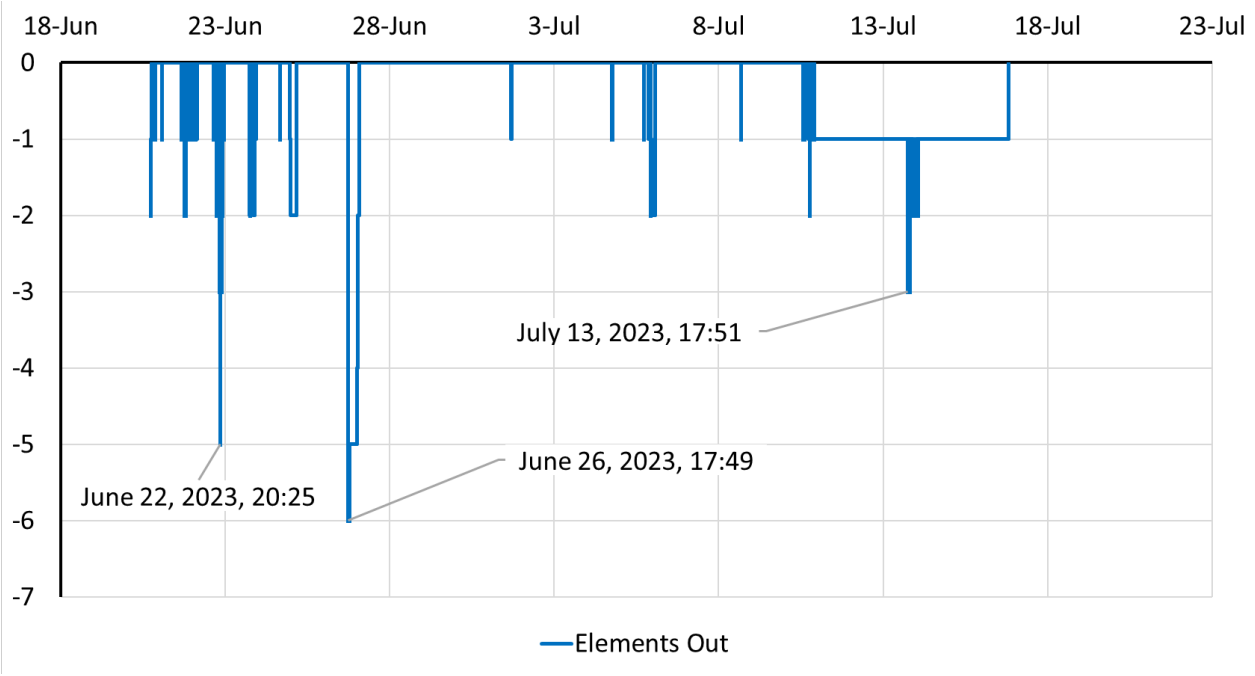


Figure 2.7: Transmission Element-Based Performance Curve for Québec Wildfire Event, June 20–July 14, 2023

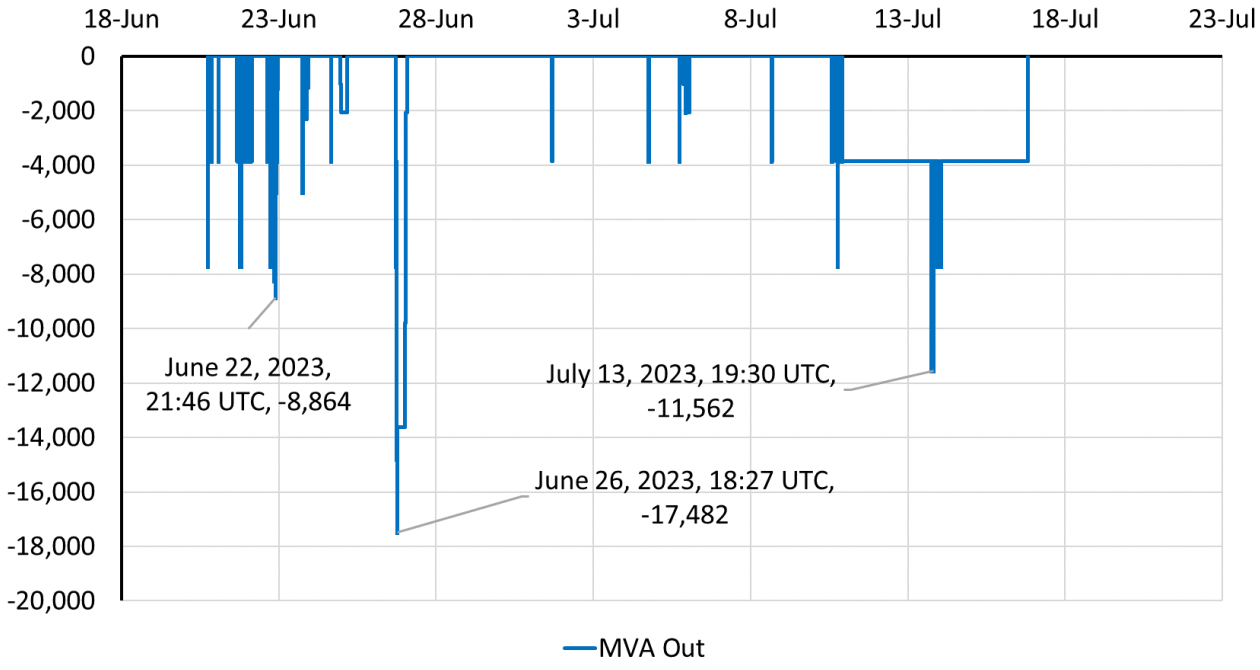


Figure 2.8: Transmission Capacity (MVA-Based) Performance Curve for Québec Wildfire Event, June 20–July 14, 2023

The maximum simultaneous loss of potential transmission capacity was greater than that of the Eastern Interconnection winter storm and tornado event, 17,482 MVA vs. 16,788 MVA, respectively. The elements' high voltages resulted in a significant total loss of 29,492 MVA-days compared to only nine element-days lost. This ratio of 3,276:1 is roughly nine times the average ratio of 363:1, clearly demonstrating how these outages disproportionately impact transmission calculations that do not account for duration.

Winter Storm and Tornado Event (March 31–April 23, 2023)

Table 2.6 indicates that the events with a combination of weather types significantly impacted the transmission system in 2023. The largest non-composite transmission outage event in 2023 was the winter storm and tornado event that started in the Eastern Interconnection on March 31, 2023, in terms of the number of element outages. This weather event was also recorded by NOAA as one of the billion-dollar weather disasters of 2023 (see Figure 2.3). It involved a series of strong storms containing high winds, heavy rain, and multiple tornadoes across the Mississippi, Tennessee, and Ohio Valleys and into the Mid-Atlantic and Northeast on Friday and Saturday, March 31, and April 1. At the storm's peak, EAGLE-I[30] indicated approximately 1.1 million distribution outages between Arkansas and New York; 268,000 in Pennsylvania; 237,000 in Ohio; and 99,000 in Tennessee.

The event caused 119 automatic transmission outages reported by 36 Transmission Owners; 20 out of the 119 outages were momentary (< 1 minute), and the remaining were sustained. The event included five transformer outages and 114 ac circuit outages with more than 3,090 ac circuit miles affected, totaling 47,097 MVA capacity. The event had a duration of 22.8 days, second only to the ERCOT winter transmission outage event that lasted 61.5 days. The element- and MVA-based curves for the winter storm are shown in Figure 2.9 and Figure 2.10, respectively. The curves are condensed with the gray area representing the time between April 11, 2023, 15:55 UTC and April 22, 2023, 0:00 UTC.

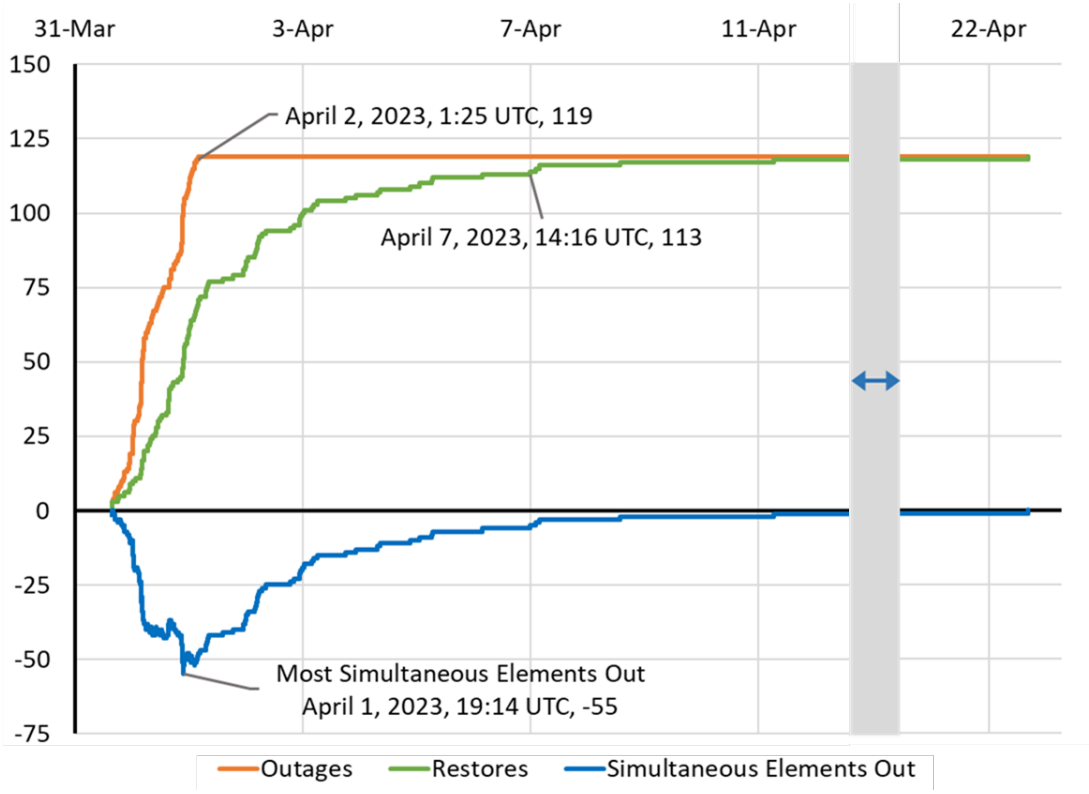


Figure 2.9: Transmission Element Outage, Restore, and Performance Curves for Winter Storm/Tornado Event, March 31–April 23, 2023

[30] EAGLE-I is an interactive geographic information system (GIS) that allows users to view and map the nation's energy infrastructure and obtain near real-time informational updates concerning the electricity, petroleum, and natural gas sectors within one visualization platform.

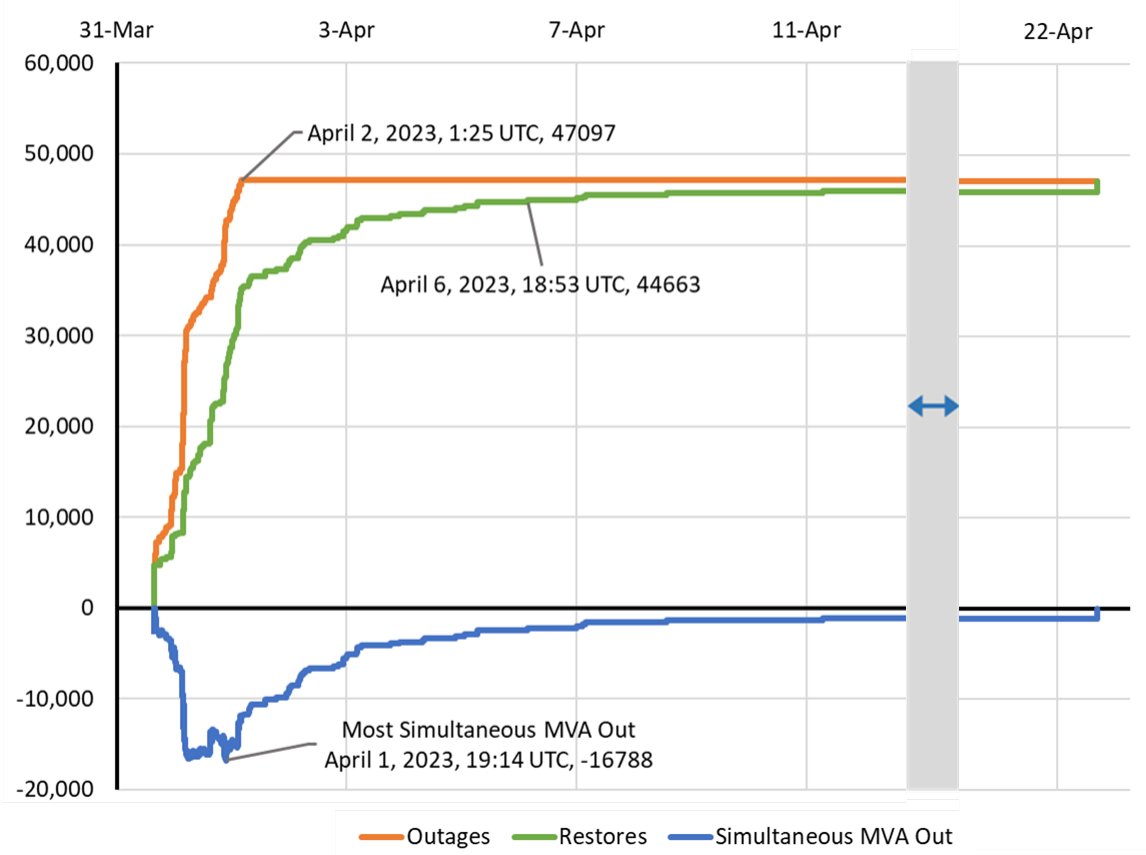


Figure 2.10: Transmission Capacity (MVA-Based) Outage, Restore, and Performance Curves for Winter Storm/Tornado Event, March 31–April 23, 2023

The large transmission outage event started with a series of ac circuit momentary outages due to galloping caused by the winter storm. During this transmission event, four distinct ac circuits followed the same scenario: a line had several momentary outages in close succession due to galloping followed by a sustained outage with a multiday duration. Due to the multiple outages of the same ac circuit, a total of 119 automatic outages occurred on 111 distinct transmission elements. The **orange** outage curves in Figure 2.9 and Figure 2.10 show that an outage process lasted 35 hours with the outages accumulating at the average rate of 3.4 outages per hour (1,359 MVA capacity per hour).

The restore process, shown in Figure 2.9 and Figure 2.10 by **green** curves, started immediately due to a momentary outage with the earliest sustained restore occurring in 10 minutes. It then followed the usual pattern for most large events.[31] The maximum number of elements (55) and MVA capacity (16,788) simultaneously out, shown by the nadir of the respective blue performance curves, was reached approximately 28 hours into the event, and the system remained in this most degraded state for six minutes. Unlike the outage process, the restore process did not occur at a constant rate, rather its rate decreased over the event duration. Using a log-normal fitted curve for the restore process,[32] the maximum instantaneous restore rate was 1.8 restores per hour, which was reached 13.7 hours into the event. At the time point when half of sustained outages were restored, the rate was 1.3 restores per hour, and it was only 0.07 restores per hour at the 95% element restoration level. The substantial restoration level when 95% of outages were restored was reached in 167.5 hours, or 31% of the event duration. The substantial restoration for transmission capacity (MVA) happened faster, 148.1 hours, or 27% of the event duration. The total loss for the event, calculated as the area between a blue performance curve and the time axis, was 164 element-days lost (Figure 2.9) and 62,675 MVA-days lost (Figure 2.10).

[31] S. Ekisheva, I. Dobson, R. Rieder, and J. Norris, "Assessing transmission resilience during extreme weather with outage and restore processes," 2022 17th International Conference on Probabilistic Methods Applied to Power Systems.
[32] S. Ekisheva, D. K. Pratt, M. Kachadurian, W. G. Martin, J. Norris, and I. Dobson, "Grid Restoration after Extreme Weather Events," 2023 IEEE PES Innovative Smart Grid Technologies Europe (ISGT) Conference.

The last unrestored outage in the event was 22.4 days, likely due to extensive damage of the 300–399 kV ac circuit. This is typical for large transmission events when few remaining elements are out either due to the inaccessibility of a portion of the line or a damaged structure or equipment. In some cases, this is attributable to a utility postponing the restoration of a single remaining element (or a few elements) after all other outages in the large event are restored because this outaged element is considered not critical for grid reliability.[33]

Transmission System Resilience Statistics by Associated Weather Type: 2019–2023

Weather Types

The outage grouping procedure identified 59 large transmission events in the years 2019–2023, only one of which was not weather-related (a 2023 contamination event).[34] The 58 large weather-related events were caused by the weather types listed in Figure 2.11. If several weather factors were observed together (e.g., hurricane, tornado, and wind), the dominant cause of transmission outages was determined to be the weather type. Multiple sources (i.e., NERC's daily BPS awareness reports, Velocity Suite, NOAA, Ventusky, public media reports) were used to determine if a weather event was associated with each large transmission event.

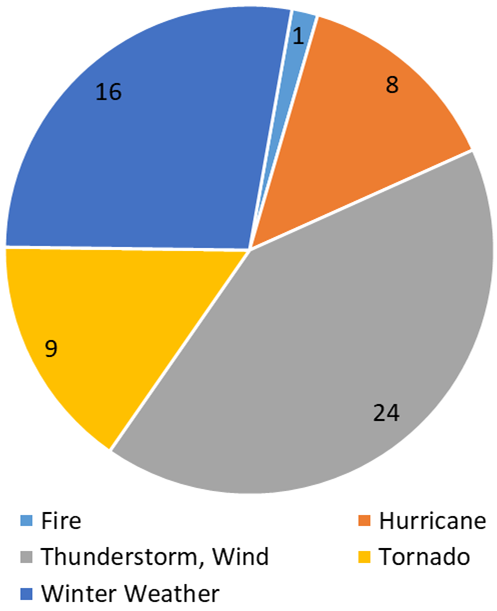


Figure 2.11: Weather Types of Large Transmission Events, 2019–2023

Figure 2.12 shows selected resilience statistics for the 2019–2023 events by weather type. Hurricanes caused the largest transmission events with an average size of 154 outages while other groups had average sizes that ranged from 40–59 outages. The maximum number of elements simultaneously out (the most degraded state in an event as indicated by the nadir of the performance curve) equals 60% of the event size on average.

[33] S. Ekisheva, I. Dobson, R. Rieder, and J. Norris, "Assessing transmission resilience during extreme weather with outage and restore processes," 2022 17th International Conference on Probabilistic Methods Applied to Power Systems.
[34] A 2023 large event in SERC with 30 outages caused by bird contamination; the event duration was 2.5 days.

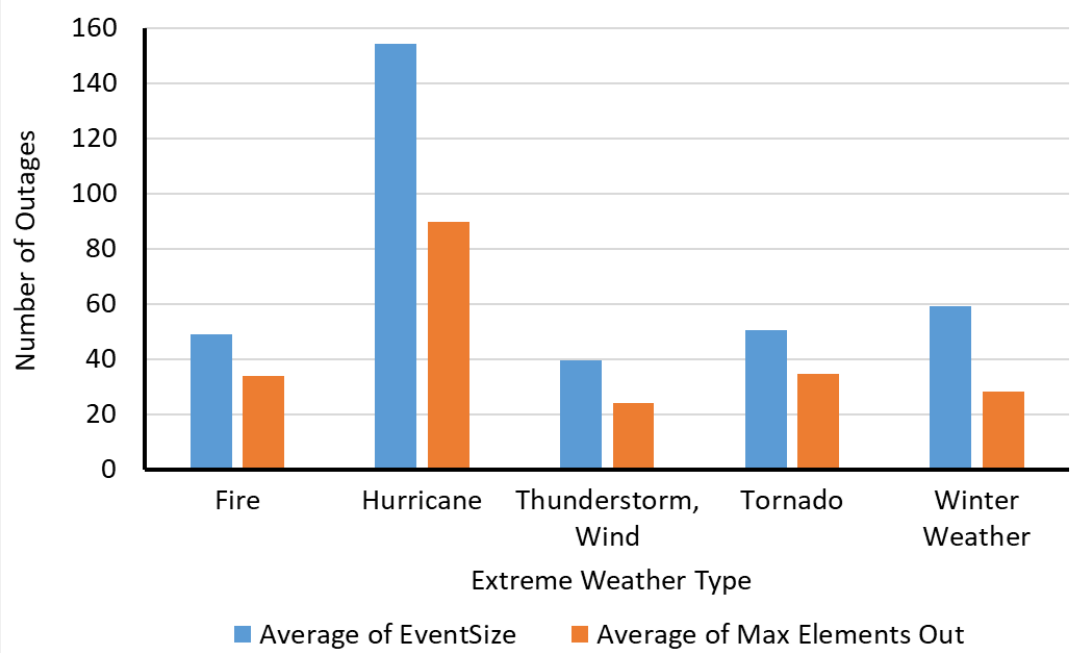


Figure 2.12: Resilience Statistics for 2019–2023 Large Weather-Related Events

Figure 2.13 compares the average event duration with the average substantial restoration duration (the time to restore 95% of outages and 95% of MVA capacity) and shows the time to first restore. The one fire event (2020 WECC wildfires) had a duration of 87 days, thus having a greater impact on this statistic due to the small group size. For other groups, the event duration is positively correlated with the event size. For all weather types, the time to restore 95% of outages (the substantial restoration level) is much shorter than the total event duration (on average, from 35% of the event duration for hurricanes to 52% of the event duration for tornadoes and thunderstorm, wind). The time to reach a restoration level of 95% MVA ranges from 29% of an event's duration for hurricanes to 63% for tornadoes. The first restore typically occurs inside one hour from the event start; hurricane events have the shortest average time to the first restore (34 minutes) among all groups. This indicates effective advanced preparation by utilities for these forecasted events. This is down two minutes from the 2017–2022 statistic calculated in the *2022 SOR* report, indicating that fast response to hurricanes is consistent.

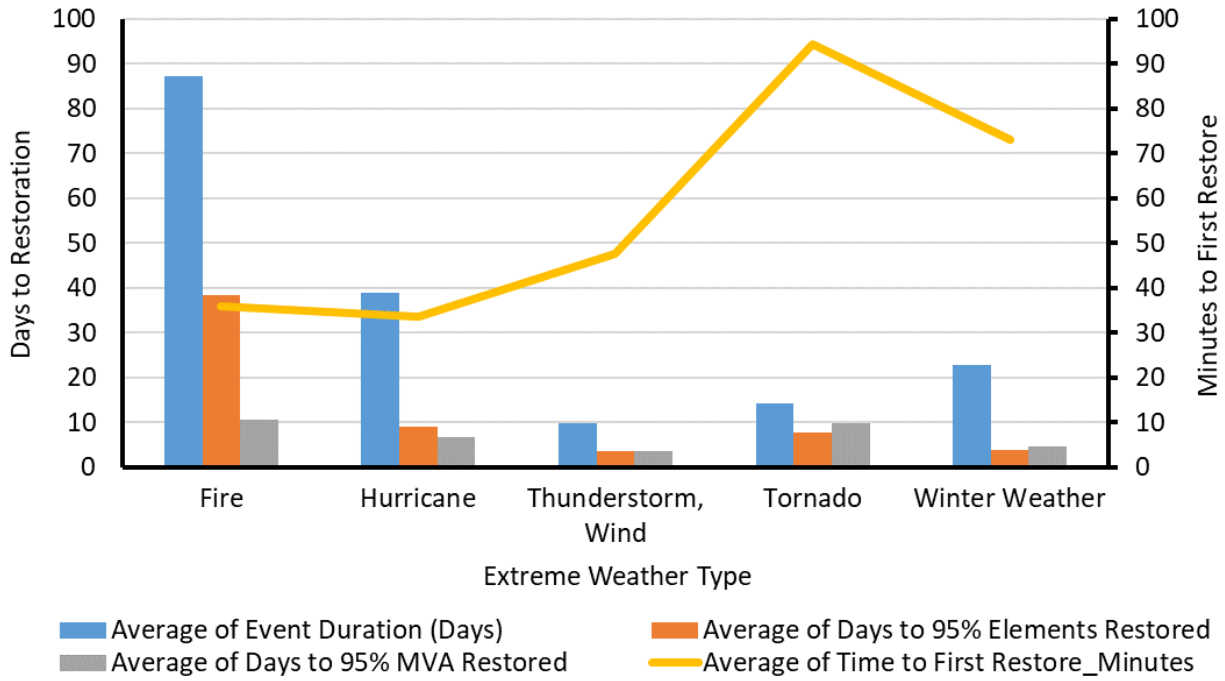


Figure 2.13: Average Event Duration vs. Average Sustained Restoration Duration

Event duration is a straightforward metric but is too highly variable to be a reliable estimate. Moreover, it depends strongly on the last few restores, making the event duration relate poorly to transmission performance because these last restores may be unimportant for customers or may be excessively delayed by factors out of the utility's control, such as the difficulty of repairing transmission lines in the mountains in the winter or structural damage caused by hurricane or tornado.[35] The substantial restoration duration is a preferable metric to measure and track the ability of the transmission system to recover from outage events caused by major weather systems.

Changes in Resilience Statistics: 2019–2023 Events vs. 2018–2022 Events

To draw conclusions about improving, stable, or declining transmission resilience against weather, the analysis focuses on capturing changes in the several metrics that quantify resilience over years. The resilience statistics are calculated for large weather-related events for the years 2018–2022 and 2019–2023, and changes in the metrics by weather types were analyzed. The five-year period is selected due to the small annual number of events in some groups (e.g., Fire).

The bubble chart in Figure 2.14 shows the groups of large weather-related transmission events by weather type; the five patterned bubbles correspond to the groups for combined 2018–2022 data, and the five solid-colored bubbles show the same groups for combined 2019–2023 data. The size of a bubble represents the group size. The X-axis of a bubble center shows the average time to restore 95% of outages for the events in this group; the Y-axis shows the average number of outages for the events. The bubble color indicates the average MVA-day loss for each group: below 30,000 MVA-days is shown in **blue**, between 30,000 and 100,000 MVA-days is shown in **yellow**, and above 100,000 MVA-days is shown in **orange**.

Change in size or position of a bubble for the same weather type in Figure 2.14 indicates changes in the impact of that weather resulting from a combination of the weather frequency and severity and improved or declined resilience performance. There was a decrease in the number of events in all categories as reflected by the bubble sizes in Figure 2.14. The average MVA-day loss increased for all weather types due to some of the smaller events falling off from 2018, which is highlighted by the change of color for Fire and Winter Weather. The average event size of Hurricanes

[35] *How Long is a Resilience Event in a Transmission System?: Metrics and Models Driven by Utility Data* | IEEE Journals & Magazine | IEEE Xplore

increased due to the removal of several small hurricanes from 2018. The average MVA-day loss for the Fire category increased when a short 2018 fire (with approximately 6,000 MVA-day loss) dropped off.

The time to substantial restoration for all extreme weather types combined in 2023 decreased compared with the previous five years (from 5.3 to 4.3 days for element recovery and from 4.9 to 4.5 days for MVA recovery). Possible explanations could be improvements in transmission resilience and less severe weather events. Additional years of the outage data as well as incorporation in the analysis of more detailed weather data are needed for more reliable inferences.

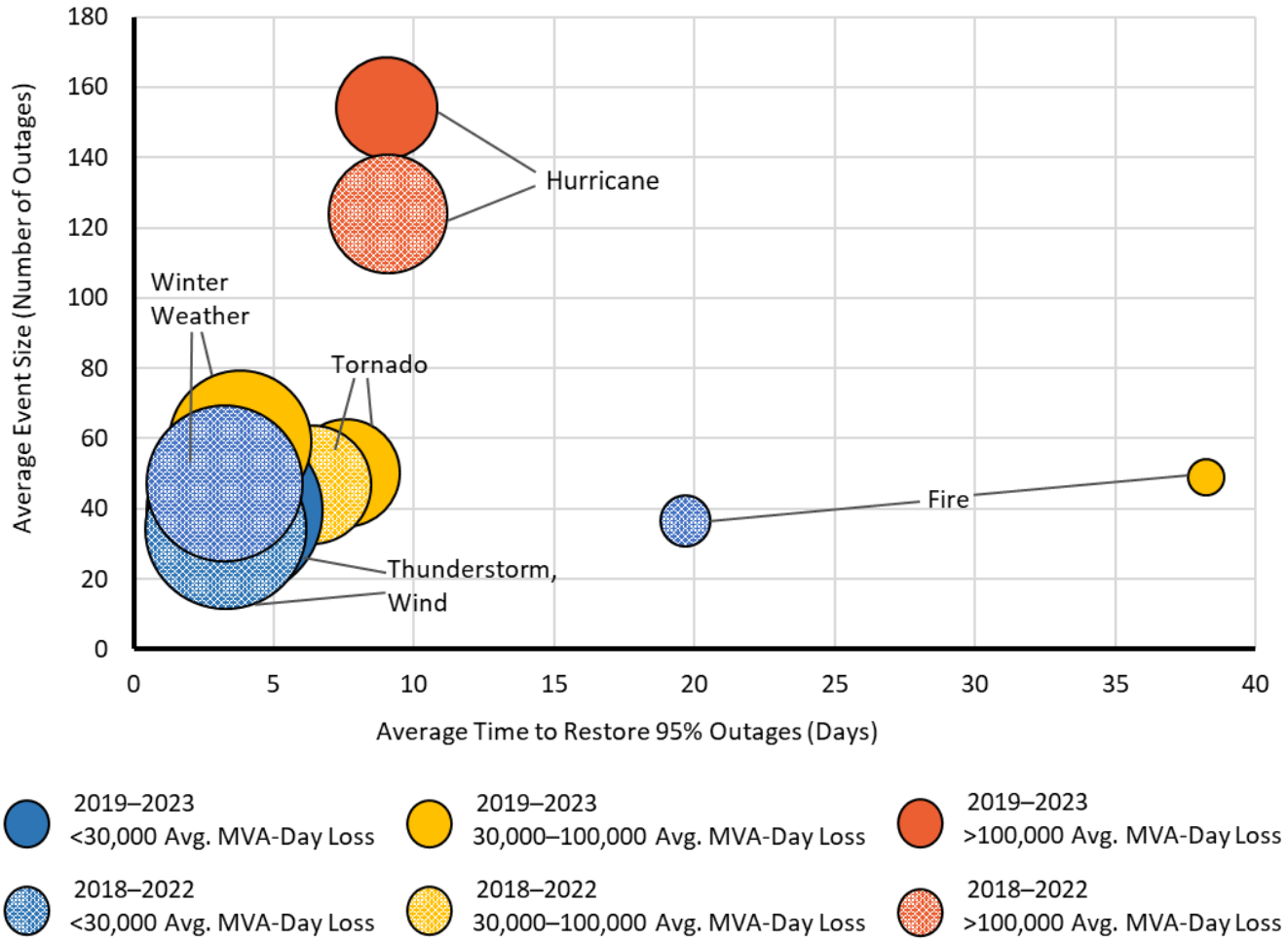


Figure 2.14: Statistics for Large Transmission Events by Weather Type for 2018–2022 vs. 2019–2023

Resource Adequacy

For this report, two measures of resource adequacy are examined for the **Energy Emergency Alerts** (EEA) section. Planning Reserve Margins present a forward-looking perspective on whether sufficient resources are expected to be available to meet demand. The EEAs provide details of actual energy emergencies within an Interconnection.

2023 Planning Reserve Margins

Planning Reserve Margins are a long-term resource adequacy indicator. Anticipated Reserve Margin (ARM) expresses the level of additional resource capacity that an area has above its peak summer (June–September) and winter (December–February) seasonal demand.[36] It is calculated as the difference in anticipated resources and net internal demand divided by net internal demand and shown as a percentage.[37] Each assessment area's ARM is compared against its Reference Margin Level (RML)—the threshold margin established by the state, provincial authority, ISO/regional transmission organization (RTO), or other regulatory body to provide the level of resources needed to meet reliability criteria (e.g., maintain loss-of-load expectation below 1-day-in-10 years).

In 2023, all assessment areas had adequate ARMs compared to their RMLs (see Figure 3.1; assessment areas are grouped together based on their peak demand season). This indicates that sufficient resource capacity was planned for 2023 to meet established resource adequacy targets. However, risks of electricity supply shortfalls arising from extreme weather, insufficient generator fuel supplies, or other energy limitations in the resource mix are not generally addressed by this traditional resource adequacy criteria.

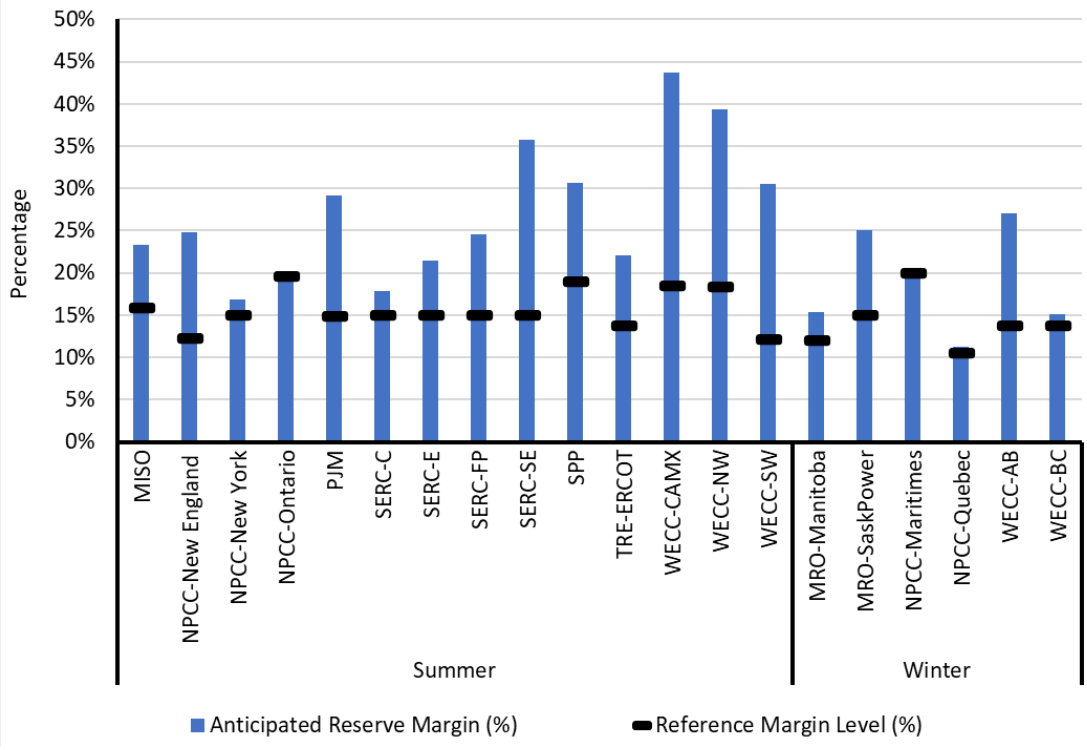


Figure 3.1: 2023 Peak Season Planning Reserve Margins and Reference Margin Levels[38]

[36] The peak demand season for an assessment area generally occurs when peak demand is highest or when planning reserves are lowest. For example, if an assessment area is summer peaking, that area experiences its highest demand levels during the summer months.

[37] Anticipated resources include all generating capacity and firm capacity transfers for the assessed summer and winter season. See the *2023 Long-Term Reliability Assessment* (*LTRA*) pp. 126–132 for complete definitions.

[38] M-1, Reserve Margin

2023 Seasonal Energy and Capacity Risk Analysis

The ERO assesses the risk of electricity supply shortfall in seasonal reliability assessments by considering Planning Reserve Margins, seasonal risk scenarios, and probability-based risk assessments. The expected impact of generator outages and extreme operating conditions on electricity supply and demand are also considered in NERC's seasonal reliability assessments. NERC evaluates the availability of supplies to meet normal seasonal peak demand as well as higher demand that may occur only once per decade, referred to as an extreme or 90/10 demand scenario. Increased demand, which can be caused by extreme temperatures, higher-than-anticipated generator forced outages, and derates, can create conditions that lead system operators to take emergency operating actions. The maps in Figure 3.2 and Figure 3.3 highlight the assessment areas that NERC identified ahead of the Summer 2023[39] and Winter 2023–2024[40] seasons as at risk for resource deficiencies.

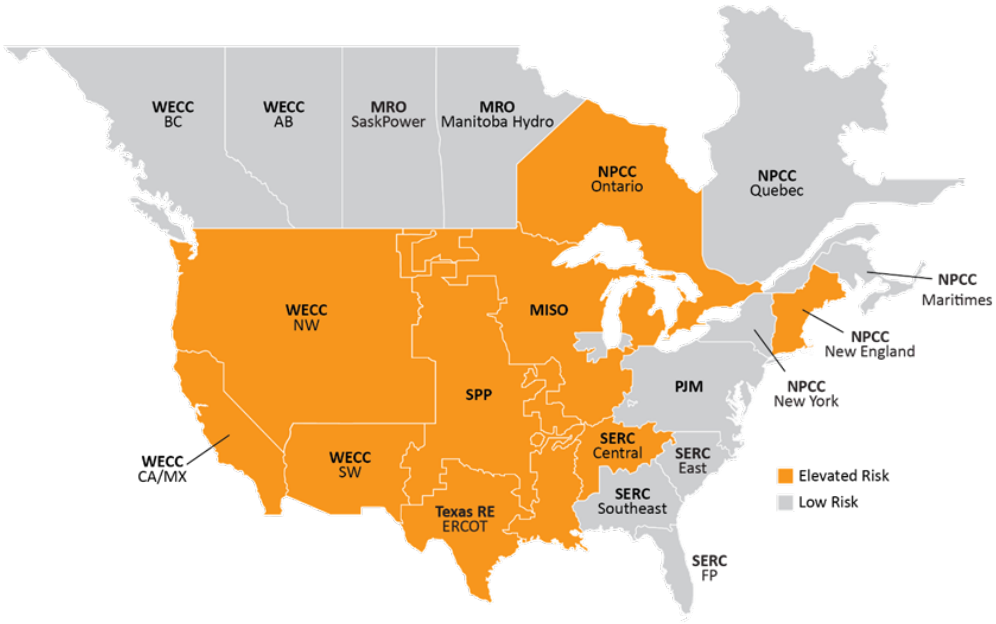


Figure 3.2: 2023 Summer Reliability Assessment Risk Area Map

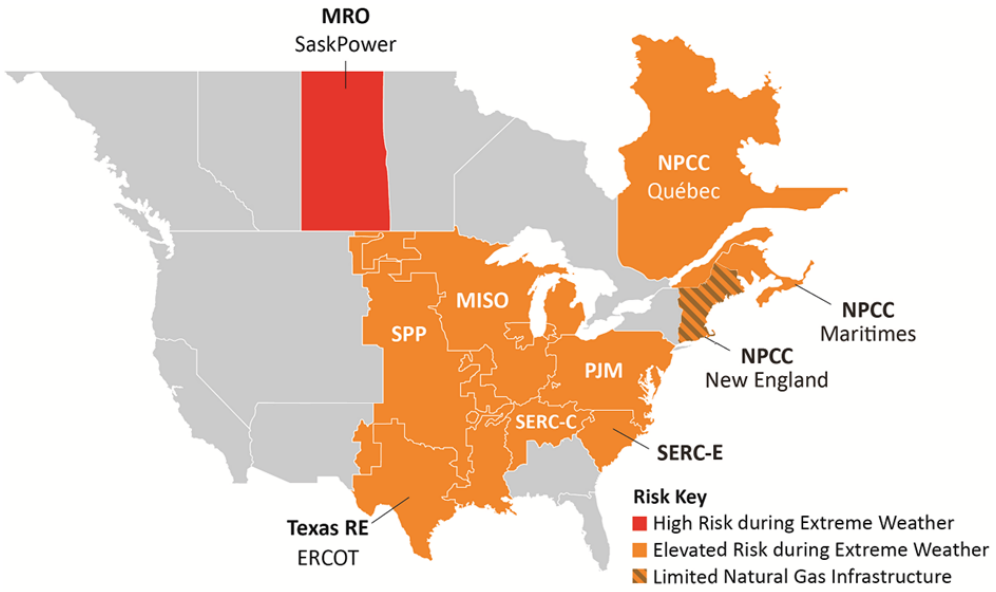


Figure 3.3: 2023–2024 Winter Reliability Assessment Risk Area Map

[39] NERC *2023 Summer Reliability Assessment*
[40] NERC *2023/2024 Winter Reliability Assessment*

2023 Capacity and Energy Performance

Actual operating conditions in 2023 stressed energy supplies to meet demand. In summer, high temperatures, wildfires, and weather conditions challenged electric grid operators in many parts of North America to maintain a reliable supply of electricity. It is noteworthy that, after a summer of soaring temperatures, extended heat waves, and new electricity demand records, few high-level EEAs were issued, and no disruptions occurred because of inadequate resources. Nonetheless, operators at BAs, TOPs, and RCs faced significant challenges and drew upon procedures and protocols to obtain all available resources, manage system demand, and ensure the flow of electricity over the transmission network. Additionally, load-serving entities and state and local officials in many parts of North America used mechanisms and public appeals to lower customer demand during periods of strained supplies. Table 3.1 and the following section describe actual demand and resource levels in comparison with NERC's *2023 SRA* and summarize 2023 resource adequacy events.

Eastern Interconnection–Canada and Québec Interconnection

Systems in parts of Canada experienced challenging conditions early in the summer from high electricity demand and wildfires over large areas. Electricity transfers from Québec to the neighboring Maritimes and New England were curtailed or disrupted during periods in May and June, when wildfires affected transmission facilities. Peak electricity demand in Ontario occurred in early September at a level near the 90/10 demand forecast. Additional imports helped the area meet the extreme demand.

Manitoba Hydro and SaskPower both experienced peak electricity demand in excess of 90/10 summer forecasts. Manitoba Hydro's peak occurred at the start of summer in June. Operators had sufficient reserves and were able to export supplies during the peak period to neighboring areas.

SaskPower peak electricity demand occurred in late July. A forced outage at a large thermal generator early in the summer contributed to operating challenges over much of the summer period. At the time of peak demand, forced outages were significantly higher than typical for summer peak periods.

Eastern Interconnection–United States

In Southwest Power Pool (SPP), summer electricity demand peaked in August and exceeded 90/10 forecasts. At the hour of peak demand, SPP experienced normal levels of forced thermal generation outages. Wind resource performance at the time of peak demand exceeded seasonal peak forecasts, helping to alleviate the strain on supplies. However, during periods in June and July, operators at SPP issued resource advisories during periods of forecasted high demand and low or uncertain wind resource output.

Midcontinent Independent System Operator (MISO) also experienced peak electricity demand during the same period in August; however, demand was between the normal and 90/10 summer peak forecast levels. Wind and solar resource output at the time of peak demand were below expectations for summer on-peak contributions. However, forced outages of thermal units were lower than expected. A Level 2 EEA was issued in August due to high forecasted loads and wind uncertainty. MISO used operating procedures to ensure that sufficient reserves were maintained during periods of high electricity demand and high forced generator outages at times throughout the summer.

PJM experienced peak electricity demand in late July at a level between normal summer peak and the 90/10 forecast. Wind and solar resource output were below seasonal peak expectations while low thermal generator outages were reported.

Peak electricity demand at NYISO and ISO-NE occurred in early September and fell below average summer peak forecasts.

Systems in the U.S. Southeast experienced peak demand above the 90/10 forecasts in mid to late August. Solar resource output exceeded the expected contributions for the peak demand period. Electricity imports into resource-constrained areas helped BAs maintain reserves during high-demand periods.

ERCOT

Extended heat waves led to record-setting system electricity demand in the ERCOT system throughout Summer 2023. Peak electricity demand occurred in mid-August at a level exceeding the 90/10 demand forecast. Simultaneous with peak demand, wind and solar generation were slightly below expected levels for peak demand periods, and thermal generator outages were also slightly higher than normal for peak periods. Nonetheless, operators were able to maintain sufficient reserves. At various times throughout the summer, ERCOT issued public appeals for conservation to help manage high-demand periods and periods when output from the solar resources is diminished (e.g., evenings). On September 6, ERCOT declared a Level 2 EEA to address a low-frequency condition on the system during a period of unusually high demand, declining solar output, and low wind output. Transmission system constraints led to the curtailment of some generation from wind resources in southern parts of the system. No load was shed during the event.

Western Interconnection–Canada

At the start of summer, the province of Alberta was in a state of emergency because of active wildfires and the threat of spreading from hot and dry conditions. A period of high demand from heat and humidity that coincided with generator forced outages and low wind conditions triggered an EEA. Alberta's system peak demand occurred in late July at a level above normal summer peak demand forecasts but below the 90/10 level. Wind and solar resource outputs were above seasonal forecast levels for peak demand periods. High temperatures in late August led to high demand at a time of planned transmission system maintenance. A Level 3 EEA was triggered when low wind conditions and insufficient imports resulted in reserve shortage.

The BC-Hydro system also experienced peak electricity demand in early August at a level near the 90/10 summer peak forecast.

Western Interconnection–United States

The California-Mexico assessment area, which consists of the CAISO, Northern California, and CENACE BAs, experienced system peak electricity demand in mid-August between the average summer peak demand forecast and the 90/10 peak demand forecast. Public appeals to shift electricity use to off-peak hours were used during some high-demand periods. The Mexico portion of the assessment area faced reserve shortages during periods in July and August because of high demand, generator outages, and unavailability of imports.

System peak electricity demand in the U.S. Northwest also occurred in mid-August and was below normal summer peak demand forecasts.

The U.S. Southwest experienced extended heat conditions and demand levels that exceeded normal summer peak demand forecasts. Wind and solar output also exceeded the expected levels for peak demand periods.

Table 3.1: 2023 Summer Demand and Generation Summary at Peak Demand

Assessment Area	Actual Peak Demand[1] (MW)	SRA Peak Demand Scenario[2] (MW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summer[4] (MW)
MISO	120,781	116,825 123,871	8,598	5,488	2,096	3,750	6,638
MRO-Manitoba Hydro	3,529	3,060 3,390	83	47	-		95
MRO-SaskPower	3,669	3,489 3,633	381	203	15		737
MRO-SPP	56,048	52,626 55,126	8,278	4,500	130	378	6,533

Table 3.1: 2023 Summer Demand and Generation Summary at Peak Demand

Assessment Area	Actual Peak Demand[1] (MW)	SRA Peak Demand Scenario[2] (MW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summer[4] (MW)
NPCC-Maritimes	3,544	3,284 3,625	131	255	40	-	1,690*
NPCC-New England	23,475	24,664 26,479	186	186	145	1,163	1,969
NPCC-New York	30,206	30,823 32,657	223	331	-	84	9,716
NPCC-Ontario	23,713	21,752 23,731	786	771	200	126	3,419*
NPCC-Québec	22,531	22,859 22,859	496	-	8		12,287*
PJM	147,605	141,771 162,666	1,278	1,688	1,826	2,984	8,020
SERC-C	44,011	40,313 42,967	15	564	673	511	1,225
SERC-E	43,307	42,881 45,606	-	-	3,032	1,473	2,129
SERC-FP	54,139	49,297 52,416	-	-	4,590	4,534	1,610
SERC-SE	45,558	44,117 44,834	-	-	2,781	4,647	2,334
TRE-ERCOT	85,432	78,927 82,316	9,557	10,293	10,431	12,509	6,699
WECC-AB	11,522	11,206 11,596	906	309	894	763	-
WECC-BC	9,157	8,636 9,234	373	137	0	1	-
WECC-CA/MX	54,130	55,494 67,344	1,074	1,111	6,930	14,489	2,444
WECC-NW	57,417	65,328 71,956	2,137	593	3,821	1,411	4,855
WECC-SW	31,689	25,612 27,992	835	3,968	1,731	5,062	2,507

Table Notes:

[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from Energy Information Agency (EIA) Form 930 data. For areas in Canada, this data was provided to NERC by system operators and utilities.

[2] See NERC *2024 SRA* demand scenarios for each assessment area (pp. 14–33). Values represent the normal summer peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.

[3] Expected values of wind and solar resources from the *2023 SRA*.

[4] Values from NERC Generator Availability Data System or provided by NERC entities for the 2023 summer hour of peak demand in each assessment area. Values marked with * include both planned and forced outages.

Operators issued Level 3 EEAs over five periods during the summer months because of projected reserve deficiencies from insufficient electricity supplies to meet forecasted demand. Table 3.2 provides an overview of resource and energy adequacy EEAs. This count of EEAs excludes events that resulted from transmission outages or storm damage to transmission.

Table 3.2: 2023 Resource and Energy EEA-3 Summary

Date (2023)	Regional Entity	EEA Description	NERC Seasonal Assessment Indication
June 7 and 12	MRO WECC (Canada Assessment Areas)	Heat and humidity contributed to high demand and thermal generator outages and derates. Low wind conditions caused wind resource output to be below seasonal norms. Some interruptible load was affected, but no firm load was shed.	**Low Risk**
July 26	WECC (Mexico Area)	High electricity demand, generator outages within the area, and transmission system congestion resulted in a reserve shortage. No load shed.	**Elevated Risk**
July 31–August 4, and August 14	MRO (Canadian Assessment Area)	Thermal generator outages and low wind conditions resulted in insufficient reserves during forecasted peak demand; periods of interruptible load shed were required to maintain reserves. No firm load was shed.	**Low Risk**
August 16	WECC (Mexico Area)	The Mexico assessment area experienced reserve deficiency when all BA resources were committed and imports from neighboring areas were curtailed during early evening hours. No firm load was shed.	**Elevated Risk**
August 28–29	WECC (Canada Assessment Area)	High temperatures caused high demand during periods when planned maintenance on a major transmission line reduced imports. Low wind conditions reduced wind generator output. No firm load was shed.	**Low Risk**

Changes in the Peak Resource Mix over the Past 10 Years

The generation resource mix is changing as older nuclear and fossil-fired generators retire and natural-gas-fired generators and wind and solar PV resources are built (see Table 3.3). Over the past 10 years, the BPS has reduced its on-peak capacity of coal-fired generation by over 122 GW and reduced its capacity of nuclear generation by 9 GW. During this time, the BPS added on-peak generation capacity: 73 GW of natural gas, 21 GW of wind, and 57 GW of solar PV.[41]

Table 3.3: Generation Resource Capacity by Fuel Type

Generation Fuel Type	2013 On-Peak		2023 On-Peak	
	GW	Percent	GW	Percent
Coal	318.0	30.1%	195.3	18.4%
Natural Gas	412.0	39.0%	485.3	45.8%
Hydro	138.9	13.2%	124.5	11.7%
Nuclear	115.2	10.9%	106.2	10.0%
Oil	48.9	4.6%	32.1	3.0%
Wind	11.6	1.1%	32.8	3.1%
Solar PV	2.0	0.2%	59.7	5.6%
Other	8.5	0.8%	24.4	2.3%
Total:	**1055.0**	**100.0%**	**1,060.2**	**100.0%**

[41] Data obtained from NERC long-term reliability assessments

The resource mix and the pace at which it is changing varies considerably across different parts of the North American BPS. **Figure 3.4** provides an Interconnection-level view of the generation resource mix since 2013.

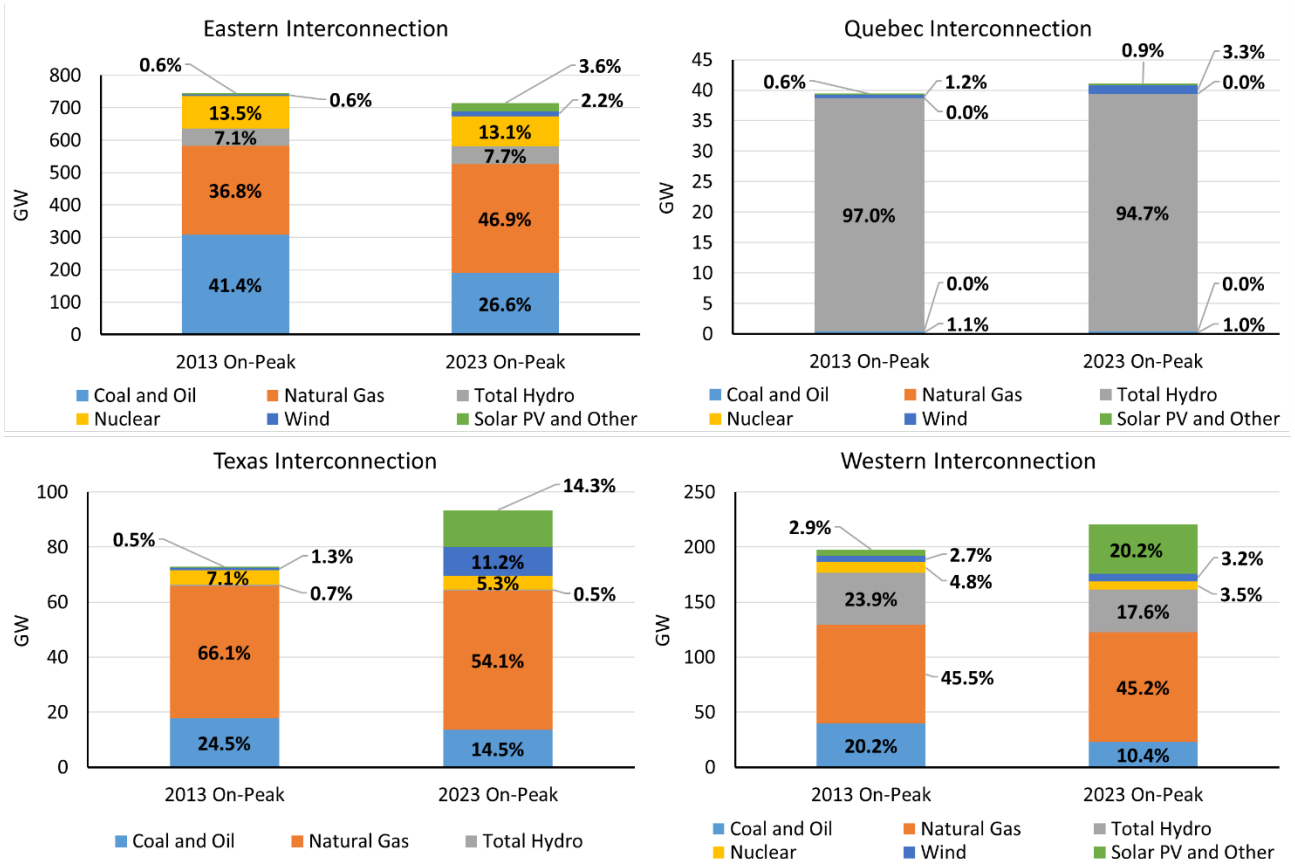


Figure 3.4: 2013 and 2023 Capacity Resource Mix by Interconnection

NERC's *LTRA* reports on both the current generation resource mix and projections for the next 10 years for each of the 20 assessment areas within the four Interconnections that encompass the North American BPS. NERC's *2023 LTRA* shows that wind, solar PV, and hybrid (battery storage combined with another type of generator) resources are projected to be the primary additions to the resource mix over the 10-year assessment period; this leads the continued energy transition as older thermal generators continue to retire. Maintaining a reliable BPS throughout the transition requires unwavering attention to ensure that the resource mix satisfies capacity, energy, and essential reliability service (ERS) needs under designed conditions. It will also require significant planning and development of the interconnected transmission system to have a deliverable electricity supply from new resources to changing types of loads and the ability to withstand system contingencies.

Critical Infrastructure Interdependencies

In addition to an increased reliance on weather-dependent fuels, such as wind and solar, today's generation resource mix includes more natural gas-fueled generation than ever before. Figure 3.5,[42] prepared by the Energy Information Agency (EIA), shows the average natural gas generation by dispatch hour for the years 2021–2023.

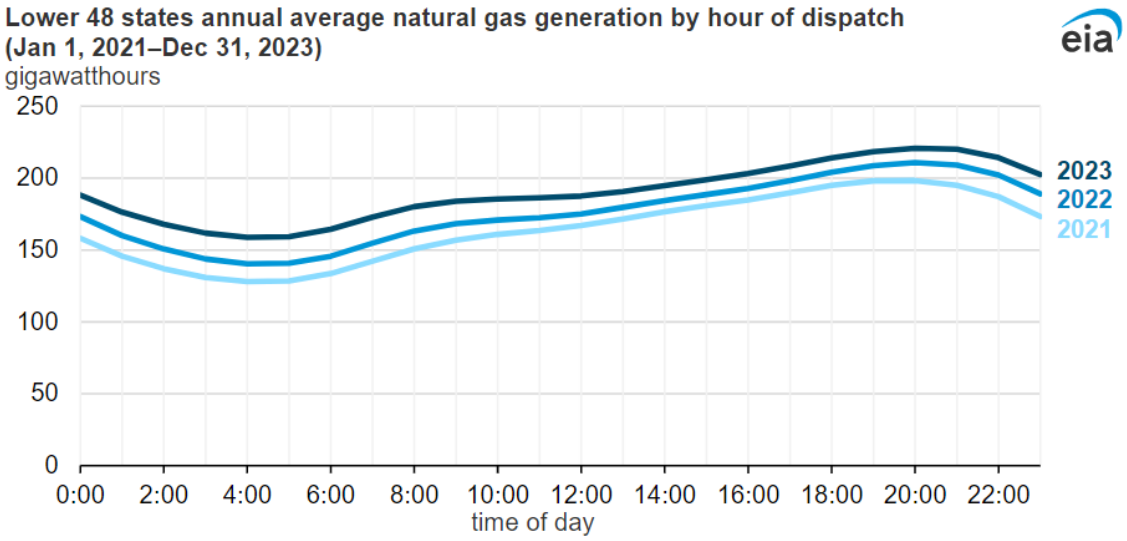


Figure 3.5: Lower 48 States Annual Average Natural Gas Generation by Hour of Dispatch

The supply and delivery of natural gas to power plants depends on the reliable operation of natural gas production, gathering, processing, and delivery facilities that in turn often rely on electricity as a prime mover. The same is true of the water supply, whether it will be used to directly generate electricity or to cool another generator, it is often managed and controlled by third-party infrastructure powered by electricity. Figure 3.6 and Figure 3.7 show generation outages over the past five years that have been attributed to a lack of natural gas fuel or water supply availability issues.

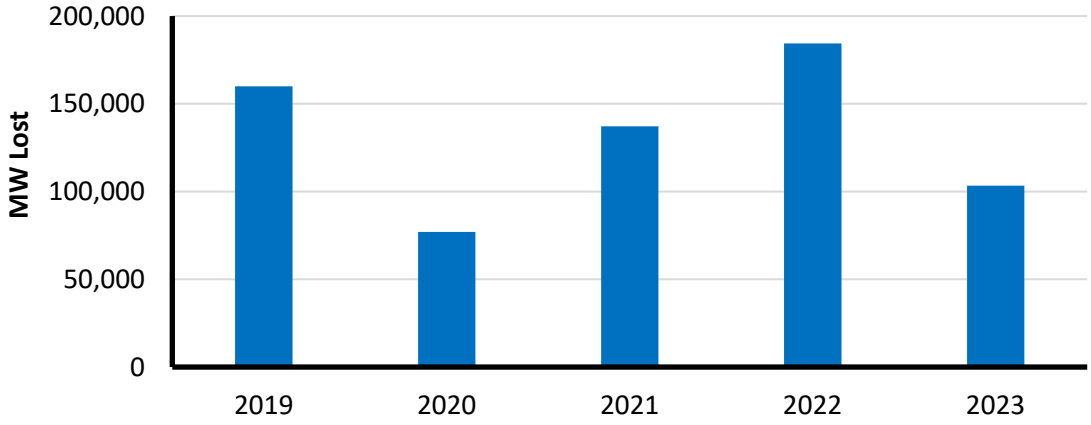


Figure 3.6: Natural-Gas-Fired Outages Due to Lack of Fuel

[42] U.S. natural gas-fired electricity generation consistently increased in 2022 and 2023 - U.S. Energy Information Administration (EIA)

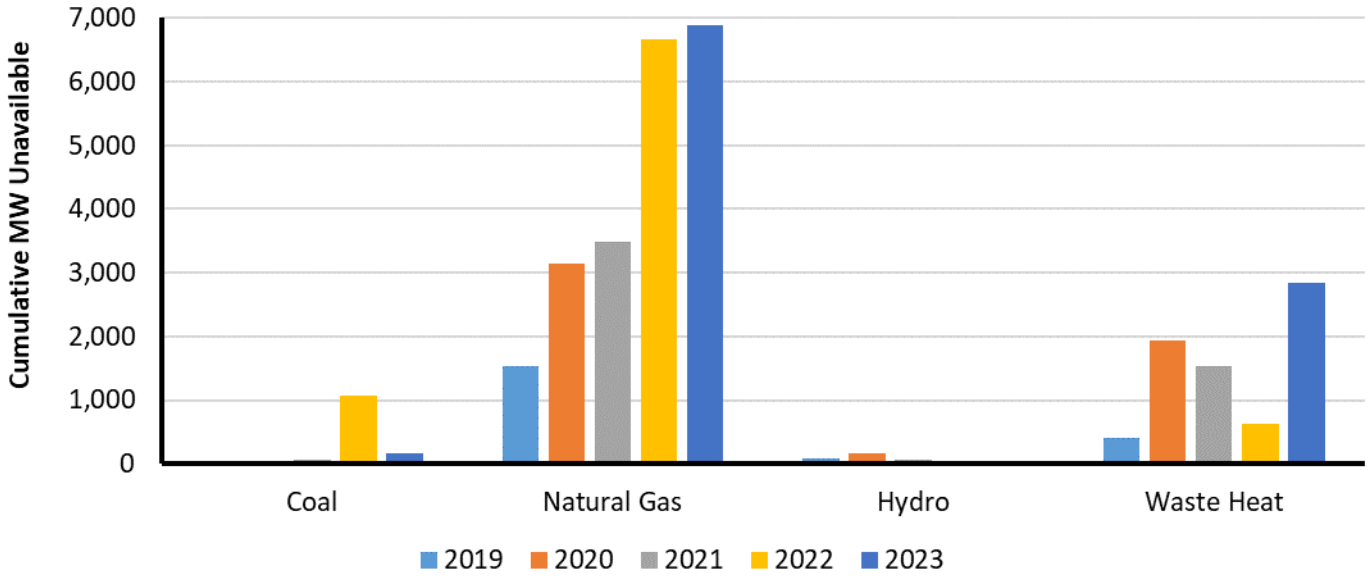


Figure 3.7: Cumulative MW–Water Supply Issues by Year

As natural gas continues to fuel more base and intermediate loaded generation, extreme weather events have highlighted the risks of the natural gas and electric industries' mutual reliance. The risk is particularly acute in winter when natural gas demand for home and commercial space heating coincides with high electricity demand. This risk was realized in February 2021 when extreme cold weather descended upon the U.S. central southwest. The resulting gas production declines, pipeline force majeures, and generator outages led to electrical energy deficiencies and load shedding, which in turn exacerbated gas unavailability issues. Since that time, efforts to maintain gas production and pipeline availability during cold weather, notably in Texas, as well as NERC and industry actions to improve cold weather generator availability, have been developed and many have been implemented.[43,44,45,46]

In October 2023, FERC and the ERO Enterprise published the official report on Winter Storm Elliott. Previously identified electric–gas interdependencies were less of a contributing factor to the electrical energy deficiencies than what occurred during the February 2021 winter storm. Energy-deficient balancing areas shed much less load than in February 2021, and gas production facilities were not impacted. The report identifies the degree to which facilities essential to the production and delivery of natural gas have still not been identified to balancing area operators as critical electrical loads, which remains a risk for future cold weather events.[47] Risks emanating from the interconnected electric–gas energy delivery system were also highlighted.[48]

[43] Fuel Assurance and Fuel-Related Reliability Risk Analysis Guideline
[44] Considerations for Performing an Energy Reliability Assessment
[45] Project 2022-03 Energy Assurance with Energy-Constrained Resources
[46] Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather
[47] WS Elliott Report Recommendation 4(c) addresses this risk.
[48] See, generally, WS Elliott Report, pp 76-88.

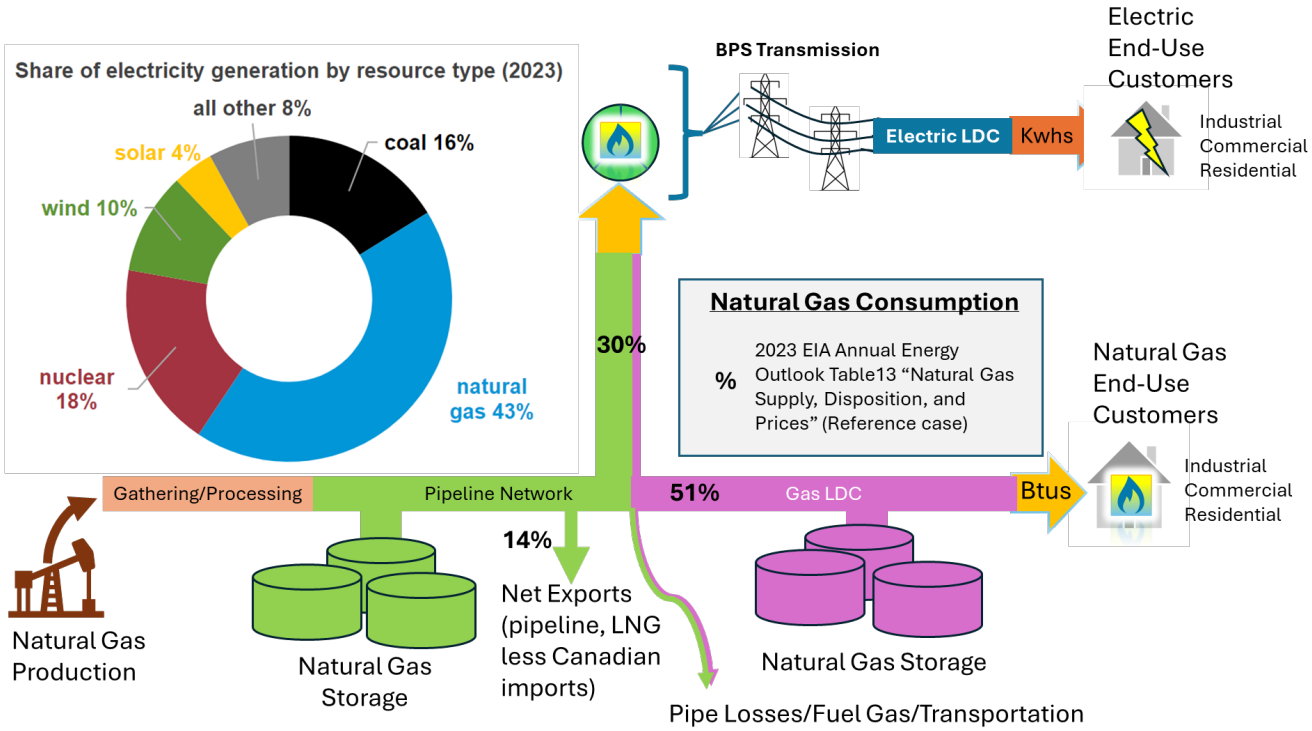


Figure 3.8: The Interconnected Gas and Electric Energy Delivery System[49,50]

Utilizing data from the EIA's 2023 Annual Energy Outlook, Figure 3.8 shows the annual generation by fuel type and natural gas consumption by end-use sector percentages. Industrial, commercial, and residential end users account for 51% of all natural gas use in the United States. Power generators use 30% of all natural gas to produce electricity, representing 37% of all electrical energy delivered. Extreme cold weather can significantly increase demand for natural gas by power generators and residential/commercial end-use customers well above these annual averages. For example, during the December 2022 event, the U.S. Northeast/Midwest/Southeast regions' natural gas consumption51 by electric generators temporarily increased by roughly 15% while consumption of natural gas by residential and commercial end-use gas customers increased by nearly 50% (shown in Table 3.4).[52]

Table 3.4: Overall and Relative Increase in Natural Gas Consumption for the Northeast, Midwest, and Southeast Regions during Winter Storm Elliott Billion Cubic Feet per Day (Bcf/day)[53]

	Dec. 15–20, 2022 Average	Dec. 21–26, 2022 Average	Percent Change
Northeast/Midwest/Southeast Natural Gas Demand	82.3	100.5	22.1%
Power Burn	21.2	24.6	15.8%
Residential/Commercial	31.4	46.0	46.5%
Industrial	15.3	16.5	7.9%
LNG Feedgas	10.6	8.5	-19.8%
Pipe Loss	3.9	5.0	29.2%

[49] Annual gas consumption percentages EIA 2023 Annual Energy Outlook
[50] Annual electric energy from fuel type EIA 2023
[51] Consumption does not include demand unmet due to fuel unavailability.
[52] WS Elliott Report, Fig. 92.
[53] WS Elliott Report, Fig. 92

This increased consumption, in combination with natural gas supply interruptions during extreme cold weather periods, challenges both grid operators and gas controllers to maintain energy deliveries to end-use customers when conditions can be life threatening. While the gas industry has long relied upon natural gas storage to manage spikes in consumption and mitigate the risk of supply interruption, electric generators typically do not store natural gas, and electric energy storage at utility scale is not currently available to overcome this risk.

Winter Storm Elliott Report Recommendation 5 addresses situational awareness issues by urging grid operators and gas controllers from across the interconnected natural gas–electric production and energy delivery system to quickly develop and formalize protocols to communicate operational issues leading up to and during extreme weather events.[54] Longer term, Recommendation 4 of the Winter Storm Elliott report calls for the creation of a natural gas reliability organization to develop rules that would require natural gas wellhead, gathering, processing, and transportation infrastructure cold weather preparations to maintain natural gas availability and energy deliveries to end-use customers when needed most.[55]

6 GHz Frequency Communications

In April 2020, the Federal Communications Commission (FCC) opened usage of the 6 GHz[56] spectrum to new users to promote spectrum sharing. Sharing this spectrum will likely impact the energy industry (specifically critical infrastructure) and BPS reliability. The industry and incumbent users continue to conduct testing on potential harmful interference for BPS communications.

In support of industry awareness and strengthening reliability, the 6 GHz Task Force published its *6 GHz Microwave Link Interference Preparedness*[57] white paper in December 2023. This white paper provides valuable background information on the current state of the FCC processes, current spectrum usage, and recommendations for the industry to assist with baseline understanding, the identification of potential harmful interference, and mitigation options to offset impacts from harmful interference. Additionally, the 6 GHz Task Force plans to conduct an awareness webinar in the second quarter of 2024.

Increasing Complexity of Protection and Control Systems

Together with the progression of interconnected power generation, transmission, and distribution assets, the landscape of automated tools and systems has transformed. This evolution spans an array of digital information platforms and microprocessor-driven devices, fostering a technologically diverse environment wherein operators can wield unprecedented control from virtually any location at a fraction of the historical cost. When meticulously designed and executed, these automated tools offer a means to enhance the reliable and secure use of the technologies and concepts in the BPS. However, the proliferation of these systems introduces an increasing web of rules, algorithms, and interdependencies that amplify the intricacy of operation. The swift decision-making capabilities of modern relays, tripping circuits, or initiating alternative actions within milliseconds epitomize the accelerated pace at which these systems must navigate intricate operational scenarios. The increasing integration of IBRs also expands this complexity, requiring the deployment of additional automated tools and systems. Navigating this expanding labyrinth demands not only vigilant maintenance, prudent asset replacement, and strategic upgrades, but also a nuanced understanding of the dynamic interplay between diverse system components. As the scope and scale of these challenges continue to proliferate, it is imperative to cultivate agile, adaptive solutions.

Protection System Misoperation Trends

Figure 3.9 presents the annual misoperation rates across all Regional Entities and separately for each Regional Entity over the last five years. The comparison of the misoperation rate of the first four years to the most recent year shows a statistically significant decreasing trend for Texas RE. No statistically significant trend is observed for any other Regional Entity, nor within the overall MIDAS data. The overall count of misoperations in 2023 was the lowest over the past five years (see Table 3.5).

[54] WS Elliott Report, p. 143.
[55] WS Elliott Report, p. 137.
[56] *6 GHz Communication Penetration in the Electric Industry*, April 23, 2024
[57] *6 GHz Microwave Link Interference Preparedness*

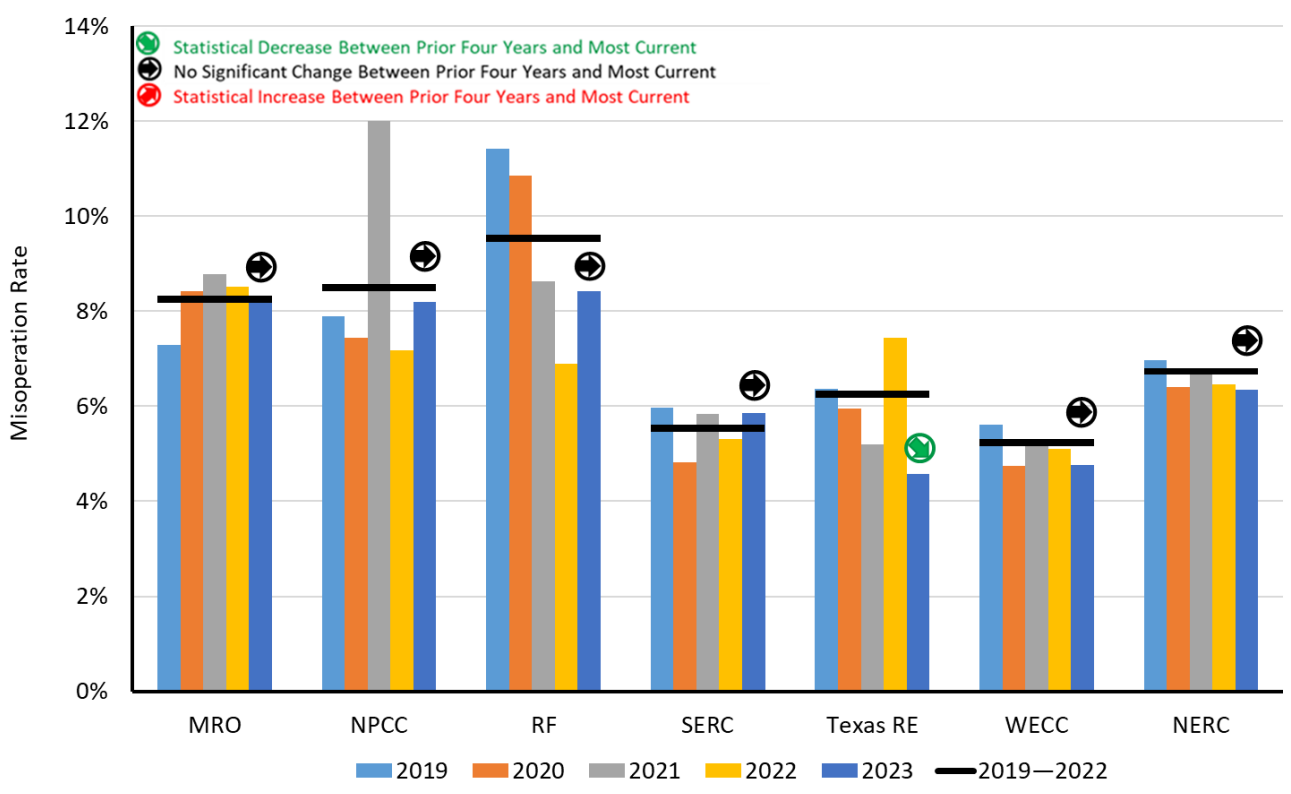


Figure 3.9: Changes and Trends in the Annual Misoperations Rate by Regional Entity[58]

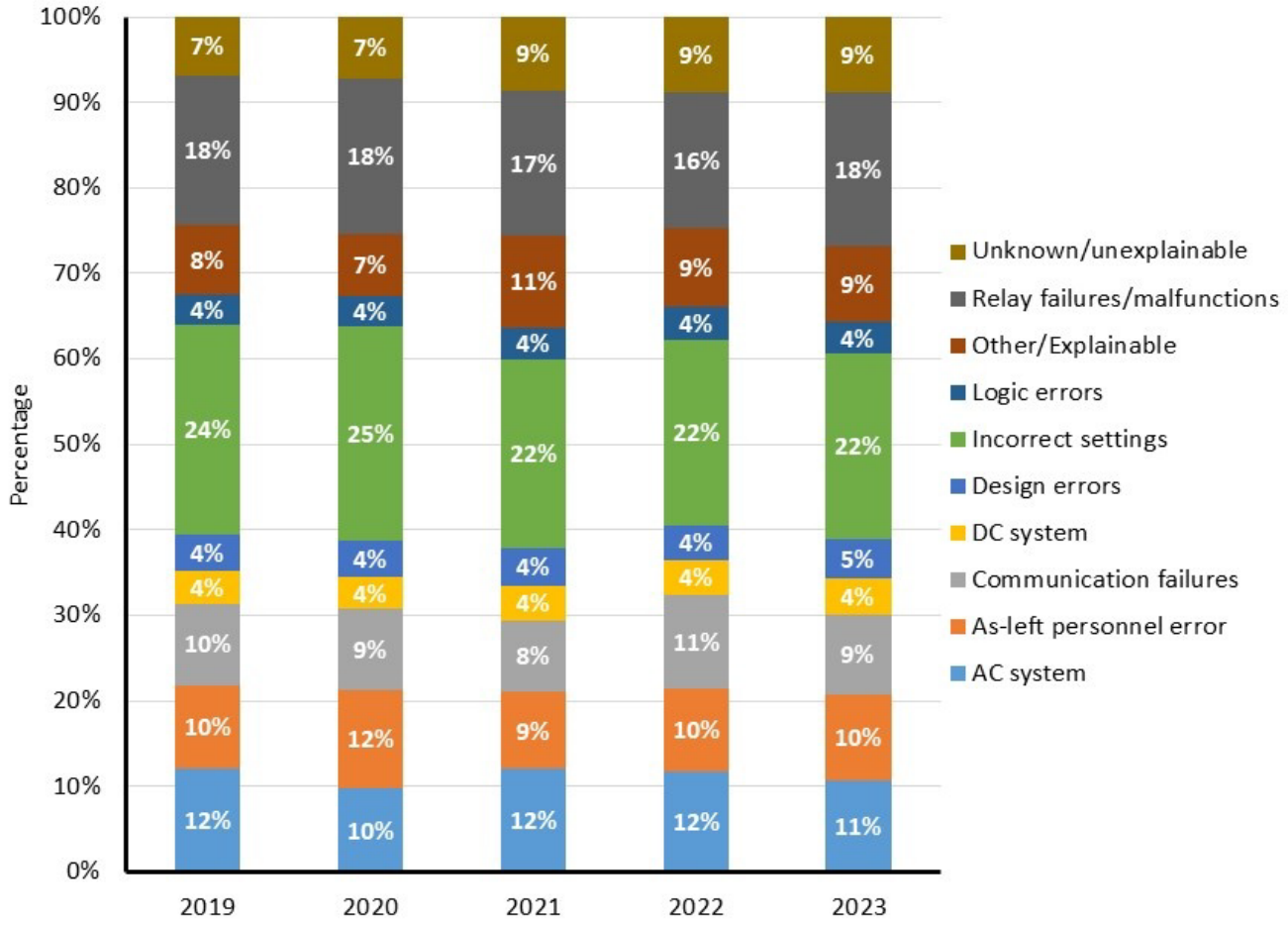
Table 3.5: Five-Year Protection System Operations and Misoperations Counts 2019–2023

Area	Protection System Operations					Misoperations				
	2019	2020	2021	2022	2023	2019	2020	2021	2022	2023
North America	19,283	18,306	17,460	18,012	17,821	13,44	1,172	1,187	1,163	1,131
MRO	3,734	3,054	2,617	3,299	2,999	272	257	230	281	247
NPCC	1,658	1,774	1,365	1,811	1,744	131	132	164	130	143
RF	2,146	1,888	1,867	2,061	1,865	245	205	161	142	157
SERC	4,736	5,267	4,622	4,775	4,894	283	254	270	254	287
Texas RE	2,640	2,000	2,599	1,991	2,182	168	119	135	148	100
WECC	4,369	4,323	4,390	4,075	4,137	245	205	227	208	197

Leading Causes of Misoperations

Figure 3.10 shows the distribution of misoperation causes over the past five years. Incorrect settings and relay failures/malfunctions remain the most common causes of misoperations. There was minimal change in the relative frequency of causes from 2022 to 2023.

[58] M-9, Protection System Misoperations Rate



Year	2019	2020	2021	2022	2023
Misoperation Count	1,344	1,172	1,187	1,163	1,131

Figure 3.10: Percentage of Misoperations by Cause Code (2019–2023)

Misoperation Impact Score

The misoperation impact score provides an estimated impact of each misoperation on the BPS. This is done by summing weighted values for the facility voltage class, equipment type, cause, and category (shown in the equation and Table 3.6 below). Note that this calculation can be scaled down to an individual misoperation. In this report, the results are aggregated and then plotted in a box and whisker plot to identify potential trends.

$$[Misoperation\ Impact\ Score] = [Voltage\ Class\ Factor] * 0.3 + [Equipment\ Type\ Factor] * 0.2 + [Cause\ Factor] * 0.1 + [Category\ Factor] * 0.4$$

Table 3.6: Generation Resource Capacity by Fuel Type Misoperation Impact Factors

Field	Value	Factor
Voltage Class	0–99 kV	0.4
	100–199 kV	0.5
	200–299 kV	0.65
	300–499 kV	0.85
	500–765 kV	1
Equipment Type	BES UFLS, BES UVLS	0.333
	Shunt Capacitor, Shunt Reactor/Inductor	0.5
	HVdc, Line, Series Capacitor, Series Reactor/Inductor, Transformer, Breaker	0.667

Table 3.6: Generation Resource Capacity by Fuel Type Misoperation Impact Factors		
Field	**Value**	**Factor**
	Bus, Other	0.833
	Dynamic VAR Systems, Generator	1
Cause	Equipment Errors (and Other)	0.5
	Human Errors	0.85
	Unknown	1
Category	Slow Trip–Other than Fault	0.167
	Unnecessary Trip–Other than Fault	0.333
	Failure to Trip–Other than Fault, Unnecessary Trip–During Fault	0.667
	Failure to Trip–During Fault, Slow Trip–During Fault	1

The median and inner quartiles of all misoperations' impact scores (see Figure 3.**11**) have remained largely unchanged over the past five years, while the number of outliers has decreased. The Duncan's grouping test[59] confirms that the mean impact score for 2023 was statistically similar to 2021 and 2022 but statistically lower than in 2019 and 2020. These factors (in combination with the slowly decreasing but statistically stable misoperation rate, number of misoperations, and cause distribution) indicate that work being done to reduce misoperations is continuing. The ERO and industry should continue to monitor and coordinate to identify any common issues to further drive down misoperations and their severity.

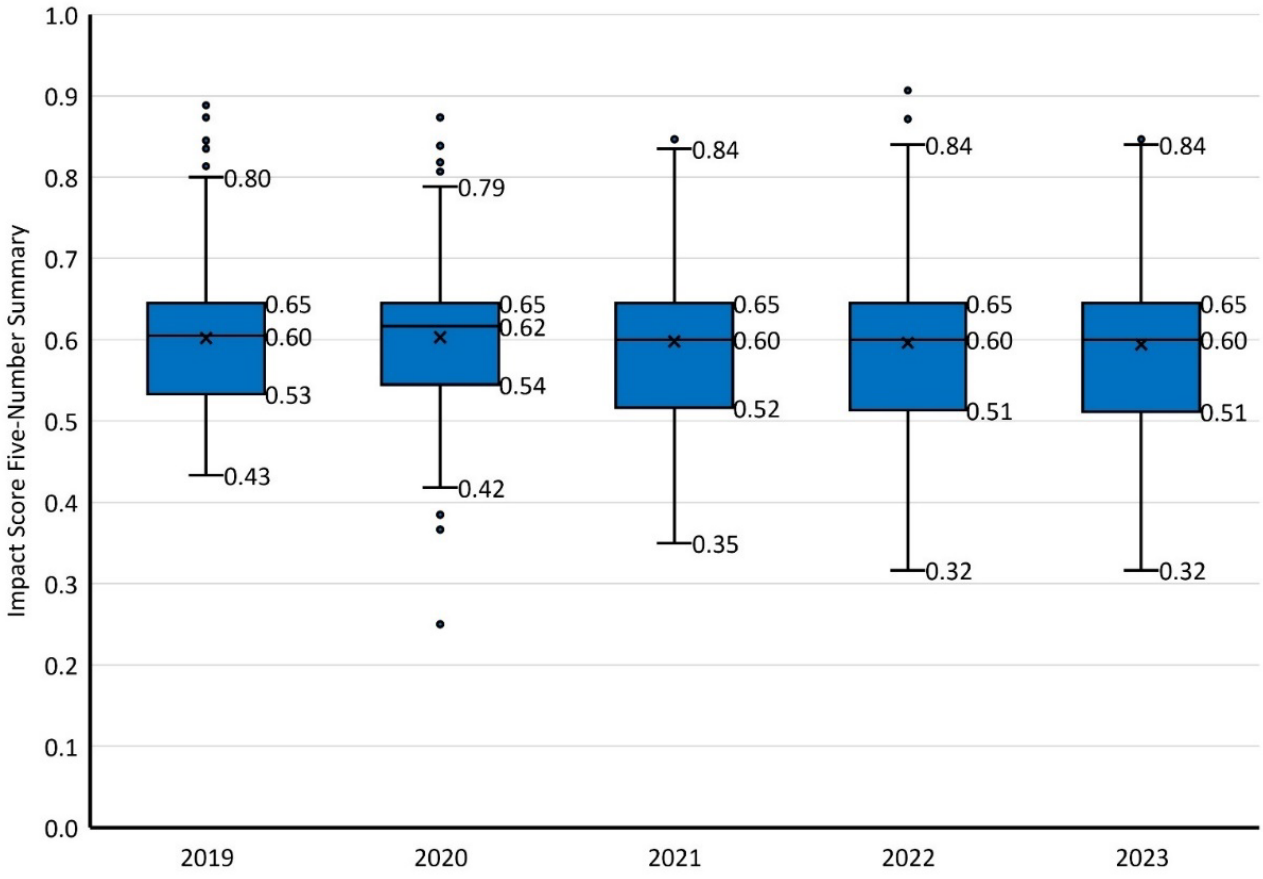


Figure 3.11: Misoperations Impact Score Distribution (2019–2023)

Year	2019	2020	2021	2022	2023
Total Impact Score	808.98	706.88	709.91	693.41	671.50

[59] Duncan, David B. "Multiple Range and Multiple F Tests." *Biometrics* 11, No. 1 (1955): 1–42. https://doi.org/10.2307/3001478.

Protection System Failures Leading to Transmission Outages

AC circuits and transformers saw a decrease in the number of outages per element in 2023, resulting in the number of outages per ac circuit being statistically significantly lower than the prior four years (see Figure 3.12).

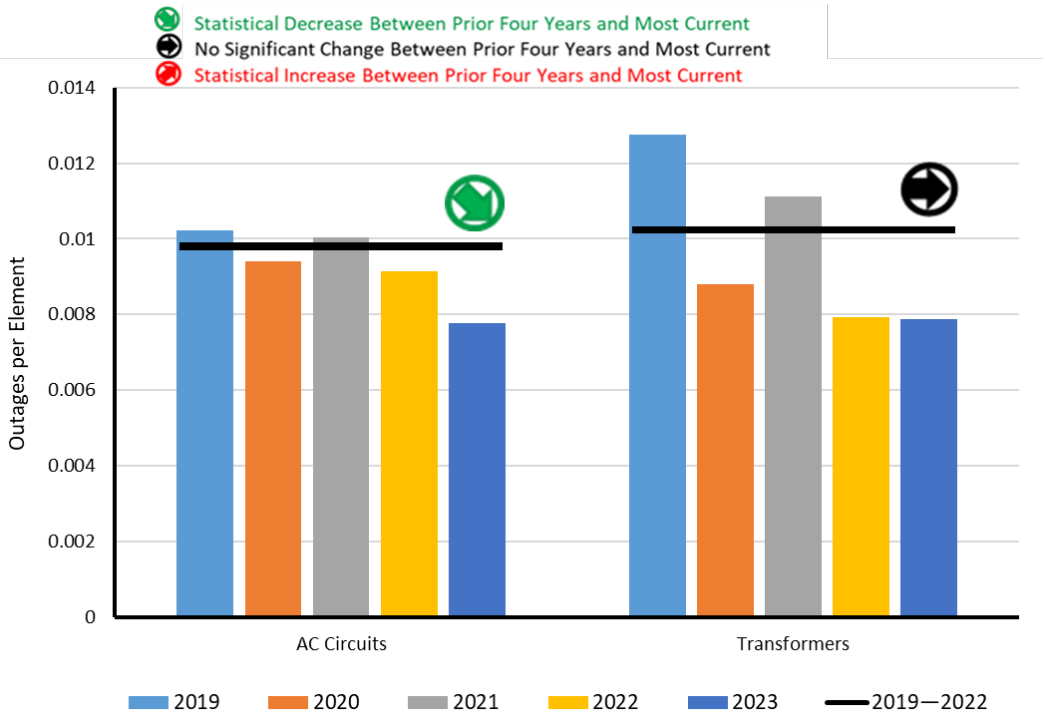


Figure 3.12: Failed Protection System Equipment Outages[60]

Event-Related Misoperations

An analysis of qualified events reported through the ERO Event Analysis Process (EAP) found that there were 72 transmission-related qualified events in 2023, 36 of which (50%) involved misoperations (see Figure 3.13). In comparison, 2019 saw 76 transmission-related qualified events, of which 41 (54%) had associated misoperations. This reduction is attributed to the ERO and industry stakeholder efforts to reduce protection system misoperations through initiatives such as various task forces, workshops, and more granular root-cause analysis.

[60] M-12, Automatic AC Transmission Outages Initiated by Failed Protection System Equipment

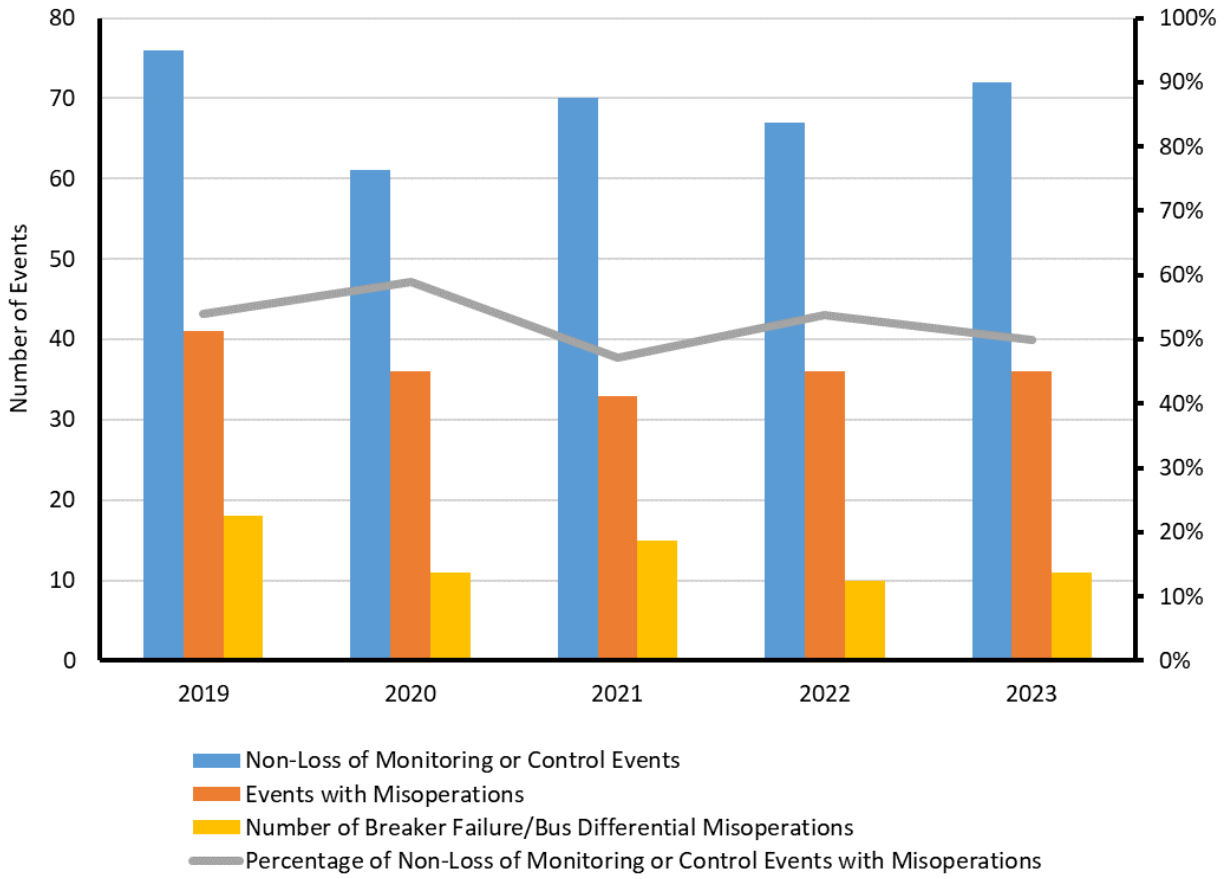


Figure 3.13: Events with Misoperations

Loss of Situational Awareness

The BPS operates in a dynamic environment with physical properties that are constantly changing. Situational awareness is necessary to maintain reliability, anticipate events, and respond appropriately when or before events occur. To maintain the reliability of the BPS, entities use various situational awareness tools, including energy management systems (EMS), transmission outage planning, load forecasting, geomagnetic disturbance/weather forecasting, data from neighboring entities' operations, and interpersonal communication within their own companies and with neighboring systems.

Without the appropriate tools and up-to-date data, system operators may have degraded situational awareness that impacts their ability to make informed decisions regarding BPS reliability. Unexpected outages of systems needed for communications or monitoring and control of equipment, as well as planned outages without appropriate coordination or oversight, can leave system operators with reduced visibility. For system operators, the EMS is a critical component of situational awareness.

At the same time, security risks have implications for industry that require a broadened perspective from what was traditionally addressed in conventional engineering practices, such as planning, design, and operations. The *2023 ERO Reliability Risk Priorities Report*[61] continued to highlight security risks as one of the four top risks for the electricity sector with cyber security risks identified as the most likely to impact the industry.

Impacts from the Loss of EMS

An EMS is a computer-aided set of tools used by system operators as a primary means to monitor, control, and optimize the performance of the generation and/or transmission system. The EMS allows system operators to monitor and control frequency, the status (open or closed) of switching devices plus real and reactive power flows

[61] *2023 ERO Risk Priorities Report*, August 2023

on BPS tie-lines and transmission facilities within the respective control area, and the status of critical applicable EMS applications (e.g., state estimator (SE), real-time contingency analysis (RTCA), automatic generation control, alarm management).

There were 32 categorized events associated with an EMS in 2023; there were no reported EMS-related events that caused loss of generation, transmission lines, or customer load. Figure 3.14 shows a trend of the reported EMS events by loss of EMS functions over the 2019–2023 period.

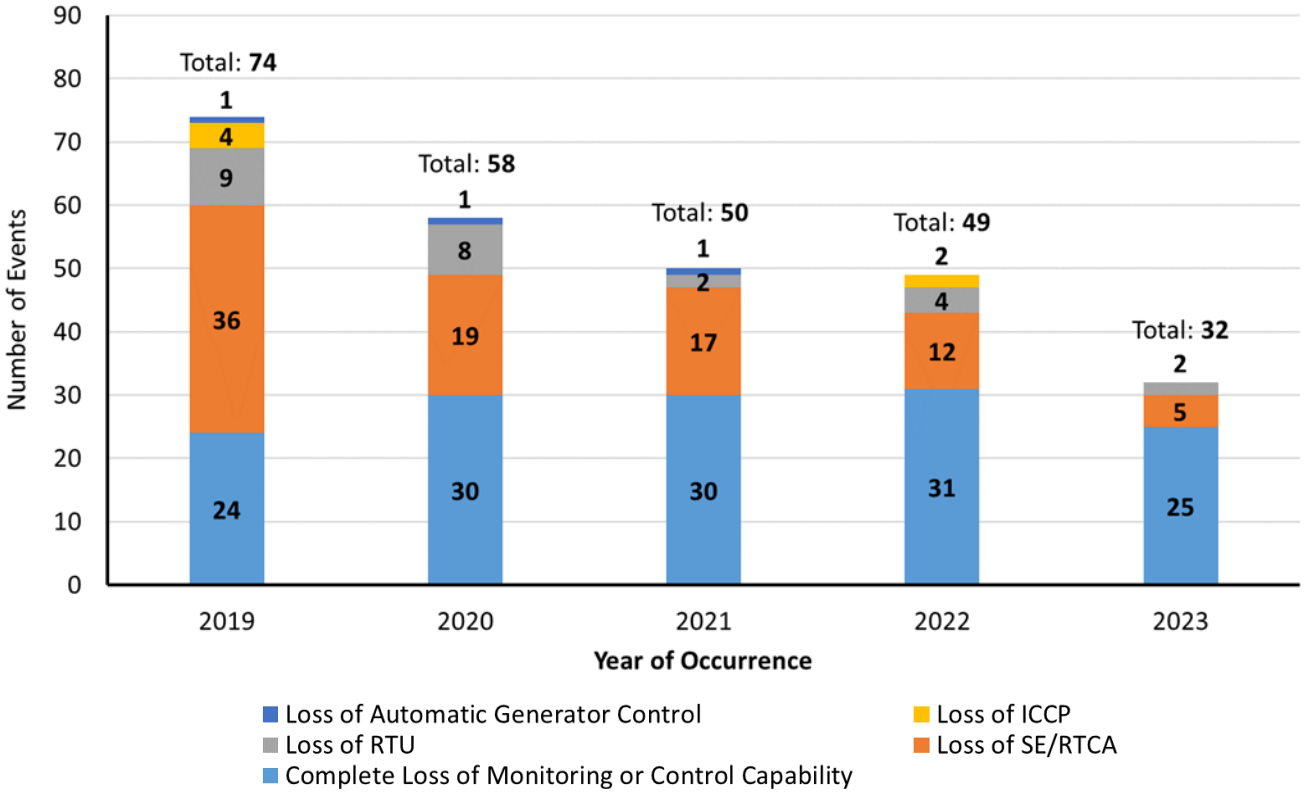


Figure 3.14: Number of EMS-Related Events (2019–2023)

There are two main reasons for the declining trend of the loss of SE/RTCA and Inter-Control Center Protocol (ICCP) events since 2019:

- **Changes to Work Environment**
  The industry has made major efforts to enhance EMS reliability and resilience. For example, many entities built a 24x7 onsite team that works with system operators and provides dedicated support to SE and RTCA. This action has reduced the outage duration, resulting in many SE/RTCA issues not being reportable.
- **Changes to Reporting**
  Partial loss events (i.e., loss of SE/RTCA, loss of ICCP, loss of remote terminal units (RTU), and loss of automatic generation control) are no longer captured as part of EOP-004-4[62] mandatory reporting (effective April 1, 2019). However, the ERO encourages partial-loss EMS reporting through the ERO EAP for trending of potential reliability risks/impacts to the BPS as some entities continue to do.

There were 25 complete loss of monitoring[63] or control[64] capability events in 2023. The following two major contributors to the events were observed:

[62] Emergency Operating Procedure, Event Reporting, EOP-004-4

[63] The ability to accurately receive relevant information about the BPS in real time and evaluate system conditions using real-time data to assess existing (pre-contingency) and potential (post-contingency) operating conditions to maintain reliability of the BPS.

[64] The ability to take and/or direct actions to maintain the reliability of the BPS in real time via entity actions or by issuing operating instructions.

- **Network Communications Configuration**
  EMS-related communications networks are moving from point-to-point serial communication infrastructures to packet-based networks. The main advantage of a packet-based network is to transmit data from one node to another node while avoiding a communications system failure caused by the breakdown of a single (or few) intermediate link(s). Consequently, the correct configuration is critical to ensure that the communications network functions as designed.
- **Power Supply**
  Stable and secure power supplies are critical to control rooms, data centers, and substations. It is essential that routines be established for monthly testing and maintenance of the backup generator, uninterruptible power supply, and associated power switches.

Database and system configuration/settings were improved in 2023, contributing to the decrease in the complete loss of monitoring or control capability events.

- **Settings**
  Periodic review of system parameters and settings with vendor support has been shown to reduce settings errors. Different flags and weighting levels may need to be adjusted as models are expanded or system conditions change.
- **Skill Development**
  More skilled in-house personnel who can troubleshoot and correct these issues can lead to shorter outage durations, including additional knowledge transfer from the vendor to the in-house staff.

Over the five-year period (2019–2023), the average partial or full function EMS outage time (see Figure 3.15) was 73 minutes, making the calculated EMS availability 99.994% during the term.

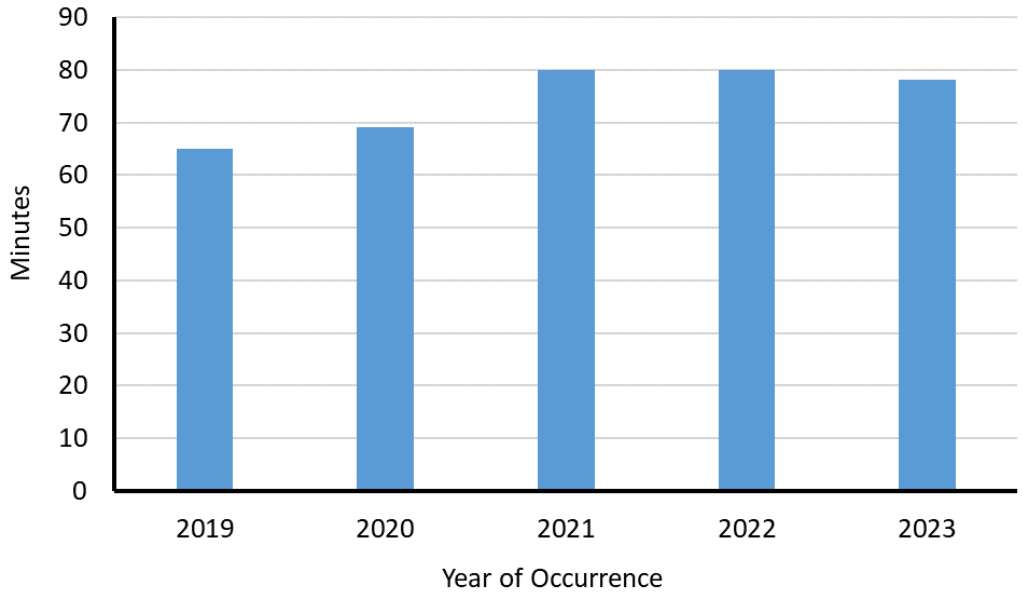


Figure 3.15: Average EMS Outage Time (2019–2023)

Largest Contributor to Loss of EMS

Reported EMS events can be grouped by the following attributes:

- **Software**: Software defects, modeling issues, database corruption, memory issues, etc.
- **Communications**: Device issues, less-than-adequate system interactions, etc.
- **Facility:** Loss of power to the control center or data center, fire alarm, ac failure, etc.

- **Maintenance:** System upgrades, job scoping, change management, software configuration, settings failure, etc.

Figure 3.16 shows that, over the evaluation period of 2019–2023, outages associated with software challenges were the leading contributors to EMS outages followed by outages associated with communications and maintenance challenges.

Software failure was usually caused by bugs, either in a vendor application or in an in-house implementation. A software testing process is always recommended to meet requirements. Systems and software assurance require a process model for formal testing based on the development framework the software was created with. The scope of the test should provide an assurance case for operation of the software under test for both known and unknown operating conditions with the inclusion of a data integrity check of the module. In general, the process is considered to have four components:

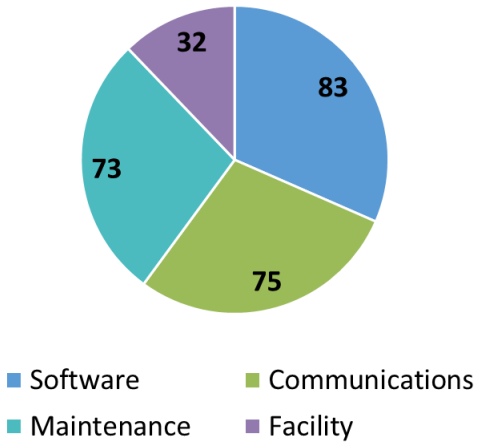


Figure 3.16: Contributors to Loss of EMS Functions (2019–2023)

- **Test Scope:** Define the requirements and setup of the test environment, features and functions that need to be tested, documentation to refer to and produce as output, approval workflows, etc.
- **Test Design:** Design the test cases that are necessary to validate the system, functions, and features being built compared to its design requirements. Typically, regression testing, and incremental testing are necessary.
- **Test Execution:** Execute tests in many different ways.
- **Test Closure:** Consider the exit criteria for signaling completion of the test cycle and readiness for release.

Communications failure means that data exchange was degraded between substations and control rooms or between the entity and its RC/neighboring entities. Internal network configuration error and hardware failure are two major contributors to this cause. Entities should maintain network devices on a schedule in accordance with the latest vendor information, security bulletins, technical bulletins, and other recommended updates. Entities must also consider redesigning communications systems such that the most critical BPS substations communicate simultaneously over entirely separate physical paths to control centers.

Maintenance failure usually occurs when system configuration/settings are not updated according to changes in the latest system operation. These EMS system configuration/settings are often uniquely programmed for the entity to meet the individual needs based on the entity's configuration, topology, contingencies, and external model. When the entity expands or modifies its model, the configuration/settings need to be tuned or calibrated based on subsequent topology changes. Periodic reviews of the settings and configuration with the vendor's help may be necessary to ensure that the EMS functions continue to converge and produce a quality solution. The frequency of these reviews will vary, but consideration of reviewing the settings and configuration following model changes, generation retirements, software upgrades, and any other significant changes made to the EMS system or model is necessary.

A review of ERO EAP data shows that a total of 5.7%, or 15 out of the 263 reportable loss of EMS events between 2019 and 2023 that were greater than 30 minutes, were related to external communication provider issues. External communication provider related issues are not currently influencing EMS outages in a major way.

Human Performance

As human error can adversely impact the performance of BPS equipment, it is important to establish and adhere to robust processes to minimize the risks. In-depth analysis often identifies that primary human error causal factors are a result of latent errors as well as organizational and programmatic weaknesses. As the *2023 ERO Reliability Risk Reliabilities Priority Report*[65] states, "The BPS is becoming more complex, and the industry will have difficulty staffing and maintaining necessary skilled workers as it faces turnover in technical expertise."

Transmission Outages

NERC's TADS collects transmission outage data, including on human error; human error as a cause of transmission outage is defined in the *TADS Data Reporting Instructions*.[66] Weaknesses in human performance hamper an organization's ability to identify and address precursor conditions that degrade effective mitigation and behavior management. Effective human performance will help mitigate the active and latent errors that negatively affect reliability.

Statistical significance testing compared the average outage rate of 2023 to that of the prior four years. For ac circuits, all forced outages caused by human error saw a statistically significant decrease in frequency (see Figure 3.17). Transformers saw a statistically significant decrease in operational outages and an apparent increase in automatic outages caused by human error; however, this was not statistically significant (see Figure 3.18).

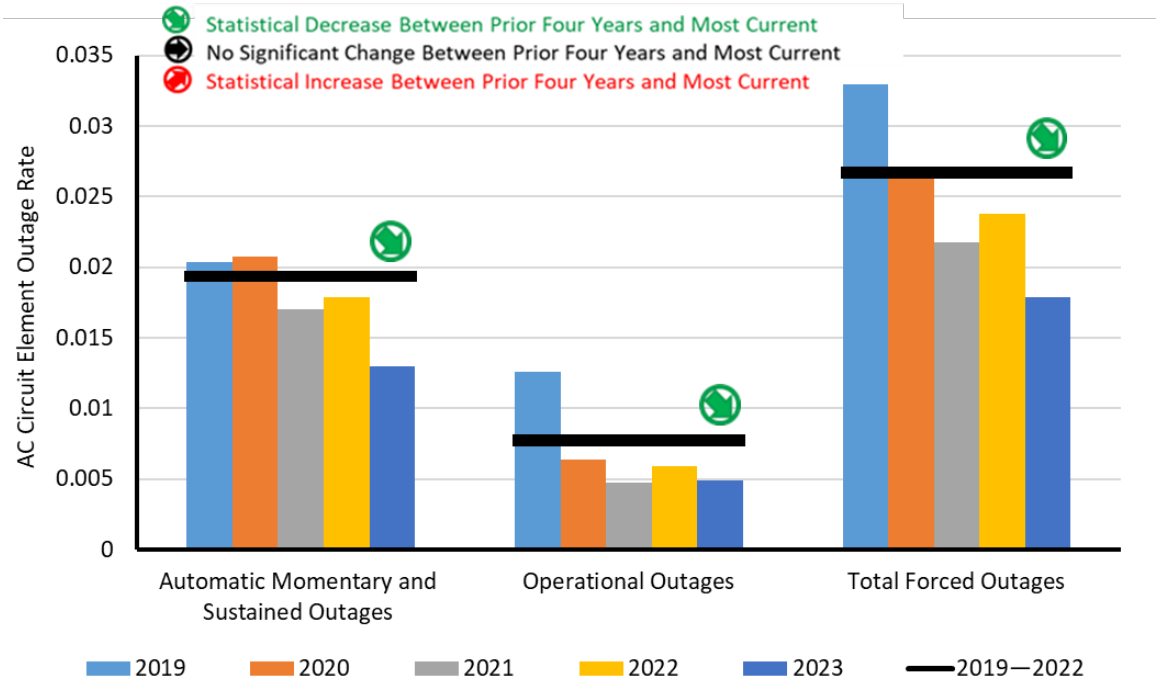


Figure 3.17: AC Circuit Outages per Circuit Initiated by Human Error[67]

[65] *2023 ERO Reliability Risk Reliabilities Priority Report*

[66] Human Error: relative human factor performance including any incorrect action traceable to employees and/or contractors of companies operating, maintaining, and/or assisting the Transmission Owner.

[67] M-13, Automatic AC Transmission Outages Initiated by Human Error

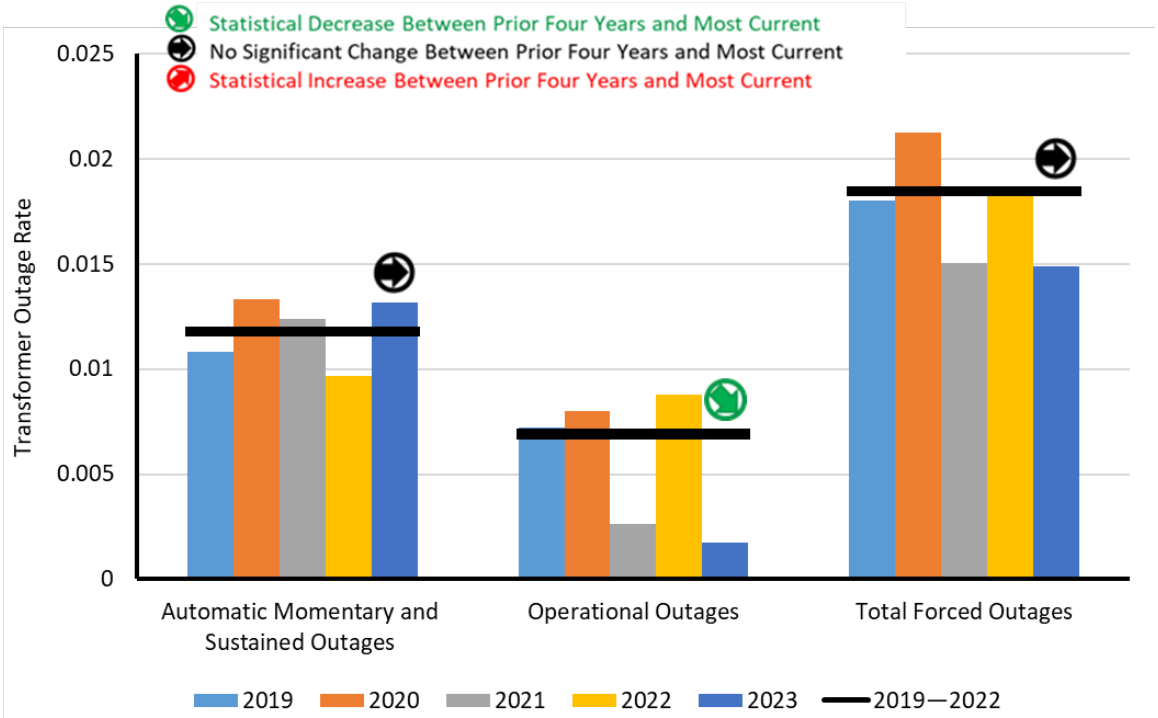


Figure 3.18: Transformer Outages per Element Initiated by Human Error[68]

Generation Outages

NERC's GADS collects generation availability data, including on outages associated with human error. While NERC continues tracking these outages, they have historically represented approximately 1% of all forced-outage events, and no systemic increase warranting presentation was observed in 2023.

Trends of Event Root Causes

In the ERO EAP, the cause sets of individual human performance and management/organization identify events or conditions that caused or contributed to the reported event. In 2023, organization/human performance was identified as the root cause for 20 processed events (see Figure 3.19). This may not fully project the final number as just more than half of the 2023 events have been assigned a final root cause. For the same period, the top five detailed root causes, listed in priority order below, are members of the management and organization performance categories or the design and engineering category:

1. Design output scope less than adequate
2. Job scoping did not identify special circumstances and/or conditions
3. Management policy guidance or expectations are not well-defined, understood, or enforced
4. Corrective action responses to a known or repetitive problem were untimely
5. System interactions not considered or identified

[68] M-13, Automatic AC Transmission Outages Initiated by Human Error

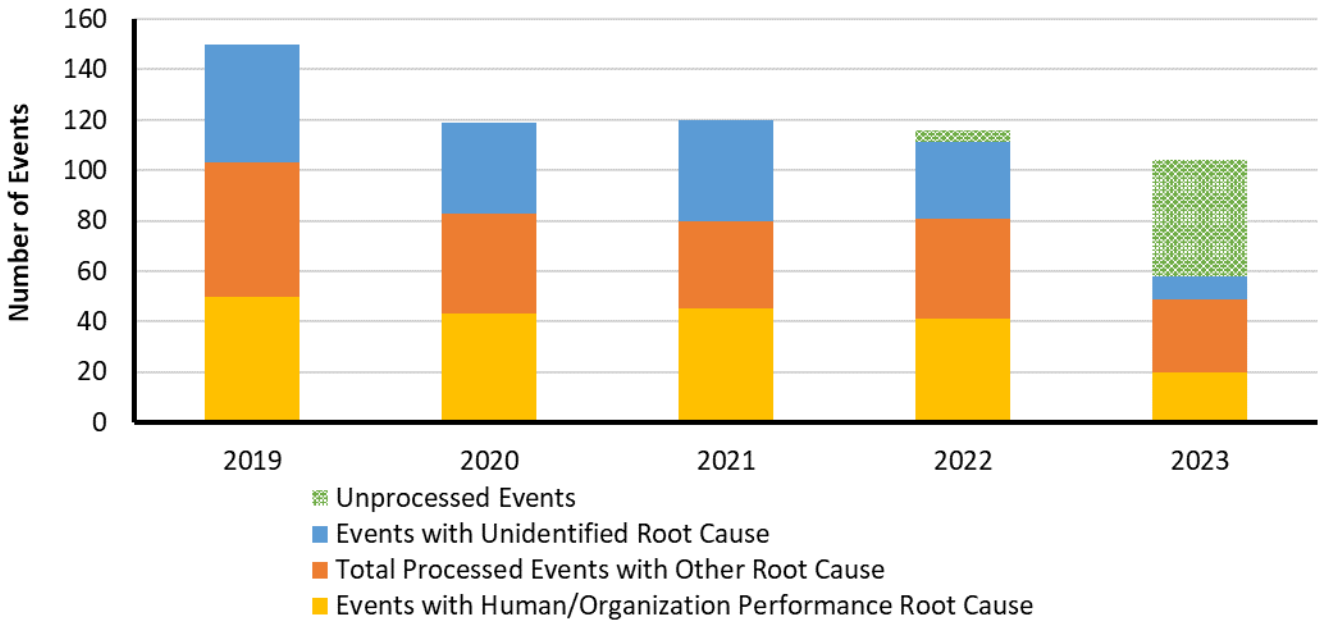


Figure 3.19: ERO EAP Organization/Human Performance Root Cause Identification by Year

Events processed between 2019 and 2023 saw three of the same top five root causes identified in the 2018–2022 time period. The causes "Design Output Scope Not Correct" and "Previous Industry or In-House Experience Was not Effectively Used To Prevent Recurrence" were replaced with "Management Policy Guidance or Expectations Are not Well-Defined, Understood, or Enforced" and "System Interactions not Considered or Identified," respectively.

An opportunity exists for industry to improve BPS reliability through increased focus in the areas of management and organization performance and engineering and design. Management and organization performance includes subcategories in which methods, actions, and/or practices are less than adequate. The Engineering and Design category includes ensuring that the engineering group employs a robust peer-review process to identify procedural errors and all considerations a design needs to be accountable. One way to improve human and organization performance would be to establish robust internal control mechanisms to ensure that processes and procedures are in place to ensure that project leaders consider the potential impacts and dependencies that may exist elsewhere on the system.

Protection System Misoperations

Human performance-related misoperations remain common, representing 41% of misoperations in 2023; consisting of 10% As-Left Personnel Error, 5% Design Errors, 22% Incorrect Settings, and 4% Logic Errors (see Figure 3.10). Figure 3.20 shows the number of misoperations related to human error by Regional Entity for the past five years. The five-year trends for all Regional Entities, except SERC, are either improving or remaining consistent.

To improve the frequency of misoperations potentially due to human error, SERC formed a task force last year to develop sub-cause categories to better identify what areas to target for improvement. Starting in 2024, the SERC Protection and Control Working Group (PCWG) has documented these subcategories to develop mitigation strategies. It is also focusing on reducing incorrect settings by having members summarize their relay settings processes to identify improvement opportunities and incorporate them into stakeholder setting processes.

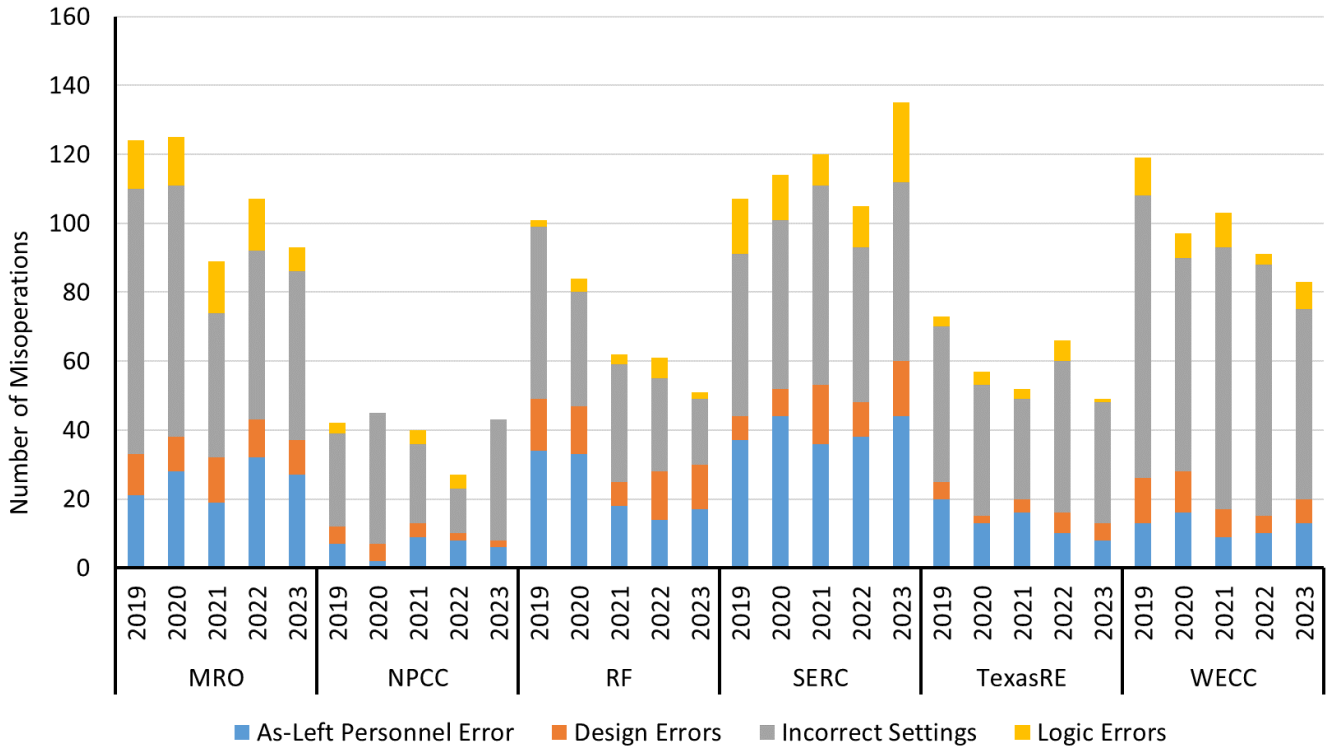


Figure 3.20: MIDAS Protection System Misoperations Due to Human Error by Regional Entity

Energy Emergency Alerts[69]

The purpose of an EEA is to provide real-time indication of potential and actual energy emergencies within an Interconnection. An EEA-3 is reported when firm load interruption is imminent or in progress. EEA trends may provide an indication of BPS capacity, energy, and transmission insufficiency. Figure 3.21 shows that 16 EEA-3s were declared in 2023, a decrease of 10 EEA-3 declarations over 2022. None of the EEA-3 declarations in 2023 included shedding of firm load (92.6 GWh in 2022 vs 0 GWh in 2023.)

All EEA-3 declarations in 2023 were associated with periods of reduced generation or import capability combined with a heavy load day. While none of these days would be considered extreme weather days, 11 of the EEA-3 reports did indicate that higher temperatures or loads were involved.

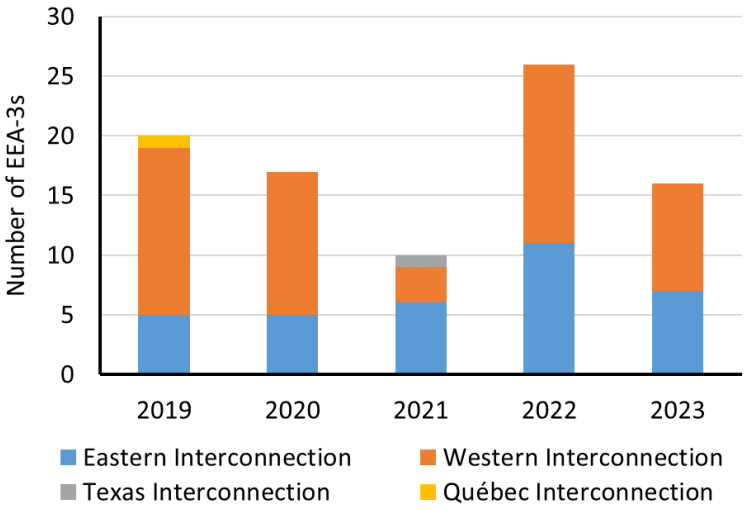


Figure 3.21: EEA-3 by Year and Interconnection

Figure 3.22 shows the number of hours when operator-initiated firm load shed was deployed during each of the past five years. In 2023, zero hours occurred, while in 2022, 21 hours occurred in June during excessive heat and 35.5 hours occurred during Winter Storm Elliott, for a total of 56.5 hours.

[69] M-11, Energy Emergency Alerts

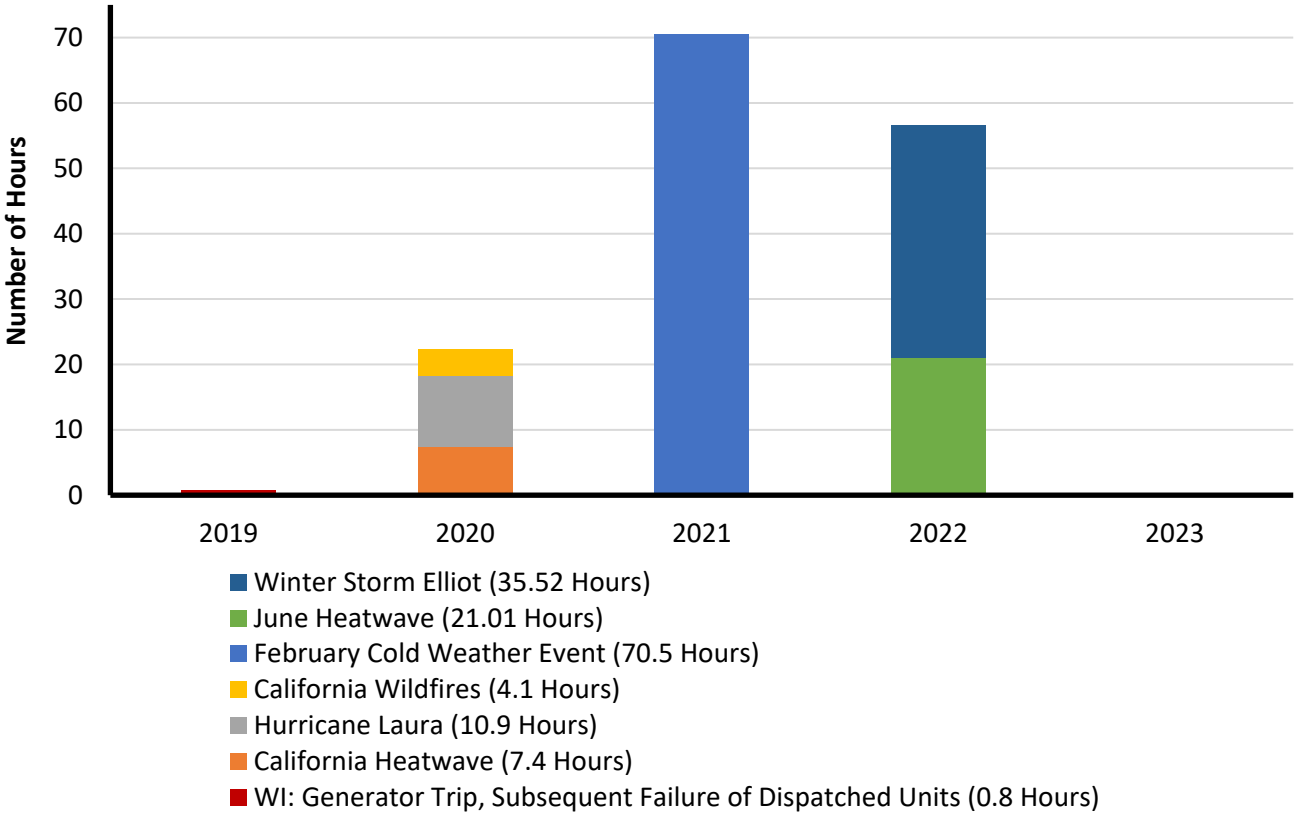


Figure 3.22: Hours with Operator-Initiated Firm Load Shed (Hours/Year)

Chapter 4: Grid Performance

Grid performance is evaluated through established reliability metrics and more in-depth analysis of specific aspects of the BPS:

- **Reliability Metrics**
- **Frequency Response Performance**
- **Generation Performance and Availability**
- **Transmission Performance and Unavailability**

Reliability Metrics

By calculating 2023 reliability metrics[70] and comparing the results to the previous years as well as the five-year average values, the reliability metrics discussed in this chapter can be categorized as either Improving, Stable, Monitor, or Actionable. Measuring and trending the relative state of the BPS in this manner supports NERC's obligation to assess the capability of the BPS. Table 4.1 shows the status of the reliability metrics and includes a reference to the specific metric.

Table 4.1: Reliability Indicators

Metric Name	Metric Performance Status		
M-1: Reserve Margin	**Actionable**		
M-2: Transmission-Related Events Resulting in Loss of Load (Excluding Weather)	**Improving**		
M-3: System Voltage Performance	**Retired**		
M-4: Interconnection Frequency Response	**Improving: Texas Interconnection**	**Stable: Eastern and Western Interconnections**	**Monitor: Québec Interconnection**
M-4.1: Inertia and Rate-of-Change-of-Frequency	**Improving: Texas Interconnection**	**Stable: Eastern and Western Interconnections**	**Monitor: Québec Interconnection**
M-5: Activation of Under Frequency Load Shedding	**Retired**		
M-6: Disturbance Control Standard Failures	**Metric is Under Review**		
M-7: Disturbance Control Events Greater than Most Severe Single Contingency	**Metric is Under Review**		
M-8: Interconnection Reliability Operating Limit (IROL) Exceedance	**Improving: Texas and Western Interconnections**		**Monitor: Eastern and Québec Interconnections**
M-9: Protection System Misoperations Rate	**Stable**		
M-10: Transmission Constraint Mitigation	**Retired**		
M-11: Energy Emergency Alerts	**Improving**		
M-12: Automatic AC Transmission Outages Initiated by Failed Protection System Equipment	**Improving**		
M-13: Automatic AC Transmission Outages Initiated by Human Error	**Improving**		
M-14: Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment	**Improving**		

[70] Current Approved Reliability Metrics; Metrics M-3, M-5, and M-10 are retired.

Table 4.1: Reliability Indicators	
Metric Name	**Metric Performance Status**
M-15: Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment	**Improving**
M-16: Transmission Element Availability Percentage and Unavailability Percentage	**Stable**
M-17: Transmission Outage Severity	**Stable**

Frequency Response Performance

Frequency response arrests and stabilizes frequency during system disturbances. NERC closely monitors the frequency response of each of the four Interconnections and measures the margin at which under-frequency load shedding (UFLS) would be activated. UFLS provides a vital safety net for preserving Interconnection reliability. Measuring the margin allows NERC and the industry to ensure that there is adequate frequency response on the system.

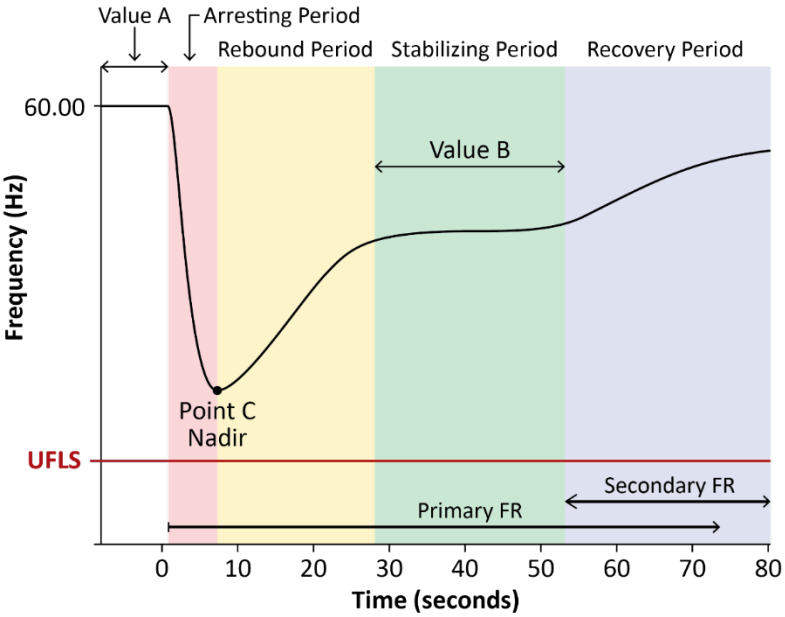


Figure 4.1: Frequency Response Methodology

During the arresting period, the goal is to arrest the frequency decline for credible contingencies before the activation of UFLS. The calculation for Interconnection frequency response obligation (IFRO) under BAL-003 is based on arresting the Point C nadir before the first step of UFLS for resource contingencies at or above the resource loss protection criteria (RLPC)[71] for the Interconnection. Measuring and tracking the margin between the first-step UFLS set point and the Point C nadir is an important indicator of risk for each Interconnection. Figure 4.1 indicates the measurement periods used for analysis of the arresting period of events by looking at the frequency response between Value A and Point C as well as at the margin between Point C and the first-step UFLS set point.

During the stabilizing period, the goal is to stabilize system frequency following a disturbance primarily due to generator governor action. Figure 4.2 indicates the measurement periods used for analysis of the stabilizing period of events by looking at the frequency response between Value A and Value B.

2023 Interconnection Frequency Response

2023 performance and trends frequency response analysis indicate an adequate level of reliability.

- For the stabilizing period, the Interconnection frequency response,[72] the Eastern Interconnection, the Québec Interconnection, and the Western Interconnection showed no statistically significant changes from 2019 through 2023. The Texas Interconnection showed a statistically significant improvement for the stabilizing period from 2019 through 2023.
- For the arresting period, the inertia and rate-of-change-of-frequency (ROCOF),[73] the Eastern and Western Interconnections showed no statistically significant changes from 2019 through 2023. The Texas

[71] BAL-003-2 specifies that the RLPC be based on the two largest potential resource losses in an Interconnection or the largest resource loss due to an N-2 RAS. This value is updated annually through the BAL-003-2 data collection process.
[72] Interconnection Frequency Response, M-4
[73] Inertia and Rate-of-Change-of-Frequency, M-4.1

Interconnection showed a statistically significant improvement. The Québec Interconnection showed a statistically significant decreasing trend.

Of note in 2023, as shown in Table 4.2, the Western Interconnection had two events within the five-year period in which the measured frequency response was less than the IFRO. Both events had a starting frequency well above 60.00 Hz and had a confirmed MW loss under 500 MW. These two factors combined alleviate concerns that the Western Interconnection frequency response is insufficient. Also, of note in 2023 was the decreasing trend in the inertia and ROCOF for the Québec Interconnection. The Québec Interconnection confirmed an overrepresentation of summer events in 2023 compared to other years (2019–2022). Twenty percent of all events in the past five years occurred between May and October 2023 (months that typically have lower inertia), in part due to the wildfire events in the region. The Eastern Interconnection, Québec Interconnection, and Texas Interconnection did not have any events within the five-year period in which the measured frequency response was less than the IFRO for the respective Interconnection.

Table 4.2: 5-Year Statistical Trend

Interconnection	M-4 Interconnection Frequency Response	M4.1 Inertia and Rate-of-Change-of-Frequency	Margin-C-UFLS	Comment
Eastern	neither decreasing nor increasing	neither decreasing nor increasing	neither decreasing nor increasing	No M4 events with FR below IFRO
Texas	increasing	increasing	increasing	No M4 events with FR below IFRO
Québec	neither decreasing nor increasing	decreasing	neither decreasing nor increasing	No M4 events with FR below IFRO
Western	neither decreasing nor increasing	neither decreasing nor increasing	neither decreasing nor increasing	Two M4 events with FR below IFRO

Of note, the Western Interconnection has had the least number of valid events since frequency response evaluation started. This trend in reduction of valid frequency response events is suspected to be due to the retirement of large generating facilities in the Interconnection over the evaluation period and is a positive indicator when considering impacts to Interconnection reliability.

Frequency response for all Interconnections indicates stable and improving performance for the stabilizing period and arresting period as shown in Table 4.3 and Table 4.4.[74]

Table 4.3: 2023 Frequency Response Performance Statistics for Stabilizing Period

	2023 Operating Year Stabilizing Period Performance					
	Number of Events	Mean Frequency Response	Median	Minimum	Maximum	Number of events with FR below the IFRO
Eastern	47	2,685	2,459	1,138	5,176	0
Texas	38	1,410	1,241	682	2,788	0
Québec	65	762	693	260	1,682	0
Western	28	2,049	1,682	912	5,050	2

[74] Frequency Response Performance Statistics

Table 4.4: 2023 Frequency Response Performance Statistics for Arresting Period								
	Operating Year (OY)							
	Number of Events	Mean Frequency Response	Median	Minimum	Maximum	Mean UFLS Margin	Median UFLS Margin	Min. UFLS Margin
Eastern	47	2,151	1,969	1,059	3,550	0.454	0.453	0.441
Texas	38	727	738	283	1,604	0.611	0.606	0.579
Québec	65	124	120	48	233	1.022	1.065	0.118
Western	28	868	829	544	1,554	0.415	0.421	0.332

Figure 4.2 represents an analysis of the arresting period of frequency response events. The Y-axis shows the percent UFLS margin from 100% (60 Hz) to 0% (first UFLS set point for the Interconnection). The X-axis represents the MW loss for the event, expressed as a percentage of the RLPC for the Interconnection. The Québec Interconnection had two events at or greater than 100% of the RLPC and maintained sufficient UFLS margin. The largest events for the Eastern Interconnection and Texas Interconnection were 45% and 50%, respectively, as measured by percentage of RLPC.

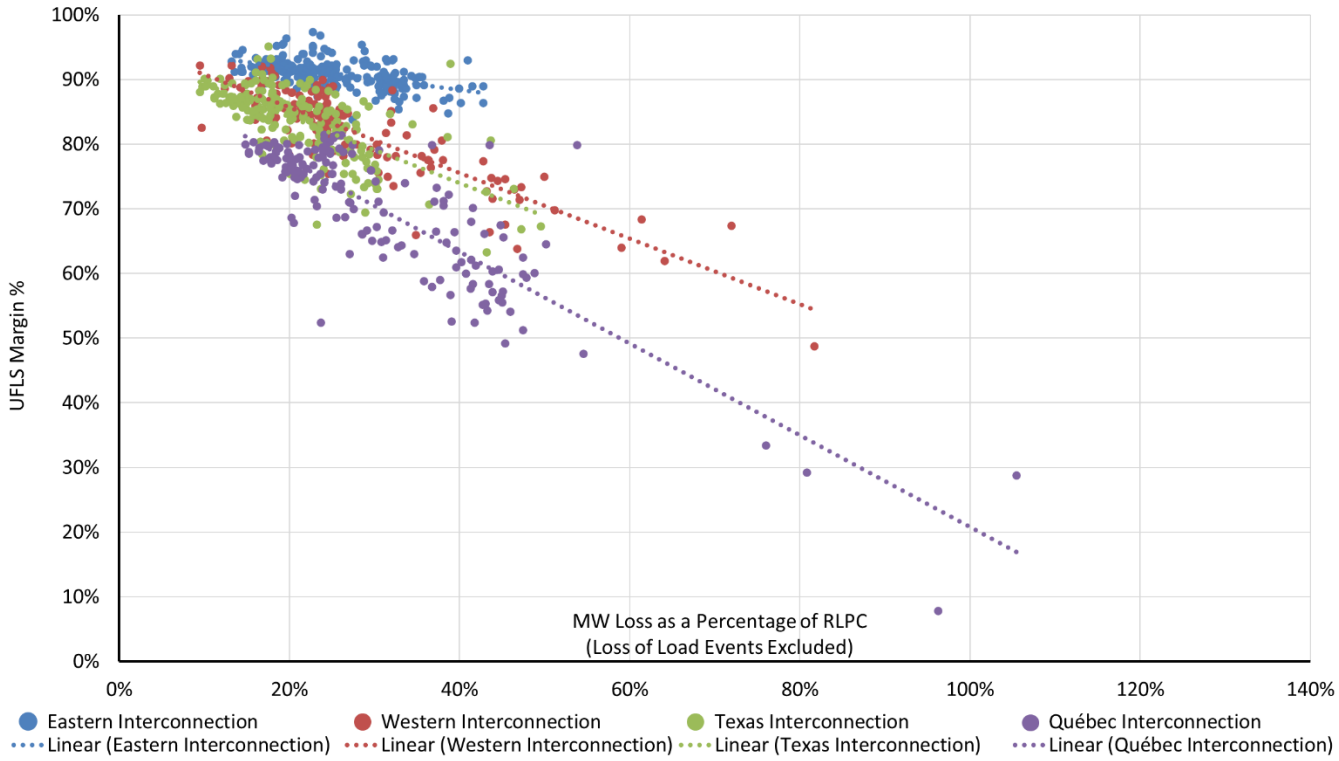


Figure 4.2: Operating Year 2019–2023 Qualified Frequency Disturbances and Remaining UFLS Margin

Interconnection Reliability Operating Limit Exceedances

2023 Performance and Trends

Each RC has a different methodology for determining Interconnection reliability operating limits (IROL)[75] based on the makeup of their area and what constitutes an operating condition that is less than desirable. The following discussion of performance on an Interconnection basis is for clarity, not comparison:

[75] M-8, IROL Exceedance

- **Eastern–Québec Interconnections:** In 2023, there were eight exceedances that lasted more than 10 minutes, less than the five-year average of 19.4 exceedances as shown in Figure 4.3. The 10- to 20-minute range continued to decline from its all-time peak in 2019 with zero exceedances greater than 20 minutes.
- **Western Interconnection:** The trend has been stable with no IROL exceedances reported in 2023.
- **Texas Interconnection:** The trend has been stable with no IROL exceedances reported in 2023.

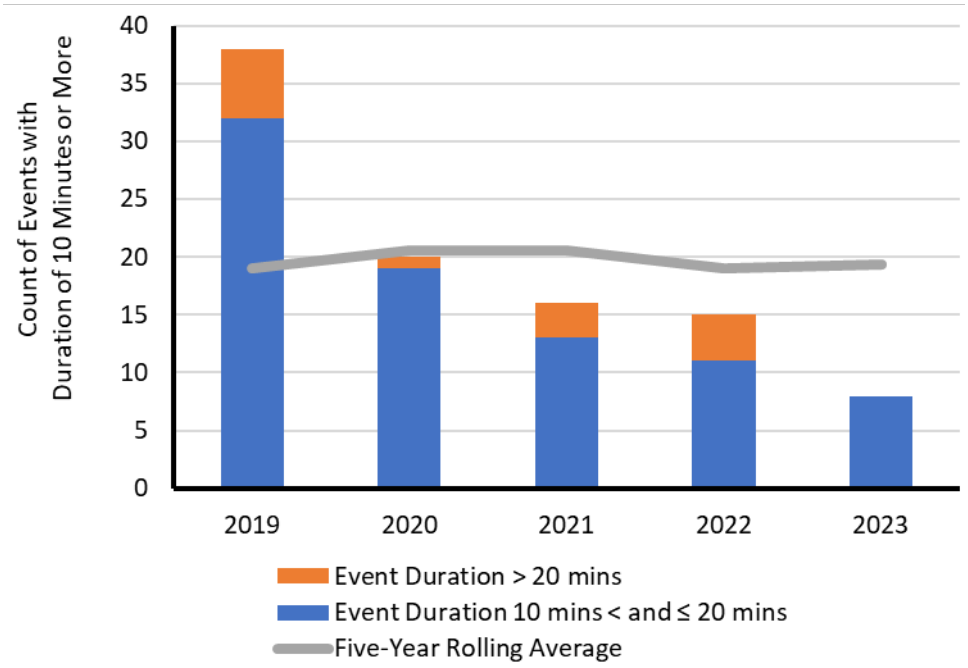


Figure 4.3: IROL Exceedance Counts[76]

Generation Performance and Availability

GADS contains information that can be used to compute reliability measures, such as WEFOR. GADS collects and stores unit operating information by pooling individual unit information, overall generating unit availability, performance, and calculated metrics.

Conventional Generation WEFOR

The horizontal lines in Figure 4.4 show the annual WEFOR compared to the monthly WEFOR columns; the solid horizontal bar shows the WEFOR for all years in the analysis period of 7.4%. While noticeably lower than the two preceding years, the annual WEFOR of 7.8% for 2023 is the third highest since NERC began digitally collecting GADS data in 2013, despite no major outlying winter weather event.

[76] M-8, IROL Exceedance

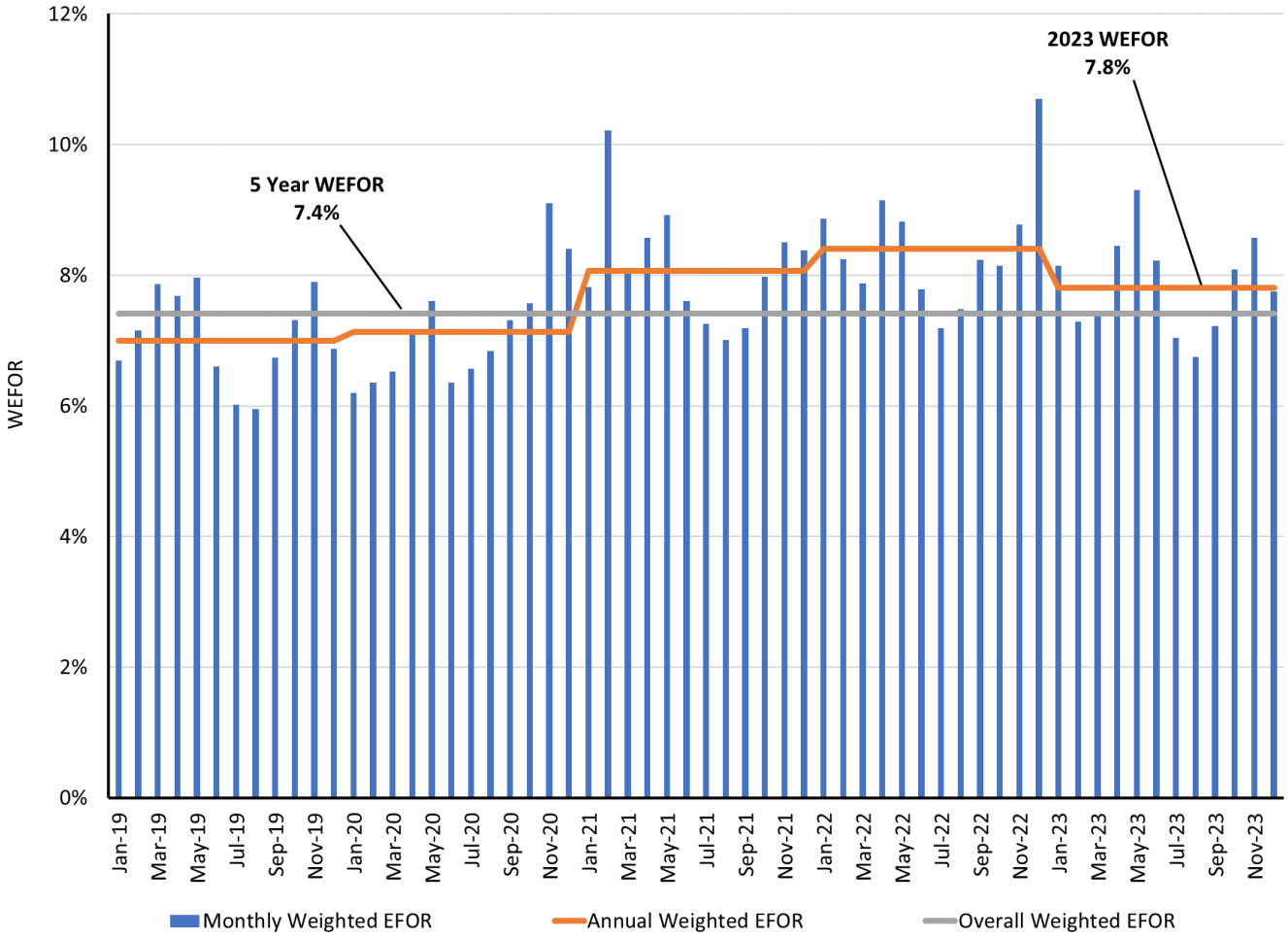


Figure 4.4: Monthly, Annual, and Five-Year WEFOR

To better illustrate 2023's high WEFOR relative to historical norms, Figure 4.5 shows the annual WEFOR by fuel type for the past 10 years. This extended analysis period is presented to illustrate how the abnormally high WEFORs in 2021 and 2022 caused by extreme cold weather conditions obfuscate long-term trends.

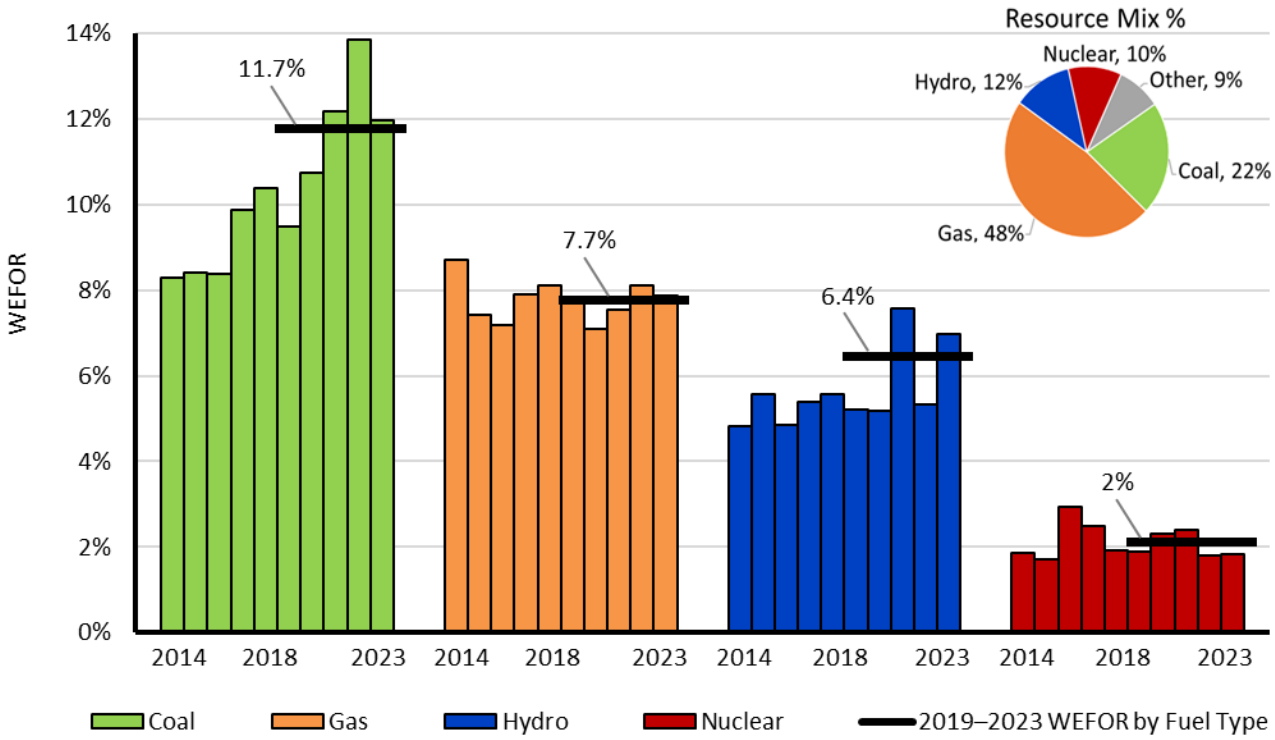


Figure 4.5: 10-Year Annual WEFOR by Fuel Type and 2023 Resource Mix by Net Maximum Capacity

Although coal-fired generation experienced a large decrease in WEFOR in 2023 (12.0% in 2023 versus 13.9% in 2022), it remains above pre-2021 rates. Due to year-over-year variability, coal generation is the primary driver of change in the overall WEFOR despite more energy being produced by both natural gas and nuclear power in 2023 (see Figure 4.6). Further investigation into baseload coal generation indicates that a unit's WEFOR negatively correlates most strongly to capacity factor.[77] Notably, once capacity factor falls below approximately 60%, unweighted average EFORs of units begin increasing more rapidly than those between 60% and 100%. Although forced-outage hours are a definite contributor to lower capacity factor units' increased WEFOR, the disproportionate change appears to be driven more by maintenance/planned outage hours and decreased service hours. This aligns with industry statements indicating that reduced investment in maintenance and abnormal cycling that are being adopted primarily in response to rapid changes in the resource mix are negatively impacting baseload coal unit performance.

Hydro units also experienced an unusually high annual WEFOR (6.9%) for the second time following one in 2021 (7.6%). However, these two relatively high years were both still lower than the associated years' overall WEFOR and do not indicate a trend at this point but warrant continued awareness.

[77] The correlation factor between capacity factor and WEFOR for baseload coal in 2023 was -0.41. While not mathematically indicative of a strong correlation (generally +/-0.7), it is notably stronger than any other aspect that is not a direct component of the WEFOR with the next highest being age (0.18) and planned outage hours (-0.16) given the relatively small sample size and amount of variation between coal units.

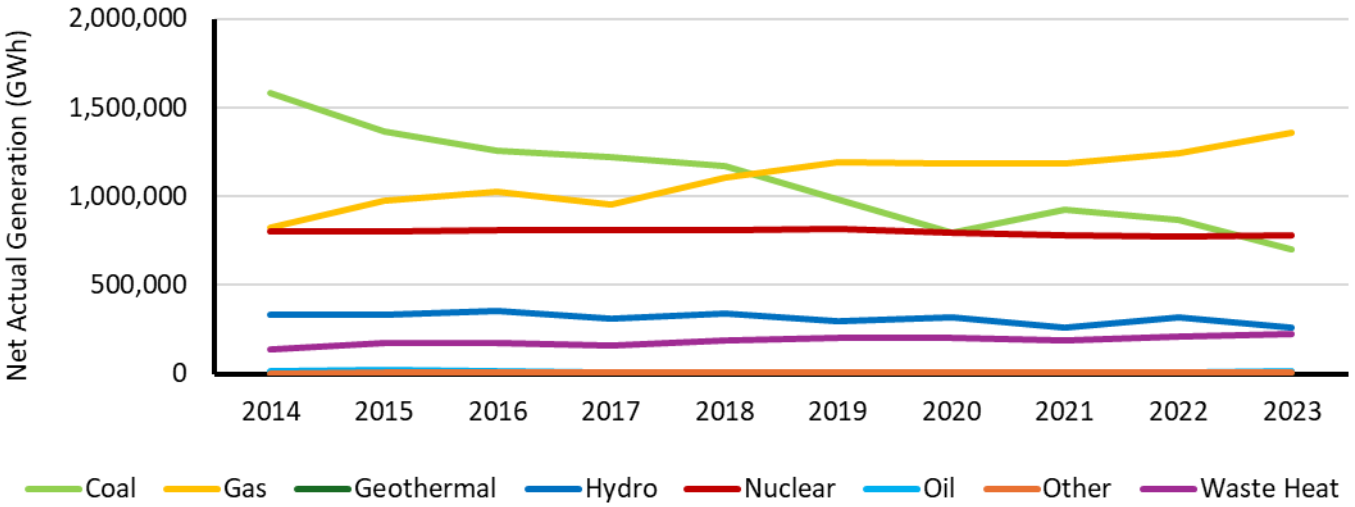


Figure 4.6: 10-Year Annual Conventional Net Actual Generation (GWh) by Fuel Type

Wind Generation Weighted Resource Forced-Outage Rate

NERC began collecting wind performance data with a phased-in approach based on plant size starting with a total installed capacity of 200 MW or greater in 2018 followed by plants with a total installed capacity of 100–199 MW in 2019 and plants with a total installed capacity of 75–99 MW in 2020 (see Figure 4.7). By the end of 2023, data from 137,737 MW of installed capacity, representing 703 wind plants across North America and 13% of nameplate generation, was reported to NERC. Data will continue to be reported separately for the reporting phase groups until sufficient history is available to analyze trends for a five-year rolling period across all wind plants comparable to the analysis for conventional generation. Specific event data collection for wind and solar began in 2024 and will allow for further analysis.

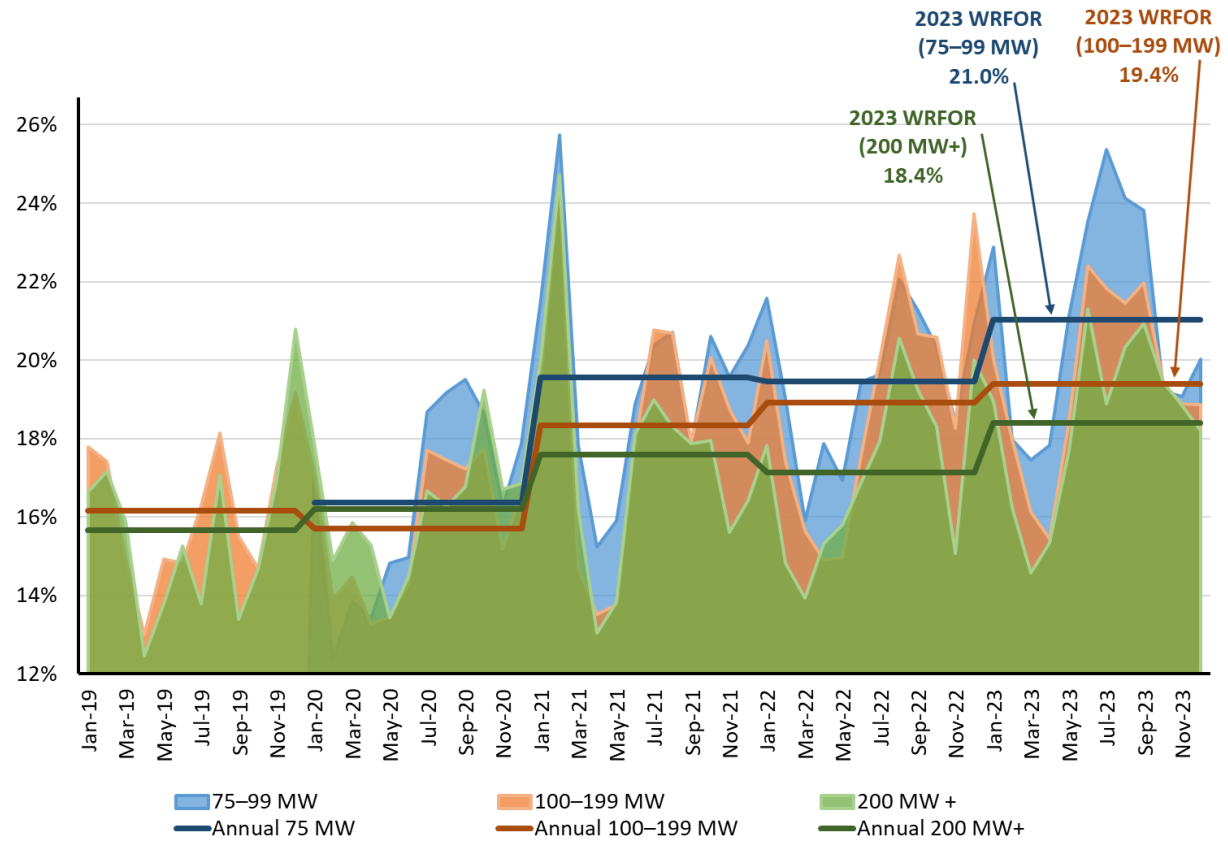


Figure 4.7: Monthly Capacity and Annual Average WRFOR Wind Plant Reporting Group

Transmission Performance and Unavailability

When evaluating transmission reliability, an important concept is that transmission line outages have different impacts on BPS reliability. Some impacts can be very severe, such as those that affect other transmission lines and load loss. Additionally, some outages are longer than others, leaving the transmission system at risk for extended periods of time. Reliability indicators for the transmission system are measured by using qualified event analysis reporting not related to weather and outages reported to TADS. The number of qualified events that include transmission outages that resulted in firm load loss not related to weather is provided in the following subsection.

Transmission-Related Events Resulting in Loss of Load

In 2023, a total of nine distinct non-weather-related transmission events resulted in a loss of firm load that met the ERO EAP reporting criteria (see Figure 4.8). The median firm load loss over the past five years was 97 MW, which is a decrease from 2018–2022's 101 MW. Although, notably, the median load loss was 113 MW in 2023, which is above the five-year median value, no discernible trend in the number of events or amount of loss is identifiable.

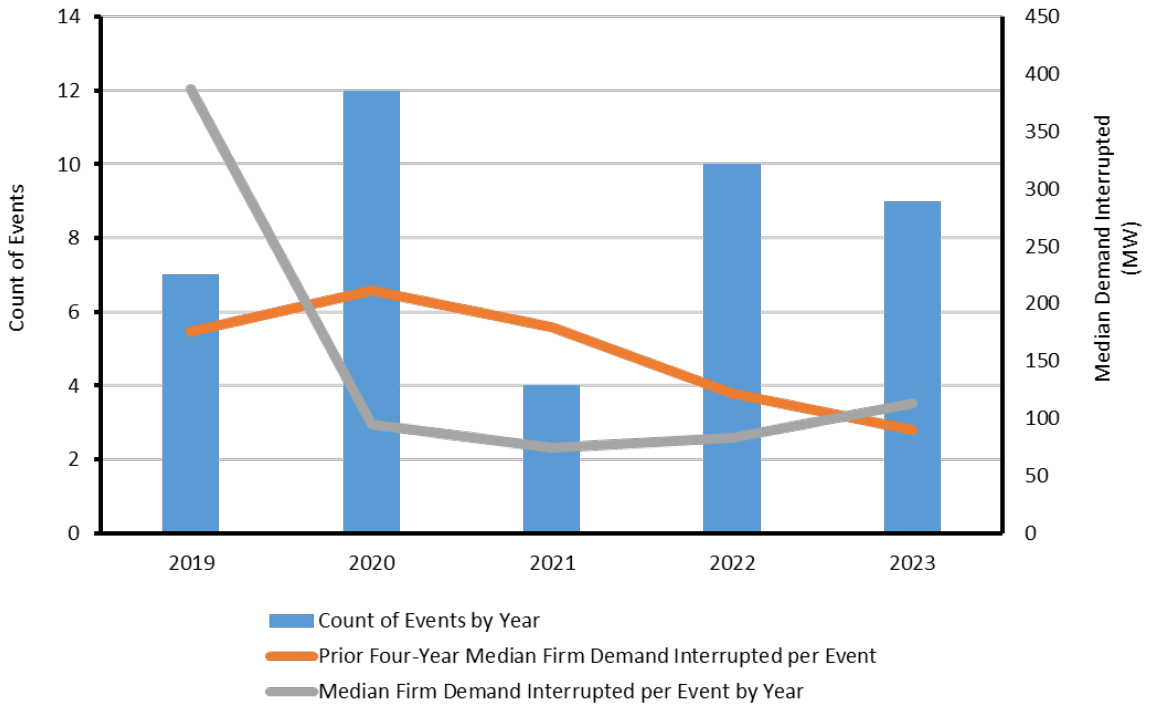


Figure 4.8: Transmission-Related Events Resulting in Loss of Firm Load and Median Amount of Firm Load Loss Excluding Weather-Related Events[78]

TADS Reliability Indicators

A TADS event is an unplanned transmission incident that results in the automatic outage (sustained or momentary) of one or more elements. TADS event information was analyzed for the following indicators in this section:

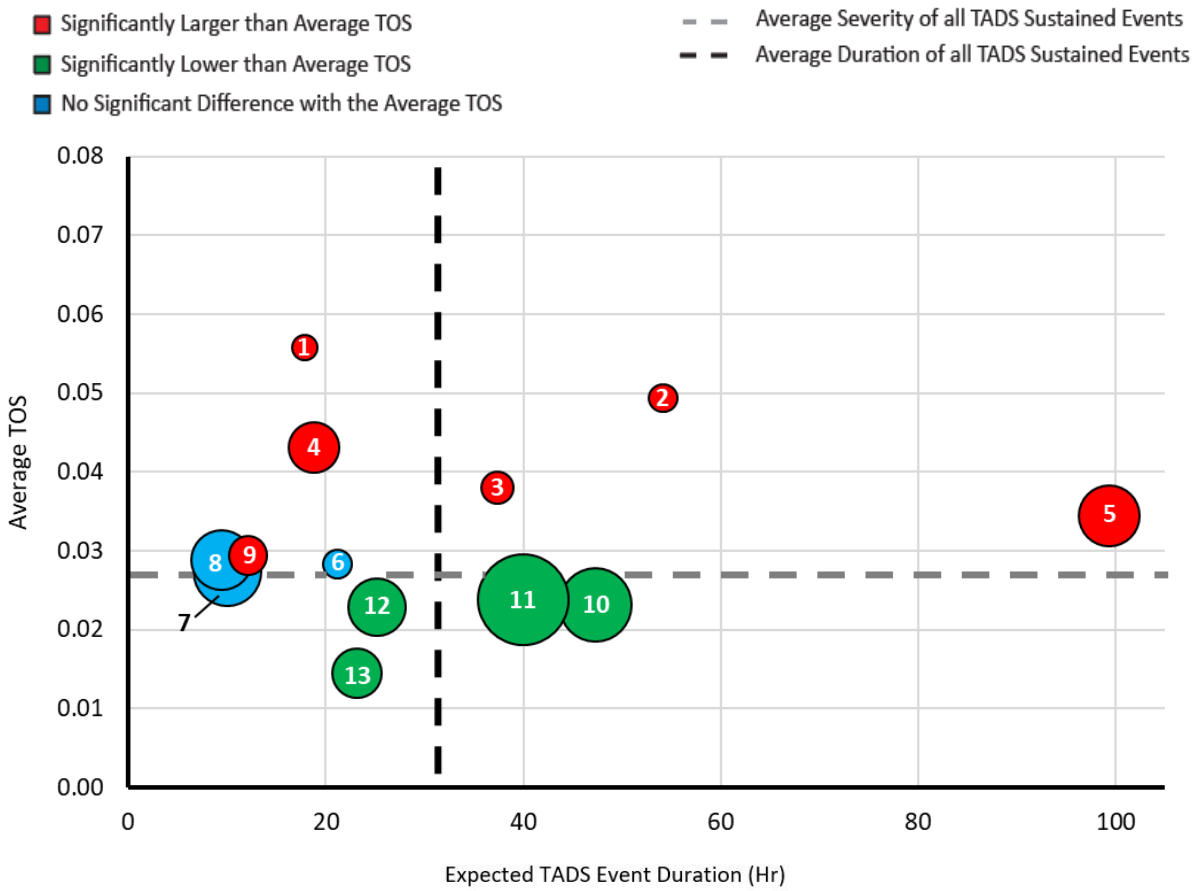
- **Transmission Outage Severity**
- **Automatic AC Transmission Outages**
- **Transmission Element Unavailability**

Transmission Outage Severity

The impact of a TADS event on BPS reliability is called the TOS of the event, which is defined by the number of outages in the event and by the type and voltage class of transmission elements involved in the event. TADS events are categorized by initiating cause codes (ICC). These ICCs facilitate the study of cause-effect relationships between each event's ICC and event severity.

[78] M-2, BPS Transmission Related Events Resulting in Loss of Load (Excluding Weather)

By examining the average TOS, duration, and frequency of occurrence for events with different ICCs (see Figure 4.9), it is possible to determine which ICCs contribute most to reliability performance for the considered period. The average TOS for events with a specific ICC is displayed on the Y-axis. A higher TOS for an ICC indicates that more outages or higher voltage elements were involved in an event. The average duration for events with a specific ICC is displayed on the X-axis; generally, events with a longer duration pose a greater risk to the BPS. The number of ICC occurrences is represented by the bubble size; larger bubbles indicate that an ICC occurs more often. Change in size or position of a bubble with the same number (identifying ICC) may indicate improved or declined performance. Lastly, the bubble colors indicate a statistical significance of a difference in the average TOS of this group and the events from other groups. The number of events per hour, average event duration, and average TOS for each ICC group are shown in Table 4.5.



1. Power System Condition
2. Fire
3. Combined Smaller ICC Groups
4. Misoperation
5. Failed AC Substation Equipment
6. Other
7. Unknown
8. Lightning
9. Human Error
10. Failed AC Circuit Equipment
11. Weather, Excluding Lightning
12. Foreign Interference
13. Vegetation

Figure 4.9: TOS vs. Expected TADS Event Duration

Table 4.5: TOS vs. Expected TADS Event Duration			
TADS Event	**Events per Hour**	**Average TOS**	**Average Event Duration**
Power System Condition	.012	.056	17.9
Fire	.014	.049	54.2
Combined Smaller ICC Groups	.019	.038	37.4
Misoperation	.046	.043	18.8
Failed AC Substation Equipment	.068	.034	99.4
Other	.015	.028	21.2
Unknown	.085	.027	10.0
Lightning	.067	.029	9.5
Human Error	.026	.029	12.2
Failed AC Circuit Equipment	.098	.023	47.3
Weather, Excluding Lightning	.153	.024	40.0
Foreign Interference	.061	.023	25.2
Vegetation	.045	.014	23.2

An analysis of the total TOS by year indicates that 2023 was an outlier from the statistically improving trend identified over the previous five years. Figure 4.10 shows the annual TOS, which is the third highest over the last five years; the shaded area shows the effect of the Québec wildfires on the 2023 TOS.

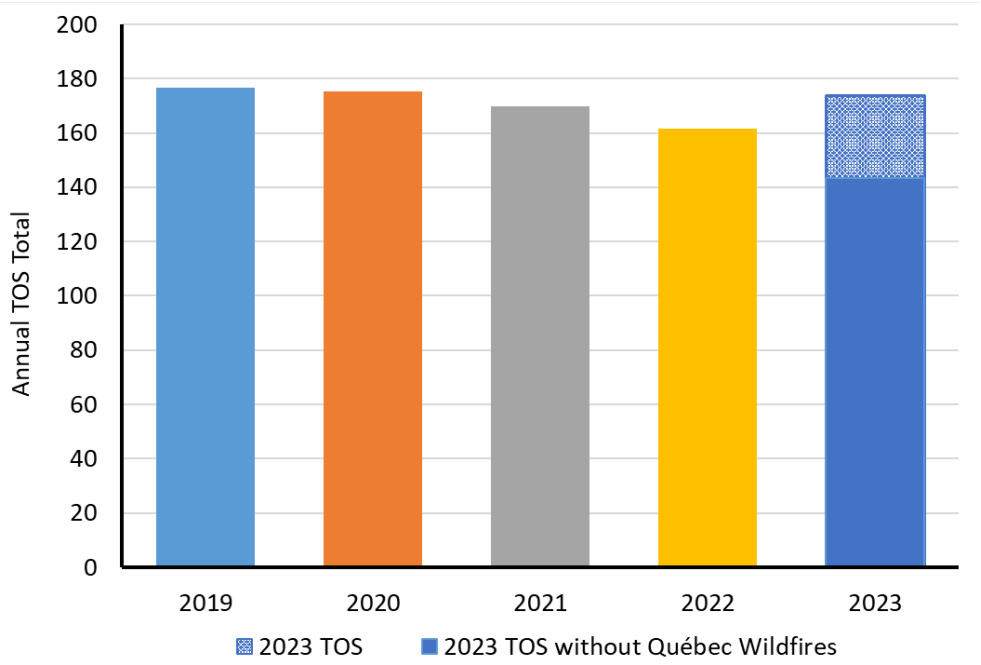


Figure 4.10: TOS of TADS Sustained Events of 100 kV+ AC Circuits and Transformers by Year[79]

Automatic AC Transmission Outages

The average number of outages per circuit due to failed ac substation equipment has continued to improve consistently over the last four years, showing a statistically significant decrease in 2023 compared to 2019–2022 (see Figure 4.11 The number of sustained outages due to failed ac circuit equipment per 100 miles saw a decrease in 2023 (see Figure 4.12).

[79] M-17, Transmission Outage Severity

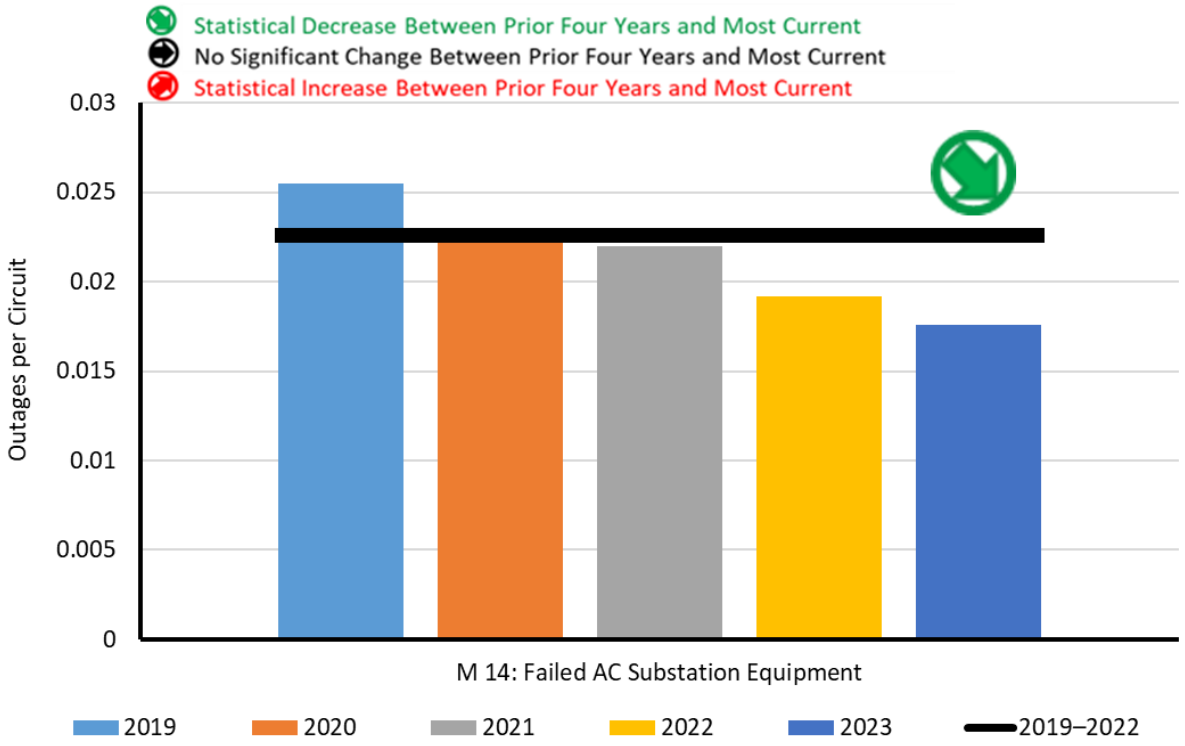


Figure 4.11: Number of Outages per AC Circuit Due to Failed AC Substation Equipment[80]

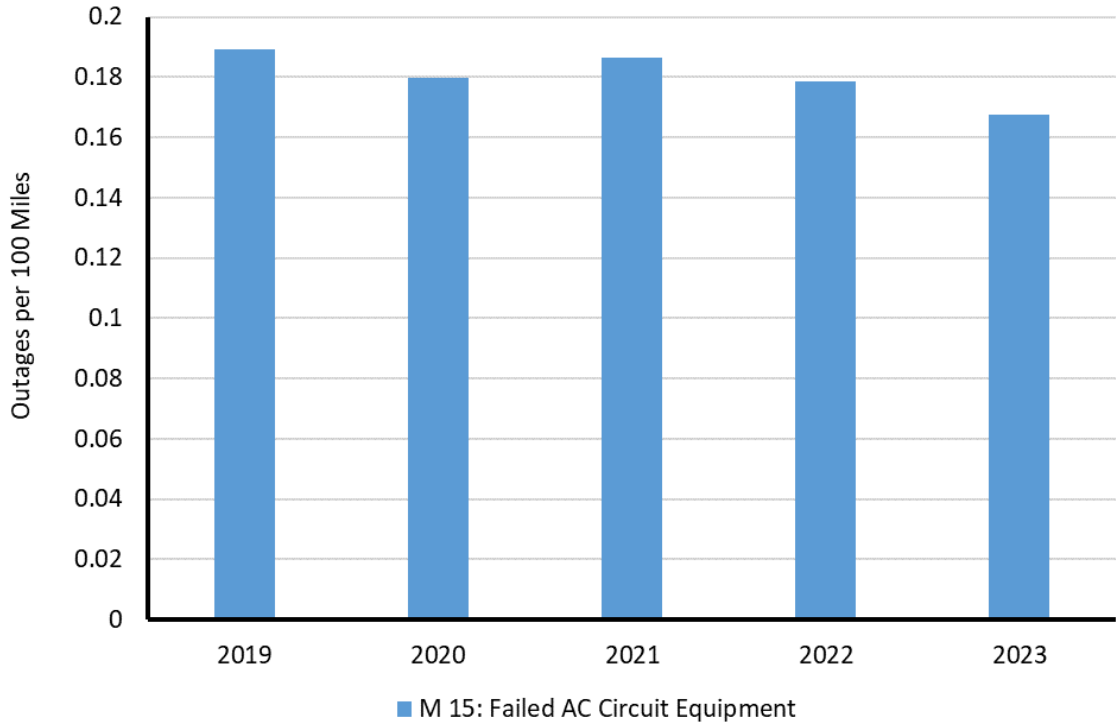


Figure 4.12: Number of Outages per 100 Miles Due to Failed AC Circuit Equipment[81]

[80] M-14, Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment
[81] M-15, Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment

Automatic AC Transformer Outages

In 2023, the number of automatic ac transformer outages per element caused by failed ac substation equipment was statistically equal to 2019–2022 (see Figure 4.13); the overall average remains stable.

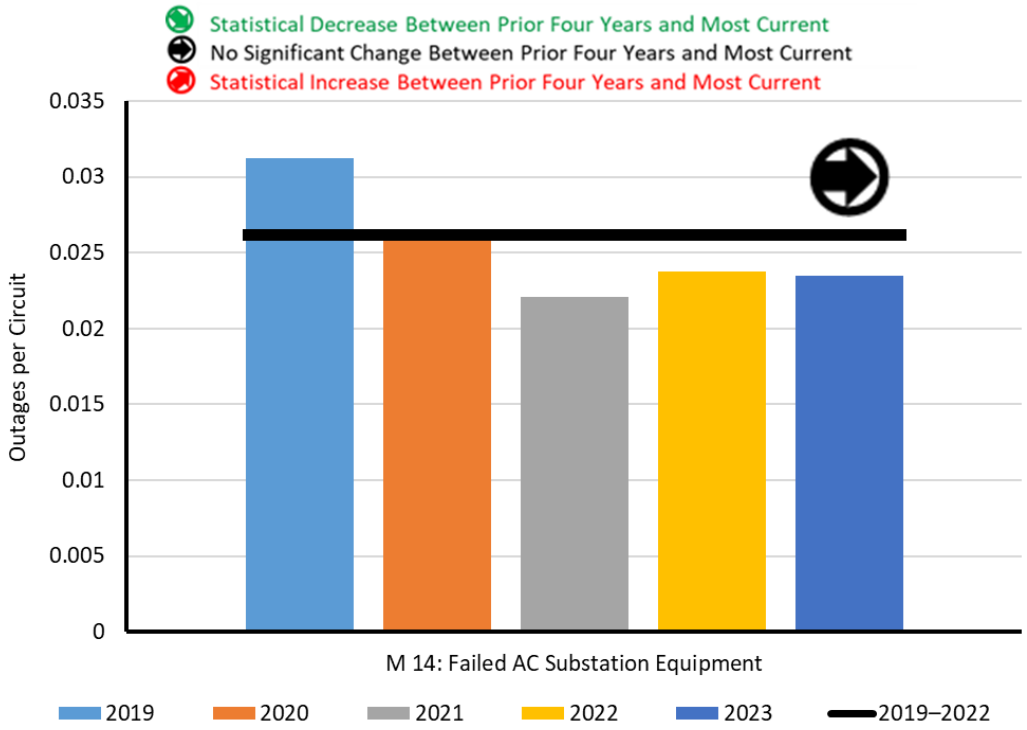


Figure 4.13: Number of Outages per Transformer Due to Failed AC Substation Equipment[82]

Transmission Element Unavailability

In 2023, ac circuits over 200 kV across North America had an unavailability rate of 0.24%, meaning that there is a 0.24% chance that a specific transmission circuit is unavailable due to sustained automatic and operational outages at any given time. Transformers had an unavailability rate of 0.25% in 2023. Figure 4.14 shows that 2023 was the lowest year for ac circuit unavailability of the five-year analysis period. Figure 4.15 shows that 2023 was the second-highest year for transformer unavailability of the five-year analysis period.

[82] M-14, Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment

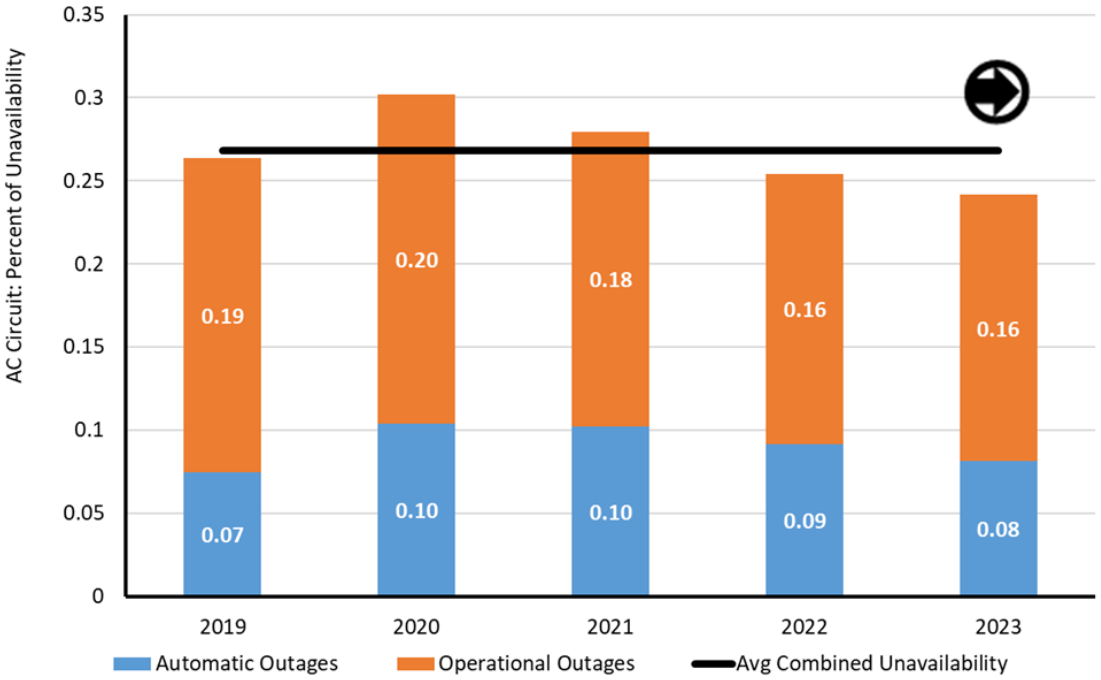


Figure 4.14: AC Circuit Unavailability > 200 kV[83]

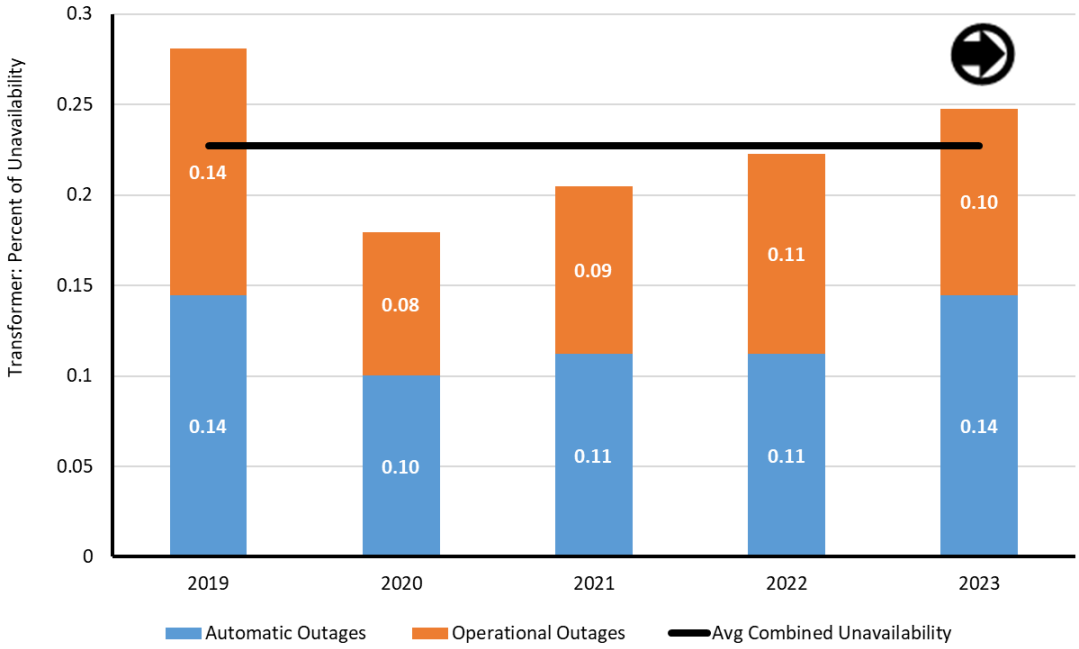


Figure 4.15: Transformer Unavailability[84]

[83] M-16, Element Availability Percentage (APC) & Unavailability Percentage
[84] Ibid.

Appendix A: Supplemental Analysis at Interconnection Level

Severity Risk Index by Interconnection

Eastern and Québec Interconnections

The cumulative SRI for the Eastern and Québec Interconnections in Table A.1 shows a 5% decrease compared to the average of the four-year period of 2019–2022.

Table A.1: Annual Cumulative SRI Eastern and Québec Interconnections

Year	Cumulative Weighted Generation	Cumulative Weighted Transmission	Cumulative Weighted Load Loss	Annual Cumulative SRI	Average Daily SRI
2019	345.9	59.3	51.3	456.4	1.25
2020	315.3	58.4	67.4	441.0	1.21
2021	346.2	54.5	64.1	464.8	1.27
2022	385.3	53.0	53.0	491.2	1.35
2023	**324.7**	**65.4**	**48.5**	**438.6**	**1.20**

The top 10 SRI days of the Eastern and Québec Interconnections were distributed throughout the year as shown in Figure A.1 (numbered circles). A total of 8 of the top 10 days that occurred in the Eastern and Québec Interconnections align with the top 10 SRI days reported for North America.

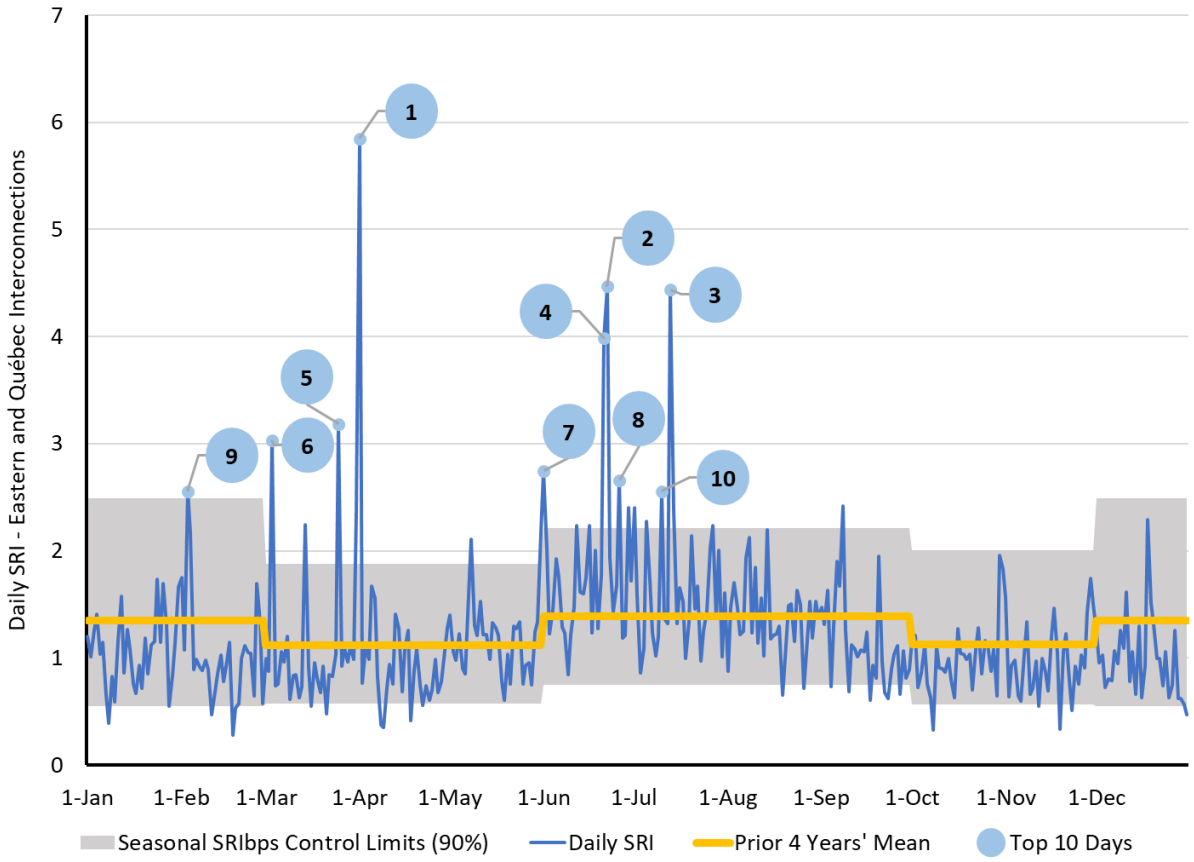


Figure A.1: 2023 Eastern and Québec Interconnections Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

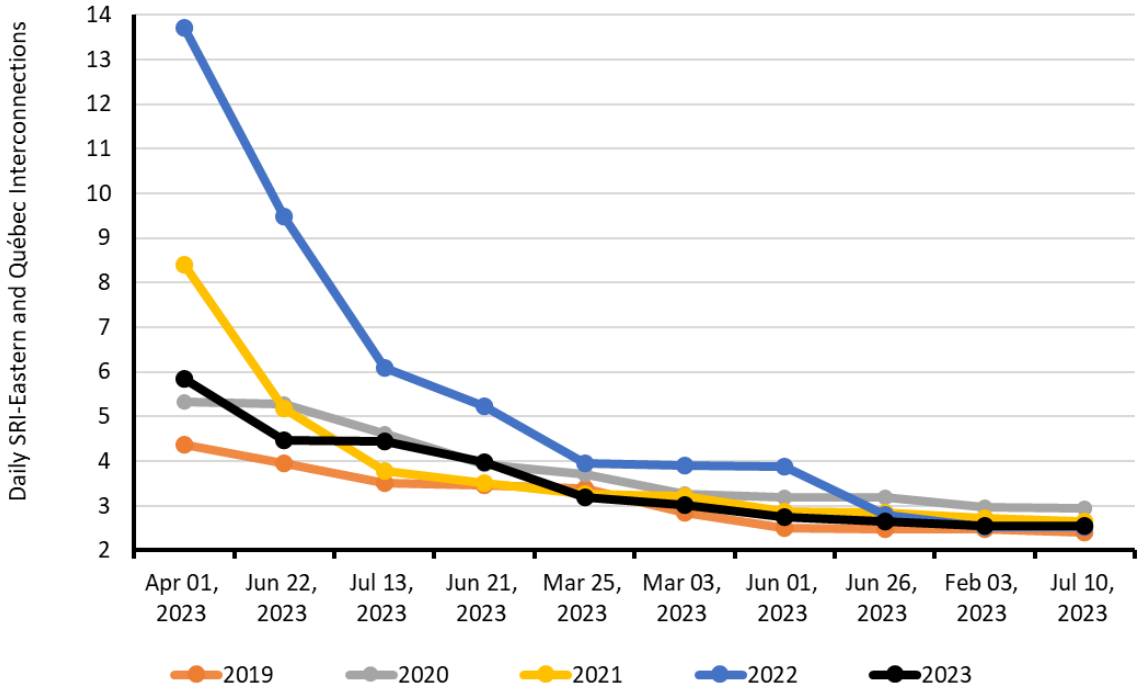


Figure A.2: Eastern and Québec Interconnections Top Annual Daily SRI Days, Sorted Descending

Table A.2 provides details on each component's contribution to the top 10 SRI days for the Eastern and Québec Interconnections.

Table A.2: 2023 Top 10 SRI Days Eastern and Québec Interconnections

Rank	Date	SRI and Weighted Components 2022				Atypical Weather Conditions	Regional Entities within the Interconnection
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	1-Apr	5.85	0.74	0.64	4.46	Widespread Storms and Tornadoes	MRO, RF, SERC
2	22-Jun	4.47	1.34	2.99	0.14	Québec Wildfires	NPCC
3	13-Jul	4.44	0.89	3.19	0.36	Québec Wildfires	NPCC
4	21-Jun	3.98	1.15	2.60	0.23	Québec Wildfires	NPCC
5	25-Mar	3.18	0.60	0.42	2.17	Widespread Storms	NPCC, RF, SERC
6	3-Mar	3.03	1.22	0.65	1.16	Severe Storms	MRO, NPCC, RF, SERC
7	1-Jun	2.75	1.62	1.07	0.05	Québec Wildfires	NPCC
8	26-Jun	2.66	1.16	1.12	0.39	Thunderstorms	MRO, NPCC, RF, SERC
9	3-Feb	2.55	2.28	0.10	0.18	Coincident Large Coal and	N/A

Table A.2: 2023 Top 10 SRI Days Eastern and Québec Interconnections							
Rank	Date	SRI and Weighted Components 2022				Atypical Weather Conditions	Regional Entities within the Interconnection
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
						Gas Generator Outages	
10	10-Jul	2.55	0.56	1.89	0.10	Québec Wildfires	NPCC

Table A.3 shows the top 10 SRI days for the Eastern and Québec interconnection over the last five years with the only date in 2023 highlighted in red.

Table A.3: 2019–2023 Top 10 SRI Days Eastern and Québec Interconnections							
Rank	Date	SRI and Weighted Components				Atypical Weather Conditions	Regional Entities within the Interconnection
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	December 23, 2022	13.72	8.88	0.91	3.92	Winter Storm Elliott	All
2	December 24, 2022	9.49	8.13	1.29	0.07	Winter Storm Elliott	All
3	February 16, 2021	8.32	4.11	0.59	3.63	Cold Weather Event	MRO, RF, SERC
4	June 14, 2022	6.10	1.71	0.49	3.90	High Temperatures and Derecho	MRO, NPCC, RF, SERC, TRE
5	April 1, 2023	5.85	0.74	0.64	4.46	Widespread Storms and Tornadoes	MRO, RF, SERC
6	August 4, 2020	5.33	1.38	1.02	2.93	Hurricane Isaias	NPCC, RF, SERC
7	August 27, 2020	5.28	1.42	1.33	2.52	Unnamed Tropical Storm	RF, SERC
8	June 15, 2022	5.23	1.63	0.24	3.36	High Temperatures and Derecho	MRO, NPCC, RF, SERC, TRE
9	February 15, 2021	5.16	3.63	0.55	0.99	Cold Weather Event	MRO, RF, SERC
10	October 29, 2020	4.62	1.03	1.42	2.17	Hurricane Zeta	MRO, RF, SERC

Western Interconnection

The 2023 cumulative SRI for the Western Interconnection (see Table A.4) shows a 4% decrease over the prior four-year period of 2019–2022. The 2023 cumulative SRI was the second lowest among the five years analyzed.

Table A.4: Annual Cumulative SRI Western Interconnection

Year	Cumulative Weighted Generation	Cumulative Weighted Transmission	Cumulative Weighted Load Loss	Annual Cumulative SRI	Average Daily SRI
2019	421.7	104.4	73.9	599.9	1.64
2020	390.8	100.6	73.0	564.4	1.54
2021	426.8	104.0	96.9	627.7	1.72
2022	423.7	93.4	61.6	578.7	1.59
2023	**423.2**	**74.3**	**68.8**	**566.3**	**1.55**

The top 10 SRI days of the Western Interconnection for 2023 were distributed throughout the year as shown in Figure A.3. None of the top 10 days that occurred in the Western Interconnection align with the top 10 SRI days reported for North America. All days were driven by either generation or load loss.

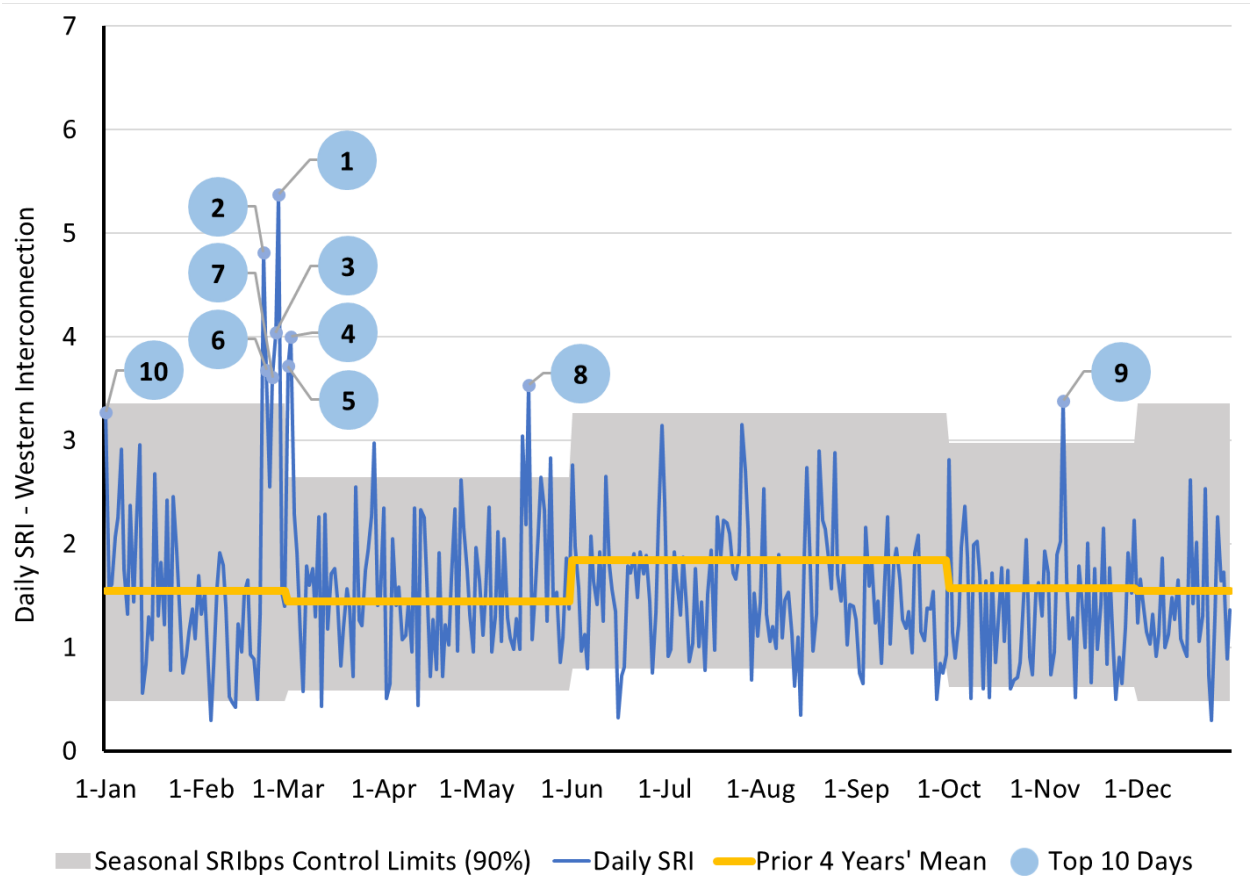


Figure A.3: 2023 Western Interconnection Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

Figure A.4 shows the Western Interconnection's top ten SRI days in 2023 relative to the four prior years.

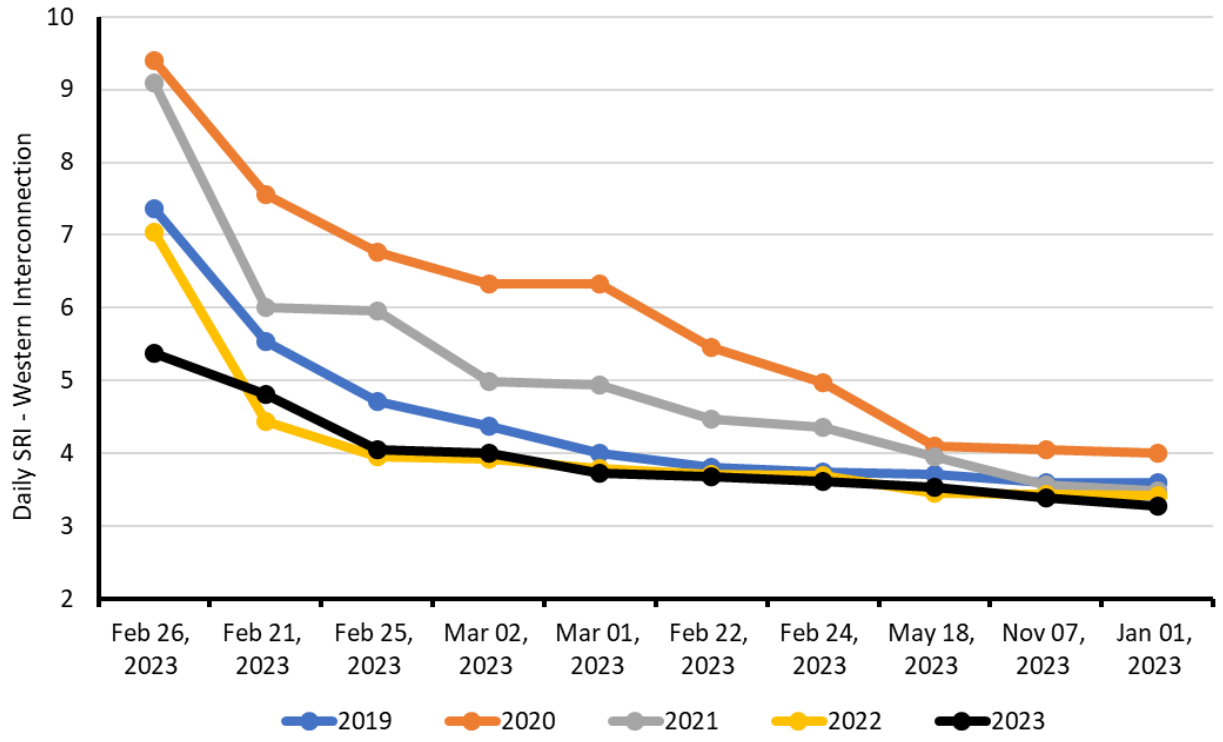


Figure A.4: Western Interconnection Top Annual Daily SRI Days Sorted Descending

Table A.5 details each component's contribution to the top 10 SRI days for the Western Interconnection; WECC is the only Regional Entity in the Western Interconnection.

Table A.5: 2023 Top 10 SRI Days Western Interconnection

Rank	Date	SRI and Weighted Components 2022				Atypical Weather Conditions
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss	
1	26-Feb	5.38	1.30	0.17	3.91	Winter Storm
2	21-Feb	4.82	1.63	0.04	3.14	Winter Storm
3	25-Feb	4.04	1.20	0.64	2.20	Flooding
4	2-Mar	4.00	1.96	0.21	1.83	Winter Storm
5	1-Mar	3.72	2.66	0.44	0.62	Winter Storm
6	22-Feb	3.68	2.22	1.23	0.22	Winter Storm
7	24-Feb	3.61	2.61	0.96	0.05	Winter Storm
8	18-May	3.53	2.80	0.48	0.25	No discernible atypical weather conditions
9	7-Nov	3.38	1.54	0.03	1.81	No discernible atypical weather conditions
10	1-Jan	3.27	1.92	1.32	0.02	Severe Storms

Table A.6 shows the top 10 SRI days for the Western interconnection over the last five years.

Table A.6: 2019–2023 Top 10 SRI Days Western Interconnection[85]

Rank	Date	SRI and Weighted Components				Atypical Weather Conditions
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss	
1	August 16, 2020	9.40	2.05	0.92	6.43	Extreme Heat
2	November 17, 2021	9.09	0.62	0.06	8.41	High winds and Special Protection System Operation
3	August 17, 2020	7.55	2.13	0.87	4.55	Extreme Heat
4	October 11, 2019	7.36	0.75	5.72	0.88	Saddle Ridge Fire
5	December 22, 2022	7.03	2.40	0.71	3.93	No discernible atypical weather conditions
6	September 8, 2020	6.76	3.38	3.14	0.25	Wildfires
7	September 9, 2020	6.33	1.44	1.11	3.78	Wildfires
8	August 19, 2020	6.33	1.63	2.12	2.58	Extreme Heat
9	January 13, 2021	6.00	1.86	4.05	0.09	Northwest Winter Weather
10	January 15, 2021	5.96	1.36	0.12	4.48	Winter Storm

Extreme Day Analysis by Interconnection

The extreme-day analyses for transmission and generation for 2023 are presented by Interconnection. The maximum TADS reported MVA capacity or GADS reported net maximum capacity for 2023 is shown in the upper-right corners of Figures A.5–A.10. The largest outliers and extreme days correlating with NERC-wide extreme days have been labeled with any atypical weather conditions during those days. Interconnection extreme days that do not align with NERC-wide extreme days are dated, but weather conditions are not identified. All dates are shown in UTC.

[85] Values in this table do not align with prior years' *SOR* reports due to a database error causing load-loss values to be shifted by two days.

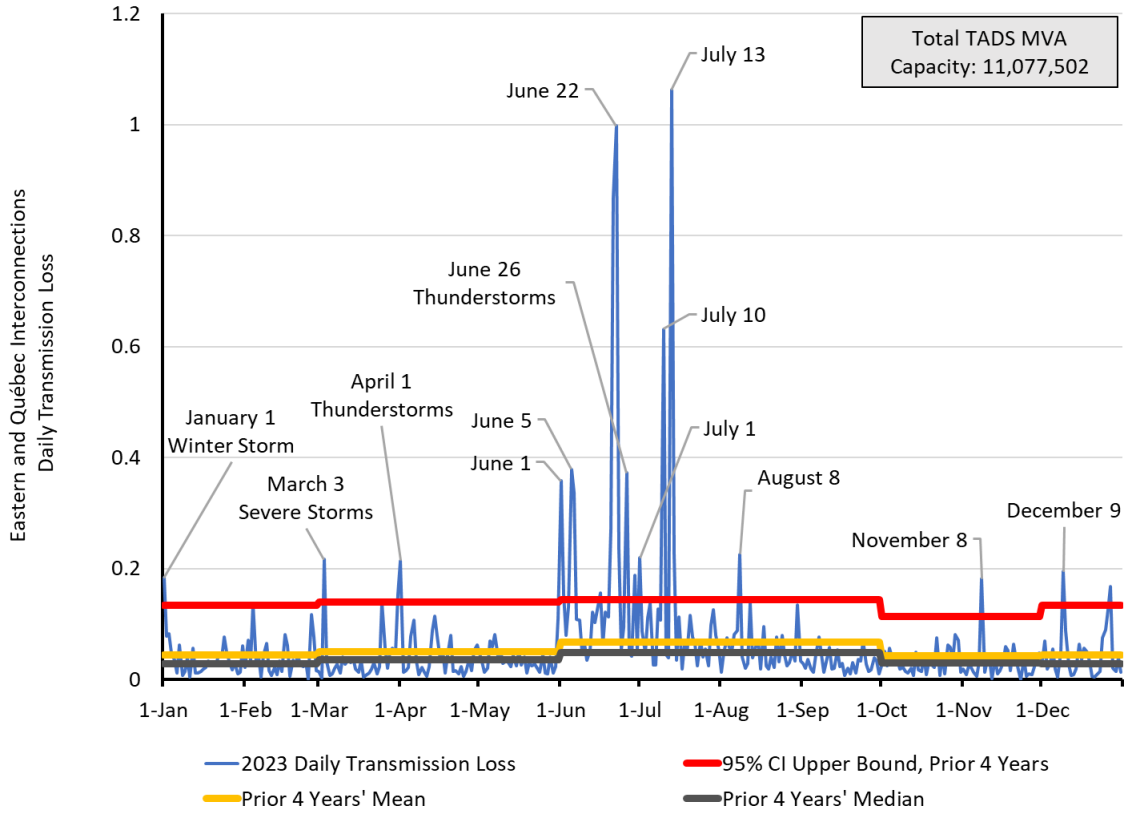


Figure A.5: Eastern and Québec Interconnections—Transmission Impacts during Extreme Days of 2023

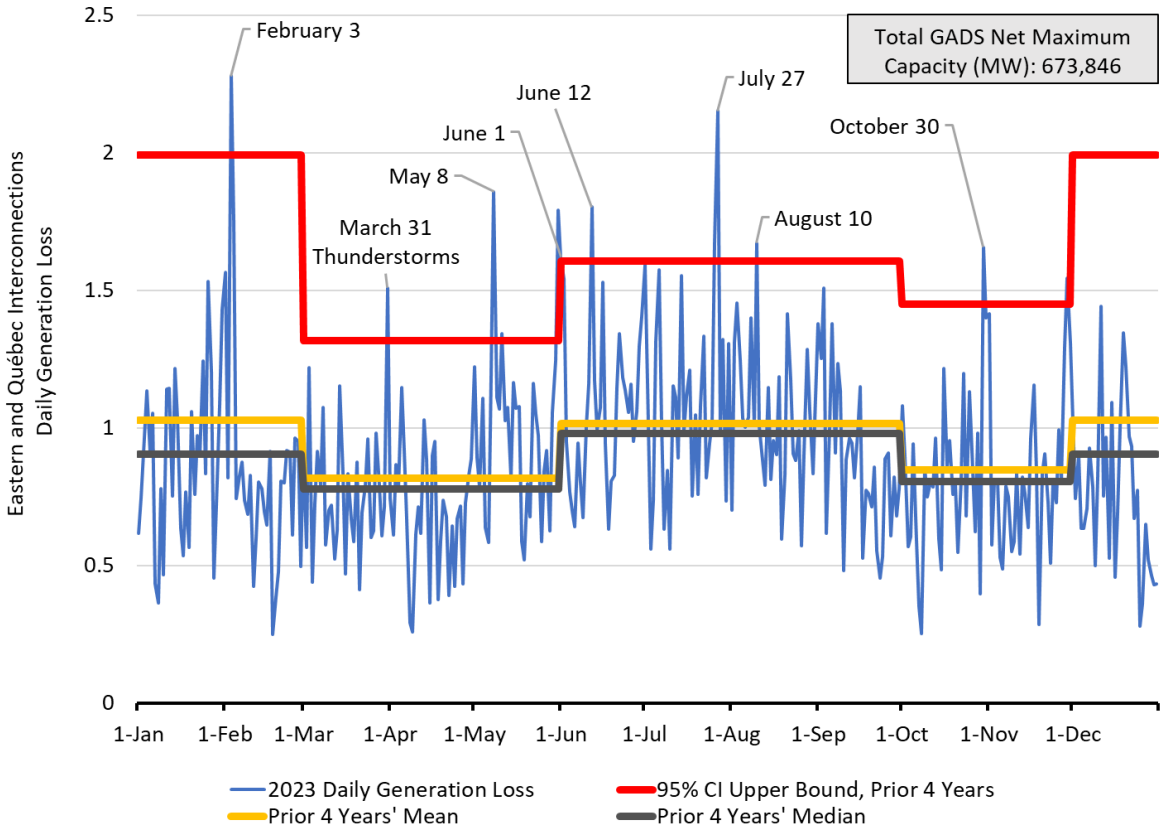


Figure A.6: Eastern and Québec Interconnections—Generation Impacts during Extreme Days of 2023

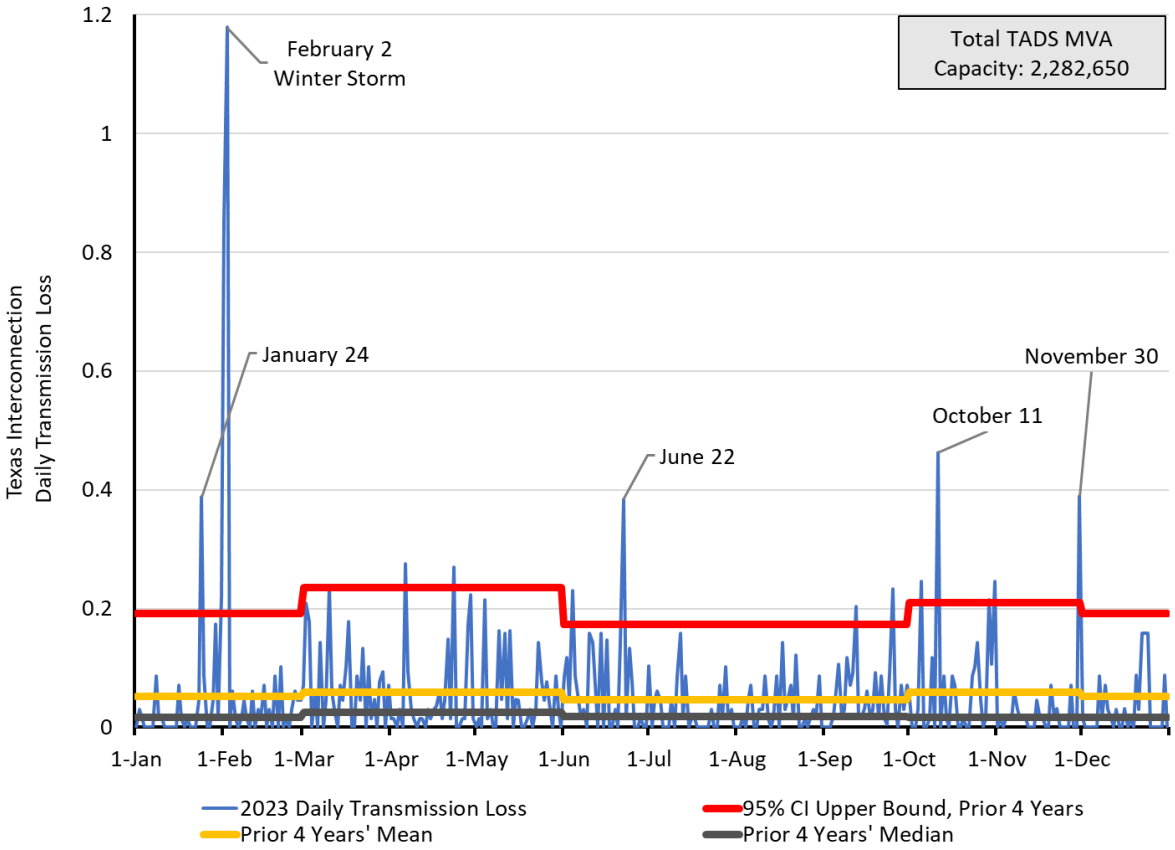


Figure A.7: Texas Interconnection—Transmission Impacts during Extreme Days of 2023

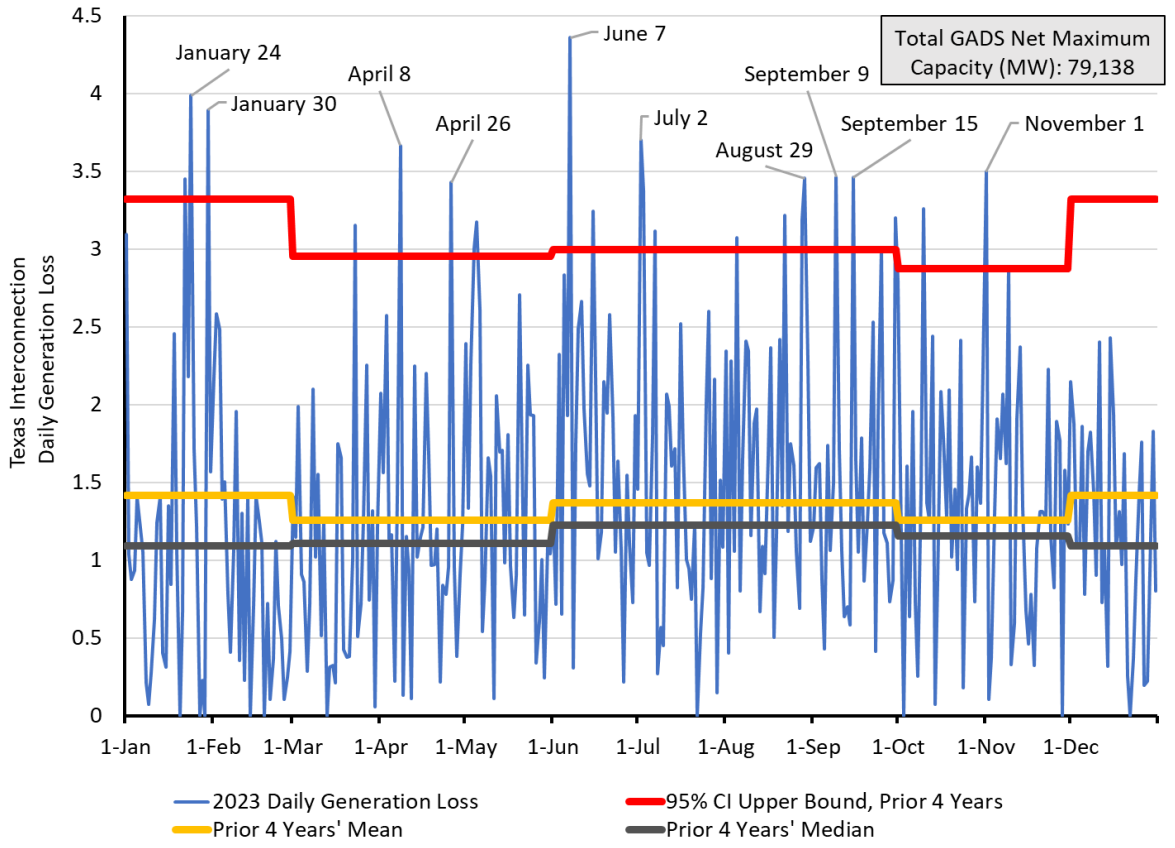


Figure A.8: Texas Interconnection—Generation Impacts during Extreme Days of 2023

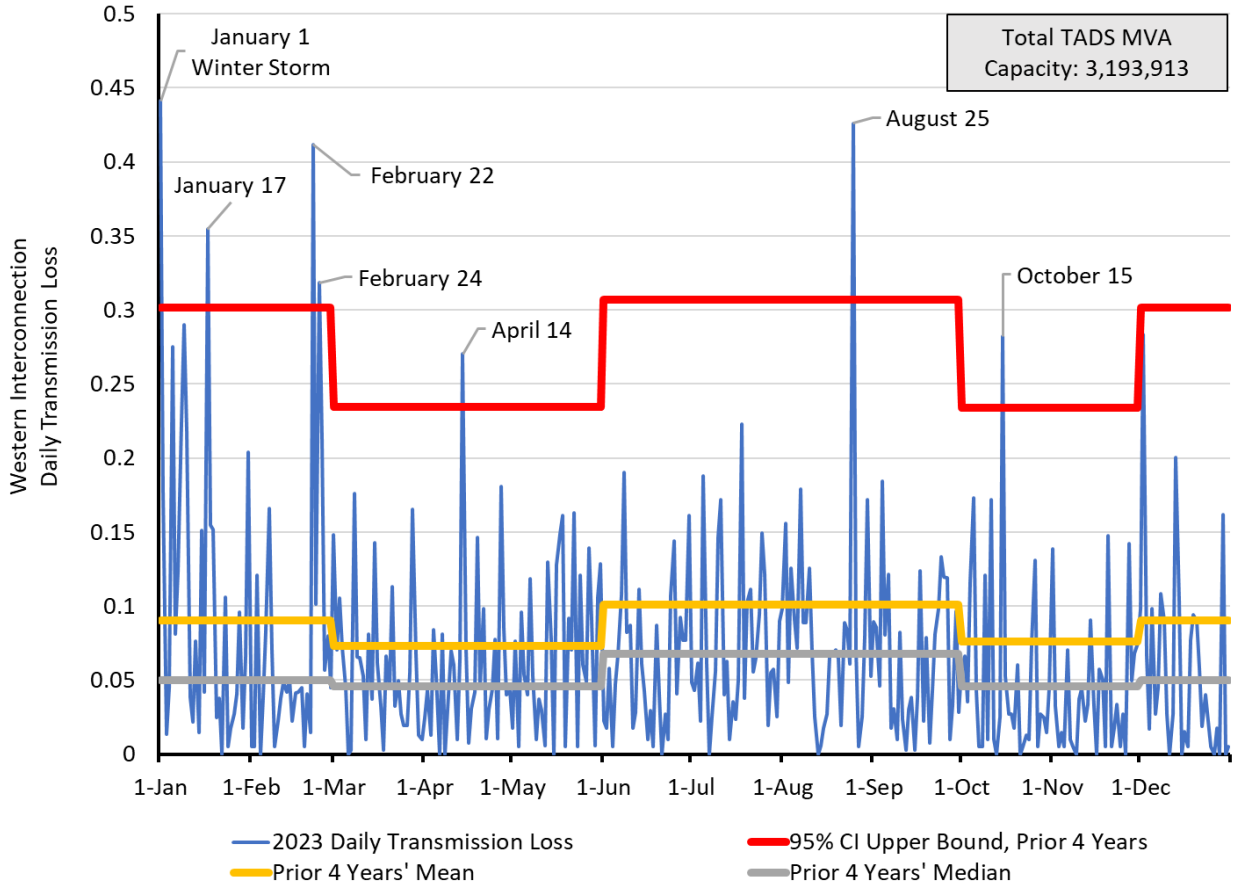


Figure A.9: Western Interconnection—Transmission Impacts during Extreme Days of 2023

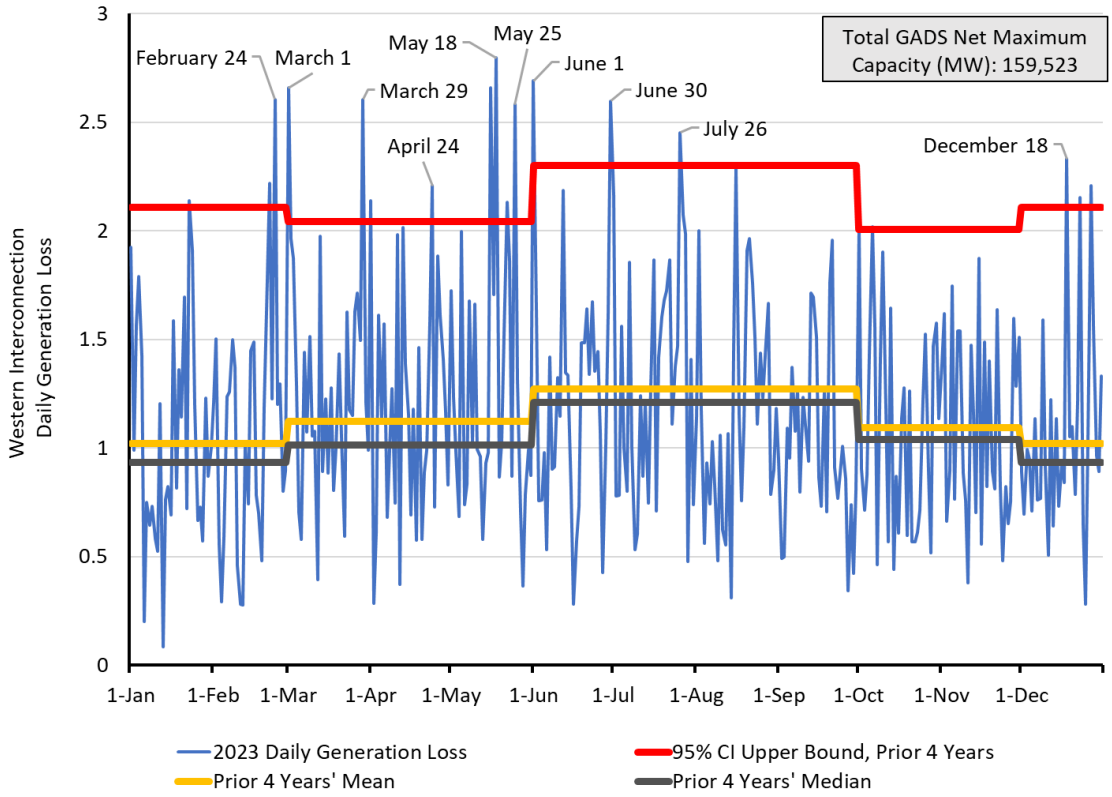


Figure A.10: Western Interconnection—Generation Impacts during Extreme Days of 2023

Appendix B: Acknowledgements

NERC would like to express its appreciation to the many people who provided direct technical support and identified areas for improvement to this document as well as all the people across the industry who work tirelessly to keep the lights on every day.

NERC Industry Group Acknowledgements	
Group	**Officers**
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Performance Analysis Subcommittee	RSTC Sponsor: Darryl Lawrence, PA Office of Consumer Advocate Chair: David Penney, Texas RE Vice Chair: Heide Caswell, Oregon Public Utilities Commission
Events Analysis Subcommittee	Chair: Chris Moran, PJM Vice Chair: James Hanson, WECC
Generation Availability Data System User Group	Chair: Danny Small, City Utilities Vice Chair: Ken Sabourin, Sunflower Energy
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Transmission Availability Data System User Group	Chair: John Idzior, ReliabilityFirst Vice Chair: Nick DePompei, SERC
Resources Subcommittee	Chair: Greg Park, WECC RS Vice Chair and NPCC: Bill Henson, ISO-NE
Real-Time Operating Subcommittee	Chair: James Hartmann, Electric Reliability Council of Texas, Inc. Vice Chair: Timothy Beach, California Independent System Operator (RC West)
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System Protection and Control Working Group	Chair: Jefrey Iler, AEP Vice Chair: Bill Crossland, ReliabilityFirst

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Nathan Strobel	Manager of Technical Publications
Robert Tallman	Senior Engineer
Lee Thaubald	Senior Application Specialist

EXHIBIT 52

UNITED STATES OF AMERICA
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order TransAlta Centralia Generation	Order No. 202-25-11

DECLARATION OF THOMAS MIDDLETON IN SUPPORT OF MOTION TO INTERVENE, REQUEST FOR REHEARING, AND MOTION TO STAY BY STATE OF WASHINGTON

I, Thomas Middleton, declare under penalty of perjury under the laws of the state of Washington that the following is true and correct:

1. I submit this declaration in support of the State of Washington's standing to challenge United States Department of Energy Order No. 202-25-11 ("Order"). *See* Ex. 1. I make this declaration of my own personal knowledge, unless otherwise indicated.

2. I am now and at all times mentioned have been a citizen of the United States and a resident of the state of Washington, over the age of 18 years, competent to make this declaration, and I make this declaration from my own personal knowledge and judgment. I submit this declaration in support of motions to challenge the Order.

3. I am currently employed by the Washington State Department of Ecology (Ecology) as a hydrogeologist and cleanup site manager in the agency's Toxics Cleanup Program. I hold Bachelor of Arts and Master of Arts degrees in Geological Sciences from the State University of New York at Buffalo. I have been practicing as a hydrogeologist since 1991 and have worked for Ecology's Toxics Cleanup Program over the past 18 years. The mission of Ecology's Toxics Cleanup Program is to protect human health and the environment by investigating and cleaning up sites contaminated with hazardous substances.

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4. About 14,000 sites in Washington are known or suspected to be contaminated with hazardous substances. Ex. 52-1 (Washington Department of Ecology, Model Toxics Control Act, Model Toxics Control Act - Washington State Department of Ecology (last visited January 5, 2026)). Ecology's Toxics Cleanup Program addresses contamination at these sites through agreed orders, enforcement orders, and consent decrees issued under the authority of the Model Toxics Control Act (MTCA), Chapter 70A.305 RCW. MTCA orders and decrees govern the investigation of contamination at cleanup sites and the development of cleanup action plans that remediate contamination.

5. As part of my work for the Toxics Cleanup Program, I am frequently involved in efforts to develop and implement MTCA orders and decrees that remediate the harm that contamination from hazardous substances causes in the state of Washington. That work typically includes investigating cleanup sites to characterize the nature, location, and extent of contamination, developing plans to remediate contamination, and overseeing the implementation of actions to clean up hazardous substances.

6. The TransAlta Centralia Steam Plant ("Plant") is a site contaminated with hazardous substances and subject to the requirements of MTCA. Contamination at the Plant results from operation of coal-fired boilers to generate electricity since 1971. I am the site manager for the MTCA investigation and cleanup at the TransAlta Centralia Steam Plant site. As site manager, I work with a team of scientists and engineers at Ecology to determine the nature, location, and extent of hazardous substances at and around the Plant. I also work with this team and with TransAlta's staff and consultants to develop plans to investigate and clean up hazardous substances located at and around the Plant.

7. As part of a 2011 Memorandum of Agreement executed with the State of Washington, TransAlta agreed to cease coal-burning operations in 2025 and conducted a series of investigations at the Site to characterize potential contamination from hazardous substances. The investigations found that soil at the Site contained concentrations of arsenic, barium,

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cadmium, copper, selenium, and zinc in soil above applicable MTCA cleanup levels. Ex. 52-2 at 6 (State of Washington Department of Ecology, Agreed Order No. DE24235 (Dec. 29, 2025)). The investigations also found the following nine contaminants of concern above MTCA cleanup levels for groundwater: arsenic, chromium, copper, manganese, selenium, zinc, 1-methylnapthalene, total petroleum hydrocarbons, and vinyl chloride. *Id.* Finally, the investigations found that sediment at the Site contains concentrations of arsenic, cadmium, chromium, mercury, nickel, and selenium above applicable MTCA cleanup levels. *Id.* Contamination from hazardous substances documented in the investigations results from the Site's use as a coal-fired generation facility from 1971 to 2025. *Id.* at 3.

8. In December of 2025, TransAlta and the State of Washington executed an Agreed Order (AO) to recognize TransAlta's plan to cease coal-fired generation and to begin the cleanup of hazardous substances at and around the Plant. The AO directs the cleanup of hazardous substances documented in the investigations and provides for an investigation of hazardous substances in the area surrounding the Plant. Operation of the coal-fired boiler and smokestack at the Plant likely caused aerial deposition of hazardous substances, including dioxin and furans, mercury, heavy metals, and carcinogenic polycyclic aromatic hydrocarbons, in these areas near the Plant. The area surrounding the Plant includes the City of Centralia, which is approximately five miles west of the Plant, and had a population of 19,061 people in 2024. Ex. 52-3 (United States Census Bureau, *Quick Facts Centralia, WA,* U.S. Census Bureau QuickFacts: Centralia city, Washington). The Centralia Micropolitan Statistical Area stretches from Centralia, west of the Plant, to Packwood, Washington, southeast of the Plant, and is home to approximately 83,925 people. Ex. 52-4 (Data USA, Centralia, WA Metropolitan Statistical Area, Centralia, WA | Data USA). These small towns and rural communities are not financially or technically equipped to address widespread contamination of hazardous substances.

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9. Since beginning operations in 1971, the TransAlta Centralia Steam Plant has utilized electrostatic precipitators (ESPs) on its smokestacks to capture some of the air pollutants produced from combustion of coal. In 2011, TransAlta added activated carbon to its flue gas treatment system to reduce mercury in emissions. However, even when coal plants use pollution control technologies such as ESPs and flue gas treatment systems, emissions from those plants contain some amounts hazardous air pollutants like heavy metals, mercury, dioxins, and polycyclic aromatic hydrocarbons. Ex. 52-5 at 28 (Environmental Health & Engineering, Inc., *Emissions of Hazardous Air Pollutants from Coal-Fired Power Plants* (Mar. 2011)). In addition, the ESPs at the TransAlta Centralia Steam Plant require the coal plant to run and reach full heat before they can be used, which can take multiple hours. Thus, pollution control technologies at the Site have not prevented releases of hazardous substances from the smokestacks in the past and will not prevent air pollutants from leaving the smokestack (especially during this start-up period) in the future where the Plant is operating in accordance with the Order.

10. Air pollution released from a smokestack results in aerial deposition of those hazardous substances which can travel over long distances. The hazardous substances are deposited on surfaces (lawns, streets, gardens, etc.) or washed out of the atmosphere in rain or snowfall. Where the aerial deposition ends up in soil (e.g., lawns, parks, schoolyards), it puts people at risk, especially children whose bodies are still developing and because they are more likely to have contact with dirt and then ingest it (e.g., eating with dirty hands, putting dirty toys in their mouths, or rubbing their eyes with dirty hands).

11. The hazardous substances which Ecology has data showing were released from the Plant are dioxin and furans, mercury, heavy metals, and carcinogenic polycyclic aromatic hydrocarbons. Each of these are listed on the CERCLA Hazardous Substance List and are also considered a hazardous substance under MTCA and pose a risk to human health and the environment. For example, dioxin and furans are persistent environmental pollutants, are

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highly toxic and can cause cancer, reproductive and developmental problems, damage to the immune system and can interfere with hormones. Mercury exposure poses significant health risks for which pregnant women and infants are particularly at risk as mercury can affect fetal development and infant health. Polycyclic Aromatic Hydrocarbons (PAHs) have a range of serious health risks from various cancers, respiratory and cardiovascular diseases, reproductive health problems and more.

12. The purpose of MTCA is to identify, investigate, and cleanup facilities where there has been a release of a hazardous substance. MTCA does not require a threshold amount of contamination to trigger investigation and cleanup requirements. *See PacifiCorp Envtl. Remediation Co. v. Dep't of Transp.,* 162 Wn. App. 627, 658 (2011) ("no minimum level of hazardous substance is required to trigger MTCA liability" (quoting *Seattle City Light v. Dep't of Transp.*, 98 Wn. App. 165, 172 (1999))). Ecology will ensure that the release will be investigated and cleaned up to the standards set forth in the MTCA statute and regulations. For this facility, Ecology has identified a release of hazardous substances through past operations of the Plant, and a threat of release through future operation of the Plant – in particular from its smokestacks during the ESP start-up period and during normal coal-burning operations while the ESPs operate.

13. Continued use of the coal-fired boiler and smokestacks at the Plant would conflict with Ecology's MTCA cleanup at and around the Plant. The plan to convert the Plant to natural gas provided an opportunity for TransAlta and Ecology to perform depositional surveys and chemometric tracing in the areas surrounding the Plant. These surveys would determine the extent and location of contamination from hazardous substances emitted from the Plant's smokestacks. If the Plant continues to burn coal and emit hazardous substances, the remediation of hazardous substances that follows would be rendered meaningless because hazardous substances would continue to be deposited after the MTCA work is complete. This

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would result in recontamination of the areas surrounding the Plant, which would interfere with the MTCA cleanup.

14. Continued aerial deposition of hazardous substances that would occur under the Order would also conflict with the MTCA cleanup effort because it could result in hundreds or even thousands of additional potentially liable parties (PLPs). Under MTCA, the current owner or operator of a "facility" is a liable party – and "facility" is defined as the area where a hazardous substance has come to be located. So, in the case of aerial deposition of hazardous substances, the "facility" (more commonly referred to as the Site) includes all properties where that hazardous substance has landed. As a MTCA liable party, property owners are strictly, jointly, and severally liable for contamination located on their property and elsewhere within the Site. Ecology is responsible for reviewing credible evidence and identifying potentially liable parties for a Site. If the Plant continues to burn coal and emit hazardous substances through its smokestacks, these hazardous substances will continue to be located on privately owned property in residential and commercial areas surrounding the Plant. Determining liability and responsibility for cleanup of hazardous substance with so many additional PLPs is a difficult and time-consuming process that could interfere with MTCA cleanup plans and timelines. Similar situations involving widespread aerial deposition of contaminants, such as the ASARCO Tacoma smelter plume, have affected thousands of properties and taken decades and millions of dollars to clean up, with some contamination still existing today. Thus, continuing to burn coal at the Plant under the Order would conflict with the MTCA investigation and cleanup that Ecology is currently working on.

15. Continuing to burn coal under the Order would also conflict with Ecology's MTCA investigation and cleanup of the settling ponds at the Plant. The Plant uses settling ponds to contain byproducts from burning coal and many of these byproducts include hazardous substances subject to MTCA. Converting the Plant to a facility that burns natural gas would allow TransAlta to decommission the settling ponds, allowing for investigation and

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remediation of the ponds pursuant to MTCA. However, continuing to burn coal at the Plant would require TransAlta to continue using the settling ponds, preventing TransAlta and Ecology from performing cleanup of the ponds under MTCA. Failure to remediate hazardous substances in the settling ponds could pose risks related to groundwater contamination, though further investigation under MTCA is necessary to fully characterize the extent of such risk.

16. Ecology strongly opposes the Order. The Order would allow hazardous substances to continue to be released at the TransAlta Centralia Steam Plant and impact the area surrounding it. Continued aerial deposition of hazardous substances from combustion of coal poses health risks to Washingtonians and would hinder the State's current MTCA cleanup effort. Continuing to burn coal under the Order would also interfere with MTCA cleanup of the settling ponds at the Plant, creating potential risks to groundwater. Thus, Ecology opposes the order due to the risks it poses to Washingtonians and its conflict with the MTCA investigation and cleanup of the Plant.

I state under penalty of perjury under the laws of the United States of America that the foregoing is true and correct to the best of my knowledge and belief.

DATED this 12th day of January, in Olympia, Washington.

THOMAS MIDDLETON

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EXHIBIT 52-1

Model Toxics Control Act

The Model Toxics Control Act (MTCA) is Washington's environmental cleanup law. MTCA funds and directs the investigation, cleanup, and prevention of sites that are contaminated by hazardous substances. It works to protect people's health and the environment, and to preserve natural resources for the future.

There are about 14,000 known or suspected contaminated sites in Washington — and the list keeps growing. Thanks to cleanup efforts funded by MTCA, more than 7,700 of these sites are already cleaned up or require no further action.

The Hazardous Substance Tax helps pay for this cleanup work. Voters approved a tax on hazardous substances (such as petroleum products, pesticides, and other chemicals) to pay for cleanups. Under MTCA, we might also recover penalties or require polluters to pay for cleanups and our oversight.

Rules and policies put MTCA into action. We've developed rules and policies that set cleanup standards and other requirements. These make sure cleanups protect your health and the environment.

The Toxics Cleanup Program is one of several Ecology programs that receive funds from MTCA. The Toxics Cleanup Program has primary responsibility for implementing and enforcing MTCA. They develop MTCA's rules, policies, and guidance, and oversee or manage most of the cleanups in Washington. They also manage a grant program that helps local governments clean up contaminated sites in their communities so they can put abandoned properties back into use.

I want to...

- Learn more about the Hazardous Substance Tax
- Subscribe to the Contaminated Site Register for updates on MTCA policies and cleanups
- Learn about other types of hazardous waste and toxic cleanups

MTCA is Washington's cleanup law

The Model Toxics Control Act (MTCA) is one of several environmental laws in Washington. Known as the state's cleanup law, MTCA governs the cleanup and prevention of contaminated sites that can threaten people's health and the environment.

MTCA's main purpose is "to raise sufficient funds to clean up all hazardous waste sites and to prevent the creation of future hazards due to improper disposal of toxic wastes into the state's lands and waters." (RCW 70A.305.010).

MTCA evolved from citizens' Initiative 97 in 1988 and became law in 1989. It's been substantially amended more than 20 times (most recently in 2019) but its key principles remain in place today:

Polluter pays
Cleanups should be as permanent as possible
Public participation is crucial
Processes should demonstrate a bias toward action, permanence, and innovation

What is a hazardous site?

We often use the terms **site, hazardous site, cleanup site,** and **contaminated site** interchangeably. A site is where we've confirmed one or more releases (or threatened release) of a hazardous or dangerous substance that needs to be cleaned up. There are about 14,000 known or suspected contaminated sites in Washington. MTCA helps us address them.

How is MTCA funded?

Taxes. Voters authorized a tax on hazardous substances to help pay for cleanups.
Cost-recovery. We recover cleanup costs from potentially liable persons.
Penalties. We collect or recover penalties under the MTCA law.
Other sources. The state Legislature may transfer other funding for cleanup work.

Revenues from these sources are deposited into three accounts: MTCA Operating Account, MTCA Capital Account, and MTCA Stormwater Account. Collectively, these are called the MTCA accounts. Learn how we're using these funds in our reports to the Legislature.

Why is MTCA important?

More than 7,700 contaminated sites in Washington have been cleaned up with MTCA funds and collection authority since it became law in 1989. That's more than half of the state's 14,000-plus cleanup sites. MTCA's role is becoming even more essential because between **200 to 300 new sites** are reported each year.

MTCA powers our work to investigate, clean up, and prevent hazardous waste. Cleanups protect people's health by removing toxic chemicals from the environment, like arsenic from playground soil or methane gas from a solid waste landfill. Cleanups preserve wildlife habitat for future generations, spur new economic developments, and put abandoned properties back into use.

MTCA — and every person involved in a cleanup — make these transformations possible.

How do we put MTCA into action?

We developed regulations (called "rules") to implement the Model Toxics Control Act. They set standards and requirements for contaminated site cleanups. Rules ensure that cleanups are protecting people's health and environment. If you're cleaning up a contaminated site in Washington, you'll need to meet the requirements of:

- Model Toxics Control Act (MTCA) - Chapter 70A.305 RCW (MTCA law)
- MTCA Cleanup Regulations - Chapter 173-340 WAC (MTCA rule, also known as the MTCA Cleanup Rule)
- Sediment Management Standards - Chapter 173-204-WAC (SMS rule, also known as the Sediment Cleanup Rule)
- Remedial Action Grants and Loans – Chapter 173-322A WAC (RAG rule)

Dangerous waste cleanups and management also need to comply with Washington's hazardous waste management law and dangerous waste regulations.

We have policies and guidance to help you meet these requirements.

What's the difference between the MTCA and SMS rules?

MTCA Rule (Cleanup Rule)	SMS Rule
MTCA Cleanup Regulations (also called the MTCA Cleanup Rule) applies to all cleanups, whether they're **upland cleanups** on land or in groundwater, or **sediment cleanups** in freshwater or marine environments. We published the first MTCA Cleanup Rule in 1991. We are updating this rule in a series of rulemakings that will take several years to complete. In 2023 we completed the first rulemaking, which focuses on procedures for conducting cleanups. Learn more at Chapter 173-340 WAC rulemaking and updating the cleanup rule.	

Programs and agencies with MTCA regulatory oversight

Programs and Agencies

Toxics Cleanup Program has primary responsibility for implementing and enforcing the Model Toxics Control Act. The program develops rules and guidelines that govern cleanups. It manages the Remedial Action Grant program that funds cleanups by local governments. It also oversees or manages most cleanups in Washington.

Hazardous Waste and Toxics Reduction Program oversees cleanups of releases from hazardous waste treatment, storage, and disposal facilities that are regulated under the Hazardous Waste Management Act (Chapter 70A.300 RCW). They also manage dangerous waste permits.

Solid Waste Management Program oversees cleanups of releases from permitted landfills and large industrial facilities — such as pulp and paper mills, aluminum smelters, and petroleum refining — and distribution systems.

Nuclear Waste Program ensures that cleanup of contaminated sites on the Hanford Nuclear Reservation is consistent with state law.

Pollution Liability Insurance Agency provides technical assistance to people who independently clean up sites contaminated by petroleum from leaking heating oil tanks. This includes written opinions on sufficiency of cleanups based on MTCA standards. In 2017, the legislature authorized PLIA to expand its existing technical assistance program to include other petroleum storage tank sites we identify. (House Bill 1266).

Find cleanup policies and guidance

MTCA Resources

TCP's policies and guidance interpret the MTCA rule and provide best management practices for conducting successful cleanups.

MTCA legislative reports: Biennial Reports describe how we spent MTCA funds over the past two years. Ten-Year Financing Reports describe cleanup financing needs in the next ten years. Cleanup Settlement Account Reports describe how we're using money from legal settlements and court orders for specific sites and restorations.

How the cleanup process works summarizes MTCA's cleanup steps. The fact sheet Process for cleanup of hazardous waste sites provides more details.

Private right of action gives steps for persons intending to recover cleanup costs from other liable persons under MTCA.

The Contaminated Site Register provides updates on MTCA policies and cleanup activities. Subscribe or download back issues.

How we developed MTCA standards and selected cleanup actions

Focus on: Washington's envrionmental cleanup law (rev. 2018)
Developing ground water cleanup standards (2005)
Developing surface water cleanup standards (2005)
Developing soil cleanup standards (2005)
Developing air cleanup standards (2005)

Related links

Hazardous Substance Tax
MTCA cleanup process
MTCA Cleanup Rule updates
Cleanup and Tank Search: Find contaminated sites in Washington
Contaminated Site Register & site lists

Contact information

Sarah Wollwage
Policy & Technical Support Unit
360-481-9101

EXHIBIT 52-2

State of Washington
Department of Ecology

In the Matter of Remedial Action by:
TransAlta Centralia Generation LLC for: TransAlta Centralia
Agreed Order
No. DE 24235

To: Mickey Dreher, Vice President, Centralia
913 Big Hanaford Rd, Centralia, WA 98531-9101

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Exhibit A Location Diagram
Exhibit B Scope of Work

1. Introduction

The mutual objective of the State of Washington, Department of Ecology (Ecology) and TransAlta Centralia Generation LLC (TransAlta) under this Agreed Order (Order) is to provide for remedial action at a facility where there has been a release or threatened release of hazardous substances. This Order requires TransAlta to conduct a remedial investigation and feasibility study, develop a draft cleanup action plan, and implement the final cleanup plan for the Site. Ecology believes the actions required by this Order are in the public interest.

2. Jurisdiction

This Order is issued pursuant to the Model Toxics Control Act (MTCA), RCW 70A.305.050(1).

3. Parties Bound

This Agreed Order shall apply to and be binding upon the Parties to this Order, their successors and assigns. The undersigned representative of each Party hereby certifies that he or she is fully authorized to enter into this Order and to execute and legally bind such Party to comply with this Order. TransAlta agrees to undertake all actions required by the terms and conditions of this Order. No change in ownership or corporate status shall alter TransAlta's responsibility under this Order. TransAlta shall provide a copy of this Order to all agents, contractors, and subcontractors retained to perform work required by this Order, and shall ensure that all work undertaken by such agents, contractors, and subcontractors complies with this Order.

4. Definitions

Unless otherwise specified herein, the definitions set forth in RCW 70A.305, WAC 173-204 and WAC 173-340 shall control the meanings of the terms in this Order.

4.1 **Site**: The Site is referred to as TransAlta Centralia. The Site constitutes a facility under RCW 70A.305.020(8). The Site is defined by where a hazardous substance, other than a consumer product in consumer use, has been deposited, stored, disposed of, or placed, or otherwise come to be located. Based upon factors currently known to Ecology, the

Site is generally located in the vicinity of 913 Big Hanaford Rd, Centralia, WA as shown in the Location Diagram (Exhibit A).

4.2 **Parties**: Refers to the State of Washington, Department of Ecology and TransAlta.

4.3 **Potentially Liable Persons (PLP(s))**: Refers to TransAlta.

4.4 **Agreed Order or Order**: Refers to this Order and each of the exhibits to this Order. All exhibits are integral and enforceable parts of this Order.

5. Findings of Fact

Ecology makes the following findings of fact, without any express or implied admissions of such facts by TransAlta:

5.1 Based upon factors currently known to Ecology, the Site is generally located in the vicinity of 913 Big Hanaford Rd, Centralia, WA and includes at a minimum, Lewis County parcels 23340001000, 23340002002, 23340003000, 23340004000, 23340005001, 23340005002, 23340005003, 23340005004, 23436000000, 23345000000, 23355001006, 23355001007, 23355001008, 23355002002 as shown in the Location Diagram (Exhibit A).

5.2 The property has been developed for use as a coal-fired power generation facility since 1968, with the first boiler commissioned in 1971 and the second coming online in 1972. Containment ponds at the facility were constructed in the 1970s. Multiple utility companies owned and operated the facility until TransAlta purchased it in 2000. Prior to its use as a coal-fired power generation facility, the land was primarily agricultural or forested/undeveloped.

5.3 TransAlta is obligated to cease operation of its coal-fired boilers by December 31, 2025, per Revised Code of Washington (RCW) 80.80.040(3)(c), RCW 80.80.100, RCW 80.82.010, and the Memorandum of Understanding executed between TransAlta and the State of Washington on December 23rd, 2011, as further amended on July 13, 2017(2011 MOA). TransAlta retired the first coal-fired boiler in 2020 and plans to retire the second coal-fired boiler in December 2025. TransAlta is actively exploring opportunities to convert the unit to a natural gas peaking facility to support reliability and regional resource adequacy.

5.4 As part of the closure requirements for the facility, RCW 80.82.010(1)(d) requires TransAlta to provide among other things "decommissioning and site restoration plan

that addresses restoring physical topography, cleanup of all hazardous substances on the site, potential future uses of site following restoration, and coordination with local and community plans for economic development in the vicinity of the site".

5.5 As part of the transfer of the facility from PacificCorp to TransAlta, PacificCorp disclosed the following environmental issues related to hazardous substances at the facility:

- In 1987, a leak in the start-up fuel oil supply line was identified. The leak was near the northwest corner of Unit #1 Lodge-Cottrell precipitator. An investigation in 1998 documented diesel contamination ranging up to 845 parts per million (ppm) at a depth of 5 feet below ground surface (bgs). A subsequent report on the extent of the contamination was produced by Dames & Moore in July 2000 (D&M 2000).

- In 1989, a leak in the fuel oil supply line was identified in the area north of the #1 ID fans.

- In 1994, the reservoir for the hydraulic hoist in the heavy equipment shop was discovered to have a leak. A report was reportedly produced titled, *Heavy Equipment Rebuild Shop Subsurface Soil Investigation* report, dated June 15, 2001.

- In 1994, there was a leak in the startup fuel oil return line in the area south of the main fuel oil tanks.

- On November 23, 1999, there was a release of approximately 2,500 gallons of fuel oil from the warm-up oil supply line. This release was reported to the EPA and Ecology. A site investigator from Ecology visited the plant.

- A memo dated December 2, 2003, by PacifiCorp noted a "tarry substance" consistent with petroleum-based paints and solvents was discovered during pipe repair activities of underground pipes located to the north of the coal and ash shop west of the sewage treatment pond. The memo states:

  "All of the tarry substance visible was excavated and disposed of with the contaminated soil from the scrubber construction area. Based on the results from the soil samples obtained prior to the excavation activities it appears that no additional work activities are required for this site."

A notification prepared by PacifiCorp stated that all the leaks had been repaired and remediation activities were complete.

5.6 TransAlta conducted post-sale investigations between 2000 and 2004. These investigations identified the following:

TPH concentrations in surface soil samples exceeded the MTCA Method A Cleanup Level in four of the samples (SS-DMB-2 to SS-DMB-5). TPH was not detected at

concentrations exceeding the MTCA Method A Cleanup Level in the subsurface soil samples.

Diesel-range TPH concentrations in groundwater exceeded the MTCA Method A Cleanup Level in samples collected from the monitoring wells. Arsenic concentrations exceeded the MTCA Method B Cleanup Level in groundwater samples collected from the wells. Lead concentrations exceeded the MTCA Method A Cleanup Level in samples collected from three wells located in the Main Plant Area and in well MW-P5, located in the Effluent Ponds area. Beryllium and chromium concentrations exceeded the MTCA Method B Cleanup Level and Method A Cleanup Level, respectively, in groundwater samples collected from wells MW-P3 and MW-P5. VOCs were not detected at concentrations exceeding MTCA Method A or B Cleanup Levels.

TPH was not detected in the accumulated solid samples in the Coal Runoff Pond at concentrations exceeding the MTCA Method A Cleanup Level, but TPH concentrations in the three South Effluent Pond samples did. Methylene chloride was detected at a concentration exceeding the MTCA Method A Cleanup Level in samples CR-Pond-A and CR-Pond-C. Metal concentrations were less than the Washington State Background Metals soil concentrations except copper and zinc. Beryllium was detected at a concentration exceeding the MTCA Method B Cleanup Level.

Three monitoring wells (MW-P3, MW-P4, and MW-P5) were sampled and analyzed for total and dissolved arsenic, beryllium, chromium, and lead. Arsenic was detected at concentrations exceeding the MTCA Method A and B Cleanup Levels.

PacifiCorp notified TransAlta of the status of ongoing remediation activities in *Current Project Status and Summary of Closed Work Activities*, dated February 23, 2004. According to the report, the scrubber construction area, the warm-up fuel line spill area, and a small area identified as the north trench were remediated to Ecology standards.

5.7 In 2003 TransAlta prepared a report to evaluate hydrogeologic conditions at the facility in accordance with their NPDES permit. A groundwater sample collected from well AFT 313 contained dissolved manganese and iron concentrations exceeding the MTCA Method A Cleanup Levels.

5.8 TransAlta performed a limited groundwater sampling event, in 2003, on wells located on the facility as well as on the neighboring Centralia Coal Mine property. Solvents tetrachloroethene (PCE) and trichloroethene (TCE) and breakdown products 1,1-dichloroethene (1,1-DCE), trans-1,2-dichloroethene, cis-1,2-dichloroethene, and vinyl

chloride were observed at concentrations in select wells exceeding their respective cleanup levels.

5.9 In 2014, a wastewater sample collected from Outfall was found to contain a mercury concentration that exceeded the NPDES permit surface water quality criterion. The source of the mercury was determined to be coal and products from its combustion.

5.10 From 2017 to present, multiple toxicity tests have been conducted on the TransAlta effluent at Outfall 001. A review of the effluent chemistry data in 2021 indicated that copper, and possibly zinc or hexavalent chromium, could contribute to chronic toxicity to *Ceriodaphnia dubia*.

5.11 In 2021, approximately 1,000 gallons of transformer oil was spilled onto soil, a roadway, and a holding pond. The spill was reported to Ecology (FS ID 119916). Absorbent material and a vacuum truck were used to remove pooled product from the roadway and soils around the transformer. Impacted soils were removed and taken to Marine Vacuum Services in Seattle, Washington, for disposal.

5.12 In response to the requirements of the 2011 MOA , TransAlta conducted a series of remedial investigations at the facility. The results of these investigations (Remedial Investigation Report, TransAlta Centralia Generation, LLC, May 2025) found the following:

There are six contaminants of concern found above applicable cleanup levels for soil at the Site. These are arsenic, barium, cadmium, copper, selenium, and zinc.

There are nine contaminants of concern found above applicable cleanup levels for groundwater at the Site. These are arsenic, chromium, copper, manganese, selenium, zinc, 1-methylnaphthalene, total petroleum hydrocarbons – diesel range, and vinyl chloride.

There are six contaminants of concern found above applicable cleanup levels in sediment at the facility. These are arsenic, cadmium, chromium, mercury, nickel, and selenium.

6. Ecology Determinations

Ecology makes the following determinations, without any express or implied admissions of such determinations (and underlying facts) by TransAlta.

6.1 TransAlta is an "owner or operator" as defined in RCW 70A.305.020(22) of a "facility" as defined in RCW 70A.305.020(8). Specifically, TransAlta is the current owner and operator of the property within the Site where there has been a release of hazardous substances to the environment.

6.2 Based upon all factors known to Ecology, a "release" or "threatened release" of "hazardous substance(s)" as defined in RCW 70A.305.020(32), and (13), respectively, has occurred at the Site.

6.3 Based upon credible evidence, Ecology issued a PLP status letter to TransAlta dated September 4, 2025, pursuant to RCW 70A.305.040, .020(26), and WAC 173-340-500. By letter dated October 8, 2025, TransAlta voluntarily waived its rights to notice and comment and accepted Ecology's determination that TransAlta is a PLP under RCW 70A.305.040.

6.4 Pursuant to RCW 70A.305.030(1), .050(1), Ecology may require PLPs to investigate or conduct other remedial actions with respect to any release or threatened release of hazardous substances, whenever it believes such action to be in the public interest. Based on the foregoing facts, Ecology believes the remedial actions required by this Order are in the public interest.

7. Work to be Performed

Based on the Findings of Fact and Ecology Determinations, it is hereby ordered that TransAlta take the following remedial actions at the Site. The area within the Site where remedial action is necessary under RCW 70A.305 is described in the Remedial Action Location Diagram (Exhibit A). These remedial actions must be conducted in accordance with WAC 173-340 and 173-204:

7.1 TransAlta will complete the remedial investigations they have begun prior to the Order, including addressing Ecology's comments on the submitted draft Remedial Investigation Report. TransAlta shall fully define the nature and extent of contamination at the Site, in a manner that meets with Ecology's approval and that meets the applicable requirements of MTCA and Chapters 173-340 and 172-204 WAC, and identify and analyze cleanup action alternatives to address contaminants above applicable levels. TransAlta shall also produce a Supplemental Remedial Investigation Work Plan, Remedial Investigation report (RI), Feasibility Study (FS), and draft Cleanup Action Plan (DCAP). TransAlta also agrees to implement a final cleanup action plan (fCAP). Work under this order must include the entire Site where a hazardous substance from a release has come to be located, including areas surrounding the coal plant property that may be subject to aerial deposition of contaminants. The work is to

be conducted in accordance with the schedule and terms of the Scope of Work and Schedule, Exhibit B, and all other requirements of this Order." The following naming conventions shall be used for documents: Agency Review Draft (designation for the first time Ecology receives a document); Public Review Draft (designates a document ready for public comment); Final (designation for a document after public comment and Ecology approval); and the preliminary Draft Cleanup Action Plan (designation for the Subject PLP(s)'s version of the DCAP).

7.2 If TransAlta learns of a significant change in conditions at the Site, including but not limited to a statistically significant increase in contaminant and/or chemical concentrations in any media, TransAlta, within seven (7) days of learning of the change in condition, shall notify Ecology in writing of said change and provide Ecology with any reports or records (including laboratory analyses, sampling results) relating to the change in conditions.

7.3 Pursuant to WAC 173-340-440(11), TransAlta shall maintain sufficient and adequate financial assurance mechanisms to cover all costs associated with the operation and maintenance of the remedial action at the Site, including institutional controls, compliance monitoring, and corrective measures.

7.3.1 Within sixty (60) days of the fCAP, TransAlta shall submit to Ecology for review and approval an estimate of the costs under this Order for operation and maintenance of the remedial actions at the Site, including institutional controls, compliance monitoring and corrective measures. Within sixty (60) days after Ecology approves the aforementioned cost estimate, TransAlta shall provide proof of financial assurances sufficient to cover all such costs in a form acceptable to Ecology.

7.3.2 TransAlta shall adjust the financial assurance coverage and provide Ecology's project coordinator with documentation of the updated financial assurance for:

7.3.3 Inflation, annually, within thirty (30) days of the anniversary date of the fCAP; or if applicable, the modified anniversary date established in accordance with this section, or if applicable, ninety (90) days after the close of TransAlta's fiscal year if the financial test or corporate guarantee is used.

7.3.4 Changes in cost estimates, within thirty (30) days of issuance of Ecology's approval of a modification or revision to the cleanup action plan (CAP) that result in increases to the cost or expected duration of remedial actions. Any

adjustments for inflation since the most recent preceding anniversary date shall be made concurrent with adjustments for changes in cost estimates. The issuance of Ecology's approval of a revised or modified CAP will revise the anniversary date established under this section to become the date of issuance of such revised or modified CAP.

7.4 All plans or other deliverables submitted by TransAlta for Ecology's review and approval under the Scope of Work and Schedule (Exhibit B) shall, upon Ecology's approval, become integral and enforceable parts of this Order. TransAlta shall take any action required by such deliverable.

7.5 Pursuant to WAC 173-340-430, an interim action is a remedial action that is technically necessary to reduce a threat to human health or the environment by eliminating or substantially reducing one or more pathways for exposure to a hazardous substance, that corrects a problem that may become substantially worse or cost substantially more to address if the remedial action is delayed, or that is needed to provide for completion of a site hazard assessment, remedial investigation/feasibility study, or design of a cleanup action plan. Any Party may propose an interim action under this Order. If the Parties are in agreement concerning the interim action, TransAlta shall prepare and submit to Ecology an Interim Action Work Plan, including a scope of work and schedule, by the date determined by Ecology. Ecology will provide public notice and opportunity to comment on the Interim Action Work Plan in accordance with WAC 173-340-600(16). TransAlta shall not conduct the interim action until Ecology approves the Interim Action Work Plan. Upon approval by Ecology, the Interim Action Work Plan becomes an integral and enforceable part of this Order, and TransAlta is required to conduct the interim action in accordance with the approved Interim Action Work Plan. If the Parties are not in agreement, Ecology reserves its authority to require interim action(s) under a separate order or other enforcement action under RCW 70A.305, or to undertake the interim action itself.

7.6 If Ecology determines that TransAlta has failed to make sufficient progress or failed to implement the remedial action, in whole or in part, Ecology may, after notice to TransAlta, perform any or all portions of the remedial action or at Ecology's discretion allow TransAlta opportunity to correct. In an emergency, Ecology is not required to provide notice to TransAlta, or an opportunity for dispute resolution. TransAlta shall reimburse Ecology for the costs of doing such work in accordance with Section 8.1

(Payment of Remedial Action Costs). Ecology reserves the right to enforce requirements of this Order under Section 10 (Enforcement).

7.7 Except where necessary to abate an emergency situation or where required by law, TransAlta shall not perform any remedial actions at the Site outside those remedial actions required by this Order to address the contamination that is the subject of this Order, unless Ecology concurs, in writing, with such additional remedial actions pursuant to Section 8.11 (Amendment of Order). In the event of an emergency, or where actions are taken as required by law, TransAlta must notify Ecology in writing of the event and remedial action(s) planned or taken as soon as practical but no later than within twenty-four (24) hours of the discovery of the event.

8. Terms and Conditions

8.1 Payment of Remedial Action Costs

TransAlta shall pay to Ecology costs incurred by Ecology pursuant to this Order and consistent with WAC 173-340-550(2). These costs shall include work performed by Ecology or its contractors for, or on, the Site under RCW 70A.305, including remedial actions and Order preparation, negotiation, oversight, and administration. These costs shall include work performed both prior to and subsequent to the issuance of this Order. Ecology's costs shall include costs of direct activities and support costs of direct activities as defined in WAC 173-340-550(2). For all Ecology costs incurred, TransAlta shall pay the required amount within thirty (30) days of receiving from Ecology an itemized statement of costs that includes a summary of costs incurred, an identification of involved staff, and the amount of time spent by involved staff members on the project. A general statement of work performed will be provided upon request. Itemized statements shall be prepared quarterly. Pursuant to WAC 173-340-550(4), failure to pay Ecology's costs within ninety (90) days of receipt of the itemized statement of costs will result in interest charges at the rate of twelve percent (12%) per annum, compounded monthly.

In addition to other available relief, pursuant to RCW 19.16.500, Ecology may utilize a collection agency and/or, pursuant to RCW 70A.305.060, file a lien against real property subject to the remedial actions to recover unreimbursed remedial action costs.

8.2 Designated Project Coordinators

The project coordinator for Ecology is:

Thomas Middleton, LHG
300 Desmond Drive, Lacey, WA 98503
360-999-9594
thomas.middleton@ecy.wa.gov

The project coordinator for TransAlta is:

Mickey Dreher
913 Big Hanaford Rd., Centralia, WA 98531-9101
360-330-8230
mickey_dreher@transalta.com

Each project coordinator shall be responsible for overseeing the implementation of this Order. Ecology's project coordinator will be Ecology's designated representative for the Site. To the maximum extent possible, communications between Ecology and TransAlta, and all documents, including reports, approvals, and other correspondence concerning the activities performed pursuant to the terms and conditions of this Order shall be directed through the project coordinators. The project coordinators may designate, in writing, working level staff contacts for all or portions of the implementation of the work to be performed required by this Order.

Any Party may change its respective project coordinator. Written notification shall be given to the other Party at least ten (10) calendar days prior to the change.

8.3 Performance

All geologic and hydrogeologic work performed pursuant to this Order shall be under the supervision and direction of a geologist or hydrogeologist licensed by the State of Washington or under the direct supervision of an engineer registered by the State of Washington, except as otherwise provided for by RCW 18.43 and 18.220.

All engineering work performed pursuant to this Order shall be under the direct supervision of a professional engineer registered by the State of Washington, except as otherwise provided for by RCW 18.43.130.

All construction work performed pursuant to this Order shall be under the direct supervision of a professional engineer or a qualified technician under the direct supervision of a professional engineer. The professional engineer must be registered by the State of Washington, except as otherwise provided for by RCW 18.43.130.

Any documents submitted containing geologic, hydrogeologic, or engineering work shall be under the seal of an appropriately licensed professional as required by RCW 18.43 and 18.220.

TransAlta shall notify Ecology in writing of the identity of any engineer(s) and geologist(s), contractor(s), subcontractor(s), and other key personnel to be used in carrying out the terms of this Order, in advance of their involvement at the Site.

8.4 Access

Ecology or any Ecology authorized representative, subject to proper qualification and conformance with TransAlta safety practices and policies applicable at the Site, shall have access to enter and freely move about all property at the Site that TransAlta either owns, controls, or has access rights to at all reasonable times for the purposes of, inter alia: inspecting records, operation logs, and contracts related to the work being performed pursuant to this Order; reviewing TransAlta's progress in carrying out the terms of this Order; conducting such tests or collecting such samples as Ecology may deem necessary; using a camera, sound recording, or other documentary type equipment to record work done pursuant to this Order; and verifying the data submitted to Ecology by TransAlta. Ecology or any Ecology authorized representative shall give reasonable notice before entering any Site property owned or controlled by TransAlta unless an emergency prevents such notice. All persons who access the Site pursuant to this section shall comply with any applicable health and safety plan(s). Ecology employees and their representatives shall not be required to sign any liability release or waiver as a condition of Site property access.

TransAlta shall make best efforts to secure access rights for those properties within the Site not owned or controlled by TransAlta where remedial activities or investigations will be performed pursuant to this Order. As used in this Section, "best efforts" means the efforts that a reasonable person in the position of TransAlta would use so as to achieve the goal in a timely manner, including the cost of employing professional assistance and the payment of reasonable sums of money to secure access and/or use restriction agreements, as required by this Section. If, within 30 days after the effective date of this Order, TransAlta is unable to accomplish what is required through "best efforts," they shall notify Ecology, and include a description of the steps taken to comply with the requirements. If Ecology deems it appropriate, it may assist TransAlta, or take independent action, in obtaining such access and/or use restrictions. Ecology reserves the right to seek payment from TransAlta for all costs, including cost of attorneys' time, incurred by Ecology in obtaining such access or agreements to restrict land, water, or other resource use.

8.5 Sampling, Data Submittal, and Availability

With respect to the implementation of this Order, TransAlta shall make the results of all sampling, laboratory reports, and/or test results generated by it or on its behalf available to Ecology. Pursuant to WAC 173-340-840(5), all sampling data shall be

submitted to Ecology in both printed and electronic formats in accordance with Section 7 (Work to be Performed), Ecology's Toxics Cleanup Program Policy 840 (Data Submittal Requirements), and/or any subsequent procedures specified by Ecology for data submittal.

If requested by Ecology, TransAlta shall allow Ecology and/or its authorized representative to take split or duplicate samples of any samples collected by TransAlta pursuant to implementation of this Order. TransAlta shall notify Ecology seven (7) days in advance of any sample collection or work activity at the Site. Ecology shall, upon request, allow TransAlta and/or its authorized representative to take split or duplicate samples of any samples collected by Ecology pursuant to the implementation of this Order, provided that doing so does not interfere with Ecology's sampling. Without limitation on Ecology's rights under Section 8.4 (Access), Ecology shall notify TransAlta prior to any sample collection activity unless an emergency prevents such notice.

In accordance with WAC 173-340-830(5)(a), all hazardous substance analyses shall be conducted by a laboratory accredited under WAC 173-50 for the specific analyses to be conducted, unless otherwise approved by Ecology.

8.6 Public Participation

RCW 70A.305.030(2)(a) requires that, at a minimum, this Order be subject to concurrent public notice. Ecology shall be responsible for providing this public notice and reserves the right to modify or withdraw any provisions of this Order should public comment disclose facts or considerations which indicate to Ecology that this Order is inadequate or improper in any respect.

Ecology shall maintain the responsibility for public participation at the Site. However, TransAlta shall cooperate with Ecology, and shall:

8.6.1 If agreed to by Ecology, develop appropriate mailing lists and prepare drafts of public notices and fact sheets at important stages of the remedial action, such as the submission of work plans, remedial investigation/feasibility study reports, cleanup action plans, and engineering design reports. As appropriate, Ecology will edit, finalize, and distribute such fact sheets and prepare and distribute public notices of Ecology's presentations and meetings.

8.6.2 Notify Ecology's project coordinator prior to the preparation of all press releases and fact sheets, and before meetings related to remedial action work to be performed at the Site with the interested public and/or local governments. Likewise, Ecology shall notify TransAlta prior to the issuance of all press releases and fact sheets related to the Site, and before meetings

related to the Site with the interested public and local governments. For all press releases, fact sheets, meetings, and other outreach efforts by TransAlta that do not receive prior Ecology approval, TransAlta shall clearly indicate to its audience that the press release, fact sheet, meeting, or other outreach effort was not sponsored or endorsed by Ecology.

8.6.3 When requested by Ecology, participate in public presentations on the progress of the remedial action at the Site. Participation may be through attendance at public meetings to assist in answering questions or as a presenter.

8.6.4 When requested by Ecology, arrange and maintain a repository to be located at:

Centralia Timberland Library
110 S. Silver Street, Centralia, WA 98531

At a minimum, copies of all public notices, fact sheets, and documents relating to public comment periods shall be promptly placed in these repositories. A copy of all documents related to this Site shall be maintained in the repository at Ecology's Southwest Regional Office in Lacey, Washington.

8.7 Access to Information

TransAlta shall provide to Ecology, upon request, copies of all records, reports, documents, and other information (including records, reports, documents, and other information in electronic form) (hereinafter referred to as "Records") within TransAlta's possession or control or that of their contractors or agents relating to activities at the Site or to the implementation of this Order, including, but not limited to, sampling, analysis, chain of custody records, manifests, trucking logs, receipts, reports, sample traffic routing, correspondence, or other documents or information regarding the work. TransAlta shall also make available to Ecology, for purposes of investigation, information gathering, or testimony, their employees, agents, or representatives with knowledge of relevant facts concerning the performance of the work.

Nothing in this Order is intended to waive any right TransAlta may have under applicable law to limit disclosure of Records protected by the attorney work-product privilege and/or the attorney-client privilege. If TransAlta withholds any requested Records based on an assertion of privilege, TransAlta shall provide Ecology with a privilege log specifying the Records withheld and the applicable privilege. No Site-related data collected pursuant to this Order shall be considered privileged, including: (1) any data regarding the Site, including, but not limited to, all sampling, analytical,

monitoring, hydrogeologic, scientific, chemical, radiological, biological, or engineering data, or the portion of any other record that evidences conditions at or around the Site; or (2) the portion of any Record that Respondents are required to create or generate pursuant to this Order.

Notwithstanding any provision of this Order, Ecology retains all of its information gathering and inspection authorities and rights, including enforcement actions related thereto, under any other applicable statutes or regulations.

8.8 Retention of Records

During the pendency of this Order, and for ten (10) years from the date of completion of the work performed pursuant to this Order, TransAlta shall preserve all records, reports, documents, and underlying data in its possession relevant to the implementation of this Order and shall insert a similar record retention requirement into all contracts with project contractors and subcontractors.

8.9 Resolution of Disputes

8.9.1 In the event that TransAlta elects to invoke dispute resolution TransAlta must utilize the procedure set forth below.

8.9.1.1 Upon the triggering event (receipt of Ecology's project coordinator's written decision or an itemized billing statement), TransAlta has fourteen (14) calendar days within which to notify Ecology's project coordinator in writing of its dispute (Informal Dispute Notice).

8.9.1.2 The Parties' project coordinators shall then confer in an effort to resolve the dispute informally. The Parties shall informally confer for up to fourteen (14) calendar days from receipt of the Informal Dispute Notice. If the project coordinators cannot resolve the dispute within those fourteen (14) calendar days, then within seven (7) calendar days Ecology's project coordinator shall issue a written decision (Informal Dispute Decision) stating: the nature of the dispute; the TransAlta position with regards to the dispute; Ecology's position with regards to the dispute; and the extent of resolution reached by informal discussion.

8.9.1.3 TransAlta may then request regional management review of the dispute. TransAlta must submit this request (Formal Dispute Notice) in writing to the Southwest Region Toxics Cleanup Section

Manager within seven (7) calendar days of receipt of Ecology's Informal Dispute Decision. The Formal Dispute Notice shall include a written statement of dispute setting forth: the nature of the dispute; the TransAlta position with respect to the dispute; and the information relied upon to support its position.

8.9.1.4 The Section Manager shall conduct a review of the dispute and shall issue a written decision regarding the dispute (Decision on Dispute) within thirty (30) calendar days of receipt of the Formal Dispute Notice. The Decision on Dispute shall be Ecology's final decision on the disputed matter.

8.9.2 The Parties agree to only utilize the dispute resolution process in good faith and agree to expedite, to the extent possible, the dispute resolution process whenever it is used.

8.9.3 Implementation of these dispute resolution procedures shall not provide a basis for delay of any activities required in this Order, unless Ecology agrees in writing to a schedule extension.

8.9.4 In case of a dispute, failure to either proceed with the work required by this Order or timely invoke dispute resolution may result in Ecology's determination that insufficient progress is being made in preparation of a deliverable, and may result in Ecology undertaking the work under Section 7 (Work to be Performed) or initiating enforcement under Section 10 (Enforcement).

8.10 Extension of Schedule

8.10.1 TransAlta's requests for an extension of schedule shall be granted only when a request for an extension is submitted in a timely fashion, generally at least thirty (30) days prior to expiration of the deadline for which the extension is

requested, and good cause exists for granting the extension. All extensions shall be requested in writing. The request shall specify:

8.10.1.1 The deadline that is sought to be extended.

8.10.1.2 The length of the extension sought.

8.10.1.3 The reason(s) for the extension.

8.10.1.4 Any related deadline or schedule that would be affected if the extension were granted.

8.10.2 The burden shall be on TransAlta to demonstrate to the satisfaction of Ecology that the request for such extension has been submitted in a timely fashion and that good cause exists for granting the extension. Good cause may include, but may not be limited to:

8.10.2.1 Circumstances beyond the reasonable control and despite the due diligence of TransAlta including delays caused by unrelated third parties or Ecology, such as (but not limited to) delays by Ecology in reviewing, approving, or modifying documents submitted by TransAlta.

8.10.2.2 A shelter in place or work stoppage mandated by state or local government order due to public health and safety emergencies.

8.10.2.3 Acts of God, including fire, flood, blizzard, extreme temperatures, storm, or other unavoidable casualty.

8.10.2.4 Endangerment as described in Section 8.12 (Endangerment).

However, neither increased costs of performance of the terms of this Order nor changed economic circumstances shall be considered circumstances beyond the reasonable control of TransAlta.

8.10.3 Ecology shall act upon any written request from TransAlta for extension in a timely fashion. Ecology shall give TransAlta written notification of any extensions granted pursuant to this Order. A requested extension shall not be effective until approved by Ecology. Unless the extension is a substantial

change, it shall not be necessary to amend this Order pursuant to Section 8.11 (Amendment of Order) when a schedule extension is granted.

8.10.4 At TransAlta's request, an extension shall only be granted for such period of time as Ecology determines is reasonable under the circumstances. Ecology may grant schedule extensions exceeding ninety (90) days only as a result of one of the following:

8.10.4.1 Delays in the issuance of a necessary permit which was applied for in a timely manner.

8.10.4.2 Other circumstances deemed exceptional or extraordinary by Ecology.

8.10.4.3 Endangerment as described in Section 8.12 (Endangerment).

8.11 Amendment of Order

The project coordinators may verbally agree to minor changes to the work to be performed without formally amending this Order. Minor changes will be documented in writing by Ecology within seven (7) days of verbal agreement.

Except as provided in Section 8.13 (Reservation of Rights), substantial changes to the work to be performed shall require formal amendment of this Order. This Order may only be formally amended by the written consent of both Ecology and TransAlta. Ecology will provide its written consent to a formal amendment only after public notice and opportunity to comment on the formal amendment.

When requesting a change to the Order, TransAlta shall submit a written request to Ecology for approval. Ecology shall indicate its approval or disapproval in writing and in a timely manner after the written request is received. If Ecology determines that the change is substantial, then the Order must be formally amended. Reasons for the disapproval of a proposed change to this Order shall be stated in writing. If Ecology does not agree to a proposed change, the disagreement may be addressed through the dispute resolution procedures described in Section 8.9 (Resolution of Disputes).

8.12 Endangerment

In the event Ecology determines that any activity being performed at the Site under this Order is creating or has the potential to create a danger to human health or the environment on or surrounding the Site, Ecology may direct TransAlta to cease such activities for such period of time as it deems necessary to abate the danger. TransAlta shall immediately comply with such direction.

In the event TransAlta determines that any activity being performed at the Site under this Order is creating or has the potential to create a danger to human health or the environment, TransAlta may cease such activities. TransAlta shall notify Ecology's project coordinator as soon as possible, but no later than twenty-four (24) hours after making such determination or ceasing such activities. Upon Ecology's direction, TransAlta shall provide Ecology with documentation of the basis for the determination or cessation of such activities. If Ecology disagrees with TransAlta's cessation of activities, it may direct TransAlta to resume such activities.

If Ecology concurs with or orders a work stoppage pursuant to this section, TransAlta's obligations with respect to the ceased activities shall be suspended until Ecology determines the danger is abated, and the time for performance of such activities, as well as the time for any other work dependent upon such activities, shall be extended in accordance with Section 8.10 (Extension of Schedule) for such period of time as Ecology determines is reasonable under the circumstances.

Nothing in this Order shall limit the authority of Ecology, its employees, agents, or contractors to take or require appropriate action in the event of an emergency.

8.13 Reservation of Rights

This Order is not a settlement under RCW 70A.305. Ecology's signature on this Order in no way constitutes a covenant not to sue or a compromise of any of Ecology's rights or authority. Ecology will not, however, bring an action against TransAlta to recover remedial action costs paid to and received by Ecology under this Order. In addition, Ecology will not take additional enforcement actions against TransAlta regarding remedial actions required by this Order, provided TransAlta complies with this Order.

Ecology nevertheless reserves its rights under RCW 70A.305, including the right to require additional or different remedial actions at the Site should it deem such actions necessary to protect human health or the environment, and to issue orders requiring such remedial actions. Ecology also reserves all rights regarding the injury to, destruction of, or loss of natural resources resulting from the release or threatened release of hazardous substances at the Site.

By entering into this Order, TransAlta does not admit to any liability for the Site. Although TransAlta is committing to conducting the work required by this Order under the terms of this Order, TransAlta expressly reserves all rights available under law, including but not limited to the right to seek cost recovery or contribution against third parties, and the right to assert any defenses to liability in the event of enforcement.

8.14 Transfer of Interest in Property

No voluntary conveyance or relinquishment of title, easement, leasehold, or other interest in any portion of the Site shall be consummated by TransAlta without provision for continued implementation of all requirements of this Order and implementation of any remedial actions found to be necessary as a result of this Order.

Prior to TransAlta's transfer of any interest in all or any portion of the Site, and during the effective period of this Order, TransAlta shall provide a copy of this Order to any prospective purchaser, lessee, transferee, assignee, or other successor in said interest; and, at least thirty (30) days prior to any transfer, TransAlta shall notify Ecology of said transfer. Upon transfer of any interest, TransAlta shall notify all transferees of the restrictions on the activities and uses of the property under this Order and incorporate any such use restrictions into the transfer documents.

8.15 Compliance with Applicable Laws

8.15.1 **Applicable laws.** All actions carried out by TransAlta pursuant to this Order shall be done in accordance with all applicable federal, state, and local requirements, including requirements to obtain necessary permits or approvals, except as provided in RCW 70A.305.090. At this time, TransAlta is obligated to fulfil the requirements of RCW Chapters 80.80 and 80.82 and that entry into and compliance with this order is done in satisfaction of those laws and the 2011 MOA. TransAlta and Ecology will also comply with the requirements of any additional agreements executed between TransAlta and the State of Washington that affect the Site. TransAlta has a continuing obligation to identify additional applicable federal, state, and local requirements which apply to actions carried out pursuant to this Order, and to comply with those requirements. As additional federal, state, and local requirements are identified by Ecology or TransAlta, Ecology will document in writing if they are applicable to actions carried out pursuant to this Order, and TransAlta must implement those requirements.

8.15.2 **Relevant and Appropriate Requirements.** All actions carried out by TransAlta pursuant to this Order shall be done in accordance with relevant and appropriate requirements identified by Ecology. At this time, no relevant and appropriate requirements have been identified as being applicable to the actions required by this Order. If additional relevant and appropriate requirements are identified by Ecology or TransAlta, Ecology will document in

writing if they are applicable to actions carried out pursuant to this Order and TransAlta must implement those requirements.

8.15.3 Pursuant to RCW 70A.305.090(1), TransAlta may be exempt from the procedural requirements of RCW 70A.15, 70A.205, 70A.300, 77.55, 90.48, and 90.58 and of any laws requiring or authorizing local government permits or approvals. However, TransAlta shall comply with the substantive requirements of such permits or approvals. For permits and approvals covered under RCW 70A.305.090(1) that have been issued by local government, the Parties agree that Ecology has the non-exclusive ability under this Order to enforce those local government permits and/or approvals. At this time, no state or local permits or approvals have been identified as being applicable but procedurally exempt under this section.

8.15.4 TransAlta has a continuing obligation to determine whether additional permits or approvals addressed in RCW 70A.305.090(1) would otherwise be required for the remedial action under this Order. In the event either Ecology or TransAlta determines that additional permits or approvals addressed in RCW 70A.305.090(1) would otherwise be required for the remedial action under this Order, it shall promptly notify the other Party of its determination. Ecology shall determine whether Ecology or TransAlta shall be responsible to contact the appropriate state and/or local agencies. If Ecology so requires, TransAlta shall promptly consult with the appropriate state and/or local agencies and provide Ecology with written documentation from those agencies of the substantive requirements those agencies believe are applicable to the remedial action. Ecology shall make the final determination on the additional substantive requirements that must be met by TransAlta and on how TransAlta must meet those requirements. Ecology shall inform TransAlta in writing of these requirements. Once established by Ecology, the additional requirements shall be enforceable requirements of this Order. TransAlta shall not begin or continue the remedial action potentially subject to the additional requirements until Ecology makes its final determination.

Pursuant to RCW 70A.305.090(2), in the event Ecology determines that the exemption from complying with the procedural requirements of the laws referenced in RCW 70A.305.090(1) would result in the loss of approval from a federal agency that is necessary for the state to administer any federal law, the exemption shall not apply and TransAlta shall comply with both the procedural and substantive requirements of the laws referenced in RCW 70A.305.090(1), including any requirements to obtain permits or approvals.

8.16 Periodic Review

So long as remedial action continues at the Site, the Parties agree to review the progress of remedial action at the Site, and to review the data accumulated as a result of monitoring the Site as often as is necessary and appropriate under the circumstances. Unless otherwise agreed to by Ecology, at least every five (5) years after the initiation of cleanup action at the Site the Parties shall confer regarding the status of the Site and the need, if any, for further remedial action at the Site. At least ninety (90) days prior to each periodic review, TransAlta shall submit a report to Ecology that documents whether human health and the environment are being protected based on the factors set forth in WAC 173-340-420(4). Ecology reserves the right to require further remedial action at the Site under appropriate circumstances. This provision shall remain in effect for the duration of this Order.

8.17 Indemnification

TransAlta agrees to indemnify and save and hold the State of Washington, its employees, and agents harmless from any and all claims or causes of action (1) for death or injuries to persons, or (2) for loss or damage to property, to the extent arising from or on account of acts or omissions of TransAlta, its officers, employees, agents, or contractors in entering into and implementing this Order. However, TransAlta shall not indemnify the State of Washington nor save nor hold its employees and agents harmless from any claims or causes of action to the extent arising out of the negligent acts or omissions of the State of Washington, or the employees or agents of the State, in entering into or implementing this Order.

9. Satisfaction of Order

The provisions of this Order shall be deemed satisfied upon TransAlta's receipt of written notification from Ecology that TransAlta has completed the remedial activity required by this Order, including implementation of the final cleanup action plan, as amended by any modifications, and that TransAlta has complied with all other provisions of this Agreed Order.

10. Enforcement

Pursuant to RCW 70A.305.050, this Order may be enforced as follows:

10.1 The Attorney General may bring an action to enforce this Order in a state or federal court.

10.2 The Attorney General may seek, by filing an action, if necessary, to recover amounts spent by Ecology for investigative and remedial actions and orders related to the Site.

10.3 A liable party who refuses, without sufficient cause, to comply with any term of this Order will be liable for:

10.3.1 Up to three (3) times the amount of any costs incurred by the State of Washington as a result of its refusal to comply.

10.3.2 Civil penalties of up to twenty-five thousand dollars ($25,000) per day for each day it refuses to comply.

10.4 This Order is not appealable to the Washington Pollution Control Hearings Board. This Order may be reviewed only as provided under RCW 70A.305.070.

Effective date of this Order: December 29, 2025

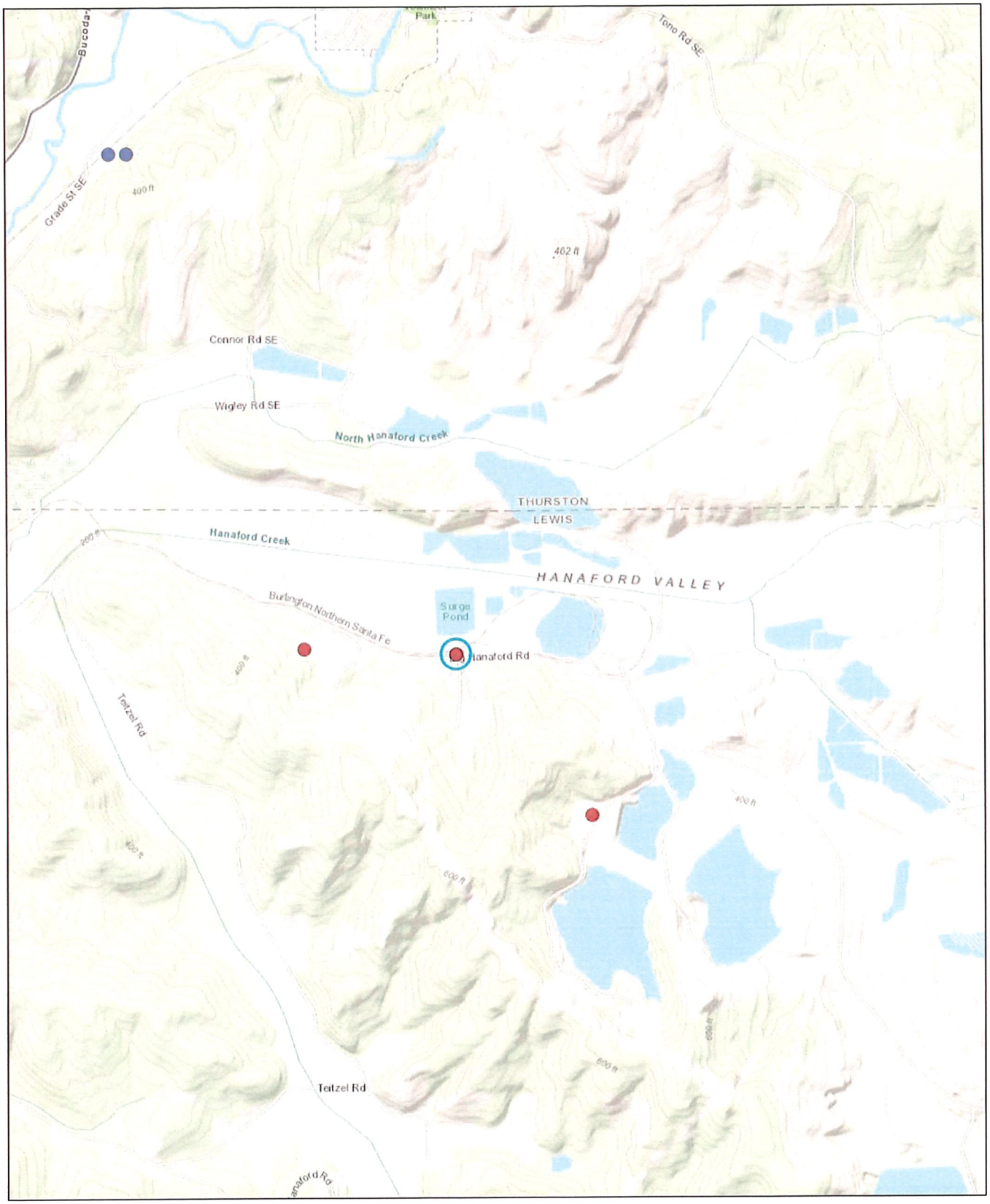
TransAlta

Mickey Dreher
Vice President, Centralia
TransAlta Centralia Generation LLC
913 Big Hanaford Rd
Centralia, WA 98531-9101
360-330-8230

State of Washington
Department of Ecology

Marian Abbett, PE
Section Manager
Toxics Cleanup Program
Southwest Region Office
360-489-4569

Exhibit A - Location Diagram



November 6, 2025

TCP Cleanupsites 2

Cleanup Status

- Awaiting Cleanup
- Complete

1:36,112

0 0.23 0.45 0.9 mi

0 0.35 0.7 1.4 km

N

Sources: Esri, HERE, Garmin, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), (c) OpenStreetMap contributors, and the GIS User Community, WA Dept. of Ecology

Exhibit B — TransAlta scope of work and schedule

Scope of work

Purpose

The work under this Agreed Order (AO) involves conducting a Remedial Investigation (RI) and Feasibility Study (FS), conducting interim actions if required or agreed to by Ecology, preparing a preliminary Draft Cleanup Action Plan (DCAP) to select a cleanup alternative, and implementing the CAP as approved by Ecology. The purpose of the RI, FS, and preliminary DCAP for the Site is to provide sufficient data, analysis, and evaluations to enable Ecology to select and approve a cleanup alternative for the Site.

TransAlta shall coordinate with Ecology throughout the development of the RI/FS and preliminary DCAP and shall keep Ecology informed of changes to any Work Plan or other project plans, and of any issues or problems as they develop.

The Scope of Work (SOW) is divided into eight major tasks as follows:

Task 1. Supplemental RI Work Plan
Task 2. Supplemental Remedial Investigation
Task 3. Interim Action(s) (if required)
Task 4. Feasibility Study
Task 5. SEPA Compliance
Task 6. Public Participation
Task 7. DCAP
Task 8. Implementation of the CAP

Task 1. Supplemental RI work plan

TransAlta shall prepare a Supplemental Remedial Investigation Work Plan (Work Plan). The Work Plan shall address the deficiencies, noted by Ecology, in our comments on the submitted RI report including provisions for a survey of potential deposition of semi-volatile organic compounds, carcinogenic polycyclic aromatic hydrocarbons, dioxins/furans, and metals including mercury, in the areas surrounding the coal plant property.

The Work Plan shall, as needed, describe general facility information; site history and conditions; including previous operations; past field investigations, including any data collection and analysis of soils, air, groundwater, surface water, and sediments; a conceptual site model showing contaminants, migration pathways in all environmental media, and potential receptors; geology and groundwater system characteristics; past, current, and future land use; identification of natural resources and ecological receptors; hazardous substances and their sources, etc., in compliance with WAC 173-340-350 and WAC 173-204-550.

The Work Plan will also identify specific data collection procedures in a Sampling and Analysis Plan (SAP) and Quality Assurance Project Plan (QAPP) as part of the Work Plan in compliance with WAC 173-340-820 and WAC 173-204-600 for defining the nature and extent of contamination. TransAlta will also submit a copy of the Health and Safety Plan (HASP) for the project.

The SAP identifies the proposed number and location of all environmental samples and methods, including soil borings, groundwater monitoring wells, soil, groundwater, stormwater, seep, catch basin and sediment samples, approximate depths, and includes a quality assurance project plan. The SAP will describe the sampling objectives, the rationale for the sampling approach (based upon the identified data gaps), and plans for data use, and shall provide a detailed description of sampling tasks. The SAP shall describe specifications for sample identifiers; sampling equipment; the type, number, and location of samples to be collected; the analyses to be performed; descriptions of sampling equipment and methods to be used; sample documentation; sample containers, collection and handling; data and records management; and schedule.

The Quality Assurance Project Plan (QAPP) will be prepared in accordance with the Guidance for Preparation of Quality Assurance Project Plans, EPA Region 10, Quality Data Management Program, QA/R-5 and requirements of the EPA Contract Laboratory Program. The QAPP will also follow Ecology's Guidelines for Preparing Quality Assurance Project Plans for Environmental Studies (July 2004) and Sediment Sampling and Analysis Plan Appendix (February 2008). Laboratories must meet the accreditation standards established in WAC 173-50. Data quality objectives will reflect the criteria or threshold values used for the source control evaluation.

The SAP, including the QAPP, will be submitted to Ecology for review and approval. As with all environmental work at the site, work may not begin without written approval from Ecology. The plan shall provide seven (7) days notice to Ecology prior to beginning sampling. Ecology may obtain split samples.

TransAlta or their contractors shall submit all new sampling data generated under this SAP and any other recently collected data to Ecology for entry into the Environmental Information Management System (EIM) in accordance with WAC 173-340-840(5) and Ecology's Toxics Cleanup Program Policy 840: Data Submittal Requirements. Only validated data will be entered into the EIM database within 30 days of submittal.

TransAlta will provide Ecology with an Agency Review Draft Work Plan. Once Ecology reviews and approves the Work Plan, it will be considered the Final Work Plan. The Work Plan shall not be implemented until approved by Ecology. Once approved by Ecology, TransAlta will implement the Final Work Plan according to the schedule contained in this Exhibit.

TransAlta shall prepare two (2) copies of the Agency Review Draft RI Work Plan and submit them, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats, to Ecology for review and comment. After incorporating Ecology's comments on the Agency Review Draft Work Plan and after Ecology approval, TransAlta shall prepare three (3) copies of the Final Work Plan and submit them, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats, to Ecology.

Task 2. Supplemental Remedial Investigation

TransAlta shall conduct a Supplemental RI that meets the requirements of WAC 173-340-350 and WAC 173-204-550 according to the Work Plan as approved by Ecology. The RI will determine the nature and extent of contamination exceeding preliminary Model Toxics Control Act (MTCA) cleanup levels, preliminary Sediment Management Standards (SMS) cleanup standards, and other regulatory requirements. The RI must provide sufficient data and information to define the nature and extent of contamination.

Field sampling and analysis will be completed in general accordance with the SAP and QAPP. Deviation(s) from the approved SAP and QAPP must be communicated to Ecology immediately and documented as required by Ecology.

TransAlta shall provide interim data reports and updates to Ecology as new site data and information become available. Laboratory analysis data shall also be provided in electronic format when it has been validated. Raw laboratory data will be provided to Ecology upon request.

Prior to submittal of the Agency Review Draft RI Report, a Key Project Meeting will be held. During the Remedial Investigation Pre-Report Check-In, Ecology and TransAlta will review available data and an updated conceptual site model and discuss the content and organization of the Draft RI Report.

TransAlta shall compile the results of the Site investigation into an Agency Review Draft RI Report. TransAlta shall prepare two (2) copies of the Agency Review Draft RI Report and submit them, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats, to Ecology for review and comment.

After incorporating Ecology's comments on the Agency Review Draft RI Report, TransAlta shall prepare three (3) copies of a Public Review Draft RI Report and submit them, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats, to Ecology for distribution and public comment. Electronic survey data for monitoring locations, electronic lab data, and GIS maps of contaminant distribution shall also be provided for both the Agency Review Draft RI Report and Public Review Draft RI Reports either in the report or as attachments. The RI Report will not be considered Final until after a public review and comment period.

If the data collected during this investigation is insufficient to define the nature and extent of contamination, and/or to select a cleanup action plan an additional phase of investigation shall be conducted to define the extent of contamination.

Task 3. Interim Actions (if required)

Remedial actions implemented prior to completion of the RI/FS, including those that:

- are technically necessary to reduce a threat to human health or the environment by eliminating or substantially reducing one or more pathways for exposure to a hazardous substance;
- correct a problem that may become substantially worse or cost substantially more to address if the remedial action is delayed; or
- are needed to provide for completion of the remedial investigation/feasibility study or design of the cleanup action

will be considered interim actions, will be implemented in accordance with WAC 173-340-430 and the AO, and will be designed in a manner that will not foreclose reasonable alternatives for any final cleanup action that may be required.

As detailed in the AO, if required by Ecology, or if proposed by TransAlta and approved by Ecology, TransAlta will implement an interim action. Based upon information in the Agency Review Draft RI Report, interim action(s) may be needed to expedite control of releases to sediments or other environmental media pursuant to WAC 173-340-430.

The scope of the interim actions may include, but not be limited to, typical source control or containment elements such as:

- Soil or sediment removal
- Groundwater remediation
- Repair, slip lining, replacement, or closure of stormwater conveyances or other structures such as conduit, vaults, catch basins, etc.
- Removal of underground storage tanks and pipes
- Removal of old drain fields or former surface impoundments
- Proper abandonment of old wells
- Removal of contaminated building or other structural material
- Construction of a treatment facility
- Shoreline stabilization such as bulkhead repair, erosion or seepage control, and grading or clearing.

If an interim action is to be performed, TransAlta will prepare and submit for Ecology approval an Agency Review Draft Interim Action Work Plan (IAWP) with detail commensurate with the work to be performed. The Agency Review Draft IAWP shall include, as appropriate:

- Description of the interim action including its purpose, general requirements, and relationship to the (final) cleanup action (to the extent known);
- Summary of relevant RI/FS information, including at a minimum existing site conditions and alternative interim actions considered;
- Information regarding design and construction requirements, including a proposed schedule and personnel roles and responsibilities;
- Compliance Monitoring Plan;
- SAP/QAPP;
- Permits required.

TransAlta will also submit a copy of the Health and Safety Plan for the project. TransAlta will be responsible for complying with the State Environmental Policy Act (SEPA) Rules including preparing and submitting an environmental checklist for the interim action, and will assist Ecology with presentations at any additional meetings or hearings that might be necessary for SEPA compliance or as part of the Public Participation Plan.

TransAlta shall prepare two (2) copies of the Agency Review Draft Interim Action Work Plan and submit them, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats, to Ecology for review. TransAlta shall incorporate Ecology's comments and then prepare two (2) copies of the Public Review Draft Interim Action Work Plan and submit them, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats, to Ecology. After a public notice and comment period for the Public Review Draft IAWP (and SEPA determination), Ecology will approve the IAWP (if appropriate) and the document will be considered Final. TransAlta shall prepare three (3) copies of the Final Interim Action Work Plan submit them, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats. Once approved by Ecology, TransAlta will implement the interim action according with the approved schedule.

Upon successful completion of the work, an Agency Review Draft Interim Action Report will be prepared as a separate deliverable. TransAlta shall prepare two (2) copies of the Agency Review Draft Interim Action Report and submit them, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats, to Ecology for review and approval. After incorporating Ecology's comments on the Agency Review Draft Interim Action Report and after Ecology approval, TransAlta shall prepare three (3) copies of the Final Interim Action Report and submit them, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats, to Ecology.

Task 4. Feasibility study

TransAlta shall use the information obtained in the RI to prepare an Agency Review Draft Feasibility Study (FS) that meets the applicable requirements of WAC 173-340-351 according to the Schedule in this exhibit. The Agency Review Draft FS will evaluate remedial alternatives for site cleanup, consistent with MTCA and SMS requirements to ensure protection of human health and the environment by eliminating, reducing, or otherwise controlling risk posed through each exposure pathway and migration route.

Prior to beginning the FS, a Key Project Meeting will be held to review ARARs, potential remedial alternatives and establish points of compliance.

The Agency Review Draft FS must include a detailed analysis of each remedial alternative according to the applicable requirements of WAC 173-340-351 and 173-204-550. The remedial alternatives will be evaluated for compliance with the applicable requirements of WAC 173-340-360 and 173-204-570.

The remedial alternative that is judged to best satisfy the evaluation criteria will be identified. Justification for the selection will be provided, and the recommended remedial alternative further developed, in the FS Report.

TransAlta shall prepare two (2) copies of the Agency Review Draft FS and submit them, including one electronic copy in Word (.doc) and Adobe (.pdf) formats, to Ecology for review. After addressing Ecology's comments on the Agency Review Draft FS, TransAlta shall prepare three (3) copies of the Public Review Draft FS and submit them, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats, to Ecology for distribution and public comment. The FS will not be considered Final until after a public review and comment period.

Task 5. SEPA compliance

TransAlta shall be responsible for complying with the State Environmental Policy Act (SEPA) Rules including preparing and submitting an environmental checklist. If the result of the threshold determination is a determination of significance (DS), TransAlta shall be responsible for the preparation of Draft and final environmental impact statements. TransAlta shall assist Ecology with coordinating SEPA public involvement requirements with MTCA public involvement requirements whenever possible, such that public comment periods and meetings or hearings can be held concurrently.

Task 6. Public participation

TransAlta shall support Ecology in presenting the Public Review Draft RI Report and the Public Review Draft FS Reports and SEPA evaluations at one public meeting or hearing. TransAlta will assist Ecology with presentations at any additional meetings or hearings that might be necessary for SEPA compliance or as part of the Public Participation Plan.

After the public comment periods are completed, TransAlta shall prepare a Agency Review Draft Responsiveness Summary that addresses public comments. TransAlta shall prepare two (2) copies of the Agency Review Draft Responsiveness Summary and submit them to Ecology for review and approval, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats, to Ecology for distribution and public comment.

After addressing Ecology's comments and after Ecology approval, TransAlta shall prepare five (5) copies of the Final Responsiveness Summary and submit them to Ecology for distribution, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats.

Task 7. Preliminary draft Cleanup Action Plan

Upon Ecology approval of the Public Review Draft Remedial Investigation Report and Public Review Draft Feasibility Study, a Key Project Meeting will be held regarding the Cleanup Action Plan. The Cleanup Action Plan Meeting will be used to review plans for developing the Agency Review preliminary Draft Cleanup Action Plan (DCAP).

TransAlta shall prepare an Agency Review preliminary DCAP in accordance with WAC 173-340-380 that provides a proposed remedial action to address the contamination present on the Site. The preliminary DCAP shall include a general description of the proposed remedial actions, cleanup standards developed from the RI/FS and rationale regarding their selection, a schedule for implementation, description of any institutional controls proposed, and a summary of applicable local, state, and federal laws pertinent to the proposed cleanup actions.

TransAlta will submit an Agency Review preliminary DCAP for Ecology's review and approval. The Agency Review preliminary DCAP will include, but not be limited to, the information listed under WAC 173-340-380. TransAlta shall prepare two (2) copies of the Agency Review preliminary DCAP and submit them, including one electronic copy each in Word (.doc) and Adobe (.pdf) formats, to Ecology for review and approval.

After receiving Ecology's comments on the Agency Review preliminary DCAP, if any, TransAlta shall revise the preliminary DCAP to address Ecology's comments and submit five (5) copies of the Public Review DCAP including one electronic copy each in Word (.doc) and Adobe (.pdf) formats.

Task 8. Implementation of CAP

TransAlta agrees, as part of the AO, that they will implement the final CAP following both public review and Ecology approval.

Schedule of deliverables

The schedule for deliverables described in the Agreed Order and the Scope of Work is presented below. If the date for submission of any item or notification required by this

Schedule of Deliverables occurs on a weekend, state or federal holiday, the date for submission of that item or notification is extended to the next business day following the weekend or holiday. Where a deliverable due date is triggered by Ecology notification, comments or approval, the starting date for the period shown is the date TransAlta received such notification, comments or approval by certified mail, return receipt requested, unless otherwise noted below. Where triggered by Ecology receipt of a deliverable, the starting date for the period shown is the date Ecology receives the deliverable by certified mail, return receipt requested, or the date of Ecology signature on a hand-delivery form.

RI/FS Deliverables	Completion Times
Agency Review Draft Supplemental RI Work Plan	60 calendar days following effective date of the Agreed Order
Completion of RI Field Work	12 months following Ecology approval of the Final SAP, QAPP and HSP
Agency Review Draft RI Report	90 days following receipt of validated laboratory data package
Public Review Draft RI Report	45 calendar days following receipt of Ecology's comments on Agency Review Draft RI Report
Agency Review Draft FS	90 days following Ecology approval of Public Review Draft RI Report
Public Review Draft FS	45 calendar days following receipt of Ecology's comments on the Agency Review draft FS
Agency Review preliminary Draft Cleanup Action Plan (DCAP)	90 calendar days following Ecology approval of the Public Review Draft FS.
Implementation of Final CAP	Following public comment on Ecology's DCAP, Ecology will finalize the CAP. Final CAP will detail schedule for design and construction of remedy.

EXHIBIT 52-3

An official website of the United States government Here's how you know

United States Census Bureau

QuickFacts

Centralia city, Washington

QuickFacts provides statistics for all states and counties. Also for cities and towns with a ***population of 5,000 or more***.

Enter state, county, city, town, or zip code -- Select a fact -- CLEAR TABLE MAP

Table

All Topics	Centralia city, Washington
Total retail sales per capita, 2022 (c)	**$15,414**
PEOPLE	
Population	
Population estimates, July 1, 2024, (V2024)	19,061
Population estimates base, April 1, 2020, (V2024)	18,322
Population, percent change - April 1, 2020 (estimates base) to July 1, 2024, (V2024)	4.0%
Population, Census, April 1, 2020	18,183
Population, Census, April 1, 2010	16,336
Age and Sex	
Persons under 5 years, percent	6.4%
Persons under 18 years, percent	20.9%
Persons 65 years and over, percent	19.2%
Female persons, percent	52.1%
Race and Hispanic Origin	
White alone, percent	79.8%
Black alone, percent (a) (a)	1.2%
American Indian and Alaska Native alone, percent (a) (a)	0.6%
Asian alone, percent (a) (a)	1.2%
Native Hawaiian and Other Pacific Islander alone, percent (a) (a)	0.1%
Two or More Races, percent	11.9%
Hispanic or Latino, percent (b) (b)	19.8%
White alone, not Hispanic or Latino, percent	72.9%
Population Characteristics	
Veterans, 2019-2023	1,124
Foreign-born persons, percent, 2019-2023	8.7%
Housing	
Housing Units, July 1, 2024, (V2024)	X
Owner-occupied housing unit rate, 2019-2023	58.5%
Median value of owner-occupied housing units, 2019-2023	$267,600
Median selected monthly owner costs - with a mortgage, 2019-2023	$1,602
Median selected monthly owner costs -without a mortage, 2019-2023	$606
Median gross rent, 2019-2023	$1,003
Building Permits, 2024	X
Families & Living Arrangements	
Households, 2019-2023	7,368
Persons per household, 2019-2023	2.46
Living in the same house 1 year ago, percent of persons age 1 year+ , 2019-2023	82.9%
Language other than English spoken at home, percent of persons age 5 years+, 2019-2023	17.1%
Computer and Internet Use	
Households with a computer, percent, 2019-2023	93.1%
Households with a broadband Internet subscription, percent, 2019-2023	
Education	
High school graduate or higher, percent of persons age 25 years+, 2019-2023	

Is this page helpful? Yes No

Bachelor's degree or higher, percent of persons age 25 years+, 2019-2023	17.6%
Health	
With a disability, under age 65 years, percent, 2019-2023	15.9%
Persons without health insurance, under age 65 years, percent	⚠ 13.3%
Economy	
In civilian labor force, total, percent of population age 16 years+, 2019-2023	54.9%
In civilian labor force, female, percent of population age 16 years+, 2019-2023	46.0%
Total accommodation and food services sales, 2022 ($1,000) (c)	75,855
Total health care and social assistance receipts/revenue, 2022 ($1,000) (c)	367,821
Total transportation and warehousing receipts/revenue, 2022 ($1,000) (c)	31,024
Total retail sales, 2022 ($1,000) (c)	288,177
Total retail sales per capita, 2022 (c)	**$15,414**
Transportation	
Mean travel time to work (minutes), workers age 16 years+, 2019-2023	26.3
Income & Poverty	
Median households income (in 2023 dollars), 2019-2023	$52,387
Per capita income in past 12 months (in 2023 dollars), 2019-2023	$28,232
Persons in poverty, percent	⚠ 19.9%
BUSINESSES	
Businesses	
Total employer establishments, 2023	X
Total employment, 2023	X
Total annual payroll, 2023 ($1,000)	X
Total employment, percent change, 2022-2023	X
Total nonemployer establishments, 2023	X
All employer firms, Reference year 2022	466
Men-owned employer firms, Reference year 2022	S
Women-owned employer firms, Reference year 2022	185
Minority-owned employer firms, Reference year 2022	S
Nonminority-owned employer firms, Reference year 2022	284
Veteran-owned employer firms, Reference year 2022	8
Nonveteran-owned employer firms, Reference year 2022	360
GEOGRAPHY	
Geography	
Population per square mile, 2020	2,385.9
Population per square mile, 2010	2,202.7
Land area in square miles, 2020	7.62
Land area in square miles, 2010	7.42
FIPS Code	5311160

About datasets used in this table

Value Notes

⚠ Methodology differences may exist between data sources, and so estimates from different sources are not comparable.

Some estimates presented here come from sample data, and thus have sampling errors that may render some apparent differences between geographies statistically indistinguishable. Click the Quick Info row in TABLE view to learn about sampling error.

The vintage year (e.g., V2024) refers to the final year of the series (2020 thru 2024). Different vintage years of estimates are not comparable.

Users should exercise caution when comparing 2019-2023 ACS 5-year estimates to other ACS estimates. For more information, please visit the 2023 5-year ACS Comparison Guidance page.

Fact Notes

- **(a)** Includes persons reporting only one race
- **(b)** Hispanics may be of any race, so also are included in applicable race categories
- **(c)** Economic Census - Puerto Rico data are not comparable to U.S. Economic Census data

Value Flags

- **D** Suppressed to avoid disclosure of confidential information
- **F** Fewer than 25 firms
- **FN** Footnote on this item in place of data
- **NA** Not available
- **S** Suppressed; does not meet publication standards
- **X** Not applicable
- **Z** Value greater than zero but less than half unit of measure shown
- **-** Either no or too few sample observations were available to compute an estimate, or a ratio of medians cannot be calculated because one or both of th open ended distribution.
- **N** Data for this geographic area cannot be displayed because the number of sample cases is too small.

Is this page helpful?
Yes No

QuickFacts data are derived from: Population Estimates, American Community Survey, Census of Population and Housing, Current Population Survey, Small Area Health Insurance Estimates, Small Area Incon Estimates, State and County Housing Unit Estimates, County Business Patterns, Nonemployer Statistics, Economic Census, Survey of Business Owners, Building Permits.

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Measuring America's People and Economy

Is this page helpful?

Yes No

EXHIBIT 52-4

CENTRALIA, WA

METROPOLITAN STATISTICAL AREA (MSA)

2023 POPULATION

83,925

1.53% 1-YEAR GROWTH

US SENATOR

Patty Murray

DEMOCRATIC PARTY

US SENATOR

Maria Cantwell

DEMOCRATIC PARTY

2023 MEDIAN AGE

42.4

0% 1-YEAR CHANGE

2023 POVERTY RATE

13%

5.77% 1-YEAR INCREASE

2023 MEDIAN HOUSEHOLD INCOME

$69,690

3.63% 1-YEAR GROWTH

2023 MEDIAN PROPERTY VALUE

$341,500

11.4% 1-YEAR GROWTH

2023 EMPLOYED POPULATION

35,277

2.28% 1-YEAR GROWTH

Population & Diversity

Economy

Civics

Education

Housing & Living

COVID-19 IN NUMBERS

About

UNITED STATES \ WASHINGTON



In the year of 2023, Centralia, WA had a population of 83.9k people with a median age of 42.4 and a median household income of $69,690. Between 2022 and 2023 the population of Centralia, WA grew from 82,663 to 83,925, a 1.53% increase and its median household income grew from $67,247 to $69,690, a 3.63% increase.

The 5 largest ethnic groups in Centralia, WA are White (Non-Hispanic) (80.6%), Two Races Including Other (Hispanic) (4.59%), Two Races Excluding Other, & Three or More Races (Non-Hispanic) (4.06%), White (Hispanic) (2.99%), and Other (Hispanic) (2.3%).

None of the households in Centralia, WA reported speaking a non-English language at home as their primary shared language. This does not consider the potential multi-lingual nature of households, but only the primary self-reported language spoken by all members of the household.
97% of the residents in Centralia, WA are U.S. citizens.

The largest universities in Centralia, WA are Centralia College (511 degrees awarded in 2023) and Centralia Beauty College (36 degrees).

In 2023, the median property value in Centralia, WA was $341,500, and the homeownership rate was 74.2%.

Most people in Centralia, WA drove alone to work, and the average commute time was 28.4 minutes. The average car ownership in Centralia, WA was 2 cars per household.

Centralia, WA borders Aberdeen, WA, Longview, WA, Olympia-Tumwater, WA, Portland-Vancouver-Hillsboro, OR-WA, Seattle-Tacoma-Bellevue, WA, and Yakima, WA.

Population & Diversity

COVID-19 IN NUMBERS

people, from which 97% are citizens. As of 2023, outside of the country (4.41k people).

EXHIBIT 52-5

ENVIRONMENTAL HEALTH & ENGINEERING

Emissions of Hazardous Air Pollutants from Coal-fired Power Plants





EMISSIONS OF HAZARDOUS AIR POLLUTANTS FROM COAL-FIRED POWER PLANTS

Prepared For:

Paul Billings
Vice President for National Policy and Advocacy
American Lung Association
1301 Pennsylvania Ave., NW
Suite 800
Washington, DC 20004-1725

Prepared By:

Environmental Health & Engineering, Inc.
117 Fourth Avenue
Needham, MA 02494-2725

EH&E Report 17505
March 7, 2011

P:17505\Report\Final

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About the Report

Scientists from Environmental Health and Engineering, Inc. (EH&E) were commissioned by the American Lung Association to prepare a report on public health and environmental impacts of hazardous air pollutant emissions from coal-fired power plants that would be a useful resource for the general public. This report represents the integrated effort of numerous talented individuals within our organization whose contributions were made under the direction of David L. MacIntosh, Sc.D., C.I.H., and John D. Spengler, Ph.D.

David L. MacIntosh, Sc.D. C.I.H., is a Principal Scientist and Associate Director of Advanced Analytics and Building Science at EH&E where he manages a group of scientists and engineers who specialize in determining the complex relationships among sources, pathways, and receptors of environmental stressors that influence public health in the built environment. Dr. MacIntosh is a former tenured faculty member of the University of Georgia and is currently an Adjunct Associate Professor at the Harvard School of Public Health where he teaches courses on exposure assessment and environmental management. He earned a doctorate in Environmental Health from the Harvard School of Public Health. He is also a Certified Industrial Hygienist. Dr. MacIntosh is active in professional service through the International Society for Exposure Science, the U.S. Environmental Protection Agency FIFRA Science Advisory Panel, the Centers for Disease Control and Prevention, and the World Health Organization.

John D. Spengler, Ph.D. is the Akira Yamaguchi Professor of Human Health and Habitation, Harvard School of Public Health and Director of the Sustainability and Environmental Management program at the Extension School. Dr. Spengler has conducted research in the areas of personal monitoring, air pollution health effects, indoor air pollution, and a variety of environmental sustainability issues. He is the author of numerous articles on air quality and other environmental issues, and co-author or co-editor of *Health Effects of Fossil Fuel Burning: Assessment and Mitigation*; *Indoor Air Pollution: A Health Perspective*; *Particles in Our Air: Concentrations and Health Effects*; and *Indoor Air Quality Handbook*. In 2003, Dr. Spengler received a Heinz Award for the Environment; in 2007, he received the Air and Waste Management Association Lyman Ripperton Environmental Educator Award; and in 2008 he was honored with the Max von Pettenkofer award for distinguished contributions in indoor air science from the International Society of Indoor Air Quality and Climate's Academy of Fellows.

EH&E is grateful to James E. Staudt, Ph.D., Andover Technology Partners, for preparing the first draft of sections on air pollution control systems for hazardous and criteria air pollutant emissions.

EH&E is also grateful to John Bachmann, Vision Air Consulting, LLC for providing input and advice on the science and policy matters presented in the report.

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LIST OF ABBREVIATIONS AND ACRONYMS

ACI	Activated carbon injection
ACS	American Cancer Society
ATSDR	Agency for Toxic Substances and Disease Registry
BTU	British Thermal Unit
CAA	Clean Air Act
CASAC	U.S. EPA Clean Air Scientific Advisory Committee
CDF	Chlorodibenzofuran
DOE	U.S. Department of Energy
DSI	Dry Sorbent Injection
EH&E	Environmental Health & Engineering, Inc.
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
ESP	Electrostatic Precipitator
FBC	Fluidized bed combustion
FGD	Flue gas desulfurization
HAP	Hazardous air pollutant
HCl	Hydrochloric acid
HCN	Hydrogen cyanide
HF	Hydrogen fluoride
ICR	U.S. EPA Electric Utilities Information Collection Request
ISA	U.S. EPA Integrated Science Assessment
lb	Pound
MACT	Maximum Available Control Technology
MW	Megawatt
NADP	National Atmospheric Deposition Program
NEI	National Emissions Inventory
NESHAP	National Emissions Standard for Hazardous Air Pollutants
NOx	Nitrogen oxides
NRC	National Research Council of the National Academies
PAH	Polycyclic aromatic hydrocarbon
PM	particulate matter
$PM_{2.5}$	particulate matter that is 2.5 micrometers or smaller in size
PM_{10}	particulate matter that is 10 micrometers or smaller in size
SO_2	Sulfur dioxide
2,3,7,8-TCDD	Tetrachlordibenzo-*p*-dioxin
TEQ	Toxicity equivalent
$\mu g/m^3$	microgram per cubic meter
WHO	World Health Organization

EXECUTIVE SUMMARY

The U.S. Environmental Protection Agency (EPA) will soon propose new limits on hazardous air pollutants released to the atmosphere from coal- and oil-fired power plants. The proposal, known as the "Utility Air Toxics Rule", will set new limits on emissions of hazardous air pollutants, which are defined by Congress as chemical pollutants that are known or suspected to cause cancer or other serious health effects, such as reproductive problems or birth defects, and that adversely affect the environment. The new power plant limits are to be based on the emissions performance of the best performing power plants and pollution control systems currently in use. When the rules are in place, this will be the first time that EPA has implemented federal limits on mercury, arsenic, lead, hydrochloric acid, hydrofluoric acids, dioxins, and other toxic substances from coal-fired power plants.

The American Lung Association commissioned Environmental Health & Engineering, Inc. to prepare a report on public health and environmental impacts of hazardous air pollutant emissions from coal-fired power plants that would be a useful resource for the general public. The major findings of the report are summarized here.

Sources and Emissions

- Over 440 power plants greater than 25 megawatts located in 46 states and Puerto Rico, burn coal to generate electric power (USEPA, 2010a); coal combustion accounts for 45% of electricity produced in the United States (USDOE, 2009a).

- The National Emissions Inventory prepared by EPA indicates that emissions to the atmosphere from coal-fired power plants:
  - contain 84 of the 187 hazardous air pollutant identified by EPA as posing a threat to human health and the environment,
  - release 386,000 tons of hazardous air pollutants annually that account for 40% of all hazardous air pollutant emissions from point sources, more than any other point source category, and
  - are the largest point source category of hydrochloric acid, mercury, and arsenic releases to air (USEPA 2007).

- Coal-fired power plants are also a major source of emissions for several criteria air pollutants; including sulfur dioxide, oxides of nitrogen, and particulate matter.

Toxicity and Impacts on Public Health and the Environment

- Hazardous air pollutants emitted to the atmosphere by coal-fired power plants can cause a wide range of adverse health effects including damage to eyes, skin, and breathing passages; negative effects on the kidneys, lungs, and nervous system; the potential to cause cancer; impairment of neurological function and ability to learn; and pulmonary and cardiovascular disease (USEPA, 1998; USEPA, 2011a; USEPA, 2011b).

- Public health risks associated with exposure to mercury in food and metals in airborne fine particulate matter are among the most notable adverse health and environmental impacts associated with emissions of hazardous air pollutants from coal-fired power plants.

- Coal-fired power plants can be significant contributors to deposition of mercury on soil and water.
  - A study in eastern Ohio reported that coal combustion accounted for 70% of the mercury present in rainfall (Keeler et al., 2006).
  - In the same area, 42% of the mercury in samples of rain collected in the summer was attributed to emissions from a coal-fired power plant located less than a mile away (White et al., 2009).
  - Mercury that deposits to the earth's surface from air can make its way into waterways where it is converted by microorganisms into methylmercury, a highly toxic form of mercury (Grandjean 2010).

- EPA has determined that exposure to fine particulate matter is a cause of cardiovascular effects including heart attacks and the associated mortality; is likely a cause of hospital admissions for breathing problems and worsening of existing respiratory illness such as asthma; and is linked to other adverse respiratory, reproductive, developmental, and cancer outcomes (USEPA, 2009a; CASAC 2010).

- Hazardous air pollutants, such as arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, radium, selenium, and other metals, are integral components of fine particulate matter emitted directly from coal-fired power plants.

- The metal content of fine particulate matter has been linked to cardiovascular public health impacts in epidemiological and other studies (e.g. Zanobetti et al., 2009).

- In a recent population-based health impact assessment, particulate matter emitted directly from coal-fired power plants was estimated to account for an average of $3.7 billion[1] of public health damages each year (NRC, 2010).

- Environmental impacts of power plant hazardous air pollutant emissions include acidification of the environment, bioaccumulation of toxic metals, contamination of rivers, lakes, and oceans, reduced visibility due to haze, and degradation of buildings and culturally important monuments.

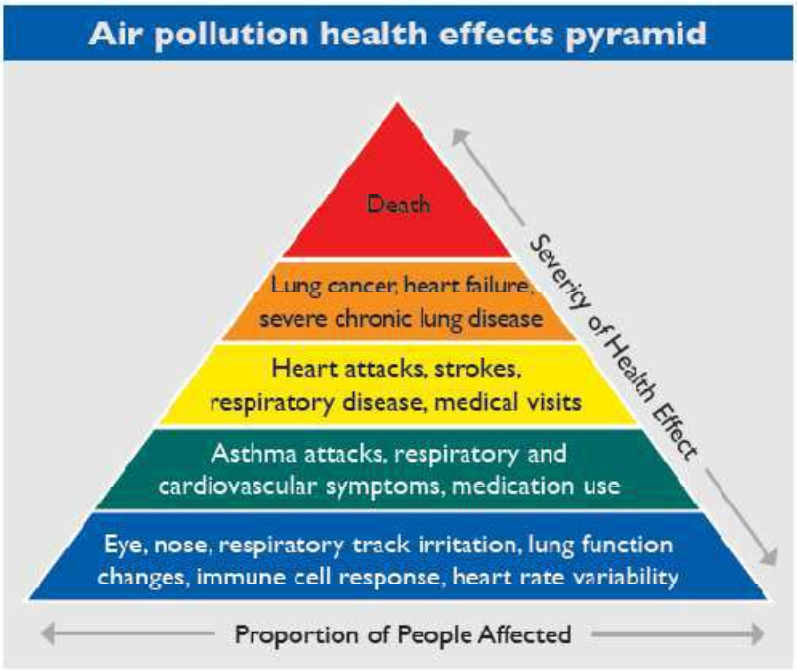


Figure 1. Air Pollution Health Effects Pyramid. Health effects of air pollution are portrayed as a pyramid, with the mildest and most common effects at the bottom of the pyramid, and the more severe but less frequent effects at the top of the pyramid. The pyramid shows that as severity decreases the number of people affected increases. Exposure to air pollution can affect both the respiratory and the cardiac systems. Adapted from USEPA, 2010b.

Transport and Range of Impacts

- Hazardous air pollutants released from coal-fired power plants influence environmental quality and health on local, regional, and global scales.

[1] Based on average damages of $9 million per coal-fired power plant determined in an analysis of 406 plants.

- Impacts of certain hazardous air pollutants, including most acid gases and some forms of mercury, appear to impact most heavily on the immediate vicinity of the facility.

- Impacts of non-mercury metals and other persistent hazardous air pollutants released from coal-fired power plants are greatest near the source, but can also influence the environment and health far from the source.
  - Analyses of coal-fired power plants have found that public health damages per person were two to five times greater for communities near the facilities than those for populations living at a greater distance from the plants (Levy and Spengler 2002).
  - Analyses conducted by EPA, the National Research Council, and other scientists show that emissions from coal-fired power plants cross state lines and impart public health damages on a regional scale.

Emission Controls for Hazardous Air Pollutants

- Emission rates of hazardous air pollutants vary widely among coal-fired power plants in the United States, in part because of variation in the use of technologies that can remove pollutants from exhaust gases.

- Hazardous air pollutant emissions from a sample of coal-fired power plants that use multiple modern control technologies were 2 to 5 times lower on average than for a random sample of plants selected by EPA.

- Controls on acid gas and non-mercury metal emissions are likely to reduce emissions of sulfur dioxide and primary particulate matter. As a result, controlling hazardous air pollutant emissions is expected to generate substantial public health and environmental benefits.

- Use of more effective control technologies by more coal-fired power plants as a result of the Utility Air Toxics Rule is expected to reduce the public health and environmental impacts of electricity generated by combustion of coal.

Table 1. Toxicological and Environmental Properties of Hazardous Air Pollutants (HAPs) Emitted from Electric Generating Stations Fueled by Coal.			
Class of HAP	**Notable HAPs**	**Human Health Hazards**	**Environmental Hazards**
Acid Gases	Hydrogen chloride, Hydrogen fluoride	Irritation to skin, eye, nose, throat, breathing passages.	Acid precipitation, damage to crops and forests.
Dioxins and Furans	2,3,7,8-tetrachlorodioxin (TCDD)	Probable carcinogen: soft-tissue sarcomas, lymphomas, and stomach carcinomas. May cause reproductive and developmental problems, damage to the immune system, and interference with hormones.	Deposits into rivers, lakes and oceans and is taken up by fish and wildlife. Accumulates in the food chain.
Mercury	Methylmercury	Damage to brain, nervous system, kidneys and liver. Causes neurological and developmental birth defects.	Taken up by fish and wildlife. Accumulates in the food chain.
Non-Mercury Metals and Metalloids (excluding radioisotopes)	Arsenic, beryllium, cadmium, chromium nickel, selenium, manganese	Carcinogens: lung, bladder, kidney, skin. May adversely affect nervous, cardiovascular, dermal, respiratory and immune systems.	Accumulates in soil and sediments. Soluble forms may contaminate water systems.
	Lead	Damages the developing nervous system, may adversely affect learning, memory, and behavior. May cause cardiovascular and kidney effects, anemia, and weakness of ankles, wrists and fingers.	Harms plants and wildlife; accumulates in soils and sediments. May adversely affect land and water ecosystems.
Polynuclear Aromatic Hydrocarbons (PAH)	Naphthlalene, benzo-a-anthracene, benzo-a-pyrene, benzo-b-fluoranthene, chrysene, dibenzo-a-anthracene	Probable carcinogens. May attach to small particulate matter and deposit in the lungs. May have adverse effects to the liver, kidney, and testes. May damage sperm cells and cause impairment of reproduction.	Exists in the vapor or particulate phase. Accumulates in soil and sediments.
Radioisotopes	Radium	Carcinogen: lung and bone. Bronchopneumonia, anemia, brain abscess.	Deposits into rivers, lakes and oceans and is taken up by fish and wildlife. Accumulates in soils, sediments, and in the food chain.
	Uranium	Carcinogen: lung and lymphatic system. Kidney disease.	
Volatile Organic Compounds	Aromatic hydrocarbons including benzene, toluene, ethylbenzene, xylene	May cause irritation of the skin, eyes, nose, and throat; difficulty in breathing; impaired function of the lungs; delayed response to a visual stimulus; impaired memory; stomach discomfort; and effects to the liver and kidneys. May also cause adverse effects to the nervous system. Benzene is a known carcinogen.	Degrade through chemical reactions in the atmosphere and contribute to carbon-based radicals that contribute to formation of ground-level ozone and its human health effects.
	Aldehydes including formaldehyde	Probable carcinogen: lung and nasopharyngeal cancer. Eye, nose, and throat irritation, respiratory symptoms.	
Hazard information compiled from toxicological profiles and concise chemical assessment documents for specific pollutants published by the Agency for Toxic Substances and Disease Registry and World Health Organization and available on-line (ATSDR, 2011; WHO, 2011).			

1.0 INTRODUCTION

In accordance with the Clean Air Act, the U.S. Environmental Protection Agency (EPA) will propose new limits on emissions of hazardous air pollutants released to the atmosphere from large power plants that burn coal and oil to generate electricity for sale. EPA will issue the proposed rule by March 16, 2011 as required by a court settlement (US District Court Consent Decree, 2010). The proposal will establish, for the first time, federal limits on emissions of hazardous air pollutants from coal- and oil-fired power plants. Commonly abbreviated as HAPs, hazardous air pollutants are chemical pollutants that are known or suspected to cause cancer or other serious health effects, such as reproductive problems or birth defects, and that adversely affect the environment. At this time, EPA has identified 187 chemical pollutants as HAPs (USEPA, 2010c).

Known formally as the National Emission Standards for Hazardous Air Pollutants for Utility Boilers, this rule will apply to all coal- and oil-fired combustion units that generate more than 25 megawatts of electricity. The new limits are to be based on the emissions performance of the maximum available control technology (MACT). According to the Clean Air Act, the MACT standards for existing sources are to be at least as stringent as the average emissions achieved by the best performing 12 percent of existing sources. For new sources, MACT standards are to be at least as stringent as the control level achieved by the best controlled similar source. The set of regulations and impending limits for electric generating stations is known as the "Utility Air Toxics Rule". Unlike most industry sectors, coal-fired power plants are currently not subject to federal limits on mercury and other HAP emissions.

The American Lung Association commissioned Environmental Health & Engineering, Inc. to prepare this report on HAPs and power plants that generate electricity by burning coal. The report is intended to be a resource for the non-scientific community that summarizes:

- Releases of HAPs to the atmosphere from combustion of coal (i.e., emissions),
- How these substances are transported and where they end up in the environment (i.e., transport and fate),
- Hazards posed by these HAPS and their impacts on human health and the environment (i.e., toxicity and impact), and
- Controls on releases of HAPs and the likely implications of more widespread use on coal-fired power plants (i.e., air pollution control technologies and their benefits).

2.0 HAZARDOUS SUBSTANCES IN COAL

Coal is a carbon-rich mineral that has been used to generate electricity in this country since the 1800s (NRC 2010). The United States is home to more than a quarter of the world's recoverable coal reserves. In 2008, more than 1 billion tons (2 trillion pounds) of coal was extracted from the earth at more than 1,600 mining operations throughout the country, approximately half of which was used for electricity generation. The electric energy generated from coal accounts for 45% of all electricity produced in the United States (USDOE, 2009a).

Coal is formed from fossilized plant life that is subjected to pressure and heat over millions of years. As coal is formed, it incorporates substances (impurities) from the surrounding soil and sediment, including sulfur and heavy metals. Some of these impurities consist of hazardous materials such as mercury, arsenic, lead, and nickel. The nature and extent of impurities in any given seam of coal depends on the conditions over the long period during which the coal is formed.



Figure 2. Coal, in Natural Form

Ultimately however, coal is classified into one of four types based on its heating value, ash content, and moisture, which in part reflect the extent of impurities present. As shown in Table 2, two types of coal – bituminous and sub-bituminous – account for over 90% of coal use in the country. Pyrite, a mineral rich in iron and sulfur, is a common impurity in bituminous coal, and is a primary host for arsenic and mercury. Sub-bituminous coal contains substantially less sulfur than bituminous coal and is therefore often favored by power plants that desire relatively low emission rates of sulfur dioxide, an important precursor to acid rain and fine particle pollution. Coal is sometimes washed with water and special chemicals to reduce some of the impurities. When burned, the impurities in coal are released and can be emitted to the atmosphere if not captured by air pollution control equipment operated at the power plant.

The average concentrations of hazardous substances present in various types of coal as reported by EPA are also shown in Table 2. Comparing the two types of coal used predominantly in the U.S.; sub-bituminous coal contains two to three times lower concentrations than bituminous coal of many substances that become HAPs when emitted from the exhaust stack of a power plant. However, sub-bituminous coal has a lower heating value than bituminous coal. As a result, more

sub-bituminous coal than bituminous coal must be burned to produce the same amount of electricity. This means that emissions of mercury and non-mercury HAPs from the two major types of coal can be comparable for a given amount of electricity output even though concentrations of HAPs within the coal types are different.

Table 2. Characteristics of Major Coal Types Used to Generate Electricity in the United States

Characteristic	Anthracite	Bituminous	Sub-bituminous	Lignite
Principal Characteristics[1]				
Percentage of U.S. Production	Less than 0.1%	46.9%	46.3%	6.9%
Heating Value (BTU/lb)	15	11 - 15	8 - 13	4 – 8
Sulfur (%)	Less than 1%	3 – 10%	Less than 1%	Less than 1%
Hazardous Air Pollutants in Coal[2]				
Arsenic	NR	0.5	0.1	0.3
Beryllium	NR	0.11	0.03	0.2
Cadmium	NR	0.03	0.01	0.06
Chlorine	NR	35	2.7	24
Chromium	NR	1.1	0.4	2.2
Lead	NR	0.6	0.2	1.0
Manganese	NR	1.8	1.3	20
Mercury	NR	0.007	0.006	0.03
Nickel	NR	0.9	0.4	1.2

BTU/lb—British Thermal Units per pound of coal; a measure of energy density of coal

NR—Not reported

1—NRC, 2010, Table 2-3.

2—Geometric mean concentration of selected elements in coal; units are pounds per billion BTU (USEPA, 2010a).

3.0 HAZARDOUS AIR POLLUTANT EMISSIONS

3.1 Emissions

Over 440 power plants in the United States generate electricity for sale by burning coal (USEPA, 2010a). As shown in Figure 3, coal is burned to produce electricity in power plants located throughout the country; with Idaho, Maine, Rhode Island, and Vermont being the only states not to host a coal-fired power plant. Coal consumption is concentrated in states of the Midwest and Southeast, although 3 of the top 10 coal consuming plants are located in Texas, near its border with Louisiana and Arkansas. As described in more detail in Section 4.0, HAPs and other pollutants released to the air by coal-fired power plants impact local air quality, but are also carried across state borders and throughout the country by prevailing winds that generally flow from west to east.

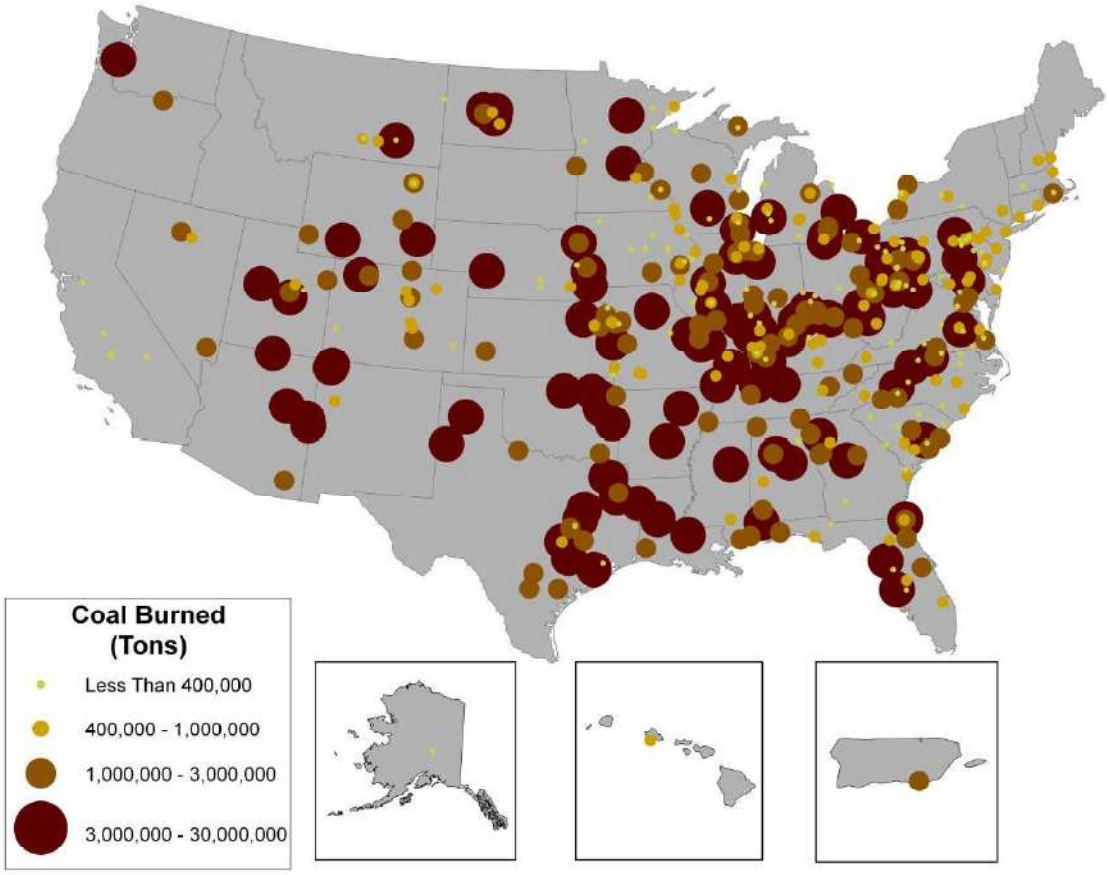


Figure 3. Annual Coal Consumption (tons per year) for Generation of Electricity for Sale by Coal-Fired Power Plants in the United States (USEPA 2010a; USDOE, 2009b). Additional information about the coal consumption of individual power plants is available at www.lungusa.org/ToxicAirReport from the Table of Electric Generating Utility Coal-fired Plants in the U.S.

Coal-fired power plants emit 84 of the 187 HAPs identified by EPA as posing a threat to human health and the environment (USEPA, 2007). With total emissions of 386,000 tons of HAPs annually, coal-fired power plants account for 40% of all HAP releases from point sources[2] to the atmosphere, more than any other point source category (Figure 4). These emissions include both 'fuel-based pollutants' – e.g., metals,[3] hydrogen chloride, hydrogen fluoride, and mercury – that are a direct result of contaminants in the coal that is combusted; as well as 'combustion-based pollutants' – e.g., dioxins and formaldehyde – which are formed during burning of the coal (USEPA, 2011a).

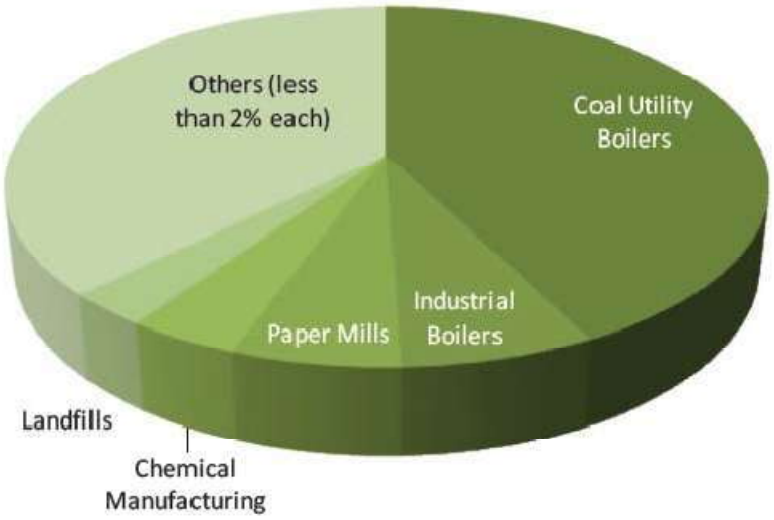


Figure 4 Proportion of Total Hazardous Air Pollutant Emissions From Coal-Fired Power Plants and Other Stationary Sources According to Data in the National Emissions Inventory from the U.S. Environmental Protection Agency (USEPA, 2007).

HAPs emitted from coal-fired power plants include neurotoxins such as mercury and lead, corrosive substances such as hydrochloric acid, carcinogens such as arsenic and benzene, radioactive elements such as radium, and potent organic carbon-based toxins such as dioxins and formaldehyde (USEPA, 2007; USEPA, 2010a). In addition to being the single largest class of total point source HAP emissions, coal-fired power plants are also a major source of emissions for many of these individual HAPs. As shown in Table 3, combustion of coal to generate electricity is the predominant source of hydrochloric acid emissions to the atmosphere (as well as sulfur dioxide and oxides of nitrogen, which are the most

[2] The term 'point source' refers to emissions released from a source that is stationary (does not move). Point sources are distinct from sources that can cover a large area, such as a wildfire, and mobile sources such as cars, trucks, and off-road machinery including bulldozers and other earth-moving equipment. Values reported here are based on the latest EPA National Emissions Inventory. EPA is anticipated to publish updated estimates of hazardous air pollutants from coal-fired power plants as part of the Utility Air Toxic Rule.

[3] As in some EPA materials, the class of pollutants referred to for simplicity here as 'metals' includes some elements (e.g. arsenic and selenium) that are not, strictly speaking, fully metallic.

important sources of atmospheric acidity). Likewise, electricity generating stations powered by coal account for 46% of mercury, and 60% of arsenic released to the atmosphere from point sources.

Table 3. Contributions of Coal-Fired Power Plants to Selected Hazardous Air Pollutant Emissions

Hazardous Air Pollutant	Percentage of Point Source Emissions
Acid Gases (hydrochloric acid and hydrofluoric acid)	76%
Arsenic	60%
Beryllium	28%
Cadmium	30%
Chromium	20%
Cobalt	34%
Lead	15%
Manganese	11%
Mercury	46%
All Non-Mercury Metal HAPs Emitted by Coal-Fired Power Plants	25%
Data obtained from USEPA, 2007	

3.2 Toxicological Properties

HAPS released to the atmosphere from coal-burning power plants have a wide range of toxicological properties, a summary of which is provided in Table 4. Some of these hazardous air pollutants are released in the form of acid gases, which can cause irritation of and tissue damage to eyes, skin, and breathing passages at high levels of exposure. Long-term exposure to metals has the potential to affect the kidneys, lungs, and nervous system. Beryllium can cause sensitization reactions that can remain latent for many years then develop into a serious condition called "Chronic Beryllium Disease." Exposure to several of the trace elements, dioxins and furans, polynuclear aromatic hydrocarbons (PAHs), and volatile organic compounds (VOCs) in coal-fired power plant emissions increases the risk of cancer. Finally, mercury is a potent neurotoxin, and high accumulation in humans is a cause of brain damage, while lower body burdens are associated with impairment of people's ability to learn and fine motor control, and may be a factor in heart disease. HAPs emitted from coal-fired power plants that have long-term impacts on the environment, such as accumulation in soil, water, and fish, and which can ultimately affect human health are also shown in Table 4.

Table 4. Toxicological and Environmental Properties of Hazardous Air Pollutants (HAPs) Emitted from Electric Generating Stations Fueled by Coal.			
Class of HAP	**Notable HAPs**	**Human Health Hazards**	**Environmental Hazards**
Acid Gases	Hydrogen chloride, Hydrogen fluoride	Irritation to skin, eye, nose, throat, breathing passages.	Acid precipitation, damage to crops and forests.
Dioxins and Furans	2,3,7,8-tetrachlorodioxin (TCDD)	Probable carcinogen: soft-tissue sarcomas, lymphomas, and stomach carcinomas. May cause reproductive and developmental problems, damage to the immune system, and interference with hormones.	Deposits into rivers, lakes and oceans and is taken up by fish and wildlife. Accumulates in the food chain.
Mercury	Methylmercury	Damage to brain, nervous system, kidneys and liver. Causes neurological and developmental birth defects.	Taken up by fish and wildlife. Accumulates in the food chain.
Non-Mercury Metals and Metalloids (excluding radioisotopes)	Arsenic, beryllium, cadmium, chromium nickel, selenium, manganese	Carcinogens: lung, bladder, kidney, skin. May adversely affect nervous, cardiovascular, dermal, respiratory and immune systems.	Accumulates in soil and sediments. Soluble forms may contaminate water systems.
	Lead	Damages the developing nervous system, may adversely affect learning, memory, and behavior. May cause cardiovascular and kidney effects, anemia, and weakness of ankles, wrists and fingers.	Harms plants and wildlife; accumulates in soils and sediments. May adversely affect land and water ecosystems.
Polynuclear Aromatic Hydrocarbons (PAH)	Naphthlalene, benzo-a-anthracene, benzo-a-pyrene, benzo-b-fluoranthene, chrysene, dibenzo-a-anthracene	Probable carcinogens. May attach to small particulate matter and deposit in the lungs. May have adverse effects to the liver, kidney, and testes. May damage sperm cells and cause impairment of reproduction.	Exists in the vapor or particulate phase. Accumulates in soil and sediments.
Radioisotopes	Radium	Carcinogen: lung and bone. Bronchopneumonia, anemia, brain abscess.	Deposits into rivers, lakes and oceans and is taken up by fish and wildlife. Accumulates in soils, sediments, and in the food chain.
	Uranium	Carcinogen: lung and lymphatic system. Kidney disease.	
Volatile Organic Compounds	Aromatic hydrocarbons including benzene, toluene, ethylbenzene, xylene	May cause irritation of the skin, eyes, nose, and throat; difficulty in breathing; impaired function of the lungs; delayed response to a visual stimulus; impaired memory; stomach discomfort; and effects to the liver and kidneys. May also cause adverse effects to the nervous system. Benzene is a known carcinogen.	Degrade through chemical reactions in the atmosphere and contribute to carbon-based radicals that contribute to formation of ground-level ozone and its human health effects.
	Aldehydes including formaldehyde	Probable carcinogen: lung and nasopharyngeal cancer. Eye, nose, and throat irritation, respiratory symptoms.	
Hazard information compiled from toxicological profiles and concise chemical assessment documents for specific pollutants published by the Agency for Toxic Substances and Disease Registry and World Health Organization and available on-line (ATSDR, 2011; WHO, 2011).			

3.3 Health and Environmental Impacts

Acid Gases

Hydrogen chloride and hydrogen fluoride are strongly corrosive acids, and coal-burning power plants are reported to be the largest anthropogenic source of hydrogen chloride and hydrogen fluoride emissions to air (USEPA, 2007). The amounts of hydrogen chloride and hydrogen fluoride produced by a particular power plant depend in large part on the concentrations of chloride and fluoride in the coal that is burned, and whether any emission control systems are in use.

Hydrogen fluoride is emitted as a gas or particle and can be adsorbed onto other particles (USEPA, 1998). Hydrogen fluoride particles tend to remain suspended in the atmosphere and can travel 500 kilometers or more as fine particles (USEPA, 1998). The majority of hydrogen chloride is believed to deposit rapidly to soil and water by wet and dry deposition or attach to particles in the atmosphere (Sanhueza, 2001).

Because of their high solubility in water, acid gas vapors can readily deposit in the upper airways. Likewise, water bound to microscopic particles can act as a "delivery system" for acids to the alveolar regions of the lung (USEPA, 1998). Controlled exposures of people with asthma have shown irritation and restriction of the airways from exposure to hydrogen chloride (Fine et al., 1987). Other studies have shown both acids to irritate and damage tissue of the eyes, nasal passages and lungs (USEPA, 2011b). The Agency for Toxic Substances and Disease Registry (ATSDR) characterizes hydrochloric acid as "corrosive and can cause irritation and burns" at high concentrations (ATSDR, 2011). Similarly, for high exposures to hydrogen flouride the Agency states that "hydrogen fluoride is irritating to the skin, eyes, and mucous membranes, and inhalation may cause respiratory irritation or hemorrhage".

When combined with water, hydrogen chloride produces "strong acid". Strong acidity in the atmosphere also results from emissions of nitrogen-based and sulfur-based gases released from coal-fired power plants. Other "strong acids" in the atmosphere can result from emissions of nitrogen-based and sulfur-based gases released from coal-fired power plants (producing nitric acid and sulfuric acid, respectively). Strong acids or their precursors that are present in inhaled particles and gases have been linked with respiratory effects in large-scale epidemiological studies. A study of 13,000 children in 24 U.S. and Canadian cities found that strong acidity in particles was associated with increased episodes of bronchitis and reduced lung function and acid gases were associated with asthma and related symptoms in children (Raizenne et al., 1996; Dockery et al., 1996). A more recent major children's

study found also acid gases and particle pollution were associated with reduced lung function (Gauderman et al., 2004). The focus of these landmark studies on children is significant; as children are likely more vulnerable than healthy adults to air pollution, including acidic gases and particles. Children have narrower airways, a faster breathing rate and tend to spend more time outdoors than adults, resulting in greater overall exposures (Bateson and Schwartz, 2008).

Chloride released from hydrogen chloride is associated with cloud acidity (USEPA, 1998) which can contribute to acid deposition over a regional scale. While much of the strong acidity has generally been thought to be related to sulfur dioxide and nitrogen oxide emissions, hydrogen chloride in particular likely plays a significant role in acid deposition in the vicinity of coal-burning power plants (USEPA, 1998).

Dioxins

The term dioxins refer to the family of structurally and chemically related polychlorinated dibenzo dioxins and polychlorinated dibenzo furans; another group of HAPs released to the atmosphere by coal-fired power plants. Dioxins are mainly formed as a by-product of combusting fossil fuels (WHO, 2010). Dioxins and furans are similar in chemical structure and consist of two six-sided rings composed of carbon and oxygen to which are attached either hydrogen or chlorine atoms. The number and position of chlorine atoms on these molecules determines the identity of each specific type of dioxin and furan, and also strongly influences their toxicity.

Dioxins have been measured in the atmosphere in both gas and particle forms. The low-chlorinated compounds have been found to be most prevalent in the gaseous form and the highly-chlorinated compounds dominant in particle form (Oh et al., 2001). The compounds undergo photochemical reactions in the lower levels of the atmosphere (troposphere). The lower-chlorinated compounds are removed from the atmosphere primarily by this photochemical process in as little as one day. The higher-chlorinated compounds are often associated with small particles and may reside in the atmosphere for more than 10 days (Atkinson, 1991) during which time people can be exposed through inhalation.

Most of the higher chlorinated dioxins eventually deposit onto soil or water bodies. Deposition of airborne particle-bound dioxins is likely the most important direct source of dioxin input to water and soil ecosystems (Lohmann and Jones, 1998; Zhang et al., 2009), where they tend to accumulate in

sediments and persist in the environment for many years. Dioxins have a high affinity for fatty molecules, which allows them to accumulate in aquatic and terrestrial food webs. As a result, humans can be exposed to these compounds by consumption of fish and meat. A study conducted by the Food Safety and Inspection Service of the U.S. Department of Agriculture in 2002-2003 found dioxin-like compounds in four classes of U.S. meat and poultry (Hoffman et al., 2006). Once ingested, it can take from 7-12 years for half of the most toxic dioxin; 2,3,7,8-TCDD; to leave the body (ATSDR, 2011). Dioxins have also been measured in the breast milk of nursing mothers (Lorber and Phillips, 2002).

Most of the information on health effects in humans comes from studies of people who were exposed to dioxins through contaminated food or from occupational activities (Kogevinas, 2001). Short-term, intense exposures to dioxins can cause liver damage and skin lesions called chloracne. Long-term exposures have been shown to harm the immune system, the developing nervous system, the reproductive system and can disrupt hormone function. Human exposure to 2,3,7,8-TCDD and to some mixtures of other dioxins have been linked to an excess risk of cancer for many types of cancer. Studies have also shown a slight increased risk of developing diabetes (WHO, 2010).

Current research is focusing on the ability of dioxins to mimic natural hormones in the body and alter their normal function; i.e., a class of contaminants known as endocrine-disrupting compounds (Casals-Casas and Desvergne, 2011). A study of 1 to 9 year-old boys accidentally exposed to 2,3,7,8-tetrachlorodibenzo-*p*-dioxin (TCDD) in 1976 reported that there were irreversible effects to reproductive hormone levels and reduced semen concentration and quality in those same individuals as adults 22 years later (Mocarelli et al. 2008). According to the World Health Organization (2010), "The developing fetus is most sensitive to dioxin exposure. The newborn, with rapidly developing organ systems, may also be more vulnerable to certain effects."

Radioisotopes

The scientific term radioisotope refers to forms of certain elements that are radioactive. Materials that are radioactive emit ionizing radiation that can damage cells and contribute to various forms of cancer and other illness. While coal does not contain large amounts of radioactive material, the large volumes of coal burned in power plants lead to substantial releases of radium and uranium to the atmosphere in particle form. Combustion of coal is the leading source of radium releases to the atmosphere (ATSDR, 2011). One study estimated that 100 times more radioactivity is released from a coal-fired plant as compared to a nuclear power plant of a similar size (McBride et al., 1978).

Mercury

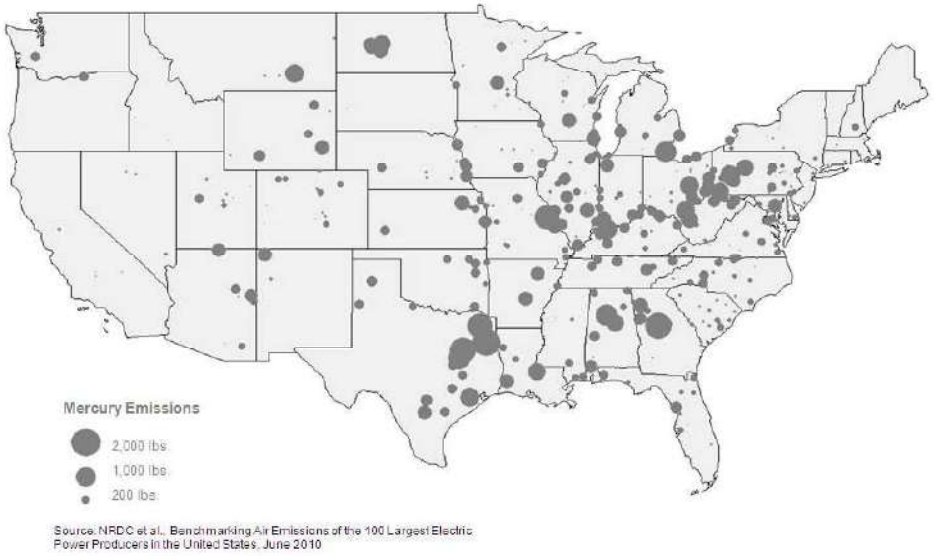
EPA identifies mercury as one of the most toxic HAPs released by coal-fired power plants, primarily because of its ability to impair functioning of the central nervous system. Coal-fired power plants are responsible for about one-third of all mercury emissions from human activity (USEPA, 1997). After being released to the atmosphere, mercury can return to the earth in rain or snow.

The local impacts of that mercury can be seen in studies of eastern Ohio. Coal combustion was estimated to account for 70% of mercury in rainfall of Steubenville, Ohio (Keeler et al., 2006), reflecting the fact that coal-fired power plants are a major source of mercury emissions to the environment. Comparing mercury emissions from coal-fired power plants and areas of local mercury deposition between the western and eastern U.S. provides qualitative support for that conclusion as well (Figure 5).[4] In another study in eastern Ohio, 42% of the mercury in samples of rain collected in the summer was attributed to emissions from a coal-fired power plant located less than a mile away (White et al, 2009). This finding demonstrates that coal-fired power plants can be significant contributors to deposition of mercury on a local scale.

Mercury that deposits to the earth's surface from air can make its way into waterways where it is converted by microorganisms into methylmercury, a highly toxic form of mercury (Grandjean 2010). As these microorganisms are eaten by larger organisms, methylmercury concentrations increase with each successive level of the food chain, in a process called bioaccumulation. The large and long-lived predators of marine and freshwater ecosystems, including many fish favored by consumers in the U.S., end up with the highest methylmercury concentrations. As a result, consumption of fish and other aquatic organisms is the predominant pathway of exposure to mercury. The amount of mercury in people correlates with typical fish intake (MacIntosh et al., 1997; Carta et al., 2003; Mozaffarian and Rimm, 2009).

[4] Note that mercury deposition shown in the map reflects contributions from all sources as well as the effects of local and regional meteorology, including wind patterns and rainfall. Consider Florida example, a state where there are few coal-fired power plants, yet mercury deposition is high in comparison to some other areas of the country. Burning of everyday garbage (i.e., incineration of municipal solid waste) is known to be an important local source of mercury deposition in Florida (Marsik et al., 2009)

Panel A: Location and Size of US Power Plants by Mercury Emissions



Panel B: Annual Amounts of Mercury Deposition in Rainfall

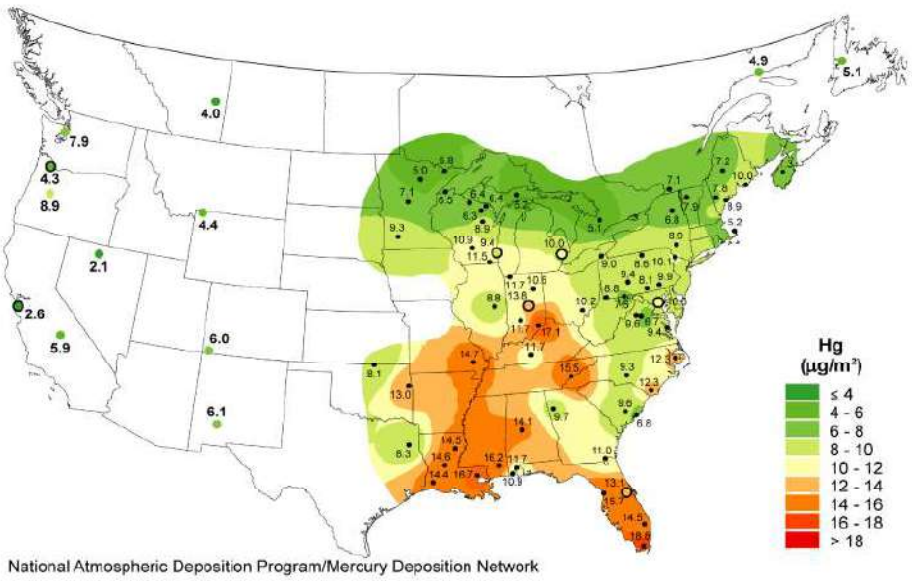


Figure 5 **Panel A—**Location and Size of Annual Mercury Emissions to Air (MJ Bradley, 2010)
Panel B—Annual Amounts of Mercury Deposition in Rainfall (NADP, 2007)

In consideration of this evidence, the major public health concern for the general population is potential health effects of long term, low-level exposure to methylmercury that could result from regular consumption of contaminated fish. Because of concern about the effect of methylmercury on the developing brain in infants, numerous government agencies have issued recommendations on fish

consumption to minimize dietary intake of mercury for women who are or may become pregnant, nursing mothers, and young children. Children are especially at risk because mercury exposure can interfere with nerve development, particularly in the brain (Bose-O'Reilly et al., 2010). Each year more than 300,000 children are born in the US with high enough levels of mercury in their blood to cause impaired performance on brain development tests and to cause permanent effects to intelligence (Trasande et al., 2005; Axelrad et al., 2007). As part of this public health information campaign, at least 39 states have issued advisories warning against fish consumption from local waters due to mercury contamination (USEPA, 2011c).

More recently, interest about public health of the general population and mercury in fish has begun to focus on risks of cardiovascular disease and outcomes (Domingo, 2007). Current evidence indicates that methylmercury in fish may lessen the cardiovascular benefits of regular fish consumption. As stated by Mozaffarian (2009), this is "a finding that has major implications for regulatory decisions regarding control of mercury emissions, because greater public health benefit may be derived from fish consumption if mercury levels were decreased."

Non-Mercury Metals

Many metals present in coal are released to the atmosphere and become part of the mix of microscopic particles produced by coal-fired power plants. The majority of the mass of the microscopic particles emitted from coal-fired power plants consists of sulfur compounds which are not HAPs, but are hazardous nonetheless and addressed by a different section of the Clean Air Act. The remainder of particles includes arsenic, beryllium, cadmium, chromium, lead, manganese, mercury, nickel, radium, and other HAP and non-HAP elements.

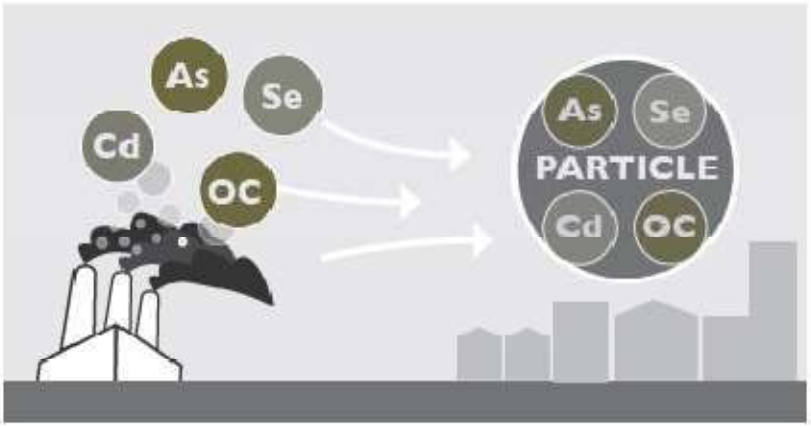


Figure 6. Hazardous Air Pollutants as a Component of Particulate Matter

Emissions of these metals[5] from coal-fired power plants are frequently referred to as primary particulate matter (PM). They are distinct in origin from PM that is formed by chemical reactions in the atmosphere, so called secondary PM.[6]

> Because of the integral relationship between HAPs and particles in exhaust from coal-fired power plants, EPA established particulate matter as a surrogate for emissions of non-mercury metals from industrial boilers required to demonstrate attainment with the *NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Source Facilities* (USEPA, 2011a).

The vast majority of primary PM emissions from coal-fired power plants are part of a class of air pollutants known as fine PM. Fine PM is defined as aerosols that are smaller than 2.5 micrometers ($PM_{2.5}$) and are smaller than the width of a human hair. Thus in addition to posing a hazard to human health and the environmental individually, many of the metal HAPs emitted from coal-fired power plants become part of the burden of fine particulate matter pollution in the United States (USEPA, 2009a).

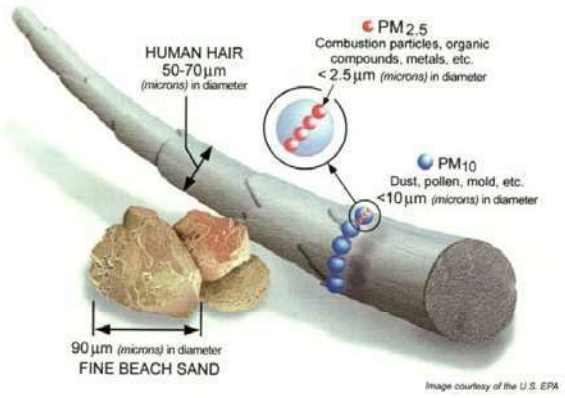


Figure 7. Fine PM: Aerosols Smaller than 2.5 microns Across ($PM_{2.5}$), Compared with a Human Hair and a Grain of Sand. (EPA Office of Research and Development, http://www.epa.gov/ord/ca/quick-finder/particulate-matter.htm)

[5] As in some EPA materials, the class of pollutants referred to for simplicity here as 'metals' includes some elements (e.g. arsenic and selenium) that are not, strictly speaking, fully metallic.

[6] Emissions of sulfur dioxide and oxides of nitrogen from coal-fired power plants are a major source of secondary PM in the United States. Secondary PM can also include large organic carbon-based molecules, such as dioxins, furans, and PAHs; that attach to aerosols as they are carried through the air. Secondary PM will be discussed further in Section 5.

The fact that non-mercury metals emitted from exhaust stacks of coal-fired power plants comprise part of PM is important. When inhaled by people, some particles deposit along the respiratory tract, while others penetrate deeply into the lung where they can enter the bloodstream. These particles aggravate the severity of chronic lung diseases causing loss of airway function, cause inflammation of lung tissue which results in the release of chemicals that impact heart function, and leads to changes in blood chemistry that results in clots that can cause heart attacks (USEPA, 2010b). Inhalation of $PM_{2.5}$ over both short and long periods of time is recognized to cause cardiovascular effects, including heart attacks and the associated mortality. Exposure to $PM_{2.5}$ is also a likely cause of hospital admissions for breathing problems and worsening of existing respiratory illness such as asthma. $PM_{2.5}$ exposure has been linked to other adverse respiratory, reproductive and developmental, and carcinogenic outcomes as well (USEPA 2009a; CASAC, 2010).

Some of the largest studies of health effects related to fine particles were conducted with participation from healthy adults living in areas across the United States. In one of the first and most important of these community-based studies, a research group from the Harvard School of Public Health followed over 8,000 healthy adults living in six U.S. cities for more than 14 years (the Six Cities Study). They concluded that death rates were higher in cities with higher fine particle pollution levels; in other words, people in those cities didn't live as long as people in cities with cleaner air (Dockery et al., 1993). The association between fine particles and early death was repeated in two much larger studies using an American Cancer Society (ACS) database of over 500,000 adults located in 151 cities across the country (Pope et al. 1995; Pope, et al. 2002). In 2000, a reanalysis of both the 1993 Six Cities study and data from the 1995 ACS cohort provided confirmation that fine particles could shorten life (Krewski et al., 2000). A follow-up analysis from the Six Cities Study found increased mortality associated with the fraction of $PM_{2.5}$ attributed to coal combustion (Laden et al., 2006).

The findings of community-based research are supported by results of detailed studies on individuals exposed to $PM_{2.5}$ in both everyday and laboratory settings. Those studies demonstrate that $PM_{2.5}$ exposure elicits markers of cardiovascular damage, including irregular heartbeat as well as pulmonary and systemic inflammation (USEPA 2010b). These findings provide consistent and compelling evidence of fine particle pollution health impacts. In consideration of the weight of evidence, USEPA (2009a), leading scientists (CASAC 2010; Pope and Dockery, 2006), and the American Heart Association (Brook et al., 2004) all agree that exposure to fine particles increases the risk of asthma attack, stroke, heart attack, and other serious illness as well as a variety of less serious, but important, effects including

irritation of the eyes, nose, and throat, chronic bronchitis, restriction of activities, and temporary changes in lung function.

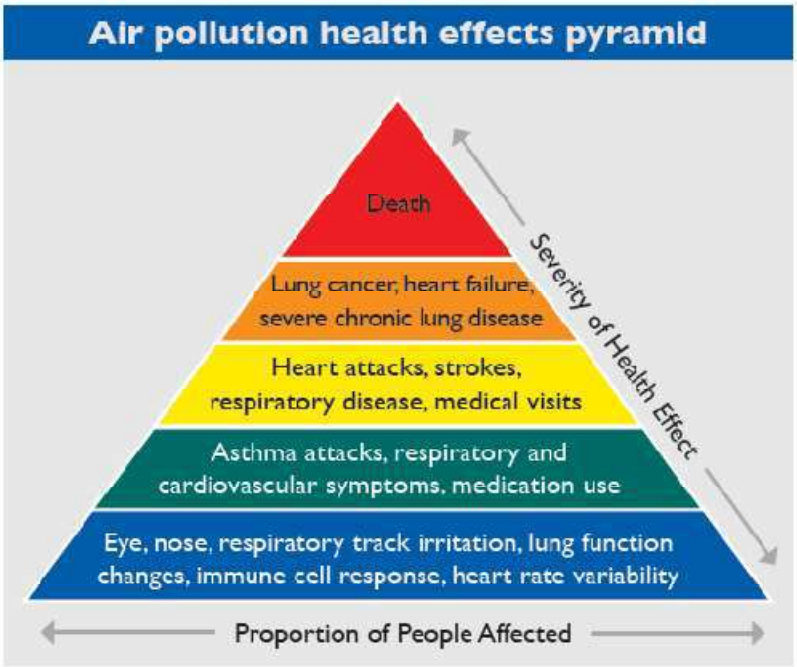


Figure 8. Air Pollution Health Effects Pyramid.

Health effects of air pollution are portrayed as a pyramid, with the mildest and most common effects at the bottom of the pyramid, and the more severe but less frequent effects at the top of the pyramid. The pyramid shows that as severity decreases the number of people affected increases. Exposure to air pollution can affect both the respiratory and the cardiac systems. Adapted from USEPA, 2010b.

The presence of metals or other pollutants in or on particles may be important in determining the toxicity of fine particles (Bell et al., 2007). Researchers have found that metals interact with particles to generate 'reactive oxygen species' which limit the body's ability to repair damage to its cells and contribute to inflammation of tissue (Carter et al., 1997; Gurgueita et al., 2002; Wilson et al., 2002; Valko, 2008). Exposure to particles enriched in sulfate, selenium, iron, nitrate, and organic carbon have been associated with immune cell response and heart variability in human volunteers (Huang et al., 2003; Chuang et al., 2007). A recent community-based study that used Medicare records from 26 communities found greater effects on hospital admissions for cardiovascular disease when the levels of certain metals, including chromium and nickel, were elevated in the $PM_{2.5}$ (Zanobetti et al., 2009). Similarly heart attack admissions were elevated for $PM_{2.5}$ enriched in arsenic, chromium, manganese, nickel and organic carbon. In the same study, diabetes-related hospital admissions were associated with

PM high in arsenic, organic carbon and sulfate, potential indicators of coal combustion. Another important and recent study examined more than one million deaths across the US and found more deaths when the fraction of aluminum, sulfate and nickel in the fine particles was highest (Franklin et al., 2008). This study also found the number of deaths to be even higher for the combination of aluminum with sulfate, compared to aluminum or sulfate alone, indicating they may be more toxic when combined.

Assessments of population-based health impacts as a result of exposure to primary PM released from coal-fired power plants also indicate the importance of non-metal HAP emissions on public health. As described above, the scientific evidence for adverse cardiovascular and respiratory effects of fine particulate matter is very strong and in fact sufficient to support quantitative assessments of public health damages. The health impacts and cost to society of primary PM emissions from coal-fired power plants have been determined in a number of analyses. For example, emissions from a single 1,230 MW facility in Wisconsin were estimated to account for 7 premature deaths, 100 emergency room visits, and 520 asthma attacks each year, with an annual cost of $42 million (MacIntosh et al., 2003). Estimated impacts are significantly larger when coal-fired power plants throughout the U.S. are considered. The National Research Council (NRC) estimated $9 million of costs as a result of direct emissions of $PM_{2.5}$ from the average U.S. coal-fired power plant (NRC, 2010). The NRC analysis considered 406 coal-fired power plants across the country, which yields cumulative annual damages of $3.6 billion as a result of primary $PM_{2.5}$ emissions from those facilities.

4.0 TRANSPORT OF COAL-FIRED POWER PLANT HAZARDOUS AIR POLLUTANTS

Hazardous air pollutants released from coal-fired power plants influence environmental quality and health on local, regional, and global scales. The extent to which a given pollutant or facility impacts each of the scales depends on a number of factors, but principally (i) how long a given pollutant remains in the air, (ii) physical attributes of the power plant, (iii) weather and (iv) the proximity of human populations. These characteristics determine whether human and environmental impacts of a power plant-related HAP are generally local or can extend to a regional or global scale.

A key factor that affects the distribution of pollution from power plant emissions is the average length of time that HAPs stay airborne, in other words their *atmospheric residence time*. Atmospheric residence time varies greatly for different classes of coal-fired power plant HAPs. This variation in persistence directly influences how far HAPs are carried by wind and accompanying weather systems. Assuming a typical ground-level wind speed, HAPs can travel approximately 5 to 10 miles from their source in an hour unless they first deposit to the earth, are transformed through a chemical reaction, or are lost from the atmosphere by any number of other means. Consequently, impacts of HAPs with atmospheric residence times of a few hours are limited to within 15 to 30 miles of their source. Longer-lived HAPs can travel hundreds to thousands of miles before being removed from the atmosphere. Representative atmospheric residence times are shown in Table 5 for several major classes of coal-fired power plant HAPs.

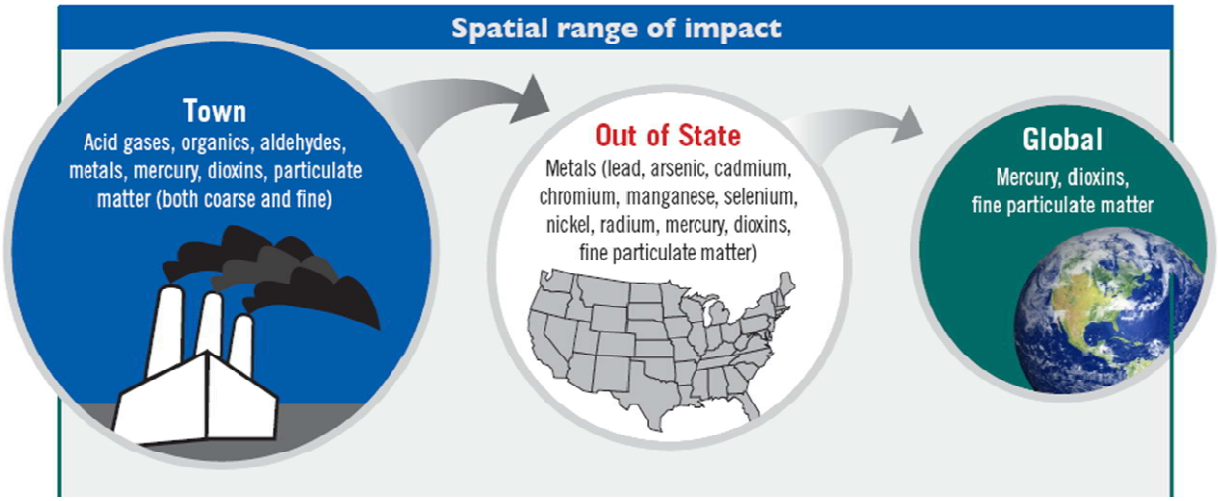


Figure 9. Schematic of the likely range that hazardous air pollutants are transported.

Table 5. Residence Time of Hazardous Air Pollutants in the Atmosphere			
HAP Group	**Indicator Pollutant(s)**	**Residence Time***	**Likely Range of Transport**
Mercury	Methylmercury	7–10 days	Local, regional, global
Metals	Arsenic	7-9 days (lifetime)	Local, regional, global
	Beryllium	10 days (lifetime)	Local, regional, global
	Cadmium	1-10 days (lifetime)	Local, regional, global
	Chromium	Up to 7-10 days	Local, regional, global
	Nickel	Up to 30 days (half-life)	Local, regional, global
	Manganese	Several days (half-life)	Local, regional
	Selenium	1-10 days	Local, regional, global
	Lead	Up to 10 days	Local, some regional
Radioisotopes	Uranium, Radium	Not reported	Local, regional, global**
Dioxins/Furans	Chlorinated dibenzo-p-dioxins	0.5 - 9.6 days (lifetime)	Local, regional, global
	Dibenzofurans	4 days (half-life)	Local, regional
	Chlorodibenzofuran (CDFs)	More than 10 days (half-life)	Local, regional, global
Aldehydes	Formaldehyde	<20 hours (half-life)	Local
Volatile Organic Compounds	Benzene	4–6 hour (half-life in presence of NOx and SO_2)	Local
	Xylene	8–14 hours (half-life)	Local
	Toluene	13 hours (half-life)	Local
	Ethylbenzene	2 days (half-life)	Local
Acid Gases	HCl/HF	1-5 days (half-life)	Local, regional, global
	HCN	530 days (half-life)	Local, regional, global
Polycyclic Aromatic Hydrocarbons (PAHs)	Benzo-a-anthracene, Benzo-a-pyrene, Fluoranthene, Chrysene, Dibenzo-a-Anthracene	Up to several days (lifetime)	Local, regional, global

*Atmospheric residence time based upon lifetime or half-life as reported in chemical specific profiles published by the Agency for Toxic Substances and Disease Registry and the World Health Organization; available on-line (ATSDR, 2011; WHO, 2011).
**Assumed to be a component of fine particles

HAPs that interact readily with water typically have atmospheric residence times of only hours as they quickly enter the water cycle in the form of clouds or water vapor, rivers or lakes. Hydrogen chloride, hydrogen fluoride, and some forms of mercury are among the notable coal-fired HAPs that can be relatively short-lived in the atmosphere. As a result, environmental and health impacts of these HAPs are likely to be concentrated in the vicinity of the power plants from which they are released. These

observations are consistent with the measurements of local mercury deposition that were described in Section 3.3.

Local impacts of coal-fired power plant HAP emissions are not limited to HAPs with short atmospheric residence times, however. Longer-lived HAPs are also present in the immediate vicinity of the source before being transported to other areas. These include metals such as lead, arsenic, cadmium and chromium. Potential exposures to these HAPS can therefore be elevated in areas surrounding a coal-fired power plant. For instance, a study of coal-fired power plants in New England found that public health damages per person are two to five times greater for communities near the facilities than for populations living at a greater distance from the plants (Levy and Spengler, 2002).

In addition to properties of a given pollutant and weather, the location and magnitude of local impacts from emissions of coal-fired power plant HAP are influenced by the height of the emission point above ground level. In general, lower stacks result in higher impacts near the source than taller stacks. The relationship between stack height and location of ground-level impacts is illustrated in Figure 10.

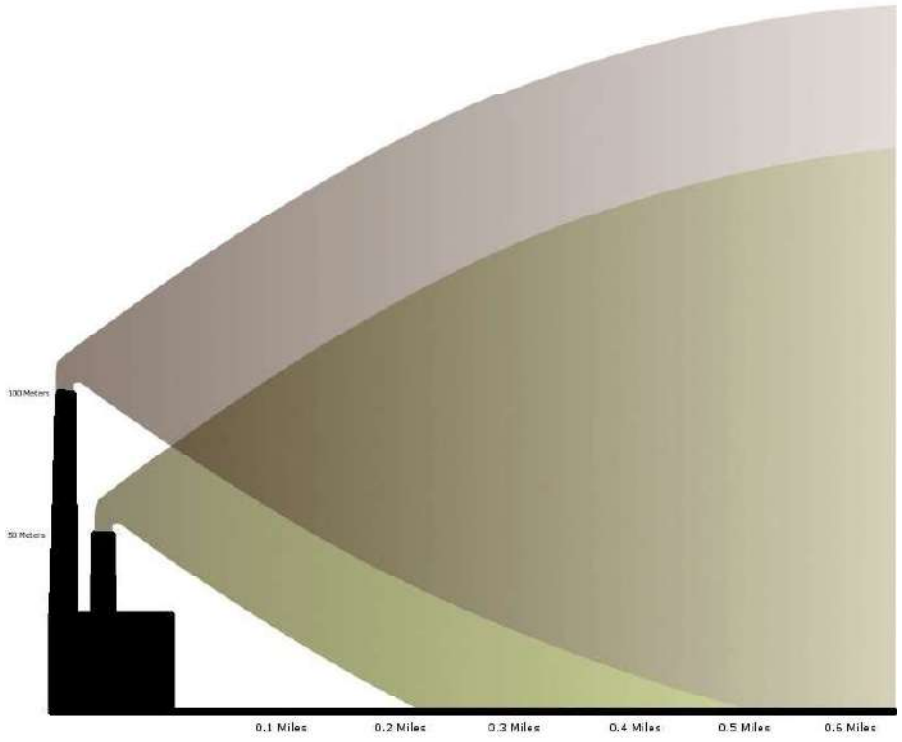


Figure 10 Schematic of location of initial ground-level impacts in relation to height of hazardous air pollutant release.

Stack heights for coal-fired power plants in the U.S. are 440 (134 meters) feet on average and range from 15 feet (about 4 meters) to 1,040 feet (about 316 meters) above ground level (USEPA 2010a). Corresponding maximum ground-level impacts range from 500 feet (about one-tenth of a mile) to 4,000 feet (about three-quarters of a mile). Consequently, the greatest ground-level impacts of HAPs emissions from any given coal-fired power plant are typically within a mile of the facility.

Tall exhaust stacks can mitigate local air quality impacts in general, although higher discharge points also release pollutants at an altitude where they are more readily transported on a regional and even global scale. Taller stack heights therefore enhance instate transport of HAPs and other pollutants. Markers of primary and secondary coal combustion have been reported in many analyses of the composition of regional fine particulate matter pollution (e.g.; Lee et al., 2002; Lee et al., 2003; Lee et al., 2006; Rutter et al., 2009). Regional transport of coal-fired power plant emissions translates to regional impacts on public health as well. One analysis of emissions from a coal-fired power plant in Wisconsin found that 80% of total public health impacts occurred beyond the state border (MacIntosh et al., 2003).

Some research has indicated that the burden of air quality impacts resulting from emissions by local sources may be borne disproportionately by disadvantaged communities. These impacts can occur in terms of both exposure and effect. With regard to exposure, lower-income and ethnic-minority residents have been found to be disproportionately exposed to air pollution because of their proximity to industrial facilities. With regard to plants that burn coal and oil for industrial processes, USEPA (2010d) recently reported that:

> *"demographic analysis showed that major source boilers are located in areas where minorities' share of the population living within a 3-mile buffer is higher than the national average. For these same areas, the percent of the population below the poverty line is also higher than the national average."*

In addition to elevated exposure to coal-fired power plant emissions, other research has suggested that socially disadvantaged populations are at greater risk of adverse health effects of air pollution. In one study, nearly 50% of the risks for premature mortality of power plant-related exposures were borne by the 25% of the population with less than high school education (Levy et al. 2002). This result reflected both higher background rates of mortality and higher relative risks for air pollution related mortality for individuals with lower education. Socially disadvantaged populations also are more likely to lack access to health care and to live in conditions associated with asthma exacerbations (Babey et al 2007). These studies indicate that social-class and ethnic-based environmental injustices appear to exist in the distribution of air pollution exposure and effects.

Another example of regional impacts of coal-fired power plant emissions is provided in Figure 11. In this case, emissions of primary PM, sulfur dioxide, and oxides of nitrogen were modeled for 11 coal-fired power plants in Michigan and used to predict annual average concentrations of $PM_{2.5}$ for counties across the continental United States. As shown on the map, the highest $PM_{2.5}$ impacts from the plants were predicted to occur throughout the Great Lakes region and parts of New York and New England.

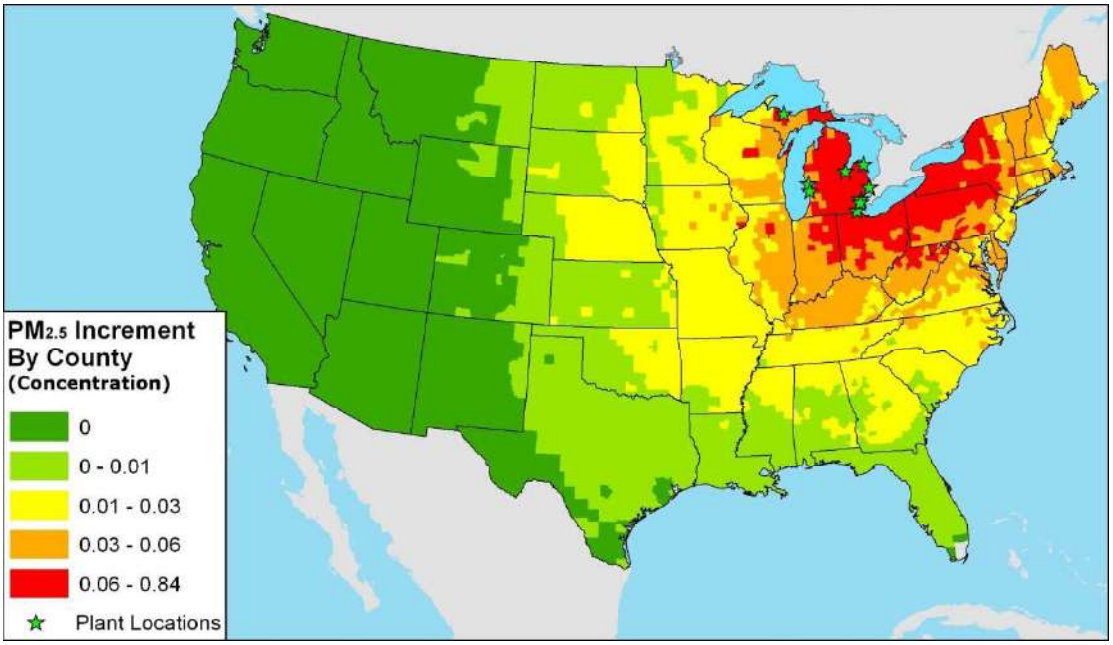


Figure 11 Annual Average Concentrations of Fine Particulate Matter ($PM_{2.5}$) Estimated for Counties of the Contiguous United States as a Result of Emissions of Primary $PM_{2.5}$, Sulfur Dioxide, and Oxides of Nitrogen from 11 Coal-Fired Power Plants in Michigan (EH&E, 2011).

5.0 CONTROL OF HAZARDOUS AIR POLLUTANTS FROM COAL-FIRED POWER PLANTS

The forthcoming Utility Air Toxics Rule is anticipated to establish limits for HAPs from power plants that produce at least 25 MW of electricity for sale. The Utility Air Toxics Rule will apply to both new and existing coal-fired power plants. According to the Clean Air Act, these plants are expected to attain HAP emission rates that are on par with the typical best performing coal-fired power plant, defined as the average of the cleanest 12% of the coal-fired power plants. Using the industrial boiler rule as a guide (USEPA, 2011a), subcategories of emissions limits may be established under the Utility Air Toxics Rule based on plant size, type of fuel, type of boiler, utilization, or other factors.

Technologies that are effective at controlling emissions of HAPs from coal-fired power plants are already in use by some power plants as evidenced by emission data gathered by USEPA from samples of both better controlled and randomly selected facilities (USEPA, 2010b). As shown in Figure 12, emissions of mercury, selenium, hydrogen chloride, and hydrogen fluoride were 5 times lower from the better controlled coal-fired power plants compared to the power plants selected at random. A 50% reduction was observed in emissions of the other non-mercury metals, dioxins, and PAHs for the sample of better performing plants in comparison to the random sample of plants.

The emissions data illustrated in Figure 12 reflect control efficiencies achieved by a wide range of technologies available to reduce the amount of acid gases, mercury, non-mercury metals, and organic-carbon based hazardous air pollutants in exhaust gas released from coal-fired power plants. A detailed description of those technologies and analysis of their effectiveness for controlling HAPs is beyond the scope of this report. However, an introduction to some of the more common technologies is provided here to aid understanding of the operating principles of these systems and the extent to which they are deployed in coal-fired power plants across the United States.

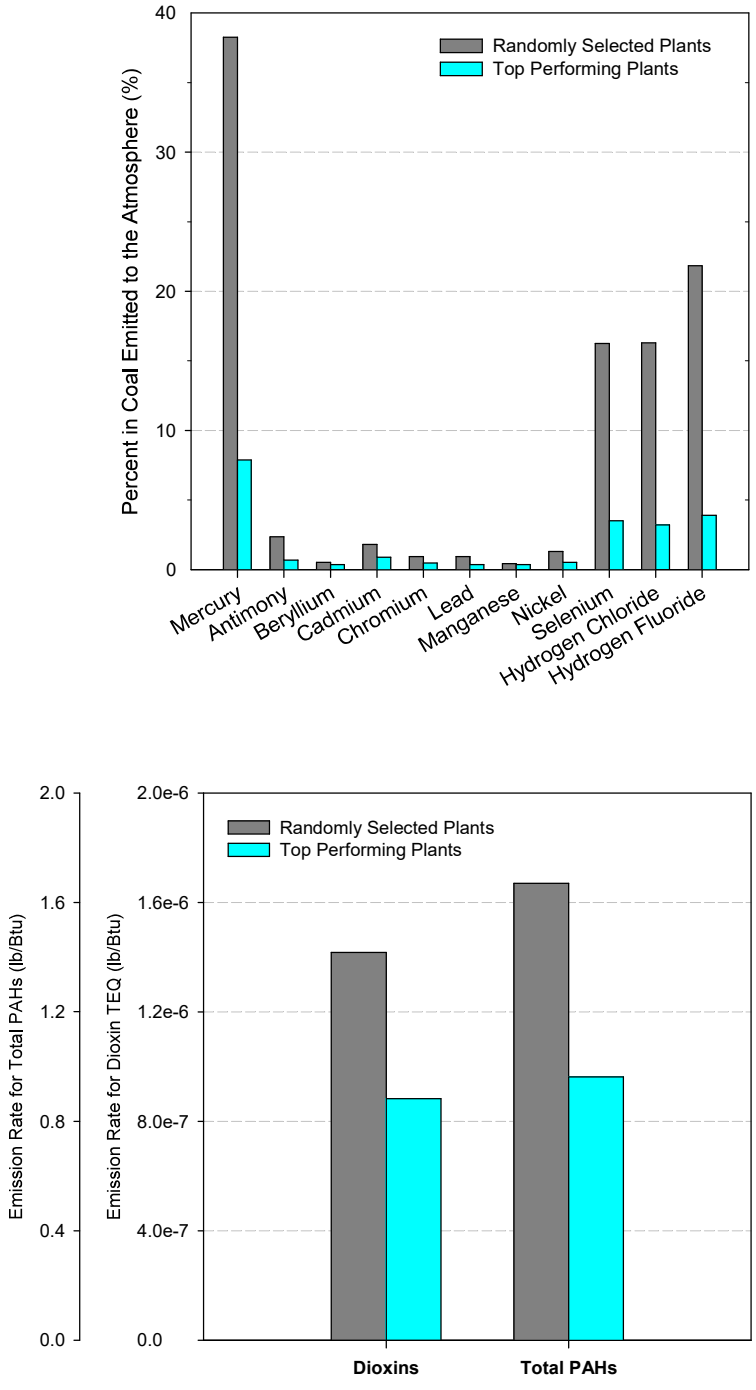


Figure 12. Comparison of Average Hazardous Air Pollutant Emissions from Top Performing and Randomly Selected Coal-Fired Power Plants Selected by EPA (EPA 2010). Abbreviations: PAHs—polynuclear aromatic hydrocarbons; TEQ—toxicity equivalents for subgroups of dioxins and furans.

Three major categories of air pollution control equipment are used to reduce emissions of HAPs including systems for acid gases, particulate matter, and mercury (Table 6). A portion of coal-fired power plants in the U.S. already use these technologies. More facilities are expected to install these or similar technologies in response to the new Utility Air Toxics Rule.

Table 6. Currently Available Control Technologies in Use for Reduction of Emissions of Air Toxics from Coal-Fired Power Plants

Control Technology	Which Pollutants Are Controlled?	How Does this Technology Work?	Number of Coal-Fired-Power Plants Using This Technology
Acid Gas Control Technologies			
Wet Flue Gas Desulfurization (FGD) (Scrubbers)	HAPs: Hydrogen chloride Hydrogen fluoride Hydrogen cyanide Mercury Collateral Pollutants Sulfur dioxide Particulate matter	Liquid mixed with limestone is sprayed into the emission, producing wet solid by-products. Sulfur oxides react with limestone to form calcium sulfite and calcium sulfate.	144 (32%)
Dry Flue Gas Desulfurization (FGD) (Scrubbers)	HAPs: Hydrogen chloride Hydrogen fluoride Hydrogen cyanide Mercury Collateral Pollutants Sulfur dioxide Particulate matter	Emissions are passed through a stream of liquid mixed with lime or a bed of basic material such as limestone, forming salts which are captured using PM controls.	64 (14%)
Dry Sorbent Injection (DSI)	HAPs: Hydrogen chloride Hydrogen fluoride Hydrogen cyanide Collateral pollutant Sulfur dioxide	Dry sorbent consisting of Trona, sodium bicarbonate, or lime is blown into duct, reacts with acid gases and is captured in downstream PM controls.	19 (4%)
Fluidized Bed Combustion (FBC)	HAPs: Hydrogen chloride Hydrogen fluoride Hydrogen cyanide Collateral pollutants Sulfur dioxide	Combustion technology more efficient than conventional boilers, air is blown through a bed of limestone and fuel during combustion.	6 (1%)

Continued on the next page

Table 6. Cont'd: Currently Available Control Technologies in Use for Reduction of Emissions of Air Toxics from Coal-Fired Power Plants			
Control Technology	**Which Pollutants Are Controlled?**	**How Does this Technology Work?**	**Number of Coal-Fired-Power Plants Using This Technology**
Non-Mercury Metal Control Technologies			
Electrostatic Precipitators (ESP)	HAPs: Antimony, Beryllium, Cadmium, Cobalt, Lead, Manganese, Nickel, Particle phase organics Collateral Pollutants Other forms of primary particulate matter	Particles are charged with electricity and collected on oppositely charged plates, particles are collected for disposal/further treatment.	333 (74%)
Baghouse	HAPs Antimony, Beryllium, Cadmium, Cobalt, Lead, Manganese, Nickel, Particle phase organics Collateral Pollutants Other forms of primary particulate matter	Emissions passed through fabric filters and collected	157 (35%)
Cyclones	HAPs Antimony, Beryllium, Cadmium, Cobalt, Lead, Manganese, Nickel, Particle phase organics Collateral Pollutants Other forms of primary particulate matter	Use centrifugal force to separate particulate from gas streams.	23 (5%)
Mercury Control Technology			
Activated Carbon Injection (ACI)	Mercury, Arsenic, Chromium, Selenium, Dioxin and other gas-phase organic carbon-based compounds	Powdered activated carbon (similar to charcoal) is blown into the flue gas after combustion, pollutants are absorbed by carbon and removed by PM controls	58 (13%)
Notes: The total number of coal-fired plants (447) and the number using each type of control technology was obtained by merging information from the U.S. Environmental Protection Agency Clean Air Markets Database (USEPA 2009b), USDOE, 2009b, and USEPA, 2010d.			

A notable aspect of the information in Table 6 is that some of the technologies that are effective for control of HAP emissions from coal-fired power plants are also effective at controlling emissions of non-HAP air pollutants such as sulfur dioxide and particulate matter (referred to as *Collateral Pollutants* in the table). As described below, control of criteria air pollutants as a collateral benefit of reducing emissions of HAPs would be an important public health benefit of the Utility Air Toxics Rule.

Coal, especially some bituminous coals can have significant chlorine content, which contributes to hydrogen chloride emissions when this type of coal is burned (Staudt, 2010). Electric utility boilers that fire bituminous coal comprise roughly half of the coal-fired electric generating capacity of the U.S. Many of these facilities are equipped with wet scrubbers that are highly efficient at capturing hydrogen chloride and other acid gases (e.g., hydrofluoric acid). However, a large number of bituminous fueled units are not equipped with scrubbers—having only particulate controls, and could need acid gas controls to meet emission limits set under the Utility Air Toxics rules.

In order to meet the emission standards for hydrogen chloride and hydrogen fluoride, some of the uncontrolled facilities may choose to install wet or dry scrubbers, also known as flue gas desulfurization. Wet scrubbers are more efficient at removing acid gases, but they are more costly than dry scrubbers. Modern wet scrubbers typically reduce sulfur dioxide emissions by about 98%, have higher capture rates for hydrogen chloride, and reduce emissions of primary PM as well. Reduction of primary PM is supported by data in USEPA's Information Collection Request on bituminous coal units equipped with an electrostatic precipitator (ESP) (USEPA, 2010a).

A review of these data showed significant reductions in condensable particulate emissions when comparing the average emissions of units with wet flue gas desulfurization versus those without it, as shown in Table 7. Condensable particulate matter consists of substances, such as many metals, that are a vapor in the hottest portions of an exhaust stack, but rapidly condense to form primary PM. These results are based upon relatively small data sets and may not be representative for all facilities, but the data show a large reduction in condensable PM from the use of this technology.

Table 7. Comparison of Average Emission Rate of Condensable Particulate Matter for Bituminous Coal Facilities With and Without Wet Flue Gas Desulfurization ("Scrubbers")

Emission Rate, pounds per million British Thermal Units			
Control Device	Without Wet Scrubbers	With Wet Scrubbers	Percent Reduction
Electrostatic Precipitators	0.041*	0.009	78%

Source: EPA, 2010a. *These data included units with selective catalytic reduction, which would increase condensable particulate matter somewhat, but typically not more than doubling it.

Because of the cost of wet scrubbers (and to a lesser extent, dry scrubbers), other technologies are likely to be deployed for hydrogen chloride capture from unscrubbed bituminous coal fired boilers. Many unscrubbed facilities may install dry sorbent injection, which is much less expensive to install than a wet scrubber. Dry sorbent injection offers the ability to reduce both hydrogen chloride and sulfur oxides, but is generally less effective at removal of sulfur dioxide than the more costly wet or dry scrubbers.

At one facility, hydrogen chloride and sulfur dioxide were removed using dry sorbent injection with both a baghouse (i.e., fabric filter) and an ESP for particle collection (Davidson, 2010). This study showed that the unit with an ESP, the most commonly used PM control device on power plants, removed 95% of the hydrogen chloride and 50% of the sulfur dioxide. At the Mirant Potomac River Power Plant, equipped with dry sorbent injection and an ESP, roughly 98% of hydrogen chloride and greater than 70% of sulfur dioxide were captured (Kong, 2008). A review of power plant data showed significant reductions in condensable PM emissions when comparing the average emissions of units with dry sorbent injection versus those without, as shown in Table 8. As before, these results are based upon relatively small data sets and may not be representative for all facilities, but the data show large reductions in condensable PM from the use of this technology.

Table 8. Comparison of Average Emission Rate of Condensable Particulate Matter from Facilities With and Without Dry Sorbent Injection (DSI)

Emission Rate, pounds per million British Thermal Units			
PM Control Device	Without DSI	With DSI	Percent Reduction
Electrostatic Precipitators**	0.041*	0.007	83%
Fabric Filters***	0.028*	0.003	91%

Source: USEPA, 2010a. *These data included units with selective catalytic reduction, that would increase condensable particulate matter somewhat, but typically not more than doubling it. ** Bituminous coal *** Powder River Basin coal

Regardless of whether scrubbers or dry sorbent injection is selected, the Utility Air Toxics Rule standards are expected to reduce aggregate emissions of hydrogen chloride and hydrogen fluoride from coal-fired power plants. Because of the physical and chemical properties of the available control technologies, the measures taken to reduce HAP acid gases are also anticipated to lower emissions of condensable PM and sulfur dioxide. These collateral benefits are important because condensable PM and secondary PM formed from sulfur dioxide comprise the majority of fine particulate matter in most areas of the United States.

The public health benefits of additional PM and sulfur dioxide controls could be substantial. The potential value of collateral benefits from the Utility Air Toxics Rule is indicated EPA's recent Regulatory Impact Analysis for MACT on industrial boilers (USEPA 2011a). In that analysis, EPA estimated that public health benefits of at least $22 billion to $54 billion would be achieved by MACT controls on industrial boilers. In comparison, the costs of controls were estimated to be $1.4 billion. EPA attributed over 90% of the public health benefit to reductions in sulfur dioxide emissions, presumably achieved as a by-product of acid gas controls on those boilers. With a benefit-cost ratio of at least 16 to 1, the public health and economic value of controlling acid gas emissions from those boilers is clear. Although not quantified directly, technologies that control acid gas emissions may also reduce emissions of hazardous metals like mercury and selenium, which are not as effectively controlled by conventional particle technologies. (USEPA, 2010).

While there has been some debate over whether collateral benefits can be considered in rulemaking for HAPs, the Clean Air Act states that EPA is authorized to consider the collateral benefits of controlling sulfur dioxide and other criteria pollutants when establishing National Emission Standards for Hazardous Air Pollutants. This aspect of the law was recently affirmed. After consideration of extensive public comments on this subject EPA concluded it knows of "no principle in law or common sense" that precludes the Agency from considering collateral environmental benefits when acting to regulate HAP emissions under the Clean Air Act (USEPA 2011b).

6.0 CONCLUSIONS

The U.S. Environmental Protection Agency (EPA) will propose new limits on emissions of selected hazardous substances to the atmosphere from utilities that burn coal and other fossil fuels. The proposal will set new limits on emissions of hazardous air pollutants, 187 chemicals identified by EPA according to criteria established by Congress. This is the first time that emissions limits for HAPs will be required on all medium and large-scale power plants. The new limits are to be based on emission rates that can be achieved by the use of maximum available control technology, referred to as MACT. The set of regulations and impending limits for electric generating stations is known as the *Utility Air Toxics Rule*.

Environmental Health & Engineering, Inc. was retained by the American Lung Association to prepare a summary of hazardous air pollutant emissions from coal-fired power plants that would be a useful resource for the general public. The major conclusions of the summary are as follows:

- Hazardous air pollutants emitted to the atmosphere by coal-fired power plants cause a wide range of adverse health effects including damage to eyes, skin, and breathing passages; negative effects on the kidneys, lungs, and nervous system; increasing the risk of cancer; impairment of neurological function and ability to learn; and pulmonary and cardiovascular disease.

- Exhaust gases discharged to the air by coal-fired power plants are reported to contain 84 of the 187 hazardous air pollutants identified by EPA.

- With total emissions of 386,000 tons of HAPs annually, coal-fired power plants account for 40% of all hazardous air pollutant releases from point sources to the atmosphere, more than any other point source category.

- Hazardous air pollutants released from coal-fired power plants influence environmental quality and health on local, regional, and continental scales.

- Public health risks of exposure to mercury in food and metals in airborne fine particulate matter are among the most notable health and environmental impacts associated with emissions of hazardous air pollutants from coal-fired power plants.

- Hazardous air pollutant emissions from a sample of coal-fired power plants selected because of their use of multiple control technologies were 2 to 5 times lower on average than from a random sample of plants selected by EPA.

- Controls on acid gas and non-mercury metal emissions are likely to reduce emissions of sulfur dioxide and primary particulate matter. As a result, controlling hazardous air pollutant emissions is expected to generate substantial public health and environmental benefits.

- Use of more effective control technologies by more coal-fired power plants as a result of the Utility Air Toxics Rule is expected to reduce the public health and environmental impacts of electricity generated by combustion of coal.

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EXHIBIT 53

UNITED STATES OF AMERICA
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order TransAlta Centralia Generation	Order No. 202-25-11

DECLARATION OF BRIAN RYBARIK
IN SUPPORT OF
MOTION TO INTERVENE, REQUEST FOR REHEARING,
AND MOTION TO STAY BY STATE OF WASHINGTON

I, Brian Rybarik, declare under penalty of perjury under the laws of the state of Washington that the following is true and correct:

1. I am now and at all times mentioned have been a citizen of the United States, over the age of 18 years, competent to make this declaration, and I make this declaration from my own personal knowledge and judgment. The statements contained herein are my own and not binding on the Washington Utilities and Transportation Commission in any future proceeding.

2. I am employed by the Washington Utilities and Transportation Commission (Commission) as the Chair of the Commission (Chair). The Commission is the regulator responsible for overseeing many of the state's private utilities, including all of the investor-owned electric and gas utilities. As Chair, I work with the other Commissioners and the UTC staff to set the state's regulatory priorities, guide major decisions on rate cases and represent the Commission in state and regional energy and infrastructure policy decisions. Prior to joining the Commission in 2025, I've spent over 20 years working on utility issues for both public and private entities, as well as working on sustainability and supply chain issues for a large technology company. I have a

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Bachelor of Arts Degree and a Law Degree from the University of Wisconsin – Madison. I am an attorney licensed to practice in the states of Wisconsin and Iowa.

3. I have reviewed the U.S. Department of Energy's Order No. 202-25-11 (Ex. 1). concerning continued operation of TransAlta's Centralia Unit 2 (Plant) beyond its planned retirement date of December 31, 2025, and provide the following testimony about resource adequacy in the State of Washington.

4. The Commission's mission, based on our statutory duties, includes regulating utilities to provide safe, equitable, available, reliable, and fairly priced services. For electric utilities, the Commission is engaged on resources adequacy (e.g. requiring available and reliable service) for the state's utilities and the region in a number of ways. This includes the Commission's work on Integrated Resource Plans (IRP), Clean Energy Action Plans (CEAP), Clean Energy Implementation Plans (CEIP), Biennial Conservation Plans (BCP), Transportation Electrification Plans (TEP), Integrated System Plans (ISP) and Requests for Proposals (RFP) that are filed by the state's investor-owned electric utilities. These plans outline the utilities' plans to meet their future resource needs consistent with state law. The plans are reviewed extensively by the Commission.

5. The Commission also follows resource adequacy issues pursuant to the requirements of Revised Code of Washington 19.280.065, which requires the Commission and the Washington Department of Commerce to hold at least one resource adequacy meeting every year to bring stakeholders together to address summer and winter readiness, regional planning, weather and hydropower forecasts, and wildfire and extreme weather readiness. Recognizing the importance of this issue to the citizens of Washington, the Commission now holds three meetings per year to specifically address: (1) summer readiness; (2) winter readiness; and (3) long-term resource adequacy.

6. During the resource adequacy meetings, the Commission learns from industry experts from our utilities, regional planning organizations, transmission operators, reliability

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experts, and the public. We report our learnings and findings to the Governor pursuant to the statutory requirements.

7. Given my industry experience, my review of the various plans filed with and acknowledged by the Commission, as well as through my role participating in the Commission's various resource adequacy meetings, I do not find that the DOE Order's conclusion that an energy emergency exists in the coming winter months credible, nor do I agree that the action under the DOE Order (keeping the Centralia coal plant available) will assist in solving the unlikely extreme conditions that could lead to an energy emergency.

8. As the Chair of the Commission, it is my view that all Washington investor-owned utilities (IOUs) have identified plans to meet their near and long-term resource adequacy requirements. For well over a decade, those plans all assumed and prepared for the retirement of the Centralia coal plant. To meet the future needs of their customers, Washington IOUs are actively developing or pursuing through contract the resources that will meet the needs of their customers. Additionally, Washington IOUs are engaged in processes to increase resource sharing across the region, including the Western Resource Adequacy Program (WRAP). The Commission is closely following the developments of WRAP as part of the Committee of State Representatives, a standing committee of the WRAP.

9. Meeting resource adequacy requirements includes the expansion of wind, solar, and energy storage resources to help the utilities meet both reliability and clean energy requirements under state law. Ensuring that clean energy is expanded while protecting reliability also includes the use of natural gas generation in the near-term, as evidenced by the Commission's recent orders approving rate recovery of Puget Sound Energy's tolling agreement for the Grey's Harbor Energy Center and the approval of PacifiCorp's new 2026 cost allocation protocol, which attributes 100% of the Chehalis natural gas plant to Washington.

10. Through the Commission's work on resource adequacy, we are aware that reserve margins are tightening and risks under extreme circumstances are increasing. However, the

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extreme circumstances that could result in loss of electric load remain highly unlikely, particularly in the current season given the recent high rainfall recharging hydro capacity. The DOE Order will not decrease any existing extreme risks and is highly unlikely to have any positive impact on resource adequacy in the near term.

11. As explained further by Commission staffer Joel Nightingale in his declaration, I agree with the conclusion that the DOE Order misrepresents or misunderstands the North American Electric Reliability Corporation's (NERC) Winter Reliability Assessment (WRA) for 2025-2026. While the report notes a heightened risk under extreme conditions, the assessment does not identify any expected unserved energy or loss of load hours for this winter.

12. The DOE Order also cites a slide deck from Energy + Environmental Economics (E3) as identifying an "emergency." This slide deck was presented to the Commission at its winter resource adequacy meeting. The analysis performed by E3 identifies resource adequacy concerns and is primarily focused on potential issues in 2030 if load growth expands and resource additions continue at their current pace. The study does not point to a near-term risk, nor does it identify coal plants like the Centralia plant as a part of the solution set to meet the resource adequacy needs of the region. The focus of the report appears to be the opportunities for demand response, battery storage, and natural gas to meet the resource adequacy needs of the region.

13. I conclude that the region and the state's IOUs are well positioned this winter to meet the needs of customers under normal and even extreme conditions such that no energy emergency exists to justify the DOE Order.

DATED this 13th day of January, in Lacey, Washington.

BRIAN RYBARIK

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EXHIBIT 54

DECLARED DECEMBER 12, 2025

SUMMARY

STATE: Washington

NUMBER: FEMA-3629-EM

INCIDENT: Severe Storms, Straight-line Winds, Flooding, Landslides, and Mudslides

INCIDENT PERIOD: December 9, 2025, and continuing

DATE REQUESTED BY GOVERNOR: December 10, 2025

FEDERAL COORDINATING OFFICER: John Harrison
National FCO Program

DESIGNATIONS AND TYPES OF ASSISTANCE:

The Department of Homeland Security, Federal Emergency Management Agency (FEMA), is authorized to provide appropriate assistance for required emergency measures, authorized under Title V of the Stafford Act, to save lives and to protect property and public health and safety, or to lessen or avert the threat of a catastrophe in the designated areas. Specifically, FEMA is authorized to provide emergency protective measures (Category B), limited to direct federal assistance, under the Public Assistance program at 75 percent federal funding.

This assistance is for Benton, Chelan, Clallam, Grays Harbor, Jefferson, King, Kittitas, Lewis, Mason, Pierce, Skagit, Snohomish, Thurston, Wahkiakum, Whatcom, and Yakima Counties, the Samish Indian Nation, and all Tribal Nations within the specified jurisdictions.

OTHER: Additional designations may be made at a later date if requested by the state and warranted by the results of further evaluation.

Note: This is an emergency declaration.

EXHIBIT 55

NOVEMBER 2024

REVISED
DECEMBER 6, 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

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The report was released November 2024. The report was then rereleased December 6th, 2024, with an updated name for Best Practice 47.

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Acknowledgments

The U.S. Department of Energy (DOE) Office of Electricity provided funding for Lawrence Berkeley National Laboratory's work described in this study, and partial funding for Synapse Energy Economics' contributions, under Contract No. DE-AC02-05CH11231. The Energy Foundation provided partial funding for Synapse Energy Economics.

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The authors thank Joe Paladino, U.S. Department of Energy (DOE) Office of Electricity, for supporting Lawrence Berkeley National Laboratory's contributions to this guide and partially funding contributions by Synapse Energy Economics. We also thank the following individuals for reviewing a draft of the guide. Individuals and affiliations are listed for identification purposes only. Participation as a reviewer does not indicate support for this document in whole or in part.

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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 other types of planning
- **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

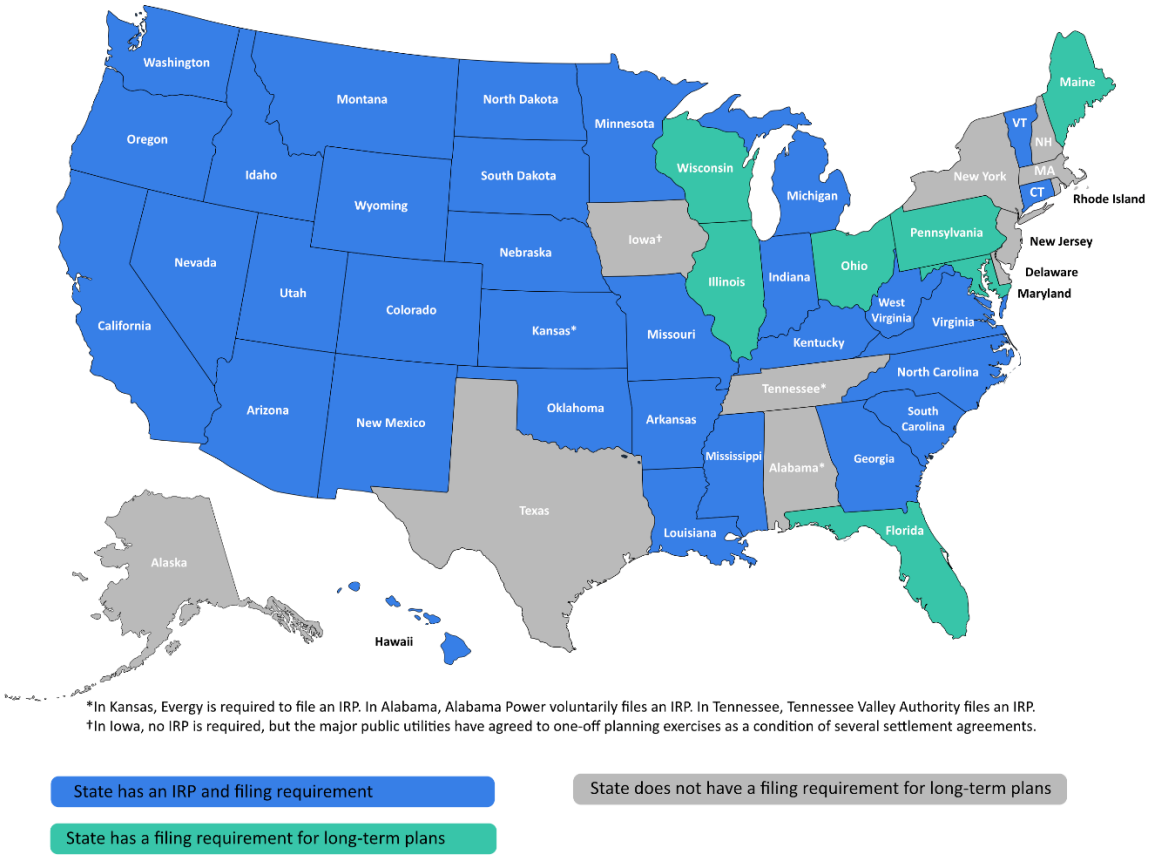
Well-planned resource investment decisions can maintain reliable, resilient electricity service and affordable utility bills for customers while minimizing negative societal impacts and enabling transformation of the energy system to meet future needs.

[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 2021b). 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.

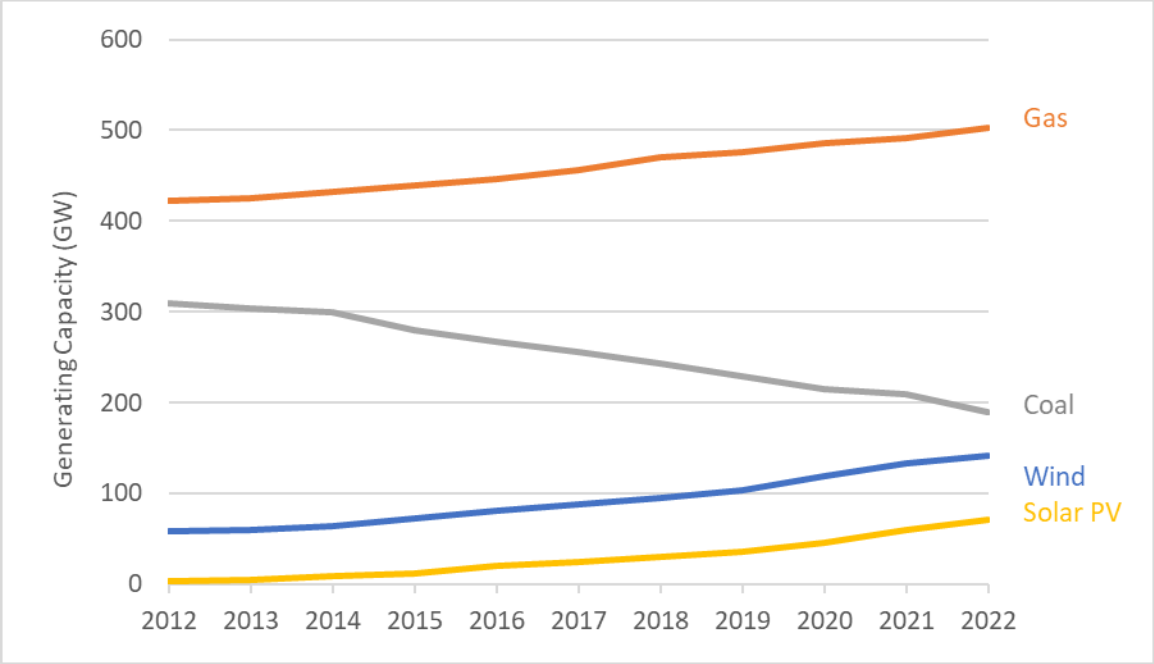
Thoughtful planning supports investments in electricity systems that are resilient, robust, and meet future needs.

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.

[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 2024b).

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 2023a) 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.

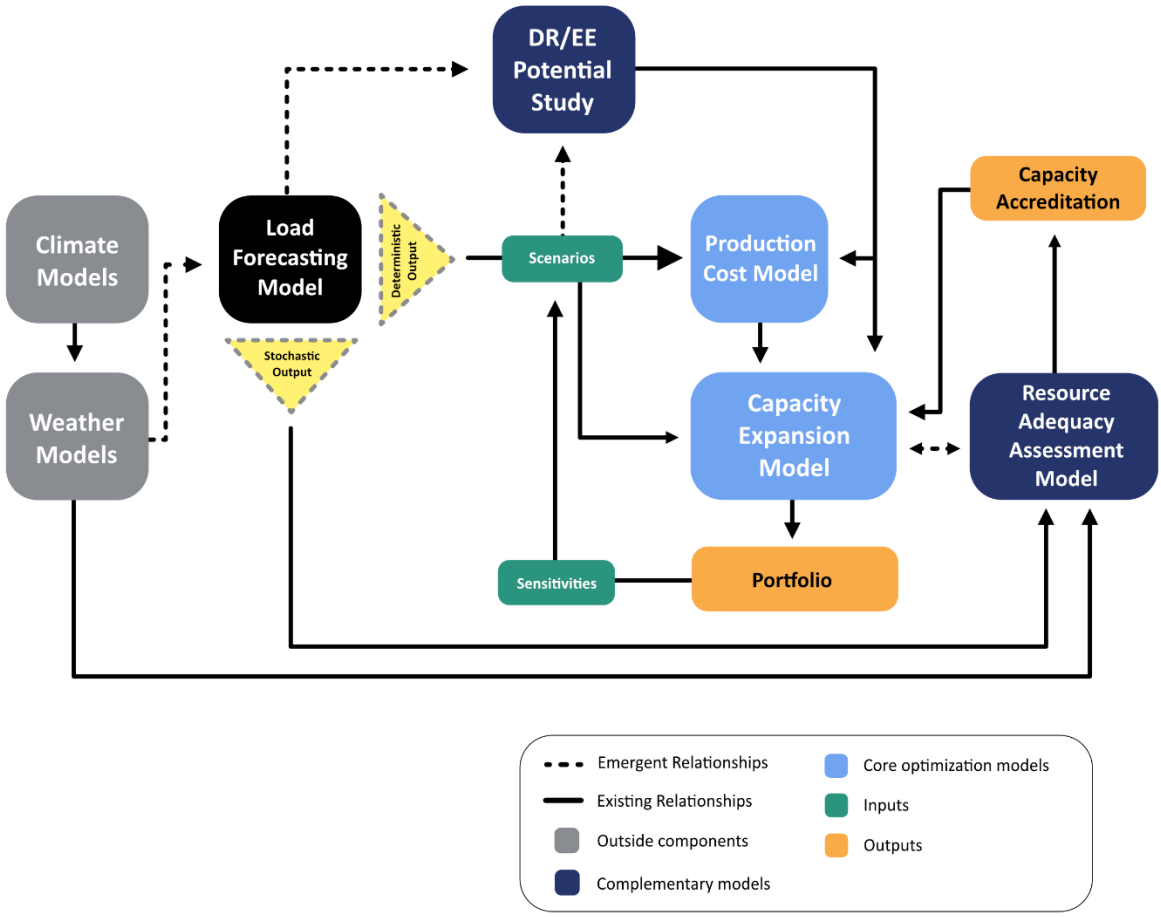
Thoughtful and robust long-term planning is needed more than ever. In this moment of rapid, widespread changes affecting both supply- and demand-side resources, the planning tools and strategies of the past do not match the scale and pace of today's needs. Emerging best planning practices can help tackle 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.

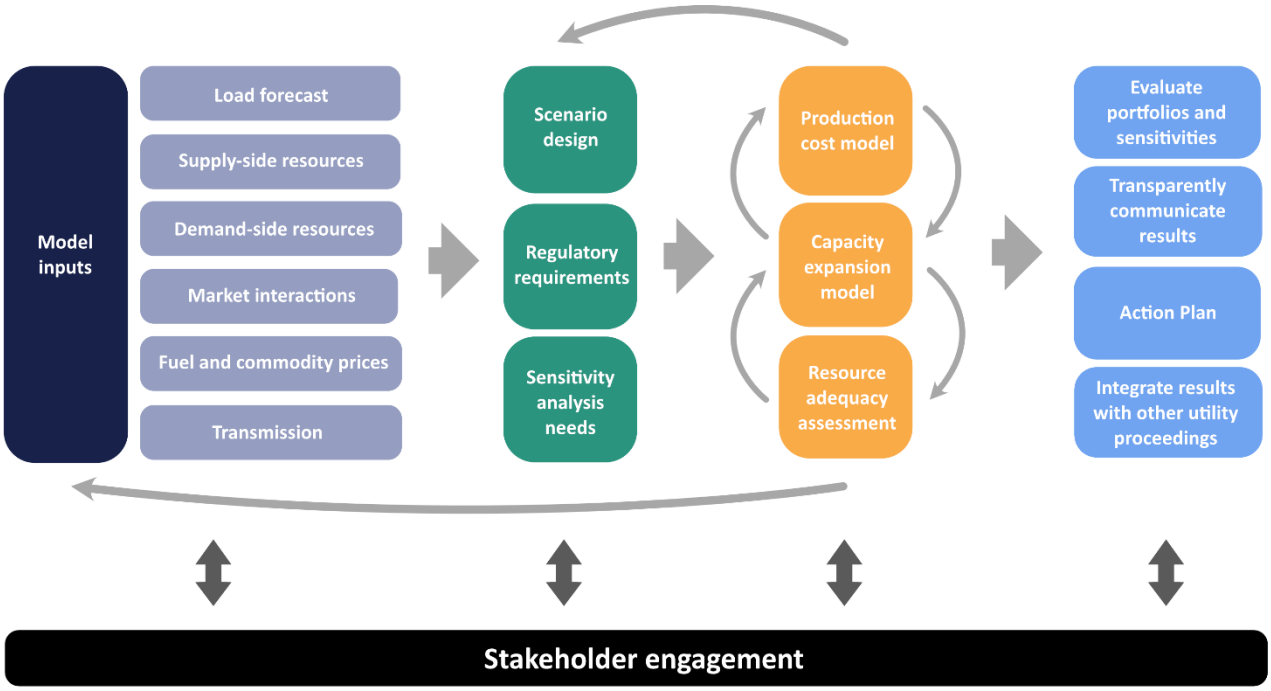
At its core, capacity expansion and production cost modeling are about minimizing system costs subject to constraints. The extent to which a modeler allows the model to optimize, and the information the modeler feeds the model for that purpose, are critical for achieving useful IRP results.

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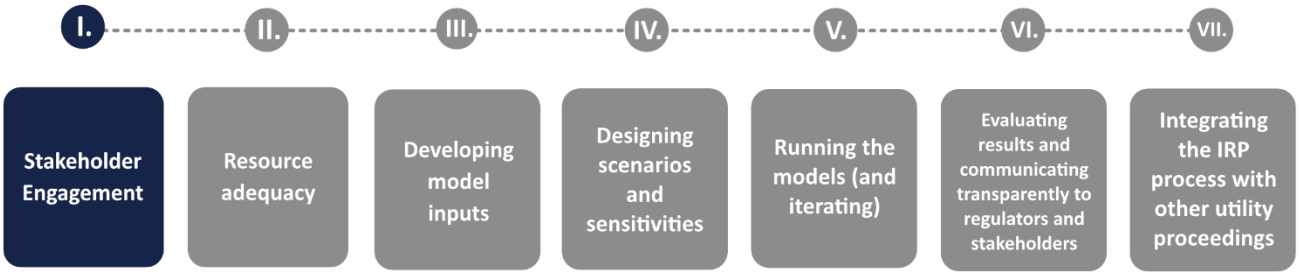
Overview of Report

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.

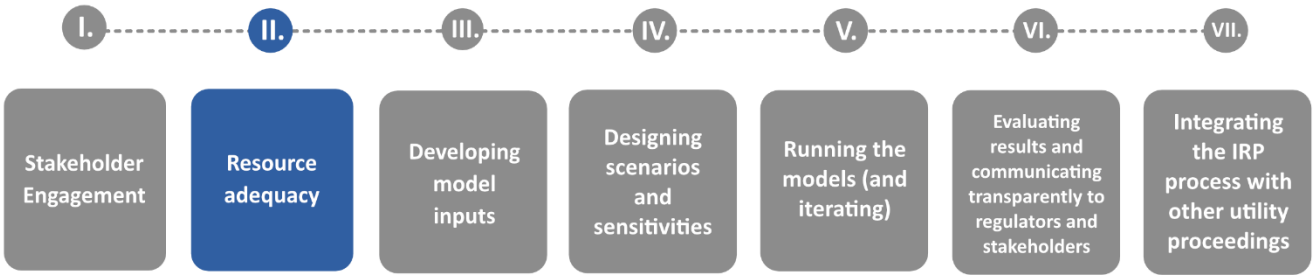
Definition: Effective load-carrying capability

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 2022a). 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



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.

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 2021c). 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.

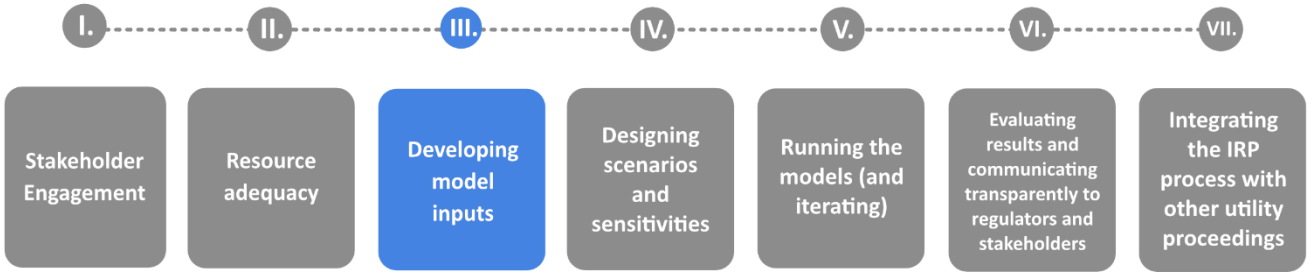
Utilities operating outside RTO/ISO regions, such as those that operate in the Southeast and Western United States, can capture regional benefits by modeling their utility footprint within the larger region in which they operate. This can include reasonable assumptions around the role of market transactions (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 2024a). 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.-c) 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

policies. A current best practice is to make clear assumptions about the regulatory and policy environment, and to develop a sensitivity analysis if a key regulatory or policy condition may change during the planning horizon (see Best Practice 30). An emerging best practice is to consider how distributed resource operation could be influenced if these resources are aggregated under virtual power plants, as Portland General Electric did in its 2023 IRP. Substantial growth of behind-the-meter storage will likely enhance rooftop solar economics amidst changes in net metering regulations, as well as provide resilience and reliability benefits (LBNL 2023d).

The consideration of avoided costs for customer- or utility-owned distributed resources is generally a matter of statute, even though it is technically adequate to recognize the upstream benefits from these resources where the models do not.[19] The analysis can consider avoided costs of transmission, distribution, and environmental and internalize them in the overall system costs. For example, Arizona Public Service's 2023 IRP included a market potential study that produced and internalized avoided costs of energy efficiency measures, which can be extended to other types of distributed resources (APS 2023).

The current practice of treating distributed generation and storage as load modifiers suffers some of the same issues as the traditional treatment of energy efficiency, demand response, and other distributed energy resources (see Best Practice 19 through Best Practice 22). In particular, conflating load and distributed resources for resource adequacy assessments introduces distortions due to the inherent differences in risk and uncertainty profiles. While using net load may be fine for lower penetrations of distributed energy resources, emerging best practice would require separately modeling distributed generation and storage from load in resource adequacy assessments.

[19] Capacity expansion models would typically internalize capacity and energy benefits of distributed energy resources when considered both as a load modifier or competitive resource, since they displace capacity and energy needs from supply-side resources.

Best Practice 12. Use accurate assumptions for the costs of new resources

Use accurate cost assumptions for new resources that reflect current market data and include all relevant programs and incentives.

The cost to procure new resources changes constantly. The most accurate way to develop present-day cost expectations for most resources is through real market data obtained directly from project developers or through competitive, all-source requests for proposals (RFP). This data reveals actual procurement costs at a specific place and time. These costs can be sense-checked against cost estimates in the best-available public resources, such as the NREL's Annual Technology Baseline, U.S. Energy Information Administration's (EIA) Annual Energy Outlook, and EPRI's Generation Technology Options Report, or proprietary data from industry sources such as Black and Veatch, Wood Mackenzie, and others (NREL ATB 2024; U.S. EIA AEO 2023a; EPRI 2024b). In Colorado, utilities such as Public Service of Colorado use both generic cost assumptions and market data. First, they develop their IRP models using generic cost assumptions. Once the model is approved by the commission, they use the model to evaluate bids from a competitive RFP (PSCo 2021). This allows the utility to see what resources the IRP model selects directionally using public industry sources, and then to use actual cost data to select specific projects.

If RFP results are out of line with expectations based on public and industry sources, utilities can conduct supplemental analysis to better understand and explain the source of the deviation. This can be particularly important during times when market disruptions occur, such as the supply chain challenges and inflation resulting from the COVID-19 pandemic. For its current 2025 IRP cycle, Puget Sound Energy hired Black and Veatch to develop cost assumptions for its IRP based on the consultant's experience as a project developer. The utility shared the study through its Resource Planning Advisory Group. As part of the study Black and Veatch will compare the cost assumptions it developed for Puget Sound Energy to those published by NREL in its Annual Technology Baseline and account for any major deviations (PSE n.d.).

Future cost trajectories are best developed based on technology maturity curves, such as those used by NREL and EIA, rather than adopting existing simplifying assumptions. Such assumptions may seem impartial, but they can skew results for or against specific resource types. Best practice is to avoid using simplifying assumptions when not supported or justified by research or analysis. For example, reliance on flat cost trajectories for all resource types when there is uncertainty about how resource costs will change in the future is not a neutral assumption. It results in bias in favor of mature generation resources with minimal additional cost declines expected, such as gas plants, and against newer

The most accurate way to develop present-day cost expectations for most resources is through real market data obtained directly from project developers or through competitive, all-source requests for proposals.

resources with larger technological advancement and cost declines expected in the future, such as solar PV, wind, and BESS.

Additionally, new resource cost assumptions will be most accurate and useful if they are developed to incorporate all relevant and up-to-date tax and program incentives as well as any other relevant funding that are likely to affect a resource's cost. Beyond correctly modeling all credits and incentives that are available for new generic and specifically planned resources, utilities can use the availability of credits and incentives to drive project selection and placement. It may be appropriate to model location-specific new resources rather than view all new resources as generic.

The IRA, in particular, changed the cost landscape for wind, solar, biomass, geothermal, battery energy storge, CCS, and hydrogen. Under the IRA, facilities generating energy from these resources are eligible for either a production tax credit based on their generation or an investment tax credit based on their size. Added bonus tax credits are available for solar and wind facilities located in energy communities and that use domestically manufactured materials. Nuclear plants and advanced energy projects can also receive tax credits through the IRA (White House, n.d.). The cost implications of these and other features of the IRA merit consideration when developing IRP inputs, including all potential bonus adders (RMI 2024b) and bonus tax credits available from siting new resources at the site of a retired or retiring fossil plant.

Best Practice 13. Represent the full cost and risk of advanced technologies

Ensure the model reflects and captures the full range of costs and risks associated with advanced technologies.

In the case of new or particularly complex technologies that are not commercially available, there may be no market data on which to rely, and annual studies from NREL or the EIA may have limited cost data. This is especially important as utilities consider advanced decarbonization solutions such as CCS, carbon capture utilization and sequestration (CCUS), advanced and small nuclear reactors, long-duration battery storage, and conversion of natural gas plants to fire or co-fire with hydrogen. While pilot projects may provide useful data points, such projects are by their nature not in the commercial stage. Therefore, planners will want to use cost and performance data cautiously and account for differences between the pilot and the planned or modeled project.

Megaprojects, especially those that rely on new technology, require special attention for cost estimation and sensitivities. History has shown that such projects are prone to dramatic cost overruns and rate impacts for utility customers (Rand 1988). The larger and more complex a project, the greater the likelihood that it will experience extreme cost growth (Rand 2017). Care must be taken to model the potential for greater risk with large projects and uncertainty with new and untested technology. The examples below from Mississippi (Schlissel 2009; Amy 2018) and Georgia (U.S. DOE 2023b) illustrate some potential issues.

Advanced Technology Example: Kemper County Coal Internal Gasification Combined Cycle (IGCC) Megaproject

The Kemper County IGCC project was intended to combine a new coal gasification plant with carbon capture and storage. When Mississippi Power Company sought a Certificate of Public Convenience and Necessity for the project in 2009, it estimated that the first-of-its-kind plant would cost $2.1 billion. There were warning signs at the time that costs were likely to increase. None of the estimates in the company's filing were subject to cost caps, few of the vendors for parts had been selected, and detailed design for the project had not yet begun. The cost to build traditional coal units at the time had already been trending upward for years. One intervenor in the 2009 regulatory docket recommended modeling sensitivities that increased costs 20 to 40 percent. Even these recommendations underestimated how much costs would rise. By 2018, the carbon capture portion of the project had been canceled, and the capital cost of the project had reached $7.5 billion. Customer rates had been 15 percent higher for 2 years, and after years of debate and testimony, utility regulators approved a settlement that required utility investors to absorb about $6.4 billion of the cost. "The economics really didn't work out and the technology was hard to perfect," the Mississippi Power CEO stated after the settlement.

In general, larger expected capital expenses warrant more careful review. Including a worst-case cost scenario informed by data and outcomes from other recent and relevant projects as an IRP sensitivity is good practice. This might take the form of a cost sensitivity that is plus or minus 20 or 50 percent, or even 100 percent, depending on the order of magnitude of cost ranges available from pilot projects, studies, or other uses of the technology. Such a scenario allows utilities and commissions to weigh and understand the costs and risks of the new technology against the likely much narrower bands of uncertainty and risk associated with commercially available alternatives to determine what cost range would make a technology cost-effective and worth the risk.

Advanced Technology Example: Georgia's Vogtle Nuclear Plant Megaproject

In 2009, at the start of site construction, Vogtle nuclear plant's Unit 3 and Unit 4 project in Georgia was expected to cost $13 billion. By June 2022, the project cost had increased to over $32 billion. According to the DOE, almost all of the overrun was attributable to four factors in the cost of construction: the need to redo improperly executed work along the way, supply chain delays, low labor productivity, and worker attrition. These issues are not necessarily unique to building nuclear power plants. Although they may be difficult to predict, greater contingency planning is needed to properly parameterize the cost of a project this size. Regarding nuclear projects specifically, the DOE's "Pathways to Commercial Liftoff" report on nuclear sets a plus-or-minus 20 percent threshold in estimating project costs as an aspirational goal for coming in on budget for future nuclear, indicating high cost uncertainty (U.S. DOE 2023b).

Best Practice 14. Include realistic assumptions about resource availability timing, without unnecessary constraints

Understand limits and constraints on timing and schedule for new resource construction without unnecessarily constraining resource builds.

In addition to developing accurate capital cost assumptions for new generation resources (discussed in Best Practice 12), robust IRP capacity expansion modeling includes factors related to timing of construction. These include the risk of construction delays due to siting and permitting, local opposition, the interconnection queue, and supply chain constraints. Utilities must carefully balance between letting optimization models optimize and imposing constraints to reflect real-world construction and interconnection bottlenecks. The best way to address this tension is to model scenarios with and without supply constraints and vary constraints over time to reflect realistic expectations about factors that will impact future resource availability.

Scenarios without constraints provide valuable information on the economically optimal solution and provide directions to the market on what the utility may be looking to procure. A more constrained scenario informs the utility about alternative options if it cannot overcome near-term supply constraints. Scenarios with static and unchanging constraints (for example, an annual build limit of 300 MW for a specific resource type for the entire study period) may be less useful than scenarios that vary constraints over time to reflect potential changing market conditions.

Supply chain issues following the COVID-19 pandemic, as well as constraints in labor availability (especially for specialized labor), demonstrate the importance of planning for risks and uncertainties related to labor and materials availability and delays. Public Service Company of New Mexico and El Paso Electric, for example, renegotiated multiple supply agreements for solar resources due to COVID-19-related supply chain challenges (PNM 2023). Although issues stemming from the pandemic have gradually improved, they have affected planning across consecutive IRPs. To incorporate delays such as these, planners either run sensitivities that deterministically alter new resource builds to reflect expected conditions or, in the case of supply chain constraints, treat them as annual, maximum build limits. DTE Energy's 2022 IRP implemented annual build limits for all resources, including renewable energy resources, citing challenges with the items mentioned above as well as recent RFP experience (DTE 2022). While the utility included these constraints throughout the study period, the IRP states that "The Company is expecting to build on these advancements and efficiencies learned through the execution of the first several years of projects, thus, the annual MW limit increased over time" (DTE 2022, 102).

While ongoing interconnection reform efforts aim to address delays in resources coming online, current and potential future interconnection-related delays are still factors to address in IRPs. Utilities can demonstrate to regulators and stakeholders that an adequate amount of new generation planned in the near term will be able to interconnect in time and provide a contingency plan. One approach to interconnection-related uncertainty is to be more proactive with resource procurement (PA Consulting 2023). For example, if IRP modeling shows it is economically optimal to add 500 MW of new solar by 2028, the utility can issue an RFP ahead of need for that amount and timing, as well as additional levels

and potentially earlier timelines. Evaluation of bids at levels in excess of the targeted amount is useful for addressing longer-term needs.

At the same time, processes and policies designed to hasten interconnection, such as surplus interconnection and generator replacement,[20] are worth exploring to understand cost and time implications of using existing interconnection rights to bring additional resources online. Using existing interconnections can help achieve economies of scale and accelerate deployment timelines. Utilities are increasingly seeing the benefits of considering existing interconnection rights in resource planning. Xcel Energy, Otter Tail Power Company, and Great River Energy in Minnesota, for example, have all planned or executed projects using existing interconnection rights in their jurisdictions (Xcel Energy 2023; Otter Tail 2021; Great River Energy 2021). All three utilities are transparent about the cost and timing benefits of such projects. Otter Tail sees "the transmission queue for new interconnection of wind as a significant hurdle to introducing new wind resources outside of utilizing surplus interconnection at existing plants (Otter Tail 2021, 65)". Xcel Energy states, "By using existing grid connections, we're able to provide customers with carbon-free energy in the most efficient and cost-effective way" (Xcel Energy 2023). Great River Energy likewise states, "Use of the existing [generator interconnection agreements] is beneficial for our membership as we receive more advantageously priced wind in our portfolio as a valuable hedge while avoiding significant costs, resulting in a net benefit to our members" (Great River Energy 2021, 1).

Best Practice 15. Limit renewable integration cost adders

Study and fully justify all integration cost adders applied to new renewable energy resources.

As the penetration of renewable energy resources on the grid increases, utilities need a way to quantify and represent the grid services needed for balancing, such as transmission upgrades, regulation and reserves, voltage support, and real-time variability. Planners can capture some of these costs in capacity expansion and production cost models. Alternatively, utilities can develop renewable energy integration costs based on external studies and evaluate the impact of increased renewable energy deployment on the need for system-level upgrades and grid services.

Caution is needed when conducting and evaluating these studies. First, the results are highly dependent on the resource plan modeled and are often more reflective of the existing resource mix than the level of new renewable resources added. Santee Cooper's solar integration study modeled as part of its most 2023 IRP illustrates this challenge. The utility assumed that Winyah, a 1,260 MW coal-fired power plant, would not retire until 2031. Since many coal plants cannot ramp up and down quickly, modeling results indicated challenges (cycling, re-dispatch) with integrating a high penetration of solar resources until after 2030. After the plant retirement date and replacement with faster-ramping peaking resources, the cost of renewable energy integration dropped significantly. The utility used these findings to support its decision to delay the retirement of Winyah from 2028 to 2031. However, the study results did not

[20] Surplus interconnection refers to an unused part of an interconnection service. When a generator retires, if the holder of the interconnection service seeks to keep the service and install replacement resources, they can often do so without having to conduct a full interconnection study and wait in the interconnection queue.

support this finding—instead they showed that delaying Winyah's retirement was what was driving high solar integration costs. Santee Cooper did not evaluate integration costs under any earlier retirement scenarios, where Winyah would be replaced by more nimble resources such as gas combustion turbines or BESS.

Another area for caution is that the results are also often portfolio-specific; they are not wholly transferable across portfolios and scenarios that rely on different resource mixes. A utility would need to model integration costs across multiple resource portfolios to more accurately capture the grid impact of new resource additions. Modeling might double-count costs across the integration cost study and the capacity expansion modeling if the utility is not careful, especially where the study is conducted in isolation from the rest of the resource planning process. This can be avoided by syncing up the integration studies with the resource planning modeling and carefully tracking the services and costs that are quantified already in the production cost and capacity expansion modeling. Finally, system costs that would be incurred regardless may be attributed to renewables only. This can be avoided with robust modeling and transparent analysis.

Best Practice 16. Model all avoidable forward-going resource costs

Model all avoidable, forward-going costs for all existing resources, including coal and gas plants.

Appropriately modeling retirement of existing fossil fuel units requires accounting for all costs that are avoidable. That includes avoidable capital costs that would be included in the rate base, fixed O&M costs included in retail rates, and variable operating costs (including fuel and variable O&M expenses). While it is common for utilities to model fuel and other variable costs, utilities sometimes omit certain capital expenditures and fixed O&M from the model and instead address these costs in a post-processing step (or not at all).[21] If the model does not evaluate all avoidable costs, it does not factor them into retirement decisions. Modeling of avoidable costs can be coupled with modeling of unit retirements to fully evaluate the economics of continued reliance on existing resources, as discussed in Best Practice 37.

Generally, utilities develop capital expenditure schedules based on specific projects planned in the near term. Often these schedules only cover the next 3 to 5 years, with projected spending substantially dropping off beyond this period.[22] This approach regularly underestimates likely capital expenditures by ignoring spending more than a few years out, as well as spending associated with unplanned outages, non-routine expenditures, and uncertain future environmental regulations. The lumpiness and unit-specific nature of ongoing capital additions to power plants can be a challenge to represent in IRP modeling, but these costs can be substantial.

Modeling capital expenditures properly, including annual variations and unit-specific detail, is important to resource planning decisions such as whether and when to retire a power plant from service.

[21] For example, Santee Cooper did not enter projections of capital expenses for its coal plants in the EnCompass capacity expansion model. Instead, the utility included capital expenditure differences by portfolio in the final net present value power costs for portfolios that varied from others in terms of coal plant retirement dates (Public Service Commission of South Carolina Docket No. 2023-154-E, Santee Cooper Response to Sierra Club Data Request 1-8).

[22] This is based on some of the authors' experience reviewing projected unit cost data in numerous rate cases.

Additionally, environmental compliance costs are often large enough (in the tens to hundreds of millions of dollars range) to drive a power plant retirement decision. Even though there is uncertainty regarding which aging facility parts may break down, when, or the likelihood of environmental regulations to increase costs, unexpected costs are all but certain. Ignoring costs because of uncertainty in the exact amount or timing results in underestimates of future system costs. For example, in Tri-State's 2023 Electric Resource Plan (ERP) in Colorado, the company's original modeling did not account for future environmental compliance costs, particularly those related to the recent U.S. Environmental Protection Agency (EPA) greenhouse gas rule under Section 111. The settlement agreement in that case, which is currently before the state regulatory commission, would secure improved modeling that accounts for these costs (CO PUC 2023).

It is best practice for a utility to benchmark capital cost projections for a unit against its spending at the plant in recent years to evaluate whether future projections may deviate substantially from recent experience. Another option is to review and incorporate into the utility's analysis current or forward-looking industry average estimates, such as average annual values based on unit type, size, and age developed by engineering firm Sargent and Lundy. The EPA developed a unit-specific "life extension cost" for use in its own capacity expansion modeling that simulates a large, one-time sustaining capital cost investment incurred when units reach a certain age (U.S. EIA 2019; U.S. EPA 2023). If the utility's projections deviate substantially from both its own historical data and industry averages, best practice is to evaluate why and adjust forecasts for modeling—or justify the deviation in the IRP.

Another best practice is to develop a schedule of planned maintenance and capital expenditures based on a unit's retirement date that factors in a typical ramp-down in spending in the years just prior to retirement. Scenario modeling is the best approach, because programming a capacity expansion model to vary capital expenditures schedules based on a unit's retirement date can be tricky.

Best Practice 17. Model battery energy storage options

Model a variety of short- and long-duration battery storage options to capture the differential value each option can provide to the system.

Energy storage is a highly flexible resource with the potential to become ubiquitous in modern power systems as both a capacity resource and a grid resource. Storage is already playing an outsized role in near-term resource deployment (U.S. EIA 2024c). Typical current IRP modeling approaches may oversimplify aspects of the design, operation, and value of storage resources, missing their full value stack (RMI 2015a). Some utilities are demonstrating improved practices. AES Indiana, for example, evaluated the value of BESS as a capacity resource and for providing grid services. As a result, the utility deployed a 20 MW battery to provide primary frequency response, an important ancillary service (AES Indiana 2024). Robust IRPs will evolve to capture the reliability and resilience benefits of BESS, including for resource adequacy and ancillary services.

The value of storage as a flexibility resource is a function of the particular portfolio. The value changes as the portfolio and system needs change. For example, when a utility is short on flexible resources, lithium-ion batteries provide significant value to the system. But once the utility has sufficient sub-hourly

reserves, the value drops to the market value—that is, until the utility's system or demand changes again, and its demand for flexible reserves increases.

Overstating the value of various value streams risks adding the wrong kind of storage. While short-duration lithium-ion batteries may be well suited to provide an initial quantity of reserves, long-duration storage such as an iron-air battery may be a more cost-effective and efficient solution for longer-term back-up and reserves. Most utilities model at least one type of short-duration storage[23] in IRPs, most commonly 4-hour BESS. Other short-duration options, such as 2-hour and 8-hour BESS, offer different services and economics that may fit better with specific grid needs. A 2-hour BESS offers narrow peak services but is lower cost than a 4-hour BESS and may be a more economic option for meeting limited periods of need. An 8-hour BESS can provide power for longer periods of time but is more expensive than a 4-hour BESS. It is important to accurately model the costs and capabilities of multiple storage options to determine the duration(s) that are the best fit for the utility's system (EPRI 2023a).

Another value of storage is its ability to enhance power system resilience. Storage can be part of microgrid and fully islanded systems, and it can make the system less dependent on fuel delivery or weather-based performance in times of stress. The IRP framework rarely captures these unique aspects of storage value. At the very least, these benefits can be qualitatively considered in portfolio screening processes.

Looking Ahead: Internalize storage resilience benefits in modeling

An aspirational practice entails internalizing the resilience benefits of storage within IRP capacity expansion models. This would entail enabling capacity expansion models to represent the stochastic elements that underpin resilience valuation, as well as modeling microgrid formation and operation as a resilience strategy.

For long-duration storage, several technologies are in the early stages of development or commercialization. Technologies include mechanical, thermal, electrochemical, and chemical systems that discharge stored energy for at least 8 hours and up to 1,000 hours, depending on the technology. Even though these technologies are in a nascent stage of development, utilities can model them as part of a resource plan and rely on them as replacement resource options further out in the study period (beyond the next 5 years).

Long-duration storage can provide firm, dispatchable, zero-carbon capacity, which is a need many utilities have identified. Our review of 20 IRPs from 2023 and 2024 found that 12 included at least a discussion of long-duration storage technologies, and 8 included them as a resource option.[24] For example, Southwestern Public Service Company in New Mexico modeled several scenarios that relied on long-duration energy storage for its 2023 IRP (Xcel Energy New Mexico 2023).

To consider long-duration storage in IRP, utilities need data on various technologies and need to know how to model them. While long-duration storage is not yet represented in commonly used sources of

[23] Definitions for short- and long-duration storage vary. Some parties also use the term medium-duration storage. In this guide, we refer to short-duration as less than 8 hours and long-duration as 8 hours or longer.
[24] IRPs vary considerably in defining "long-duration," so interpreting this finding requires a fair degree of caution.

information on capital and operating costs of generation and storage resources, such as NREL's Annual Technology Baseline, utilities can use other publicly available data sources. One such source is McKinsey & Company's report, *Net-zero power: Long duration energy storage for a renewable grid* (McKinsey 2021). Utilities can also refer to other industry projections of capital and operating costs and parameters for long-duration storage technologies, issue a Request for Information from technology developers prior to IRP development, or use data from recent RFPs. As with solar, wind, and lithium-ion battery technologies, it is reasonable to assume a downward cost trajectory for BESS technologies associated with technological advancement and learnings, as well as resolution of supply chain challenges in future years.

Best Practice 18. Be consistent in treatment of emerging technologies

Model the costs, availability, and risks of emerging technologies in a consistent and unbiased manner.

Planners can model emerging supply-side technologies in IRPs despite uncertainty related to costs, procurement, and performance. As deployment of BESS, solar, and wind over the past decade has demonstrated, the cost to deploy emerging technologies can change quickly. Emerging technologies are likely to be part of a least-cost portfolio, especially in a decarbonized future. The challenge for planners is to ensure they evaluate emerging technologies consistently and to make informed, transparent decisions about which emerging technologies to include in capacity expansion modeling. Consistent, unbiased evaluation allows utilities to understand the cost and system impacts of particular technologies and clearly communicate to regulators and stakeholders the reasoning for technologies utilities included and omitted from resource plans for a given timeframe.

Examples of emerging supply-side technologies include small modular nuclear reactors, long-duration energy storage, hydrogen, and CCS, to name a few. A best practice is to evaluate emerging technologies for cost, availability, potential, deployment timing, and associated performance risks to both shareholders and utility customers. Portland General Electric's 2023 Clean Energy Plan/IRP (PGE 2023) includes a discussion of all of these technologies, among others, though not all were included in portfolio modeling. Other IRPs, such as the 2024 Xcel Upper Midwest IRP (Xcel Energy 2024), include emerging technologies in the capacity expansion model, though typically for limited sensitivity runs after the date by which they are expected to be commercially available. Evaluation of emerging technologies also may occur outside of IRP, in supplementary studies.

While available information varies by emerging technology, it is important that the IRP clearly discuss how the utility considered each technology and evaluated them fairly. It would be inappropriate for planners to include one resource type while omitting another without clear support, including the timing of its expected availability. For example, modeling for Santee Cooper's and Dominion Energy South Carolina's 2023 IRPs includes small modular reactors as supply-side resources as emerging resource options, but no others (Santee Cooper 2023; Dominion SC 2023). This choice effectively gives small modular reactors a privileged status among technologies that have yet to reach commercial viability and could bias results in favor of the reactors.

As a general rule, utility plans that rely on emerging technologies in the near term (e.g., 5–10 years in the future) draw substantial scrutiny and skepticism. Cleco Louisiana, for example, modeled the Madison coal plant installing CCS technology in 2028 in all scenarios for its 2021 IRP (Cleco 2023). CCS is not currently deployed by any electric utility in the United States.[25] While CCS is likely to be commercially available at some point in the future, it is not realistic to assume that any utility can economically deploy the technology within the next 5 years. Likewise, good planners make it clear what assumptions are required for an emerging technology to be feasible and reasonable. For instance, characterizing how much of a capital cost overrun would eliminate cost-effectiveness of the technology can help illuminate risk and contextualize portfolio results.

In some instances, cost parameters for emerging technologies are too uncertain to estimate. In the context of deep decarbonization scenarios, Duke and other utilities have modeled an emerging resource with all of the performance characteristics and costs of a combustion turbine, but without greenhouse gas emissions or fossil fuel costs. This so-called "clean capacity resource" typically first appears approximately 20 years in the future, in the 2040s, and represents a proxy resource that is expected to be developed by that timeframe. The advantage of this method is that it allows utilities to run scenarios that examine what type of new resource may be needed in a deep decarbonization future and what a least-cost portfolio may look like should such a resource materialize. However, there is inherent risk in modeling scenarios that feature unknown and unproven technologies. The greater the importance of such technologies in the company's preferred portfolio, and the further they are from common commercial practice, the more information stakeholders and regulators will need from the utility to understand the risks.

Demand-Side Resource Inputs

The IRP process began with least-cost planning in the 1980s, developed in part to explicitly account for demand-side resources to meet load (LBNL and ORNL 1989; Hirst and Goldman 1990). Traditionally, utilities have developed a companion study—the market potential study—that quantifies the technical and achievable/economic potential of demand-side resources as a part of the utility's preferred portfolio. The market potential study has historically focused only on demand response and energy efficiency. This section of the report focuses on practices for these resources. (For treatment of other distributed energy resources, see Best Practice 11.)

Using market potential study results, an IRP internalizes the effects of energy efficiency, demand response, and other demand-side resources in one of two ways:

1. *Load modifier approach*. This is the most common method and relies on demand-side resource potential studies performed outside of the IRP process. Using this approach, planners incorporate cost-effective demand-side resources into the IRP as a load reduction. Examples of utilities that used the load modifier approach in recent IRPs include Jacksonville Electric

[25] See the Advanced Technology Example on page 33. Southern Company attempted to construct an IGCC unit with a CCS plant at Kemper. This resulted in costs that were three times the initial project estimate (from $2.5 billion to $7.5 billion) before the Mississippi Public Service Commission ultimately pulled the plug on the project and ordered Mississippi Power Company to continue to operate the plant on natural gas.

Authority, Avista, and Dominion Energy South Carolina (Black and Veatch 2023; Avista 2023; Dominion SC 2023).

2. *Competitive resource approach*. This approach incorporates demand-side resources in the capacity expansion model as priced, competitive resources that can be selected endogenously as part of the capacity expansion optimal decisions. The Northwest Power and Conservation Council (Northwest Council) uses this approach for its regional power plans under the federal *Northwest Power Act,* as do utilities such as PacifiCorp, Portland General Electric, and Xcel Energy (Northwest Council 2022; PacifiCorp 2023; PGE 2023; Xcel Energy 2024).

Rather than prescribe one approach, the following sections provide best practices for implementing each of the methods, depending on the approach regulators or utilities select.

Best Practice 19. Ensure thoughtful and consistent assumptions for demand-side resources

Ensure assumptions driving demand-side resource characterization potential are thoughtful and consistent with other assumptions in the IRP.

Both the load modifier approach and competitive resource approach need to reflect actual program implementation and evaluation practices closely, including: (1) realistic program design and implementation practices, (2) appropriate levels of measure adoption rates (reflecting various non-economic factors), (3) measure and program costs, and (4) policy and regulatory requirements.

While market potential studies themselves are outside the scope of this guide, best practices entail including in these studies emerging demand-side technologies and practices, potential cost reductions for demand-side resources in the future, non-energy benefits (e.g., improvements in comfort, indoor air quality, productivity), up-to-date avoided costs, and maximum achievable adoption rates based on best practices by leading jurisdictions.

IRP modelers can run a variety of scenarios to capture a full range of demand-side resource estimates based on the potential study. For example, Ameren Missouri conducted a comprehensive DSM market potential study in April 2023 to inform its 2023 IRP. The study employed a methodology to account for interactions among DSM measures, load flexibility analysis, and scenario analysis. The utility benchmarked results of the study against comparable utility programs to ensure consistency with industry expectations (Ameren Missouri 2023a).

Both the load modifier approach and competitive resource approach are susceptible to bias with respect to measure adoption rates. If IRP modelers or market potential study analysts use overly conservative rates for measure adoption or measure adoption growth, savings results will be lower than can be supported by studies.[26] Customer paybacks for demand-side investments, non-energy impacts, and customer knowledge and awareness of technologies and programs (supported by the utility's customer outreach and marketing) may substantially influence customer decisions to implement DSM measures. Market potential study developers and IRP modelers would ensure results from the study are realistically

[26] For example, see TVA's 2015 IRP, which uses low adoption rate assumptions (Synapse 2015), pp. 10 to 15.

implementable by internalizing customer adoption rates that reflect customer economics and assumed program interventions (e.g., rebates, financing, customer outreach).

Best practice includes developing and using varying adoption rates for demand-side resources, including the maximum achievable adoption scenario based on aggressive historical savings achievements by leading jurisdictions and favorable policy and program scenarios (e.g., paying for 100 percent of the measure cost–comparable to treatment of supply-side resource costs, comprehensive customer outreach, and marketing and financing programs). A case in point is the NWPCC's approach to estimating total achievable potential for the regional power plan. NWPCC assumes that total cumulative market penetration rates increase to 65 percent, then 85 percent of the total technical potential over a 20-year timeframe (LBNL 2021e). Best practice for the competitive resource approach is for IRP modelers to produce a capacity expansion model run that offers savings up to those consistent with the measure adoption rates in the maximum achievable scenario in the most recent market potential study. Best practice for the load modifier approach is to include a maximum achievable scenario in the market potential study, as DTE did in its 2019 study by using "high" and "low" adoption scenarios (DTE 2019).

Policy considerations also need attention. For example, if certain energy efficiency investments for low-income households are required, the IRP model needs to select these investments regardless of the cost and consider them as a fixed input. In addition, some jurisdictions have minimum savings or budget targets for other market segments (e.g., small commercial customers) that are set by policy or regulation. While these targets could create suboptimal resource selection results, IRP modelers can strive to model these mandates as accurately as possible in at least one IRP scenario. States such as Washington require all cost-effective conservation to be procured (subject to a rate cap), regardless of the market segment. Utilities can model some of these requirements with a load modifier approach or simply by requiring the model to select these resources, while treating remaining conservation and demand response measures through a competitive resource approach.

Best Practice 20. Model and bundle demand-side resources carefully

If utilizing the competitive resource approach, model and bundle demand-side resources carefully to closely reflect actual program implementation and evaluation practices.

Under the competitive resource approach, demand-side resources are grouped together in a manageable number of bundles as inputs to the capacity expansion model. IRP modelers can develop these bundles to reflect how energy efficiency and demand response programs are typically designed, implemented, and evaluated for cost-effectiveness. Some programs (e.g., home retrofit) contain multiple measures from low cost (e.g., lighting) to high cost (e.g., HVAC) in order to meet customer needs and avoid "cream skimming" that targets only the most cost-effective measures and abandons others often offered with them as a package. IRP modelers also need to model specific market segments carefully so that the modeling approach closely resembles actual program implementation practices.

Carefully bundling energy efficiency and demand response measures[27] avoids unnecessary computational complexity within a capacity expansion model. Modeling energy efficiency and demand response at the measure level and allowing the model to select individual measures based on costs, for example, may prevent the model from solving. Current practices for measure bundling include aggregation by cost (e.g., NWPCC, PacifiCorp) and load shape (e.g., Indiana Michigan Power). For example, Indiana Michigan Power divides the bundled energy efficiency measures in 5-year increments and annual 1,000 MWh units to reduce modeling time (IMP 2022).

When creating bundles for demand-side resources, planners can ensure that the temporal sequence of expenditures is realistic and relatively smooth, without large changes over time. Without such guardrails, the model may select considerably different amounts of demand-side resources each year. This may fail to capture realistic patterns of consistent program offerings or follow actual program design and administrative practices for stable or gradually increasing program efforts and funding.

Another best practice is to allow the model to select bundles less frequently than annually. Modelers also can ensure that costs for continued programs and new programs are different. Given first-year start-up costs, existing programs should produce a smoother output and are more likely to be selected in subsequent years. This is easily achieved by bundling measures based on whether they are new or existing and assigning bundle costs accordingly.

An example of this approach is Duke Energy Indiana's 2022 IRP. Duke Energy Indiana modeled a study period from 2021 to 2050. It represented its DSM savings with increased granularity in the near term and consistent with its DSM planning cycles: 2021–2023 and 2024–2026. The IRP grouped subsequent savings in 8-year periods from 2027–2034, 2035–2042, and 2043–2050. During the period 2021–2023, the model was required to select the bundle that corresponded with the utility's currently approved demand-side management portfolio as well as low-income program savings. The model could then choose an "expanded measure" bundle, an "expanded measure + higher avoided cost" bundle, or no bundle. The expanded measure scenario included current and newly proposed measures, as well as new energy efficiency programs where measures included in the study did not logically fit into an existing offering. A bundle with higher avoided costs further enhanced savings by increasing participation, increasing measures offered, or doing both. While Duke Energy Indiana did not model all potential scenarios developed through the market potential study, the utility chose which scenarios to model through collaboration with its Demand-Side Management Oversight Board. The utility aimed to implement several best practices, including offering bundles of savings in excess of those achieved under existing programs and constructing near-term bundles in a way that mimics their procurement through a 3-year DSM cycle.

Some state requirements call for cost-effectiveness of energy efficiency programs to be determined at the program or portfolio level (NESP DSP n.d.). Modelers can produce program-level bundles that reflect a few key programs that are complemented by measure-level bundles. However, demand-side resource choices made by the capacity expansion model do not translate directly to optimal program design; rather, those choices should inform the amount, market segment, location, and type of demand-side

[27] Bundling should be done separately for demand response and energy efficiency and measures. Demand response measures are oriented to capacity savings, while energy efficiency is mostly oriented towards energy savings (although it provides capacity contributions as well).

resource to procure. This is consistent with supply-side model outcomes that select generic resources but leave the specifics to CPCN, siting and permitting, and procurement processes.

Best Practice 21. Ensure consistency with IRP scenarios

Ensure consistency between demand-side resource assumptions and IRP scenarios.

A key IRP principle is to represent the potential of energy efficiency, demand response, and other demand-side resources in a way that is consistent with the scenarios modeled in IRP. That is because assumptions made for IRP scenarios, such as those related to electrification and other load growth, also affect the potential for peak load reduction, load-shifting, and energy savings. This consistency is particularly important in the load modifier approach to DSM modeling because potential studies are typically developed before and in isolation from IRP modeling exercises. The competitive resource approach can produce more internally consistent portfolio choices, although consistency in basic cost and technology assumptions to characterize load and demand-side resource is important.

Aligning key assumptions (especially avoided costs and underlying load forecasts) in the demand-side resources potential study with assumptions in the IRP can mitigate distortions in modeling energy efficiency and demand response in IRP. A utility can conduct the potential study at the same time as, or right before, the IRP process and ensure consistency of key assumptions. Stakeholders need sufficient time and resources to participate in both the potential study and IRP processes, if they are conducted separately. If timing of the potential study does not allow for seamless coordination with the IRP, the potential studies can include sensitivities on avoided cost and load forecast assumptions. The utility, with stakeholder engagement, can select results from the sensitivity or scenario analyses that fit best with IRP modeling assumptions or outputs.

Looking Ahead: Co-developed scenarios for IRPs and market potential studies

Ideally, a set of scenarios would be developed ahead of both the IRP and the market potential study to be used in both; however, this is an aspirational practice with implementation challenges.

Best Practice 22. Incorporate all relevant benefits for demand-side resources

If using the competitive resource approach, incorporate all relevant benefits for demand-side resources by following policy objectives and requirements for assessing their cost-effectiveness.

To fairly value demand-side resources, IRP modelers need to incorporate all utility system benefits as well as non-utility benefits that are consistent with all applicable policy objectives. Modeling demand-side resources dynamically in a capacity expansion model is not sufficient because the model typically captures only the benefits of avoiding energy and generation capacity and, when modeled, transmission capacity. However, demand-side resources provide other utility system benefits such as avoided

transmission capacity (when not explicitly modeled), avoided distribution capacity, and risk management/hedging, as well as societal benefits such as avoided greenhouse gas emissions and other pollutants.

When a jurisdiction requires consideration of customer and societal benefits (e.g., reducing water usage and greenhouse gases, improving air quality) in cost-effectiveness screening tests to evaluate the benefits of demand-side programs, IRP modelers need to incorporate such non-utility benefits when screening cost-effective demand-side resources (LBNL 2021e). This is one of the principles of the *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*, which recommends inclusion of all benefits and costs to achieve policy objectives (NESP 2020a). For example, in its regional power plan modeling the NWPCC incorporates avoided T&D costs in the form of credits that reduce the cost of energy efficiency measures. The NWPCC also incorporates non-utility benefits (e.g., water and O&M cost savings) when modeling energy efficiency in its capacity expansion model (LBNL 2021e). Incorporation of non-utility benefits is consistent with traditional qualitative discussions of supply-side portfolios that have environmental, financial, and other benefits.

Competitive resource approaches can leverage some avoided costs that are endogenously modeled in the IRP process, such as transmission costs or emissions costs. The load modifier approach typically cannot internalize these costs directly in the IRP, instead using externally produced avoided cost studies. Planners can verify consistency between assumptions used to develop avoided cost studies and those used in the current IRP and adjust avoided costs accordingly.

Market Inputs

Utilities commonly rely on market purchases to meet a portion of their energy and capacity needs. Utilities that model themselves as an island–that is, model their utility footprint as if it is not connected to external markets or energy sources–are not accurately reflecting their position in the larger electricity grid and are omitting market resources from consideration. Market resources, both energy and capacity, can frequently lower utility portfolio costs and impact resource selection. Reliance on market purchases, however, requires that utilities study regional resource adequacy conditions to ensure the market can be relied upon to supply energy and capacity needs (PSE 2021; LBNL 2019b). This regional awareness can inform design of scenarios for capacity expansion modeling.

Best Practice 23. Use reasonable market interaction assumptions

Model reasonable levels of market purchases that capture the benefits from market integration without exposing the utility system to risky levels of market exposure.

Aligning capacity expansion modeling with regional resource availability is particularly important because factors such as load growth, growth of variable energy resources, and coal plant retirements affect available capacity. Utilities can provide transparency into treatment of market purchases in their modeling by describing their market studies and justifying the level of market purchases determined to be available for selection by the capacity expansion model.

Modeling a utility footprint as an island simplifies the modeling exercise, but it does not accurately capture potential lower resource costs, including market revenue potential. This tends to disadvantage zero marginal-cost resources such as solar and wind, which the utility can sell in the market. This approach can also disadvantage energy storage, which can store power from the market during hours of low cost for use when costs of supply-side resources are high. These values and revenues streams impact the economics of resource build decisions. Accurate representation of external markets allows the model to see the benefits from market interaction and impacts the model's resource selection decisions.

On the flip side, high reliance on the market requires proper justification. Detailed regional and market risk studies are best practice, but they are also resource-intensive. If the utility is unable to perform a full study or chooses to rely on simplified approaches to market interactions instead of a full study, it can align modeling assumptions with available transmission studies, recent market performance, and other external studies and projections of resource availability in the region.

Puget Sound Energy's 2021 IRP illustrates the importance of assessing regional energy and capacity availability (PSE 2021). The utility historically assumed that 1,500 MW of firm transmission capacity from the Mid-Columbia market hub would provide the utility with the equivalent to 1,500 MW generation capacity available to meet demand. In the past, Puget Sound Energy relied on this assumption to procure less generation capacity and lower its system costs. By 2021, however, three regional organizations had published studies indicating that the Pacific Northwest would transition from a capacity surplus into a shortfall at some point in the following decade without additional resource buildout.[28] In response, the utility decided to conduct a market risk and resource adequacy assessment for the 2021 IRP.

By aligning its resource adequacy model with regional reliability models, Puget Sound Energy was able to "translate the regional load curtailments forecasted […] into PSE-level impacts"(PSE 2021). Results showed that in some simulations, the availability of market purchases could be limited by 500 MW by January 2027. By that date, the utility might only be able to fill 1,000 MW of the available 1,500 MW of transmission (PSE 2021, chap. 7). The market risk assessment further analyzed recent market supply and demand fundamentals. Results showed that trading volume in the day-ahead market had declined 70 percent since 2015, while price volatility had increased. Increases in market volatility were particularly evident when high temperature events aligned with fossil fuel supply constraints at key power units (PSE 2021, chap. 7). This assessment resulted in Puget Sound Energy's decision to limit the number of market purchases going forward and transition short-term market purchases from a 1,500 MW limit to 500 MW. To fulfill its resource adequacy needs, the utility designed its preferred portfolio to reflect additional firm capacity contracts (PSE 2021).

Fuel and Commodity Inputs

Widespread extreme weather events have shown that fossil-fuel-based units whose fuel supply is not properly winterized are subject to outages during winter weather events. In Winter Storm Uri, for

[28] These included NWPCC, Pacific Northwest Utilities Conference Committee, and Bonneville Power Administration. See (PSE 2015) Appendix G.

example, as much as 6.7 GW of thermal generation capacity was unavailable due to “fuel limitations”(UT Austin 2021).

Resource adequacy assessments performed as part of the IRP process typically do not capture the weather dependence of fuel availability. Even more concerning, the assessment rarely captures such common mode failures, when an underlying event causes a series of correlated outages across certain technologies.

Best Practice 24. Model fuel supply limitations

Incorporate fuel supply limitations, weather-sensitive failures rates, and weatherization investments in resource planning.

Two related best practices improve IRP characterization of fuel availability for fossil fuel resources during extreme events, in line with utilities' continued focus on the impact of weather on the performance of solar, wind, and storage. First, as discussed in Best Practice 4, utilities (and ISO/RTOs) can develop and implement weather-sensitive failure rates that allow for highly correlated asset failures due to fuel availability. Second, in conducting IRP processes, utilities can plan for and model investments in winterizing fuel supply to reduce the common-mode failure rate for fossil fuel resources. These investments require careful analysis to ensure that further investment in the plant for winterization is economically optimal based on the forward-going economics of the plant relative to alternatives. A review of recent resource plans shows a focus on the impact of weather on the performance of solar, wind, and storage without enough focus on the weather impacts on other resource types, including coal and gas plants (LBNL 2023a).

The impacts of fuel supply limitations are another key factor for utilities to carefully consider in resource build or buy decisions. For example, Georgia Power Company recently filed an IRP update requesting approval to build three peaking combustion turbines (GPC 2023). The utility does not have a firm source of natural gas for the proposed plants and plans to operate them on oil during times when gas is not available. Oil is significantly more expensive than gas and has higher pollution levels across multiple emission types. Reliance on oil at the plant means the project will have higher costs and environmental impacts than a combustion turbine unit operated just on gas. Further, if the company faces natural gas constraints in the future, beyond what it assumes in the model, its reliance on oil will increase and so will the associated cost and environmental impacts.

Best Practice 25. Evaluate the impacts of gas price volatility and coal supply constraints

Incorporate fuel price volatility and fuel supply constraints into resource planning, and consider resource-portfolio solutions to limit risk.

Fuel price volatility is a fact of the market and not something that individual utilities can control. High natural gas prices are straightforward to model, but volatility is much more challenging to capture

through deterministic modeling. To incorporate fuel price volatility in electricity system modeling, utilities can use stochastic risk analyses that use Monte Carlo simulation to evaluate portfolio performance under different commodity price scenarios.

Utilities can take measures to manage and mitigate price volatility through various fuel procurement strategies—for example, through hedging programs that lock in a portion of supply at known costs to avoid the risk of high costs in the future. But hedging can be costly and, ultimately, a utility has more control over its resource supply mix than its fuel supply. By diversifying its resource mix and reducing the portion of its system that relies on the volatile input, a utility can control its fuel price volatility risk. Specifically, utilities can manage the portion of generation that comes from natural gas in each resource portfolio and design and model scenarios that limit the portion of a utility's portfolio subject to price volatility. This means focusing energy resource procurement on energy resources such as solar and wind that do not require fossil fuel inputs.

Price volatility and uncertainty has historically been most common in the gas market, but it has also been present in coal markets in recent years due to several factors. First, challenges stemming from labor strikes at both mines and the railroad transportation network resulted in price spikes in some parts of the country, particularly the Midwest and Appalachian region (Energy Ventures Analysis 2022; U.S. EIA 2023b). Some coal plants had to reduce operations due to low coal supply. There is likely to be more price uncertainty and possibly increasing prices in the future as more coal plants close, demand for coal drops, smaller coal suppliers go out of business, and the coal supply chain continues to contract. With more market power, the remaining large coal producers will have more control over coal supply, likely driving up the cost of coal in the future. Stochastic analysis and modeling of various coal price forecasts can help capture this risk. In addition, utilities can limit their exposure to these risks by reducing operations at, and planning for retirement of, coal plants.

Transmission Inputs

The IRP process provides crucial inputs for regional transmission planning. In May 2024, FERC issued a Final Rule (Order 1920) that provides guidance for transmission planners on transmission planning and cost allocation issues (FERC 2024). The order requires regional transmission planners to identify transmission needs driven by changes in power supply and demand by developing long-term scenarios at least 20 years long—a timescale that matches the typical IRP planning horizon. Likewise, FERC noted the need for proactive planning for resources not yet in development, so that planners can prioritize the most cost-effective solutions.

Best Practice 26. Consider transmission alternatives and infrastructure expansion

Consider transmission alternatives and expansion of regional transmission infrastructure as part of the resource planning process.

To prioritize transmission solutions, transmission planners look to IRPs for long-term forecasts of supply-side resources that are most likely to materialize. In turn, utilities can incorporate information from these

long-range transmission plans into IRP scenarios and allow endogenous transmission builds in capacity expansion models (where modeling capabilities allow). This best practice informs regional transmission planning and helps co-optimize transmission expansion and generation portfolio development. This is already occurring to some extent, and new modeling capabilities may support further effort in the future.

The primary driver for regional transmission expansion is the changing mix of generation resources that utilities are selecting. Regional transmission planning organizations including NorthernGrid and WestConnect build their regional transmission plans in a bottom-up manner using individual utility inputs (Gridworks 2023). In California, the reference IRP prepared by CPUC staff directly provides inputs for CAISO's Transmission Planning Process (CPUC 2023). Some large utilities such as PacifiCorp consider regional-scale transmission within the IRP. It's common even for smaller utilities to consider intra-system transmission upgrades in the IRP. However, these are typically in the form of hardcoded, preplanned transmission projects, rather than allowing the model to select transmission to help meet resource needs. The absence of wider exploration of transmission expansion and transmission optimization in IRPs are barriers to regional transmission buildout (Gridworks 2023).

A critical improvement is enabling capacity expansion models to select transmission buildout via tranches of transmission available at different costs. Modelers can also run scenarios that enlarge intrastate or regional connections to see how such changes shape optimized utility resource portfolios and costs. Doing so creates two benefits: (1) the utility is better prepared for a future with greater regional transmission planning and buildout, and (2) the utility can generate information that helps shape regional planning by informing regional planners about how different transmission options fit into a least-cost portfolio.

Some utilities already explicitly perform resource planning in a way intended to inform transmission planning. As PacifiCorp's 2023 IRP notes, "IRP and transmission planning processes complement each other by helping PacifiCorp optimize the timing of its transmission and resource investments to deliver cost-effective and reliable energy to our customers." The IRP included several large, preplanned, hardcoded transmission projects and endogenous selection of transmission to inform the relationship between "probable near-term projects and their transmission dependencies." Endogenous transmission capabilities specifically included "new incremental transmission options tied to resource selections, existing transmission rights tied to the use of post-retirement brownfield sites, incorporation of costs associated with these transmission options, and transmission options that interact with multiple or complex elements of the IRP transmission topology"(PacifiCorp 2023). As another example, Public Service Company of Colorado incorporated a section in its Clean Energy Plan that analyzed the necessary transmission investments to support its Preferred Plan, acknowledging the substantial transmission grid support investments required to interconnect a large portfolio of increasingly spread-out generation resources and accommodate generation retirements (PSCo 2021).

Best Practice 27. Properly justify bulk power system interconnection costs and constraints

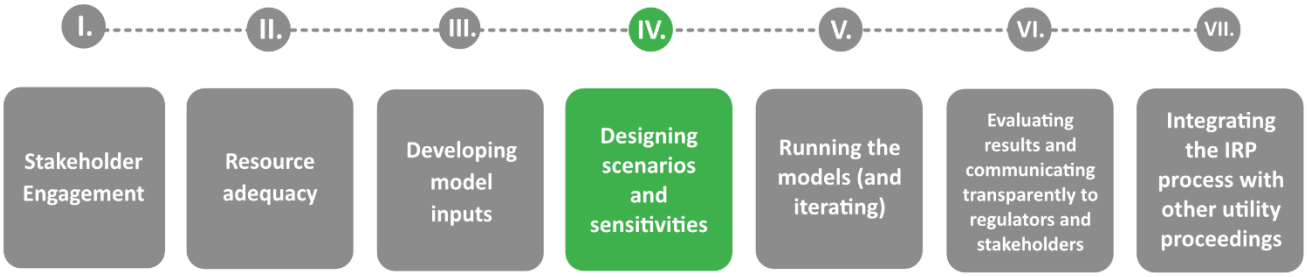
Properly justify interconnection costs and constraints modeled for new generation resources at the bulk power system level.

Ideally, transmission planning is integrated with generation planning. Transmission resources can be made available to the IRP model to select endogenously in the same manner as supply- and demand-side resources. For reasons discussed above, it is not always feasible or possible to fully integrate transmission planning into capacity expansion modeling based on model limitations, computing limitations, and a lack of full information on transmission expansion options. As an alternative, utilities sometimes estimate incremental transmission interconnection costs and attribute them to specific generation projects in the capacity expansion model. Even where interconnection capacity is constrained, utilities can model interconnection costs representative of the cost of addressing the constraints rather than omitting generation resources.

Given recent sharp growth in the total cost of interconnection-related network upgrades and the cost of such upgrades relative to generation project costs, it is best practice for utilities to factor interconnection costs into a project's capital costs. According to one report (Grid Strategies 2021) interconnection costs for new renewable resources were less than 10 percent of total generation project costs until a few years ago. Recently interconnection costs have risen to between 50 percent and 100 percent of total generation project costs as penetration of renewable energy resources on the grid increases.

Although reform is underway at both national and regional scales to change how costs are allocated, interconnection charges are still generally borne by the energy project developer. Utilities can ensure that the interconnection costs they model in IRPs are properly justified based on robust studies. Interconnection costs beyond the near term can reflect improvements in the interconnection process that are already underway. Additionally, interconnection costs can be applied fairly across all resource types to avoid bias in resource selection. Proper modeling and representation of interconnection costs will remain an important issue as additional transmission upgrades are increasingly needed to accommodate interconnection of resources on the bulk power system.

IV. Designing scenarios and sensitivities



Definitions

A **scenario** is a model run with a specific set of input assumptions and constraints—internal and external—to provide insights on distinct questions. Often, scenarios represent different goals or views of the future. Scenario A, for example, may include a high gas price forecast and low renewable energy capital costs, whereas Scenario B may include a low gas price forecast and high renewable energy capital costs. In this example, both scenarios serve as bookends at opposite ends of two scales. This is a common method for structuring scenarios.

A **sensitivity** is a model run that changes a single key input to understand how that input affects or drives results, often across multiple scenarios. The objective of a sensitivity analysis is to understand how results are affected by a single variable. For example, a higher load forecast may be applied to Scenarios A and B to test the effect of that one change layered across the range of other variables represented by each scenario.

A **portfolio** is the resulting resource mix from each scenario or sensitivity analysis, or a particular set of resources programed into a scenario to test. An optimized portfolio represents the least-cost solution to a capacity expansion model for a given scenario, considering risk and uncertainty.

Scenarios are the foundation of resource plan development and the framework for the model's optimization runs. Because utilities cannot evaluate every potential system outcome, they use scenarios to focus on inputs that are most likely to vary in the future and organize them around views of the likely future, specific policy goals, or other priorities. Modelers feed inputs and constraints for each scenario in the optimization engine (capacity expansion model) to produce a distinct optimized resource portfolio for each scenario. They then feed the resulting resource mixes into the production cost model to produce the optimized operational and dispatch plans for each scenario. The goal is for the utility to model a representative number of scenarios that provide sufficient information to inform the development of a preferred portfolio.

Sensitivity analysis enables a utility to understand how a change in a single input or constraint impacts its optimal resource mix. There are two general types of sensitivities: (1) a sensitivity that tests how the optimal resource mix changes assuming the utility plans for a change in one assumption from the start and (2) a sensitivity that performs a "robustness check" on a specific portfolio to quantify the operational and cost risks of an inaccurate single assumption. Both types of sensitivities are important, and both can help inform a utility resource plan.

For example, if the utility wants to understand how a higher gas price forecast will impact its resource mix, it re-runs the capacity expansion model using a high gas price forecast. The results will tell the utility how to plan its system if it thinks that gas prices are likely to rise (or even just become increasingly volatile). Alternatively, if the utility is interested in understanding the risks or robustness of each portfolio to high gas prices, modelers can run all of the portfolios through a new production cost modeling run with a high gas price forecast. The results will reveal how system operations and costs will change for each scenario if the system is built assuming base gas prices, but then gas prices are much higher.

Planners face several challenges to designing effective IRP scenarios and sensitivities, including the following:

1. *Modeling a full, comprehensive range of uncertainties vs. producing straightforward, informative results.* Too many scenarios, with too much complexity, risk confusing stakeholders. But too few scenarios risk omitting evaluation of critical factors.
2. *Balancing stakeholder requests with utility priorities and commission requirements.* Utilities can reduce the number of scenarios they have to run by designing scenarios that satisfy the priorities of multiple parties where interests overlap.
3. *Minimizing shareholder risks vs. minimizing ratepayer costs. The interests of utility shareholders and ratepayers do not always align.* That can drive utilities to model specific scenarios and omit others that could be lower cost or lower risk. For example, a utility may not model early retirement of an aging fossil fuel generator with a large undepreciated balance because that creates shareholder risk.

All these challenges require common sense, an open mind, and prudent judgment. This chapter offers best practices for exercising these qualities when building scenarios, evaluating scenarios, and using scenario results.

Best Practice 28. Model a base case that allows for easy comparison

Model a base case scenario that facilitates comparison across scenarios and sensitivities and ensure internal consistency across all scenarios and sensitivities.

Utilities include multiple scenarios in their IRPs to test a range of future outcomes. To ensure a useful comparison across all of these scenarios, a best practice is to first develop a base scenario as the starting point for all other scenarios. Modelers can use this base scenario to ensure they design all subsequent scenarios and sensitivities to be internally consistent so that results can be readily compared across scenario and sensitivities. Any subsequent scenarios can be designed to deviate from the base in a clear

and methodical manner—i.e., with different loads, commodity prices, regulatory assumptions, new resource cost assumptions, and more.

Best practice is to design the base scenario to reflect a realistic view of the world—i.e., an "expected" scenario—and abide by all existing federal, state, and regulatory requirements. Where there is regulatory uncertainty about the future of a final regulation, utilities can model a range of scenarios both with and without the regulation (as discussed in Best Practice 30).

Where a utility is modeling both its own footprint and the larger market the utility operates in, it is also important that assumptions be applied consistently across geographic scales (except where deviations are intentional). For example, it is critical to align input assumptions, such as commodity and market prices, regulatory assumptions, and resource cost inputs, across geographic scales.

Consistency across scenarios is also important. A high decarbonization scenario, for example, is likely to result in lower market energy prices in many hours of the year due to the higher prevalence of zero-marginal-cost resources, but also higher prices in some hours. If the utility does not develop its own scenario-specific market prices, it can select a third-party market price forecast that reflects the utility's assumptions about the relationship between decarbonization in its footprint relative to decarbonization in the rest of the market. A lower energy market price may reflect the assumption that decarbonization is happening across all regions, while a base or high market price may reflect the assumption that decarbonization is happening more rapidly in the utility's footprint than in the broader market region.

It is also important for utilities to use the results of sensitivities and scenarios thoughtfully in drawing conclusions. Revenue requirement results can be most easily compared across portfolios developed using the same fundamental price forecasts for commodities (e.g., gas, coal), electricity market prices, emissions, loads, new resource costs, regulatory context, and other consistent inputs. Comparing costs across portfolios developed with different fundamental inputs can be used to understand risk and uncertainty, but not to draw direct conclusions about which portfolio is least-cost.

Best Practice 29. Design scenarios to evaluate uncertainty and risk

Design a range of scenarios that provide information about uncertainty and risk across a range of futures.

The objective of scenario development is to understand uncertainty and risk in the electricity system and determine how to best manage them through resource planning. Scenarios focus on evaluating and understanding likely future views of the world (and the electricity system), the impact of specific policy goals on resource planning, how market trends could impact resource options, and how risk and uncertainty around various inputs and variables impact the optimal resource mix. Some scenarios may focus on isolating the impact of a few specific variables. Others help the utility understand what type of full system changes are necessary to meet a specific goal. Ideally, all of the scenarios modeled meet existing state and regulatory requirements and represent reasonable stakeholder priorities.

Table 1 identifies common uncertainties and risks that IRP scenarios address, with examples. Best practice is to focus on developing scenarios that evaluate real and likely variables and futures. Scenarios

that evaluate extreme themes or views of the world may be interesting, but ultimately are not likely to provide useful information for resource planning purposes.

Table 1. Common uncertainties and risks that IRP scenarios address, with examples

Uncertainties and Risks	Examples
High electrification	Dominion Energy South Carolina 2023 – high electrification scenario (Dominion SC 2023)
High DER and DSM future	Dominion Energy South Carolina 2023 – high DSM scenario (Dominion SC 2023)
Technology advancement (CCS, hydrogen, small modular reactors)	Tucson Electric Power 2023 – P09 Portfolio with Small Modular Reactors (TEP 2023a)
Long-duration storage	Public Service Company of New Mexico 2023 – long-duration storage scenario (PNM 2023)
Decarbonization by a certain year	Xcel Energy Upper Midwest 2024 – 100 percent carbon-free by 2050, Avista 2023 – Clean Portfolio by 2045 (Xcel Energy 2024; Avista 2023)
No new fossil resources after a certain year	Avista 2023 – no new natural gas, Santee Cooper 2023 – no new fossil generation (Avista 2023; Santee Cooper 2023)
Retirement of all fossil fuel plants by a certain date	PacifiCorp 2023 – retire all coal plants by year-end 2029, retire all natural gas plants by year-end 2039 (PacifiCorp 2023)
Compliance with proposed environmental regulations (e.g., Clean Air Act section 111(d) rule for greenhouse gas emissions)	Xcel Upper Midwest 2024 – environmental policy scenario (Xcel Energy 2024)
Increased environmental regulation	Dominion Energy South Carolina 2023 – aggressive regulation scenario (Dominion SC 2023)
Extreme weather	PacifiCorp 2023 – extreme weather load forecast sensitivity (PacifiCorp 2023)
Change in reliability requirement or reserve margin	Public Service Company of New Mexico 2023, Avista 2023, Xcel Energy Upper Midwest 2024 (PNM 2023; Avista 2023; Xcel Energy 2024)
Increased industrial and data center loads	Xcel Energy Upper Midwest 2024 – data center load sensitivity (Xcel Energy 2024)
Increased transmission buildout	PacifiCorp 2023 – All Gateway scenario (PacifiCorp 2023)
Stakeholder-requested scenarios	Public Service Company of New Mexico 2023, Avista 2023, PacifiCorp 2023, DTE Electric Company 2022, Duke Energy Indiana 2021 (PNM 2023; Avista 2023; PacifiCorp 2023; DTE 2022; DEI 2021)
Commission-mandated scenarios	Public Service Company of New Mexico 2023 – impacts of a range of carbon prices (PNM 2023)

Sometimes it makes sense to combine multiple uncertainties and risks in a single portfolio to test a scenario with a complete view of the future. Other times it makes sense to isolate and test particular changes in sensitivities. Transparency is key, for scenarios and sensitivities as well as the utility's preferred portfolio.

Best Practice 30. Plan for and incorporate important regulatory factors

Model all final, proposed, and likely regulations to allow time for proactive planning and identification of no-regrets actions.

Regulatory uncertainty is a particularly impactful uncertainty for planners to account for in scenario analysis. This can take the form of final rules that are being legally challenged, formally proposed rules, or even regulations that are likely but not yet proposed.

For example, NREL's annual Standard Scenarios report accounts for regulatory uncertainty in its U.S. electricity sector outlook by modeling all scenarios under current policies, as well as under two national electricity sector carbon dioxide emissions constraints: one that reaches 95 percent net decarbonization by 2050 and another that reaches 100 percent net decarbonization by 2035 (NREL 2023). Reference scenarios that only include current policies may serve as a point of comparison for other scenarios and provide insight on the risk of the status quo, but do not represent the expected future.

For final regulations that are new or subject to legal challenge, some utilities choose to model compliance as a single alternative scenario rather than as part of a base scenario. Modeling compliance as just a single sensitivity or alternate scenario and not in the base case limits the utility's ability to plan for a future with the regulation in place and identify no-regrets actions that are economic regardless of the regulation's status.

Proposed policies and regulations provide valuable insight into the direction of regulatory momentum and can give utilities the opportunity to figure out how to model new and complex requirements. When it comes to environmental regulations in particular, failing to model any further regulation prior to a finalized rule nearly guarantees that capacity expansion modeling misrepresents the future by underestimating environmental compliance costs. Future regulations are inherently uncertain, but modeling current or pending regulations is a better central case than assuming no future regulation. For example, EV deployment targets aimed at decarbonizing transportation will very likely grow as low-cost EVs become more readily available and charging infrastructure becomes more prevalent. Environmental regulations of emissions related to air and water will almost certainly continue to increase in stringency and call for lower levels over time, even if there is temporary backsliding. Modeling scenarios and sensitivities that examine the impacts of regulatory factors such as these provides insights into how the utility's strategy would need to respond to changes to rules and makes resource plans more responsive to potential

> ***Such modeling can also help the utility understand which resource options are most robust or less risky regardless of future regulations, and which are highly sensitive to regulatory outcomes. Crucially, these scenarios and sensitivities can also inform the utility's preferred portfolio.***

changes. Such modeling can also help the utility understand which resource options are most robust or less risky regardless of future regulations, and which are highly sensitive to regulatory outcomes. Crucially, these scenarios and sensitivities can also inform the utility's preferred portfolio.

It is common for utilities to reject modeling regulations that are not yet finalized, with the justification that prior to finalization, uncertainty surrounding the rule is too great for incorporation into planning. Utilities also may avoid modeling final rules that are being formally challenged in legal venues. For instance, Avista's 2023 IRP acknowledges the impact of draft rules that EPA issued in May 2023 relating to coal- and natural-gas-fired resources, but states that no adjustments will be made to the resource plan prior to issuance of final rules (Avista 2023). Duke Energy's 2023 IRP for North and South Carolina devotes a chapter to "Planning for a Changing Energy Landscape," noting the rapid advancement of policy-driven financial incentives, such as clean-energy-related tax credits under the *Infrastructure Investment and Jobs Act* and IRA, as well as new environmental regulations such as EPA's proposed *Clean Air Act* Section 111 rule for greenhouse gas emissions. Duke evaluated the performance of its Core Portfolios and Supplemental Portfolios under conditions of the proposed 111 rule for "informational purposes" (Duke Energy Carolinas 2023, chap. 2). Although Duke's modeling shows that the proposed rule may have important planning ramifications, the utility did not include the proposed rule in its base planning assumptions because it is "still being interpreted, clarified, and commented on and may change prior to being finalized" (Duke Energy Carolinas 2023, chap. 3). Similarly, Dominion Energy in Virginia and Santee Cooper in South Carolina did not consider the proposed rules in their recent IRPs (Dominion VA 2023; Santee Cooper 2023).

EPA's proposed Greenhouse Gas Regulations under Section 111 of the *Clean Air Act* is an example of how a proposed environmental rule can provide an advanced look at the direction of a final rule. The proposed rule included a variety of compliance measures including the option to comply through CCS, hydrogen conversion, co-firing with natural gas, or lowering capacity factors. Although the final rule, published in 2024, altered some specific aspects of the rule and removed the hydrogen conversion compliance option, the basic structure of the regulation, its stringency, and ramifications for highly-polluting power units—namely, reductions in carbon dioxide emissions—were largely unchanged. Studying the impact of the proposed rule would have provided an advanced look at the risk of continued reliance on regulated units, particularly those that pollute the most.

Modeling the impact of proposed regulations can also inform intelligent regulatory design. When EPA publishes new environmental rules, the agency solicits feedback from industry. Incorporating proposed environmental regulations into IRPs can provide quantitative evidence to support industry feedback.

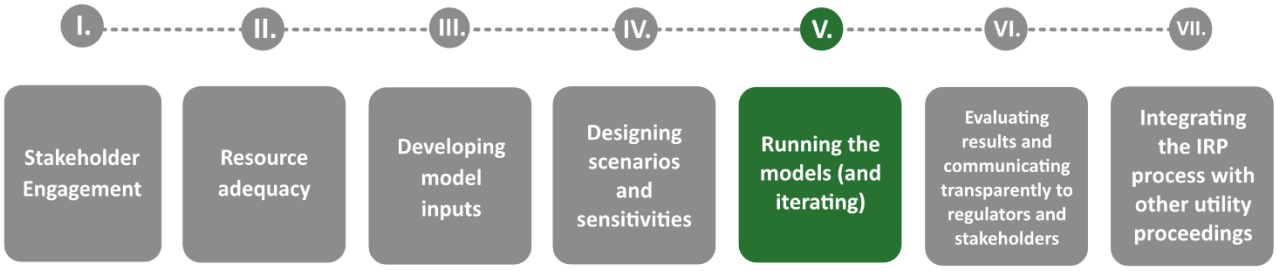
For example, Duke's modeling of the proposed 111 rule shows that although the Core Scenarios are "generally in line" with the first phase of the proposed 111 rule, compliance paths through later phases produce dramatically different results from the Core Scenario, with striking cost impacts. One tested path would require an additional 1.6 GW of offshore wind and an additional gas combustion turbine by 2035, both of which exceed Duke's forecast for resource availability and add $3.9 billion to the sensitivity's present value of revenue requirements (PVRR). Another path relies on hydrogen blending and increases the PVRR through 2050 by $11.4 billion. While these changes indicate that EPA's proposed 111 rule has the potential to change the least-cost system for Duke, the utility did not factor the

sensitivities into its preferred resource plan.[29] This creates a risk that the utility's plan will be rendered suboptimal by EPA's final 111 rule.

Best IRP practice is to take a reasonable and considered view of expected future regulations and include them in the base case scenario. Where there is significant uncertainty, planners can analyze alternative futures with more and less strict regulations in other scenarios or sensitivity analyses, or both. Assuming environmental regulations that are not finalized will not exist in the future can lead to costly resource decisions and delays in resource planning and resource procurement decisions.

[29] Duke notes a variety of near-term (2023–2026) actions to study hydrogen availability; but it otherwise does not incorporate the proposed 111 rule into its planning, aside from stating that it will update its planning assumptions as new requirements evolve (Duke Energy Carolinas 2023, chap. 4).

V. Running the models (and iterating)



This section of the report presents nine best practices relating to selecting, initializing, calibrating, and running the various models used in the IRP process.

Best Practice 31. Thoughtfully select capacity expansion and production cost models

Thoughtfully select capacity expansion and production cost models and use modeling software that can perform both functions if possible.

Capacity expansion and production cost models offer two complementary perspectives on the costs of the power system. While the industry trend has been attempting to integrate these models, software still tends to be specialized. A best practice is to verify the outcomes of a capacity expansion model using a more accurate and detailed production cost model in an iterative process.

Historically, some utilities relied on models that only have production cost capabilities. Instead of letting the model develop an optimized portfolio, utilities manually develop and test specific scenarios. This approach is inefficient, imprecise, and unlikely to lead to a least-cost outcome. Another best practice is selecting modeling software that can perform both capacity expansion and production cost functions.

A small number of commercially available models are typically used by utilities for capacity expansion and production cost optimization in IRPs, such as EnCompass, Aurora, and Plexos (Yes Energy, n.d. EnCompass; Energy Exemplar, n.d.-a Aurora; n.d.-b Plexos). That is in part because few models have adequate capabilities; have been used widely enough for utilities, regulators, and stakeholders to trust the results;[30] and offer sophisticated and consistent customer service to address the myriad of issues that using these models entail (including access to prepared and curated datasets). Expanding the pool of available models could help lower barriers to accessing modeling capabilities. National laboratories have developed several well vetted open-source models such as ReEDS (NREL ReEDS n.d.-d) and RPM (NREL RPM n.d.-e) capacity expansion models and the Sienna production cost model (NREL Sienna n.d.-f), among others (MIT and Princeton GenX n.d.; PyPSA, n.d.; RAEL SWITCH n.d.). These open-source

[30] This creates a barrier to entry for new models. A model must be trusted in order to be widely used, and it must be commonly enough used to be trusted.

models have limitations in their user base, support, and user interface that would need to be addressed before being fully viable alternatives.

Capacity expansion and production cost models developed and maintained by third parties such as commercial vendors and government agencies are important because they are accessible at least in theory by any stakeholder. That means results can be replicated and models remain relatively unbiased in their design. Open access to datasets also is critical for result replication. In practice, stakeholder access to models can be challenging due to the cost of model licensing,[31] the technical sophistication required for users, concerns about data confidentiality, and some utilities' ambivalence about collaborating with stakeholders at this level (see Section I on stakeholder engagement for more information).

Looking Ahead: Benchmark models to support IRP best practices

To support adoption of best practices in resource planning, utilities would benefit from third-party benchmarking of models—comparing them in terms of performance and outcomes.*

Different models emphasize certain characteristics of the power system over others. For example, they differ in the temporal resolution used to capture operational and investment timeframes. Some models use a time slice approach that emphasizes energy and ancillary service needs; other models use a sample hour approach that emphasizes capacity needs. Ideally, a third party would compare existing models to inform choices to represent the utility-specific power system analyzed in the IRP.

Model assessments would ideally go beyond comparing model attributes to help resource planners choose and implement a suite of models. Challenges with this approach include the proprietary nature of datasets and the time required to set up and run models. A common standard for data inputs could allow for a manageable yet informative number of redundant simulations to verify key decisions.

While model performance is important, other considerations for model selection include transparency, usability, and vendor support (see DTE Electric Company's Integrated Resource Plan Modeling Software Collaborative Summary Report in MPSC Case No. U-20471)(DTE 2020).

* *The Energy Modeling Forum compares energy and climate models, but to our knowledge, no one has systematically compared and validated models used for utility IRP* (Stanford University).

Best Practice 32. Thoughtfully select a geographic model scale

Thoughtfully select a geographic model scale that allows meaningful analysis of the resource potential and diversity available to the utility system being planned.

There is an inevitable tradeoff between model complexity and performance. This tradeoff is especially relevant to IRP modeling, which can include hundreds of runs to simulate a wide range of scenarios and sensitivities. The more complex the model, the longer the run time. That will limit how many model runs planners can complete within a given timeframe.

[31] In some states, regulators have required utilities to purchase model licenses for intervenors, as in Arizona and Iowa.

Two key aspects characterize model complexity: spatial scales and temporal scales. The spatial scale relates to the level of topological and geographical detail used to represent the power system under study. The temporal scale relates to the time-sensitive granularity of the system's operation as well as the time horizon for investment decisions. Thoughtful choices for spatial and temporal scales—with consideration for their interactions—balance accuracy and tractability (see Best Practice 33 and Best Practice 34).

Key spatial decisions include the choice between zonal and nodal modeling,[32] modeling of integration with regional markets, modeling of transmission connections and limits, and modeling of the utility footprint within the larger region and any relevant ISO/RTO to capture regional impacts on reliability and resource mix (for example, how much can the utility rely on the market).

While nodal modeling is most accurate, zonal is much less computationally- and data-intensive and likely sufficient from a resource planning perspective. Regional market integration can be reflected through a one- or two-step process. For the one-step option, the utility uses full capacity expansion and production cost modeling for the utility's footprint as part of the larger ISO/RTO or region it sits within. For the more common two-step option, the utility first runs the capacity expansion model for the full region to produce market prices, with relaxed constraints for resource builds and unit dispatch.[33] Then, in a second step, the utility uses market prices as an input to model the utility footprint with more granular settings and constraints for both capacity expansion and production cost runs (see Best Practice 40). While full regional modeling is more accurate, it is unlikely to be computationally viable for production cost modeling. At the same time, modeling the utility as an island without regional connections is not a reasonable IRP practice.

Regional modeling requires a scale that reflects geographic diversity in renewable resources and load characteristics. Modeling choices for supply- and demand-side resources are influenced by how their temporal profiles interact and by their location. A best practice is to study historical load and variable renewable energy generation patterns and then establish a minimum set of zones that are explicitly reflected in the model to capture diversity in these patterns. Reliability and resource constraints and parameters are critical model inputs.

Generally, transmission planning is integrated with resource planning processes, but through different modeling exercises. To simulate major transmission connections and limits in a zonal model, planners can create distinct zones for each region. An appropriate spatial scale will reasonably represent transmission corridors—in particular, lines that are typically congested—so the model can more accurately consider transmission lines for expansion (see Best Practice 26III.Best Practice 26). Planners usually choose higher voltage lines (i.e., above 220 kV) and several key substations to capture system topology. In addition, planners will want to consider including nodes that have historically presented patterns in locational marginal prices that reflect congestion, regardless of the nodes' voltage levels.

[32] Nodal modeling refers to using actual transmission substations and the transmission grid topology to locate load within the model. Zonal models aggregate substations and associated transmission lines and connected load into contiguous zones that simplify the model.

[33] Market price forecasts are dependent upon specific assumptions for gas prices, regulations, policies, and resource deployment within the ISO/RTO footprint.

Best Practice 33. Thoughtfully define the appropriate study period

Use a study period that is long enough to allow meaningful comparison between capital-intensive resources and others that might be considered and built in the future.

The temporal scale for IRPs works at two levels: investment and operation. Capacity expansion and production cost models interact across these scales to ensure rigorously tested least-cost outcomes. With respect to investment temporal scales—the IRP planning horizon—the minimum planning period may be defined by statute or regulation. As a general best practice, the study period extends far enough into the future to include important differences between scenarios with respect to recovery of investment costs and avoid distortions, as discussed below.

Any optimization that is done for a finite modeling period (e.g., 5 years or 20 years) has the potential to be influenced by "end effects," meaning significant costs that would be incurred beyond the study period. This issue has been recognized since the late 1970s. Proposed solutions include adding a salvage value to any asset and liability or approximating the system's continued operation (UC Berkeley 1979; Murphy and Soyster 1986). In many instances this is not a significant problem, particularly if the study period is long and the investment scenarios do not have large capital investments whose cost recovery would occur beyond the end year. On the other hand, in cases where there are large investments made near the end of the modeling period, considering and accounting for "end effects" can be quite important.

Typically, planners compare scenarios based on their PVRR (or cumulative discounted costs) over the study period. For example, if a capital-intensive project is brought online near the end of the planning period in one resource scenario but not in another, then the cost comparison between the scenarios may not reflect the real cost differences between the cases. Planners might address this issue by extending the study period a few more years or by making an "end effects" adjustment to the scenario costs.

In addition to issues regarding the overall length of the study period and accounting for potential costs that would be incurred beyond the study period, some optimization modeling assumes "perfect foresight." The model optimizes the entire study period as each if year's capacity expansion and retirement decisions can be made with knowledge of future loads, fuel costs, capacity additions, etc. For a particular year, the model assumes future regulatory costs, which can be used to inform near-term decisions. This can be desirable in some instances, but if there is a high level of uncertainty around decisions far into the future, it may be less desirable to have uncertain information drive near-term decisions. In addition, because some optimization models consider more information in making decisions, a long optimization period can also result in long model runtime. Conversely, single-year or multi-year foresight/optimization reduces the model run time, can help space out new builds, and can exclude uncertain drivers from near-term consideration.

The choice of optimization horizon can be especially important for resources expected to have declining costs over time, as with the significant annual capital cost reductions for some renewable and storage resources. In such cases, the optimization algorithm of a least-cost model might delay as much as possible capital-intensive decisions in ways that would not reflect appropriate decision-making. Most models today solve the problem by annualizing investments, applying useful lifetimes, and internalizing

these annuities in the objective function. This practice, coupled with using an extended modeling horizon, should prevent end-effect distortions.

Best Practice 34. Thoughtfully select the appropriate time granularity for production cost modeling

Use a time granularity for the production costing simulation that enables modeling of important timing considerations in dispatch.

In addition to the time horizon over which the model makes investment decisions, the resolution or granularity of the dispatch for operation costs is also a critical modeling parameter decision. A best practice for operational temporal scales for both production cost modeling and capacity expansion modeling is using hourly representation, consistent with resource adequacy assessments. Hourly scales enable single-day or even multiple-day chronological representation for system operation that captures some ancillary services needs, such as ramping requirements. Intra-hour analysis that includes primary and secondary frequency, voltage regulation, and other non-economic simulations may be conducted as well in suitable power flow, dynamic, and reliability models.

Full 8,760-hour representations for annual system operation are generally tractable. However, in cases where the spatial scale needs to be highly granular, the complexity of the simulation may increase substantially. In these cases, modelers can use a subset of hours that reflect peak and non-peak hours and seasonality of loads and resources. Ideally, modelers will choose this subset of hours carefully and, when possible, capture consecutive 24-hour periods and even longer timeframes for modeling long-duration storage. While less common in capacity expansion models, many utilities use 8,760-hour representations in production cost models and similar portfolio refinement steps, as demonstrated in several 2023 IRPs (Santee Cooper 2023; PacifiCorp 2023; Avista 2023).

Best Practice 35. Calibrate the production cost and capacity expansion models

Calibrate the production cost and capacity expansion models to anchor them to current system conditions and validate the legitimacy and accuracy of the model results.

Capacity expansion modeling is an inherently theoretical exercise that studies possible evolutions of a power system based on initial conditions and forecasts of key variables. Nevertheless, the model still needs to be anchored in, and calibrated to, current system conditions. The calibration process may be time-intensive and iterative, but it is necessary for the legitimacy and accuracy of models and results.

A best practice is to ensure that the dispatch, dynamics, and prices/costs from the production cost model match those seen in the current power system. For utility-scale modeling, this may include ensuring capacity factors for each simulated unit and technology class are consistent with recent dispatch outcomes, and that the production cost model reflects reasonably well overall system costs.

For larger regional modeling, metrics for calibration may include matching total generation by resource type and zone to capture both technology-level production and spatial distribution. In some cases, matching by individual unit may be possible and necessary to appropriately reflect transmission flows. In any case, planners will need to carefully analyze the import and export profiles in the production cost model output, particularly if the dispatch in neighboring areas is also being simulated, rather than as serving as an input to the model. Puget Sound Energy's 2021 IRP provides an example of such simulation (PSE 2021). Import and export profiles would ideally approximate the seasonal and daily patterns so that the model adequately reflects the surpluses and deficits of power within the planning entity footprint.

In this calibration process, the utility would evaluate its model inputs, make adjustments, and iterate until the model delivers results that more closely match reality. Planners might want to use some level of discretion to avoid overfitting the models, since this may introduce distortions into the production cost model or capacity expansion model that could affect results. For example, trying to closely match winter dispatch conditions for certain resources may induce large distortions in assumed summer operation for the same resources. In addition, actual utility decisions may be driven by factors that the model does not consider, such as risk aversion, sunk costs, or political environment—and hence planners will want to account for these when analyzing model fit against operational data.

Best Practice 36. Let optimization models optimize

Let optimization models optimize resource additions and retirements as a complement to modeling specific retirement scenarios.

The concept of optimization—a process aimed at developing the "best" path that balances tradeoffs, costs, and benefits—sits at the core of IRP modeling. Capacity expansion models are founded on the principle that optimizing for least cost should drive resource builds and retirements. A best practice is to limit unnecessary constraints on the model and allow the model to do what it was designed to do: optimize. The results from optimization model runs provide important information on the best way to balance system costs, needs, and constraints.

Planners can program many aspects of capacity expansion and production cost modeling into the model, including:

1. *System constraints.* These include reserve margins, emission programs, transmission capacity limits, regional import and export limits, reserve and ancillary service requirements, and any other parameters that cover the entire utility system.
2. *Load and demand.* System load and system peak demand.
3. *Resource input assumptions*. These include resource costs, operational characteristics (ramp rates, heat rates), capacity accreditation, shapes (for variable energy resources), outage rates and schedules, and other resource inputs.
4. *Commodity costs.* Examples include fuel costs and carbon prices.

These parameters require programing into the model because capacity expansion and production cost models are not designed to endogenously make decisions about most system constraints and resource inputs. The modeler is responsible for selecting reference values for each input and varying them

manually through different scenarios and sensitivities as necessary. Some of these inputs can and should be determined by exercises outside of the core resource planning modeling—for example, the reserve margin and resource capacity accreditation.

There are also key decisions where it is best *not* to hardcode and constrain across resource planning exercises. These are decisions that a capacity expansion model makes endogenously by design, mainly:

1. Resource build decisions
2. Resource retirement decisions

There are legitimate reasons why a utility also may design certain scenarios with specific resource build and retirement decisions programed in, instead of relying solely on an optimized scenario. Such considerations include computational limits, regulatory deadlines, policy requirements, settlement agreements, just energy transition, and many others. Additionally, the remaining life of a resource radically changes plant investment, which can be challenging to accurately and dynamically capture in the model.

Putting aside near-term decisions that are already locked in, a starting point and default best practice is to optimize resource retirement decisions, rather than hardcode them based on utility preference or a decision the utility already made. For example, this frees the model to reveal whether a different retirement date, in the context of all other model parameters, assumptions, and resource alternatives, yields a more desirable solution. The practice of overly constraining IRP modeling through hardcoding retirement dates is very common in utility IRPs. This is driven in part by the outage and capital upgrade cycles for existing fossil plants, such as coal plants. To accommodate these cycles, some utilities, such as Duke Energy Carolinas, conduct separate retirement analyses to develop coal unit retirement dates that they then hardcode into the capacity expansion models. While the external studies provided useful information, the utility did not integrate these retirement analyses with modeling the rest of the electricity system, preventing the model from finding a truly optimal solution.

Likewise, when it comes to new resource builds, capacity expansion models work best when free to choose from among all currently available resource types (and even some emerging ones over the longer term) and free to build what is needed to meet load (subject to system constraints and regulations) in each year. That includes both supply- and demand-side resources, as well as transmission expansion options. Capacity expansion models by design evaluate continued operations versus retirement and replacement with alternatives, but the models can only do this if they are unconstrained in doing so.

Again, there may be value in testing portfolios that lock in retirement or resource build decisions or place reasonable limits on those decisions. Still, best practice is to conduct unconstrained optimization runs for retirement or resource build decisions and include an optimized modeling run with the utility's preferred portfolio. Locking in resource addition and retirement decisions for scenarios and sensitivities may be appropriate after robust modeling is performed to provide clear reasoning and support resource decisions with evidence.

Other modeling constraints may be useful—when testing high and low ranges of uncertain values, evaluating specific unit retirement dates, and seeking to limit the problem size and computing requirements. Supply chain interruptions or interconnection queue constraints, for example, may

warrant setting a maximum annual build cap on a given resource type. In such cases, best practice is to be transparent about setting the cap, limit the timeframe for applying it, and provide a well-reasoned explanation. Best practice is to also run scenarios without any caps to determine whether there is a better solution if deployment barriers can be overcome. Further, it is essential for the utility to recognize that such a cap is a modeling construct, and that the market and other on-the-ground realities represent the actual limits to procurement.

A model can only act on information given and can only make the choices it is allowed to make. Using an optimization model is therefore only a first step, not a replacement for critical thinking.

While a utility's preferred portfolio may deviate from the optimized portfolio, it is essential for the utility and regulator to understand the economically optimal results, especially in planning near-term procurement activities. For example, if an optimized scenario shows it is most economic to add 3 GW of solar PV in 2028 to replace a retiring resource, this finding can be used for developing RFPs and communicating to the market that the utility is going to be looking to procure as much solar as it can economically get by 2028, even if there are legitimate reasons for the preferred portfolio as modeled to stagger that resource addition over multiple years.

Limits to optimization models are important to keep in mind in implementing best practices for model optimization. Any model reflects a simplified version of reality. An optimization model, for example, will show planners the lowest-cost resource plan based on selected inputs. It will not tell them which alternative plan could be even lower cost if the planner used different modeling assumptions or inputs. Best practice includes testing a wide enough range of reasonable scenarios that build off optimized results to capture a comprehensive range of possible future conditions. A model can only act on information given and can only make the choices it is allowed to make. Using an optimization model is therefore only a first step, not a replacement for critical thinking.

Best Practice 37. Base power plant retirement decisions on forward-looking costs

Base power plant retirement decisions on forward-looking costs, not sunk costs or cost recovery concerns.

Almost all utility assets have undepreciated plant balances. This is particularly true of legacy fossil fuel generators such as coal plants, which have both an existing plant balance from past investment and ongoing and future capital expenditures to maintain operations and comply with environmental regulations. Existing plant balances are sunk costs that are unavoidable with retirement.[34] Sunk costs do not provide relevant information for resource planning decisions. On the other hand, O&M and fuel costs, as well as ongoing capital expenditures which become part of a plant's undepreciated balance once they are incurred, *are* avoidable with retirement (as discussed in Best Practice 16). In IRP modeling, planners must differentiate between sunk costs and avoidable future costs to accurately assess resource

[34] A variety of regulatory mechanisms, including accelerated depreciation, can help address sunk costs for plants the utility plans to retire.

retirement decisions. Avoidable future costs can only be considered by an IRP model in selecting a retirement date if they are included in the model.

There are three pieces to retirement analysis: *whether* a plant should be retired, *when* it should be retired—including the optimal retirement date, and *how* any remaining balance should be treated in rates after retirement. The IRP process, through capacity expansion modeling, addresses the first piece and part of the second piece.

The determination of *whether* to retire a unit is based on a unit's expected forward-going economic performance and all expected forward-going costs, including sustaining capital expenditures, environmental capital expenditures, and fixed O&M. Best practice is for a utility to ramp down investment in a plant in the years leading up to retirement and include those assumptions in capacity expansion modeling. Ideally, when a unit is expected to become uneconomic on a forward-going basis, planners prioritize it for retirement to avoid incurring additional costs and operational losses that would be passed on to utility customers. Again, sunk costs are *not* considered in the IRP process.

Capacity expansion modeling can identify a unit's economically optimal retirement date. But the decision of *when* to retire a unit also needs to consider the timeline for procuring replacement resources, as well as *how* the utility will handle sunk costs. These decisions typically occur outside IRP processes. Specifically, procurement, cost recovery, and cost allocation decisions are typically addressed in other proceedings. Aligning resource planning modeling with resource planning decisions made outside of the IRP process is important and is discussed in Section VII in this report.

Best Practice 38. Use modeling parameters that capture the value of battery energy storage

Use modeling chronology and parameters that capture the full value that BESS can provide to the grid and accurately capture charging and discharging cycles.

Appropriate capacity expansion modeling capabilities and methodologies are critical for simulating high-renewable electric grids, particularly those that include battery storage of varying durations. The model chronology used in the long-term capacity expansion component is particularly important. Capacity optimization models have long relied on a simulation chronology that optimizes resource builds based on a subset of representative days. That might be some number of days distributed across the entire year, one on-/off-peak day per month, or a typical week per month. Such sampling methods fail to capture the variability in variable renewable energy generation, and storage charging and discharging, across longer time scales. Thus, these methods fail to accurately value the flexibility that long-duration storage resources can provide. To capture the ability of these resources to shift energy across days, weeks, and seasons, it is essential to optimize resource builds using a modeled chronology of 8,760 hours.

Sampled modeling chronologies often fail to capture multi-day lulls in renewable energy generation as they occur both within and across years. They therefore do not consider the implications of such events on resource builds, grid reliability, and energy prices. The magnitude of these lulls will only increase as

electric supply shifts toward even greater penetrations of renewable resources. It is critical that utility resource planning include scenarios that capture these lulls as well as other periods of grid stress.

Similarly, best practice in modeling long-duration storage resources requires modeling storage build and dispatch over multiple weather-years and including weather-years with extreme conditions that lead to periods of grid stress. Industry-standard modeling often builds an optimized resource mix designed to meet the annual peak load, with an established reserve margin, under typical weather conditions. However, weather varies from year to year, and that variance can have substantial impacts on energy system requirements. A resource portfolio built around average weather conditions might not meet system resource adequacy standards in a weather-year that includes one or more grid stress periods. Modeling a single weather-year also tends to underestimate the flexibility benefits of long-duration storage resources. Best practice modeling optimizes resource builds over multiple weather-years to produce a resource portfolio that is more robust against weather variability, though we are unaware of any utility that has incorporated this practice into its capacity expansion modeling.

Storage resources are characterized by power discharge capacity as well as energy storage capacity. Most IRP models simplify the representation of storage by prescribing its duration, either with a single value (e.g., 4-hour storage) or modeling storage resources in cohorts of discrete, fixed durations. For example, Portland General Electric's 2023 Clean Energy Plan/IRP modeled six lithium-ion battery durations, ranging from 2 to 24 hours, as well as a 10-hour pumped-storage hydro resource (PGE 2023). This approach simplifies the optimization process and might be the best that utilities can do with commercially available capacity expansion models. But it can miss identifying system needs that could be met with specific durations of storage located at specific points in the system. Best practice would treat power discharge capacity and energy storage capacity as two independent variables, such that the optimal solution ultimately defines the designs for the storage resources needed.

Further, IRP best practice would simulate fully dispatching storage resources with explicit representation of charging and discharging cycles. The 2023 PacifiCorp Clean Energy Plan/IRP describes endogenously modeling dispatched storage resources according to their roundtrip efficiency and other operational constraints (PacifiCorp 2023). The 2023 Tucson Electric Power IRP includes an example of the hourly battery dispatch in its production cost model (TEP 2023a). Accurate modeling of real-world operational conditions for these units requires comparison of sample charge-discharge cycles to empirical profiles. A related practice involves appropriate modeling of different types of long-duration storage—multi-day, multi-week, and seasonal storage units. For more details on best practices for modeling long-duration storage in IRP, see Best Practice 17.

Best Practice 39. Use stochastic approaches for robust portfolio creation

Use stochastic modeling approaches to produce portfolios that are robust to changes in inputs.

A key challenge in IRP is assessing the risk that stems from the array of uncertain inputs to the exercise. Load location and growth, weather, fuel prices, variable renewable energy production, asset outages, capital cost reductions, policies, and regulations are all uncertain. Two key risks that arise from these

uncertainties and need assessment are (1) whether the preferred portfolio remains a least-cost option within reasonable variation of inputs, and (2) whether the resulting system is resource-adequate when exposed to varying load, weather, and resource availability. As reported in Section II in this report, properly developed resource adequacy assessments use stochastic modeling to represent the likelihood of shortfalls in the bulk power system and address the second point. This best practice expands on the first point.

Conventional capacity expansion modeling in IRP is a deterministic analysis. Planners input deterministic forecasts for uncertain variables exogenously, and the model optimizes based on these pre-set values. As discussed in Section IV of this report, running scenarios and sensitivities is the traditional approach to managing uncertainty in least-cost or economic decision-making. These mechanisms are easy to understand, but their interpretation is qualitative, and there is no reassurance that the portfolio decisions stemming from these qualitative assessments are optimal (see Best Practice 41).

Capacity expansion models have the capability to run with stochastic inputs, providing tools to test the impacts of uncertainty, although uptake from planners has been slow. Examples of utilities that use stochastic inputs include AES Indiana's 2019 IRP. The utility employed a stochastic capacity expansion model that reflected fuel price volatility and correlation to produce multiple portfolios (AES Indiana 2019). A more common alternative is to use a stochastic approach to test the distribution of costs of preferred portfolios by running a production cost model of the portfolio with stochastic inputs. In contrast to running the capacity expansion model with stochastic inputs, this approach uses stochastic variable costs to recalculate production costs for deterministically defined portfolios. In CenterPoint Indiana's 2023 IRP, for example, the utility performed a stochastic risk assessment to compare portfolios. The stochastic inputs used in these risk assessments included natural gas prices, coal prices, carbon prices, peak loads, and capital costs for renewable energy resources (CenterPoint Energy 2023). TVA, PacifiCorp, AES Indiana, Puget Sound Energy, Idaho Power, and DTE also have recently used this approach. Entities such as PacifiCorp, the NWPCC, and TVA with a substantial amount of hydropower resources in their analyses have traditionally used stochastic representation of hydrological variability in production cost modeling, as well as developing related sensitivities in capacity expansion modeling (PacifiCorp 2023; Northwest Council 2022; TVA 2019).

These best practices produce multiple portfolios based on stochastic inputs or assess the short-run economic performance of portfolios when input variables are stochastic.

Looking Ahead: Use optimization algorithms in stochastic economic modeling

An aspirational practice in stochastic economic modeling would employ advanced robust optimization or chance-constrained optimization algorithms to ensure the distribution of outcomes falls within prescribed ranges given probabilistically defined inputs. These advanced algorithms produce a single preferred portfolio that is designed to be robust to changes in inputs. Inevitably, any best or aspirational practice to perform stochastic analysis in IRPs will substantially increase computational needs, runtime, and complexity.

Stochastic approaches to capacity expansion and production cost modeling do not entirely replace scenario-based analysis and sensitivities. Stochastic approaches are useful when the input variables can be modeled through rigorous probability distributions. However, several inputs to IRPs cannot be modeled like this, such as the likelihood of adoption of certain policies or predetermined retirement of certain assets, among others. Load growth, weather-driven parameters, fuel prices, capital costs, and similar quantitative variables are suitable for stochastic representation. Behavioral aspects that drive load and flexibility profiles are an emergent area of research for stochastic representation.

Best Practice 40. Use the models iteratively

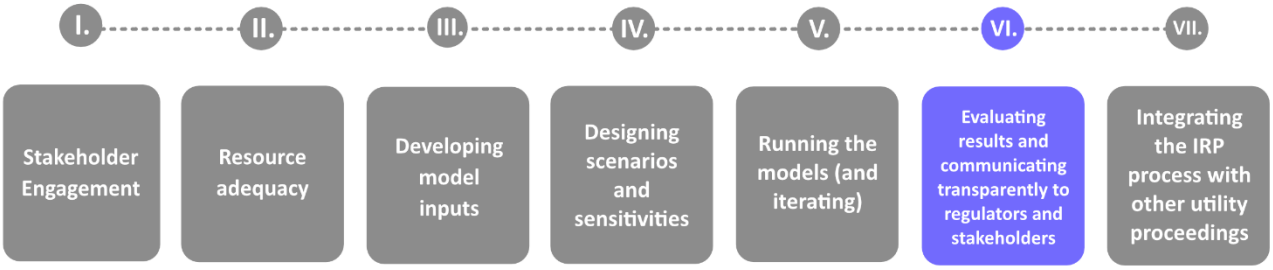
Use capacity expansion and production cost models iteratively to help refine results.

Capacity expansion and production costs models are best used iteratively in resource planning. Planners make necessary simplifications during the capacity expansion stage to decrease the problem size. Results from production cost modeling may reveal, for instance, that the capacity expansion model did not develop enough resources to provide ancillary services, omitted impacts of more detailed transmission systems, left unserved energy, or did not reflect well the contributions of variable resources such as wind, solar, and demand-side resources. For example, PacifiCorp found that portfolios developed in its initial capacity expansion model led to consistent capacity shortfalls when tested in a more granular dispatch model that explicitly accounted for operating reserve requirements (PacifiCorp 2023). Similarly, Public Service Company of Colorado found that the initial portfolio developed by the capacity expansion model was unable to satisfy reliability criteria (PSCo 2021).[35] In this case, using a supplemental resource adequacy modeling run identifies reliability shortfalls which can inform modifications for another set of capacity expansion runs.

An iterative approach to modeling is a best practice. Production cost runs help refine capacity expansion runs, and supplemental resource adequacy modeling sheds light on any reliability concerns. This produces more robust results and may allow the capacity expansion model to select and retire resources that minimize both long-term investment costs as well as short-term operational costs.

[35] Capacity expansion models are generally constrained by reserve margins. This approach generally ensures there is sufficient capacity to meet firm peak demand, but it does not answer questions about how a system will perform under extreme weather conditions, for example. Generally, separate stochastic reliability modeling is needed to answer such questions.

VI. Evaluating results and communicating transparently to regulators and stakeholders



The following section discusses best practices for presenting results to regulators and stakeholders, as well as selecting a preferred portfolio.

Best Practice 41. Use appropriate metrics to evaluate IRP results

Use appropriate metrics that have been intentionally designed to avoid skewing results towards a predetermined outcome.

After a utility has finalized its modeling results, the next step typically involves summarizing portfolio results in a matrix that presents utility performance across key metrics to facilitate comparison and communicate key differences across scenarios, often referred to as a scorecard. Scorecards can synthesize a large amount of information into a digestible format. In designing a scorecard, a best practice is for utilities to solicit feedback from stakeholders and regulators about the metrics included and whether the information is clear and unbiased.

Ideally, the process of selecting scorecard metrics would be an iterative process with stakeholder involvement. Utilities, regulators, and stakeholders can define core metrics at the outset of the IRP process that are aligned with region-specific needs and goals, such as pollutant emissions, rate impacts, customer satisfaction, economic development, and many others. Other important metrics can be added as the modeling progresses.

While there is no one-size-fits-all scorecard, there are common pitfalls to avoid. If a utility plans to use a weighting system to rank the relative importance of metrics, a pitfall to avoid is adjusting weights of metrics to reach a predetermined outcome. Instead, the utility can clearly communicate and justify the methodologies it uses for weighting, stakeholders can provide input, and regulators can review how weighting affects the selection of the utility's preferred portfolio.

In general, it is important to avoid using qualitative analyses that can be easily adjusted to preferentially highlight certain scenarios and thereby skew portfolio results. A good scorecard includes only those metrics that measure an explicit goal of the state, utility, or stakeholders, and excludes metrics that are already accurately reflected in PVRR results. All portfolios considered “should be safe and reliable, and to the extent that more or less system flexibility implies a cost, that cost should already (and accurately) be

reflected in PVRR" (Synapse 2015). In addition, best practice is to avoid using extreme scenarios to skew portfolio rankings and the selection of the utility's preferred portfolio (for more information on preferred portfolio selection, see Best Practice 44 and Best Practice 45).

Following are examples of common metrics commonly included in a scorecard:

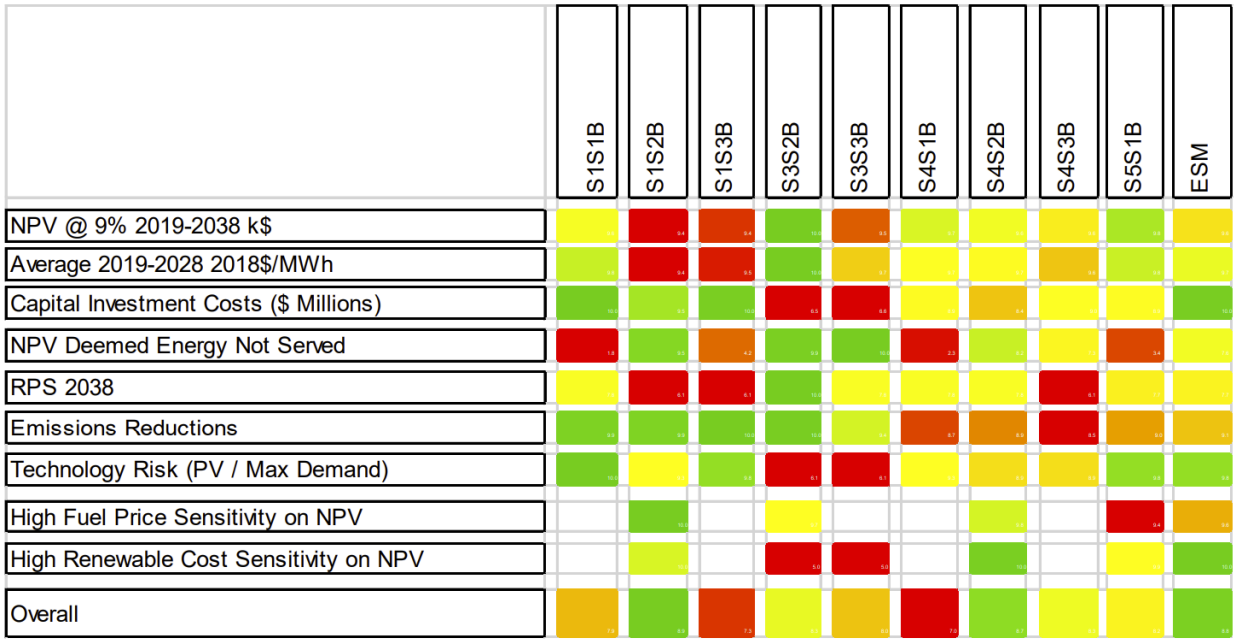
- **Cost.** Net PVRR over the short-term (5–10 year) and full study period (20 years or more), in absolute terms
- **Environmental sustainability.** Carbon emissions (total tons) and carbon intensity (tons per kWh), percent of generation from carbon-emitting resources vs. low carbon resources
- **Reliability.** If differentiated by portfolio, metrics could include LOLE and expected energy not served, among others that are relevant to the system being modeled
- **Cost exposure.** Exposure to fuel price volatility as measured by percent of generation provided by gas, coal, and oil plants
- **Market exposure.** Percent of load met through market purchases

The following examples highlight a scorecard that does not follow Best Practice 41, as well as a scorecard that does.

The Puerto Rico Electric Power Authority's (PREPA) 2018–2019 IRP scorecard does not follow best practice for clear presentation of results. The effort to create a qualitative, colorful scorecard resulted in a highly subjective, potentially biased, and confusing figure. The IRP explains that the scorecard (Figure 6) complements quantitative analysis of the PVRR of each scenario (Siemens Industry 2019). Elements that create room for misunderstanding include the following:

- Scenario names are not defined in the table or the text describing the figure, and the coded names provide insufficient summary information for each scenario.
- Metrics for each scenario are not clearly defined in the figure or descriptive text.
- Color-coding is not based on a defined or quantitative scale and obscures valuable information about the spread between and across variables.
- Weightings are not clearly defined, especially in relation to the "Overall" category and how it was calculated for each scenario.

Figure 6. Scorecard for PREPA's 2018–2019 IRP



Source: Recreated from Siemens Industry. Puerto Rico Integrated Resource Plan 2018–2019, Exhibit 8-7. Prepared for Puerto Rico Electric Power Authority.

The clearly presented scorecard in AES Indiana's 2022 IRP (see Figure 7) provides a good example of Best Practice 41.

Figure 7. AES Indiana 2022 IRP scorecard results

	Affordability	Environmental Sustainability						Reliability, Stability & Resiliency	Risk & Opportunity							Economic Impact	
	20-yr PVRR	*CO_2 Emissions*	*SO_2 Emissions*	*NO_x Emissions*	*Water Use*	*Coal Combustion Products (CCP)*	*Clean Energy Progress*	*Reliability Score*	*Environmental Policy Opportunity*	*Environmental Policy Risk*	*General Cost Opportunity **Stochastic Analysis** *	*General Cost Risk **Stochastic Analysis** *	*Market Exposure*	*Renewable Capital Cost Opportunity (Low Cost)*	*Renewable Capital Cost Risk (High Cost)*	*Generation Employees (+/-)*	*Property Taxes*
	Present Value of Revenue Requirements ($000,000)	Total portfolio CO2 Emissions (mmtons)	Total portfolio SO2 Emissions (tons)	Total portfolio NOx Emissions (tons)	Water Use (mmgal)	CCP (tons)	% Renewable Energy in 2032	Composite score from Reliability Analysis	Lowest PVRR across policy scenarios ($000,000)	Highest PVRR across policy scenarios ($000,000)	P5 [Mean - P5]	P95 [P95 – Mean]	20-year avg sales + purchases (GWh)	Portfolio PVRR w/ low renewable cost ($000,000)	Portfolio PVRR w/ high renewable cost ($000,000)	Total change in FTEs associated with generation 2023 - 2042	Total amount of property tax paid from AES IN assets ($000,000)
1	$ 9,572	101.9	64,991	45,605	36.7	6,611	45%	7.95	$ 8,860	$ 11,259	$ 9,271	$ 9,840	5,291	$ 9,080	$ 10,157	222	$ 154
2	$ 9,330	72.5	13,513	22,146	7.9	1,417	55%	7.95	$ 8,564	$ 11,329	$ 9,030	$ 9,746	5,222	$ 8,763	$ 9,999	99	$ 193
3	$ 9,773	88.1	45,544	42,042	26.7	4,813	52%	7.86	$ 9,288	$ 11,462	$ 9,608	$ 10,237	5,737	$ 9,244	$ 10,406	195	$ 204
4	$ 9,618	79.5	25,649	24,932	15.0	2,700	48%	7.90	$ 9,135	$ 11,392	$ 9,295	$ 9,903	5,512	$ 9,104	$ 10,249	74	$ 242
5	$ 9,711	69.8	25,383	24,881	14.8	2,676	64%	7.57	$ 9,590	$ 11,275	$ 9,447	$ 10,039	6,088	$ 9,017	$ 10,442	55	$ 256
6	$ 9,262	76.1	18,622	25,645	10.9	1,970	54%	7.95	$ 8,517	$ 11,226	$ 8,952	$ 9,629	5,136	$ 8,730	$ 9,909	88	$ 185

Strategies

1. No Early Retirement
2. Pete Conversion to Natural Gas (est. 2025)
3. One Pete Unit Retires in 2026
4. Both Pete Units Retire in 2026 and 2028
5. Clean Energy Strategy – Both Pete Units Retire and replaced with Renewables in 2026 and 2028
6. Encompass Optimization without Predefined Strategy

Source: Recreated from AES Indiana 2022 Scorecard Results, Figure 9-78.

AES Indiana based its evaluation categories (affordability; environmental sustainability; reliability, stability, and resiliency; risk and opportunity; and economic impact) on a set of pillars for electric utility service defined by a task force created by the Indiana General Assembly. This kind of intentional alignment with policy areas of interest helps ensure that the IRP is most informative for regulators (AES Indiana 2022). The scorecard clearly explains each category in detail in the text of the IRP and breaks it down into a set of quantitative metrics (e.g., PVRR, total portfolio carbon dioxide emissions). While the chart uses colors to indicate high and low values for each metric, it also includes quantitative values. In addition, the IRP immediately defines coded scenarios below the figure for stakeholder reference. The IRP also did not roll all metrics into a single score for each scenario, so there is no question of how weighting may slant results. While this eliminates one area of concern, it also puts the onus on AES Indiana to clearly explain why Strategy 2 was selected as the preferred portfolio rather than Strategy 5, which appears to result in similar outcomes overall.

Best Practice 42. Report results clearly

Ensure that modeling results are reported in a way that is transparent and easy to understand.

Effective IRPs report results in a way that is transparent and easy to digest, with sufficient information for effective stakeholder engagement, review of modeling methodology and findings, and regulatory oversight. At the same time, providing too much unprocessed data without proper synthesis can

challenge all but the most sophisticated stakeholders to understand and provide input. This applies to scorecard matrices, as well as informational results that are not necessarily being used to evaluate or rank scenarios. Some stakeholders may have technical expertise to review raw data, and some may even want access to raw modeling data. Nevertheless, it is critical for the utility to summarize and synthesize results so that all stakeholders and regulators can understand the inputs, modeling process, and final results. A good example of a utility clearly reporting results and providing key information is Tucson Electric Power's 2023 IRP Dashboard (TEP 2023b).

Best practice IRPs provide a narrative for each scenario, alongside the following public information on results, at a minimum:

- Summary load and resources table for each portfolio, by year, for the full study period. The table summarizes all existing capacity by resource type, all new resource additions by resource type, the utility's demand forecast, and total capacity requirement including reserve margin—both firm (accredited) capacity and nameplate capacity. The table also includes the utility's firm capacity assumptions, including ELCC, for all resources.
- Summary table of generation (GWh) and capacity factors (percent) for each portfolio. The table summarizes generation by resource type and year, broken down by existing and new resources.
- Capacity graphs. These figures display firm capacity, nameplate capacity, and generation by resource type and by year.
- Table of air emissions**.** The table includes greenhouse gases and criteria pollutants by year for each portfolio.
- Table of plant retirements. The table shows retirement dates modeled for existing resources and indicates whether the date was programmed in or selected endogenously by the model through optimization.
- Table of new resources. The table clearly shows the quantity of new resources coming online each year, by resource type, showing both firm (accredited) capacity and nameplate capacity.
- Cost. Net PVRR over the short-term (5–10 year) and full study period (20 years or more), in absolute terms. While providing PVRR delta results from the preferred portfolio may also be useful, providing the final PVRR by scenario helps stakeholders contextualize the magnitude of the deltas.

Utilities can avoid providing stakeholders with an overwhelming number of metrics or scenarios while at the same time not obscuring important data with simplistic graphics.

Best Practice 43. Benchmark inputs and results to other utilities

While developing input assumptions and analyzing results, utilities can look to see how inputs and results of neighboring or similar utilities compare to each other. If there are major differences, these need to be justified or explained to stakeholders.

Over the next few years, dozens of utilities across the United States will produce and file IRP reports and annual updates. IRP practice could benefit immensely if utilities compared quantitative outcomes in their reports to provide data for benchmarks that stakeholders can use to assess appropriateness of IRP assumptions and results. Strong benchmarks require a large enough sample of utilities to serve as analogs that report customer number, peak demand, sales, and climate zone, among others, to produce normalized benchmark outputs. Examples of these quantitative outcomes include the expected percent of load growth for base and alternative scenarios, rates of adoption of renewable resources, speed of retirement of coal plants, and assumptions about resource costs and fuel prices. As part of its 2025 IRP process, Tennessee Valley Authority hired Deloitte to review the utility's 2019 IRP and conduct benchmarking of peer IRPs, including identifying key themes and trends to be considered in its current IRP (TVA 2024).

Looking Ahead: Publish standardized planning metrics for easy comparison

In addition to benchmarking against key planning assumptions in a public repository such as the Resource Planning Portal, the jurisdiction's utilities, regulatory commission, and stakeholders can agree on sets of standardized metrics that enable efficient comparison of IRP inputs and outputs. There is no current best practice in this area; these guidelines are aspirational.

For example, calculating, recording, and comparing average annual load growth might facilitate assessment of the reasonableness of load forecasts across utilities under normal conditions. A metric such as MW-kilometer of transmission capacity per MW of solar power may be a way to assess and compare the costs of renewable energy integration and support a discussion on assumptions that may be biasing estimated costs upwards or downwards. Regulators could define a set of standardized metrics that could be used to benchmark IRPs and support rigorous quantitative analysis of assumptions, parameters, and outputs. Under this potential best practice, utilities with assumptions that reasonably deviate from the norm would need to justify the differences.

Wilkerson et al. (2014)recognized the benefits of benchmarking for IRP a decade ago when they analyzed and compared plans filed by 38 load-serving entities. However, the same paper identified multiple shortcomings and inconsistencies in the collection and reporting of planning assumptions. Lawrence Berkeley National Laboratory started to address this issue by designing and developing the Resource Planning Portal, an online publicly available tool to collect key quantitative planning assumptions from IRPs (LBNL Planning Portal n.d.-a). The portal collects and shares key inputs and outputs for each IRP's preferred portfolio. Lab researchers seek to standardize the way IRP inputs and outputs are defined and recorded. Parameters recorded include annual consumption and peak load forecasts, annual energy efficiency and demand response resources, fleets of existing and planned generation and storage units, fuel prices, capital costs, and carbon costs.

Best Practice 44. Select a preferred portfolio

Select a preferred portfolio to guide near-term actions and justify any substantial deviations from the optimized portfolio.

Best practice IRPs identify a preferred portfolio, a collection of resource builds and retirements the utility selects based on one of the portfolios tested in the IRP process. The preferred portfolio reflects the utility's short- and long-term resource plan and serves as the basis of near-term procurement plans. A robust preferred portfolio is developed in the capacity expansion model and vetted comprehensively as part of the IRP process. Under this best practice, utilities avoid developing preferred portfolios outside the model or selecting a preferred portfolio that is a hybrid of multiple candidate portfolios at the end of the process—and not subject to the same level of sensitivity and risk analysis as other modeled portfolios. When the utility selects a preferred portfolio, it also is good practice to evaluate and explain any significant differences between optimized portfolios and the preferred portfolio. This is because the optimized portfolio is, by design, the least-cost portfolio for a scenario.

Traditionally, utilities select or design a preferred portfolio based on cost, as quantified by a portfolio's net PVRR. While net PVRR is a key pillar of scenario evaluation, and minimizing cost is important for utility customers, it is not the only differentiator between scenarios. Nor is it an automatic determinant of which examined portfolio the utility ought to select as the preferred portfolio. The portfolio may only appear least-cost in the context of the others the utility examined. If the modeling examined a narrow set of options, or used key inputs that were hardcoded, out of date, or poorly designed, the portfolio may not be the least-cost option available. Additionally, a portfolio may misleadingly appear least-cost because modeling did not fully capture and internalize associated risks and uncertainties (see Best Practice 29 and Best Practice 39).

Because the IRP process is tied to near-term procurement efforts, a preferred portfolio is essential to provide a clear short-term plan. If the utility does not select a preferred portfolio, it is likely not committing to a near-term procurement plan. Without a preferred portfolio, it is hard for stakeholders and regulators to focus their feedback and oversight. Considering the near-term action plan for resource procurement is an important part of the IRP review process. As discussed in Section VII of this report, IRP results can be important in other dockets, including in rate cases for determining cost recovery, in CPCN dockets for evaluating the reasonableness of new resource build proposals, in renewable portfolio standard compliance dockets for determining if resource plans meet state renewable energy requirements, and in fuel dockets for evaluating the reasonableness of utility fuel procurement and operational decisions.

The utility's selection of a preferred portfolio does not necessarily tie the utility to that portfolio, even in the short term, depending on how much and how quickly conditions change. But the preferred portfolio creates an important baseline for utility planning. The regulator may require the utility to justify changes to its resource plan, or why the plan has not changed if conditions shift markedly. Some states, such as Virginia (Virginia General Assembly, n.d.) and Oregon (Oregon 2021) require utilities to file IRP updates annually or when plans change significantly.

Best Practice 45. Model state goals and priorities in the preferred portfolio

Align the preferred portfolio with articulated state goals and priorities.

It is common for regulators to require specific IRP elements. A typical example is requiring the utility to select a "preferred portfolio," as discussed above. While the requirement to select a preferred portfolio does not prescribe resources that must be included, in many states, regulators require utilities to model specific scenarios and sensitivities to inform the preferred portfolio and make the results publicly available in a useful manner. Running mandated scenarios is not enough. The utility's modeling choices and presentation of results are critical for illuminating which factors affect planning costs and decisions.

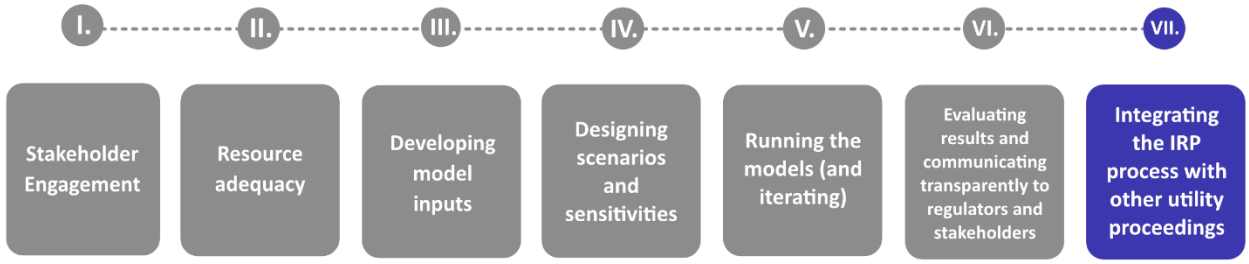
For example, the Arizona Corporation Commission required Arizona Public Service to run more than 10 specified scenarios for its 2023 IRP, including a minimal load growth scenario, rapid DSM adoption, and a variety of sensitivities that examined early retirement of the Four Corners coal power plant. While the utility followed through on this direction, some parties ultimately had concerns with how the utility designed and presented some of the scenarios—particularly the early coal plant retirement scenarios (Sierra Club 2024).

Running mandated scenarios is not enough. The utility's modeling choices and presentation of results are critical for illuminating which factors affect planning costs and decisions.

Arizona Public Service developed the required early retirement sensitivities by altering the retirement date of Four Corners in a reference case and then allowing the model to re-optimize. This method showed that early retirement in 2028, for example, would cost $139 million less than the reference case, which retired the plant in 2031. Separately, the utility designed a preferred portfolio, which maintains the 2031 retirement date but differs from the reference portfolio in other ways. Arizona Public Service concluded that this portfolio would be $357 million cheaper than the reference portfolio. The utility presented this information as evidence that the preferred portfolio would cost less than the portfolio representing the early retirement date.

Although Arizona Public Service followed the commission's direction in modeling additional scenarios, the scenarios differed in critical ways from the preferred portfolio. It is also unclear why the utility did not test earlier retirement dates for Four Corners using its preferred portfolio, not just the reference portfolio. Comparing an early retirement sensitivity in the reference portfolio to a 2031 retirement in the preferred portfolio is not an apples-to-apples comparison. In addition, since early retirement in the reference portfolio yielded lower costs, an early retirement sensitivity for the preferred portfolio also would have resulted in lower costs. Such analysis would have provided a full picture of potential cost savings across portfolios (Sierra Club 2024). In situations like these, regulators can scrutinize the scenarios modeled by the utility and request that the utility run additional scenarios that align with the commission's original goals.

VII. Integrating the IRP process with other utility proceedings



IRP scenario analysis requires careful design of modeling assumptions and possible pathways. It produces a wealth of useful data that has implications for the power system as a whole. Modeling assumptions that are intentionally prepared to easily port them into other modeling exercises have important consistency and transparency benefits. The following best practices apply to using IRP scenario results to inform other regulatory proceedings.

Best Practice 46. Use IRP results to inform an Action Plan and utility procurement processes

Integrate resource planning and related procurement processes.

A primary purpose of IRP scenario results is to inform utility procurement processes. In practice, this translates to utilities using IRPs to support an RFP, CPCN, or other procurement process. The first step in this direction is for the IRP to include a well-designed Action Plan.

The Action Plan is a section in the IRP document that describes near-term actions the utility will take over the next 1 to 3 years related to implementing outcomes in the preferred portfolio. An effective Action Plan is supported by the results, analysis, and conclusions of the IRP. It clearly states the action the utility plans to undertake to procure resources, including issuing RFPs, securing any required CPCN, initiating siting and licensing process, and deploying or expanding energy efficiency and demand response programs (LBNL 2021d). The Action Plan outlines how the utility plans to comply with specific regulatory requirements (e.g., a renewable portfolio standard target for an upcoming year) and proposes any regulatory changes that may be needed to support the development and execution of the preferred portfolio. In cases where the IRP recommends a wait-and-see strategy for risk management, the Action Plan can include near-term milestones to pursue the strategy (e.g., in an IRP update report, describe progress on a certain component of the IRP that was deemed uncertain). Finally, the Action Plan can outline near-term actions the utility identified to improve its analytical capabilities, such as developing certain datasets, working with vendors to implement new tools, or collaborating with stakeholders to refine input assumptions. PacifiCorp's 2023 IRP provides an example of a clear Action Plan, using a table

format to identify and organize near-term actions for specific units, projects, and regulatory requirements (PacifiCorp 2023).

A best practice for procurement is to use the same inputs and assumptions reviewed by regulators in the IRP process, unless there are significant changes in market conditions. In cases where the investment environment has changed from what the utility assumed in the most recently filed IRP, the utility can leverage scenario results to support departures from the preferred portfolio—given that scenarios are least-cost expansions of the bulk power system under different assumptions. If no existing scenarios match current investment conditions, the utility can conduct new scenario runs to support procurement decisions and ensure these procurement-specific scenarios inform the next IRP filing.

Best Practice 47. Use IRP results to inform other types of planning

Use IRP results to inform evolution of planning for bulk power systems and distribution systems.

IRP scenario results offer a range of potential pathways for evolution of the bulk power system. Several other planning processes would benefit from information on these pathways:

- Planning for distributed energy resource programs and virtual power plants. Wholesale electricity prices and new build capacity costs—especially when developed with thoughtful spatial resolution (V.Best Practice 32)—can be used for avoided cost calculations that serve as the basis for incentives for distributed energy resource programs. These same data can also inform assessments and planning for virtual power plants.
- Renewable Portfolio Standards planning. Comparison of system costs across pathways that offer different penetration levels of renewable resources, with different emissions profiles, can inform renewable energy certificate price forecasts and emission abatement cost estimates.
- Transmission planning. Transmission expansion decisions made by the capacity expansion model can inform more detailed regional transmission expansion studies.
- Distribution system planning. IRP assumptions and results on the relative balance between utility-scale and distributed energy resources can inform distribution system analysis—in particular, distributed energy resource adoption and operation scenarios. IRP scenario assumptions and model results that capture interactions between distributed and bulk power system resources are critical inputs into distribution system planning analysis. Conversely, high levels of distributed energy resources at the distribution level impact the need for bulk power system resources, as well as bulk power system operation. A growing number of states require integrated distribution system planning (LBNL n.d.-b), a decision framework that addresses interactions across planning domains and enables formulation of long-term grid investment strategies to address policy objectives and priorities, consumers' needs, and evolution at the grid edge (U.S. DOE n.d.).

Best Practice 48. Evaluate bill impacts

Evaluate bill impacts by customer class as part of the IRP process.

IRP modeling evaluates how resource decisions impact total system costs, not how decisions impact cost recovery and cost allocation. If a resource planning decision is likely to have a significant impact on system costs and customer bills, ignoring rate impacts during an IRP may lead to unexpected impacts on utility customers. Examples of such decisions are large buildouts of supply-side resources to meet data center load growth and retirement decisions for aging power plants.

First, data center load is expected to grow dramatically in many parts of the country. The attractiveness of these locations to prospective data centers is based in large part on current low power costs. But to meet projected data center load, utilities are proposing to build a substantial quantity of new resources and continue to operate aging resources. The new power system will not look or cost the same as the current system, and therefore electricity rates are not likely to be the same. Regulators need information on what portion of bulk power system costs the data centers are likely to pay, and what portion residential and other customer classes will pay to make well-informed decisions regarding approval of new supply-side resources. This is particularly important in the case where the utility considers data center load as a potential market to justify new generating resources, even though the load would be located outside the utility service territory, where the utility has no obligation to serve (GPC 2023 Response to STF-JFK Data Request 4-4).

Second, for aging fossil fuel plants, utilities can analyze different ratemaking options to determine retail rate impacts and impacts on retirement timelines. Once a utility has identified in an IRP proceeding an economic early retirement date, it can explore all ratemaking options under which to economically retire that unit. Such analyses can be included as part of the IRP process, or the analysis may be done partially or entirely outside of an IRP proceeding—for example, in a rate case.

Typically, utilities depreciate assets according to a depreciation schedule aligned with the useful life of the resource. Ideally, by the time the asset retires, its value has been fully depreciated and it is removed from rate base. But when an asset becomes uneconomic before its scheduled retirement date, the utility and the regulator have options for addressing the remaining plant balance. Generally, maintaining the existing depreciation schedule while retiring a plant early is not an option, given the misalignment it would perpetuate between when costs are incurred and when they are recovered through rates. Stated another way, it is not good rate design practice to spread cost recovery out over a period of time when the asset is no longer providing value to utility customers.[36]

Regulatory options include the following:

1. *Status quo depreciation and retirement.* The utility can continue to operate the unit for its planned lifetime, regardless of economics, to allow the utility to continue to collect a full rate of return on the asset. The utility will continue to spend capital to maintain the asset, which will be

[36] In some states, such practice is unlawful. For example, Oregon ORS 757.355 states, "...a public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer." (Oregon n.d.).

added to rate base, and will continue to pass costs onto utility customers for the originally planned lifetime.

2. *Accelerated depreciation and retirement.* A utility can request to adopt an accelerated depreciation schedule to more closely align the depreciation schedule for the resource with a retirement date that is earlier than the planned lifetime. This can cause rate shock if the change in schedule is too drastic (e.g., going from 15 years remaining lifetime to 5 years). To mitigate the shock, the utility can adjust the pace of accelerated retirement.
3. *Disallowance.* The regulator can disallow recovery of some or all undepreciated costs of the asset before the retirement date, with shareholders picking up the cost. However, this is more common for specific capital investments that are deemed imprudent, rather than for remaining balances for plants determined to be prudent at the time of the original investment.
4. *Regulatory asset.* The utility can turn the remaining plant balance into a regulatory asset with a depreciation date somewhere between the original date and the current retirement date. The negotiated rate of return would be lower than what the utility was collecting originally.
5. *Securitization or other alternative finance mechanism.* The utility can use securitization (where allowed by law) or another alternative financing mechanism, such as a loan from the Energy Infrastructure Reinvestment program under the IRA, to retire the plant early. The rate of return the utility receives on the asset would be lower than it was receiving before, but cost recovery of the remaining balance is more secure. For example, after its 2019/2020 IRP, CenterPoint Energy Indiana South pursued securitization of its A.B. Brown coal units as part of its generation transition plan (CenterPoint Energy 2023).

Best Practice 49. Consider energy justice comprehensively

Factor energy justice into all parts of an IRP process and engage impacted communities.

Energy justice considerations are best factored in throughout the IRP process, from the time planners choose a model, develop input assumptions, and run scenarios, to when they present results to stakeholders and regulators. While energy justice is not a new concept, it is an emerging field of inquiry—in part because much of the data needed to fully estimate the comparative impacts of portfolios on impacted communities are not readily available. An emerging best practice for utilities is to begin to collect data on impacts of concern (e.g., high energy burdens, health impacts from emissions, poor system reliability) for priority populations (e.g., disadvantaged communities, minorities, customers with low incomes, customers who are medically dependent on electric service) during IRP processes. As the utility collects more data, it can be used to inform more detailed integration of energy justice considerations in future IRP cycles. Some jurisdictions are beginning to require this level of detail. For example, Washington state law requires electric utilities to file a clean energy implementation plan every 4 years. By law, the plan must identify highly impacted communities and vulnerable populations, as well as quantify customer benefits and reduction of burdens (Washington State Legislature 2022).

A comprehensive discussion of how energy justice factors into various best practices discussed in this report is outside our scope. Resources on this topic include a recently published report by Lawrence Berkeley National Laboratory and Synapse on distributional equity impacts of utility programs for energy

efficiency and other distributed energy resources, which could be useful for informing equitable decision-making in the context of resource planning (LBNL and Synapse 2024).

RMI highlights several best practices for addressing energy justice in IRPs, such as the following (RMI 2023):

- Plan for community transition associated with asset retirements, including job losses, increased unemployment, loss of tax revenue, and reduced property values.
- Estimate comparative rate impacts of portfolios.
- Define and map disadvantaged communities to assess impacts, using tools such as Climate and Economic Justice Screening tool (CEJST), developed by the U.S. Council on Environmental Quality (U.S. CEQ CEJST n.d.), and Environmental Justice Screen (EJScreen) developed by the EPA (U.S. EPA EJScreen 2014)
- Factor community acceptance into resource availability and feasibility of plans.

Additionally, resource planners can also consider the following actions:

- Provide translation services and IRP modeling results in multiple languages suited to a utility's customers (refer to Best Practice 1 on creating an inclusive stakeholder process).
- Factor in resilience and disproportionate impacts during extreme events (Synapse 2021).
- Explicitly define how programs for energy efficiency and other distributed energy resources deployment support energy justice objectives.
- Define energy justice metrics and quantify how well each portfolio scores with respect to these metrics (see Step 4, Develop DEA metrics, in the Distributional Equity Analysis Practical Guide for information on how to do this) (LBNL and Synapse 2024).
- Publish and map pollutant values for existing assets and potential portfolios.
- Develop environmental and health cost scenarios and analyze portfolio impacts.

Hawaiian Electric Company is among utilities that have started to incorporate energy justice practices into resource planning processes. The utility mapped locations for microgrid hosting based on criticality (emergency or critical loads, facilities or infrastructure), vulnerability (areas that are prone to natural hazards, are inaccessible, or have experienced high outage rates), and societal impact (locations with social implications). For the societal impact criterion, Hawaiian Electric mapped disadvantaged communities using EJScreen (Hawaiian Electric 2022).

Figure 8 provides additional resources (clickable) with information on advancing energy justice in an IRP process.

Figure 8. Additional resources on advancing energy justice in an IRP process—Click to view



Best Practice 50. Consider the evolving natural gas distribution industry

Track the technical, financial, and regulatory developments of natural gas distribution firms operating in the electric utility's service territory to improve coordination.

Electricity IRPs and gas distribution system planning are closely linked in multiple ways. For example, in areas of the Northeast that have limited access to natural gas, winter gas demand for building heating is creating emerging reliability challenges for natural-gas-fired power plants. Looking to the future, growing electrification of customer technologies such as water heaters, space heating systems, and cooking appliances is expected to increasingly transfer energy demand from gas distribution systems to electricity systems. This may change the dynamics of natural gas availability in places such as the Northeast and have wider effects nationwide on electricity IRPs and gas distribution planning. Crucially, economic decommissioning of natural gas distribution system assets, due to reduced gas demand, would prompt unexpected switching to electrified end uses across residential and commercial customers.

A best practice for electric utilities would be to track the technical, financial, and regulatory developments of natural gas distribution firms operating entirely or partially in their service territories. The IRP section that describes the utility's planning environment could describe the status of these

natural gas distribution firms and potentially inform a sensitivity analysis for load forecasting that includes larger blocks of customers shifting to electrified end uses due to natural gas service phase-out.

Looking Ahead: Integrate electricity and natural gas industry planning

An emerging practice points towards integration of electricity and natural gas industry planning to ensure improved coordination for optimal societal outcomes, both economic and distributional. A potential decrease in customers on gas distribution systems would translate to fewer customers available to pay for their maintenance. This may increase the financial burden on remaining gas customers, which raises energy justice concerns if higher-income customers electrify first and the risk of higher gas rates falls on those who are already disadvantaged. For example, the state of Washington issued a rulemaking decision mandating Integrated System Planning across electricity and natural gas (WA UTC 2024).

Conclusion

Resource planning is challenging. During times of transition and market uncertainty it becomes even harder. It also becomes more important. As we leave behind a decade of flat load growth and look forward to projections of record load growth and continued decarbonization and electrification, robust resource planning is necessary to identify economic and reliable resource plans to serve utility customers, balancing uncertainties and risks facing the U.S. power sector today.

This guide outlines a list of 50 best practices for resource planning. They cover stakeholder engagement, resource adequacy, model input development, scenario and sensitivity design, modeling, portfolio and result evaluation, and integration of the IRP process with other proceedings.

Some best practices are straightforward and simple to implement while others require a considerable shift and reform of the resource planning process. All of these best practices represent actions or approaches we have seen implemented, or at the very least studied, by one of more utilities. Implementation steps vary, based on each utility's current planning practice.

The objective of this guide is to provide concrete steps for progress. While an ideal IRP process incorporates all best practices, IRP reform takes time. Utilities can use the guide to develop a roadmap and plan for how to improve the robustness of their IRP processes. Stakeholders can use the guide to help prioritize their engagements in the IRP process and identify where utilities are falling short. And regulators can use the guide to evaluate the reasonableness and robustness of each element of the IRP process and decide where to direct utilities to shift their approach to meet a higher standard for planning.

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EXHIBIT 56

Trump Signs Orders Aimed at Reviving a Struggling Coal Industry

The moves include loosening environmental rules, but it is unclear how much they can help reverse the sharp decline in coal power over the last two decades.

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By Brad Plumer and Mira Rojanasakul
Reporting from Washington

April 8, 2025

President Trump signed a flurry of executive orders Tuesday aimed at expanding the mining and burning of coal in the United States, in an effort to revive the struggling industry.

One order directs federal agencies to repeal any regulations that “discriminate” against coal production, to open new federal lands for coal mining and to explore whether coal-burning power plants could serve new A.I. data centers. Mr. Trump also said he would waive certain air-pollution restrictions adopted by the Biden administration for dozens of coal plants that were at risk of closing down.

In a move that could face legal challenges, Mr. Trump directed the Energy Department to develop a process for using emergency powers to prevent unprofitable coal plants from shutting down in order to avert power outages. Mr. Trump proposed a similar action in his first term but eventually abandoned the idea after widespread opposition.

Flanked by dozens of miners in white hard hats at the White House, Mr. Trump said he was also instructing the Justice Department to identify and fight state and local climate policies that were “putting our coal miners out of business.” He added that he would issue “guarantees” that future administrations could not adopt policies harmful to coal, but did not provide details.

“This is a very important day to me because we’re bringing back an industry that was abandoned despite the fact that it was the best, certainly the best in terms of power, real power,” Mr. Trump said.

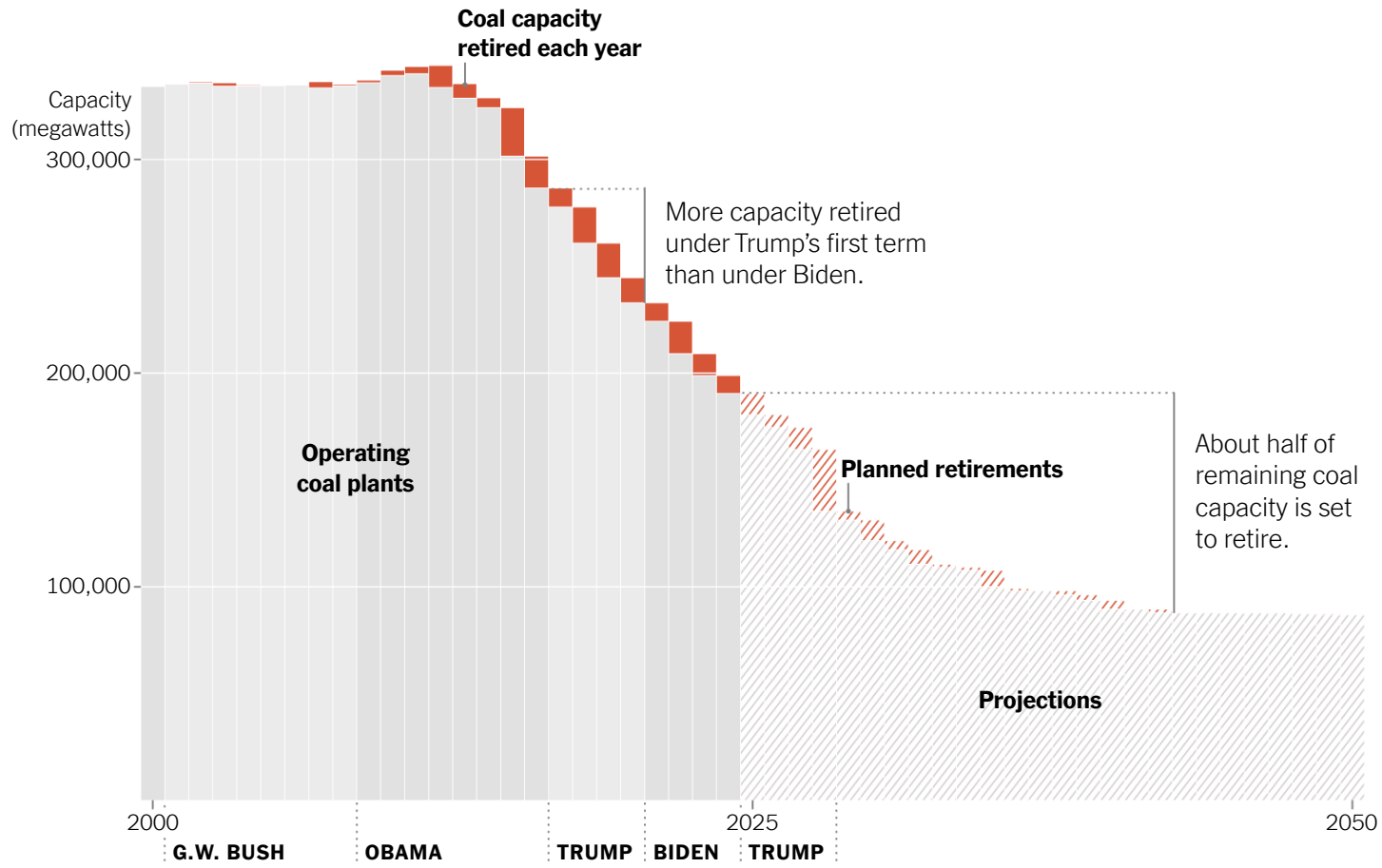
In recent weeks, Mr. Trump, Chris Wright, the energy secretary, and Doug Burgum, the interior secretary, have all spoken about the importance of coal. The two cabinet members sat in the front row at the White House ceremony, which was attended by members of Congress from Wyoming, Kentucky, West Virginia and other coal-producing states.

“Beautiful clean coal,” Mr. Trump told the gathering. “Never use the word ‘coal’ unless you put ‘beautiful, clean’ before it.”

Coal is the most polluting of all fossil fuels when burned, and accounts for roughly 40 percent of the world’s industrial carbon dioxide emissions, the main driver of global warming. It releases other pollutants, including mercury and sulfur dioxide, that are linked to heart disease, respiratory problems and premature deaths. Coal mining and the resulting coal ash from power plants can also present environmental problems.

Over the past two decades, the use of coal has fallen precipitously in the United States, as utilities have switched to cheaper and cleaner electricity sources like natural gas, wind and solar power. That transition has been the biggest reason for the drop in U.S. emissions since 2005.

Coal power has declined sharply — and more retirements are coming.



Source: Global Energy Monitor and New York Times reporting. • Note: Includes coal capacity added. • By Mira Rojanasakul/The New York times

It is unclear how much Mr. Trump could reverse that decline. In 2011, the nation generated nearly half of its electricity from coal; last year, that fell to just 15 percent. Utilities have already closed hundreds of aging coal-burning units and have announced retirement dates for roughly half of the remaining plants.

In recent years, growing interest in artificial intelligence and data centers has fueled a surge in electricity demand, and utilities have decided to keep more than 50 coal-burning units open past their scheduled closure dates, according to America's Power, an industry trade group. And as the Trump administration moves to loosen pollution limits on coal power — including regulations applied to carbon dioxide and mercury — more plants could stay open longer, or run more frequently.

"You know, we need to do the A.I., all of this new technology that's coming on line," Mr. Trump said on Tuesday. "We need more than double the energy, the electricity, that we currently have."

Yet a major coal revival is unlikely, some analysts said.

“The main issue is that most of our coal plants are older and getting more expensive to run, and no one’s thinking about building new plants,” said Seth Feaster, a data analyst who focuses on coal at the Institute for Energy Economics and Financial Analysis, a research firm. “It’s very hard to change that trajectory.”

During his first term, Mr. Trump sought to prevent unprofitable coal plants from closing, using emergency authority that is normally reserved for fleeting crises like natural disasters. But that idea brought a fierce blowback from oil and gas companies, grid operators and consumer groups, who said it would drive up electricity bills, and the administration eventually backed away from the idea.

If the idea was tried again today, it would be likely to lead to lawsuits, said Ari Peskoe, director of the Electricity Law Initiative at Harvard Law School. “But there’s not a lot of litigation history here,” he said. “Typically these emergency orders last for no longer than 90 days.”

Ultimately, Mr. Trump struggled to fulfill his first-term pledge of rescuing the coal industry. Despite the fact that his administration repealed numerous climate regulations and appointed a coal lobbyist to lead the Environmental Protection Agency, 75 coal-fired power plants closed, and the industry shed about 13,000 jobs during his presidency.

Coal’s decline continued under President Joseph R. Biden Jr., who sought to move the country away from the fossil fuel altogether in an effort to fight climate change. Last year, his administration issued a sweeping E.P.A. rule that would have forced all of the nation’s coal plants to either install expensive equipment to capture and bury their carbon dioxide emissions or shut down by 2039.

This year, upon returning to office, Mr. Trump ordered the E.P.A. to repeal that rule. And Trump administration officials have repeatedly warned that shutting down coal plants would harm power supplies. Unlike wind and solar energy, coal plants can run at any hour of the day, making them useful when electricity demand spikes.

Some industry executives who run the nation’s electric grids have also warned that the country could face a greater risk of blackouts if too many coal plants retire too quickly, especially since power companies have faced delays in bringing new gas, wind and solar plants online, as well as in adding battery storage and transmission lines.

“For decades, most people have taken electricity and coal for granted,” said Michelle Bloodworth, chief executive of America’s Power. “This complacency has led to damaging federal and state policies that have caused the premature retirement of coal plants, thus weakening our electric grid and threatening our national security.”

Yet coal opponents say that keeping aging plants online can worsen deadly air pollution and increase energy costs. Earlier this year, PJM Interconnection, which oversees a large grid in the Mid-Atlantic, ordered a power plant that burns coal and another that burns oil to stay open until 2029, four years past their planned retirement date, to reduce the risk of power outages. The move could ultimately cost utility customers in the area of more than $720 million.

“Coal plants are old and dirty, uncompetitive and unreliable,” said Kit Kennedy, managing director for power at the Natural Resources Defense Council, an environmental group. “The Trump administration is stuck in the past, trying to make utility customers pay more for yesterday’s energy. Instead, it should be doing all it can to build the electricity grid of the future.”

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A version of this article appears in print on , Section A, Page 15 of the New York edition with the headline: Trump Signs Orders Aimed At Reviving Coal Industry

EXHIBIT 57

BRENNAN CENTER FOR JUSTICE

Declared National Emergencies Under the National Emergencies Act

Emergencies that are still in effect today are shaded in the table below.
Emergencies that did *not* involve the International Emergency Economic Powers Act (IEEPA) are indicated with an asterisk (*)

	Declaration	Date	Title	Citation/Status
1.	E.O. 12170	11/14/79	Blocking Iranian Government Property	3 C.F.R., 1979 Comp., pp. 457-458; *most recently continued by notice of 11/05/25, see 90 FR 50735.*
2.	E.O. 12211	04/17/80	Further Prohibitions on Transactions with Iran	3 C.F.R., 1980 Comp., pp. 253-255; *prohibitions revoked but national emergency left in effect by E.O. 12282 of 01/19/81. National emergency does not appear to have ever been terminated or continued.*
3.	E.O. 12444	10/14/83	Continuation of Export Control Regulations	3 C.F.R., 1983 Comp., pp. 214-215; *revoked by E.O. 12451 of 12/20/83.*
4.	E.O. 12470	03/30/84	Continuation of Export Control Regulations	3 C.F.R., 1984 Comp., pp. 168-169; *revoked by E.O. 12525 of 07/12/85.*
5.	E.O. 12513	05/01/85	Prohibiting Trade and Certain Other Transactions Involving Nicaragua	3 C.F.R., 1985 Comp., p. 342; *revoked by E.O. 12707 of 03/13/90.*
6.	E.O. 12532	09/09/85	Prohibiting Trade and Certain Other Transactions Involving South Africa	3 C.F.R., 1985 Comp., pp. 387-391; *revoked by E.O. 12769 of 07/10/91.*
7.	E.O. 12543	01/07/86	Prohibiting Trade and Certain Transactions Involving Libya	3 C.F.R., 1986 Comp., pp. 181-182; *revoked by E.O. 13357 of 09/20/04.*
8.	E.O. 12635	04/08/88	Prohibiting Certain Transactions with Respect to Panama	3 C.F.R., 1988 Comp., pp. 563-564; *revoked by E.O. 12710 of 04/05/90.*
9.	E.O. 12722	08/02/90	Blocking Iraqi Government Property and Prohibiting Transactions with Iraq	3 C.F.R., 1990 Comp., pp. 294-295; *expanded in scope by E.O. 12743 of 01/18/91; revoked by E.O. 13350 of 07/29/04.*

10.	E.O. 12730	09/30/90	Continuation of Export Control Regulations	3 C.F.R., 1990 Comp., pp. 305-306; *revoked by E.O. 12867 of 09/30/93.*
11.	E.O. 12735	11/16/90	Chemical and Biological Weapons Proliferation	3 C.F.R., 1990 Comp., pp. 313-316; *revoked by E.O. 12938 of 11/14/94.*
12.	E.O. 12775	10/04/91	Prohibiting Certain Transactions with Respect to Haiti	3 C.F.R., 1991 Comp., pp. 349-350; *revoked by E.O. 12932 of 10/14/94.*
13.	E.O. 12808	05/30/92	Blocking "Yugoslav Government" Property and Property of the Governments of Serbia and Montenegro	3 C.F.R., 1992 Comp., pp. 305-306; *revoked by E.O. 13304 of 05/28/03.*
14.	E.O. 12865	09/26/93	Prohibiting Certain Transactions Involving UNITA	3 C.F.R., 1993 Comp., pp. 636-638; *revoked by E.O. 13298 of 05/06/03.*
15.	E.O. 12868	09/30/93	Measures to Restrict the Participation by United States Persons in Weapons Proliferation Activities	3 C.F.R., 1993 Comp., pp. 650-651; *revoked by E.O. 12930 of 09/29/94.*
16.	E.O. 12923	06/30/94	Continuation of Export Control Regulations	3 C.F.R., 1994 Comp., pp. 916-917; *revoked by E.O. 12924 of 08/19/94.*
17.	E.O. 12924	08/19/94	Continuation of Export Control Regulations	3 C.F.R., 1994 Comp., pp. 917-919; *revoked by E.O. 13206 of 04/04/01.*
18.	E.O. 12930	09/29/94	Measures to Restrict the Participation by United States Persons in Weapons Proliferation Activities	3 C.F.R., 1994 Comp., pp. 924-925; *revoked by E.O. 12938 of 11/14/94.*
19.	E.O. 12934	10/25/94	Blocking Property and Additional Measures With Respect to the Bosnian Serb- Controlled Areas of the Republic of Bosnia and Herzegovina	3 C.F.R., 1994 Comp., pp. 930-932; *revoked by E.O. 13304 of 05/28/03.*
20.	E.O. 12938	11/14/94	Proliferation of Weapons of Mass Destruction	3 C.F.R., 1994 Comp., pp. 950-954; *amended by E.O. 13094 of 07/30/98, E.O. 13382 of 06/28/05, and E.O. 13883 of 08/01/19; most recently continued by notice of 11/05/25, see 90 FR 50737.*
21.	E.O. 12947	01/23/95	Prohibiting Transactions with Terrorists Who Threaten to Disrupt the Middle East Peace Process	3 C.F.R., 1995 Comp., pp. 319-320; *amended by E.O. 13099 of 08/20/98, E.O. 13224 of 09/23/01, and E.O. 13372 of 02/16/05; revoked by E.O. 13886 of 09/09/19. E.O. 13224 is listed as a separate emergency and remains in effect.*

22.	E.O. 12957	03/15/95	Prohibiting Certain Transactions with Respect to the Development of Iranian Petroleum Resources	3 C.F.R., 1995 Comp., pp. 332-333; *supplemented by E.O. 12959 of 05/06/95; revoked in part by E.O. 13059 of 08/19/97; expanded by E.O. 13553 of 09/28/10, E.O. 13606 of 04/22/12, E.O. 13846 of 08/06/18, E.O. 13902 of 01/10/20, and E.O. 13949 of 09/21/20; most recently continued by notice of 03/07/25, see 90 FR 11887 (technically lapsed for two months in 2018, because the 2017 one-year extension was issued on 01/13/17, see 82 FR 6187, and the subsequent renewal notice was not issued until 03/12/18, see 83 FR 11393). E.O. 13606 amended by E.O. 14312 of 06/30/25.*
23.	E.O. 12978	10/21/95	Blocking Assets and Prohibiting Transactions with Significant Narcotics Traffickers	3 C.F.R., 1995 Comp., pp. 415-417; *amended by E.O. 13286 of 02/28/03; most recently continued by notice of 10/16/25, see 90 FR 48391.*
24.	Proc. 6867*	03/01/96	Regulation of the Anchorage and Movement of Vessels with Respect to Cuba	3 C.F.R., 1996 Comp., pp.; *expanded by Proc. 7757 of 02/26/04; modified by Proc. 9398 of 02/24/16 and Proc. 9699 of 02/22/18; most recently continued by notice of 02/20/25, see 90 FR 10571.*
25.	E.O. 13047	05/22/97	Prohibiting New Investment in Burma	3 C.F.R., 1997 Comp., pp. 202-204; *revoked in part by E.O. 13310 of 07/28/03; expanded by E.O. 13448 of 10/18/07, E.O. 13464 of 04/30/08, E.O. 13619 of 07/11/12, and E.O. 13651 of 08/06/13; terminated by E.O. 13742 of 10/07/16.*
26.	E.O. 13067	11/03/97	Blocking Sudanese Government Property and Prohibiting Transactions with Sudan	3 C.F.R., 1997 Comp., pp. 230-231; *expanded by E.O. 13400 of 04/26/06, E.O. 13412 of 10/13/06, and E.O. 14098 of 05/04/23; revoked in part by E.O. 13761 of 01/13/17; most recently continued by notice of 10/16/25, see 90 FR 48393.*

27.	E.O. 13088	06/09/98	Blocking Property of the Governments of the Federal Republic of Yugoslavia (Serbia and Montenegro), the Republic of Serbia, and the Republic of Montenegro, and Prohibiting New Investment in the Republic of Serbia in Response to the Situation in Kosovo	3 C.F.R., 1998 Comp., pp. 191-193; *revoked by E.O. 13304 of 05/28/03.*
28.	E.O. 13129	07/04/99	Blocking Property and Prohibiting Transactions with the Taliban	3 C.F.R. 1999 Comp., pp. 200-203; *revoked by E.O. 13268 of 07/02/02.*
29.	E.O. 13159	06/21/00	Blocking Property of the Government of the Russian Federation Relating to the Disposition of Highly Enriched Uranium Extracted from Nuclear Weapons	3 C.F.R. 2000 Comp., pp. 277-278; *expired as of 06/21/13 pursuant to section 202(d) of the National Emergencies Act; E.O. 13617, issued 06/25/12, declared a new national emergency that had the practical effect of protecting the same property and interests blocked by E.O. 13159.*
30.	E.O. 13194	01/18/01	Prohibiting the Importation of Rough Diamonds from Sierra Leone	3 C.F.R. 2001 Comp., pp. 741-743; *expanded by E.O. 12213 of 05/22/01; revoked by E.O. 13324 of 01/15/04.*
31.	E.O. 13219	06/26/01	Blocking Property of Persons Who Threaten International Stabilization Efforts in the Western Balkans	3 C.F.R. 2001 Comp., pp. 778-782; *revised by E.O. 13304 of 05/28/03; scope expanded by E.O. 14033 of 06/08/21 and E.O. 14140 of 01/08/25; most recently continued by notice of 06/20/25, see 90 FR 26917.*
32.	E.O. 13222	08/17/01	Continuation of Export Control Regulations	3 C.F.R. 2001 Comp., pp. 783-784; *originally modified E.O. 12947 of 01/23/95, now revoked; amended by E.O. 13637 of 03/08/13; most recently continued by notice of 08/04/25, see 90 FR 37999.*
33.	Proc. 7463*	09/14/01	Declaration of National Emergency by Reason of Certain Terrorist Attacks	*3 C.F.R. 2001 Comp., p. 263; expanded by E.O. 13223 of 09/14/01;* E.O. 13235 of 11/16/01; and E.O. 13321 of 12/17/03; most recently continued by notice of 08/29/25, see 90 FR 42695.* **Most expansions of authority under this declaration were announced as amendments to E.O. 13223, including: E.O. 13253 of 01/16/02, E.O. 13286 of 02/28/03, and E.O. 13814 of 10/20/17.*

34.	E.O. 13224	09/23/01	Blocking Property and Prohibiting Transactions With Persons Who Commit, Threaten To Commit, or Support Terrorism	3 C.F.R. 2001 Comp., pp. 786-789; *amended by E.O. 13268 of 07/02/02, E.O. 13284 of 01/23/03, E.O. 13372 of 02/16/05, and E.O. 13886 of 09/09/19; most recently continued by notice of 09/08/25, see 90 FR 43903.*
35.	E.O. 13288	03/06/03	Blocking Property of Persons Undermining Democratic Processes or Institutions in Zimbabwe	3 C.F.R. 2003 Comp., pp. 186-191; *amended and superseded in part by E.O. 13391 of 11/22/05; most recently continued by notice of 03/01/23, see 88 FR 13289; terminated by E.O. 14118 of 03/04/24.*
36.	E.O. 13303	5/22/03	Protecting the Development Fund for Iraq and Certain Other Property in Which Iraq has an Interest	3 C.F.R. 2003 Comp., pp. 227-229; *scope expanded by E.O. 13315 of 08/28/03; substantive provisions terminated but emergency left in place by E.O. 13668 of 05/27/14; most recently continued by notice of 05/09/25, see 90 FR 20559.*
37.	E.O. 13338	05/11/04	Blocking Property of Certain Persons and Prohibiting the Export of Certain Goods to Syria	3 C.F.R. 2004 Comp., pp. 168-172; clarified E.O. 13399 of 04/25/2006; *amended by E.O. 13460 of 02/13/08; scope expanded by E.O. 13572 of 04/29/11, E.O. 13573 of 05/18/11, and E.O. 13606 of 04/22/12; most recently continued by notice of 05/07/25, see 90 FR 19619; E.O. 13338 and other E.O.'s listed revoked by E.O. 14312 of 06/30/25.*
38.	E.O. 13348	07/22/04	Blocking Property of Certain Persons and Prohibiting the Importation of Certain Goods from Liberia	3 C.F.R. 2004 Comp., pp. 189-195; *revoked by E.O. 13710 of 11/12/15.*
39.	Proc. 7924*	09/08/05	To Suspend Subchapter IV of Chapter 31 of Title 40, United States Code, Within a Limited Geographic Area in Response to the National Emergency Caused by Hurricane Katrina	*3 C.F.R. 2005 Comp., pp. 104-106; revoked by Proc. 7959 of 11/03/05.* ***This limited declaration did not initially cite the President's authority under the National Emergencies Act, but the revocation proclamation did. For more information, see Prevailing Wage Requirements and the Emergency Suspension of the Davis-Bacon Act, RL33276, Congressional Research Service, February 16, 2006, 4-7.*

40.	E.O. 13396	02/07/06	Blocking Property of Certain Persons Contributing to the Conflict in Côte d'Ivoire	3 C.F.R., 2006 Comp., *pp. 209-213; terminated by E.O. 13739 of 09/14/16.*
41.	E.O. 13405	06/16/06	Blocking Property of Certain Persons Undermining Democratic Processes or Institutions in Belarus	3 C.F.R., 2006 Comp., pp. 231-234; *expanded by E.O. 14038 of 08/09/21; most recently continued by notice of 06/09/25, see 90 FR 24953.*
42.	E.O. 13413	10/27/06	Blocking Property of Certain Persons Contributing to the Conflict in the Democratic Republic of the Congo	3 C.F.R., 2006 Comp., pp. 247-249; *amended by E.O. 13671 of 07/08/14; most recently continued by notice of 10/16/25, see 90 FR 48395.*
43.	E.O. 13441	08/01/07	Blocking Property of Persons Undermining the Sovereignty of Lebanon or Its Democratic Processes and Institutions	72 Fed. Reg. 43499-43501; *most recently continued by notice of 07/25/25, see 90 FR 35825.*
44.	E.O. 13466	06/26/08	Continuing Certain Restrictions With Respect to North Korea and North Korean Nationals	73 Fed. Reg. 36787-36788; *expanded by E.O. 13551 of 08/30/10, E.O. 13570 of 04/18/11, E.O. 13687 of 01/02/15, E.O. 13722 of 03/15/16, and E.O. 13810 of 09/20/17; most recently continued by notice of 06/20/25, see 90 FR 26915.*
45.	Proc. 8443*	10/23/09	Declaration of a National Emergency With Respect to the 2009 H1N1 Influenza Pandemic	74 Fed. Reg. 55439-55440; *does not appear to have ever been terminated or continued.*
46.	E.O. 13536	04/12/10	Blocking Property of Certain Persons Contributing to the Conflict in Somalia	75 Fed. Reg. 19869-19872; *amended by E.O. 13620 of 07/20/12; most recently continued by notice of 04/08/25, see 90 FR 15391.*
47.	E.O. 13566	02/25/11	Blocking Property and Prohibiting Certain Transactions Related to Libya	76 Fed. Reg. 11315-11318; *expanded by E.O. 13726 of 04/19/16; most recently continued by notice of 02/20/25, see 90 FR 10573.*
48.	E.O. 13581	07/24/11	Blocking Property of Transnational Criminal Organizations	76 Fed. Reg. 44757-44759; *expanded by E.O. 13863 of 03/15/19; most recently continued by notice of 07/21/25, see 90 FR 34759.*
49.	E.O. 13611	05/16/12	Blocking Property of Persons Threatening the Peace, Security, or Stability of Yemen	77 Fed. Reg. 29533-29535; *most recently continued by notice of 05/07/25, see 90 FR 20081.*

50.	E.O. 13617	06/25/12	Blocking Property of the Government of the Russian Federation Relating to the Disposition of Highly Enriched Uranium Extracted from Nuclear Weapons	77 Fed. Reg. 38457-38461; *revoked by E.O. 13695 of 05/26/15.*
51.	E.O. 13660	03/06/14	Blocking Property of Certain Persons Contributing to the Situation in Ukraine	79 Fed. Reg. 13491-13495; *expanded by E.O. 13661 of 03/16/14, E.O. 13662 of 03/20/14, and E.O. 14065 of 02/21/22; relied on for additional steps taken in E.O. 13685 of 12/19/14 and E.O. 13849 of 09/20/18; most recently continued by notice of 02/27/2025, see 90 FR 11009.*
52.	E.O. 13664	04/03/14	Blocking Property of Certain Persons With Respect to South Sudan	79 Fed. Reg. 19281-19285; *most recently continued by notice of 03/28/25, see 90 FR 14329.*
53.	E.O. 13667	05/12/14	Blocking Property of Certain Persons Contributing to the Conflict in the Central African Republic	79 Fed. Reg. 28385-28391; *most recently continued by notice of 05/07/25, see 90 FR 19621.*
54.	E.O. 13692	03/08/15	Blocking Property and Suspending Entry of Certain Persons Contributing to the Situation in Venezuela	80 Fed. Reg. 12747-12751; *expanded by E.O. 13808 of 08/24/17,* E.O. 13827 of 03/19/18, *E.O. 13835 of 05/21/18, and E.O. 13884 of 08/05/19; most recently continued by notice of 02/27/2025, see 90 FR 11011; expanded by E.O. 14245 of 03/24/25.*
55.	E.O. 13694	04/01/15	Blocking the Property of Certain Persons Engaging in Significant Malicious Cyber-Enabled Activities	80 Fed. Reg. 18077-18079; *amended by E.O. 13757 of 12/28/16, E.O. 13984 of 01/19/21, E.O. 14110 of 10/30/23, and E.O. 14144 of 01/16/25; most recently continued by E.O. 14327 of 03/27/25; further amended by E.O. 14306 on 06/06/25.*
56.	E.O. 13712	11/22/15	Blocking Property of Certain Persons Contributing to the Situation in Burundi	80 Fed. Reg. 73633-73636; *terminated by E.O. 14054 of 11/18/21.*
57.	E.O. 13818	12/20/17	Blocking the Property of Persons Involved in Serious Human Rights Abuse or Corruption	82 Fed. Reg. 60839-60843; *most recently continued by notice of 12/10/25, see 90 FR 57863.*
58.	E.O. 13848	09/12/18	Imposing Certain Sanctions in the Event of Foreign Interference in a United States Election	83 Fed. Reg. 46843-46848; *most recently continued by notice of 08/29/25, see 90 FR 42697.*

59.	E.O. 13851	11/27/18	Blocking Property of Certain Persons Contributing to the Situation in Nicaragua	83 Fed. Reg. 61505-61507; *relied on for additional steps taken in E.O. 14088 of 10/24/22; most recently continued by notice of 11/20/25, see 90 FR 53193.*
60.	Proc. 9844*	02/15/19	Declaring a National Emergency Concerning the Southern Border of the United States	84 Fed. Reg. 4949-4950; *continued by notice of 01/15/21, see 86 FR 6557; terminated by Proc. 10142 of 01/20/21; reinstated by Proc. 10886 on 01/20/2025, see 90 FR 8327.*
61.	E.O. 13873	05/15/19	Executive Order on Securing the Information and Communications Technology and Services Supply Chain	84 Fed. Reg. 22689-22692; *expanded by E.O. 13942 of 08/06/20, E.O. 13943 of 08/06/20, E.O. 13971 of 01/05/21, and E.O. 14034 of 06/09/21; most recently continued by notice of 05/09/2025, see 90 FR 20557.*
62.	E.O. 13882	07/26/19	Blocking Property and Suspending Entry of Certain Persons Contributing to the Situation in Mali	84 Fed. Reg. 37055-37058; *most recently continued by notice of 07/21/25, see 90 FR 34757.*
63.	E.O. 13894	10/14/19	Blocking Property and Suspending Entry of Certain Persons Contributing to the Situation in Syria	84 Fed. Reg. 55851-55855; *continued by notice of 09/30/25, see 89 FR 82929*; expanded by E.O. 14142 of 01/15/25 and *E.O. 14312 of 06/30/25.*
64.	Proc. 9994*	03/13/20	Declaring a National Emergency Concerning the Novel Coronavirus Disease (COVID-19) Outbreak	85 Fed. Reg. 15337-15338; *expanded by E.O. 13911 of 03/27/20, E.O. 13912 of 03/27/20,* and *E.O. 13916 of 04/18/20*; *further expanded by decisions of the Secretary of Homeland Security of 03/20/20 without additional E.O. at 85 FR 16547 (extended on 04/22/22 by 87 FR 24041) and 85 FR 16548 (extended on 04/22/22 by 87 FR 24048); terminated by H.J. Res. 7 on 04/10/23.*
65.	E.O. 13920	05/01/20	Securing the United States Bulk-Power System	85 Fed. Reg. 26595-26599; *suspended for 90 days by E.O. 13990 of 01/20/21; does not appear to have been formally terminated or continued.*
66.	E.O. 13928	06/11/20	International Criminal Court; Blocking Property of Certain Associates	85 Fed. Reg. 36139-36142; *terminated by E.O. 14022 of 04/01/21.*

67.	E.O. 13936	07/14/20	The President's Executive Order on Hong Kong Normalization	85 Fed. Reg. 43413-43417; *most recently continued by notice of 07/10/25, see 90 FR 31129.*
68.	E.O. 13953	09/30/20	Addressing the Threat to the Domestic Supply Chain From Reliance on Critical Minerals From Foreign Adversaries and Supporting the Domestic Mining and Processing Industries	85 Fed. Reg. 62539-62544; *does not appear to have ever been terminated or continued.*
69.	E.O. 13959	11/12/20	Addressing the Threat From Securities Investments That Finance Communist Chinese Military Companies	85 Fed. Reg. 73185-73189; *amended by E.O. 13974 of 01/13/20 and E.O. 14032 of 06/03/21; most recently continued by notice of 11/05/25, see 90 FR 50739.*
70.	E.O. 14014	02/10/21	Blocking Property With Respect to the Situation in Burma	86 Fed. Reg. 9429-9432; *most recently continued by notice of 02/04/25, see 90 FR 9111.*
71.’’’’’[[[

76.	E.O. 14078	07/19/22	Bolstering Efforts To Bring Hostages and Wrongfully Detained United States Nationals Home	87 Fed. Reg. 43389-43394; *most recently continued by notice of 07/15/25, see 90 FR 33869.*
77.	E.O. 14105	08/09/23	Addressing United States Investments in Certain National Security Technologies and Products in Countries of Concern	88 Fed. Reg. 54867-548; *most recently continued by notice of 08/06/25, see 90 FR 38601.*
78.	E.O. 14115	02/01/24	Imposing Certain Sanctions on Persons Undermining Peace, Security, and Stability in West Bank	89 Fed. Reg. 7605; most recently continued by notice of 01/14/25, see 90 FR 5467; *terminated by E.O. 14148 on 01/20/25, see 90 FR 8237.*
79.	E.O. 14117	02/28/24	Preventing Access to Americans' Bulk Sensitive Personal Data and United States Government-Related Data by Countries of Concern	89 Fed. Reg. 15421-15430.
80.	E.O. 14144	01/16/25	Strengthening and Promoting Innovation in the Nation's Cybersecurity	90 Fed. Reg. 6755-6771; *this order was a modification of E.O. 14028 of 05/12/2021; further amended by E.O. 14306 on 06/06/25.*
81.	E.O. 14156	01/20/2025	Declaring a National Energy Emergency	90 Fed. Reg. 8433-8437; *expanded by E.O. 14241 of 03/20/25; relied on for additional steps taken in E.O. 14262 of 04/08/25.*
82.	E.O. 14157	01/20/2025	Designating Cartels and Other Organizations as Foreign Terrorist Organizations and Specially Designated Global Terrorists	90 Fed. Reg. 8439-8440.
83.	Proc. 10886	01/20/2025	Declaring a National Emergency at the Southern Border of the United States	90 Fed. Reg. 8327-8329; clarified by E.O. 14167 of 01/20/25; further authority invoked by presidential memorandum on 04/11/25; modified by notice of 07/15/25, see 90 FR 37371.
84.	E.O. 14193	02/01/2025	Imposing Duties To Address the Flow of Illicit Drugs Across Our Northern Border	90 Fed. Reg. 9113; modified by E.O. 14197 of 02/03/25, E.O. 14193 to take effect on 03/04/25; amended by E.O. 14226 of 03/02/2025; amended by E.O. 14231 on 03/06/25; amended by E.O. 14324 on 07/30/25; further amended by E.O. 14325 of 07/31/25.

85.	E.O. 14194	02/01/2025	Imposing Duties To Address the Situation at Our Southern Border	90 Fed. Reg. 9117; *modified by E.O. 14198 of 02/03/25, E.O. 14194 to take effect on 03/04/25; amended by E.O. 14227 of 03/02/25; amended by E.O. 14324 on 07/30/25.*
86.	E.O. 14195	02/01/2025	Imposing Duties To Address the Synthetic Opioid Supply Chain in the People's Republic of China	90 Fed. Reg. 9121; *amended by E.O. 14200 of 02/05/25, E.O. 14228 of 03/03/25, E.O. 14256 of 04/02/25, E.O. 14259 of 04/08/25, E.O. 14324 on 07/30/25, and E.O. 14357 on 11/04/25.*
87.	E.O. 14203	02/06/2025	Imposing Sanctions on the International Criminal Court	90 Fed. Reg. 9369.
88.	E.O. 14257	04/02/2025	Regulating Imports With a Reciprocal Tariff To Rectify Trade Practices That Contribute to Large and Persistent Annual United States Goods Trade Deficits	*90 Fed. Reg. 15041; amended by E.O. 14259 of 04/08/25; modified by E.O. 14266 of 04/09/25, E.O. 14298 of 05/12/25, E.O. 14309 of 06/16/25 and E.O. 14316 of 07/07/25; amended by E.O. 14324 on 07/30/25; modified by E.O. 14326 of 07/31/25, E.O. 14334 of 08/11/25, E.O. 14345 of 09/04/25, E.O. 14346 of 09/05/25, E.O. 14358 of 11/04/25, and E.O. 14360 of 11/14/25.*
89.	E.O. 14323	07/30/2025	Addressing Threats to the United States by the Government of Brazil	90 Fed. Reg. 37739; modified by E.O. 14361 of 11/20/25.

EXHIBIT 58

Order No. 202-25-7

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. §7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

Order No. 202-25-3

J.H. Campbell Generating Plant (Campbell Plant) is a 1,420 MW coal-fired plant primarily owned by Consumers Energy Company (Consumers) and located in West Olive, MI. In 2021, Consumers announced that it planned to implement a "speed closure" of the Campbell Plant fifteen years before the end of its scheduled design life.[1] Instead of retiring the Campbell Plant at the end of its design life, Consumers planned to accelerate the Campbell Plant's retirement and discontinue its operations on May 31, 2025.

Order No. 202-25-3, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until August 21, 2025. That order was based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO). Specifically, I determined that MISO likely faced tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. I determined that the continued operation of the Campbell Plant would provide additional generation capacity during these periods which would help prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety. I determined that the continued operation of the Campbell Plant was necessary to alleviate immediate and anticipated threats to reliability. My determination was based on a number of facts.

First, the North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[2] In particular, NERC explained that the retirement of thermal generation capacity increased the likelihood of electricity supply

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[1] *See Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan's Clean Energy Transformation*, Consumers Energy (June 23, 2021), https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation. As a coal-fired facility, it would be difficult for the Campbell Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline.

[2] *2025 Summer Reliability Assessment*, North American Electric Reliability Corporation, at 16 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf (NERC 2025 Summer Reliability Assessment).

shortfalls. NERC anticipated that the near-term period of greatest capacity shortfall for MISO would likely occur in August.[3]

Second, multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[4] Additionally, EIA stated, "[t]ypically, Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[5] The state's Big Rock Point nuclear power plant shut down in 1997, and the Palisades nuclear power plant closed in 2022. While the Palisades nuclear power plant may reopen in 2025, it was not projected to be available during the peak demand period this summer.[6]

Third, the Campbell Plant's retirement would have further decreased available dispatchable generation within MISO's service territory, adding to the loss of the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. Although MISO and Consumers have incorporated the planned retirement of the Campbell Plant into their supply forecasts and Consumers acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates "elevated risk of operating reserve shortfalls."[7]

Fourth, MISO's Planning Resource Auction Results for the 2025-2026 Planning Year, released in April 2025, noted that for the northern and central zones, which includes Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[8] While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance" and these results "reinforce the need to increase capacity."[9]

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order No. 202-25-3 continue, both in the near and long term. The summer season has not yet ended, and the production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO this summer. That need is evidenced by the fact that the Campbell Plant was called on by MISO to generate large amounts of electricity during the heat wave that hit MISO this past June. According

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[3] *Id.*
[4] *Michigan State Profile and Energy Estimates*, U.S. Energy Info. Admin. (Oct. 17, 2024), https://www.eia.gov/state/print.php?sid=MI.
[5] *Id.*
[6] The start-up of Palisades is scheduled for the fourth quarter of 2025.
[7] NERC 2025 Summer Reliability Assessment at 16.
[8] *Planning Resource Auction—Results for Planning Year 2025–2026,* Midcontinent Independent System Operator, Inc., 13 (May 29, 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf. (MISO Planning Resource Auction – Results for Planning Year 2025-26).
[9] *Id*. at 2,12.

to the U.S. Environmental Protection Agency's data, over the month of June, the Campbell Plant generated approximately 664,000 MWh, running at 61% capacity.[10] In fact, between June 11 and August 18, MISO issued dozens of alerts to manage grid reliability in its Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits. MISO issued alerts for the Central Region on at least 40 of the 69 days between June 11 and August 18. In June, MISO issued alerts affecting the Central Region on 18 days, including an Energy Emergency Alert (EEA) level 1 ("Max Gen Step 1b") on June 23 to enable MISO to take emergency action to ensure grid stability, including bringing additional resources online.[11] The Central Region had alerts on 21 days in July, including one Max Generation Warning on July 29 and two Max Generation Alerts on July 28 and 29.[12] Two Capacity Advisory Initiate alerts have been issued in August to date.[13] Moreover, the May 2025 NERC Summer Reliability Assessment referenced a Seasonal Outlook issued by the National Oceanic and Atmospheric Administration (NOAA), which estimates that much of the Midwest has a 33%-40% chance to experience above-normal temperatures this summer.[14] The Seasonal Outlook released by NOAA on July 17, 2025, increased this estimate for much of the region to a 40%-50% chance.[15]

MISO's resource adequacy problems are not limited to the summer. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[16] MISO justified this revision by explaining that "Reliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round

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[10] *See, Custom Data Download, EPA CAMPD (Clean Air Markets Program Data), https://campd.epa.gov/data/custom-data-download (search criteria to produce these results could include Emissions >> Monthly >> Unit (default) >>Apply >>"2025" and "June." The data can then be filtered to only include the Campbell Plant.)*

[11] An Energy Emergency Alert is an alert declared by the Transmission Provider in accordance with the NERC Operating Manual associated with the Transmission Provider's inability to provide for the Energy and Operating Reserve requirements of the MISO Balancing Authority Area. For more information, see MISO, FERC Electric Tariff, Module A, § 1.E (Definitions) (92.0.0). For more information on Energy Emergency Alert levels, see North American Electric Reliability Corporation. (n.d.). *EOP-011-1 Emergency Operations*. https://www.nerc.com/pa/stand/reliability%20standards/eop-011-1.pdf.

[12] A Max Gen Alert occurs when MISO is forecasting a potential capacity shortage. A Max Gen Warning is a warning to prepare for a possible Max Gen Event. *See* MISO Operating Procedures, https://efis.psc.mo.gov/Document/Display/9379 (20180920).

[13] A Capacity Advisory alert is an advisory issued based on the potential for limited operating capacity margins (<5%) in the following 2-3 days. *See* MISO Operating Procedures, https://efis.psc.mo.gov/Document/Display/9379 (20180920).

[14] NERC 2025 Summer Assessment at 9.

[15] *Seasonal Outlook*, NOAA Climate Prediction Ctr., (July 17, 2025), https://www.cpc.ncep.noaa.gov/products/predictions/long_range/seasonal.php?lead=1.

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

concern."[17] MISO noted that over 60 percent of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[18]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[19] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projects that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[20]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative."*[21] In a section of that report entitled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season.

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[22]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Michigan.[23]

On June 6, 2025, subsequent to the issuance of Order No. 202-25-3, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy

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[17] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).
[18] *Id.* at 3-4.
[19] *Attributes Roadmap*, MISO (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.
[20] *Id.* at 11.
[21] *MISO's Response to the Reliability Imperative*, MISO (Updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.
[22] *Id.* at 12.
[23] MISO Planning Resource Auction – Results for Planning Year 2025-26 at 13.

planning reserve margin requirements.[24] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[25] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[26] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[27]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large amounts of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[28] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[29]

MISO has been taking steps to address these projected deficits. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[30] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three year grace period to commence commercial operations.[31] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[32] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

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[24] *2025 OMS-MISO Survey Results*, OMS and MISO (Updated June 6, 2025) https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.
[25] *Id.* at 2.
[26] *Id.* at 7.
[27] *Id.* at 9.
[28] *Id.* at 7, 9.
[29] *Id.*
[30] M*idcontinent Independent System Operator, Inc.,* 192 FERC ¶ 61,064 (2025).
[31] 192 FERC ¶ 61,064 at P 84.
[32] *See generally*, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, S&P Global (May 2025), US gas-fired turbine wait times as much as seven years; costs up sharply | S&P Global. "With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."

Order 202-25-3 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. 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."[33] 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."[34] 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."[35]

The Department's 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. "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."[36] 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. This growth is illustrated by the fact that there are more than twenty AI companies operating in Michigan alone.[37] In addition, as just one example, Consumers has announced an additional 1 GW of new power to a planned hyperscale data center and "continue[s] to see positive momentum with data centers within the 9 GW pipeline . . . ."[38]

Grid operators—including MISO itself—have likewise acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the

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[33] 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-the-reliability-and-security-of-the-united-states-electric-grid/.

[34] 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/.

[35] *Id*.

[36] *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.

[37] Ekku Jokinen, *Top 21 Artificial Intelligence Companies in Michigan*, (last accessed Aug. 13, 2025), https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan.

[38] *See Michigan utility Consumers Energy to provide 1GW of power to new hyperscale data center*, Data Center Dynamics (August 05, 2025), https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-to-provide-1gw-of-power-to-new-hyperscale-data-center/ (quoting Consumers Energy CEO Garrick Rochow).

changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[39] Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[40] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[41]

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."[42] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Campbell Plant 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 accelerated retirements of generation facilities supporting the issuance of Order No. 202-25-3 will continue in the near term and are also likely to continue in subsequent years. This could lead to the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest under FPA section 202(c).

To ensure the Campbell Plant will be available if needed to address emergency conditions, the Campbell Plant shall remain in operation until November 19, 2025.[43]

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[39] Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce, Subcommittee on Energy, 119th Cong. (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), at 5, https://democrats-energycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/files/evo-media-document/witness-testimony_curran_eng_grid-operators_03.25.2025.pdf.

[40] *Id.* at 6.

[41] *Id.* at 7.

[42] 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) (2018).

[43] 16 U.S.C. § 824a(c)(4).

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

A. From August 21, 2025, MISO and Consumer Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

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

C. All operation of the Campbell Plant 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 September 4, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Campbell Plant consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

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

F. This Order shall not preclude the need for the Campbell Plant 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 Campbell Plant shall not be considered a capacity resource.

H. This Order shall be effective from 00:00 Eastern Daylight Time (EDT) on August 21, 2025, and shall expire at 00:00 EDT on November 19, 2025, with the exception of applicable compliance obligations in paragraph D.

I. Issued in Norfolk, Virginia at 8:50pm Eastern Daylight Time on this 20th day of August 2025.

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

Michigan Public Service Commissioners
Chairman Dan Scripps
Commissioner Katherine Peretick
Commissioner Shaquila Myers

EXHIBIT 59

Department of Energy
Washington, DC 20585

Order No. 202-25-8

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and 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 facilities for the generation of electric energy, resource adequacy concerns, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

Order No. 202-25-4

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. That order was based on my determination that emergency conditions existed in the PJM region. I explained that there was a potential shortage of electric energy and 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 is 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.[1] He stated that, through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics of resources in PJM's interconnection queue.[2] Upcoming retirements, including the planned retirement of the Eddystone Units, would exacerbate these resource adequacy issues.

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[1] *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 Interconnection) (Asthana Test.) at 4-5, available at https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf.
[2] *Id.*

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."[3] 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.[4]

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."[5]

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order No. 202-25-4 continue, both in the near and long term. The summer season has not yet ended, and the production of electricity from the Eddystone Units will continue to be critical to maintaining reliability in PJM this summer. This need is evidenced by the fact that the Eddystone Units were called on by PJM to generate electricity during heat waves that hit the region in June and July.

According to U.S. Environmental Protection Agency data, the Eddystone Units generated over 17,000 MWhs during the month of June.[6] Further, over a period of hot weather from June 23 to June 26, Unit 3 ran for a total of 65 hours and Unit 4 ran for a total of 59 hours.[7] During a hot weather period from July 28 to July 30, Unit 3 ran for 39 hours and Unit 4 ran 8 hours.[8]

Over the course of the summer, PJM has issued Hot Weather Alerts and/or Maximum Generation Alerts (EEA 1) covering a total of 20 days, including days in June, July, and August.[9] The hot weather may continue in the near term, as the Seasonal Outlook released by the National Oceanic and Atmospheric Administration (NOAA) on August 21, 2025, projects between a 40%

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

[4] *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-pjm-resource-retirements-replacements-and-risks.ashx.

[5] *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084 (2025).

[6] *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" (search date Aug. 22, 2025).

[7] *See PJM daily reports to DOE under Order No. 202-25-4, June 24-27, 2025.*

[8] *See PJM daily reports to DOE under Order No. 202-25-4, July 29-31, 2025.*

[9] *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).

and 60% probability of above-normal temperatures in the Mid-Atlantic region, which includes the PJM region, over the next three calendar months.[10]

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

In its 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."[11]

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.[12] 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.[13] PJM determined that the pace of new capacity additions "would be insufficient to keep up with expected retirements and demand growth by 2030."[14] 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 . . . ."[15] PJM warned that its "resource adequacy concerns are increasing at an extraordinary pace."[16] 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.[17] 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."[18] Although the RRI process will help expedite the construction of needed

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[10] *Seasonal Outlook*, NOAA Climate Prediction Ctr., (Aug. 21, 2025), https://www.cpc.ncep.noaa.gov/products/predictions/long_range/seasonal.php?lead=1.
[11] *PJM Statement on the U.S. Department of Energy 202(c) Order of May 30*, PJM (May 31, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/2025-releases/20250531-doe-202c-statement-to-defer-retirements-of-certain-generators.pdf.
[12] Four Rs Report, *supra* n. 4, at 2.
[13] *Id.*
[14] *Id.* at 16, Table 1.
[15] *PJM Interconnection, L.L.C.*, FERC Docket No. ER25-712, Tariff Revisions for Reliability Resource Initiative at 10 (Dec. 13, 2024).
[16] *Id.*
[17] *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…").
[18] *Id.* at 14.

new capacity, it is unlikely to result in the addition of any new generation capacity in the next few years.[19]

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."[20] 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.[21]

The North American Electric Reliability Corporation (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."[22] NERC assessed the PJM region at an elevated risk starting in 2026,[23] explaining that "[r]esource additions are not keeping up with generator retirements and demand growth."[24] 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.[25]

Order 202-25-4 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. 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."[26] 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."[27] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure,

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[19] *See id.*, Attachment C (Affidavit of Mr. Donald Bielak) ¶ 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.").
[20] *Id*. at 12.
[21] *Id*. at 7.
[22] *2024 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%20Assessment_2024.pdf at 92.
[23] *Id.* at 4.
[24] *Id.* at 7.
[25] *Id.* at 91-92.
[26] 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-the-reliabilityand-security-of-the-united-states-electric-grid/.
[27] 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/.

weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[28]

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."[29] 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.[30] 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.[31] 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.[32] 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 hours of approximately 21.335 GW.[33]

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."[34] 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 industrial growth."[35] 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." Therefore, Mr. Asthana stated that PJM

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[28] *Id.*

[29] *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.

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

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

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

[33] *Id.* at 27.

[34] Asthana Test. at 4.

[35] *Id*.

"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."[36]

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."[37] 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 accelerated retirements of generation facilities supporting the issuance of Order No. 202-25-4 will continue in the near term and are also likely to continue in subsequent years. This could lead to the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety. 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 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 November 26, 2025.[38]

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

A. From 5:03PM EDT on August 28, 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

[36] *Id*. at 10.
[37] 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) (2018).
[38] 16 U.S.C. § 824a(c)(4).

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 September 12, 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. 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 5:03 PM Eastern Daylight Time (EDT) on August 28, 2025, and shall expire at 00:00 EST on November 26, 2025, with the exception of applicable compliance obligations in paragraph D.

I. Issued in Washington, D.C., at 7:11 PM Eastern Daylight Time on this 27th day of August 2025.

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

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

EXHIBIT 60

Michigan

This article is more than **1 month old**

Trump order to keep Michigan power plant open costs taxpayers $113m

Critics say JH Campbell coal-fired plant in western Michigan is expensive and emits high levels of toxic pollution



The JH Campbell coal-fired power plant in West Olive, Michigan. Photograph: Jim West/UCG/Universal Images Group via Getty Images

Tom Perkins*in Detroit, Michigan*

Fri 28 Nov 2025 08.00 EST

Trump administration orders to keep an ageing, unneeded Michigan coal-fired power plant online has cost ratepayers from across the US midwest about $113m so far, according to estimates from the plant's operator and regulators.

Still, the US energy department last week ordered the plant to remain open for another 90 days.

The Trump administration in May ordered utility giant Consumers Energy to keep the 63-year-old JH Campbell coal plant in western Michigan, about 100 miles north-east of Chicago, online just as it was being retired.

The order has drawn outrage from consumer advocates and environmental groups who say the plant is expensive and emits high levels of toxic air pollution and greenhouse gas.

The costs will be spread among households across the northern and central regional Miso grid, which stretches from eastern Montana to Michigan, and includes nine other states

"The costs of unnecessarily running this jalopy coal plant just continue to mount," said Michael Lenoff, an attorney with Earthjustice, which is suing over the order.

Gary Rochow, Consumers Energy's CEO, told investors in a 30 October earnings call that the Trump administration in its order stated that ratepayers should shoulder the costs, and detailed how the company should pass on the costs.

"That order from the energy department has laid out a clear path to cost recovery," Rochow said.

The utility has said in regulatory filings that the order is costing customers about $615,000 per day. The order has been in place for around six months.

Michigan attorney general Dana Nessel filed a motion for a stay in federal court, alleging the administration's latest order is "arbitrary and illegal".

The coal plant is one of two in Michigan that the Trump administration has moved to keep open under the president's controversial national energy emergency executive order, which is being challenged in court by multiple lawsuits.

The other plant is not scheduled to close for two years. The two factories emit about 45% of the state's greenhouse gas pollution.

Trump has also used his emergency energy order to keep gas plants near Baltimore and Philadelphia online.

Consumers Energy said it did not ask for Campbell to remain open. The Trump administration did not consult local regulators, a spokesperson for the Michigan public service commission (MPSC), which regulates utilities and manages the state's grid, told the Guardian in May.

"The unnecessary recent order ... will increase the cost of power for homes and businesses in Michigan and across the midwest," the chair of the MPSC, Dan Scripps, said in a statement at the time.

The latest figures proved Scripps correct.

In May, an energy department spokesperson insisted in a statement that retiring the coal plants "would jeopardize the reliability of our grid systems".

But regulatory data from Miso and the MPSC over the last six months shows that statement was wrong.

The Miso grid had excess power far above what Campbell provided during peak demand this summer. And the plant often was not operating at full capacity, likely because its power was not needed, advocates say. But the plant still costs ratepayers even when not operating at capacity.

The energy department did not immediately respond to a request for comment on the data showing it was not necessary to keep the plant open.

Campbell and Michigan's other coal plant that the Trump administration is aiming to keep online release high levels of carbon dioxide, sulfur dioxide and particulate matter into the air. Meanwhile, their coal ash ponds leach arsenic, lead, lithium, radium and sulfate into local drinking water and the Great Lakes.

Consumers Energy had since 2021 been planning for the Campbell's closure as required by the state's energy plan. The company said the plant's closure would save ratepayers in the state about $600m by 2040.

At this unsettling time

We hope you appreciated this article. Before you close this tab, we want to ask if you could support the Guardian at this crucial time for journalism in the US.

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organizations have folded when faced with the mere specter of hostility from the administration - long before their hand was forced.

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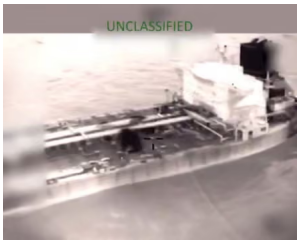
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