BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

EXHIBIT 41

DOE, ENERGY DEPT TO USE DEFENSE PRODUCTION ACT FUNDING TO EXPAND COAL CAPACITY

Energy Department to Use Defense Production Act Funding to Expand Coal Capacity at 13 Plants and Build Export Infrastructure

The U.S. Department of Energy today announced it will support 13 American coal-fired power plants and new coal export infrastructure by providing up to $500 million in Defense Production Act Title III (DPA) funds.

Energy.gov

June 4, 2026

Estimated Read Time 2 min

WASHINGTON—The U.S. Department of Energy (DOE) today announced it will support 13 American coal-fired power plants and new coal export infrastructure by providing up to $500 million in Defense Production Act Title III (DPA) funds.

The DPA funding includes up to $425 million for twelve projects selected to expand and reinvigorate America's coal fleet and up to $75 million for the West Gateway Terminal Project, a rail-served marine export terminal capable of handling more than 10 million tons of bulk commodities annually. The West Gateway project in Oakland, California, will expand West Coast export capacity and support energy exports to allied nations including Japan, South Korea, Taiwan, Vietnam, and Malaysia.

The selected projects are intended to strengthen domestic coal mining value chains, support reliable baseload power generation, and enhance the resilience of critical energy infrastructure. By leveraging DPA authorities, DOE is helping ensure the United States maintains the industrial capacity and energy resources needed to strengthen national security.

"To ensure our national security, the United States will continue to support our coal fleet and domestic supply chains," said **U.S. Secretary of Energy Chris Wright**. "For too long, limited West Coast export capacity has constrained America's ability to move coal and other energy resources to global markets. By investing in both coal generation and critical export infrastructure, including the West Gateway Terminal Project, the Energy Department is strengthening U.S. energy security, reinforcing strategic supply chains, and advancing American energy dominance."

"The West Gateway Terminal Project fills a critical infrastructure gap in the U.S. energy export system by providing additional West Coast export capacity for American coal producers," said **DOE Under Secretary of**

Energy Kyle Haustveit. "By expanding access to global markets, the project will support continued growth in U.S. coal exports, improve supply chain resilience, and strengthen energy partnerships with allies throughout the Indo-Pacific region."

Read more about the DPA-funded projects here.

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Energy Department to Invest $350 Million to Build, Modernize, and Restart Coal Plants

June 4, 2026

Department of Energy Celebrates First Advanced Reactor Criticality

June 4, 2026

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)
Emergency Order: Orlando Utilities Commission
Regarding the Stanton Energy Center

Order No. 202-26-26

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

EXHIBIT 42

DOE, CLEAN ENERGY RESOURCES TO MEET DATA CENTER ELECTRICITY DEMAND

Clean Energy Resources to Meet Data Center Electricity Demand

The last time the United States experienced rising electricity demand was before the early 2000s due to a growing economy, a growing population, and a corresponding change in consumer adoption of electric products such as air conditioners, computers, and incandescent lighting. During that time, we experienced electricity demand increases of up to 30%. However, that time of intense growth was followed by years of flat electricity demand, primarily due to innovations in and implementation of energy efficiency improvements, and because of economic headwinds and a decline in domestic manufacturing.[1]

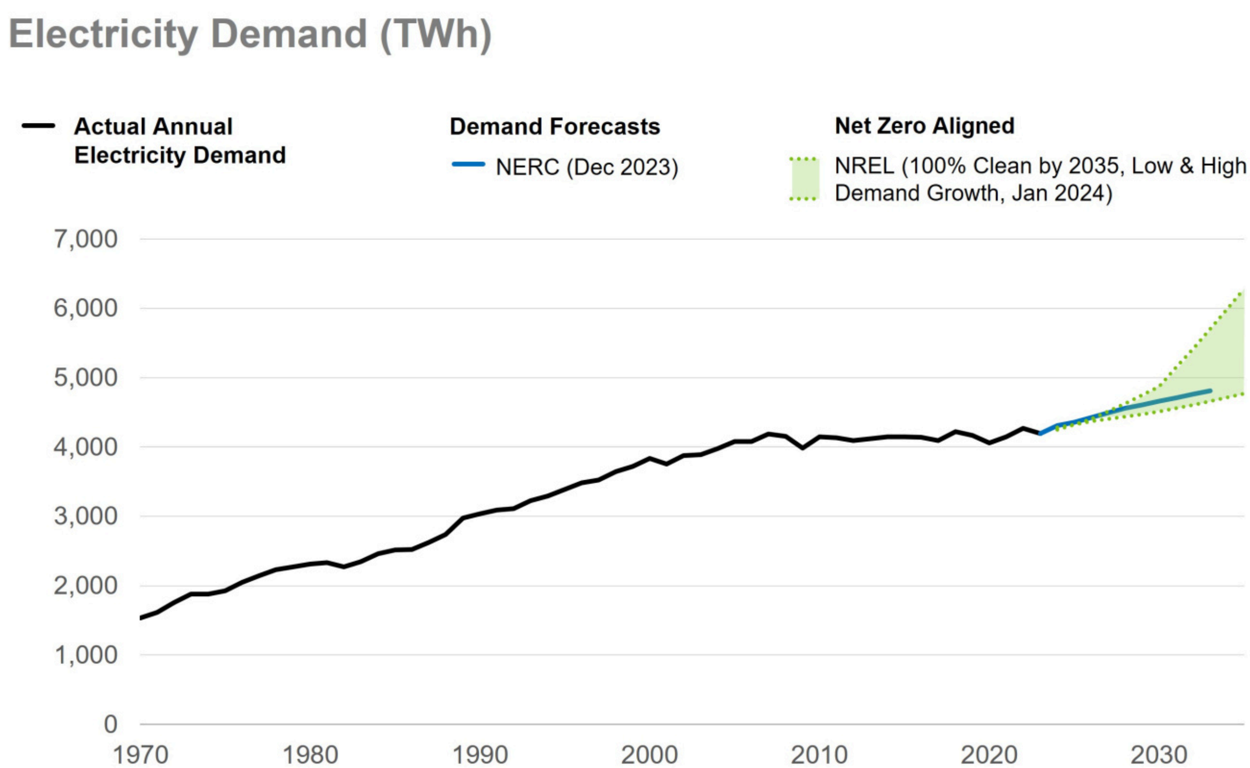
Now, in response to transformations in technologies like artificial intelligence (AI), data center expansion, new domestic manufacturing, and electrification in different sectors, the United States is returning to a period of rising electricity demand, with total energy demand potentially growing ~15-20% in the next decade (See Figure 1).

The U.S. Department of Energy (DOE) has been anticipating and planning for rising electricity demand underscored by the nationwide goal to reach net-zero emissions economy-wide by 2050. To reach this goal, we expect at least a doubling in current electricity demand.[2] Addressing rising electricity demand requires a portfolio approach to meet near-term growth with commercially available technologies, while also paving the way to support long-term growth.

Data center deployment, partly driven by the need to power new AI applications, is a significant factor of near-term electricity demand growth. The Electric Power Research Institute (EPRI) estimates that data centers could grow to consume up to 9% of U.S. electricity generation annually by 2030, up from 4% of total load in 2023.[3] At a national level, data centers are critical to supporting America's economic growth by powering businesses and enabling continued leadership in innovation, including for AI applications.

This blog outlines DOE resources available to help data center developers meet electricity demands with clean energy solutions that can improve flexibility and modernize the grid while maintaining reliability and affordability.

Figure 1: U.S. Electricity Demand (1970-2035)



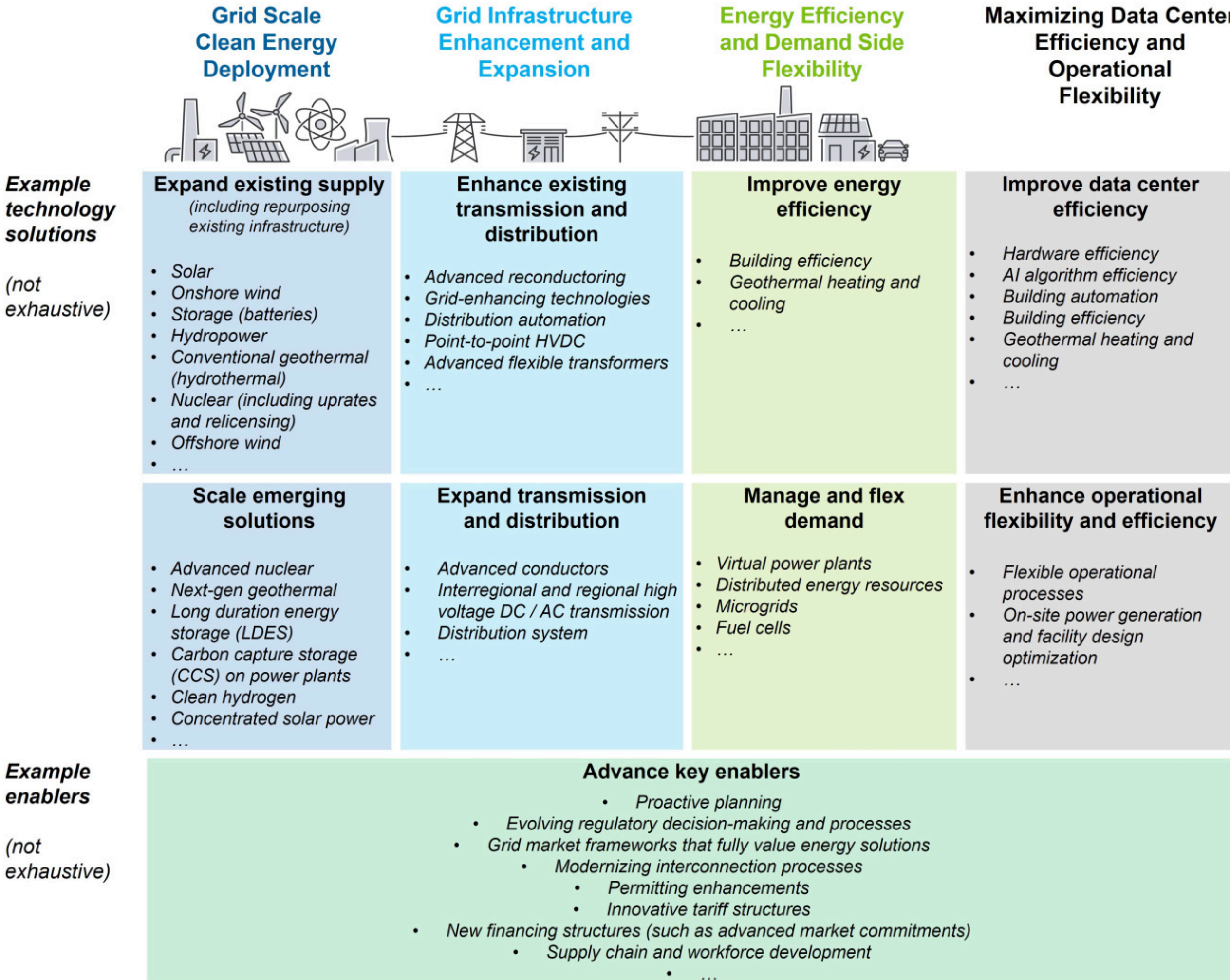
Meeting Data Center Electricity Demand

Data center electricity demand has specific characteristics. It is growing rapidly and varies regionally. Data centers can impact regional grids given the steep increases in load size, may be geographically constrained due to latency requirements, and often require firm power sources to operate continuously. Projections of data center electricity demand growth continue to evolve due to developing use cases and demand for AI and the speed of improvements in energy efficiency. **Building on a series of congressionally mandated reports on data center energy use and efficiencies, DOE's Lawrence Berkeley National Laboratory (LBNL) is assessing current and near-future data center energy consumption and water use.** The report is scheduled to be released at the end of 2024.

A broad suite of tools can be used to meet and manage rising electricity demand and lower overall peak demand (See Figure 2). Approaches that span the whole power system include deploying clean generation and storage technologies; leveraging existing nuclear and hydropower infrastructure; redeveloping retired coal power plant sites; enhancing and expanding grid infrastructure; and maximizing energy efficiency and demand resources. Complementary non-technology-based solutions for managing demand growth include proactive planning, innovative tariff structures, optimizing grid performance, adopting alternative financing structures to fund new energy projects, and supply chain and workforce development. Pursuing key enablers like interconnection and regulatory reforms can unlock the barriers to adopting these energy solutions. DOE's Future of Resource Adequacy Report outlines the portfolio of solutions available to address rising electricity demand in the near and long term, while maintaining system reliability.

Near-term data center driven electricity demand growth is an opportunity to accelerate the build out of clean energy solutions, improve demand flexibility, and modernize the grid while maintaining affordability. Today, solar energy, land-based wind energy, battery storage, and energy efficiency are some of the most rapidly scalable and cost competitive ways to meet increased electricity demand from data centers. Given data centers' need for clean firm power, scaling other energy technologies, such as next-generation geothermal and nuclear, will also be critically important to meet data center electricity demand. With greater investment today, these energy solutions, which are covered by DOE's Pathways to Commercial Liftoff reports, could enable hundreds of gigawatts of capacity on the grid by the mid-2030s and through 2050 to help meet the energy and power needs of data centers and increase the reliability and affordability of the power system.

Figure 2: Examples of Tools to Address Growing Electricity Demand from Data Centers



While the pace and characteristics of data center electricity demand can present challenges in an evolving power system, targeted actions can help the United States maintain a reliable, affordable, secure, and resilient power system. State policymakers, regulators, utilities, data center owners and operators, energy developers, technology providers, grid planners, communities, and the broader grid stakeholder ecosystem all have critical roles to play in accelerating deployments of the solutions needed to support demand growth alongside decarbonization and grid security.

Stakeholders can start acting today to leverage funding opportunities, tax credits, technical reports, and technical assistance to address demand growth and expand our clean energy ecosystem. Detailed below are DOE resources available to support data center electricity needs including:

- Grid Scale Clean Energy Deployment
- Grid Infrastructure Enhancement and Expansion
- Maximizing Energy Efficiency of Data Centers
- Demand Side Flexibility

- Technical Assistance Programs for State and Local Officials, Energy Professionals, Communities, and Large Energy Users

If you have questions on the DOE resources, please feel free to submit them through the businesshub@hq.doe.gov mailbox with the subject “Load Growth”.

DOE Resources Available to Support Data Center Electricity Needs

Grid Scale Clean Energy Deployment

Building additional clean energy is a cost-effective way to meet new loads and is necessary for meeting carbon emissions reduction goals. Tax credits such as the Clean Energy Production Tax Credit (§45Y) and Clean Energy Investment Tax Credit (§48E) also can help support clean energy investments on top of existing DOE funding.

Name	Type	Eligibility	Description
Title 17 Innovative Energy Loans (1703)	Loan; Financing Program	Project developers	Loan guarantees for projects that deploy innovative or significantly improved clean energy technologies (e.g., energy generation and storage, transmission and distribution systems, efficient end-use technologies, etc.) or employ innovative manufacturing processes or manufacture innovative technologies at commercial scale.
Title 17 Energy Infrastructure Reinvestment Program (1706)	Loan; Financing Program	Project developers	Direct loans and loan guarantees available to projects that retool, repower, repurpose, or replace energy infrastructure that has ceased operations.
Tribal Energy Financing Program	Loan; Financing Program	Federally recognized Tribes, tribally-owned developers	Direct loans and loan guarantees for energy-related projects available to federally recognized tribes, including Alaska Native village or village

			corporations, or a Tribal Energy Development Organization that is wholly or substantially owned by a federally recognized Indian tribe or Alaska Native Corporation.
Civil Nuclear Credit Program	Grant	Owners or operators of commercial U.S. reactors	Funding to help preserve the existing nuclear fleet at risk of retirement due to economic factors, which can provide carbon-free power to data centers.
Generation III+ Small Modular Reactor Pathway to Deployment Program	Notice of Intent issued to for funding opportunity	Project developers	To spur the necessary industry-wide momentum, DOE intends to offer funding for projects under this solicitation through two tiers: Tier 1 will provide up to $800 million to support up to two first-mover teams of utility, reactor vendor, constructor, and end-users/off-takers committed to deploying a first plant while facilitating a multi-reactor, Gen III+ SMR orderbook. Tier 2 will provide up to $100 million to spur additional Gen III+ SMR deployments by addressing key gaps that have hindered the domestic nuclear industry in areas such as design, licensing, supplier development, and site preparation.
Critical Facility Energy Resilience (CiFER)	Notice of Intent issued for funding opportunity	Project developers	DOE intends to issue a Funding Opportunity Announcement (FOA) seeking applications for financial assistance awards under a competitive pilot demonstration grant program, as authorized in section 3201 of the Energy Act of 2020, for energy storage projects that are wholly U.S.-made, sourced, and supplied.
Hydroelectric Incentive Programs	Grant	Owners or authorized operators of a hydroelectric facility	More than $750 million through three programs to support energy production, energy efficiency improvements, and enhancements at existing hydropower facilities.
Interconnection Innovation e-Xchange (i2X)	Technical Assistance	Interconnection stakeholders	The i2X program enables simpler, faster, and fairer interconnection of clean energy resources via stakeholder engagement, data and analysis, strategic

			roadmaps, and tailored technical assistance.
Non-powered Dam Development Assistance	Technical Assistance	Project developers	Holistic pre-feasibility assessments of non-powered dam retrofits supported by the best available nationwide data and a suite of online tools.
HydroWIRES Calls for Technical Assistance	Technical Assistance	Hydropower hybrids and pumped hydro power developers and other stakeholders	These recurring technical assistance calls aim to pair utilities and hydropower developers with leading national lab capabilities on pumped storage valuation, hydropower hybrid design, hydropower operations, and other grid integration topics.
Rural and Agricultural Income & Savings from Renewable Energy (RAISE) Initiative	Technical Assistance	Farmers, farm associations	Provides technical assistance, market analysis, and business model research to help farmers and communities deploy wind technologies at multiple scales for local and regional consumption with the goals of enabling farmers and small businesses to earn supplemental income, including through farm associations that could develop and own projects financed through fee-for-service models. Includes funding for technology development and commercialization of distributed wind turbines for the agricultural sector.

Grid Infrastructure Expansion and Enhancement

A variety of innovative grid solutions, including those enabled by artificial intelligence (AI), can help utilities and asset owners improve utilization of existing infrastructure. Technologies such as dynamic line ratings, grid topology optimization, and other solutions can meet growing load by more efficiently and intelligently using existing infrastructure.

Name	Type	Eligibility	Description
Grid Resilience and Innovation Partnerships (GRIP)	Grant	Varies by Topic Area; includes states, grid	$10.5 billion in federal funding to support projects that enhance grid resilience and deploy innovative grid

		operators, project developers, and others.	technologies that improve reliability and resilience. This program seeks to support innovative partnerships or innovative technologies to transform the grid and catalyze non-federal public and private sector capital.
Title 17 Innovative Energy Loans (1703)	Loan; Financing Program	Project developers	Loan guarantees for projects that deploy innovative or significantly improved clean energy technologies (e.g., energy generation and storage, transmission and distribution systems, efficient end-use technologies, etc.) or employ innovative manufacturing processes or manufacture innovative technologies at commercial scale.
Title 17 Energy Infrastructure Reinvestment Program (1706)	Loan; Financing Program	Project developers	Direct loans and loan guarantees available to projects that retool, repower, repurpose, or replace energy infrastructure that has ceased operations.
Transmission Facilitation Program	Loan; Financing Program	Project developers	$2.5 billion in commercial support for qualified transmission projects through tools such as capacity contracts, public-private partnerships, and loans.
Transmission Facility Financing Program	Loan; Financing Program	Project developers	$2 billion to pay for the costs of direct loan for the construction and modification of transmission facilities.
Reconductoring Economic & Financial Analysis Tool (REFA)	Tool	Utility transmission planners and grid planners	REFA is a first of its kind tool designed to help utility transmission planners better understand the financial, environmental and economic benefits of reconductoring upgrades, using traditional or advanced conductors.
National Interest Electric Transmission Corridors (NIETC)	Other	Project developers, other stakeholders (anyone may submit information to inform NIETC designation)	Special designation that enables DOE and the Federal Energy Regulatory Commission to use financing and permitting tools to spur construction of transmission projects within a NIETC.

Maximizing Energy Efficiency of Data Centers

Energy efficiency is a key tool in reducing energy consumption from data center facilities. DOE has long been a leader in developing improved cooling technologies, including for data centers. For instance, ARPA-E has an ongoing COOLERCHIPS program focused on commercializing innovative cooling technologies for data centers. DOE national labs have built exascale computing facilities with a Power Usage Efficiency (PUE) of 1.03, demonstrating state of the art techniques for data center efficiency.[4] DOE is also leading the Energy Efficiency Scaling for 2 Decades initiative, with a goal to increase the energy efficiency of the microelectronics that are needed for computation at data centers by a factor of 1000 over 2 decades. DOE is continuing to develop programs to support data center owners in energy efficiency and industrial decarbonization. In addition, tax incentives, such as the 179D Tax Deduction, enable building owners to claim a tax deduction for installing qualifying energy efficient systems in buildings.

Name	Type	Eligibility	Description
Center of Expertise for Energy Efficiency in Data Centers	Technical Assistance	Data center operators, owners, and other stakeholders	Lawrence Berkeley National Laboratory offers assessment tools, trainings on specific technologies and best practices, and certification for data center energy practitioners.

Data Center Energy Practitioner Program (DCEP)	Training and Credentialing	Individuals, groups, organizations, federal employees	The DCEP Program training is a comprehensive program spanning 1-4 days. The DCEP program certifies practitioners as qualified to evaluate the energy status as well as efficiency and decarbonization opportunities in data centers. The curriculum includes several software tools with what-if capabilities to enhance the learning experience. Three credentials are available. • Generalist • IT specialist • HVAC specialist Best practices factsheets and other resources are available through the DCEP website.
Better Plants Initiative	Technical Assistance	Any U.S. based manufacturing company or industrial-scale energy-using organizations	Manufacturers and owners of industrial facilities (including data centers) in the Better Plants Program set energy saving goals, usually 25% over 10 years. Participants receive national recognition, technical support, in-plant trainings, energy saving resources, and other opportunities.
Data Center Accelerator Toolkit	Report/Resource Collection	Data centers	The Data Center Accelerator Toolkit collects guidance, factsheets, best practices, and other resources to help navigate these dynamics, based on the work of DOE's Better Buildings Data Center Accelerator. This toolkit addresses specific barriers and solutions for energy management in 5 primary data center types, including real-world examples for each.

Better Climate Challenge	Technical Assistance	Organizations, such as data center owners or operators, committed to reducing GHG emissions	Owners and operators of commercial and industrial facilities commit to a target of at least 50% reduction in scope 1&2 GHG emissions within 10 years. Participants receive national recognition, direct technical assistance, resources, and opportunities for peer exchange.
Onsite Energy Program	Technical Assistance	Industrial facilities and other large energy users	Provides technical assistance, market analysis, and best practices to help large energy users, including data centers, increase the adoption of onsite clean energy technologies.
Energy Efficiency Revolving Loan Fund Capitalization Grant Program	Direct Support; Technical Assistance	States	$250 million in federal funding to provide capitalization grants to States to establish a revolving loan fund under which the state provides loans and grants for energy efficiency audits, upgrades, and retrofits to increase energy efficiency and improve the comfort of buildings.
50001 Ready	Resource	Facilities and organizations	Energy management program provides guidance and resources for implementing best practices and standard operating procedures aligned with the ISO 50001 energy management system standard.

Demand Side Flexibility

Demand flexibility can help avoid increasing peak demand. Distribution resources, such as virtual power plants, have the potential to increase the efficiency of existing and new grid infrastructure. DOE is accelerating the use of virtual power plants to support grid needs. For example, the Office of Clean Energy Demonstrations Distributed Energy Systems' program provided $50 million for projects that design and operate distributed energy systems that integrate high levels (>25% of peak demand) of variable clean energy resources.

Name	Type	Eligibility	Description

Title 17 Innovative Energy Loans (1703)	Loan; Financing Program	Project developers	Loan guarantees for projects that deploy innovative or significantly improved clean energy technologies (e.g., energy generation and storage, transmission and distribution systems, efficient end-use technologies, etc.) or employ innovative manufacturing processes or manufacture innovative technologies at commercial scale.
Grid Resilience and Innovation Partnerships (GRIP)	Grant	Project developers	$10.5 billion in federal funding to support projects that enhance grid resilience and deploy innovative grid technologies that improve reliability and resilience. This program seeks to support innovative partnerships or innovative technologies to transform the grid and catalyze non-federal public and private sector capital.
Connected Communities 2.0	Grant	Governments, industry stakeholders, communities	$65 million in federal funding to validate grid-edge technology innovations in real-world situations and provide new tools for utilities, grid planners and operators.
Distributed Energy Systems Demonstrations	Financial Assistance	Project developers	$50 million in federal funding to support a portfolio of projects that demonstrate and validate reliable operations and financial value from a range of grid topologies with diverse energy resources and distributed energy systems ownership models.

Technical Assistance Programs for State and Local Officials, Energy Professionals, Communities, and Large Energy Users

DOE and the National Laboratories can provide technical assistance to states to help develop specific solutions and projects to address growing electricity demand.

Name	Type	Eligibility	Description

State Technical Assistance Program	Technical Assistance	Public utility commissions and state energy offices	For State Regulators, offered through a multi-lab consortium including Lawrence Berkeley National Laboratory, National Renewable Energy Laboratory, and Pacific Northwest National Laboratory. This program provides regulators targeted support in addressing regulatory challenges, including developing innovative tariffs structures and regulatory environments to enable efficient deployment of resources for data centers, and in developing regulatory strategies to enable data center operational flexibilities and behind-the-meter resources.
State Energy Program Technical Assistance	Technical Assistance	States, territories, and the District of Columbia	For State Energy Offices, to provide national lab and 3rd party expertise in support of state-led energy initiatives. This can include supporting development of regional plans and solutions for states that want to plan for data center development.
Clean Energy Innovator Fellowship Program	Technical Assistance/Capacity Building	Recent graduates and energy professionals	The program supports recent graduates and energy professionals to spend two years working with eligible Institutions including electric cooperatives, grid operators, municipal utilities, public utility commissions, state energy offices and Tribal entities.
National Association of Regulatory Utility Commissioners (NARUC)-National Association of State Energy	Technical Assistance	Public utility commissions and state energy offices	Provides state energy officials access to DOE and national lab nuclear expertise to inform regulatory and policy questions surrounding the consideration and deployment of new nuclear generation.

Officials (NASEO) Advanced Nuclear State Collaborative			
The Interagency Working Group (IWG) on Coal and Power Plant Communities and Economic Revitalization	Technical Assistance	Energy communities	Provides technical assistance, resources, and funding guides to support economic revitalization in Energy Communities. The IWG houses resources such as the Coal Power Plant Redevelopment Visualization Tool, which serves as a public database and map to enable state and local economic development officials, project developers, and power plant owners to identify clean energy generation and data center siting opportunities in fossil energy communities.
Renewable Energy Siting through Technical Engagement and Planning (R-STEP)	Technical Assistance	State and local governments, communities	Helps communities better plan for and meaningfully engage in the development of large-scale renewable energy and energy storage projects.
Onsite Energy Technical Assistance Partnerships (TAPs) | Better Buildings Initiative	Technical Assistance	Industrial facilities and other large energy users	DOE's regional network of Onsite Energy Technical Assistance Partnerships helps facilities across the nation integrate the latest onsite energy technologies by providing specialized technical assistance, including initial screenings for multi-technology solutions, more advanced analysis to support project installations, and more.
Supercharging the Electric Grid	Technical Assistance	Industry Stakeholders	Enhances internal and external coordination in the energy industry through resources and best practices, analytical and

			capacity support, and field validations.

[1] Energy Information Administration, Per Capital Residential Electricity Sales in the U.S. Have Fallen Since 2010, 2017.

[2] North American Electric Reliability Corporation (NERC), Electricity Supply and Demand Data, 2023; Energy Information Administration (EIA) Monthly Energy Review; National Renewable Energy Laboratory (NREL) Pathways to 100% Clean Electricity, 2022. Note that electricity demand includes transmission losses and direct use.

[3] EPRI, Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption, 2024.

[4] Oak Ridge Frontier Supercomputer: https://science.osti.gov/-/media/ascr/ascac/pdf/meetings/202207/UpdateFrontier_ASCAC_202207.pdf

NREL Energy Integration Facility: https://www.nrel.gov/computational-science/measuring-efficiency-pue.html

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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EXHIBIT 43

DOI, MEMO FROM DEPUTY CHIEF OF STAFF GREGORY WISCHER

United States Department of the Interior

OFFICE OF THE SECRETARY
Washington, DC 20240

JULY 15 2025

Memorandum

To: Assistant Secretaries
Bureau and Office Heads

From: Deputy Chief of Staff – Policy GREGORY WISCHER Digitally signed by GREGORY WISCHER Date: 2025.07.15 10:58:31 -04'00'

Subject: Departmental Review Procedures for Decisions, Actions, Consultations, and Other Undertakings Related to Wind and Solar Energy Facilities

Consistent with Executive Order (EO) 14315, entitled "Ending Market Distorting Subsidies for Unreliable, Foreign-Controlled Energy Sources," EO 14156, entitled "Declaring a National Energy Emergency," Presidential Memorandum, entitled "Temporary Withdrawal of All Areas on the Outer Continental Shelf from Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects," Secretary's Order (SO) 3417, entitled "Addressing the National Energy Emergency," and SO 3418, entitled "Unleashing American Energy," all decisions, actions, consultations, and other undertakings—including but not limited to the following—related to wind and solar energy facilities shall require submission to the Office of the Executive Secretariat and Regulatory Affairs, subsequent review by the Office of the Deputy Secretary, and final review by the Office of the Secretary:

1. *Federal Register* notices;
2. notices to proceed;
3. scoping reports;
4. determinations of National Environmental Policy Act (NEPA) adequacy;
5. draft and final environmental assessments;
6. draft, final, and supplemental environmental impact statements;
7. findings of no significant impact;
8. records of decision;
9. approval letters;
10. plans of development;
11. land use plan amendments and revisions;
12. land withdrawals and revocations;
13. areas of critical environmental concern designations;
14. site testing and monitoring authorizations;

15. proposed and final sale notices;
16. lease sales;
17. lease assignments;
18. lease issuances;
19. proofs of construction;
20. site assessment plans;
21. preconstruction environmental surveys;
22. supplemental environmental reports;
23. temporary use permits;
24. access road authorizations;
25. utility corridor concurrences;
26. facility design reports;
27. fabrication and installation reports;
28. certified verification agent approvals;
29. construction and operation plans (COPs);
30. conditions of COP approvals;
31. COP revisions;
32. Engineering and Technical Review Branch recommendation memos;
33. proposed technical and navigational and aviation safety conditions;
34. cable burial risk assessments;
35. oil spill response plans;
36. decommissioning applications;
37. Outer Continental Shelf Lands Act compliance memos;
38. compendium reports;
39. memoranda of agreement;
40. compensatory mitigation plans;
41. historic properties management plans;
42. historic properties treatment plans;
43. performance and reclamation bonding approvals;
44. rental and royalty determinations;
45. cost recovery agreements;
46. financial assurances;
47. rights-of-use and easement;
48. right-of-way (ROW) applications;

49. ROW grants;
50. ROW leases;
51. ROW transfers;
52. leases and ROWs on Tribal lands;
53. Tribal environmental impact reviews;
54. government-to-government Tribal consultations;
55. Wild and Scenic Rivers Act determinations;
56. National Trails System impact evaluations;
57. National Landscape Conservation System coordination;
58. visual impact assessments;
59. visual resource management analyses;
60. cumulative historic resources visual effects analyses;
61. cultural resource consultations;
62. section 106 compliance under the National Historic Preservation Act;
63. consultation under the Magnuson-Stevens Fishery Conservation and Management Act, Endangered Species Act (ESA), Migratory Bird Treaty Act (MBTA), and Bald and Golden Eagle Protection Act (BGEPA);
64. permits under the ESA, MBTA, and BGEPA;
65. biological assessments;
66. biological opinions;
67. approval and publication of studies and assessments, including ecological baseline studies;
68. grants; and
69. any other similar or related decisions, actions, consultations, or undertakings.

These review procedures are effectively immediately.

Cc: Deputy Assistant Secretaries
Bureau and Office Deputy Heads
Assistant Secretary Chiefs of Staff
Bureau and Office Chiefs of Staff

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EXHIBIT 44

DOI, ORDER NO. 3438

THE SECRETARY OF THE INTERIOR
WASHINGTON

ORDER NO. 3438

Subject: Managing Federal Energy Resources and Protecting the Environment

Sec. 1. **Purpose**. This Order directs the Department of the Interior (Department), consistent with the Federal Land Policy and Management Act (FLPMA) and the Outer Continental Shelf Lands Act (OSCLA), to optimize the use of lands under its direct management, including the Outer Continental Shelf, (hereafter referred to collectively as "Federal lands") by considering, when reviewing a proposed energy project under the National Environmental Policy Act (NEPA), a reasonable range of alternatives that includes projects with capacity densities meeting or exceeding that of the proposed project. For the purposes of this Order, capacity density is defined as the nameplate generation capacity of an energy project multiplied by its projected capacity factor, the product of which is then divided by the total acres of the project area. Ultimately, FLPMA's multiple use mandate for onshore lands, OCSLA's multiple requirements for offshore activities, and NEPA's requirement to consider reasonable alternatives to a proposed action give rise to the question on whether the use of Federal lands for *any* wind and solar projects is consistent with the law, given these projects' encumbrance on other land uses, as well as their disproportionate land use when reasonable project alternatives with higher capacity densities are technically and economically feasible. This Order is consistent with Executive Order (EO) 14156, entitled "Declaring a National Energy Emergency," which directs the Department to exercise its authorities "to facilitate the identification, leasing, siting, production, transportation, refining, and generation of domestic energy resources, including, but not limited to, on Federal lands," and EO 14315, entitled "Ending Market Distorting Subsidies for Unreliable, Foreign-Controlled Energy Sources," which finds, "The proliferation of [wind and solar] projects displaces affordable, reliable, dispatchable domestic energy sources, compromises our electric grid, and denigrates the beauty of our Nation's natural landscape."

Sec. 2. **Authorities**. This Order is issued under the authority of section 2 of the Reorganization Plan No. 3 of 1950 (64 Stat. 1262), as amended; FLPMA (43 U.S.C. §§ 1701 *et seq.*); OCSLA (43 U.S.C. §§ 1331 *et seq.*); NEPA (42 U.S.C. §§ 4331 *et seq.*); EO 14156; and EO 14315.

Sec. 3. **Background**. The Department, via the Bureau of Land Management (BLM), manages 245 million surface acres, which is approximately one-tenth of our Nation's land base. Additionally, the Department manages 3.2 *billion* acres on the Outer Continental Shelf. Under FLPMA, the BLM must manage Federal lands in accordance with multiple use. Specifically, the BLM shall make "the most judicious use of the land for some or all of these resources" and consider "the long-term needs of future generations for renewable and nonrenewable resources, including, but not limited to, recreation, range, timber, minerals, watershed, wildlife and fish, and natural scenic, scientific and historical values." 43 U.S.C. § 1702(c). Similarly, under OCSLA, the Secretary must ensure that any activity on the Outer Continental Shelf provides for:

- “safety;”
- “protection of the environment,” including fisheries, marine mammals, migratory birds, and bald and golden eagles;
- “conservation of the natural resources of the outer Continental Shelf;”
- “coordination with relevant Federal agencies,” including the U.S. Department of Defense, the U.S. Department of Transportation, and the U.S. Department of Commerce;
- “protection of national security interests of the United States,” including impacts on airports;
- “prevention of interference with reasonable uses,” including commercial fishing; and
- “consideration of…any other use of the sea or seabed, including use for a fishery, a sealane, a potential site of a deepwater port, or navigation [.]” 43 U.S.C. § 1337(p)(4).

To ensure the Department optimizes the use of its Federal lands in accordance with these statutes and to “attain the widest range of beneficial uses of the environment without degradation, risk to health or safety, or other undesirable and unintended consequences” as directed by NEPA, 42 U.S.C. § 1331(b), the Department shall consider energy projects’ capacity density in its decision-making, including when considering reasonable alternatives to a proposed energy project. Capacity density is a technology-neutral, objective calculation of how efficiently land is used for energy generation. Simply put, higher capacity density means greater energy generation with less impact to Federal lands. Because energy projects with higher capacity densities have lower Federal land use impacts and therefore disturb far less of the natural environment for fish, birds, and other wildlife, they provide more Federal lands for other uses, fulfilling FLPMA’s multiple use mandate and OCSLA’s multiple requirements for offshore activities. Moreover, consideration of a project’s capacity density better informs the Department and the public of a project’s potential environmental impact and energy generation.

Based on common sense, arithmetic, and physics, wind and solar projects are highly inefficient uses of Federal lands. On a technology-neutral basis, wind and solar projects use disproportionate Federal lands relative to their energy generation when compared to other energy sources, like nuclear, gas, and coal. For instance, based on data from the U.S. Energy Information Administration, one advanced nuclear plant (2 x AP1000) produces 33.17 megawatts (MW) per acre, while one offshore wind farm produces approximately 0.006 MW/acre, which is approximately 5,500 times less efficient than one nuclear plant. *See* Appendix. Thus, when there are reasonable alternatives that can generate the same amount of or more energy on far less Federal land, wind and solar projects may unnecessarily and unduly degrade Federal lands.

Considering capacity densities in the Department’s decision-making process, including when assessing alternatives to a proposed energy project, also addresses the artificially stimulated proliferation of intermittent energy sources, namely wind and solar projects, as identified by EO 14315. Such proliferation has displaced dispatchable energy sources and destabilized our electric grid, leading President Trump to declare a national energy emergency due to the unusual and extraordinary threat to our Nation’s economy, national security, and foreign policy posed by the Nation’s insufficient energy production, transportation, refining, and generation. As the U.S. Department of Energy’s report titled “Evaluating the Reliability and Security of the United States

Electric Grid," (July 2025) notes, the Nation's energy grid outlook has been undermined by "the accelerated retirement of existing [baseload] generation capacity and the insufficient pace of firm, dispatchable generation additions (partly due to a recent focus on intermittent rather than dispatchable sources of energy)."

Sec. 4. **Directives**. Consistent with the aforementioned statutory authorities, the Department shall only permit those energy projects that are the most appropriate land use when compared to a reasonable range of project alternatives.

To implement this directive and to the extent that the following information is not already requested by Secretary's Order 3437, titled "Ending Preferential Treatment for Unreliable, Foreign-Controlled Energy Sources in Department Decision-Making," the Department shall identify and make the necessary revisions, as appropriate and consistent with applicable law, to any regulations, guidance, policies, or practices, necessary to implement this directive.

a. Within 30 days of the issuance of this Order, each Assistant Secretary, in coordination with the Solicitor, shall submit a report to the Office of the Secretary a list of the actions taken and to be taken to implement this directive,

b. Within 60 days of the issuance of this Order, the Office of the Secretary, in coordination with the Deputy Secretary, the Solicitor, and each Assistant Secretary, shall submit to me a report on the actions taken and to be taken to implement this directive.

Sec. 5. **Implementation**. The Office of the Secretary is responsible for implementing all aspects of this Order, in coordination with the Deputy Secretary, the Solicitor, and applicable Assistant Secretaries or their equivalents.

Sec. 6. **Effect of This Order**. This Order is intended to improve the internal management of the Department; to comply with FLPMA, OCSLA, and NEPA; and to implement EO 14156 and EO 14315. This Order and any resulting reports or recommendations are not intended to, and do not create any right or benefit, substantive or procedural, enforceable at law or equity by a party against the United States, its departments, agencies, instrumentalities or entities, its officers or employees, or any other person. To the extent there is any inconsistency between the provisions of this Order and any Federal laws or regulations, the laws or regulations will control.

Sec. 7. **Effective Date**. This Order is effective immediately and will remain in effect until it is amended, superseded, or revoked, whichever occurs first.

Doug Burgum

Secretary of the Interior

Date:

Aug 1st, 2025

APPENDIX 1

Energy Type[a]	Capacity Density (MW/Acre)	Different Energy Types' Capacity Densities Compared to…		
		Solar PV with Single-Axis Tracking	Onshore Wind	Offshore Wind
Advanced Nuclear Plan (2 x AP1000)	33.17	945	2686	5402
Combined Cycle Plant 2x2x1	24.42	696	1977	3977
Small Modular Reactor Nuclear Power Plant	12.66	361	1025	2062
Combined Cycle Plant 1x1x1, Single Shaft	12.48	355	1010	2032
Combined Cycle Plant 1x1x1, Single Shaft, with 95% Carbon Capture	5.40	154	438	880
Combustion Turbine – Simple Cycle Plant (H-class)	4.23	121	343	689
Combustion Turbine – Simple Cycle Plant (Aeroderivative)	2.13	61	173	347
Ultra-Supercritical Coal Plant without Carbon Capture	0.69	20	56	113
Ultra-Supercritical Coal Plant with 95% Carbon Capture	0.64	18	52	105
Geothermal	0.16	4.63	13	26
Solar PV with Single-Axis Tracking and AC-Coupled Battery Storage	0.04	1.16	3	7
Solar PV with Single-Axis Tracking with DC-Coupled Battery Storage	0.04	1.03	3	6
Solar PV with Single-Axis Tracking	0.04	-	3	6
Onshore Wind[b]	0.01	0.35	-	2
Offshore Wind[c]	0.006	0.17	0.5	-

[a] For all energy types other than onshore and offshore wind, the capacity density was calculated using data from the U.S. Energy Information Administration, U.S. Department of Energy, "Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies," January 2024, 5-6, 15, 21, 27, 34, 41-42, 48, 63, 67-68, 73, 98, 103-104, 109, https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf; and "Table 6.07.A. Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels," 2024 annual data, U.S. Energy Information Administration, U.S. Department of Energy, accessed July 31, 2025, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_6_07_a.

[b] To calculate the capacity density for onshore wind, the midpoint of 4.1 - 13.7 MW/km^2 (0.0166 - 0.0555 MW/acre), or 0.036 MW/acre, was used. This number was then multiplied by a capacity factor of 34.3 percent, with the product being approximately 0.01 MW/acre. See Trieu Mai et al., "Land of Opportunity: Potential for Renewable Energy on Federal Lands," National Renewable Energy Laboratory, Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy, January 2025, 25, https://docs.nrel.gov/docs/fy25osti/91848.pdf; and "Table 6.07.B. Capacity Factors for Utility Scale Generators Primarily Using Non-Fossil Fuels," 2024 annual data, U.S. Energy Information Administration, U.S. Department of Energy, accessed July 31, 2025, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_6_07_b.

[c] To calculate the capacity density for offshore wind, 4.42 MW/km^2 was used and converted to 0.0179 MW/acre and then multiplied by a capacity factor of 34.3 percent. See Daniel Mulas Hernando et al., "Summary Analysis of Different Offshore Wind Capacity Density Drivers in Proposed U.S. Projects and Impacts on Progress Towards State and Federal Deployment Targets," National Renewable Energy Laboratory, Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy, October 2023, 9, https://docs.nrel.gov/docs/fy24osti/87947.pdf; and "Table 6.07.B. Capacity Factors for Utility Scale Generators Primarily Using Non-Fossil Fuels," 2024 annual data, U.S. Energy Information Administration, U.S. Department of Energy, accessed July 31, 2025, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_6_07_b.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

EXHIBIT 45

DOT, BIDEN-BUTTIGIEG IGNORED THE DANGERS OF WIND TURBINES NEAR RAILROADS & HIGHWAYS

Media Contact

Press Office
US Department of Transportation
1200 New Jersey Ave, SE
Washington, DC 20590
United States
Email: pressoffice@dot.gov
Phone: 1 (202) 366-4570

If you are deaf, hard of hearing, or have a speech disability, please dial 7-1-1 to access telecommunications relay services.

President Trump's Transportation Secretary Sean P. Duffy: Biden-Buttigieg Ignored the Dangers of Wind Turbines Near Railroads & Highways, Put Climate Religion Ahead of Safety

Tuesday, July 29, 2025

USDOT calls on Congress to investigate why safety recommendations were dropped, the depth of the Biden-Buttigieg scheme

WASHINGTON, D.C. — U.S. Transportation Secretary Sean P. Duffy today announced that the Department of Transportation (USDOT) will restore safety recommendations previously overruled by the Biden-Buttigieg administration for wind turbines built near highways and railroads.

Secretary Duffy and his team recently discovered that Biden-Buttigieg overruled a safety recommendation for dozens of wind energy projects despite concerns that turbines can interfere with radio spectrum frequencies critical to safety.

"Joe Biden and Pete Buttigieg put climate religion ahead of safety – blatantly ignoring engineers who warned of the danger of constructing wind turbines near railroads and highways. That's why I'm immediately implementing a higher standard of safety. What the past administration did is a shame, but it's a pattern for Biden and Buttigieg. They invested over $80 billion on DEI and the Green New Deal while safety was ignored," said **U.S. Transportation Secretary Sean P. Duffy**.

The information USDOT has compiled raises serious questions. In addition to conducting a department-wide review, Secretary Duffy is calling on Congress to investigate.

Secretary Duffy's USDOT will now recommend a minimum 1.2-mile setback for turbines built near highways and railroads following a recent report:

"wind farm deployment could potentially obstruct radio communication links and/or degrades radio RF signal reception by means of lowering signal to noise ratio through several mechanisms and factors such as diffraction, scattering, wind farm density, distance, speed, etc."

Additional Information:

In 2023, the Biden-Buttigieg USDOT found one wind farm proposal close to high-speed passenger and freight rail infrastructure that fell within "one-to-three-mile boundary... may be problematic for train communications in this area and present an undue risk."

In 2024, the Biden-Buttigieg USDOT subsequently "withdraws its previous recommendation of a setback for this project." No explanation was provided for this change.

In total, 33 projects have been uncovered where the original safety recommendation was rescinded.

Secretary Duffy's USDOT is launching a study to collect additional data to inform safety guidelines for wind turbines built near critical transportation infrastructure that use radio frequency dependent safety systems. Further, the Federal Aviation Administration will thoroughly evaluate proposed wind turbines to ensure they do not pose a danger to aviation, including new market entrants like Advanced Air Mobility.

USDOT will provide feedback on windmill siting through the National Telecommunications and Information Administration (NTIA) Interdepartment Radio Advisory Committee (IRAC) Frequency Assignment Subcommittee.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

EXHIBIT 46

IRS NOTICE 2025-42

Part III – Administrative, Procedural, and Miscellaneous

Beginning of Construction Requirements for Purposes of the Termination of Clean Electricity Production Credits and Clean Electricity Investment Credits for Applicable Wind and Solar Facilities

Notice 2025-42

SECTION 1. PURPOSE

This notice provides guidance, consistent with Executive Order 14315 of July 7, 2025, *Ending Market Distorting Subsidies for Unreliable, Foreign-Controlled Energy Sources*, 90 F.R. 30821 (Executive Order 14315), regarding when construction of an applicable wind facility or applicable solar facility (each as defined in section 2.02 of this notice) has begun for purposes of determining whether such facility is subject to credit termination provisions added to §§ 45Y and 48E of the Internal Revenue Code (Code)[1] by §§ 70512 and 70513 of Public Law 119-21, 139 Stat. 72 (July 4, 2025), commonly known as the One, Big, Beautiful Bill Act (OBBBA). Section 70512(a) and (l)(4) of the OBBBA terminates the clean electricity production credit determined under § 45Y (§ 45Y credit), and § 70513(a) and (g)(5) of the OBBBA terminates the clean electricity investment credit determined under § 48E (§ 48E credit), in the case of an applicable wind facility or applicable solar facility that is placed in service after December 31, 2027

[1] Unless otherwise specified, all "section" or "§" references are to sections of the Code or the Income Tax Regulations (26 CFR part 1).

(credit termination date). The credit termination date applies to applicable wind and solar facilities the construction of which begins after July 4, 2026 (beginning of construction deadline), the date that is 12 months after the date of enactment of the OBBBA.

SECTION 2. BACKGROUND

.01 Overview of pre-OBBBA §§ 45Y and 48E.

Sections 45Y and 48E were added to the Code by §§ 13701(a) and 13702(a), respectively, of Public Law 117-169, 136 Stat. 1818, 1982 (August 16, 2022), commonly known as the Inflation Reduction Act of 2022. The § 45Y credit is determined with respect to electricity produced by a taxpayer at a "qualified facility" and either sold by the taxpayer to an unrelated party during the taxable year or, if the facility is equipped with a metering device which is owned or operated by an unrelated person, sold, consumed, or stored by the taxpayer during the taxable year. The § 48E credit is determined with respect to a taxpayer's "qualified investment" in a qualified facility. A taxpayer's qualified investment in a qualified facility is determined with respect to the taxpayer's basis in "qualified property" placed in service by the taxpayer that is part of the qualified facility as well as expenditures paid or incurred for certain qualified interconnection property.

Sections 45Y(b)(1)(A) and 48E(b)(3)(A) define a "qualified facility" for purposes of §§ 45Y and 48E, respectively, as a facility which is used for the generation of electricity, which is placed in service after December 31, 2024, and for which the greenhouse gas emissions rate (for § 45Y) or anticipated greenhouse gas emissions rate (for § 48E) is not greater than zero. The Department of the Treasury (Treasury Department) and the

Internal Revenue Service (IRS) published final regulations under §§ 45Y and 48E on January 15, 2025 (90 FR 4006). Sections 1.45Y-2 and 1.48E-2 clarify the definition of a "qualified facility" for purposes of §§ 45Y and 48E, respectively.

Section 45Y(b)(2)(C)(i) requires that the Secretary of the Treasury or the Secretary's delegate annually publish a table that sets forth the greenhouse gas emissions rates for types or categories of facilities, which a taxpayer must use for purposes of § 45Y. The Treasury Department and the IRS published the initial annual table required by § 45Y(b)(2)(C)(i) in Revenue Procedure 2025-14, 2025-7 I.R.B. 770. That table lists both wind facilities and solar facilities as having a greenhouse gas emissions rate of not greater than zero.

As noted in section 2.02 of Notice 2022-61, 87 FR 73580, 2022-52 I.R.B. 560, the IRS has issued several notices, collectively referred to in this notice as the "IRS Notices,"[2] which provide that taxpayers may establish the beginning of construction using the "Physical Work Test" or the "Five Percent Safe Harbor," and may satisfy either the "Continuity Requirement" or the "Continuity Safe Harbor," with respect to the credits determined under §§ 45, 45Q, and 48.

Section 5 of Notice 2022-61 provides guidance, in part, to determine when construction begins for purposes of the credit determined under §§ 45Y and 48E. Section 5 of Notice 2022-61 states that principles similar to those under Notice 2013-29 regarding the Physical Work Test and Five Percent Safe Harbor apply, and taxpayers

[2] *See* Notice 2013-29, 2013-20 I.R.B. 1085; *clarified by* Notice 2013-60, 2013-44 I.R.B. 431; *clarified and modified by* Notice 2014-46, 2014-36 I.R.B. 520; *updated by* Notice 2015-25, 2015-13 I.R.B. 814; *clarified and modified by* Notice 2016-31, 2016-23 I.R.B. 1025; *updated, clarified, and modified by* Notice 2017-04, 2017-4 I.R.B. 541; Notice 2018-59, 2018-28 I.R.B. 196; *modified by* Notice 2019-43, 2019-31 I.R.B. 487; *modified by* Notice 2020-41, 2020-25 I.R.B. 954*; clarified and modified by* Notice 2021-5, 2021-3 I.R.B. 479; *clarified and modified by* Notice 2021-41, 2021-29 I.R.B. 17; Notice 2020-12, 2020-11 I.R.B. 495.

satisfying either test will be considered to have begun construction. Section 5 of Notice 2022-61 additionally provides, in part, that principles similar to those provided in the IRS Notices regarding the Continuity Requirement and the Continuity Safe Harbor apply for purposes of §§ 45Y and 48E, and that taxpayers may rely on the Continuity Safe Harbor provided the facility is placed in service no more than four calendar years after the calendar year during which construction began.

.02 Overview of OBBBA Changes to §§ 45Y and 48E.

Sections 70512(a) and 70513(a) of the OBBBA added new §§ 45Y(d)(4) and 48E(e)(4), respectively, to the Code. These new Code provisions terminate the § 45Y credit and the § 48E credit, respectively, for applicable wind and solar facilities placed in service after December 31, 2027. For purposes of this notice, the term "applicable wind facility" means an applicable facility as provided in §§ 45Y(d)(4)(B)(i) and 48E(e)(4)(B)(i) (except as provided in § 48E(e)(4)(C) relating to energy storage technology) and "applicable solar facility" means an applicable facility as provided in §§ 45Y(d)(4)(B)(ii) and 48E(e)(4)(B)(ii) (except as provided in § 48E(e)(4)(C)). Sections 70512(l)(4) and 70513(g)(5) of the OBBBA provide that the amendments made by §§ 70512(a) and 70513(a) of the OBBBA, respectively, apply to facilities the construction of which begins after the date which is 12 months after the date of enactment of the OBBBA (that is, July 4, 2026).

.03 Executive Order 14315.

Section 3(a) of Executive Order 14315 directs the Secretary of the Treasury, within 45 days following enactment of the OBBBA, to take action he deems necessary and appropriate to strictly enforce the termination provisions with respect to the § 45Y credit and the § 48E credit for wind and solar facilities. Such action includes issuing new and revised guidance for applicable wind and solar facilities to ensure that policies concerning “beginning of construction” are not circumvented, including guidance to prevent the artificial acceleration or manipulation of eligibility and to restrict the use of broad safe harbors unless a substantial portion of an applicable wind or solar facility has been built.[3]

The Treasury Department and the IRS have determined that the guidance contained in this notice is necessary and appropriate to properly enforce the credit termination date for applicable wind and solar facilities. Congress provided a beginning of construction deadline after which the new credit termination date for applicable wind and solar facilities applies. This notice provides beginning of construction guidance to prevent taxpayers from circumventing the statutory credit termination date, prevent the artificial manipulation of eligibility for the § 45Y credit and § 48E credit for applicable wind and solar facilities, and ensure that a substantial portion of any applicable wind or solar facility not subject to the credit termination date is built by the beginning of construction deadline. Accordingly, except as provided in section 6 of this notice, the Five Percent Safe Harbor provided under the IRS notices is not available for purposes

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[3] In addition, § 3(b) of Executive Order 14315 directs the Secretary of the Treasury, within 45 days following enactment of the OBBBA, to take prompt action as the Secretary of the Treasury deems appropriate and consistent with applicable law to implement the enhanced “Foreign Entity of Concern” restrictions in the OBBBA (also known as “Prohibited Foreign Entities”). Section 70512 of the OBBBA added those new restrictions regarding certain foreign entities in order to qualify for the § 45Y credit and the § 48E credit, among others, and included separate beginning of construction rules for those new provisions. See § 7701(a)(51) and (52) of the Code. The guidance in this notice is not intended to address the beginning of construction rules for the purposes of those foreign entity restrictions. The Treasury Department and the IRS are currently drafting additional guidance as is necessary and appropriate to implement those restrictions, as enacted by the OBBBA.

of determining whether an applicable wind or solar facility has met the beginning of construction deadline and, thus, is not subject to the credit termination date.

SECTION 3. METHOD FOR ESTABLISHING BEGINNING OF CONSTRUCTION

.01 In general. For purposes of the beginning of construction deadline in §§ 70512(l)(4) and 70513(g)(5) of the OBBBA, a taxpayer may establish that construction has begun before July 5, 2026, by satisfying the Physical Work Test as described in section 3.02 of this notice. Except as provided in section 6 of this notice, the Physical Work Test described in section 3.02 of this notice is the sole method that a taxpayer may use for these purposes. The Physical Work Test also requires that a taxpayer maintain a continuous program of construction (Continuity Requirement). Section 4 of this notice discusses the Continuity Requirement and section 4.04 of this notice provides a safe harbor for satisfying this requirement (Continuity Safe Harbor).

.02 Physical Work Test. Construction of an applicable wind or solar facility begins when physical work of a significant nature begins. Work performed by the taxpayer and work performed for the taxpayer by other persons under a binding written contract that is entered into prior to the manufacture, construction, or production of the applicable wind or solar facility for use by the taxpayer in the taxpayer's trade or business (or for the taxpayer's production of income) is taken into account in determining whether construction has begun. See section 5.01 of this notice. Whether physical work of a significant nature has begun with respect to an applicable wind or solar facility before July 5, 2026, will depend on the relevant facts and circumstances.

.03 Physical work of a significant nature. The Physical Work Test requires that physical work of a significant nature be performed. This test focuses on the nature of the work performed, not the amount or the cost. Provided that physical work performed is of a significant nature, there is no fixed minimum amount of work or monetary or percentage threshold required to satisfy the Physical Work Test. Both off-site and on-site work (performed either by the taxpayer or by another person under a binding written contract) may be taken into account for purposes of demonstrating that physical work of a significant nature has begun.

(1) Off-site physical work of a significant nature. Generally, off-site physical work of a significant nature may include the manufacture of components, mounting equipment, support structures such as racks and rails, inverters, and transformers and other power conditioning equipment.

(2) On-site physical work of a significant nature. The following non-exclusive list of examples is intended to illustrate what constitutes on-site physical work of a significant nature for applicable wind and solar facilities:

(a) Applicable wind facility. On-site physical work of a significant nature begins with the beginning of the excavation for the foundation, the setting of anchor bolts into the ground, or the pouring of the concrete pads of the foundation. If the applicable wind facility's wind turbines and tower units are to be assembled on-site from components manufactured off-site by a person other than the taxpayer and delivered to the site, physical work of a significant nature begins when the manufacture of the components begins at the off-site location, but only if: (i) the manufacturer's work is done pursuant to a binding written contract (as described in section 5.01(1) of this notice); and (ii) these components are not held in the manufacturer's inventory (as described in section 3.05 of this notice). If a manufacturer produces components for multiple applicable facilities, a reasonable method must be used to associate individual components with particular applicable facilities.

(b) Applicable solar facility. On-site physical work of a significant nature may include the installation of racks or other structures to affix photovoltaic (PV) panels, collectors, or solar cells to a site.

.04 Preliminary activities. Physical work of a significant nature does not include preliminary activities, even if the cost of those preliminary activities is properly included in the depreciable basis of the applicable wind or solar facility. Generally, preliminary activities for applicable wind or solar facilities include, but are not limited to:

(a) planning or designing;

(b) securing financing;

(c) exploring;

(d) researching;

(e) conducting mapping and modeling to assess a resource;

(f) obtaining permits and licenses;

(g) conducting geophysical, gravity, magnetic, seismic and resistivity surveys;

(h) conducting environmental and engineering studies;

(i) clearing a site;

(j) conducting test drilling to determine soil condition (including to test the strength of a foundation);

(k) excavating to change the contour of the land (as distinguished from excavation for a foundation); and

(l) removing existing foundations, turbines, and towers, solar panels, or any components that will no longer be part of the applicable wind or solar facility (including those on or attached to building structures).

.05 Inventory. Physical work of a significant nature does not include work (performed either by the taxpayer or by another person under a binding written contract) to produce a component/part of an applicable wind or solar facility that is either in existing inventory or is normally held in inventory by one selling the component/part to the taxpayer.

SECTION 4. CONTINUITY REQUIREMENT

.01 Continuous program of construction. A taxpayer will satisfy the Continuity Requirement of this section 4 only if the taxpayer maintains a continuous program of construction with respect to an applicable wind or solar facility. A continuous program of construction involves continuing physical work of a significant nature (as described in section 3.03 of this notice). Unless the Continuity Safe Harbor provided in section 4.04 of this notice applies, whether a taxpayer maintains a continuous program of construction to satisfy the Continuity Requirement will be determined by the relevant facts and circumstances.

.02 Excusable disruptions to continuous program of construction. Certain disruptions in a taxpayer's continuous construction to advance towards completion of an applicable wind or solar facility that are beyond the taxpayer's control will not be considered as indicating that a taxpayer has failed to satisfy the Continuity Requirement.

The following is a non-exclusive list of construction disruptions that will not be considered as indicating that a taxpayer has failed to satisfy the Continuity Requirement:

(a) delays due to severe weather conditions;

(b) delays due to natural disasters;

(c) delays in obtaining permits or licenses from federal, state, local, or Indian tribal governments, including, but not limited to, delays in obtaining permits or licenses from the Federal Energy Regulatory Commission (FERC), the Environmental Protection Agency (EPA), the Bureau of Land Management (BLM), and the Federal Aviation Agency (FAA);

(d) delays at the written request of a federal, state, local, or Indian tribal government regarding matters of public safety, security, or similar concerns;

(e) interconnection-related delays, such as those relating to the completion of construction on a new transmission or distribution line or necessary transmission or distribution upgrades to resolve grid congestion issues that may be associated with an applicable wind or solar facility's planned interconnection;

(f) delays in the manufacture of custom components;

(g) delays due to labor stoppages;

(h) delays due to the inability to obtain specialized equipment of limited availability;

(i) delays due to the presence of endangered species;

(j) financing delays; and

(k) delays due to supply shortages.

.03 Timing of excusable disruption determination. In the case of a single project comprised of multiple facilities (as described in section 5.02(2) of this notice), whether an excusable disruption has occurred for purposes of the Continuity Requirement must be determined in the calendar year during which the last of multiple facilities is placed in service. In the case of a single applicable wind or solar facility, whether an excusable disruption has occurred for purposes of the Continuity Requirement must be determined in the calendar year during which the applicable wind or solar facility is placed in service.

.04 Continuity safe harbor: deemed satisfaction of continuity requirement. Except as provided in this section 4.04, if a taxpayer places an applicable wind or solar facility in service by the end of a calendar year that is no more than four calendar years after the calendar year during which construction of the applicable wind or solar facility began (Continuity Safe Harbor Deadline), the applicable wind or solar facility will be considered to satisfy the Continuity Requirement (Continuity Safe Harbor). The excusable disruption rules in section 4.02 of this notice do not apply for purposes of applying the Continuity Safe Harbor. If an applicable wind or solar facility is not placed in service before the end of the fourth calendar year after the calendar year during which construction of the applicable wind or solar facility began, whether the applicable wind or solar facility satisfies the Continuity Requirement under the Physical Work Test will be determined by the relevant facts and circumstances.

For example, if construction begins on an applicable wind or solar facility on August 20, 2025, and the applicable wind or solar facility is placed in service by December 31, 2029, the applicable wind or solar facility will be considered to satisfy the

Continuity Safe Harbor. If the applicable wind or solar facility is not placed in service before January 1, 2030, whether the Continuity Requirement was satisfied will be determined by the relevant facts and circumstances.

SECTION 5. OTHER RULES

.01 Construction by contract. For property that is manufactured, constructed, or produced for the taxpayer by another person under a binding written contract (as described in section 5.01(1) of this notice), the work performed under the contract is taken into account in determining when physical work of a significant nature begins, provided the contract is entered into prior to the work taking place.

(1) Binding written contract. A contract is binding only if it is enforceable under local law against the taxpayer or a predecessor and does not limit damages to a specified amount (for example, by use of a liquidated damages provision). For this purpose, a contractual provision that limits damages to an amount equal to at least five percent of the total contract price will not be treated as limiting damages to a specified amount. For additional guidance regarding the definition of a binding contract, see § 1.168(k)-1(b)(4)(ii)(A)-(D).

(2) Master contract. If a taxpayer enters into a binding written contract for a specific number of components to be manufactured, constructed, or produced for the taxpayer by another person (a “master contract”), and then through a new binding written contract (a “project contract”) the taxpayer assigns its rights to certain components to an affiliated special purpose vehicle that will own the applicable wind or solar facility for which such property is to be used, work performed with respect to the

master contract may be taken into account in determining when physical work of a significant nature begins with respect to the applicable wind or solar facility.

.02 Qualified facility – (1) In general. Physical work of a significant nature with respect to an applicable wind or solar facility must be performed with respect to property included in a qualified facility, as defined in § 1.45Y-2(b) or § 1.48E-2(d), as applicable.

(2) Single project. Solely for purposes of determining whether construction of an applicable wind or solar facility has begun for purposes of this notice, multiple facilities that are operated as part of a single project (along with any property, such as a computer control system, that serves some or all such facilities) will be treated as a single applicable wind or solar facility. Whether multiple facilities are operated as part of a single project will depend on the relevant facts and circumstances. Factors indicating that multiple facilities are operated as part of a single project include, but are not limited to:

(a) The facilities are owned by a single legal entity;

(b) The facilities are constructed on contiguous pieces of land;

(c) The facilities are described in a common power purchase agreement or agreements;

(d) The facilities have a common intertie;

(e) The facilities share a common substation;

(f) The facilities are described in one or more common environmental or other regulatory permits;

(g) The facilities were constructed pursuant to a single master construction contract; and

(h) The construction of the facilities was financed pursuant to the same loan agreement.

(3) <u>Timing of single project determination</u>. The determination of whether multiple facilities are operated as part of a single project and are therefore treated as a single applicable wind or solar facility for purposes of this notice must be made in the calendar year during which the last of the multiple facilities is placed in service.

.03 <u>Property integral to the applicable wind or solar facility</u>. Only physical work of a significant nature on tangible personal property and other tangible property used as an integral part of the activity performed by the applicable wind or solar facility will be considered for purposes of determining whether a taxpayer has begun construction of an applicable wind or solar facility. This includes property integral to the production of electricity, but does not include property used for electrical transmission. See §§ 1.45Y-2(b)(3) and 1.48E-2(d)(3) for additional descriptions of property integral to a qualified facility.

.04 <u>Application of 80/20 rule to retrofitted applicable wind or solar facilities</u> – (1) <u>In general</u>. A retrofitted applicable wind or solar facility may qualify as originally placed in service even though it contains some used components of property, provided the fair market value of the used components of property is not more than 20 percent of the applicable wind or solar facility's total value (the cost of the new components of property plus the value of the used components of property) (80/20 Rule). See §§ 1.45Y-4(d) and 1.48E-4(c). In the case of a single project comprised of multiple facilities (as described in section 5.02(2) of this notice), the 80/20 Rule is applied to each facility comprising the single project. For purposes of the 80/20 Rule, the cost of a new applicable wind or solar facility includes all properly capitalized costs of the new applicable wind or solar facility.

(2) Beginning of construction. In situations where the 80/20 Rule applies, the Physical Work Test applies only with respect to the work performed on, or amounts paid or incurred for, new components of property used to retrofit an existing applicable wind or solar facility. The total cost of the applicable wind or solar facility does not include the cost of land (including lease payments) or any property that is not part of the applicable wind or solar facility, as described in section 5.03 of this notice.

.05 Transfer of an applicable wind or solar facility – (1) In general. A taxpayer may claim either the § 45Y credit with respect to electricity produced by such taxpayer at an applicable wind or solar facility or the § 48E credit with respect to the taxpayer's qualified investment with respect to an applicable wind or solar facility. Neither § 45Y nor § 48E requires the taxpayer to own the applicable wind or solar facility at the time construction began on the applicable wind or solar facility. Accordingly, except as provided in section 5.05(3) of this notice, a fully or partially developed applicable wind or solar facility may be transferred without losing its qualification under the Physical Work Test for purposes of the § 45Y credit or the § 48E credit.

(2) Relocation of equipment by a taxpayer. A taxpayer may begin construction of an applicable wind or solar facility with the intent to develop the applicable wind or solar facility at a certain site, and thereafter transfer components of property of the applicable wind or solar facility to a different site, complete its development, and place it in service. The work performed or the amounts paid or incurred prior to the site transfer by such a

taxpayer may be taken into account for purposes of determining when the applicable wind or solar facility satisfies the Physical Work Test.

(3) Transfers of equipment between unrelated parties. In the case of a transfer consisting solely of tangible personal property (including contractual rights to such property under a binding written contract) to a transferee not related (within the meaning of §§ 197(f)(9)(C) and 1.197-2(h)(6)) to the transferor, any work performed or amounts paid or incurred by the transferor with respect to such transferred property will not be taken into account with respect to the transferee for purposes of the Physical Work Test.

For example, a developer, X, intends to develop and operate Facility A at a location to be determined. In 2025, X pays or incurs $60,000 to have tangible personal property integral to Facility A manufactured off-site pursuant to a binding written contract. Thereafter, X incurs no further development costs and engages in no further development activity with respect to Facility A. In January 2026, X sells the tangible personal property to another developer, Y, a party unrelated to X. Y is developing and intends to operate Facility B, located on a parcel of land owned by Y. Y incorporates the tangible personal property acquired from X into Facility B. In October 2026, Y places Facility B in service on the parcel of land. The total cost of Facility B is $1,000,000. Work performed for X in 2025 on the tangible personal property cannot be taken into account by Y for purposes of satisfying the Physical Work Test with respect to Facility B, because X and Y are not related persons (within the meaning of §§ 197(f)(9)(C) and 1.197-2(h)(6)) as described in section 5.05(3) of this notice. However, if without regard to the tangible personal property acquired from X, Y has otherwise satisfied the Physical

Work Test with respect to Facility B in 2025, Y will be considered to have begun construction in 2025.

SECTION 6. FIVE PERCENT SAFE HARBOR FOR LOW OUTPUT SOLAR FACILITIES

.01 In general. In the case of a low output solar facility (as defined in section 6.02 of this notice), a taxpayer may establish that construction has begun before July 5, 2026, by satisfying either the Physical Work Test described in section 3.02 of this notice, or by applying principles similar to those provided in section 5 of Notice 2013-29 regarding the Five Percent Safe Harbor (as described in section 2.02(2)(ii) of Notice 2022-61).

.02 Low output solar facility.

(1) Definition. A low output solar facility is an applicable solar facility that has maximum net output of not greater than 1.5 megawatt (MW) (as measured in alternating current) (1.5-Megawatt Maximum). For purposes of the 1.5-Megawatt Maximum, output is measured at the level of the qualified facility.

(2) Property included in an applicable solar facility. An applicable solar facility includes a unit of a qualified solar facility, which, in turn, includes all functionally interdependent components of property owned by the taxpayer that are operated together and that can operate apart from other property to produce electricity. Components of property are functionally interdependent if the placing in service of each of the components is dependent upon the placing in service of each of the other components to produce electricity. A qualified solar facility also includes property owned by the taxpayer that is an integral part of the qualified solar facility. A component of

property owned by the taxpayer is an integral part of the qualified facility if it is used directly in the intended function of the facility and is essential to the completeness of such function. See §§ 1.45Y-2(b)(3) and 1.48E-2(d)(3) for additional descriptions of property integral to a qualified facility.

.03 Measurement of output.

(1) In general. The maximum net output of an applicable solar facility is measured only by nameplate generating capacity (in alternating current) of the unit of qualified facility (as described in §§ 1.45Y-2(b)(2) and 1.48E-2(d)(2)), which does not include the nameplate capacity of any component that is an integral part (as described in §§ 1.45Y-2(b)(3) and 1.48E-2(d)(3)) of the applicable solar facility, at the time the applicable solar facility is placed in service. The nameplate generating capacity of the applicable solar facility is measured independently from any other applicable solar facility that shares an integral part with the applicable solar facility. Notwithstanding this rule, the nameplate generating capacity of two or more applicable solar facilities having integrated operations are measured in the aggregate for purposes of the 1.5-Megawatt Maximum.

(2) Nameplate capacity. For purposes of section 6.02(1) of this notice, the determination of whether a qualified facility has a maximum net output of not greater than 1.5 MW (as measured in alternating current) is based on the nameplate capacity. The nameplate capacity for purposes of the 1.5-Megawatt Maximum is the maximum electrical generating output in megawatts that the unit of qualified facility is capable of producing on a steady state basis and during continuous operation under standard conditions, as measured by the manufacturer and consistent with the definition of

nameplate capacity provided in 40 CFR 96.202. If applicable, taxpayers should use the International Standard Organization (ISO) conditions to measure the maximum electrical generating output of a unit of qualified facility. For applicable solar facilities that generate electricity in direct current, a taxpayer determines whether an applicable solar facility has a maximum net output of not greater than 1.5 MW (in alternating current) by using the lesser of:

(a) The sum of the nameplate generating capacities within the applicable solar facility in direct current, which is deemed the nameplate generating capacity of the unit of applicable solar facility in alternating current; or

(b) The nameplate capacity of the first component of the applicable solar facility that inverts the direct current electricity into alternating current.

(3) Integrated operations. For the purposes of the 1.5-Megawatt Maximum, an applicable solar facility is treated as having integrated operations with one or more other applicable solar facilities of the same technology type if the facilities are:

(a) Owned by the same or related taxpayers;

(b) Placed in service in the same taxable year; and

(c) Transmit electricity generated by the facilities through the same point of interconnection or, if the facilities are not grid-connected or are delivering electricity directly to an end user behind a utility meter, are able to support the same end user.

(4) Related taxpayers. For purposes of section 6.03(3) of this notice, the term “related taxpayers” means members of a group of trades or businesses that are under common control (as defined in § 1.52-1(b)). Related taxpayers are treated as one taxpayer in determining whether an applicable facility has integrated operations.

SECTION 7. EFFECTIVE DATE

This notice is effective for applicable wind and solar facilities the construction of which did not begin (as determined under section 5 of Notice 2022-61) prior to September 2, 2025.

SECTION 8. EFFECT ON OTHER DOCUMENTS

Except as provided in sections 6 and 7 of this notice, this notice modifies Notice 2022-61 to provide that section 5 of such notice is not applicable for determining whether construction of an applicable wind or solar facility began prior to the beginning of construction deadline in §§ 70512(l)(4) and 70513(g)(5) of the OBBBA.

SECTION 9. DRAFTING INFORMATION

The principal author of this notice is the Office of Associate Chief Counsel (Energy, Credits, and Excise Tax); however, other personnel from the Treasury Department and the IRS participated in its development. For further information regarding this notice contact (202) 317-6853 (not a toll-free call).

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

EXHIBIT 47

ORSTED, REVOLUTION WIND RECEIVES STOP-WORK ORDER FROM US DOI BOEM

This page is also available in Danish. To switch language click here(https://orsted.com/da/company-announcement-list/2025/08/revolution-wind-receives-offshore-stop-work-order--145387701) .

22.08.2025 16:52

Revolution Wind receives offshore stop-work order from US Department of the Interior’s Bureau of Ocean Energy Management

(https://www.facebook.com/sharer/sharer.php?u=https%3a%2f%2forsted.com%2fen%2fcompany-announcement-list%2f2025%2f08%2frevolution-wind-receives-offshore-stop-work-order--145387701)
https://www.linkedin.com/shareArticle?mini=true&url=https%3a%2f%2forsted.com%2fen%2fcompany-announcement-list%2f2025%2f08%2frevolution-wind-receives-offshore-stop-work-order--145387701)
(https://twitter.com/intent/tweet?url=https%3a%2f%2forsted.com%2fen%2fcompany-announcement-list%2f2025%2f08%2frevolution-wind-receives-offshore-stop-work-order--145387701)

On 22 August 2025, Ørsted’s subsidiary Revolution Wind LLC, a 50/50 joint venture with Global Infrastructure Partner’s Skyborn Renewables, received an order instructing the project to stop activities on the outer continental shelf related to the Revolution Wind project from the US Department of the Interior’s Bureau of Ocean Energy Management (BOEM). Revolution Wind is complying with the order and is taking appropriate steps to stop offshore activities, ensuring the safety of workers and the environment.

The project commenced offshore construction following the final federal approval from BOEM last year. The project is 80% complete with all offshore foundations installed and 45 out of 65 wind turbines installed.

Ørsted is evaluating all options to resolve the matter expeditiously. This includes engagement with relevant permitting agencies for any necessary clarification or resolution as well as through potential legal proceedings, with the aim being to proceed with continued project construction towards COD in the second half of 2026.

Revolution Wind is fully permitted, having secured all required federal and state permits including its Construction and Operations Plan approval letter on 17 November 2023 following reviews that began more than nine years ago. Revolution Wind has 20-year power purchase agreements to deliver 400 MW of electricity to Rhode Island and 304 MW to Connecticut, enough to power over 350,000 homes across both states to meet their growing energy demand. As a reference, South Fork Wind, which is adjacent to Revolution Wind and uses the same turbine technology, delivered reliable energy to New York at a capacity factor of 53% for the first half of 2025, on par with the state's baseload power sources.

Ørsted is investing into American energy generation, grid upgrades, port infrastructure, and a supply chain, including US shipbuilding and manufacturing extending to more than 40 states. Revolution Wind is already employing hundreds of local union workers supporting both on and offshore construction activities. Ørsted's US offshore wind projects have totalled approximately 4 million labour union hours to date, 2 million of which are with Revolution Wind.

Ørsted is evaluating the potential financial implications of this development, considering a range of scenarios, including legal proceedings. Ørsted will, in due course, advise the market on the potential impact of the order on the plan announced on 11 August 2025 (company announcement 12/2025) to conduct a rights issue. Existing shareholders and prospective investors are advised to await further announcements by the company.

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About Ørsted

The Ørsted vision is a world that runs entirely on green energy. Ørsted develops, constructs, and operates offshore and onshore wind farms, solar farms, energy storage facilities, and bioenergy plants. Ørsted is recognised on the CDP Climate Change A List as a global leader on climate action and was the first energy company in the world to have its science-based net-zero emissions target validated by the Science Based Targets initiative (SBTi). Headquartered in Denmark, Ørsted employs approx. 8,300 people. Ørsted's shares are listed on Nasdaq Copenhagen (Orsted). In 2024, the group's revenue was DKK 71.0 billion (EUR 9.5 billion).

Visit orsted.com(http://orsted.com/) or follow us.

Attachments

- Ørsted CA no. 15 2025.pdf(https://via.ritzau.dk/ir-files/13560592/14538770/15983/%C3%98rsted%20CA%20no.%2015%202025.pdf)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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EXHIBIT 48

UTILITY DRIVE, TRUMP ADMINISTRATION TO REVOKE APPROVAL FOR 2.2-GW MARYLAND OFFSHORE WIND

DIVE BRIEF

Trump administration to revoke approval for 2.2-GW Maryland Offshore Wind

The Interior Department said it will "reevaluate under the Outer Continental Shelf Lands Act" its decision to approve the project's construction and operations plan and move for a remand by Sept. 12.

Published Aug. 27, 2025

Diana DiGangi
Reporter

Seeking a revocation of Maryland Offshore Wind's construction and operations plan approval is the latest in a series of efforts from the Trump administration to cancel or delay offshore wind projects that received federal approval and are under construction — including Revolution Wind and Empire Wind 1. Getty Images

Dive Brief:

- In a Friday court filing, the Department of the Interior said it intends to revoke the approved construction and operations plan, or COP, for US Wind's 2.2 GW Maryland Offshore Wind project off the coast of Maryland and Delaware.

- The filing was made in the docket for a complaint filed in February by South Bethany property owner and attorney Edward Bintz, who alleged that the Biden administration's approval of the COP violated the Coastal Zone Management Act.
- "Interior now intends to reevaluate under the Outer Continental Shelf Lands Act its decision to approve the COP and, as a result, will be moving no later than September 12 … for remand of that prior COP approval," Interior said in its filing.

Dive Insight:

The filing came in the form of a motion to stay the case, with Interior arguing that if its motion is granted, "the agency action that Plaintiff challenges will be vacated, and thus his claims will be entirely moot. And even if Interior's motion is denied, the agency's reconsideration of the COP will likely result in significant changes that will impact the positions and arguments of the parties here."

Interior noted that Maryland Offshore Wind's COP is also being challenged in a complaint filed in U.S. District Court for the District of Maryland by the leadership of Ocean City, and said it plans to file its motion for a remand in that case.

"Though the Maryland court dismissed the differently pled [Coastal Zone Management Act] claim in that case, the operative complaint in the Maryland Action still alleges Interior's COP approval was contrary to the [Outer Continental Shelf Lands Act], [Administrative Procedure Act], and Marine Mammal Protection Act," Interior said.

Seeking a revocation of the project's COP is the latest in a series of efforts from the Trump administration to cancel or delay offshore wind projects that received federal approval under the Biden administration and are under construction.

Interior issued a stop work order, also on Friday, to Revolution Wind – a 700-MW offshore wind farm close to being completed and set to supply energy to Rhode Island and Connecticut.

In April, the administration ordered Equinor to stop work on its 810-MW Empire Wind 1 wind energy project offshore New York. Equinor said the delay cost the company up to $50 million each week, and came close to having to terminate the project before New York Governor Kathy Hochul negotiated with the administration to allow work to resume.

Last week, the U.S. Department of Commerce opened a probe into "the effects on the national security of imports of wind turbines and their parts and components." Capstone analysts said in a note that they expect the Commerce Department to ultimately apply tariffs "likely around 25%-50%, consistent with other Section 232 duties imposed by this administration."

"Offshore wind certainly has taken a beating," said Lauren Collins, a tax partner at Vinson & Elkins. "Both through the One Big Beautiful Bill Act, and recent news on offshore wind projects basically being shuttered even though they're almost done."

Kat Burnham, Rhode Island policy lead at Advanced Energy United, said the Trump administration's "escalating attacks on offshore wind are creating chaos in the energy sector. Pulling back approvals for projects that are already permitted and in some cases nearly built, undermines years of planning, billions of dollars in private investment, and thousands of jobs."

According to the Bureau of Ocean Energy Management, Maryland Offshore Wind's COP "includes up to 114 wind turbine generators, four offshore substations, a meteorological tower, and up to four offshore export cable corridors with subsea transmission cables making landfall in Sussex County, Delaware ... Two phases, known as MarWin and Momentum Wind, already have offshore renewable energy certificates from the State of Maryland."

The 300-MW MarWin project is set to start delivering electricity this year, while the 800-MW Momentum Wind is set to start doing so in 2028.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
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EXHIBIT 49

ISO NEWSWIRE, STATEMENT ON REVOLUTION WIND STOP WORK ORDER

ISO NEWSWIRE
A Wholesale Electricity Industry Update

August 25, 2025

ISO-NE statement on Revolution Wind stop work order

ISO New England is aware of the stop work order received by Revolution Wind. Through the region's wholesale markets, Revolution Wind has committed to helping meet New England's demand for electricity, beginning in 2026. The ISO is expecting this project to come online and it is included in our analyses of near-term and future grid reliability. Delaying the project will increase risks to reliability.

Recent heatwaves in New England drove demand for electricity to very high levels and demonstrated that our region needs all generation resources with market obligations to be available to meet demand and maintain required reserves. Beyond near-term impacts to reliability in the summer and winter peak periods, delays in the availability of new resources will adversely affect New England's economy and industrial growth, including potential future data centers.

As demand for electricity grows, New England must maintain and add to its energy infrastructure. Unpredictable risks and threats to resources—regardless of technology—that have made significant capital investments, secured necessary permits, and are close to completion will stifle future investments, increase costs to consumers, and undermine the power grid's reliability and the region's economy now and in the future.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

EXHIBIT 50

DOE, RESOURCE ADEQUACY REPORT: EVALUATING THE RELIABILITY AND SECURITY OF THE US ELECTRIC GRID

U.S. DEPARTMENT of ENERGY

Resource Adequacy Report

Evaluating the Reliability and Security of the United States Electric Grid

July 2025

Acknowledgments

This report and associated analysis were prepared for DOE purposes to evaluate both the current state of resource adequacy as well as future pressures resulting from the combination of announced retirements and large load growth.

It was developed in collaboration with and with assistance from the Pacific Northwest National Laboratory (PNNL) and National Renewable Energy Laboratory (NREL). We thank the North American Electric Reliability Corporation (NERC) for providing data used in this study, the Telos Corporation for their assistance in interpreting this data, and the U.S Energy Information Administration (EIA) for their dissemination of historical datasets. In addition, thank you to NREL for providing synthetic weather data created by Evolved Energy Research for the Regional Energy Deployment System (ReEDS) model.

DOE acknowledges that the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level. The DOE study team built the methodology and analysis upon the best data that was available. However, entities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience.

Historically, the nation's power system planners would have shared electric reliability information with DOE through mechanisms such as EIA-411, which has been discontinued. Thus, one of the key takeaways from this study process is the underscored "call to action" for strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our collective economic and national security.

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List of Acronyms

AI	Artificial Intelligence
CAISO	California Independent System Operator
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EO	Executive Order
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
GADS	Generating Availability Data System
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ITCS	Interregional Transfer Capability Study
LBNL	Lawrence Berkeley National Laboratory
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LTRA	Long-Term Reliability Assessment
MISO	Midcontinent Independent System Operator
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
PJM	PJM Interconnection, LLC
PNNL	Pacific Northwest National Laboratory
ReEDS	Regional Energy Deployment System
RTO	Regional Transmission Organization
SERC	SERC Reliability Corporation
TPR	Transmission Planning Region
USE	Unserved Energy

Background to this Report

On April 8, 2025, President Trump issued Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid." EO 14262 builds on EO 14156, "Declaring a National Emergency (Jan. 20, 2025)," which declared that the previous administration had driven the Nation into a national energy emergency where a precariously inadequate and intermittent energy supply and increasingly unreliable grid require swift action. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy and the integrity of our Nation's electrical grid.

EO 14262 mandates the development of a uniform methodology for analyzing current and anticipated reserve margins across regions of the bulk power system regulated by the Federal Energy Regulatory Commission (FERC). Among other things, EO 14262 requires that such methodology accredit generation resources based on the historical performance of each generation resource type. This report serves as DOE's response to Section 3(b) of EO 14262 by delivering the required uniform methodology to identify at-risk region(s) and guide reliability interventions. The methodology described herein and any analysis it produces will be assessed on a regular basis to ensure its usefulness for effective action among industry and government decision-makers across the United States.

Executive Summary

Our Nation possesses abundant energy resources and capabilities such as oil and gas, coal, and nuclear. The current administration has made great strides—such as deregulation, permitting reform, and other measures—to enable addition of more energy infrastructure crucial to the utilization of these resources. However, even with these foundational strengths, the accelerated retirement of existing generation capacity and the insufficient pace of firm, dispatchable generation additions (partly due to a recent focus on intermittent rather than dispatchable sources of energy) undermine this 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. A failure to power the data centers needed to win the AI arms race or to build the grid infrastructure that ensures our energy independence could result in adversary nations shaping digital norms and controlling digital infrastructure, thereby jeopardizing U.S. economic and national security.

Despite current advancements in the U.S. energy mix, this analysis underscores the urgent necessity of robust and rapid reforms. Such reforms are crucial to powering enough data centers while safeguarding grid reliability and a low cost of living for all Americans.

Key Takeaways

- **Status Quo is Unsustainable**. The status quo of more generation retirements and less dependable replacement generation is neither consistent with winning the AI race and ensuring affordable energy for all Americans, nor with continued grid reliability (ensuring "resource adequacy"). Absent intervention, it is impossible for the nation's bulk power system to meet the AI growth requirements while maintaining a reliable power grid and keeping energy costs low for our citizens.
- **Grid Growth Must Match Pace of AI Innovation**. The magnitude and speed of projected load growth cannot be met with existing approaches to load addition and grid management. The situation necessitates a radical change to unleash the transformative potential of innovation.
- **Retirements Plus Load Growth Increase Risk of Power Outages by 100x in 2030**. The retirement of firm power capacity is exacerbating the resource adequacy problem. 104 GW of firm capacity are set for retirement by 2030. This capacity is not being replaced on a one-to-one basis and losing this generation could lead to significant outages when weather conditions do not accommodate wind and solar generation. In the "plant closures" scenario of this analysis, annual loss of load hours (LOLH) increased by a factor of a hundred.
- **Planned Supply Falls Short, Reliability is at Risk**. The 104 GW of retirements are projected to be replaced by 209 GW of new generation by 2030; however, only 22 GW would come from firm baseload generation sources. Even assuming no retirements, the model found increased risk of outages in 2030 by a factor of 34.

- **Old Tools Won't Solve New Problems.** Antiquated approaches to evaluating resource adequacy do not sufficiently account for the realities of planning and operating modern power grids. At a minimum, modern methods of evaluating resource adequacy need to incorporate frequency, magnitude, and duration of power outages; move beyond exclusively analyzing peak load time periods; and develop integrated models to enable proper analysis of increasing reliance on neighboring grids.

This report clearly demonstrates the need for rapid and robust reform to address resource adequacy issues across the Nation. Inadequate resource adequacy will hinder the development of new manufacturing in America, slow the re-industrialization of the U.S. economy, drive up the cost of living for all Americans, and eliminate the potential to sustain enough data centers to win the AI arms race.

Developing a Uniform Methodology

DOE's resource adequacy methodology assesses the U.S. electric grid's ability to meet future demand through 2030. It provides a forward-looking snapshot of resource adequacy that is tied to electricity supply and new load growth, systematically exploring a range of dimensions that can be compared across regions. As detailed in the methodology section of this report, the model is derived from the North American Electric Reliability Corporation (NERC) Interregional Transfer Capability Study (ITCS) which leverages time-correlated generation and outages based on actual historic data.[1] A deterministic approach[2] simulates system stress in all hours of the year and incorporates varied grid conditions and operating scenarios based on historical events:

- **Demand for Electricity – Assumed Load Growth:** The methodology accounts for the significant impact of data centers, particularly those supporting AI workloads, on electricity demand. Various organizations' projections for incremental data center electricity use by 2030 range widely (35 GW to 108 GW). DOE adopted a national midpoint assumption of 50 GW by 2030, aligning with central projections from Electric Power Research Institute (EPRI)[3] and Lawrence Berkeley National Laboratory (LBNL).[4] This 50 GW was allocated regionally using state-level growth ratios from S&P's forecast,[5] reflecting infrastructure characteristics, siting trends, and market activity; and, mapped to NERC Transmission Planning Regions (TPRs).

1. This model differs from traditional peak hour reliability assessments in that it explicitly simulates grid performance hour-by-hour across multiple weather years with finer geographic detail and optimized inter-regional transfers, and explores various retirement and build-out scenarios. Furthermore, the DOE approach integrates weather-synchronized outage data.
2. Deterministic approaches evaluate resource adequacy using relatively stable or fixed assumptions about the representation of the power system. Probabilistic approaches incorporate data and advanced modeling techniques to represent uncertainty that require more computing power. Deterministic was chosen for this analysis for transparency and to model detailed historic system conditions.
3. EPRI, "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption," March 2024, https://www.epri.com/research/products/3002028905.
4. Shehabi, A., et al., "2024 United States Data Center Energy Usage Report," https://escholarship.org/uc/item/32d6m0d1.
5. S&P Global – Market Intelligence, "US Datacenters and Energy Report," 2024.

An additional 51 GW of non-data center load was modeled using NERC data, historical loads (2019-2023), and simulated weather years (2007-2013), adjusted by the Energy Information Administration's (EIA) 2022 energy forecast, with interpolation between 2024 and 2033 to estimate 2030 demand.

- **Supply of Electricity – Assumed Generation Retirements and Additions:** Between the current system and the projected 2030 system, the model considers three scenarios for generator retirements and additions. These scenarios were selected to describe the metrics of interest and how they change during certain assumptions of generation growth and retirements.

The resource adequacy standard (or criterion) is the measure that defines the desired level of adequacy needed for a given system. Conceptually, a resource adequacy criterion has two components—metrics and target levels—that determine whether a system is considered adequate. Comprehensive resource adequacy metrics[6] are incorporated in this analysis to capture the magnitude and duration of system stress events:

- **Magnitude of Outages – Normalized Unserved Energy (NUSE):** Measures the amount of unmet electrical energy demand because of insufficient generation or transmission, typically measured in megawatt hours (MWh).

  While USE describes the absolute amount of energy not delivered, it is less useful when comparing systems of different size or across different periods. Normalizing, by dividing by total load over a whole period (for example, a year) allows comparison of these metrics across different system sizes, demand levels, and periods of analysis. For example, 100 MWh of USE in a small, isolated microgrid can be more impactful than 100 MWh of USE in a larger regional grid that serves millions of people. USE is normalized by dividing by total load:

$$\frac{100\, MWh\ (of\ unserved\ energy)}{10{,}000{,}000\, MWh\ (of\ total\ energy\ delivered\ in\ a\ year)} x100 = 0.001\, percent$$

Although the use of NUSE is not standardized in the U.S. today,[7] several system operators domestically and across the world have begun using NUSE as a useful metric.

- **Duration of Outages – Loss of Load Hours (LOLH):** Measures the expected duration of power outages when a system's load exceeds its available generation capacity. At the core, LOLH helps assess how frequently and for how long the power system is likely to experience insufficient supply, providing a picture of reliability in terms of time. LOLH is calculated as both a total and average value per year, in addition to the maximum percentage of load lost in any given hour per year.

6. In the interest of technical accuracy, and separate from their contextualization in the main text, NUSE is more precisely a measure of volume that is expressed as a percentage. Similarly, 2.4 hours of LOLH represents the cumulative sum of distinct periods of load loss, not a singular, continuous duration.
7. There is no common planning criterion for this metric in North America. NERC's Long-Term Reliability Assessment employs a normalized expected unserved energy (NEUE) metric to define target risk levels for each region. Grid operators, such as ISO-NE, have also considered NUSE in energy adequacy studies. For example, see ISO-NE, "Regional Energy Shortfall Threshold (REST): ISO's Current Thinking Regarding Tail Selection," April 2025, https://www.iso-ne.com/static-assets/documents/100022/a09_rest_april_2025.pdf.

Reliability Standard

DOE's methodology recognizes that the traditional 1-in-10 loss of load expectation (LOLE) criterion is insufficient for a complete assessment of resource adequacy and risk profile. This antiquated criterion is not calculated uniformly and fails to adequately account for crucial factors such as the duration and magnitude of potential outages.[8] To provide a comprehensive understanding of system reliability and, specifically, to complement current resource adequacy standards while informing the creation of new criteria, the methodology uses the following reliability standard:

- **Duration of Outages:** No more than 2.4 hours of lost load in an individual year.[9] This translates into one day of lost load in ten years to meet the 1-in-10 criteria.

- **Magnitude of Outages:** No more than an NUSE of 0.002%.[10] This means that the total amount of energy that cannot be supplied to customers is 0.002% of the total energy demanded in a given year.

Achieving Reliability Standard

- **Perfect Capacity Surplus/Deficit:** Defined as the amount of generation capacity (in MW) a region would need to achieve specified threshold conditions. Based on these thresholds, this standard helps answer the hypothetical question of how much more (or less) power plant capacity is needed for a power system to be considered "perfectly reliable" according to pre-defined standards. This methodology employs this perfect capacity metric to identify the amount of capacity needed to remedy potential shortfalls (or excesses) in generation.

Key Results Summary

This analysis developed three separate cases for 2030. The "**Plant Closures"** case assumes all announced retirements occur plus mature generation additions based on NERC's Tier 1 resources category,[11] which encompasses completed and under-construction power generation projects, as well as those with firm-signed and approved interconnection service or power purchase agreements. The "**No Plant Closures"** case assumes no retirements plus mature additions. A "**Required Build**" case further compares the impacts of retirements on perfect capacity additions needed to return 2030 to the current system level of reliability.

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8. While 1-in-10 analyses have evolved, industry experts have raised concerns about its effectiveness to address future system risks. Concerns include energy constraints that arise from intermittent resources, increasing battery storage, limited fuel supplies, and the shifting away of peak load periods from times of supply shortfalls.
9. The "1-in-10 year" reliability standard for electricity grids means that, on average, there should be no more than one day (24 hours) of lost load over a ten-year period. This translates to a maximum of 2.4 hours of lost load per year.
10. This analysis targets NUSE below 0.002% for each region because this is the target NERC uses to represent high risk in resource adequacy analyses. Estimates used in industry and analyzed recently range from 0.0001% to 0.003%.
10. Mature generation additions are based on NERC's 2024 LTRA Tier 1 resources, which assume that only projects considered very mature in the development pipeline will be built. For example, Tier 1 additions are those with signed interconnection agreements or power purchase agreements, or included in an integrated resource plan, indicating a high degree of certainty in their addition to the grid. Full details of the retirement and addition assumptions can be found in the methodology section of this report.

DOE ran simulations using 12 different years of historical weather. Every hour was based on actual data for wind, solar, load, and thermal availability to stress test the grid under a range of realistic weather conditions. The benefit of this approach is that it allows for transparent review of how actual conditions manifest themselves in capacity shortfalls. For all scenarios, LOLH and NUSE are calculated and used to compare how they change based on generation growth, retirements, and potential weather conditions.

- **Current System:** Supply of power (generation) and demand for power (load) consistent with 2024 NERC Long-Term Reliability Assessment (LTRA), including 2023 actual generation plus Tier 1 additions for 2024.

- **Plant Closures:** This case assumes 104 GW of announced retirements based on NERC estimates including approximately 71 GW of coal and 25 GW of natural gas, which closely align with retirement numbers in EIA's 2025 Annual Energy Outlook. In addition, this case assumes 100% of 2024 NERC LTRA Tier 1 additions totaling 209 GW are constructed by 2030. This includes 20 GW of new natural gas, 31 GW of additional 4-hour batteries, 124 GW of new solar and 32 GW of incremental wind. Details of the breakdown can be found in Appendix A.

- **No Plant Closures:** This case adds all the Tier 1 NERC additions but assumes no retirements.

- **Required Build:** To understand how much capacity may need to be added to reach reliability targets, the analysis adds hypothetical perfect capacity (which is idealized capacity that has no outages or profile) until a NUSE target of 0.002% is realized in each region. This scenario includes the same assumptions about retirements as our Plant Closures scenario described above.

As shown in the figures and tables below, the model shows a significant decline in all reliability metrics between the current system scenario and the 2030 Plant Closures scenario. Most notably, there is a hundredfold increase in annual LOLH from 8.1 hours per year in the current case to 817 hours per year in the 2030 Plant Closures. In the worst weather year assessed, the total lost load hours increase from 50 hours to 1,316 hours.

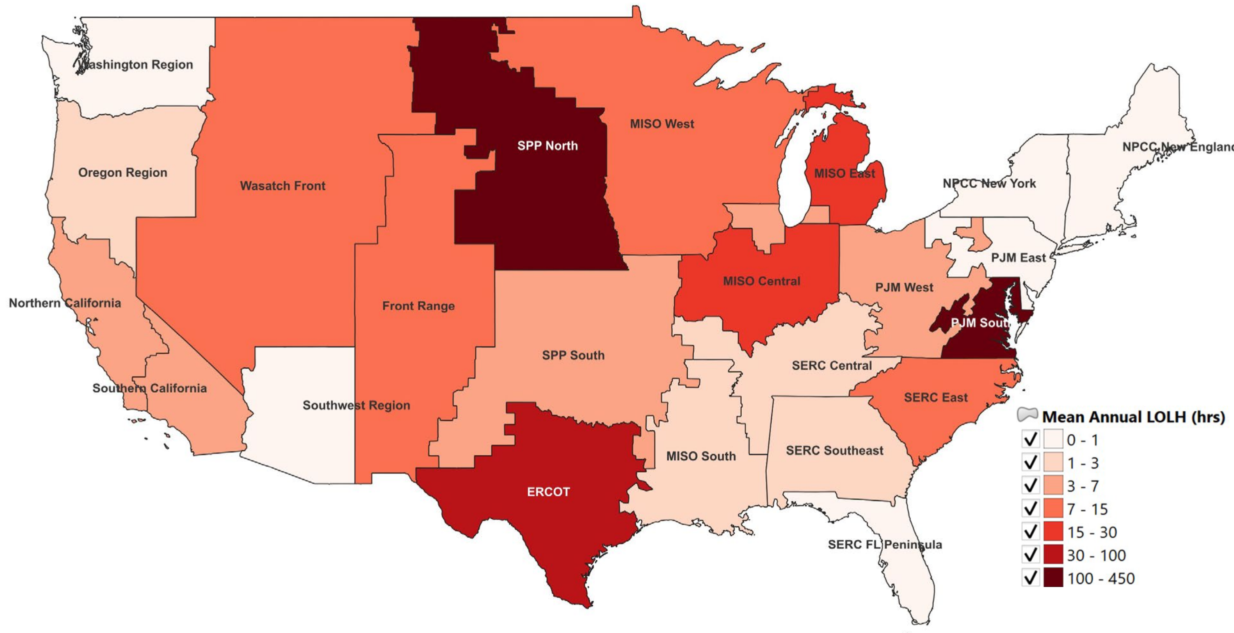


Figure 1. Mean Annual LOLH by Region (2030) – Plant Closures

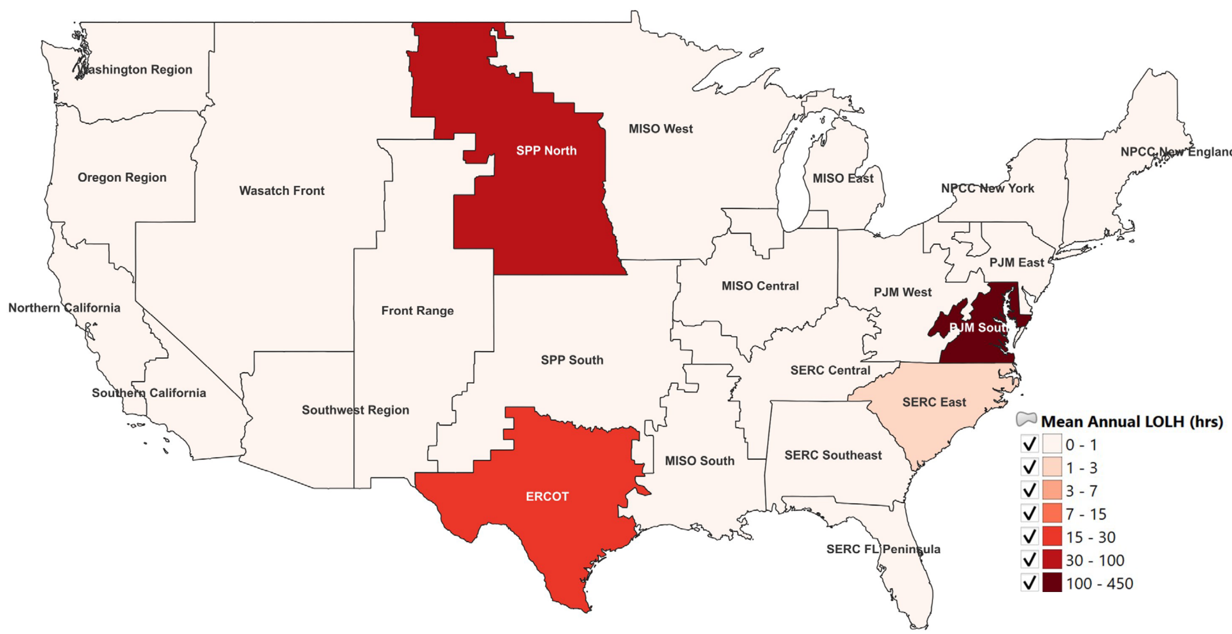


Figure 2. Mean Annual LOLH by Region (2030) – No Plant Closures

Table 1. Summary Metrics Across Cases

Reliability Metric		2030 Projection		
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	8.1	817.7	269.9	13.3
Normalized Unserved Energy (%)	0.0005	0.0465	0.0164	0.00048
WORST WEATHER YEAR				
Annual Loss of Load Hours	50	1316	658	53
Normalized Unserved Load (%)	0.0033	0.1119	0.0552	0.002

Current System Analysis

Analysis of the current system shows all regions except ERCOT have less than 2.4 hours of average loss of load per year and less than 0.002% NUSE. This indicates relative reliability for most regions based on the average indicators of risk used in this study. In the current system case, ERCOT would be expected to experience on average 3.8 LOLH annually going forward and a NUSE of 0.0032%. When looking at metrics in the worst weather years, regions meet or exceed additional criteria. All regions experienced less than 20% of lost load in any hour.

However, PJM, ERCOT,[12] and SPP experienced significant loss of load events during 2021 and 2022 winter storms Uri and Elliot which translated into more than 20 hours of lost load. This results in a concentration of lost load within certain years such that some regions exceeded 3-hours-per-year of lost load. It is worth noting that in the case of PJM and SPP, the current system model shortfalls occurred within subregions rather than for the entire ISO footprint.

12. ERCOT has since winterized its generation fleet and did not suffer any outages during Winter Storm Elliot.

2030 Model Results

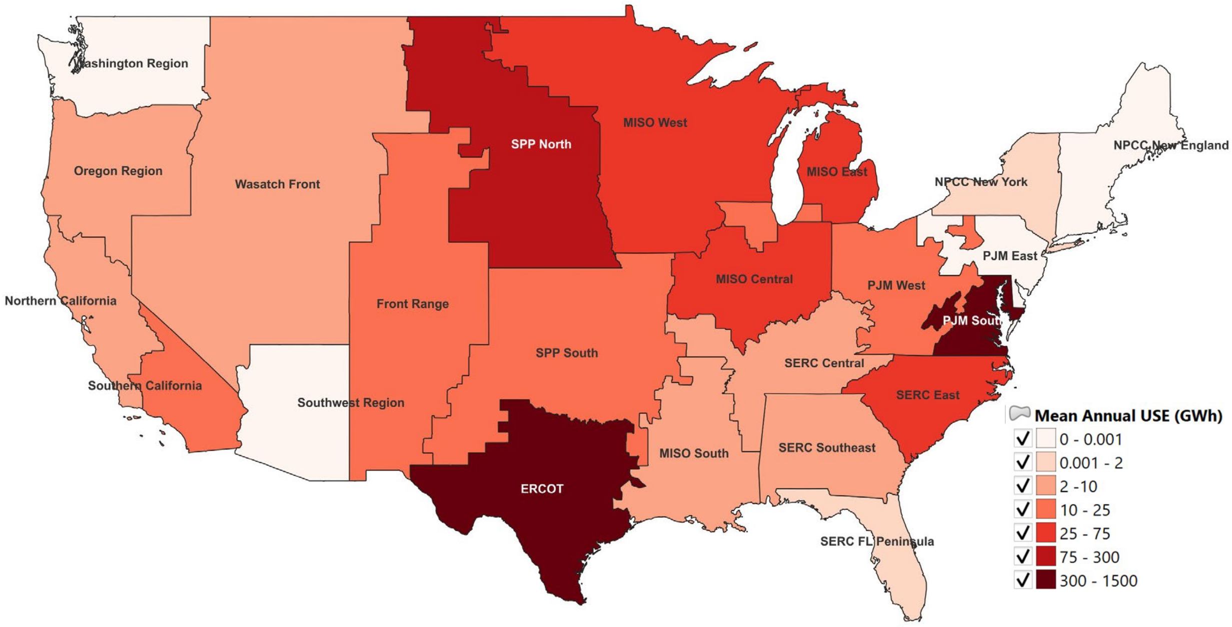


Figure 3. Mean Annual NUSE by Region (2030) -Plant Closures

Key Findings – Plant Closures Case:

- **Systemwide Failures**: All regions except ISO-NE and NYISO failed reliability thresholds. These two regions did not have additional AI/data center (AI/DC) load growth modeled.
- **Loss of Load Hours (LOLH)**: Ranged from 7 hours/year in CAISO to 430 hours/year in PJM.
- **Load Shortfall Severity**: Max shortfall reached as high as 43% of hourly load in PJM; 31% in CAISO.
- **Normalized Unserved Energy**: Normalized values ranged from 0.0032% (non-CAISO West) to 0.1473% (PJM), far exceeding thresholds of 0.002%.
- **Extreme Events**: Most regions experienced ≥3 hours of unserved load in at least one year. PJM had 1,052 hours in its worst year.
- **Spatial Takeaways**: Subregions in PJM, MISO, and SERC met thresholds—indicating possible benefits from transmission—but SPP and CAISO failed in all subregions.

Key Findings – No Plant Closures Case:

- **Improved System Performance**: Most regions avoided loss of load events. PJM, SPP, and SERC still experienced shortfalls.
- **Regional Failures**:

- **PJM**: 214 hours/year average, 0.066% normalized unserved energy, 644 hours in worst year, max 36% of load lost.

- **SPP**: 48 hours/year average, 0.008% normalized unserved energy, max 19% load lost.

- **ERCOT**: 20 average hours, 0.028% normalized unserved energy, 101 max hours/year, peak shortfall of 27%.

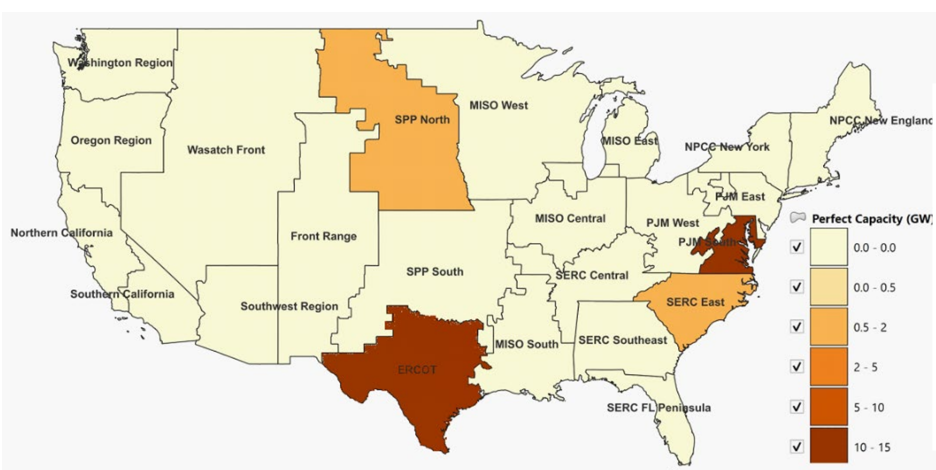
- **SERC-East**: Generally adequate (avg. 1 hour/year, 0.0003% NUSE), but Elliot storm in 2022 caused 42 hours of shortfall.

The overall takeaway is that avoiding announced retirements improves grid reliability, but shortfalls persist in PJM, SPP, ERCOT, and SERC, particularly in winter.

Required Build

This required build analysis quantifies "hypothetical capacity," defined as power that is 100% reliable and available that is needed to resolve the shortfalls. Known in industry as “perfect capacity,” this metric is utilized to avoid the complex decision of selecting specific generation technologies, as that is ultimately an optimization of reliability against cost considerations. Nevertheless, it serves as a valuable indicator, illustrating either the magnitude of a resource gap or the scale of large load that will be unable to interconnect. For the Required Build case, this hypothetical capacity was calculated by adding new generating resources to each region until a target of 0.002% of NUSE is reached.

The table below shows the tuned perfect capacity results. For the current system, this analysis identifies an additional 2.4 MW of capacity to meet the NUSE target for PJM, which experiences shortfalls due to the winter storm Elliot historical weather year. By 2030, without considering any generation retirements, an additional 12.5 GW of generating capacity is needed across PJM, SPP, and SERC to reduce shortfalls.



	2024-Current System (MW)	2030-No Plant Closures (MW)
PJM	2400	10,500
SERC-E		500
SPP-N		1,500
ERCOT	1600	10500
Total	4000	23000

Perfect Capacity/Additions

Figure 4. Tuned Perfect Capacity (MW) By Region

1 Modeling Methodology

The methodology uses a zonal PLEXOS[13] model with hourly time-synchronous datasets for load, generation, and interregional transfer for the 23 U.S. subregions (referred to as TPRs in this study)[14] including ERCOT (see Figure 5 below). While ERCOT operates outside of FERC's general jurisdiction,[15] it provides a valuable case for understanding broader reliability and resource adequacy challenges in the U.S. electric grid, and FPA Section 202(c) allows DOE to issue emergency orders to ERCOT.

We base this analysis on actual weather and power plant outage data from 2007 to 2023 using NERC's ITCS[16] base dataset. DOE specifically decided to start this analysis with the ITCS dataset since it is a complete representation of the interconnected electrical system for the lower 48 and it has been thoroughly reviewed by industry experts in a public and transparent process. DOE has in turn made modifications to the dataset to fit the needs of this study. The contents of this section focus on those modifications which DOE implemented for purposes of this study.

PLEXOS is an industry-trusted simulation tool used for energy optimization, resource adequacy, and production cost modeling. This study leverages PLEXOS' ability to exercise an hourly production cost model to determine the balance between loads, generation, and imports for each region. Modeling was carried out using a deterministic approach that evaluates whether a power system has sufficient resources to meet projected demand under a pre-defined set of conditions which correspond to the past few years of real-world events. The model ultimately determines the amount of unmet load if generation resources and imports are not sufficient for meeting the load in each discrete time period.

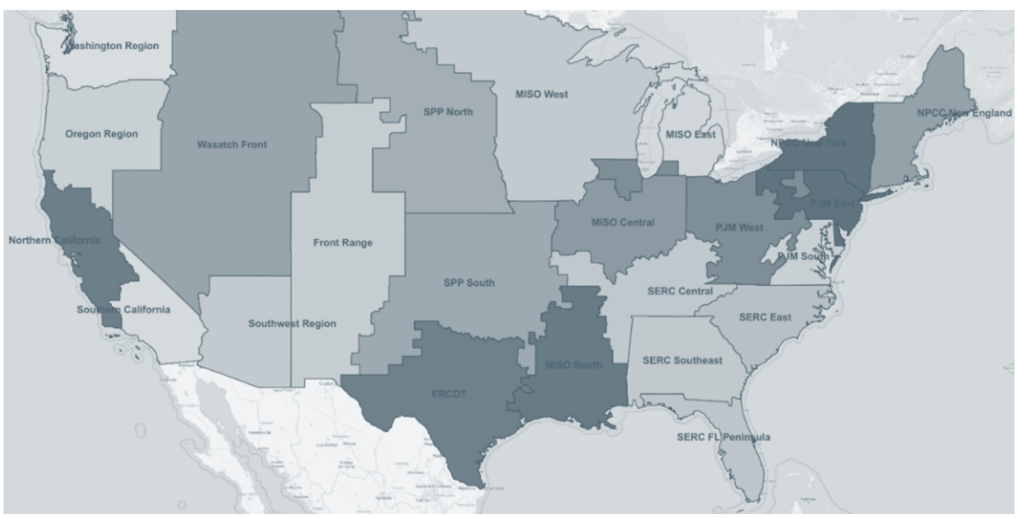


Figure 5. TPRs used in NERC ITCS

13. Energy Exemplar, "PLEXOS," https://www.energyexemplar.com/plexos.
14. The TPRs match the regional subdivisions in the NERC ITCS study, itself based on FERC's transmission planning regions.
15. Transmission within ERCOT is intrastate commerce. 16 U.S.C. § 824(b)(1) (provisions applying to "the transmission of electric energy in interstate commerce").
16. NERC "Integrated Transmission and Capacity System (ITCS)," accessed June 25, 2025, https://www.nerc.com/pa/RAPA/Pages/ITCS.aspx.

This methodology developed a current model and series of scenarios to explore how different assumptions impact resource adequacy. This sensitivity analysis includes assumptions regarding load growth, generation build-outs and retirements, and transfer capabilities. By comparing the results of the current model with the scenario results, we can assess how generation retirements and load growth affect future generation needs.

The assessment uses data from 2007–2013 (synthetic weather data) and 2019–2023 (historical data). A brief summary of the methodological assumptions is provided here, with additional details available in the relevant appendixes.

- **Solar and Wind Availability** – Created from historical output from EIA 930 data, with bias correction of any nonhistorical data to match regional capacity factors, as calibrated to EIA 930 data.[17] Synthetic years used 2018 technology characteristics from NREL based on the Variable Energy Potential (reV) model, then mapped to synthetic weather year data. See Appendix A for more details.

- **Thermal Availability** – Calculated according to NERC LTRA capacity data, adjusted for historical outages and derates, primarily with GADS data. GADS data does not capture historical outages caused by fuel supply interruptions.[18]

- **Hydroelectric Availability** – Historical outputs are processed by NERC to establish monthly power rating limits and energy budgets, but energy budgets are not enforced in alignment with how they were treated in the ITCS. The team evaluated performance under different energy budget restrictions, but did not find significant differences during peak hours, justifying NERC ITCS assumptions that hydroelectric resources could generally be dispatched to peak load conditions. Later work may benefit from exploring drought scenarios or combinations of weather and hydrological years, where energy budgets may be significantly decreased.

- **Outages and Derates** – Data for the actual data period (2019–2023) are based on historical forced outage rates and deratings. Outage and deratings data for the synthetic period (2007–2013) are based on the historical relationships observed between temperature and outages (see Appendix G of the NERC ITCS Final Report for more information).

- **Load Projections and AI Growth** – Load growth through 2030 is assumed to match NERC 2024 ITCS projections, scaling the 12 weather years to meet 2030 projections. Additional AI and data center load is then added according to reports from EPRI and S&P regarding potential futures.

- **Transfer Capabilities and Imports/Exports -** Each subregion is treated as a "copper plate," with the transfer capacity between each subregion defined by the availability of transmission pathways. It is an approximation that assumes all resources are connected to a single point, simplifying the transmission system within the model. Subregions are generally assumed to exhaust their own capacity before utilizing capacity available from their neighbors. Once the net remaining capacity is at or below 10 percent of load, the subregion begins to use capacity from a neighbor.

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17. See ITCS Final Report, Appendix F, for the method that was implemented to scale synthetic weather years 2007–2013.
18. See ITCS Final Report, Appendix G, for outage and derate methods.

  - Imports are assumed to be available up to the minimum total transfer capacity and spare generation in the neighboring subregion.

  - To the extent the remaining capacity after transmission and demand response falls below the 6 percent or 3 percent needed for error forecasting and ancillary services, depending on the scenario, the model projects an energy shortfall. See "Outputs" in the appendix for more details.

  - To ensure that transfers are dispatched only after local resources are exhausted, a wheeling charge of $1,000 is applied for every megawatt-hour of energy transferred between regions through transmission pathways.

- **Storage** – In alignment with the NERC ITCS methodology, storage was split into pumped hydro and battery storage. Pumped hydro was assumed to have 12 hours duration at rated capacity with 30% round-trip losses, while battery storage was assumed to have four hours and 13% round-trip losses. Storage is dispatched as an optimization to minimize USE and demand response usage under various constraints and is recharged during periods of surplus energy.

- **Demand Response –** Demand Response (DR) is treated as a supply-side resource and dynamically scheduled after all other regional resources and imports are exhausted. It is modeled with both capacity (MW) and energy (MWh) limitations and assumed to have three hours of availability at capacity but could be spread across more than three hours up to the energy limit. DR capacity was based on LTRA Form A data submissions for "Controllable and Dispatchable Demand Response – Available", or firm, controllable DR capacity.

- **Retirements** – Retirements as per the NERC LTRA 2024 model. To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant level data are used to tabulate generation retirement or addition capacity for each ITCS region and NERC assessment area. Disaggregation fractions are then calculated by technology based on planned retirements through 2030. See Appendix B for further information. Retirements are categorized into two categories:

  1. *Announced Retirements*: Includes both confirmed retirements and announced retirements. Confirmed retirements are generators formally recognized by system operators as having started the official retirement process and are assumed to retire on their expected date. To go from LTRA regions to ITCS regions, weighting factors are derived in the same way as in the generation set, based on EIA retirement data. In addition to confirmed retirements, announced retirements are generators that have publicly stated retirement plans that have not formally notified system operators and initiated the retirement process. This disaggregation method for announced retirements mirrors used for confirmed retirements.[19]

  2. *None*: Removes all retirements (after 2024) for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirement contributes to some of the adequacy challenges in some regions.

- **Additions** – Assumes only projects that are very mature in the pipeline (such as those with a signed interconnection agreement) will be built. This data is based on projects

19. If announced retirements were less than or equal to confirmed retirements, the model adjusted the announced retirement to equal confirmed.

designated as Tier 1 in the NERC 2024 LTRA and are mapped to ITCS regions with EIA 860-derived weighting factors similar to those described for the retirements above. See Appendix A for further information.

- **Perfect Capacity Required** - Estimates perfect capacity (which is idealized capacity that has no outages or profile and is described in Section 2) until we reach a pre-defined reliability target. We used a metric of NUSE given the deterministic nature of the model, to be consistent with evolving metrics, and to be consistent with NERC's recent LTRAs. We targeted NUSE of below 0.002% for each region.

1.1 Modeling Resource Adequacy

This model calculates several reliability metrics to assess resource adequacy. These metrics were calculated using PLEXOS simulation outputs, which report the USE (in MWh) for all 8,760 hourly periods in each of the 12 weather years:

- **USE** refers to the amount of electricity demand that could not be met due to insufficient generation and/or transmission capacity. Several USE-derived indicators were considered:
    - *Normalized USE (percentage %):* The total amount of unserved load over 12 years of weather data, normalized by dividing by total load, and reported as a percentage.[20]
    - *Mean Annual USE (GWh)*: The 12-year average of each region's total USE in each weather year. This mean value represents the average annual USE across weather variability.
    - *Mean Max Unserved Power (GW)*: The 12-year average of each region's maximum USE value in each weather year. This mean value characterizes the typical non-coincident peak stress on system reliability.
    - *% Max Unserved Power*: The Mean Max Unserved Power expressed as a percentage of the average native load during those peak unserved hours for each region. This percentage value provides a normalized measure of the severity of peak unserved events relative to demand.
    - *Total number of customers without power*. The Mean Max Unserved Power expressed as the equivalent number of typical U.S. persons assuming a ratio of 17,625 persons/MW lost. This estimation contextualizes the effects of the outage on average Americans.
- **Loss of Load Hours (LOLH)** refers to the number of hours during which the system experiences USE (i.e., any hour with non-zero USE). Two LOLH-based indicators were considered:

20. NUSE can be reported as parts per million or as a percentage (or parts per hundred); though for power system reliability, this would include several zeros after the decimal point.

- *Mean Annual LOLH*: for each weather year and *TPR*, we count the total number of hours with USE across all 8,760 hours, and we then take the average of those 12 totals. *Annual LOLH Distribution* is represented in box and whisker plots for 12 samples, each sample corresponding to a unique weather year.

- *Max Consecutive LOLH (hours)*[21]: The longest continuous period with reported USE in each weather year.

It should be noted that USE is not an indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system. Rather, it represents the unrealizable AI and data center load growth under the given assumptions for generator build outs by 2030, generator retirements by 2030, reserve requirements, and potential load growth. These numbers are used as indicators to determine where it may be beneficial to encourage increased generation and transmission capacity to meet an expected need.

This study does not employ common probabilistic industry metrics such as EUE or LOLE due to their reliance on probabilistic modeling. Instead, deterministic equivalents are used.

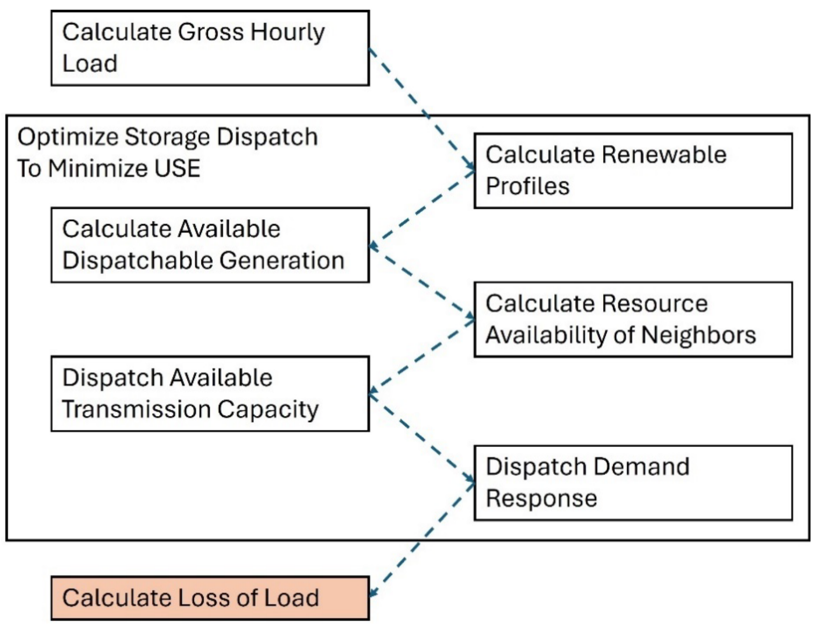


Figure 6. Simplified Overview of Model

21. One caveat on the maximum consecutive LOLH and max USE values is in how storage is dispatched in the model. Storage is dispatched to minimize the overall USE and is indifferent to the peak depth or the duration of the event. This may construe some of the max USE and max consecutive LOLH values to be higher than if storage was dispatched to minimize these values.

1.2 Planning Years and Weather Years

For the planning year (2030), historical weather year data are applied based on conditions between 2007 and 2024 to calculate load, wind and solar generation, and hydro generation. Dispatchable capacity (including dispatchable hydro capacity) is calculated through adjustment of the 2024 LTRA capacity data for historical outages from GADS data. Storage assets are scheduled to arbitrage hourly energy margins or else charge during periods of high energy margins (surplus resources) and discharge during periods of lower energy margins.

1.3 Load Modeling

Data Center Growth

Several utilities and financial and industry analysts identify data centers, particularly those supporting AI workloads, as a key driver of electricity demand growth. Multiple organizations have developed a wide range of projections for U.S. data center electricity use through 2030 and beyond, each using distinct methodologies tailored to their institutional expertise.

These datasets were used to explore reasonable boundaries for what different parts of the economy envision for the future state of AI and data center (AI/DC) load growth. For the purposes of this study, rather than focusing on any specific analysis, a more generic sweep was performed across AI/DC load growth and the various sensitivities that fit within those assumptions, as summarized below:

- McKinsey & Company projects ~10% annual growth in U.S. data center electricity demand, reaching 2,445 TWh by 2050. Their model blends internal scenarios with public signals, including announced projects, capital investment, server shipments, and chip-level power trends, supported by third-party market data.

- Lawrence Berkeley National Laboratory (LBNL) uses a bottom-up approach based on historical and projected IT equipment shipments, paired with assumptions on power draw, utilization, and infrastructure efficiency (PUE, WUE). Their projections through 2028 account for AI hardware adoption, operational shifts, and evolving cooling technologies.

- EPRI combines public data, expert input, and historical trends to define four national growth scenarios, low to higher, for 2023–2030, reflecting data processing demand, efficiency improvements, and AI-driven load impacts.

- S&P Global merges technology and power-sector models, evaluating grid readiness and facility growth under varying demand scenarios. Their forecasts consider AI adoption, efficiency trends, grid and permitting constraints, on-site generation, and offshoring risk, resulting in a wide range of outcomes.

These projections show wide variation, with 2030 electricity demand ranging from approximately 35 GW to 108 GW of average load. Given this uncertainty, including differences in hardware intensity, thermal management, siting assumptions, and behind-the-meter generation, the modeling team adopted a national midpoint assumption of approximately 50 GW by 2030.

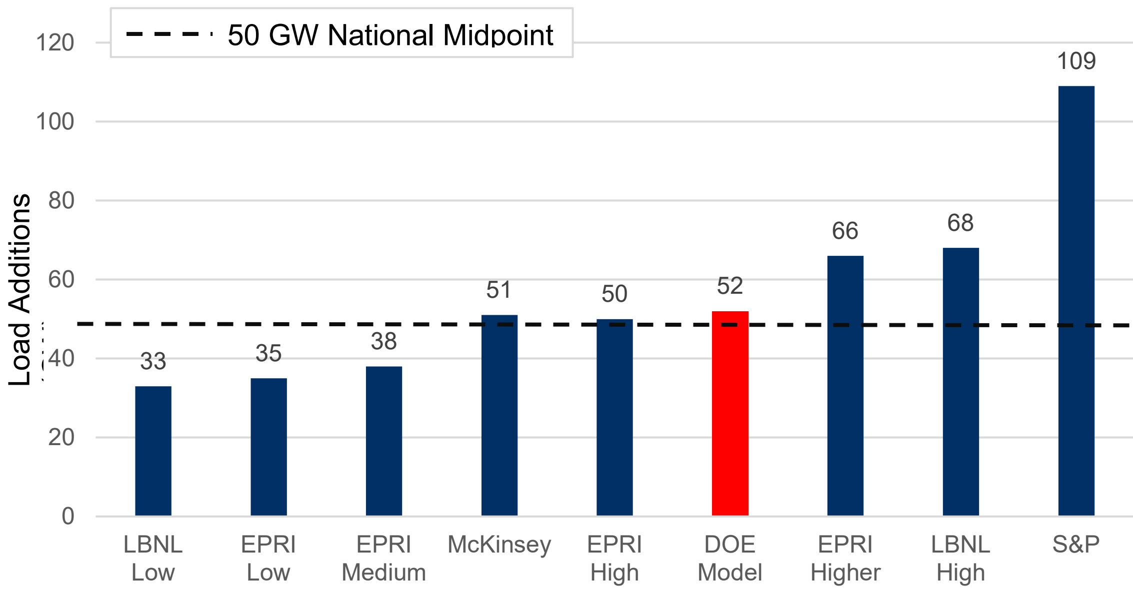


Figure 7. 2024 to 2030 Projected Data Center Load Additions

Figure 2 above displays a benchmark reflecting the median across major studies and aligns with central projections from EPRI and LBNL. Using a single planning midpoint avoids double counting and enables consistent load allocation across national transmission and resource adequacy models.

Data Center Allocation Method

To allocate the 50 GW midpoint regionally, the team used state-level growth ratios from S&P's forecast. These ratios reflect factors such as infrastructure, siting trends, and projected market activity. The modeling team mapped the state-level projections to NERC TPRs, ensuring transparent and repeatable regional allocation. While other methods exist, this approach ensured consistency with the broader modeling framework.

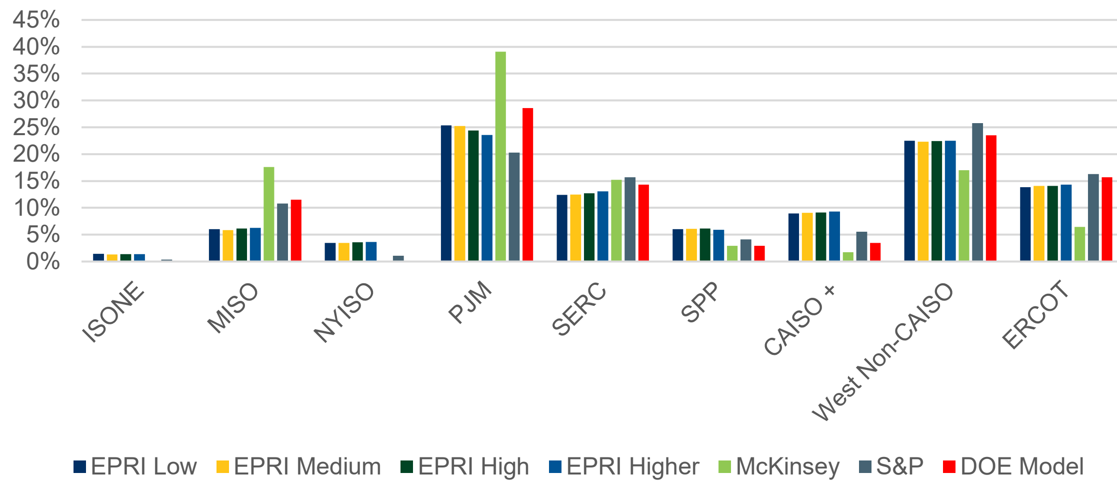


Figure 8. New Data Center Build (% Split by ISO/RTO) (2030 Estimated)

Non-Data Center Load Modeling

The current electricity demand projections were built from NERC data, using historical load (2019–2023) and simulated weather years (2007–2013). These were adjusted based on the EIA's 2022 energy forecast. To estimate 2030 demand, the team interpolated between 2024 and 2033, scaling loads to reflect energy use and seasonal peaks. NERC provided datasets to address anomalies and include behind-the-meter and USE.

Given the rapid emergence of AI/DC loads, additional steps were taken to account for this category of demand. It is difficult to determine how much AI/DC load is already embedded in NERC LTRA forecast, for example, the 2024 LTRA saw more than 50GW increase from 2023, signaling a major shift in utility expectations. To benchmark existing AI/DC contribution, DOE assumed base 2023 AI/DC load equaled the EPRI low-growth case of 166 TWh.

Overall Impact on Projected Peak Load

As a result of the methods applied above, the average year co-incident peak load is projected to grow from a current average peak of 774 GW to 889 GW in 2030. This represents a 15% increase or 2.3% growth rate per year. Excluding the impact of data centers, this would amount to a 51GW increase from 774 GW to 826 GW which represents a 1.1% annual growth rate.

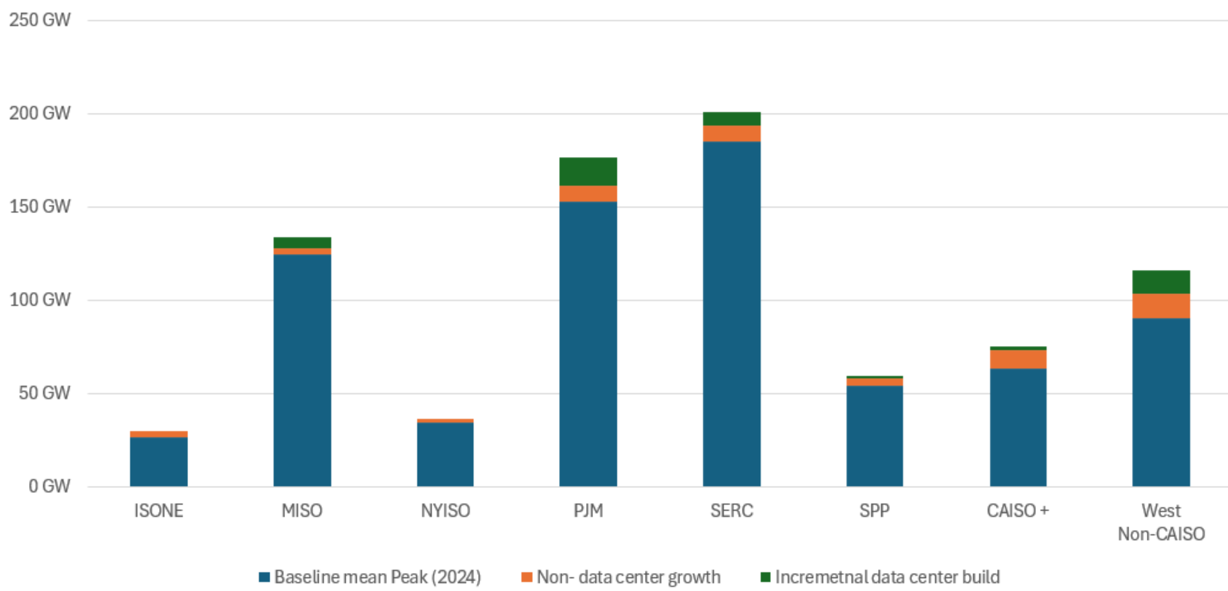


Figure 9. Mean Peak Load by RTO (Current Case vs 2030 Case)

1.4 Transfer Capabilities and Import Export Modeling

The methodology assumes electricity moves between subregions, when conditions start to tighten. Each region has a certain amount of capacity available, and the methodology determines if there is enough to meet the demand. When regions reach a “Tight Margin Level” of 10% of capacity, i.e., if a region’s available capacity is less than 110% of load, it will start transferring from other regions if capacity is available. A scarcity factor is used to determine which regions to transfer from and at what fraction – those with a greater amount of reserve capacity will transfer more. A region is only allowed to export above when it is above the Tight Margin Level.

Total Transfer Capability (TTC) was used and is the sum of the Base Transfer Level and the First Contingency Incremental Transfer Capability. These were derived from scheduled interchange tables or approximated from actual line flows. It should be noted that the TTC does not represent a single line, but rather multiple connections between regions. It is similar to path limits used by many entities but may have different values.

Due to data and privacy limitations, the Canadian power system was not modeled directly as a combination of generation capacity and demand. Instead, actual hourly imports were used from nearly 20 years of historical data, along with recent trends (generally less transfers available during peak hours), to develop daily limits on transfer capabilities. See Appendix B for more details on Canadian transfer limits.

1.5 Perfect Capacity Additions

To understand how much capacity may need to be added to reach approximate reliability targets, we tuned two scenarios by adding hypothetical perfect capacity to reach the reliability threshold based on NUSE.[22] Today, NERC uses a threshold of 0.002% to indicate regions are at high risk of resource adequacy shortfalls. In addition, several system operators, including the Australia Energy Market Operator and Alberta Electric System Operator, are using NUSE thresholds in the range of 0.001% to 0.003%. Several U.S. entities are considering lower thresholds for U.S. power systems in the range of 0.0001% to 0.0002%. [23]

For this analysis, we target NUSE below 0.002% for each region to align with NERC definitions. We iteratively ran the model, hand-tuning the "perfect capacity" to be as small as possible while reaching NUSE values below 0.002% in all regions.[24] As the work was done by hand with a limited number of iterations (15), this should not be considered the minimum possible capacity to accomplish these targets. Further, because the perfect capacity can be located in various places, there would be multiple potential solutions to the problem. These scenarios represent the approximate quantity of perfect capacity each region would require (beyond announced retirements and mature generation additions only) that would lead to Medium or Low risk based on the NERC metrics for USE.

Due to some regions with zero USE, the tuned cases do not reach the same level of adequacy, where the national average is 0.00045% vs. 0.00013%. Due to transmission and siting selection of perfect capacity, there could be many solutions.

22. We are not using the standard term "expected unserved energy" because we are not running a probabilistic model, so we do not have the full understanding of long-term expectations

23. MISO, "Resource Adequacy Metrics and Criteria Roadmap," December 2024. https://cdn.misoenergy.org/Resource%20Adequacy%20Metrics%20and%20Criteria%20Roadmap667168.pdf.

24. NERC, "Evolving Criteria for a Sustainable Power Grid," July 2024. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Evolving_Planning_Criteria_for_a_Sustainable_Power_Grid.pdf.

2 Regional Analysis

This section presents more regional details on resource adequacy according to this analysis. For each of the nine Regional Transmission Organizations (RTOs) and sub-regions, comprehensive summaries are provided of reliability metrics, load assumptions, and composition of generation stacks.

2.1 MISO[25]

In the current system model and the No Plant Closures cases, MISO did not experience shortfall events. MISO's minimum spare capacity in the tightest year was negative, showing that adequacy was achieved by importing power from neighbors. In the Plant Closures case, MISO experienced significant shortfalls, with key reliability metrics exceeding each of the threshold criteria defined for the study.

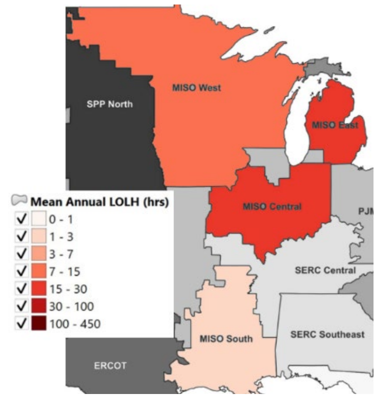


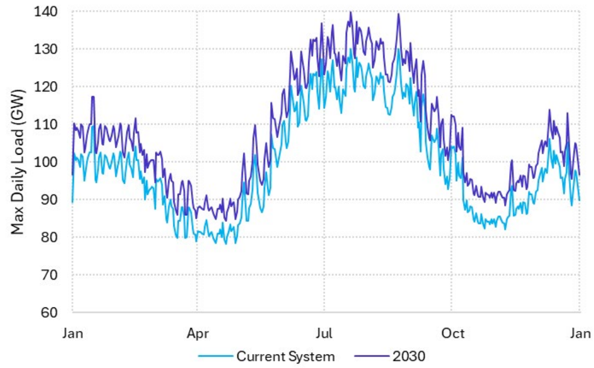
Table 2. Summary of MISO Reliability Metrics

Reliability Metric	Current System	2030 Projection: Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	37.8	-	-
Normalized Unserved Energy (%)	-	0.0211	-	-
Unserved Load (MWh)	-	157,599	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	124	-	-
Normalized Unserved Load (%)	-	0.0702	-	-
Unserved Load (MWh)	-	524,180	-	-

Load Assumptions

MISO's peak load was roughly 130 GW in the current model and projected to increase to roughly 140 GW by 2030. Approximately 6 GW of this relates to new data centers being installed (12% of U.S. total).

25. Following the initial data collection for this report, MISO issued its 2025 Summer Reliability Assessment. Based on that report, NERC revised evaluations from its 2024 LTRA and reclassified the MISO footprint from being an 'elevated risk' to 'high risk' in the 2028–2031 timeframe, depending on new resource additions/retirements. While DOE's analysis is based on the previously reported figures, DOE is committed to assessing the implications of updated data on overall resource adequacy and providing technical updates on findings, as appropriate.



Subregion	2024	2030
MISO-W	37,913	40,981
MISO-C	35,387	39,243
MISO-S	36,476	38,596
MISO-E	23,167	23,758
Total	**130,136**	**139,846**

Figure 10. MISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 207 GW.[26] In 2030, 21 GW of new capacity was added leading to 228 GW of capacity in the No Plant Closures case. In the Plant Closures case, 32 GW of capacity was retired such that net retirements in the Plant Closures case were -11 GW, or 196 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
MISO-W	71,612	67,453	77,605
MISO-C	51,982	47,735	58,823
MISO-S	54,511	52,756	59,710
MISO-E	29,213	28,105	32,255
Total	**207,319**	**196,049**	**228,393**

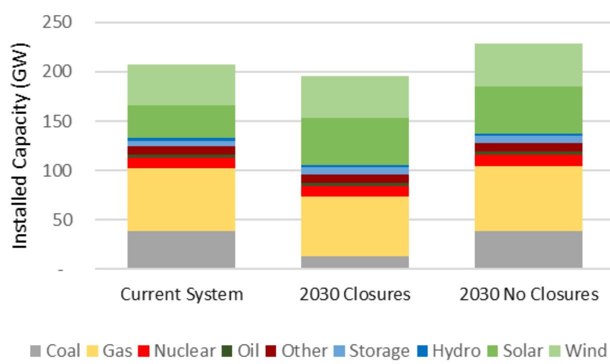


Figure 11. MISO Generation Capacity by Technology and Scenario

MISO's generation mix was comprised primarily of natural gas, coal, wind, and solar. In 2024, natural gas comprised 31% of nameplate, wind comprised 20%, coal 18%, and solar 14%. In 2030, most retirements come from coal and natural gas while additions occur for solar, batteries, and wind. In addition, the model assumed 3 GW of rooftop solar and 8 GW of demand response.

26. The total installed capacity numbers reported in this regional analysis section do not reflect the generating capability of all resources during stress conditions.

Table 3. Nameplate Capacity by MISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**37,914**	**64,194**	**11,127**	**2,867**	**8,717**	**5,427**	**2,533**	**32,826**	**41,715**	**207,319**
MISO-W	12,651	13,608	2,753	1,491	2,613	200	777	8,109	29,411	**71,612**
MISO-C	15,050	10,307	2,169	494	2,211	1,272	769	12,361	7,350	**51,982**
MISO-S	5,493	31,052	5,100	589	2,469	54	845	8,315	596	**54,511**
MISO-E	4,720	9,227	1,105	292	1,424	3,901	143	4,042	4,359	**29,213**
Additions	**0**	**2,535**	**0**	**330**	**0**	**1,929**	**0**	**14,354**	**1,926**	**21,074**
MISO-W	0	537	0	172	0	374	0	3,552	1,358	**5,993**
MISO-C	0	407	0	57	0	934	0	5,103	339	**6,841**
MISO-S	0	1,226	0	68	0	9	0	3,868	27	**5,199**
MISO-E	0	364	0	34	0	611	0	1,831	201	**3,042**
Closures	**(24,913)**	**(6,597)**	**0**	**(324)**	**(140)**	**(16)**	**(83)**	**0**	**(272)**	**(32,345)**
MISO-W	(8,313)	(1,398)	0	(168)	(56)	0	(25)	0	(192)	**(10,152)**
MISO-C	(9,889)	(1,059)	0	(56)	(7)	(3)	(25)	0	(48)	**(11,088)**
MISO-S	(3,609)	(3,191)	0	(67)	(55)	(0)	(28)	0	(4)	**(6,954)**
MISO-E	(3,102)	(948)	0	(33)	(21)	(13)	(5)	0	(28)	**(4,150)**

2.2 ISO-NE

In the current system model and the No Plant Closures case, ISO-NE did not experience shortfall events. The region maintained adequacy throughout the study period through reliance on imports. In the Plant Closures case, ISO-NE still did not exceed any key reliability thresholds, despite moderate retirements. This finding is partly due to the absence of additional AI or data center load growth modeled in the region. Accordingly, no additional perfect capacity was deemed necessary by 2030 to meet the study's reliability standards.

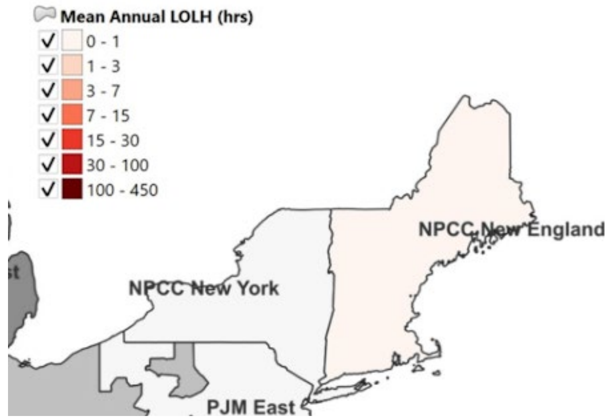
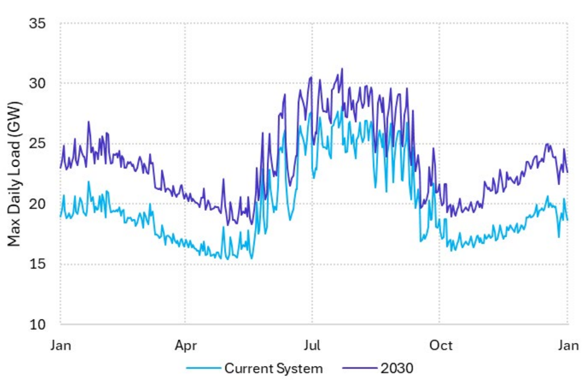


Table 4. Summary of ISO-NE Reliability Metrics

Reliability Metric	Current System	2030 Projection		
		Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	-	-	-
Normalized Unserved Energy (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	-	-	-
Normalized Unserved Load (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
Max Unserved Load (MW)	-	-	-	-

Load Assumptions

ISO-NE's peak load was roughly 28 GW in the current model and projected to increase to roughly 31 GW by 2030. No additional AI/DCs were projected to be installed.



Subregion	2024	2030
ISO-NE	28,128	31,261
Total	28,128	31,261

Figure 12. ISO-NE Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 40 GW. In 2030, 5.5 GW of new capacity was added leading to 45.5 GW of capacity in the No Plant Closures case. In the Plant Closures case, 2.7 GW of capacity was retired such that net generation change in the Plant Closures case was +11 GW, or 42.8 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
ISO-NE	39,979	42,845	45,534
Total	**39,979**	**42,845**	**45,534**

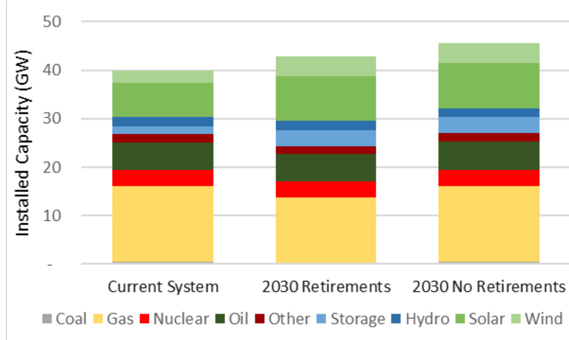


Figure 13. ISO-NE Generation Capacity by Technology and Scenario

ISO-NE's generation mix was comprised primarily of natural gas, solar, oil, and nuclear. In 2024, natural gas comprised 39% of nameplate, solar comprised 17%, oil 14%, and nuclear 8%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed nearly 2 GW of rooftop solar and 1.6 GW of energy storage.

Table 5. Nameplate Capacity by ISO-NE Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**541**	**15,494**	**3,331**	**5,710**	**1,712**	**1,628**	**1,911**	**7,099**	**2,553**	**39,979**
ISONE	541	15,494	3,331	5,710	1,712	1,628	1,911	7,099	2,553	**39,979**
Additions	**0**	**90**	**0**	**181**	**0**	**1,607**	**0**	**2,183**	**1,495**	**5,555**
ISONE	0	90	0	181	0	1,607	0	2,183	1,495	**5,555**
Closures	**(534)**	**(1,875)**	**0**	**(203)**	**(77)**	**0**	**0**	**0**	**0**	**(2,690)**
ISONE	(534)	(1,875)	0	(203)	(77)	0	0	0	0	**(2,690)**

2.3 NYISO

In both the current system model and the No Plant Closures case, NYISO maintained reliability and did not exceed any shortfall thresholds. Adequacy was preserved through reliance on imports. In the Plant Closures case, NYISO experienced shortfalls but average annual LOLH remaining well below the 2.4-hour threshold and NUSE under the 0.002% standard. The worst weather year produced only 6 hours of lost load and a peak unserved load of 914 MW. Given the modest impact of retirements and no additional AI/data center load modeled, the study concluded that NYISO would not require additional perfect capacity to remain reliable through 2030.

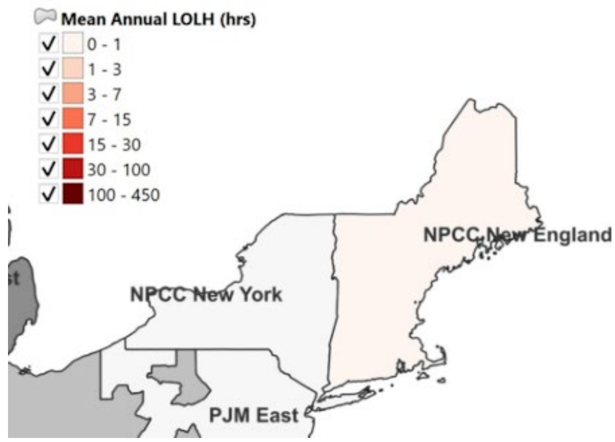
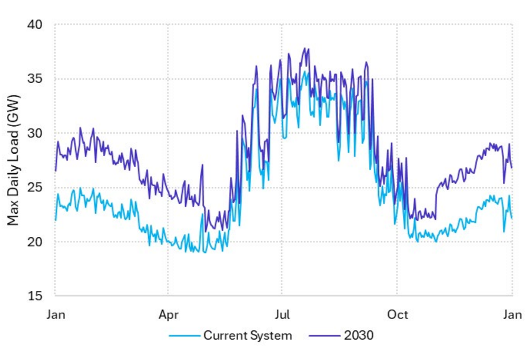


Table 6. Summary of NYISO Reliability Metrics

Reliability Metric	Current System	2030 Projection		
		Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.2	0.5	-	-
Normalized Unserved Energy (%)	0.00001	0.0001	-	-
Unserved Load (MWh)	18	209	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	2	6	-	-
Normalized Unserved Load (%)	0.0001	0.0013	-	-
Unserved Load (MWh)	216	2,505	-	-
Max Unserved Load (MW)	194	914	-	-

Load Assumptions

NYISO's peak load was roughly 36 GW in the current system model and projected to increase to roughly 38 GW by 2030. No additional AI/DCs were projected to be installed.



Subregion	2024	2030
NYISO	35,669	37,844
Total	35,669	37,844

Figure 14. NYISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 46 GW. In 2030, 5.5 GW of new capacity was added leading to 51 GW of capacity in the No Plant Closures case. In the Plant Closures case, 1 GW of capacity was retired such that net generation in the Plant Closures case was +4 GW, or 50 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
NYISO	45,924	50,396	51,444
Total	**45,924**	**50,396**	**51,444**

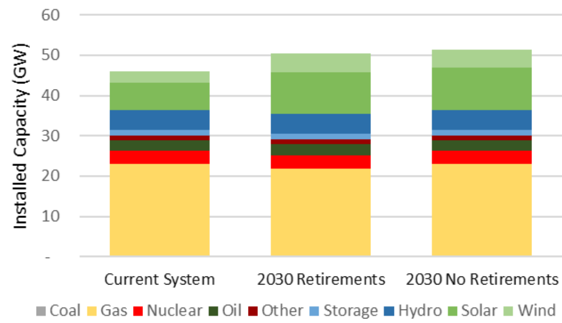


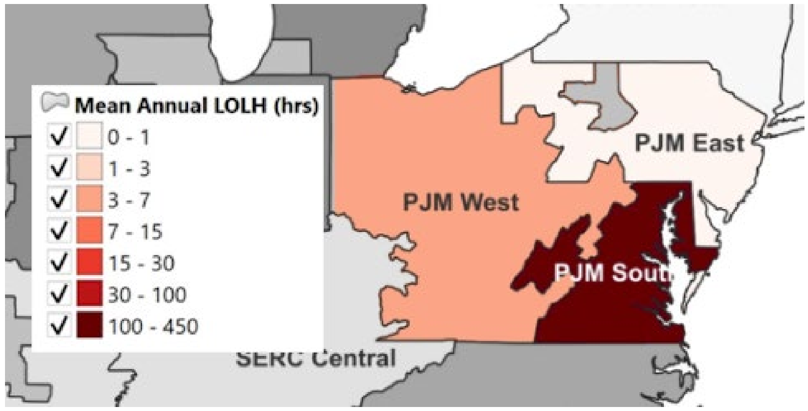
Figure 15. NYISO Generation Capacity by Technology and Scenario

NYISO's generation mix was comprised primarily of natural gas, solar, and hydro. In 2024, natural gas comprised 50% of total nameplate generation, solar comprised 14%, and hydro 11%. In 2030, most retirements come from natural gas while additions occur for solar and wind. The model assumed 6 GW of rooftop solar and nearly 1 GW of demand response.

Table 7. Nameplate Capacity by NYISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**0**	**22,937**	**3,330**	**2,631**	**1,194**	**1,460**	**4,915**	**6,749**	**2,706**	**45,924**
NYISO	0	22,937	3,330	2,631	1,194	1,460	4,915	6,749	2,706	**45,924**
Additions	**0**	**0**	**0**	**15**	**0**	**0**	**0**	**3,604**	**1,902**	**5,521**
NYISO	0	0	0	15	0	0	0	3,604	1,902	**5,521**
Closures	**0**	**(1,030)**	**0**	**(19)**	**0**	**0**	**0**	**0**	**0**	**(1,049)**
NYISO	0	(1,030)	0	(19)	0	0	0	0	0	**(1,049)**

2.4 PJM



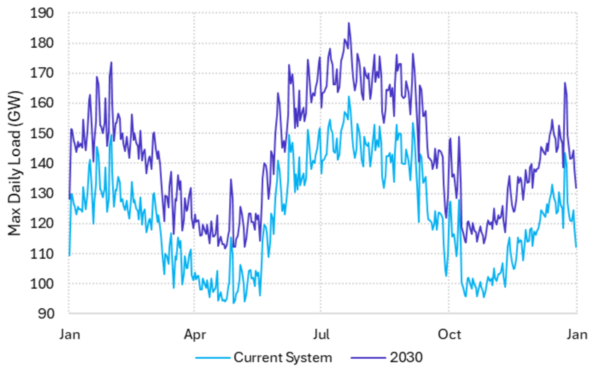
In the current system model, PJM experienced shortfalls, but they were below the required threshold. In the No Plant Closures case, shortfalls increased dramatically, with 214 average annual LOLH and peak unserved load reaching 17,620 MW, indicating growing strain even without retirements. In the Plant Closures case, reliability metrics worsened significantly, with annual LOLH surging to over 430 hours per year and NUSE reaching 0.1473%—over 70 times the accepted threshold. During the worst weather year, 1,052 hours of load were shed. To restore reliability, the study found that PJM would require 10,500 MW of additional perfect capacity by 2030.

Table 8. Summary of PJM Reliability Metrics

Reliability Metric	Current System	2030 Projection Plant Closures	2030 Projection No Plant Closures	2030 Projection Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	2.4	430.3	213.7	1.4
Normalized Unserved Energy (%)	0.0008	0.1473	0.0657	0.0003
Unserved Load (MWh)	6,891	1,453,513	647,893	2,536
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	29	1,052	644	17
Normalized Unserved Load (%)	0.0100	0.4580	0.2703	0.0031
Unserved Load (MWh)	82,687	1,453,513	647,893	2,536
Max Unserved Load (MW)	4,975	21,335	17,620	4,162

Load Assumptions

PJM's peak load was roughly 162 GW in the current system model and projected to increase to roughly 187 GW by 2030. Approximately 15 GW of this relates to new AI/DC being installed (29% of U.S. total), primarily in PJM-S.



Subregion	2024	2030
PJM-W	81,541	92,378
PJM-S	39,904	51,151
PJM-E	41,003	43,118
Total	**162,269**	**186,627**

Figure 16. PJM Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 215 GW. In 2030, 39 GW of new capacity was added leading to 254 GW of capacity in the No Plant Closures case. In the Plant Closures case, 17 GW of capacity was retired such that net generation in the Plant Closures case was +22 GW, or 237 GW of overall nameplate capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
PJM-W	114,467	123,100	135,810
PJM-S	39,951	48,850	50,667
PJM-E	60,221	64,848	67,027
Total	**214,638**	**236,798**	**253,504**

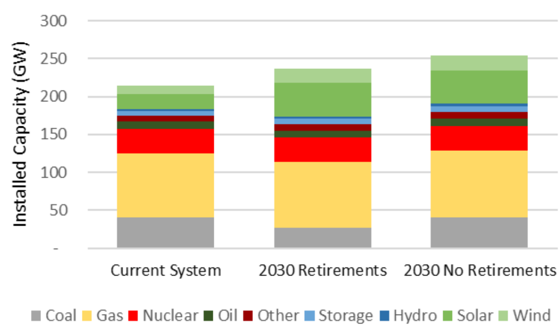


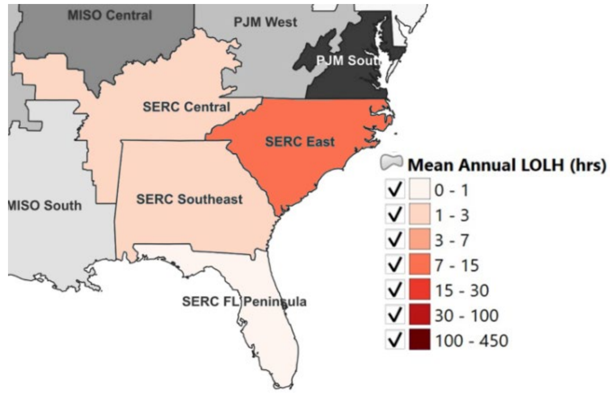
Figure 17. PJM Generation Capacity by Technology and Scenario

PJM's generation mix was comprised primarily of natural gas, coal, and nuclear. In 2024, natural gas comprised 39% of nameplate, coal comprised 19%, and nuclear 15%. In 2030, most retirements come from coal and some natural gas and oil while significant additions occur for solar plus lesser additions of wind, storage, and natural gas. The model assumed 9 GW of rooftop solar and 7 GW of demand response.

Table 9. Nameplate Capacity by PJM Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**39,915**	**84,381**	**32,535**	**9,875**	**8,248**	**5,400**	**3,071**	**19,495**	**11,718**	**214,638**
PJM-W	34,917	39,056	16,557	1,933	3,926	383	1,252	6,379	10,065	**114,467**
PJM-S	2,391	15,038	5,288	3,985	2,303	3,085	1,070	6,430	360	**39,951**
PJM-E	2,608	30,287	10,690	3,956	2,019	1,932	749	6,686	1,294	**60,221**
Additions	**0**	**4,499**	**0**	**32**	**317**	**1,938**	**0**	**24,991**	**7,089**	**38,866**
PJM-W	0	2,082	0	6	135	855	0	12,176	6,089	**21,343**
PJM-S	0	802	0	13	102	726	0	8,856	218	**10,717**
PJM-E	0	1,615	0	13	81	357	0	3,958	783	**6,806**
Closures	**(13,253)**	**(1,652)**	**0**	**(1,790)**	**(11)**	**0**	**0**	**0**	**0**	**(16,706)**
PJM-W	(11,593)	(765)	0	(350)	(1)	0	0	0	0	**(12,710)**
PJM-S	(794)	(294)	0	(722)	(6)	0	0	0	0	**(1,817)**
PJM-E	(866)	(593)	0	(717)	(3)	0	0	0	0	**(2,179)**

2.5 SERC



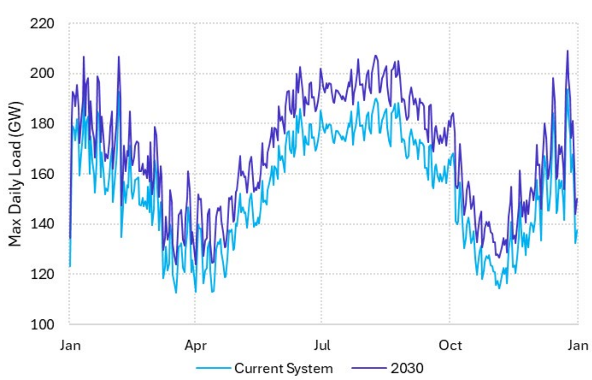
In the current system model and the No Plant Closures case, SERC maintained overall adequacy, though some subregions—particularly SERC-East—faced emerging winter reliability risks. In the Plant Closures case, shortfalls became more severe, with SERC-East experiencing increased unserved energy and loss of load hours during extreme cold events, including 42 hours of outages in a single winter storm. The analysis identified that planned retirements, combined with rising winter load from electrification, would stress the system. To restore reliability in SERC-East, the study found that 500 MW of additional perfect capacity would be needed by 2030. Other SERC subregions performed adequately, but continued monitoring is warranted due to shifting seasonal peaks and fuel supply vulnerabilities.

Table 10. Summary of SERC Reliability Metrics

Reliability Metric		2030 Projection		
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.3	8.1	1.2	0.8
Normalized Unserved Energy (%)	0.0001	0.0041	0.0004	0.0002
Unserved Load (MWh)	489	44,514	3,748	2,373
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	4	42	14	10
Normalized Unserved Load (%)	0.0006	0.0428	0.0042	0.0026
Unserved Load (MWh)	5,683	465,392	44,977	2,373
Max Unserved Load (MW)	2,373	19,381	6,359	5,859

Load Assumptions

SERC's peak load was roughly 193 GW in the current system model and projected to increase to roughly 209 GW by 2030. Approximately 7.5 GW of this relates to new AI/DCs being installed (14% of U.S. total).



Subregion	2024	2030
SERC-C	50,787	52,153
SERC-SE	48,235	54,174
SERC-FL	58,882	62,572
SERC-E	51,693	56,313
Total	193,654	209,269

Figure 18. SERC Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 254 GW. In 2030, 26 GW of new capacity was added leading to 279 GW of capacity in the No Plant Closures case. In the Plant Closures case, 19 GW of capacity was retired such that net generation change in the Plant Closures case was +7 GW, or 260 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
SERC-C	53,978	54,014	59,660
SERC-SE	67,073	64,768	69,478
SERC-FL	72,714	83,127	86,173
SERC-E	59,914	58,513	63,973
Total	**253,680**	**260,423**	**279,285**

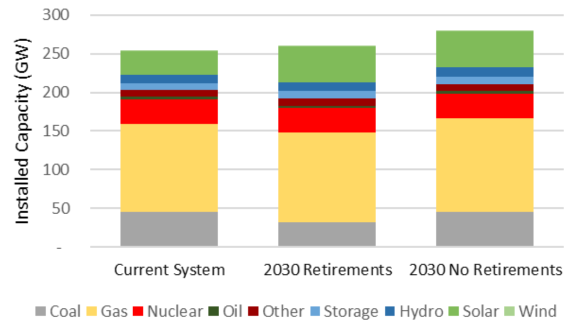


Figure 19. SERC Generation Capacity by Technology and Scenario

SERC's generation mix was comprised primarily of natural gas, coal, nuclear, and solar. In 2024, natural gas comprised 45% of nameplate, coal comprised 18%, nuclear 12%, and solar 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar and some storage. The model assumed 3 GW of rooftop solar and 8 GW of demand response.

Table 11. Nameplate Capacity by SERC Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**45,747**	**113,334**	**31,702**	**4,063**	**8,779**	**7,469**	**11,425**	**30,180**	**982**	**253,680**
SERC-C	13,348	20,127	8,280	148	1,887	1,884	4,995	2,328	982	**53,978**
SERC-SE	13,275	29,866	8,018	915	2,493	1,662	3,260	7,584	0	**67,073**
SERC-FL	4,346	47,002	3,502	1,957	3,198	538	0	12,172	0	**72,714**
SERC-E	14,777	16,340	11,902	1,044	1,202	3,384	3,170	8,096	0	**59,914**
Additions	**0**	**6,898**	**0**	**0**	**381**	**2,254**	**0**	**16,073**	**0**	**25,606**
SERC-C	0	4,831	0	0	0	80	0	771	0	**5,682**
SERC-SE	0	906	0	0	19	0	0	3,135	0	**4,059**
SERC-FL	0	1,161	0	0	218	1,670	0	10,410	0	**13,459**
SERC-E	0	0	0	0	144	504	0	1,757	0	**2,405**
Closures	**(14,075)**	**(4,115)**	**0**	**(672)**	**0**	**0**	**0**	**0**	**0**	**(18,862)**
SERC-C	(4,465)	(1,181)	0	0	0	0	0	0	0	**(5,646)**
SERC-SE	(5,160)	(124)	0	(176)	0	0	0	0	0	**(5,460)**
SERC-FL	(1,495)	(1,071)	0	(480)	0	0	0	0	0	**(3,046)**
SERC-E	(2,955)	(1,739)	0	(16)	0	0	0	0	0	**(4,710)**

2.6 SPP

In the current system model, SPP experienced shortfalls, but they were below the required threshold. Adequacy was preserved through reliance on imports. In the No Plant Closures case, SPP experienced persistent reliability challenges, with average annual LOLH reaching approximately 48 hours per year and peak hourly shortfalls affecting up to 19% of demand. In the Plant Closures case, system conditions deteriorated further, with unserved energy and outage hours increasing substantially. These shortfalls were concentrated in the northern subregion, which lacks the firm generation and import capacity needed to meet peak winter demand. The analysis determined that 1,500 MW of additional perfect capacity would be needed in SPP by 2030 to restore reliability.

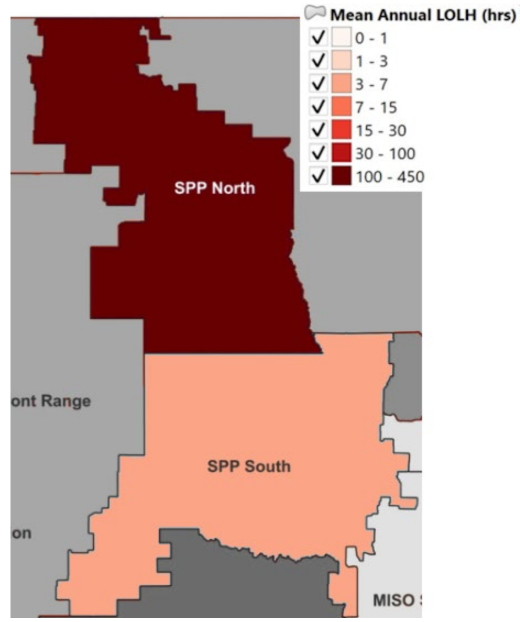
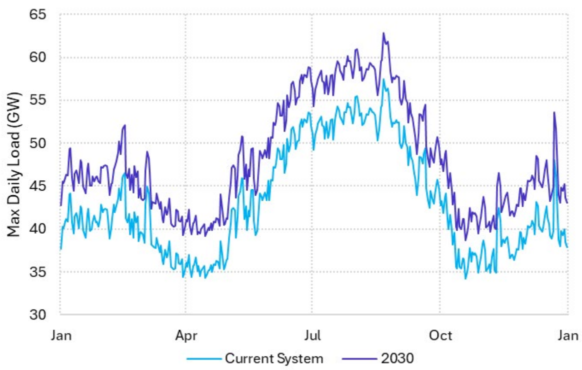


Table 12. Summary of SPP Reliability Metrics

Reliability Metric	Current System	2030 Projection Plant Closures	2030 Projection No Plant Closures	2030 Projection Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	1.7	379.6	47.8	2.4
Normalized Unserved Energy (%)	0.0002	0.0911	0.0081	0.0002
Unserved Load (MWh)	541	313,797	27,697	803
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	20	556	186	26
Normalized Unserved Load (%)	0.0022	0.2629	0.0475	0.0027
Unserved Load (MWh)	6,492	907,518	163,775	9,433
Max Unserved Load (MW)	606	13,263	2,432	762

Load Assumptions

SPP's peak load was roughly 57 GW in the current system model and projected to increase to roughly 63 GW by 2030. Approximately 1.5 GW of this relates to new AI/DCs being installed (3% of U.S. total).



Subregion	2024	2030
SPP-N	12,668	14,676
SPP-S	44,898	48,337
Total	**57,449**	**62,891**

Figure 20. SPP Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 95 GW. In 2030, 15 GW of new capacity was added leading to 110 GW of capacity in the No Plant Closures case. In the Plant Closures case, 7 GW of capacity was retired such that net generation change in the 2030 Plant Closures case was +8 GW, or 103 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
SPP-N	20,065	20,679	22,385
SPP-S	75,078	82,451	88,064
Total	**95,142**	**103,130**	**110,449**

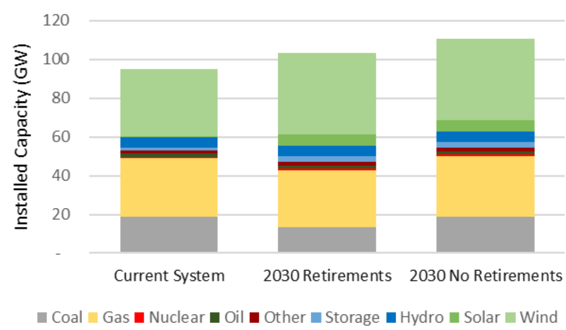


Figure 21. SPP Generation Capacity by Technology and Scenario

SPP's generation mix was comprised primarily of wind, natural gas, and coal. In 2024, wind comprised 36% of nameplate, natural gas comprised 32%, and coal 20%. In the 2030 case, most retirements come from coal and natural gas while additions occur for wind, solar, storage, and natural gas. The model assumed almost no rooftop solar and 1.3 GW of demand response.

Table 13. Nameplate Capacity by SPP Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**18,919**	**30,003**	**769**	**1,626**	**1,718**	**1,522**	**5,123**	**774**	**34,689**	**95,142**
SPP-N	5,089	3,467	304	504	519	8	3,041	91	7,041	**20,065**
SPP-S	13,829	26,536	465	1,121	1,199	1,514	2,082	683	27,649	**75,078**
Additions	**0**	**1,094**	**0**	**7**	**462**	**1,390**	**0**	**5,288**	**7,066**	**15,306**
SPP-N	0	126	0	2	114	11	0	633	1,434	**2,320**
SPP-S	0	968	0	5	348	1,379	0	4,655	5,632	**12,987**
Closures	**(5,530)**	**(1,732)**	**0**	**(56)**	**0**	**0**	**0**	**0**	**0**	**(7,318)**
SPP-N	(1,488)	(200)	0	(17)	0	0	0	0	0	**(1,705)**
SPP-S	(4,042)	(1,532)	0	(39)	0	0	0	0	0	**(5,613)**

2.7 CAISO+

In the current system and No Plant Closures cases, CAISO+ did not experience major reliability issues, though adequacy was often maintained through significant imports during tight conditions. In the Plant Closures case, however, the region faced substantial shortfalls, particularly during summer evening hours when solar output declines. Average LOLH reached 7 hours per year, and the worst-case year showed load shed events affecting up to 31% of demand. The NUSE exceeded reliability thresholds, signaling the system's vulnerability to high load and low renewable output periods.

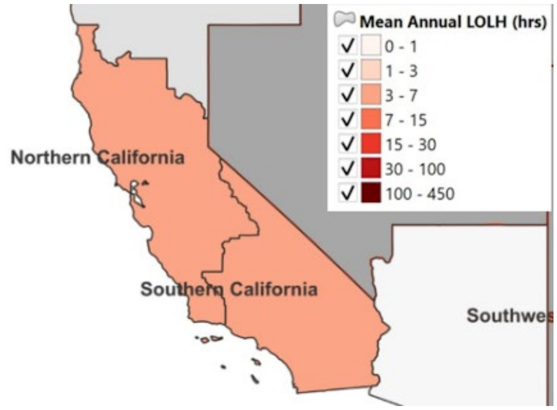
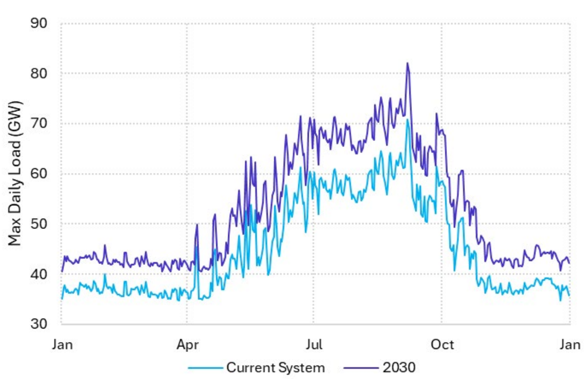


Table 14. Summary of CAISO+ Reliability Metrics

Reliability Metric		2030 Projection		
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	6.8	-	-
Normalized Unserved Energy (%)	-	0.0062	-	-
Unserved Load (MWh)	-	23,488	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	21	-	-
Normalized Unserved Load (%)	-	0.0195	-	-
Unserved Load (MWh)	-	73,462	-	-
Max Unserved Load (MW)	-	12,391	-	-

Load Assumptions

CAISO+'s peak load was roughly 79 GW in the current system model and projected to increase to roughly 82 GW by 2030. Approximately 2 GW of this relates to new AI/DCs being installed (4% of U.S. total).



Subregion	2024	2030
CALI-N	29,366	34,066
CALI-S	41,986	48,666
Total	**70,815**	**82,146**

Figure 22. CAISO+ Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 117 GW. In 2030, 14 GW of new capacity was added leading to 131 GW of capacity in the No Plant Closures case. In the Plant Closures case, 8 GW of capacity was retired such that net closures in the Plant Closures case were +6 GW, or 123 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
CALI-N	47,059	48,897	52,501
CALI-S	69,866	74,041	78,308
Total	**116,925**	**122,938**	**130,809**

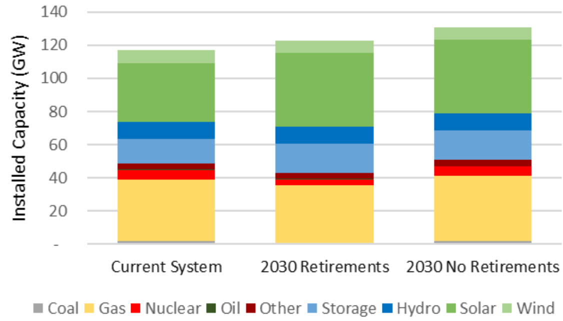


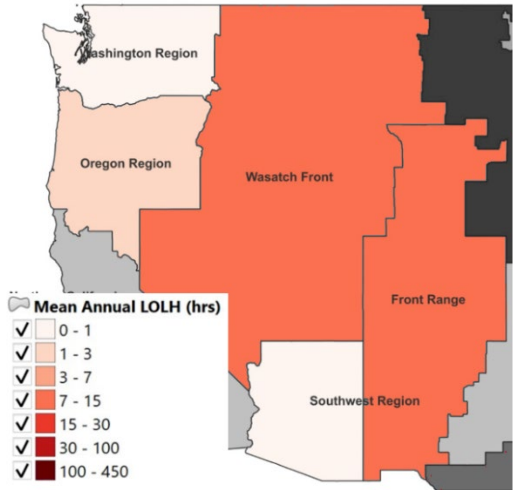
Figure 23. CAISO+ Generation Capacity by Technology and Scenario

CAISO+'s generation mix was comprised primarily of natural gas, solar, storage, and hydro. In 2024, natural gas comprised 32% of nameplate, solar comprised 31%, storage 13%, and hydro 9%. In 2030, most retirements come from coal, natural gas, and nuclear while additions occur for solar and storage. The model assumed 10 GW of rooftop solar and less than 1 GW of demand response.

Table 15. Nameplate Capacity by CAISO+ Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**1,816**	**37,434**	**5,582**	**185**	**3,594**	**14,670**	**10,211**	**35,661**	**7,773**	**116,925**
CALI-N	0	12,942	5,582	165	1,872	4,639	8,727	11,759	1,373	**47,059**
CALI-S	1,816	24,492	0	20	1,722	10,031	1,483	23,902	6,400	**69,866**
Additions	**0**	**2,126**	**0**	**0**	**92**	**3,161**	**0**	**8,507**	**0**	**13,885**
CALI-N	0	735	0	0	44	757	0	3,906	0	**5,442**
CALI-S	0	1,391	0	0	48	2,404	0	4,600	0	**8,442**
Closures	**(1,800)**	**(3,771)**	**(2,300)**	**0**	**0**	**0**	**0**	**0**	**0**	**(7,871)**
CALI-N	0	(1,304)	(2,300)	0	0	0	0	0	0	**(3,604)**
CALI-S	(1,800)	(2,467)	0	0	0	0	0	0	0	**(4,267)**

2.8 West Non-CAISO



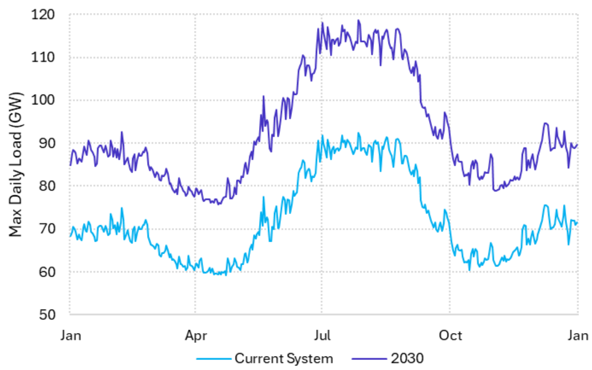
In both the current system and No Plant Closures cases, the West Non-CAISO region maintained adequacy on average. In the Plant Closures case, the region's reliability declined, with annual LOLH increasing and peak shortfalls in the worst year affecting up to 20% of hourly load in some subregions. While overall NUSE normalized unserved energy remained just above the 0.002% threshold, specific areas, especially those with limited local resources and constrained transmission, exceeded acceptable risk levels. These reliability gaps were primarily driven by increasing reliance on variable energy resources without sufficient firm generation.

Table 16. Summary of West Non-CAISO Reliability Metrics

Reliability Metric		2030 Projection		
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	17.8	-	-
Normalized Unserved Energy (%)	-	0.0032	-	-
Unserved Load (MWh)	-	21,785	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	47	-	-
Normalized Unserved Load (%)	-	0.0098	-	-
Unserved Load (MWh)	-	66,248	-	-
Max Unserved Load (MW)	-	5,071	-	-

Load Assumptions

West Non-CAISO's peak load was roughly 92 GW in the current system model and projected to increase to roughly 119 GW by 2030. Approximately 12 GW of this relates to new AI/DCs being installed (24% of U.S. total).



Subregion	2024	2030
WASHINGTON	20,756	23,187
OREGON	11,337	16,080
SOUTHWEST	23,388	30,169
WASATCH	27,161	35,440
FRONT R	20,119	24,996
Total	92,448	118,657

Figure 24. West Non-CAISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 178 GW. In 2030, 29 GW of new capacity was added leading to 207 GW of capacity in the No Plant Closures case. In the Plant Closures case, 13 GW of capacity was retired such that net generation change in the Plant Closures case was 16 GW, or 193 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
WASHINGTON	35,207	36,588	37,573
OREGON	19,068	21,689	22,081
SOUTHWEST	42,335	47,022	49,158
WASATCH	42,746	45,175	50,251
FRONT R	38,572	43,011	47,844
Total	177,929	193,485	206,908

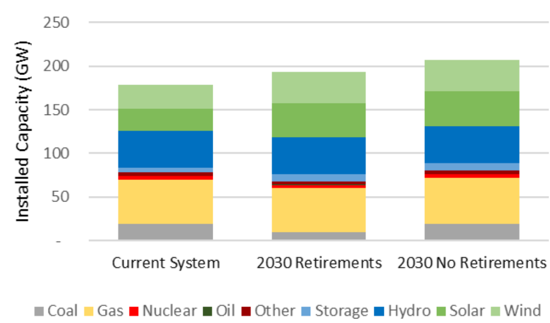


Figure 25. West Non-CAISO Generation Capacity by Technology and Scenario

West Non-CAISO's generation mix was comprised primarily of natural gas, hydro, wind, solar, and coal. In 2024, natural gas comprised 28% of nameplate, hydro comprised 24%, wind 15%, solar 13%, and coal 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar, wind, storage, and natural gas. The model assumed 6 GW of rooftop solar and over 1 GW of demand response.

Table 17. Nameplate Capacity by West Non-CAISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**19,850**	**49,969**	**3,820**	**644**	**4,114**	**5,104**	**42,476**	**24,652**	**27,298**	**177,929**
WASHINGTON	560	3,919	1,096	17	595	489	24,402	1,438	2,690	**35,207**
OREGON	0	3,915	0	6	456	482	8,253	2,517	3,440	**19,068**
SOUTHWEST	4,842	17,985	2,724	323	1,316	2,349	1,019	8,093	3,685	**42,335**
WASATCH	7,033	14,061	0	87	1,433	1,194	7,587	7,299	4,052	**42,746**
FRONT R	7,415	10,089	0	211	314	590	1,215	5,306	13,432	**38,572**
Additions	**0**	**2,320**	**0**	**1**	**8**	**2,932**	**0**	**14,759**	**8,959**	**28,979**
WASHINGTON	0	246	0	0	0	109	0	1,059	952	**2,366**
OREGON	0	246	0	0	0	150	0	1,399	1,218	**3,013**
SOUTHWEST	0	309	0	0	0	2,338	0	3,578	599	**6,823**
WASATCH	0	884	0	0	7	233	0	4,946	1,435	**7,505**
FRONT R	0	634	0	0	0	102	0	3,779	4,756	**9,271**
Closures	**(9,673)**	**(2,540)**	**0**	**(6)**	**(311)**	**(170)**	**(627)**	**0**	**(95)**	**(13,422)**
WASHINGTON	(317)	(195)	0	(0)	(66)	(28)	(369)	0	(11)	**(986)**
OREGON	0	(195)	0	(0)	(58)	0	(125)	0	(14)	**(392)**
SOUTHWEST	(1,185)	(951)	0	0	0	0	0	0	0	**(2,136)**
WASATCH	(3,978)	(699)	0	(2)	(178)	(89)	(115)	0	(16)	**(5,077)**
FRONT R	(4,194)	(501)	0	(4)	(8)	(53)	(18)	0	(54)	**(4,832)**

2.9 ERCOT

In the current system model, ERCOT exceeded reliability thresholds, with 3.8 annual Loss of Load Hours and a NUSE of 0.0032%, indicating stress even before future retirements and load growth. In the No Plant Closures case, conditions worsened as average LOLH rose to 20 hours per year and the worst-case year reached 101 hours, driven by data center growth and limited dispatchable additions. The Plant Closures case intensified these risks, with average annual LOLH rising to 45 hours per year and unserved load reaching 0.066%. Peak shortfalls reached 27% of demand, with outages concentrated in winter when generation is most vulnerable. To meet reliability targets, ERCOT would require 10,500 MW of additional perfect capacity by 2030.

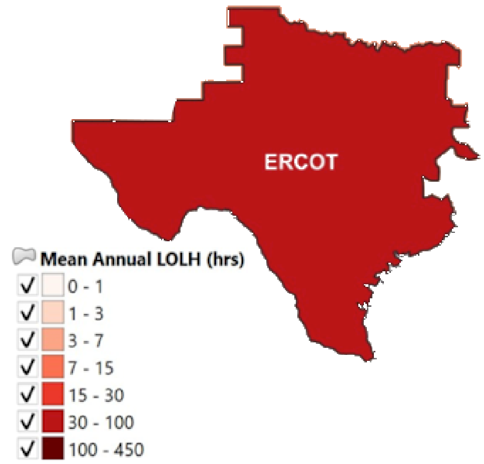
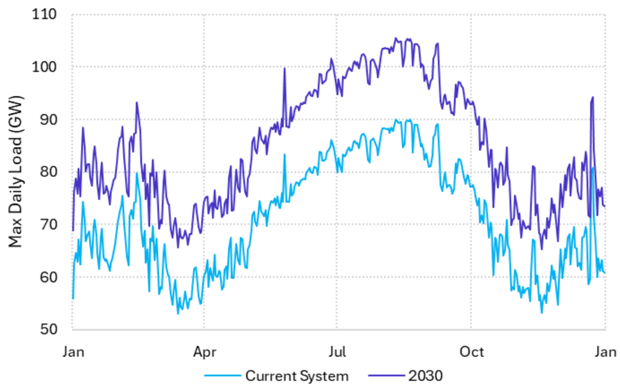


Table 18. Summary of ERCOT Reliability Metrics

Reliability Metric	Current System	2030 Projection: Plant Closures	2030 Projection: No Plant Closures	2030 Projection: Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	3.8	45.0	20.3	1.0
Normalized Unserved Energy (%)	0.0032	0.0658	0.0284	0.0008
Unserved Load (MWh)	15,378	397,352	171,493	4,899
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	30	149	101	12
Normalized Unserved Load (%)	0.0286	0.02895	0.01820	0.0098
Unserved Load (MWh)	136,309	1,741,003	1,093,560	58,787
Max Unserved Load (MW)	10,115	27,156	23,105	8,202

Load Assumptions

ERCOT's peak load was roughly 90 GW in the current system model and projected to increase to roughly 105 GW by 2030. Approximately 8 GW of this relates to new data centers being installed (62% of U.S. total).



Subregion	2024	2030
ERCOT	90,075	105,485
Total	90,075	105,485

Figure 26. ERCOT Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 157 GW. In 2030, 55 GW of new capacity was added leading to 213 GW of capacity in the No Plant Closures case. In the Plant Closures case, 4 GW of capacity was retired such that net generation change in the Plant Closures case was +51 GW, or 208 GW of overall nameplate capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
ERCOT	157,490	208,894	212,916
Total	157,490	208,894	212,916

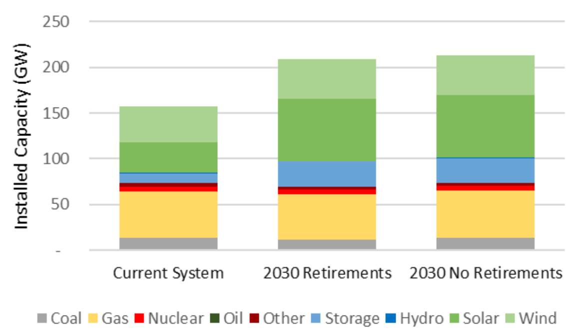


Figure 27. ERCOT Generation Capacity by Technology and Scenario

ERCOT's generation mix was comprised primarily of natural gas, wind, and solar. In 2024, natural gas comprised 32% of nameplate, wind comprised 25%, and solar 22%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed 2.5 GW of rooftop solar and 3.5 GW of demand response.

Table 19. Nameplate Capacity for ERCOT and by Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**13,568**	**50,889**	**4,973**	**10**	**3,627**	**10,720**	**583**	**33,589**	**39,532**	**157,490**
ERCOT	13,568	50,889	4,973	10	3,627	10,720	583	33,589	39,532	**157,490**
Additions	**0**	**569**	**0**	**0**	**0**	**16,538**	**0**	**34,681**	**3,638**	**55,426**
ERCOT	0	569	0	0	0	16,538	0	34,681	3,638	**55,426**
Closures	**(2,000)**	**(2,022)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(4,022)**
ERCOT	(2,000)	(2,022)	0	0	0	0	0	0	0	**(4,022)**

Appendix A - Generation Calibration and Forecast

The study team started with the grid model from the NERC ITCS, which was published in 2024 with reference to NERC 2023 LTRA capacity.[27] This zonal ITCS model serves as the starting point for the network topology (covering 23 U.S regions), transmission capacity between zones, and general modeling assumptions. The resource mix and retirements in the ITCS model were updated for this study to reflect the various 2030 scenarios discussed previously. Prior to developing the 2030 scenarios, the study team also updated the 2024 ITCS model to ensure consistency in the current model assumptions.

2024 Resource Mix

Because there were noted changes in assumed capacity additions between the 2023 and 2024 LTRAs[28], the ITCS model was updated with the 2024 LTRA data, provided directly by NERC to the study team. The 2024 LTRA dataset, reported at the NERC assessment area level—which is more aggregated in some areas than the ITCS regional structure (covering 13 U.S. regions; see Figure A.1)—includes both existing resource capacities[29] and Tier 1, 2, and 3 planned additions for each year from 2024 to 2033. As explained below, to incorporate this data into the ITCS model, a mapping process was developed to disaggregate generation capacities from the NERC assessment areas to the more granular ITCS regions by technology type. To preserve the daily or monthly adjustments to generator availability for certain categories (wind, solar, hybrid, hydropower, batteries, and other) by using the ITCS methods, the nameplate LTRA capacity was used. For all other categories (mostly thermal generators), summer and winter on-peak capacity contributions were used.

27. NERC, "Interregional Transfer Capability Study (ITCS)." https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf.

28. NERC, "2024 Long-Term Reliability Assessment," December, 2024, 24. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

29. Capacities are reported for both winter and summer seasonal ratings, along with nameplate values.

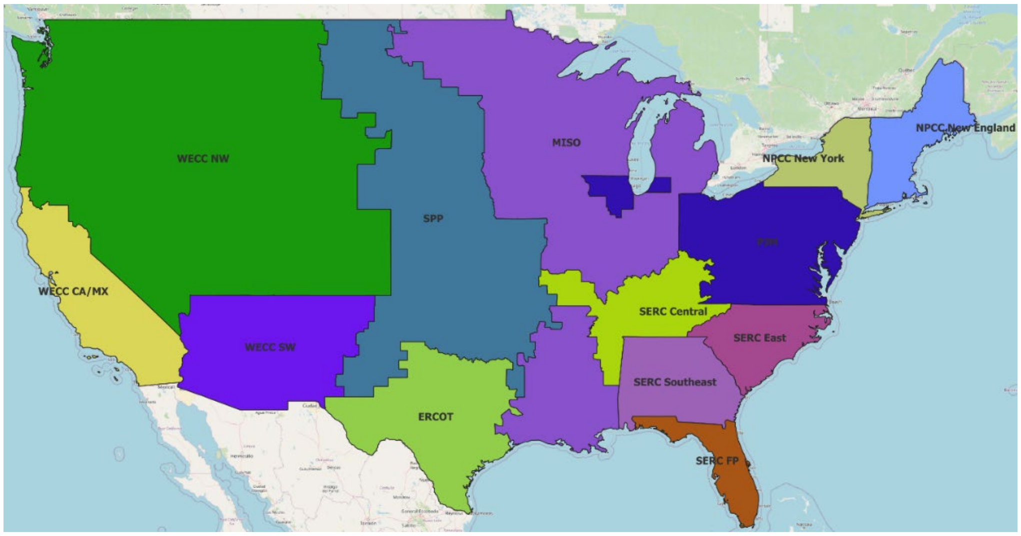


Figure A.1. NERC assessment areas.

To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant-level data were used to tabulate the generation capacity for each ITCS region and NERC assessment area. The geographical boundaries for the NERC assessment areas and the ITCS regions were constructed based on ReEDS zones.[30] Disaggregation fractions were then calculated by technology type using the combined existing capacity and planned additions through 2030 from EIA 860 data as of December 2024. Specifically, to compute each fraction, an ITCS region's total (existing plus planned) capacity was divided by the corresponding total capacity across all ITCS regions within the same mapped NERC assessment area and fuel type group:

$$Fraction_{rf} = \frac{Capacity_{rf}}{\sum_{r' \in ITCS(R)} Capacity_{r'f}} \qquad \textit{(Equation.1)}$$

Where $Capacity_{rf}$ is the capacity of fuel type f in ITCS region r and $ITCS(R)$ is the set of all ITCS regions mapped to the same NERC assessment area R. The denominator is the total capacity of that fuel type across all ITCS regions mapped to R.

Note that in cases where NERC assessment areas align one-to-one with ITCS regions, no mapping was required. Table A.1 summarizes which areas exhibited a direct one-to-one matching and which required disaggregation (1-to-many) or aggregation (many-to-one) to align with the ITCS regional structure.

An exception to this general approach is the case of the Front Range ITCS region, which geographically spans across two NERC assessment areas—WECC-NW and WECC-SW—resulting in two-to-one mapping. For this case, a separate allocation method was used: Plant-level data from EIA 860 were analyzed to determine the proportion of Front Range capacity located in each NERC area. These proportions were then used to derive custom weighting factors for allocating capacities from both WECC-NW and WECC-SW into the Front Range region.

30. NREL, "Regional Energy Development System," https://www.nrel.gov/analysis/reeds/.

Table A.1. Mapping of NERC assessment areas to ITCS regions.

NERC Area	ITCS Region	Match
ERCOT	ERCOT	1 to 1
NPCC-New England	NPCC-New England	1 to 1
NPCC-New York	NPCC-New York	1 to 1
SERC-C	SERC-C	1 to 1
SERC-E	SERC-E	1 to 1
SERC-FP	SERC-FP	1 to 1
SERC-SE	SERC-SE	1 to 1
WECC-SW	Southwest Region	1 to 1
MISO	MISO Central	1 to 4
MISO	MISO East	
MISO	MISO South	
MISO	MISO West	
SPP	SPP North	1 to 2
SPP	SPP South	
WECC-CAMX	Southern California	1 to 2
WECC-CAMX	Northern California	
WECC-NW	Oregon Region	1 to 3
WECC-NW	Washington Region	
WECC-NW	Wasatch Front	
WECC-NW	Front Range	2 to 1
WECC-SW	Front Range	

Table A.2 and Figure A.2 show the same combined capacities by ITCS region and NERC planning region, respectively.

Table A.2. Existing and Tier 1 capacities by NERC assessment area (in MW) in 2024.

2024 Exsting + Tier 1			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**143,035**	**330,342**	**82,793**	**26,771**	**3,624**	**-**	**991**	**19,607**	**3,298**	**28,980**	**72,757**	**94,364**	**25,753**	**24,367**	**856,682**
	ISONE	**Total**	541	15,494	3,331	5,710	818	-	233	1,571	57	1,911	3,386	2,553	661	3,713	39,979
	MISO	**Total**	**37,914**	**64,194**	**11,127**	**2,867**	**613**	**-**	**329**	**4,396**	**1,031**	**2,533**	**29,777**	**41,715**	**7,775**	**3,049**	**207,319**
		MISO-W	12,651	13,608	2,753	1,491	244	-	2	-	200	777	7,368	29,411	2,367	741	71,612
		MISO-C	15,050	10,307	2,169	494	32	-	152	773	499	769	10,587	7,350	2,026	1,774	51,982
		MISO-S	5,493	31,052	5,100	589	243	-	117	49	5	845	8,024	596	2,109	291	54,511
		MISO-E	4,720	9,227	1,105	292	94	-	57	3,574	327	143	3,799	4,359	1,273	243	29,213
	NYISO	**Total**	-	22,937	3,330	2,631	334	-	-	1,400	60	4,915	1,039	2,706	860	5,710	45,924
	PJM	**Total**	**39,915**	**84,381**	**32,535**	**9,875**	**851**	**-**	**-**	**5,062**	**338**	**3,071**	**10,892**	**11,718**	**7,397**	**8,603**	**214,638**
		PJM-W	34,917	39,056	16,557	1,933	112	-	-	234	149	1,252	5,780	10,065	3,814	599	114,467
		PJM-S	2,391	15,038	5,288	3,985	479	-	-	2,958	127	1,070	3,932	360	1,824	2,498	39,951
		PJM-E	2,608	30,287	10,690	3,956	260	-	-	1,870	62	749	1,180	1,294	1,759	5,506	60,221
	SERC	**Total**	**45,747**	**113,334**	**31,702**	**4,063**	**989**	**-**	**83**	**6,701**	**768**	**11,425**	**26,959**	**982**	**7,707**	**3,221**	**253,680**
		SERC-C	13,348	20,127	8,280	148	36	-	-	1,784	100	4,995	2,308	982	1,851	20	53,978
		SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	115	3,260	7,267	-	2,069	317	67,073
		SERC-FL	4,346	47,002	3,502	1,957	310	-	83	-	538	-	10,121	-	2,804	2,051	72,714
		SERC-E	14,777	16,340	11,902	1,044	219	-	-	3,369	15	3,170	7,263	-	983	833	59,914
	SPP	**Total**	**18,919**	**30,003**	**769**	**1,626**	**20**	**-**	**345**	**477**	**1,044**	**5,123**	**703**	**34,689**	**1,353**	**71**	**95,142**
		SPP-N	5,089	3,467	304	504	1	-	185	-	8	3,041	84	7,041	333	7	20,065
		SPP-S	13,829	26,536	465	1,121	19	-	160	477	1,037	2,082	619	27,649	1,020	64	75,078
ERCOT	**Total**		**13,568**	**50,889**	**4,973**	**10**	**163**	**-**	**-**	**-**	**10,720**	**583**	**31,058**	**39,532**	**3,464**	**2,531**	**157,490**
	ERCOT	**Total**	13,568	50,889	4,973	10	163	-	-	-	10,720	583	31,058	39,532	3,464	2,531	157,490
WEST	**Total**		**21,666**	**87,403**	**9,403**	**829**	**1,565**	**4,093**	**106**	**4,536**	**15,238**	**52,687**	**44,042**	**35,071**	**1,944**	**16,271**	**294,854**
	CAISO+	**Total**	**1,816**	**37,434**	**5,582**	**185**	**726**	**2,004**	**35**	**3,514**	**11,156**	**10,211**	**25,614**	**7,773**	**829**	**10,047**	**116,925**
		CALI-N	-	12,942	5,582	165	465	1,049	9	1,967	2,672	8,727	6,723	1,373	349	5,036	47,059
		CALI-S	1,816	24,492	-	20	261	955	26	1,547	8,484	1,483	18,891	6,400	480	5,011	69,866
	Non-CA WECC	**Total**	**19,850**	**49,969**	**3,820**	**644**	**839**	**2,089**	**71**	**1,022**	**4,082**	**42,476**	**18,428**	**27,298**	**1,115**	**6,224**	**177,929**
		WA	560	3,919	1,096	17	352	-	-	140	350	24,402	1,052	2,690	243	386	35,207
		OR	-	3,915	-	6	293	21	-	-	482	8,253	2,145	3,440	141	372	19,068
		SOUTHWEST	4,842	17,985	2,724	323	102	1,047	-	176	2,173	1,019	5,641	3,685	168	2,452	42,335
		WASATCH	7,033	14,061	-	87	56	1,011	61	444	750	7,587	5,625	4,052	305	1,674	42,746
		FRONT R	7,415	10,089	-	211	36	10	10	262	328	1,215	3,966	13,432	258	1,340	38,572
		Total	178,268	468,635	97,169	27,610	5,353	4,093	1,096	24,144	29,256	82,249	147,856	168,966	31,161	43,169	1,309,026

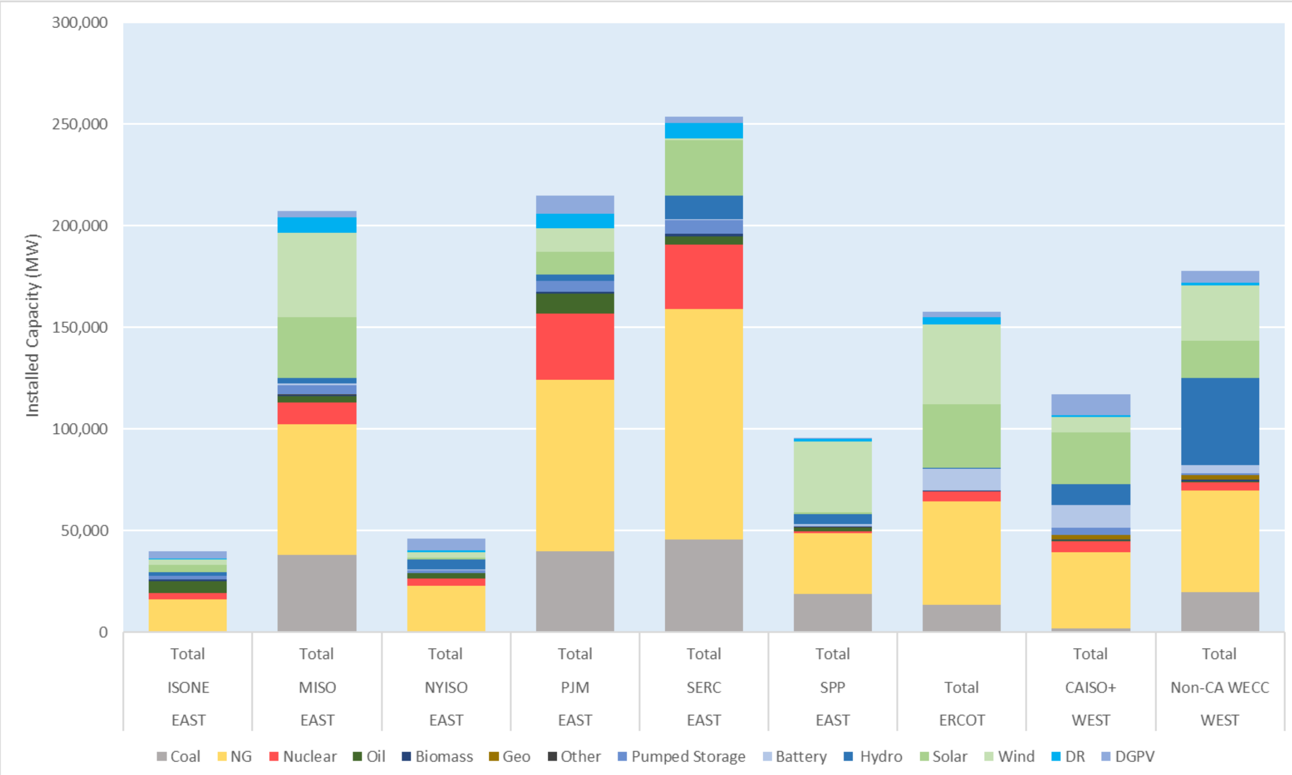


Figure A.2. Existing and Tier 1 capacities by NERC assessment area in 2024.

Forecasting 2030 Resource Mixes

To develop the 2030 ITCS generation portfolio, the study team added new capacity builds and removed planned retirements.

(i) *Tier 1*: Assumes that only projects considered very mature in the development pipeline—such as those with signed interconnection agreements—will be built. This results in minimal capacity additions beyond 2026. The data are based on projects designated as Tier 1 in the 2024 LTRA data for the year 2030.

Retirements

To project which units will retire by 2030, the study team primarily used the LTRA 2024 data and cross-checked it with EIA data. The assessment areas were disaggregated to ITCS zones based on the ratios of projected retirements in EIA 860 data. The three scenarios modeled are as follows:

(i) *Announced*: Assumes that in addition to confirmed retirements, generators that have publicly announced retirement plans but have not formally notified system operators have also begun the retirement process. This is based on data from the 2024 LTRA, which were collected by the NERC team from sources like news announcements, public disclosures, etc.

(ii) *None*: Assumes that there are no retirements between 2024 and 2030 for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirements contribute to resource adequacy challenges in regions where rapid AI and data center growth is expected.

Generation Stack for Each Scenario

Finally, when summing all potential future changes, the team arrived at a generation stack for each of the various scenarios to be studied. The first figure provides a visual comparison of all the cases, which vary from 1,309 GW to 1,519 GW total generation capacity for the entire continental United States, to enable the exploration of a range of potential generation futures. The tables below provide breakdowns by ITCS region and by resource type.

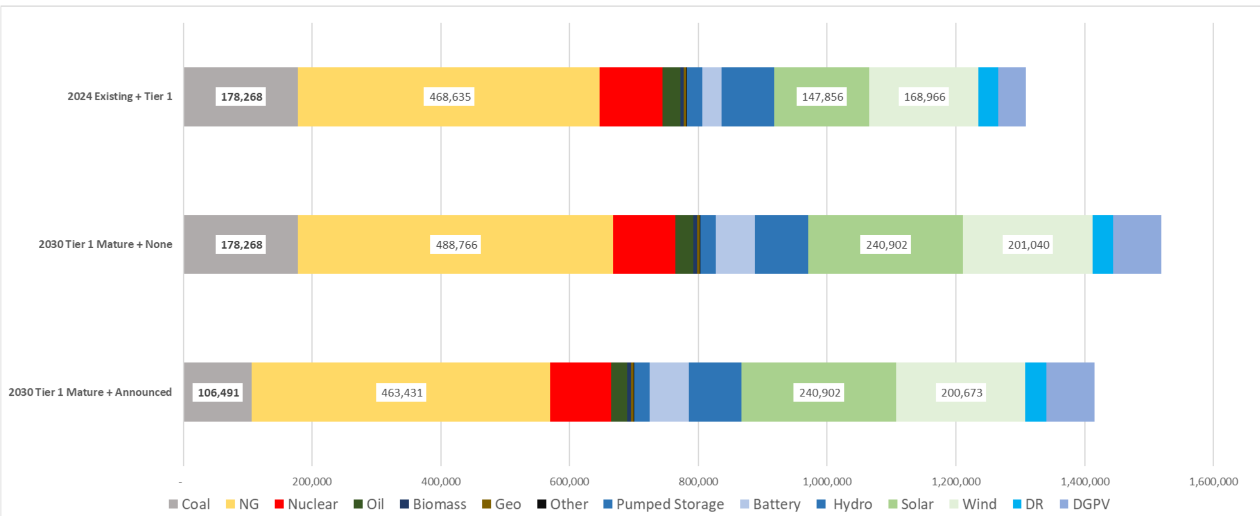


Figure A.9. Comparison of 2030 generation stacks for the various scenarios.

Table A.4. 2030 generation stack for Tier 1 mature + announced retirements.

2030 Tier 1 Mature + Announced			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**84,730**	**328,457**	**82,793**	**24,272**	**3,473**	**-**	**991**	**19,591**	**12,415**	**28,897**	**126,849**	**113,568**	**26,837**	**36,768**	**889,641**
	ISONE	**Total**	7	13,708	3,331	5,687	741	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	42,845
	MISO	**Total**	**13,001**	**60,132**	**11,127**	**2,873**	**473**	**-**	**329**	**4,380**	**2,960**	**2,450**	**44,132**	**43,369**	**7,775**	**3,049**	**196,049**
		MISO-W	4,338	12,747	2,753	1,494	188	-	2	-	574	751	10,920	30,577	2,367	741	67,453
		MISO-C	5,161	9,655	2,169	495	25	-	152	770	1,433	743	15,690	7,642	2,026	1,774	47,735
		MISO-S	1,883	29,087	5,100	591	187	-	117	49	14	817	11,892	619	2,109	291	52,756
		MISO-E	1,619	8,643	1,105	293	72	-	57	3,561	938	138	5,630	4,531	1,273	243	28,105
	NYISO	**Total**	-	21,907	3,330	2,628	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	50,396
	PJM	**Total**	**26,662**	**87,228**	**32,535**	**8,117**	**917**	**-**	**-**	**5,062**	**2,276**	**3,071**	**33,530**	**18,807**	**7,638**	**10,955**	**236,798**
		PJM-W	23,323	40,373	16,557	1,589	120	-	-	234	1,004	1,252	17,793	16,153	3,939	762	123,100
		PJM-S	1,597	15,546	5,288	3,276	516	-	-	2,958	853	1,070	12,105	577	1,883	3,181	48,850
		PJM-E	1,742	31,309	10,690	3,252	280	-	-	1,870	419	749	3,632	2,076	1,816	7,012	64,848
	SERC	**Total**	**31,672**	**116,117**	**31,702**	**3,391**	**989**	**-**	**83**	**6,701**	**3,021**	**11,425**	**38,360**	**982**	**8,088**	**7,893**	**260,423**
		SERC-C	8,883	23,777	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	54,014
		SERC-SE	10,321	28,127	8,018	899	424	-	-	1,548	618	3,260	9,024	-	2,213	317	64,768
		SERC-FL	2,851	47,092	3,502	1,477	310	-	83	-	2,208	-	16,717	-	3,022	5,865	83,127
		SERC-E	9,617	17,122	11,902	868	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	58,513
	SPP	**Total**	**13,389**	**29,365**	**769**	**1,576**	**20**	**-**	**345**	**477**	**2,434**	**5,123**	**5,991**	**41,755**	**1,815**	**71**	**103,130**
		SPP-N	3,602	3,394	304	489	1	-	185	-	18	3,041	717	8,475	447	7	20,679
		SPP-S	9,787	25,971	465	1,087	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	82,451
ERCOT	**Total**		**11,568**	**49,436**	**4,973**	**10**	**163**	**-**	**-**	**-**	**27,258**	**583**	**62,406**	**43,169**	**3,464**	**5,864**	**208,894**
	ERCOT	**Total**	11,568	49,436	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	208,894
WEST	**Total**		**10,193**	**85,538**	**7,103**	**823**	**1,427**	**3,983**	**106**	**4,366**	**21,330**	**52,060**	**51,648**	**43,935**	**1,981**	**31,931**	**316,424**
	CAISO+	**Total**	**16**	**35,789**	**3,282**	**185**	**726**	**2,059**	**35**	**3,514**	**14,316**	**10,211**	**27,112**	**7,773**	**866**	**17,055**	**122,938**
		CALI-N	-	12,373	3,282	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	48,897
		CALI-S	16	23,416	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	74,041
	Non-CA WECC	**Total**	**10,177**	**49,749**	**3,820**	**639**	**701**	**1,924**	**71**	**852**	**7,014**	**41,849**	**24,536**	**36,162**	**1,115**	**14,876**	**193,485**
		WA	243	3,971	1,096	16	286	-	-	111	459	24,033	1,404	3,631	243	1,092	36,588
		OR	-	3,967	-	6	238	18	-	-	632	8,128	2,865	4,644	141	1,051	21,689
		SOUTHWEST	3,657	17,343	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	47,022
		WASATCH	3,055	14,247	-	86	45	850	61	355	983	7,472	7,512	5,470	305	4,733	45,175
		FRONT R	3,221	10,222	-	208	30	8	10	209	430	1,197	5,296	18,133	258	3,789	43,011
		Total	**106,491**	**463,431**	**94,869**	**25,106**	**5,063**	**3,983**	**1,096**	**23,958**	**61,003**	**81,539**	**240,902**	**200,673**	**32,282**	**74,563**	**1,414,959**

Table A.5. 2030 generation stack for Tier 1 mature + no retirements.

2030 Tier 1 Mature + No Retirements			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**143,035**	**345,459**	**82,793**	**27,336**	**3,701**	**-**	**991**	**19,607**	**12,415**	**28,980**	**126,849**	**113,840**	**26,837**	**36,768**	**968,610**
	ISONE	**Total**	541	15,584	3,331	5,891	818	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	45,534
	MISO	**Total**	**37,914**	**66,729**	**11,127**	**3,197**	**613**	**-**	**329**	**4,396**	**2,960**	**2,533**	**44,132**	**43,641**	**7,775**	**3,049**	**228,393**
		MISO-W	12,651	14,145	2,753	1,662	244	-	2	-	574	777	10,920	30,768	2,367	741	77,605
		MISO-C	15,050	10,714	2,169	551	32	-	152	773	1,433	769	15,690	7,690	2,026	1,774	58,823
		MISO-S	5,493	32,278	5,100	657	243	-	117	49	14	845	11,892	623	2,109	291	59,710
		MISO-E	4,720	9,592	1,105	326	94	-	57	3,574	938	143	5,630	4,560	1,273	243	32,255
	NYISO	**Total**	-	22,937	3,330	2,646	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	51,444
	PJM	**Total**	**39,915**	**88,880**	**32,535**	**9,907**	**928**	**-**	**-**	**5,062**	**2,276**	**3,071**	**33,530**	**18,807**	**7,638**	**10,955**	**253,504**
		PJM-W	34,917	41,138	16,557	1,939	122	-	-	234	1,004	1,252	17,793	16,153	3,939	762	135,810
		PJM-S	2,391	15,840	5,288	3,998	522	-	-	2,958	853	1,070	12,105	577	1,883	3,181	50,667
		PJM-E	2,608	31,902	10,690	3,969	284	-	-	1,870	419	749	3,632	2,076	1,816	7,012	67,027
	SERC	**Total**	**45,747**	**120,232**	**31,702**	**4,063**	**989**	**-**	**83**	**6,701**	**3,021**	**11,425**	**38,360**	**982**	**8,088**	**7,893**	**279,285**
		SERC-C	13,348	24,958	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	59,660
		SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	618	3,260	9,024	-	2,213	317	69,478
		SERC-FL	4,346	48,163	3,502	1,957	310	-	83	-	2,208	-	16,717	-	3,022	5,865	86,173
		SERC-E	14,777	17,246	11,902	1,044	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	63,973
	SPP	**Total**	**18,919**	**31,098**	**769**	**1,632**	**20**	**-**	**345**	**477**	**2,434**	**5,123**	**5,991**	**41,755**	**1,815**	**71**	**110,449**
		SPP-N	5,089	3,594	304	506	1	-	185	-	18	3,041	717	8,475	447	7	22,385
		SPP-S	13,829	27,504	465	1,126	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	88,064
ERCOT	**Total**		**13,568**	**51,458**	**4,973**	**10**	**163**	**-**	**-**	**-**	**27,258**	**583**	**62,406**	**43,169**	**3,464**	**5,864**	**212,916**
	ERCOT	**Total**	13,568	51,458	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	212,916
WEST	**Total**		**21,666**	**91,849**	**9,403**	**829**	**1,565**	**4,156**	**106**	**4,536**	**21,330**	**52,687**	**51,648**	**44,030**	**1,981**	**31,931**	**337,717**
	CAISO+	**Total**	**1,816**	**39,560**	**5,582**	**185**	**726**	**2,059**	**35**	**3,514**	**14,316**	**10,211**	**27,112**	**7,773**	**866**	**17,055**	**130,809**
		CALI-N	-	13,677	5,582	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	52,501
		CALI-S	1,816	25,883	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	78,308
	Non-CA WECC	**Total**	**19,850**	**52,289**	**3,820**	**645**	**839**	**2,097**	**71**	**1,022**	**7,014**	**42,476**	**24,536**	**36,257**	**1,115**	**14,876**	**206,908**
		WA	560	4,166	1,096	17	352	-	-	140	459	24,402	1,404	3,642	243	1,092	37,573
		OR	-	4,161	-	6	293	22	-	-	632	8,253	2,865	4,658	141	1,051	22,081
		SOUTHWEST	4,842	18,294	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	49,158
		WASATCH	7,033	14,945	-	88	56	1,018	61	444	983	7,587	7,512	5,486	305	4,733	50,251
		FRONT R	7,415	10,723	-	212	36	10	10	262	430	1,215	5,296	18,187	258	3,789	47,844
		Total	**178,268**	**488,766**	**97,169**	**28,175**	**5,429**	**4,156**	**1,096**	**24,144**	**61,003**	**82,249**	**240,902**	**201,040**	**32,282**	**74,563**	**1,519,243**

Appendix B - Representing Canadian Transfer Limits

Introduction

The reliability and stability of cross-border electricity interconnections between the United States and Canada are critical to ensuring continuous power delivery amid evolving demands and variable supply conditions. In recent years, increased integration of wind and solar generation, coupled with extreme weather events, has introduced significant uncertainties in regional power flows.

This report describes the development and implementation of a machine learning (ML)-based model designed to project the maximum daily energy transfer (MaxFlow) across major United States–Canada interfaces, such as BPA–BC Hydro and NYISO–Ontario. Leveraging 15 years of high-resolution load and generation data, summarizing it into key daily statistics, and training a robust eXtreme Gradient Boosting (XGBoost) regressor can allow data-driven predictions to be captured with quantified uncertainty.

The project team provided percentile-based forecasts—25, 50, and 75 percent—to support both conservative and strategic planning. The conservative methodology (25 percent) was used for this report to ensure availability when needed.

The subsequent sections detail the methodology used for data processing and feature engineering, the architecture and training of the predictive model, and the validation metrics and feature importance analyses used. Future enhancements could include incorporating weather patterns, neighboring-region dynamics, and fuel-specific generation profiles to further strengthen predictive performance and support grid resilience.

Methodology

This section describes the ML approach used to build the MaxFlow prediction model.

Dataset Collection and Preparation

Data were collected for hourly and derived daily load and generation over a 15-year period (2010–2024), comprising 8,760 hourly observations annually. Hourly interconnection flow rates were collected for the same years across all major United States–Canada interfaces.[1–17]

Underlying Hypothesis

The team hypothesized that the MaxFlow between interconnected regions is critically influenced by regional load and generation extrema (maximum and minimum) and their variability. These statistics reflect grid stress conditions, influencing interregional energy flow. Additionally, nonlinear interactions due to imbalances in adjacent regions further affect energy transfer dynamics.

Regression Model

The XGBoost regression model was chosen because of its ability to capture complex, nonlinear relationships, regularization capability to prevent overfitting, high speed and performance, fast convergence, built-in handling of missing data, and ease of confidence interval approximation.

XGBoost builds many small decision trees, one after another. Each new tree learns to correct the mistakes of the previous ensemble by focusing on which predictions had the greatest error. Instead of creating one large, complex tree, it combines many simpler trees—each making a modest adjustment—so that, together, they capture nonlinear patterns and interactions. Regularization (penalties for tree size and leaf adjustments) prevents overfitting, and a “learning rate” scales each tree’s contribution so that improvements are made gradually. The final prediction is simply the sum of all those small corrections.

Model Training, Validation, and Assessment

Figure B.1 shows the data analysis and prediction process, which ties together seven stages—from raw CSV loading through outlier filtering, feature engineering, projecting to 2030, rebuilding 2030 features, training an XGBoost model, and finally making and evaluating the 2030 flow forecasts with quantiles. Each stage feeds into the next, ensuring that the features used for training mirror exactly those that will be available for future (2030) predictions.

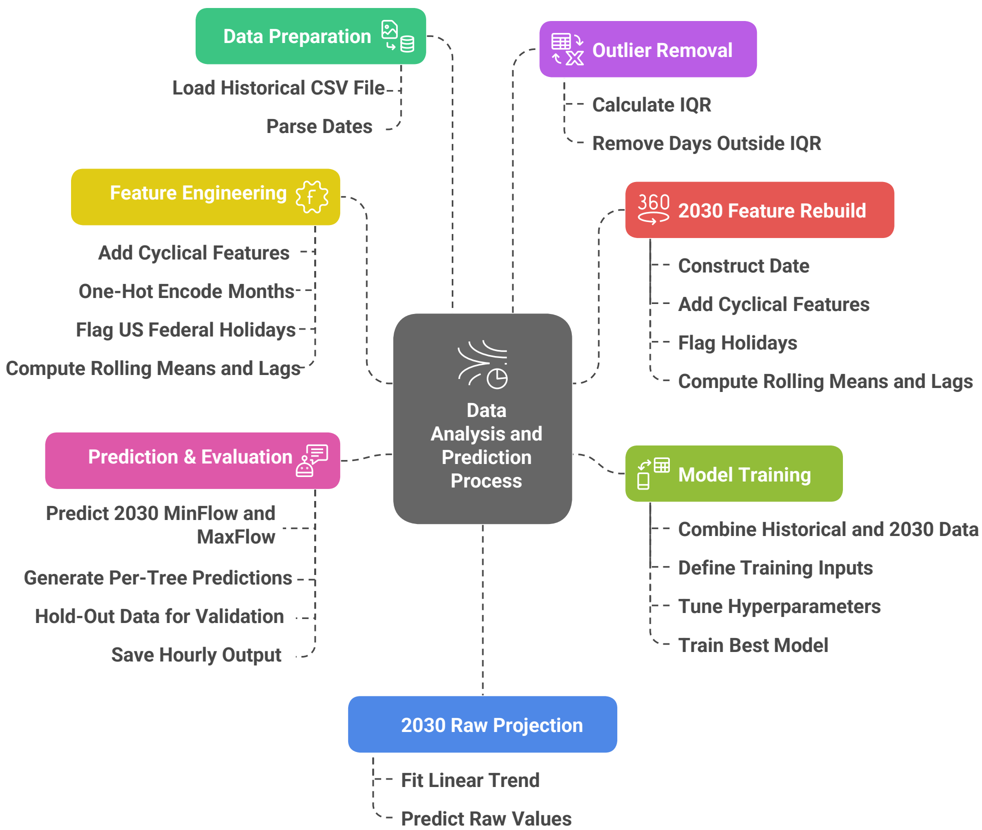


Figure B.1. Data analysis and prediction process.

Example Feature Importance for Predicting MaxFlow from Ontario to NYISO

The trained ML/XGBoost model can be used for predicting the desired year’s MaxFlow. In addition, feature importance analysis can be added to assess the contribution of each variable.

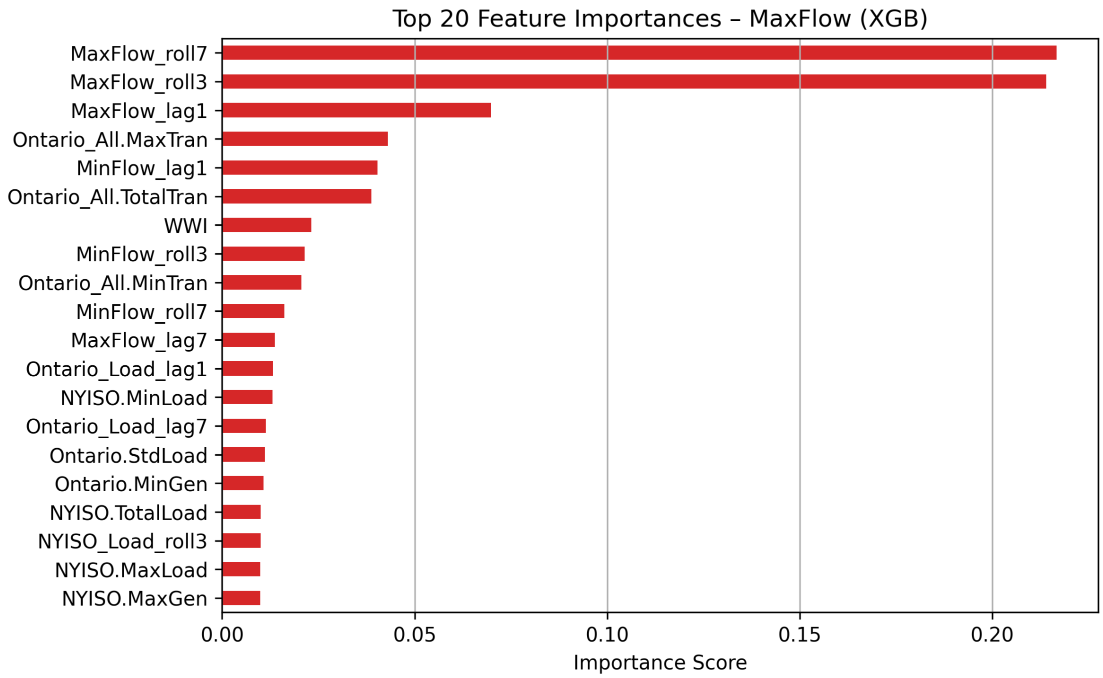


Figure B.2. Feature importance for predicting the hourly maximum energy transfer (MaxFlow) between NYISO and Ontario. XGB = eXtreme Gradient Boosting.

The feature importance plot shows that MaxFlow rolling/lagging features and Ontario_All.MaxTran are the dominant predictors of MaxFlow, meaning temporal patterns and Ontario's peak transfer capacity strongly influence interregional flow limits. Weather-related variables (WWI, e.g., temperature, humidity, etc.) and Ontario_All.TotalTran also rank highly. The 2030 MaxFlow prediction plot shows seasonal fluctuations, with higher values early and late in the year. The red shaded area represents a 95 percent confidence interval for the predictions.

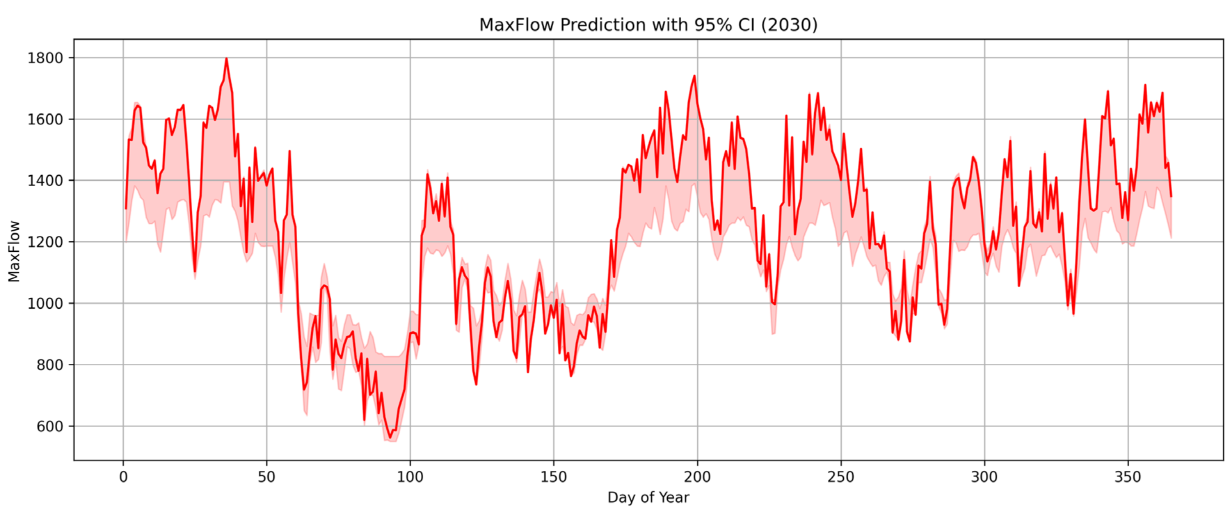


Figure B.3. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI).

Model Performance

Validating model performance on unseen data is essential to ensure the model's reliability and generalizability. The following evaluation examines how well the XGBoost model predicts minimum energy transfer (MinFlow) and MaxFlow on the validation split, highlighting strengths and areas for improvement.

Rigorous performance evaluation is a fundamental step in any ML workflow. From quantifying error metrics (root mean square error and mean absolute error) and goodness-of-fit (R^2) on both training and validation splits, it is possible to identify overfitting, assess generalization, and guide model refinement. Table B.1 shows XGBoost model performance for the Ontario–NYISO transfer limit.

Table B.1. eXtreme Gradient Boosting model performance for the Ontario–NYISO transfer limit.

Metric	Value	Explanation
MinFlow RMSE (Train)	69.2528	Root mean square error (RMSE) on training data for minimum energy transfer (MinFlow)
MinFlow R^2 (Train)	0.9651	R^2 on training data for MinFlow (higher → better fit)
MinFlow RMSE (Validation)	163.6642	RMSE on held-out data for MinFlow
MinFlow R^2 (Validation)	0.8073	R^2 on held-out data for MinFlow (higher → better generalization)
MaxFlow RMSE (Train)	114.4234	RMSE on training data for maximum energy transfer (MaxFlow)
MaxFlow R^2 (Train)	0.8838	R^2 on training data for MaxFlow (higher → better fit)
MaxFlow RMSE (Validation)	144.9614	RMSE on held-out data for MaxFlow
MaxFlow R^2 (Validation)	0.8178	R^2 on held-out data for MaxFlow (higher → better generalization)

Overall, the XGBoost model delivers excellent in-sample as well as out-of-sample accuracy. Similar outputs are available for each transfer limit.

Maximum flow predictions: Ontario to New York

Ontario and NYISO are connected through multiple high-voltage interconnections, which collectively provide a total transfer capability of up to 2,500 MW, subject to individual tie-line limits. Table B.2 outlines the data sources, preparation process, and assumptions used in creating datasets for the prediction models.

Table B.2. Ontario to New York transmission flow data and assumptions overview.

	Description
Data source	https://www.ieso.ca/power-data/data-directory
Data preparation	IESO public hourly inter-tie schedule flow data can be accessed for the years spanning from 2002 to 2023.
Assumptions	Positive flow indicates that Ontario is exporting to NY, and negative flow indicates that Ontario is importing from NY.

Figure B.4 illustrates the historical monthly MaxFlow for Ontario from 2007 through 2024, alongside 2030 projected quartile scenarios (Q1, Q2, and Q3). Analyzing these trends helps assess future reliability and facilitates capacity planning under varying conditions.

Historical monthly peaks (2007–2023) reveal a clear seasonal cycle for ONT–NYISO transfers: flows typically increase in late winter/early spring (February–April) and again in late fall/early winter (November–December). Over 16 years, the average spring peaks hovered around 1,700–1,900 MW, with occasional spikes above 2,200 MW. The 2030 forecast for Q1, Q2, and Q3 aligns with this pattern, predicting a springtime peak near 1,800 MW, a summer trough around 1,400 MW, and a modest late-summer uptick near 1,500 MW.

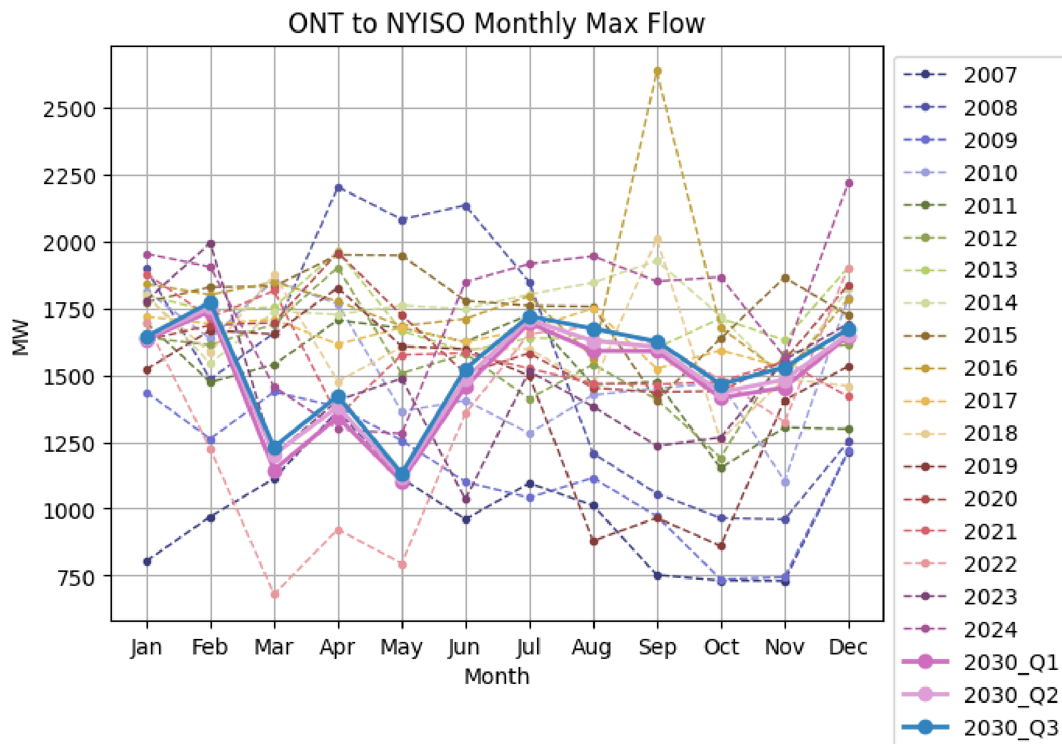


Figure B.4. Monthly maximum energy transfer between Ontario (ONT) and New York (NYISO).

The team used robust validation metrics to justify these results. When trained on daily data from the 2010–2024 period—incorporating projected 2030 loads, seasonal flags, and holiday effects—the XGBoost model achieved $R^2 > 0.80$ and a root mean square error below 150 MW on an unseen 20 percent hold-out dataset. Moreover, the 95 percent confidence intervals for monthly maxima were narrow (approximately ±150 MW), demonstrating low predictive uncertainty. A comparison of predicted maxima with historical extremes revealed that 2030 forecasts consistently fell within (or slightly above) the previous window of variability, implying realistic demand-driven behavior. In summary, the close alignment with historical peaks, strong cross-validated performance, and tight confidence bands collectively validate the results.

Discussion

The reason that the team used ML/XGBoost to approximate the 2030 transfer profiles was to ensure that there would be no violations or inconsistencies between transfer limits, load, and generation. The 15 years of data used were sufficient for having the models learn historical relationships and project them forward to 2030 to capture the underlying trends in load, generation, and their interactions. The use of such an extensive dataset justifies using ML to establish consistent transfer profiles.

However, in some regions, like Ontario to NYISO, the available data encompassed a shorter time period, and the relationships were only partially captured because of a lack of neighboring-region data. In such cases, it was necessary to incorporate additional predictors, such as rolling and lag features from the transfer limits. Although the direct use of transfer limit data to project future transfer limits would typically be avoided, these engineered features help improve predictions when data coverage is sparse and the model's goodness-of-fit is low.

In all cases, the ML models ensured that these historical relationships were not violated, maintaining internal consistency among load, generation, and transfer limits. Overall, the team relied on ML when long-term data were available for training and projecting load and generation profiles. Rolling and lag features were used to reinforce the model when data availability was limited, but always with the goal of upholding consistent physical relationships in the 2030 projections.

Supplementary Plots for Additional Transfers

This section presents figures and tables showing results and source data information for each transfer listed below:

(iii) Pacific Northwest to British Columbia
(iv) Alberta to Montana
(v) Manitoba to MISO West
(vi) Ontario to MISO West
(vii) Ontario to MISO East
(viii) Ontario to New York
(ix) Hydro-Quebec to New York
(x) Hydro-Quebec to New England
(xi) New Brunswick to New England

The figures show the daily MaxFlow for each transfer that was considered in this analysis.

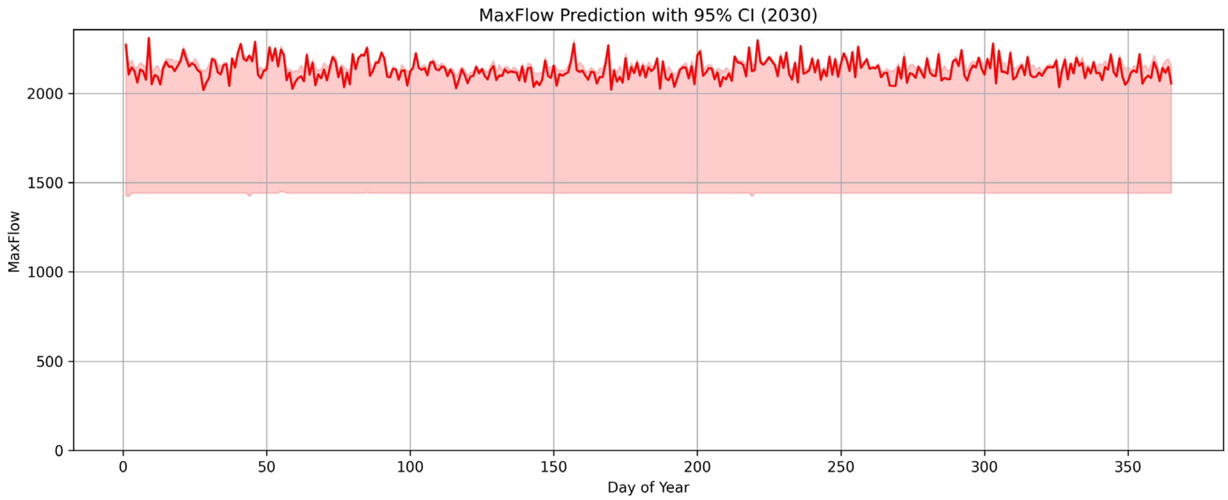


Figure B.5. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between British Columbia and the Pacific Northwest.

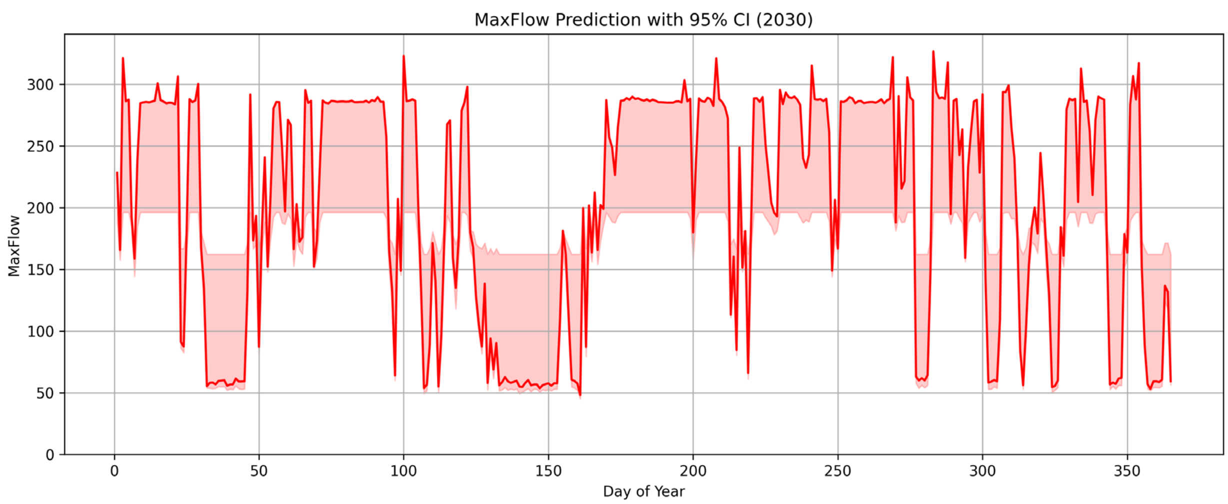


Figure B.6. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between AESO and Montana.

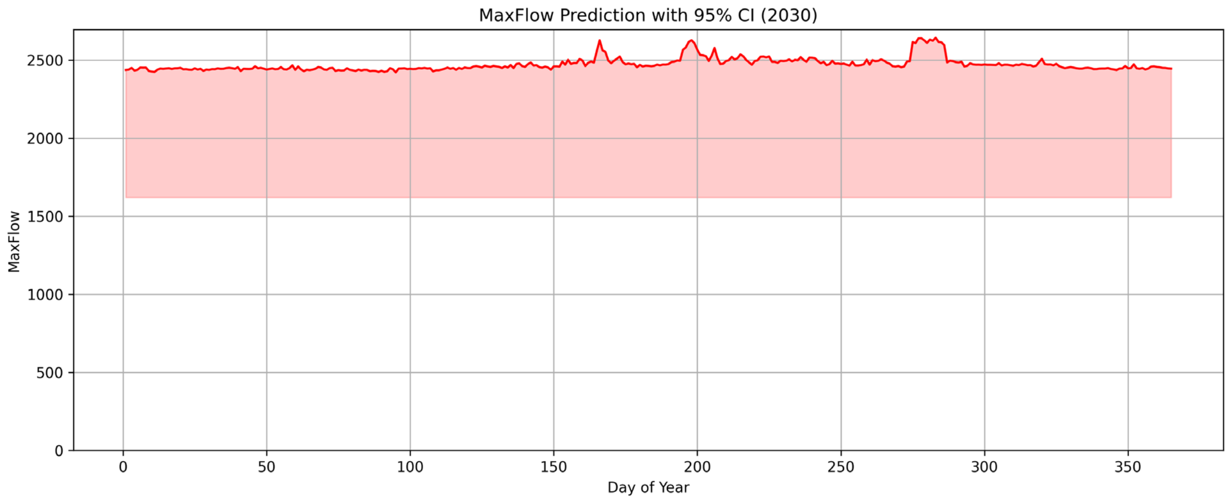


Figure B.7. Projected 2030 maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Manitoba and MISO.

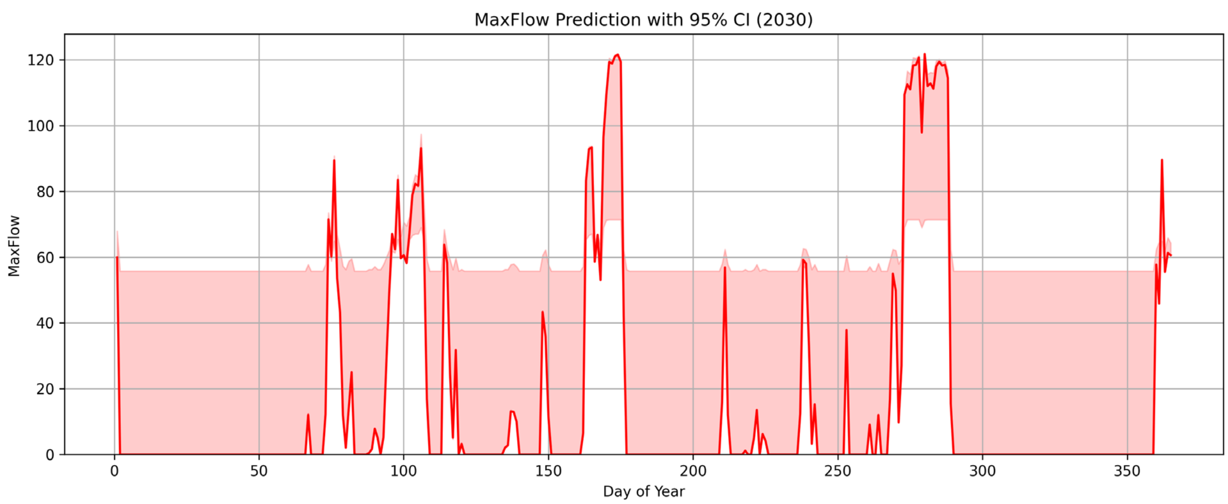


Figure B.8. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO West.

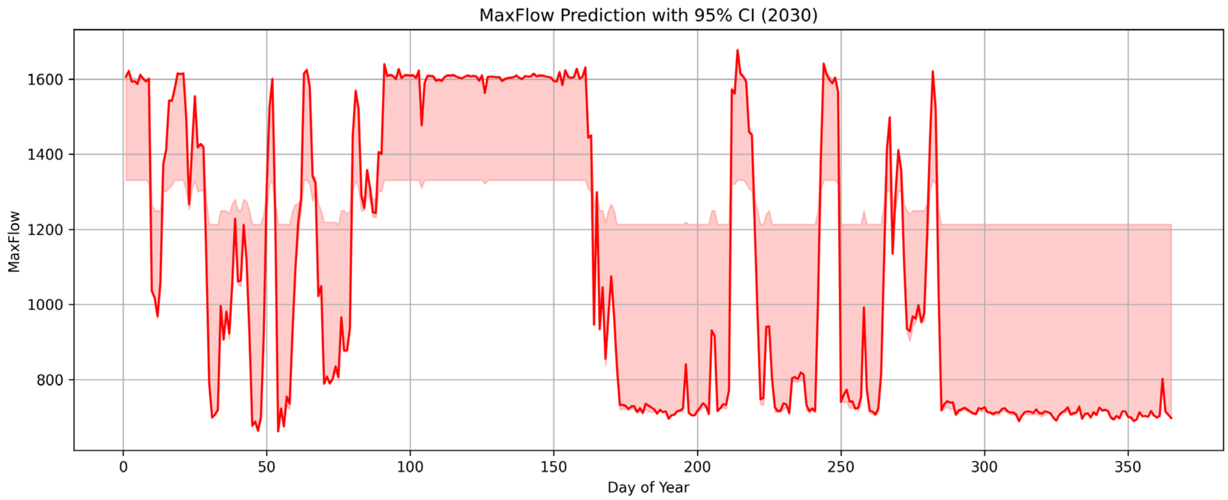


Figure B.9. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO East.

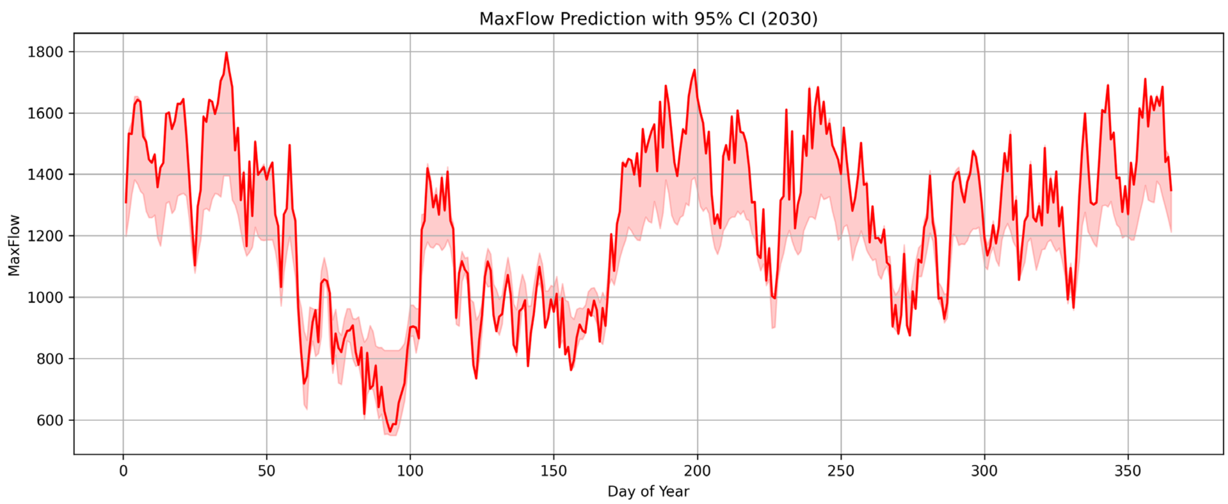


Figure B.10. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and New York.

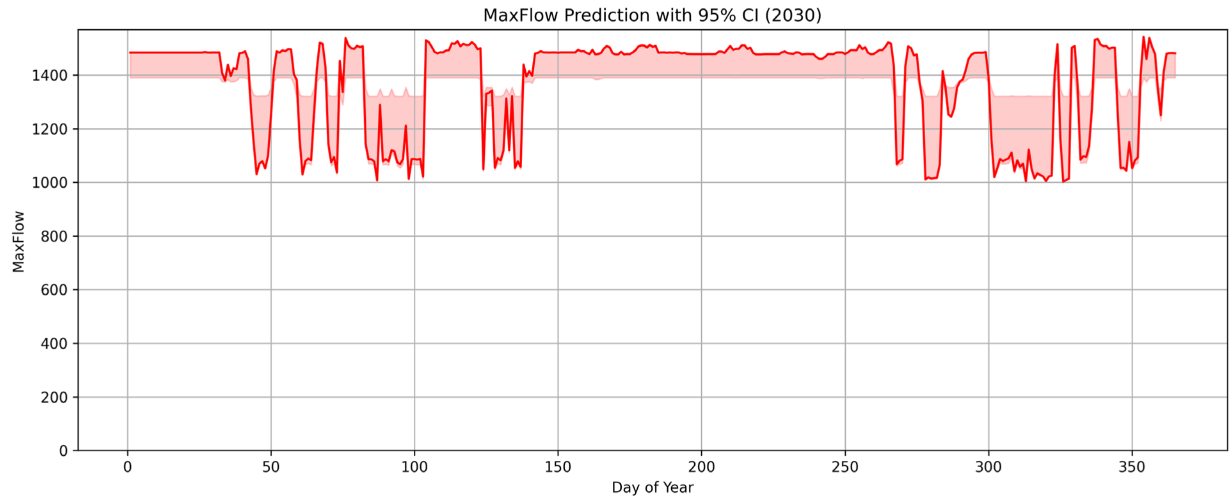


Figure B.11. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New York.

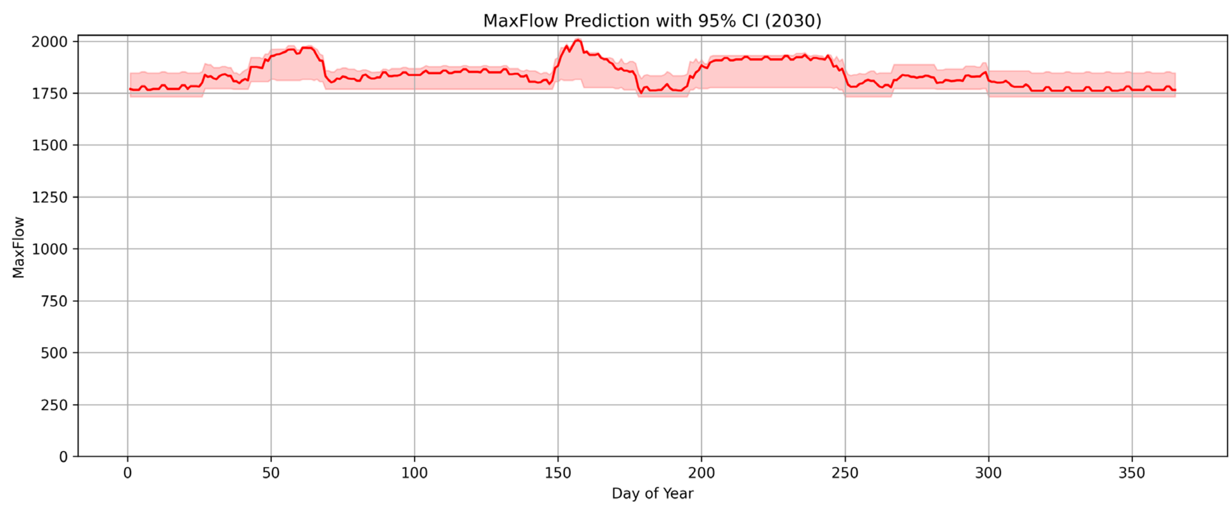


Figure B.12. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New England.

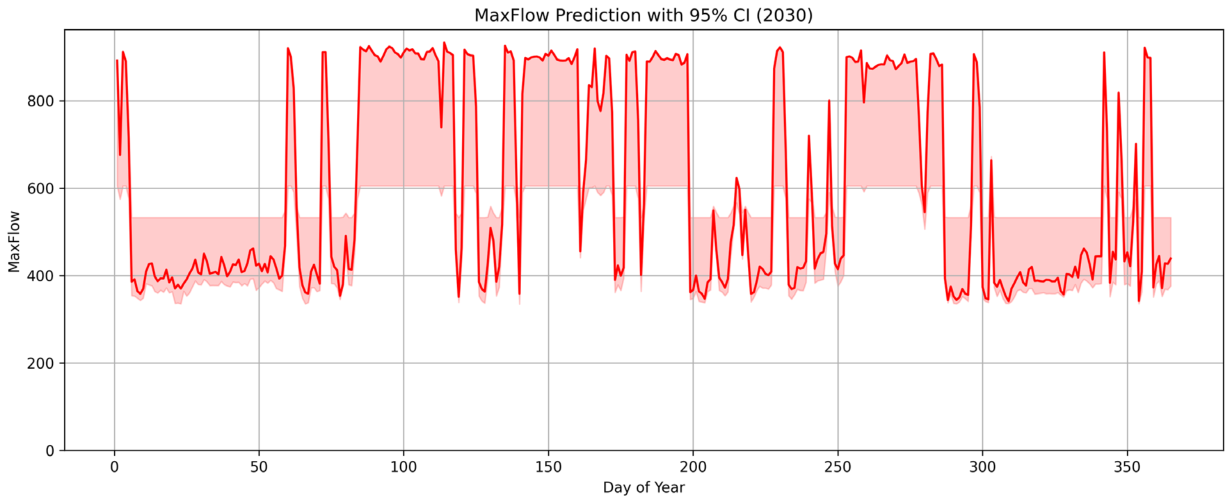


Figure B.13. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between New Brunswick and New England.

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EO 14262

Federal Register / Vol. 90, No. 70 / Monday, April 14, 2025 / Presidential Documents 15521

Presidential Documents

Executive Order 14262 of April 8, 2025

Strengthening the Reliability and Security of the United States Electric Grid

By the authority vested in me as President by the Constitution and the laws of the United States of America, it is hereby ordered:

Section 1. *Purpose.* 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 an increase in domestic manufacturing. This increase in demand, coupled with existing capacity challenges, places a significant strain on our Nation's electric grid. Lack of reliability in the electric grid puts the national and economic security of the American people at risk. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy from all available electric generation sources and the integrity of our Nation's electric grid.

Sec. 2. *Policy.* It is the policy of the United States to ensure the reliability, resilience, and security of the electric power grid. It is further the policy of the United States that in order to ensure adequate and reliable electric generation in America, to meet growing electricity demand, and to address the national emergency declared pursuant to Executive Order 14156 of January 20, 2025 (Declaring a National Energy Emergency), our electric grid must utilize all available power generation resources, particularly those secure, redundant fuel supplies that are capable of extended operations.

Sec. 3. *Addressing Energy Reliability and Security with Emergency Authority.* (a) To safeguard the reliability and security of the United States' electric grid during periods when the relevant grid operator forecasts a temporary interruption of electricity supply is necessary to prevent a complete grid failure, the Secretary of Energy, in consultation with such executive department and agency heads as the Secretary of Energy deems appropriate, shall, to the maximum extent permitted by law, streamline, systemize, and expedite the Department of Energy's processes for issuing orders under section 202(c) of the Federal Power Act during the periods of grid operations described above, including the review and approval of applications by electric generation resources seeking to operate at maximum capacity.

(b) Within 30 days of the date of this order, the Secretary of Energy shall develop a uniform methodology for analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy. This methodology shall:

(i) analyze sufficiently varied grid conditions and operating scenarios based on historic events to adequately inform the methodology;

(ii) accredit generation resources in such conditions and scenarios based on historical performance of each specific generation resource type in the real time conditions and operating scenarios of each grid scenario; and

(iii) be published, along with any analysis it produces, on the Department of Energy's website within 90 days of the date of this order.

15522 **Federal Register** / Vol. 90, No. 70 / Monday, April 14, 2025 / Presidential Documents

(c) The Secretary of Energy shall establish a process by which the methodology described in subsection (b) of this section, and any analysis and results it produces, are assessed on a regular basis, and a protocol to identify which generation resources within a region are critical to system reliability. This protocol shall additionally:

(i) include all mechanisms available under applicable law, including section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource within the at-risk region; and

(ii) prevent, as the Secretary of Energy deems appropriate and consistent with applicable law, including section 202 of the Federal Power Act, an identified generation resource in excess of 50 megawatts of nameplate capacity from leaving the bulk-power system or converting the source of fuel of such generation resource if such conversion would result in a net reduction in accredited generating capacity, as determined by the reserve margin methodology developed under subsection (b) of this section.

Sec. 4. *General Provisions.* (a) Nothing in this order shall be construed to impair or otherwise affect:

(i) the authority granted by law to an executive department or agency, or the head thereof; or

(ii) the functions of the Director of the Office of Management and Budget relating to budgetary, administrative, or legislative proposals.

(b) This order shall be implemented consistent with applicable law and subject to the availability of appropriations.

(c) This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.

THE WHITE HOUSE,
April 8, 2025.

[FR Doc. 2025–06381
Filed 4–11–25; 8:45 am]
Billing code 3395–F4–P

Available at (accessed on 5/27/2025):
https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid

U.S. DEPARTMENT of ENERGY

For more information, visit:
energy.gov/topics/reliability

DOE/Publication Number • July, 7 2025

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

EXHIBIT 51

GRIDLAB, ANAYLSIS: DOE RESOURCE ADEQUACY REPORT

GridLab Analysis: Department of Energy Resource Adequacy Report

Ric OConnell

Rethinking Reliability July 11, 2025

Overview:

This memo provides a high-level overview of the recently released Department of Energy (DOE) Resource Adequacy Report, released on July 7, 2025. This report is a result of the Executive Order from the Trump Administration on Strengthening the Reliability and Security of the Grid, which directed the agency to develop and publish a methodology for "analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy."

The Executive Order also directs the DOE to prevent generation sources exceeding 50 MW from retiring or converting fuel sources if it would reduce generating capacity in at-risk regions, based on the new methodology. The DOE has so far issued two emergency orders under section 202(c) of the Federal Power Act. These orders directed plant owners and grid operators to delay by 90 days the retirement of the Campbell coal plant in Michigan owned by Consumers Energy and the Eddystone gas and oil plant in Pennsylvania, owned by Constellation. The EO and its methodology report did not include a mechanism for public input.

Bottomline of the DOE report:

The report warns of a 100X increased risk of outages if the forecasted retirements by 2030 take place. The report blames the lack of "firm" generation replacement in the planned supply.

Bottomline of GridLab analysis:

The report's conclusions are problematic since the **report undercounts the resources that are likely to be added to the grid,** and **overstates** the retirements expected. Utilities and markets *already* have plans to meet increased load growth, yet the **DOE report assumes they are doing nothing after 2026** the **DOE report assumes they are doing nothing after 2026.**

DOE Report Analysis – Key Takeaways:

- The report is based on three key assumptions: (1) the amount of load that will be added to the grid over the next five years, (2) the number of plants assumed to retire, and (3) the amount of new capacity added to the grid. The study used aggressive assumptions regarding load growth and retirements, but conservative assumptions about how much new generation capacity will be added, even assuming no new resources after 2026.
    - Load Growth: The report assumes 50 GW of data center load and allocates it regionally. It does not address flexibility of this load, however, which was recently demonstrated in a report from Duke University to allow for 100 GW of large load additions today with minimal grid impact. The DOE report then adds 51 GW of non-data center load, which means overall load growth by 2030 is 101 GW or 15%. For comparison, EIA assumed 6% growth in their Annual Energy Outlook 2025 high growth case. This is very aggressive load growth, although not necessarily unreasonable, as it is collected from each of the RTOs and utilities.
    - Retirements: The report assumed 104 GW of retirements by 2030, with 3/4 of this coal and 1/4 gas. But the most recent data from the U.S. Energy Information Administration released in June (the EIA 860) has just **half** of this capacity retiring. In the report, the DOE assumed these 50 GW of likely retirements, but included another 50 GW of *announced* retirements, inconsistent with their assumption around capacity additions. Most likely many plants will choose

not to retire due to the changing regulatory and economic landscape, driven by the administration's policies.

- Capacity Additions: The report assumes just 22 GW of new "firm" capacity (narrowly defined as gas) is added which is based on NERC LTRA "Tier 1" – projects with a very high likelihood of success. The report assumes no projects are built post 2026, which is not realistic for a report forecasting to 2030. A more reasonable assumption for capacity additions is the EIA 860 released in June, which has 35 GW of gas additions, and another 53 GW of batteries – **88 GW of firm additions by 2030.**

- The study ignores both utility plans for meeting increased load growth and how markets will respond. In fact, markets and utilities have already responded with plans to add new capacity and fast track new resources. These include PJM's Reliability Resource Initiative, which plans on adding 11 GW of new firm resources by 2030. SPP and MISO both have proposals at FERC (called ERAS) that will likely add another 30 GW of firm resources. Those three regional efforts alone would add roughly twice what the DOE assumed for the entire nation.
- This national report attempts to address what is primarily a regional issue with regional solutions. A handful of regions face pressure due to rising load growth, and those regions have already enacted plans to address this growth. For example, MISO, SPP and PJM have all instituted "fast track" processes to get firm generation online (gas and batteries), which is expected to install 43 GW of new resources by 2030. The DOE report, however, shows just 13.5 GW of new firm resources in those three regions.

DOE Report Assumptions vs. U.S. Energy Information Administration

Energy Information Administration Data:

Previous post
London Calling: How UK Grid Innovation ...

	DOE Report	EIA 860
Load growth:	101 GW	N/A
Capacity Additions	209 GW	200 GW
Gas Capacity Additions	22 GW	35 GW
Battery Capacity Additions	31 GW	53 GW
Retirements	104 GW	52 GW

Next post
Why the U.S. Does Not Need New Gas to ...

Conclusion:

If the DOE report had used more consistent assumptions, it would have likely come to very different conclusions. Utilities and RTOs have planning processes and market mechanisms in place to build new resources in response to higher load growth and the retirement of older, uneconomic plants. The DOE's solution to keep older units online past retirement dates is a crude and expensive approach. The DOE should defer to state planning processes and regional markets to meet the challenge.

GridLab

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

EXHIBIT 52

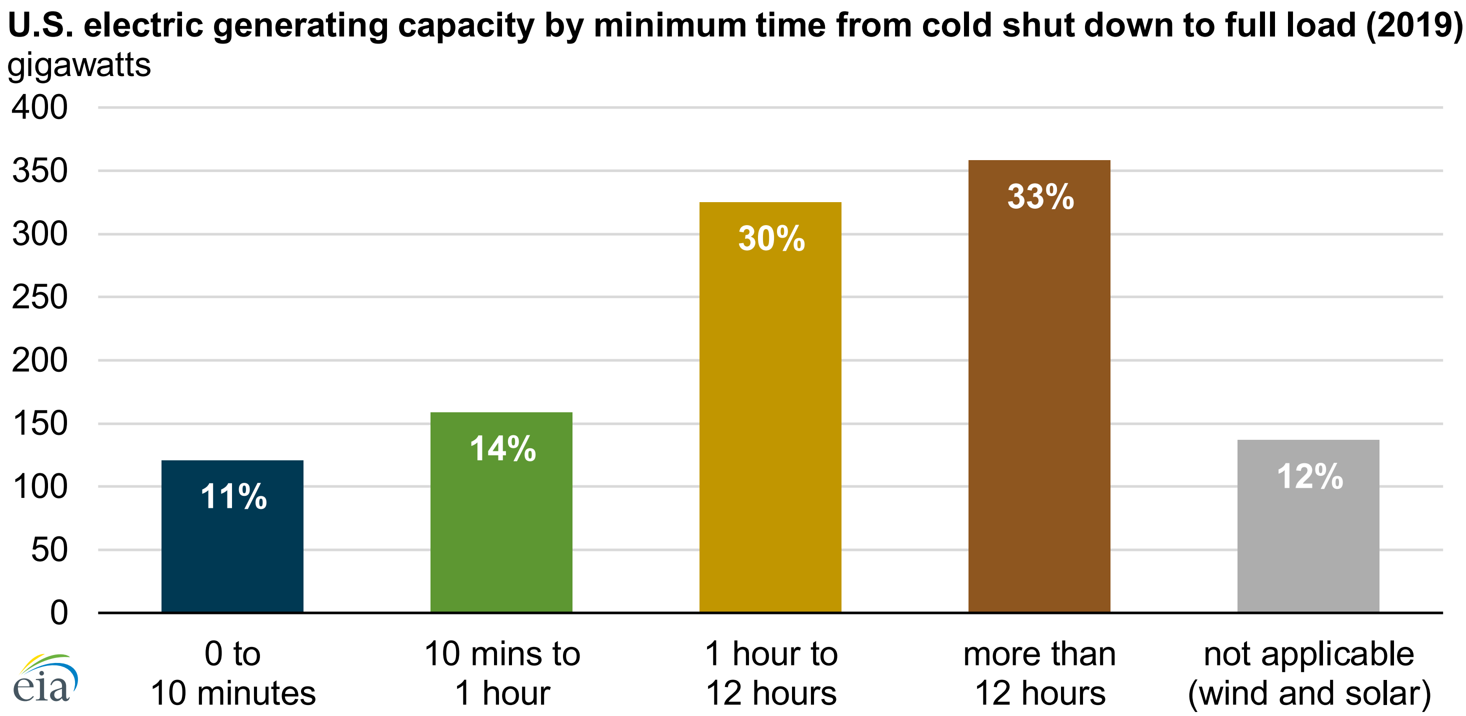
EIA, ABOUT 25% OF US POWER PLANTS CAN START UP WITHIN AN HOUR

U.S. Energy Information Administration

Today in Energy

November 19, 2020

About 25% of U.S. power plants can start up within an hour



Source: U.S. Energy Information Administration, *Annual Electric Generator Inventory*

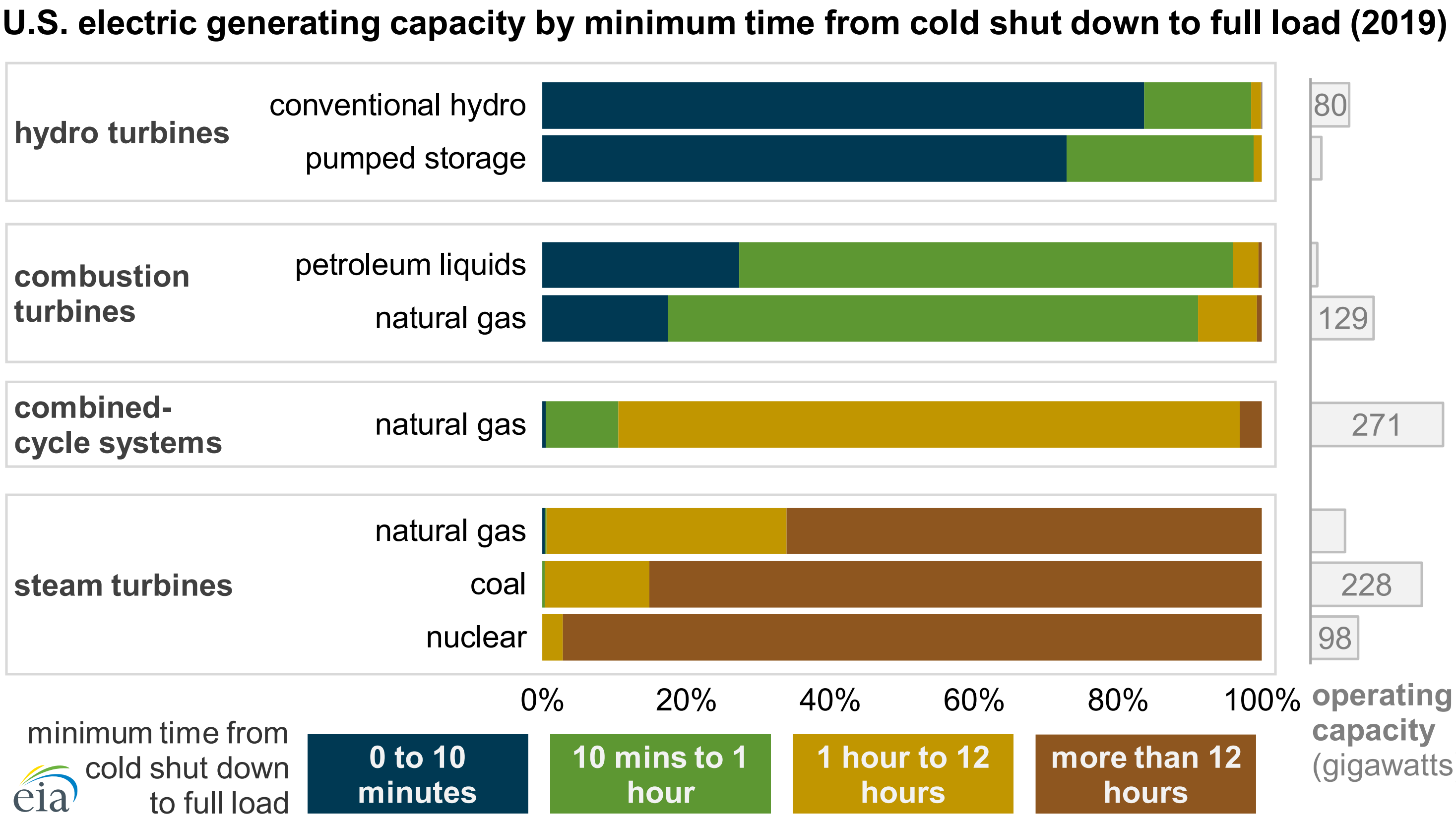
About 25% of U.S. power plants can start up—going from being shut down to fully operating—within one hour, based on data collected in EIA's annual survey of electric generators. Some power plants, especially those powered by coal and nuclear fuel, require more than half a day to reach full operations. The time it takes a power plant to reach full operations can affect the reliability and operations of the electric grid.

Generator startup time differs across electricity-generating technologies because of the differences in the complexity of electricity generating processes, especially when starting again after all processes have been stopped (cold shut down). A generator's startup time is different from a generator's ramp rate, which reflects how quickly that generator can modify its power output once it's operating.

Most hydroelectric turbines, which use flowing water to spin a turbine, can go from cold start to full operations in less than 10 minutes. Combustion turbines, which use a combusted fuel-air mixture to spin a turbine, are also relatively fast to start up.

Steam turbines often require more time. A fuel heats up water to form steam, and that steam needs to reach certain temperature, pressure, and moisture content thresholds before it can be directed to a turbine that can spin the electricity generator.

Nuclear power plants use steam turbines, but these plants have additional time-intensive processes that involve managing their nuclear fuel. Almost all nuclear power plants require more than 12 hours to reach full operations. Power plants that require more than 12 hours to start up are increasingly rare. Only 4% of the generating capacity that came online from 2010 to 2019 requires more than half a day to reach full load.



Source: U.S. Energy Information Administration, *Annual Electric Generator Inventory*
Note: Only technology/fuel combinations with at least 10 gigawatts of operating capacity are shown.

Natural gas combined-cycle systems, which involve both a steam turbine and a combustion turbine, account for more capacity than any other generating technology in the United States. Most of those systems can reach full operations in between 1 hour to 12 hours, although some can start up within an hour.

The percentage of the generator fleet that does not respond to this question in EIA's survey has doubled—from 6% in 2013, when EIA first collected this data, to 12% in 2019—as a result of the number of utility-scale solar and wind power plants added in recent years. This question is not relevant for these types of plants.

Principal contributor: Owen Comstock

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)
Emergency Order: Orlando Utilities Commission
Regarding the Stanton Energy Center

Order No. 202-26-26

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

EXHIBIT 53

PEW REPORT

SHORT READS | APRIL 13, 2026

Most new data centers in the U.S. are coming to rural areas

Add Us On Google

BY SKYLER SEETS AND KAITLYN RADDE

Construction continues at a new Meta data center in Beaver Dam, Wisconsin, on March 31. (Joe Timmerman/Wisconsin Watch via Getty Images)

The United States has more than 3,000 operational data centers, and that number is expected to grow substantially in the years ahead. More than 1,500 new data centers are in various stages of development nationwide, according to a Pew Research Center analysis of data from Data Center Map.

About this research

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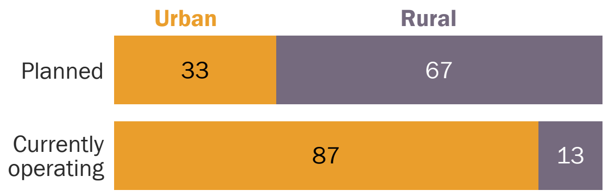
In a shift, most planned data centers in the U.S. are in rural areas

% of data centers in the U.S. that are in ___ areas



Note: Urban/rural categories based on U.S. Census Bureau. Planned category includes data centers listed as “under construction,” “planned” or “land banked.”
Source: Data Center Map, accessed Feb. 19, 2026.

PEW RESEARCH CENTER

Chart Data Download Image Share

These planned data centers are largely in different parts of the country from those that currently exist:

- 67% of planned data centers are in rural areas, while 87% of existing data centers are in urban ones.
- 39% of planned data centers are in counties that currently don’t have any.

South, Midwest lead in planned data centers

Most of the planned construction of U.S. data centers will happen in the South and Midwest. Three-quarters of all planned data centers will be built in these two regions, with the South alone accounting for nearly half of them (48%).

Virginia, Texas and Georgia lead the country in planned data centers

Number of data centers in each state, by operating status

State	Total	Currently operating	Planned
Virginia	685	398	287
Texas	466	296	170
California	331	277	54
Illinois	262	139	123

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State	Total	Currently operating	Planned
Georgia	235	94	141
Ohio	223	166	57
Arizona	184	98	86
New York	154	148	6
Oregon	142	115	27
Washington	135	124	11
Pennsylvania	129	78	51
Florida	128	120	8
North Carolina	113	72	41

Download data as .csv

Note: Planned category includes data centers listed as “under construction,” planned or “land banked.” Only the top 15 states by total are shown.
Source: Data Center Map, accessed Feb. 19, 2026.

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Here’s a look at the regional breakdown of planned and existing data centers:

- The South has 754 planned data centers and 1,209 existing ones – a 62% increase from its current total.
- The Midwest has 419 planned data centers and 655 existing ones – a 64% increase.
- The West has 277 planned data centers and 807 existing ones – a 34% increase.
- The Northeast has 106 planned data centers and 397 existing ones – a 26% increase.

Virginia and Texas have the most planned data centers (287 and 170, respectively). They are followed by Georgia (141), Illinois (123) and Arizona (86).

Virginia and Texas also have the most currently operating data centers (398 and 296, respectively). They are followed by California (277), Ohio (166) and New York (148).

How many Americans live near a data center?

Currently, 38% of Americans live within 5 miles of at least one operational data center.

These structures tend to be built in clusters: Nine-in-ten data centers are within 5 miles of another one. As a result, a majority of Americans who live near one data center also live near at least one more.

Another 4% of Americans don't live near a currently operational data center but live within 5 miles of one that's planned. Taken together, that means 42% of the population lives close to an existing or planned data center.

Related

- *How Americans view data centers' impact in key areas, from the environment to jobs*
- *What we know about energy use at U.S. data centers amid the AI boom*

Living near a data center doesn't have much of an effect on public opinion about the facilities, however. Americans who live near a data center – whether existing or planned – are about as likely as those who do not to say they've heard or read at least a little bit about them. And the two groups of Americans have similar views about the impact that data centers have on things like the environment, home energy costs and local jobs.

Note: Here are the survey questions, the detailed responses and the survey methodology.

Topics

Artificial Intelligence, Emerging Technology, State & Local Government, Technology Policy Issues

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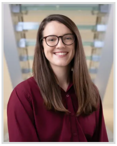
Skyler Seets is a computational social science assistant at Pew Research Center.



Kaitlyn Radde is a computational social science assistant at Pew Research Center.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

EXHIBIT 54

OUC 202(C) APPLICATION – BACKUP GENERATORS

The Reliable One®

January 31, 2026

VIA EMAIL

The Honorable Chris Wright
Secretary of Energy
United States Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585-1000
Attn: *AskCR@hq.doe.gov*

Re: Request for Emergency Order Under Section 202(c) of the Federal Power Act

Dear Secretary Wright:

Pursuant to Section 202(c) of the Federal Power Act ("FPA") and the regulations promulgated thereunder by the Department of Energy ("Department" or "DOE"), the Orlando Utilities Commission (OUC) respectfully request that the Secretary of Energy ("Secretary") find that an emergency exists within OUC's service area that requires intervention by the Secretary, in the form of a Section 202(c) emergency order, to preserve the reliability of the bulk electric power system. As described in the Secretary's January 22, 2026 letter, "Leveraging Backup Generation Facilities During Energy Emergencies," OUC respectfully requests that the Secretary issue an order immediately, effective January 31, 2026, authorizing certain backup generating units located within OUC's service areas to operate up to their maximum generation output levels under the limited circumstances described below, notwithstanding air emissions or other permit limitations. OUC further requests that the order remain effective through 10:00 a.m. Eastern Standard Time (EST) on February 6, 2026. OUC is requesting the Department issue an order for this duration with this limiting condition because OUC anticipates unusually high load forecasts during this time due to extreme cold weather conditions for all of the State of Florida during this period.

I. Background

On Friday, January 23 and continuing into Monday, January 26, 2026, a significant winter weather event known as Winter Storm Fern brought heavy snow, sleet, and freezing rain, as well as dangerously cold temperatures and wind chills to multiple states, ranging from the southern plains to the eastern United States. As the storm drifted across the East Coast, more Arctic air moved in behind the storm, prolonging the bitter cold, icy conditions for several days. To date, Winter Storm Fern has caused or threatens to cause severe and widespread impacts across multiple regions of the United States, including extreme cold temperatures, freezing precipitation, high winds, disruptions to electric generation and transmission systems, natural gas supply constraints, and increased demand for electric and water services. On January 31, and February 1, 2026, and the following week, another round of extreme cold is forecasted to impact the southeast, including Peninsular Florida and South Florida and the entirety of OUC's service territory. As such, customer demand is projected to exceed record-breaking thresholds for OUC on Sunday, February 1, 2026, and again on Monday, February 2, 2026, and which may continue throughout the following week.

While the vast majority of generating units available to cover the load in OUC's service territory continue to function adequately under these stressed conditions, some units will be limited in providing the generation needed by the system conditions and limitations in their environmental permits. As a result, OUC is concerned that under these conditions the system may not have sufficient generation available to meet this unusually high demand and may be forced to curtail load in order to maintain security and reliability of the grid.

OUC has identified several non-essential commercial and industrial customers as well as city and county-owned wastewater and water facilities that have back-up generation that is available and subject to deployment to help reduce demand and potentially avoid the need for any firm load shedding that may be required during this extreme cold weather event.

Subject to the exceptions requested herein, OUC commits to continuing to take such actions, including utilizing other supply resources, before operating any units or calling on any generator to operate any units in a manner that will result in a conflict with a requirement of any federal, state, or local environmental statute or regulation, including requirements in permits issued pursuant to such laws or regulations. Even with the requested order, however, it is possible that OUC will have no choice but to curtail firm load to ensure system reliability.

II. Relief Requested

In an effort to further reduce load, non-essential customer-owned or operated backup generation facilities, as well as city and county-owned wastewater and water facilities, within the OUC's service areas may be available to disconnect from the grid and operate during this emergency (the "Specified Resources"). However, these units may be limited in their power output due to emissions and other limits established by federal and state environmental and other laws and permits. Specifically, the operation of the Specified Resources could result in emissions of NOx, carbon monoxide, and volatile organic compounds exceeding regulatory limits when operated continuously in support of the cold weather emergency. These exceedances could be the result of combustion concerns or supply issues for materials such as Diesel Emission Fluid (DEF) which helps to minimize emissions. Additionally, the units could exceed run hour limitations in their permits or as described in applicable regulations, causing such units to be placed in a category of greater regulatory scrutiny and control, due to extended run times to meet the needs of the electric grid during this cold weather emergency. Extended run periods could also cause a unit to exceed a specified maintenance interval while operating in support of this emergency.

Because the output from the units subject to these restrictions and regulatory treatment could help to reduce electric demand and potentially avoid the need for any firm load shedding that may be required during this extreme cold weather emergency, OUC seeks an immediate order from the Department authorizing the operation of the Specified Resources regardless of emissions or other permit limitations and excluding these run time hours for the emergency from compliance limits and other regulatory consideration. This relief would be available only under the following limited circumstances:

- For any unit that is unable, or expected to be unable, to produce at its maximum output in compliance with environmental statute, regulation, or permit for the duration of the order, the unit will be allowed to operate at maximum output regardless only during any period for which EEA Level 2 or Level 3 is in effect in the impacted OUC service areas, except as described in the bullet below in certain limited circumstances in anticipation of an EEA Level 2 or above. Once it is declared that the EEA Level 2 (or above) event has ended, the units would be required to immediately return to operation within their permitted limits, except for the limited exceptions provided herein for operation in anticipation of an EEA Level to prevent the cycling of units. At all other times, the units would be required to operate within their permitted limits.

- Exception: OUC seeks authority for the Specified Resources to operate in certain limited circumstances in advance of a declared EEA Level 2, or in between such events, where such operation or continued operation of the Specified Resource is reasonably necessary to avoid shutting down and restarting the Specified Resource, because such cycling of units can cause reliability issues regarding restarting, delays, and increased emissions during start up.

- To minimize adverse environmental impacts as set forth herein, this request for an order limits operation of the Specified Resources to the times and within the parameters identified in this request and as determined by OUC or the statewide security coordinator, as necessary for grid reliability to avoid adverse health and safety impacts to customers from shedding firm customer load. Consistent with good utility practices, OUC shall exhaust all reasonably and practically available resources, including available imports, demand response and identified behind-the-meter generation resources selected to minimize an increase in emissions to the extent that such resources provide support to maintain grid reliability prior to calling on Specified Resources to potentially operate at levels in excess of environmental permits.

- OUC will provide such additional information regarding the environmental impacts of the order and its compliance with the conditions of the order, in each case as requested by the Department of Energy from time to time.

OUC requests this order because it is committed to public health and safety, takes its compliance obligations seriously, and understands the importance of the environmental permit requirements that are at issue. In this case, the risk of power outages in extremely cold temperatures is a more imminent and prominent threat to the communities in OUC's service area than the temporary exceedances of those permit limits that would be allowed under the order. Authorizing the generation resources to operate notwithstanding permit and other limitations may reduce the likelihood that OUC will need to curtail load.

This request is narrowly tailored to allow only the exceedances that are necessary to ensure reliability during the limited timeframe of this request. Limiting the requested allowance to situations described above will ensure that the operation of the generation resources in excess of environmental permit limits will be a last resort to maintain grid stability, thus minimizing any environmental impact to the greatest degree possible.

OUC greatly appreciates the Department of Energy's expedited consideration of this request and commits to respond to any requests for additional information on an expedited basis. Please do not hesitate to contact me if you have any questions or require additional information in order to act on this request.

Respectfully Submitted,

Clint Bullock

Clint Bullock
General Manager and CEO

cc: rebecca.michael@hq.doe.gov
tim.kocher@hq.doe.gov
angelo.mastrogiacomo@hq.doe.gov

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

EXHIBIT 55

OUC 202 (C) APPLICATION

OUC The Reliable One®

January 31, 2026

VIA EMAIL

The Honorable Chris Wright
Secretary of Energy
United States Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585-1000
Attn: *AskCR@hq.doe.gov*

Re: Request for Emergency Order Under Section 202(c) of the Federal Power Act

Dear Secretary Wright:

Pursuant to Section 202(c) of the Federal Power Act ("FPA") and the regulations promulgated thereunder by the Department of Energy ("Department" or "DOE"), the Orlando Utilities Commission (OUC) respectfully request that the Secretary of Energy ("Secretary") find that an emergency exists within OUC's service area that requires intervention by the Secretary, in the form of a Section 202(c) emergency order, to preserve the reliability of the bulk electric power system. OUC respectfully requests that the Secretary issue an order immediately, effective January 31, 2026, authorizing certain electric generating units supplying power to OUC's service area to operate up to their maximum generation output levels under the limited circumstances described in this letter, notwithstanding air emissions or other permit limitations. OUC further requests that the order remain effective through 10:00 a.m. Eastern Standard Time (EST) on February 6, 2026. OUC is requesting the Department issue an order for this duration with this limiting condition because OUC anticipates unusually high load forecasts during this time due to extreme cold weather conditions for all of the State of Florida during this period.

I. Background

On Friday, January 23 and continuing into Monday, January 26, 2026, a significant winter weather event known as Winter Storm Fern brought heavy snow, sleet, and freezing rain, as well as dangerously cold temperatures and wind chills to multiple states, ranging from the southern plains to the eastern United States. As the storm drifted across the East Coast, more Arctic air moved in behind the storm, prolonging the bitter cold, icy conditions for several days. To date, Winter Storm Fern has caused or threatens to cause severe and widespread impacts across multiple regions of the United States, including extreme cold temperatures, freezing precipitation, high winds, disruptions to electric generation and transmission systems, natural gas supply constraints, and increased demand for electric and water services. On January 31, and February 1, 2026, and the following week, another round of extreme cold is forecasted to impact the southeast, including Peninsular Florida and South Florida and the entirety of OUC's service territory. As such, customer demand is projected to exceed record-breaking thresholds for OUC on Sunday, February 1, 2026, and again on Monday, February 2, 2026, and which may continue throughout the following week.

While the vast majority of generating units available to cover the load in OUC's service territory continue to function adequately under these stressed conditions, some units will be limited in providing the generation needed by the system conditions and limitations in their environmental permits. As a result, OUC is concerned that under these conditions the system may not have sufficient generation available to meet this unusually high demand and may be forced to curtail load in order to maintain security and reliability of the grid.

II. Relief Requested

Because the output from all of the generation units available to OUC would help to reduce the need for any firm load shedding that may be required during this extreme cold weather event, OUC seeks an immediate order from the Department authorizing the provision of additional energy from the generation units as described in Exhibit A ("Specified Resources"), regardless of emissions or other permit limitations.

To minimize adverse environmental impacts as set forth herein, this order would limit operation of dispatched units to the times and within the parameters determined by OUC as necessary for grid reliability to avoid adverse health and safety impacts to customers from shedding firm customer load. Consistent with good utility practices, OUC shall exhaust all reasonably and practically available resources, including available imports, demand response and identified behind-the-meter generation resources selected to minimize an increase in emissions to the extent that such resources provide support to maintain grid reliability prior to dispatching the generation resources at levels in violation of environmental laws.

OUC requests this order because it is committed to public health and safety, takes its compliance obligations seriously, and understands the importance of the environmental permit requirements that are at issue. In this case, the risk of power outages in extremely cold temperatures is a more imminent and prominent threat to the communities in OUC's service area than the temporary exceedances of those permit limits that would be allowed under the order. Authorizing the generation resources to operate notwithstanding permit and other limitations may reduce the likelihood that OUC will need to curtail load. This request is narrowly tailored to allow only the exceedances that are necessary to ensure reliability during the limited timeframe of this request. Limiting the requested allowance to situations described above will ensure that the operation of the Specified Resources in excess of environmental permit limits will be a last resort to maintain grid stability, thus minimizing any environmental impact to the greatest degree possible.

OUC greatly appreciates the Department of Energy's expedited consideration of this request and commits to respond to any requests for additional information on an expedited basis. Please do not hesitate to contact me if you have any questions or require additional information in order to act on this request.

Respectfully Submitted,

Clint Bullock

Clint Bullock
General Manager and CEO

cc: rebecca.michael@hq.doe.gov
tim.kocher@hq.doe.gov
angelo.mastrogiacomo@hq.doe.gov

EXHIBIT A
(List of Specified Resources)

Unit Location	Nominal rating MW's	Primary Fuel	Backup Fuel
IND RVR CT A	36	Natual Gas	Diesel
IND RVR CT B	36	Natual Gas	Diesel
IND RVR CT C	110	Natual Gas	Diesel
IND RVR CT D	110	Natual Gas	Diesel
OSCEOLA-CT1	157	Natual Gas	Diesel
OSCEOLA-CT2	157	Natual Gas	Diesel
OSCEOLA-CT3	157	Natual Gas	Diesel
STANTON #1	470	Coal	NA
STANTON #2	490	Coal	NA
STANTON A-CC	665	Natual Gas	Diesel
STANTON B-CC	310	Natual Gas	Diesel

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

EXHIBIT 56

RATEPAYER PROTECTION PLEDGE

RELEASES

Ratepayer Protection Pledge

The White House

March 4, 2026

America's continued economic and technological leadership depends on reliable, large-scale data center infrastructure built here at home. Data center infrastructure is the foundation of the internet, cloud computing, and artificial intelligence (AI), and supports our economic and national security. As that infrastructure grows and the related electricity demand increases, the American people should not be footing the bill for the benefit of private companies. Instead, the data center boom should be leveraged to address affordability and benefit all American households and businesses.

President Trump is calling on the leading United States hyperscalers and AI companies to build, bring, or buy all of the energy needed for building and operating data centers, paying the full cost of their energy and infrastructure, no matter what.

As part of the Ratepayer Protection Pledge, companies agree to protect American consumers from price hikes due to data center energy and infrastructure requirements, and lower electricity costs for consumers in the long term, including by:

1. Building, Bringing, or Buying New Power Supply

- **WHAT**: Companies will build, bring, or buy the new generation resources and electricity needed to satisfy their new energy demands, paying the full cost of those resources whether by building, or buying from, new or otherwise additive power plants. Where possible, these companies will also add more capacity that serves the broader public by increasing supply.
- **WHY**: This advances self-sufficiency and protects Americans from higher prices.

2. Paying for New Power Delivery Infrastructure Upgrades

- **WHAT**: Companies will pay for all new power delivery infrastructure upgrades required to service their data centers, including adequate network upgrade costs to ensure that these expenses are not passed on to the ordinary household.

- **WHY**: This way, data centers can benefit all ratepayers and the grid.

3. Paying Whether They Use the Power or Not

- **WHAT:** Companies will voluntarily negotiate new, separate rate structures with their utilities and relevant State governments wherever they build data centers. Importantly, they will pay these rates for the power and related infrastructure that are brought online to service their data centers, whether they use the electricity or not.
- **WHY**: This will protect the American people from increased utility bills as a result of the development of these data centers.

4. Investing in Local Job Creation and Workforce Development

- **WHAT**: Companies will invest in the local communities in which they build data centers. This includes hiring from within the local community and establishing programs to develop relevant skills.
- **WHY:** This allows all American workers to benefit from the oncoming technological boom at every step from construction to operation.

5. Contributing to Electric and Community Resilience

- **WHAT**: Companies will coordinate with grid operators to contribute to a more reliable grid and, whenever possible, make available their backup generation resources at times of scarcity to prevent blackouts and power shortages in their communities.
- **WHY**: Consumers will benefit from enhanced grid resilience from data center power resources in times of emergency.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

Exhibit to
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Public Interest Organizations

EXHIBIT 57

ENERGY INNOVATION REPORT

ENERGY INNOVATION
POLICY & TECHNOLOGY LLC®

DODGING THE FIRM FIXATION FOR DATA CENTERS AND THE GRID

Eric G. Gimon

Senior Fellow, Energy Innovation
November 2025

ACKNOWLEDGEMENTS:

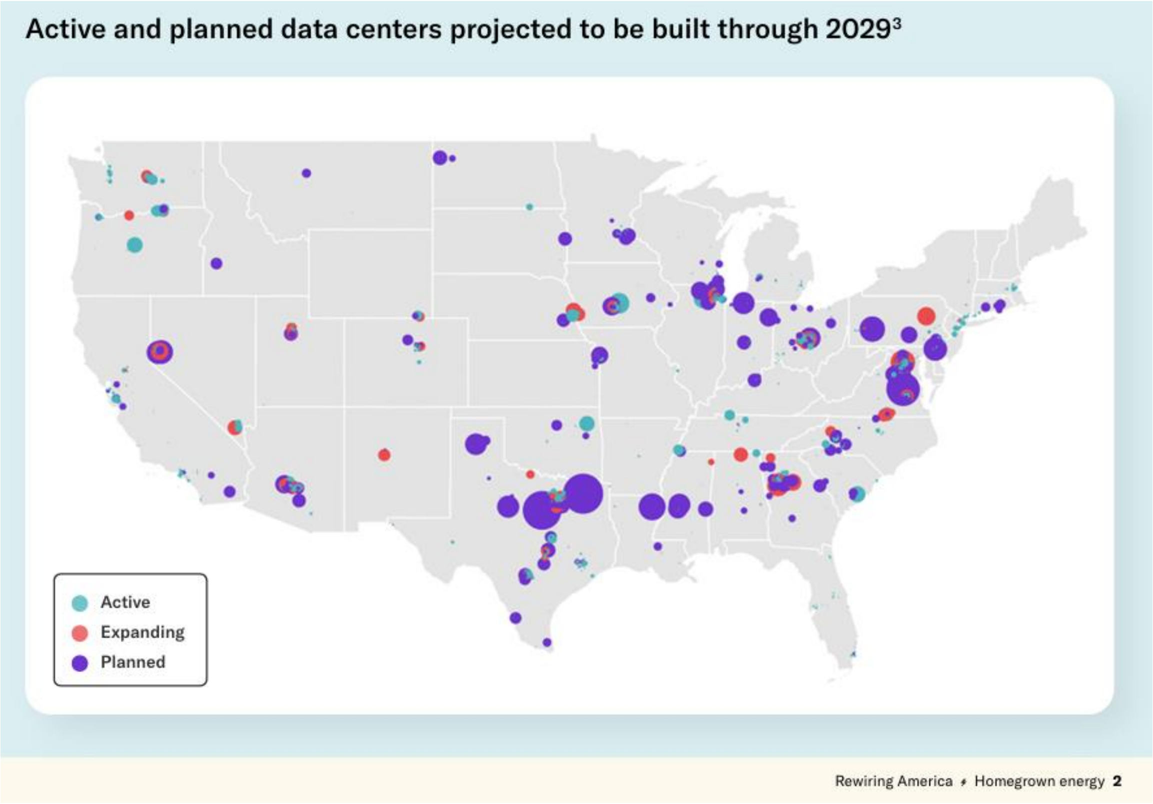
I would like to thank my Energy Innovation colleagues for their patient review and feedback on various drafts of this report. I would also like to acknowledge the Energy Systems Integration Group for their conferences, taskforce meetings, and webinars which helped me get started on my research.

TABLE OF CONTENTS

EXECUTIVE SUMMARY

In multiple states[1,2] (see Figure 1) massive new data center campuses and a coterie of smaller ones have reversed years of flat or declining electricity demand, leaving utilities and policymakers scrambling for solutions.

Figure 1 Existing and Projected data centers from Rewiring America's "Homegrown Energy" report[3].



Faced with this onslaught of new demand, many utilities and developers are depending on old habits by adding new gas plants, refurbishing coal units, or turning to nuclear partnerships along with extensive grid upgrades near new load centers – the "firm fixation."

It reflects a belief that only firm resources and major transmission upgrades can handle data centers' needs. Yet this approach overlooks two essential truths: (1) power plants and data centers are both parts of a larger, interconnected system, and (2) data center loads, especially those driven by artificial intelligence (AI), are far more dynamic than the flat, baseload profiles they are often assumed to be. Firm fixation leads utilities and regulators to default to outdated firm-generation solutions instead of modern, modular approaches that consider the full complexities of today's power grid. At the scale of even the most compact new data centers, connecting to the grid is no small matter.

Regardless of approach, three features of recent growth are well known to the electricity industry and policy community, and to some extent the wider public. First, new data center load is being amplified by extreme investment interest in AI. Second, incremental load tends to be highly concentrated due to the nature of the growing individual server need for power and the geographic concentration of data centers. Third, the data center industry's appetite for new growth is so large, and other facility capital costs so high that new project owners are willing to pay more for power than average existing electricity consumers.

In a 2024 brief, Energy Innovation proposed instead that a portfolio of solutions – clean energy portfolios, advanced transmission technologies, demand-side flexibility, and efficiency – could work together to obviate the need to rush to meet demand with new fossil generation.[4] Reality so far has deviated significantly from this vision, setting up the power sector for failure: Either new demand will not be met or the negative cost and performance impacts of doing so on other grid users will challenge electricity markets and other long-standing arrangements in a dangerous manner.

The mad scramble to meet data center demand using traditional but crude resource investment methods can create potential missed opportunities to manage load growth that come from a deeper understanding of data centers. Of course, their electricity demand is problematic because it is concentrated, growing fast, and willing to outspend other users. However, it is also far more complex than the flat, 24/7 block it is often assumed to be. This primer identifies six defining features that provide a more nuanced version picture of data centers:

- **Agency and Split Incentives** – Multiple actors (developers, operators, and tenants) and ownership or usage types of data centers create a divided responsibility over grid interaction and access to energy-saving incentives that complicates energy decisions.
- **Clustering** – Facilities tend to concentrate geographically, amplifying local grid stress and transmission costs while creating systemic planning challenges.
- **Consumption Profiles** – Loads are not 24/7 blocks. Instead, they are choppy, with swings of hundreds of megawatts over short intervals, undermining assumptions of steady baseload behavior and potentially affecting the stability of the grid if safeguards are not put in place.
- **Flexibility** – While some AI-driven workloads can be scheduled for off-peak hours, this flexibility is uneven across facility types and even within users in the same data center campuses. While modest levels of curtailment or load-shifting based demand response during peak hours could ease interconnection bottlenecks and peak demand requirements, these may work best in combination with battery energy storage to overcome split incentives and other complexities.

- **Backup Requirements** – Current reliance on diesel for backup generation is unsustainable. Batteries and longer-duration storage are cleaner, more scalable options that provide knock-on benefits for the grid if allowed to participate as both backup and demand response.
- **Modularity** – Data centers grow in phases just as demand grows in phases rather than all at once, aligning poorly with "lumpy" firm large one-time investments in dispatchable power plants and infrastructure upgrades, while fitting well with modular renewables and battery deployments.

When examined as a whole, these features undermine the firm fixation logic. One-to-one matching of data centers with dedicated or "captive" firm power plants is particularly unwise for both the power generator and the new data centers, even given their willingness to pay for speed-to-power. Relying on captive plants for all supply such as pairing a nuclear plant with a large data center exposes them to outages, inflexibility, and stranded-asset risks, while hybrid co-location deals still rely heavily on the broader grid.

Most new demand will need to be served fully or in-part through the bulk power system, requiring upgrades in three key areas: **connection infrastructure, grid services (especially peak capacity), and bulk electricity supply.**

Once this is established, it's clear that data centers can tap the grid's advantages as a "system of systems" that pools variable demand and generation resources solutions together and ensures supply and demand match in real-time. As peak demand rises, this crucial service must be met, but not necessarily by firm generation. A deeper understanding of data center demand attributes yields a more complete solution set which includes data center flexibility, onsite storage, portfolios of clean energy, and others.

The challenges data centers pose include lengthy interconnection queues, peak stress, price impacts, and rising emissions – but these are not insurmountable. Three core lessons emerge for policymakers and stakeholders:

- The process of connecting any new **large load is a key leverage point.** It is the moment to ensure consumption tariffs reflect cost causation, encourage flexibility, and align incentives without imposing unworkable burdens later. Interconnection is the moment of maximum leverage: not to extract unreasonable concessions, but to ensure new entrants cover the full costs of the infrastructure they trigger, and to nudge data center developers towards solutions such as flexible demand or local storage that relieves local bottlenecks and supports the broader grid. Likewise, developers and customers should lean toward local fixes that speed access to the grid, improve power quality, and ease broader impacts—reducing the likelihood of being saddled with extraordinary requirements later.

- **Demand side is a resource hiding in plain sight**. Household electrification and distributed resources can free up tens of gigawatts (GW) at costs comparable to new gas plants and on a faster timetable, offering a more pragmatic and equitable path to integration. Yet at the state and regional level, policy innovation still lags behind. However, several widespread mechanisms exist to channel data center owners and operators' willingness to pay into new solutions that help other existing customers accommodate rapid data center load growth in a fair, fast and equitable way. Because grid connection bottlenecks can be managed by multiple possible combinations of diverse resources, data centers don't need to do all the work of mitigating their grid impacts onsite or through a single counterparty. Once a data center has invested in flexibility and equipment to resolve local connection issues, additional constraints such as upstream transmission and grid services bottlenecks as well as large incremental amounts of annual electricity delivery can be addressed with demand-side solutions from other grid users. A recent report from Rewiring America proposes that many of the resources needed to meet data center load growth could come from sponsoring household upgrades instead of new generation.[5]
- **Storage and flexibility deliver a two-for-one win.** Batteries and managed demand not only ease all manner of data center impacts but can also accelerate renewable integration, providing cleaner, faster, and cheaper capacity than firm fossil solutions. Because batteries are increasingly essential for buffering, backup, and power quality, they also provide a built-in solution for integrating variable renewables—a two-for-one advantage. Furthermore, these renewable-plus-battery solutions can capitalize upon existing surplus interconnection to more quickly connect data centers to the grid in co-located arrangements.

This report challenges the electricity and data center industries to move beyond a firm fixation and adopt solutions that leverage the full capabilities of modern power systems.

The next section describes six defining features of data centers: agency, clustering, consumption profile, flexibility, backup needs, and modularity. We then pivot to explaining why traditional firm responses fall short within the broader context of how the modern grid supplies power to consumers, especially large, new consumers. We will look at how new, modular solutions can meet digital demand more effectively. These steps will depend on a more nuanced understanding of data centers, as opposed to how they are often imagined.

Our hope is that this information will empower policymakers to make wiser decisions when faced with AI growth and proposed public investments, avoiding a firm fixation on simplistic approaches and reaching for more realistic answers that embrace the full complexities of the challenge that rapid data center load growth presents today. By moving beyond simplistic assumptions, policymakers can avoid overcommitting to outdated firm resources and instead adopt strategies that embrace modularity, flexibility, and clean energy. We want to leave policymakers with three key takeaways to avoid falling into a firm power matching fallacy and to instead embrace the ability to mix and match resources to meet data center needs.

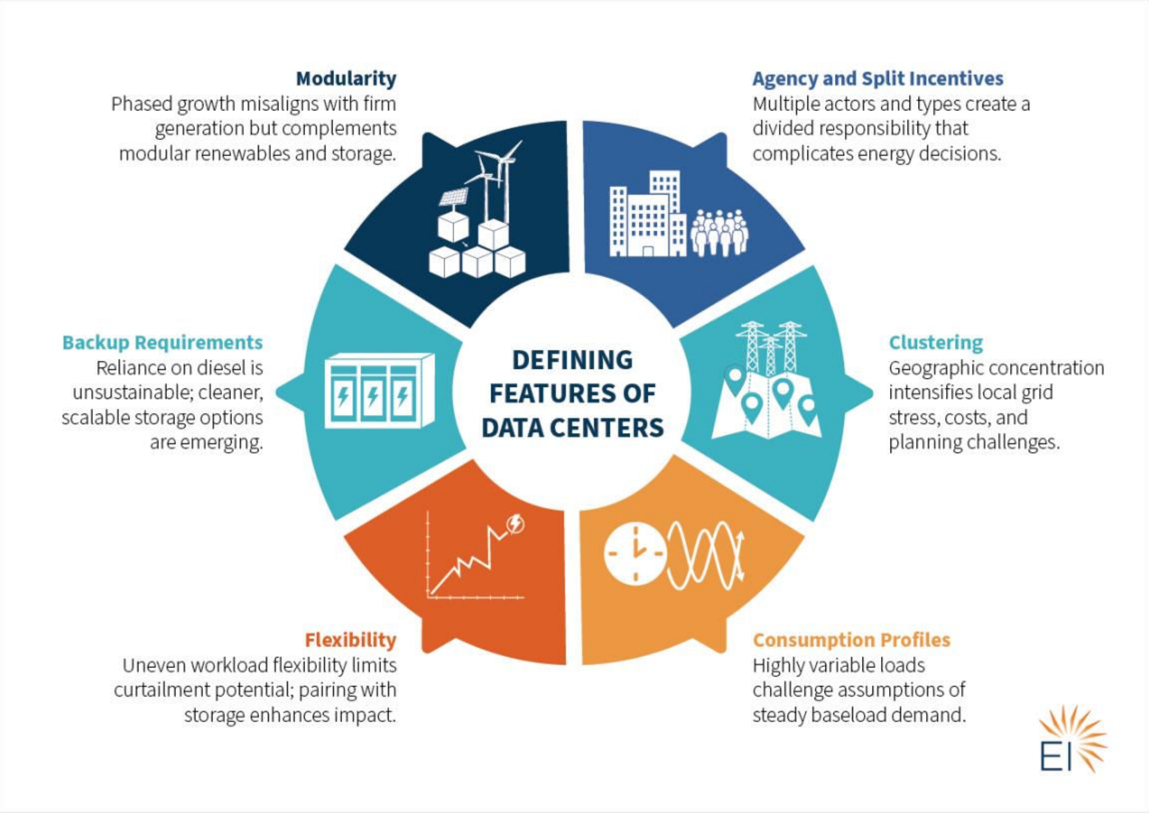
What began as a major strain on the grid can become the catalyst for building a smarter one, supporting both the digital economy's explosive growth and the clean energy transition.

COMMERCIAL AND INDUSTRIAL REALITIES THAT APPLY TO DATA CENTERS

Actual data centers are not the simple "flat 24/7 block of demand" people imagine.

Six different demand features of data centers explain the diversity of data center types (agency, clustering, and profile) and their internal workings (flexibility, backup, and modularity).

Figure 2 Actual data centers are not the simple "flat 24/7 block of demand" people imagine.

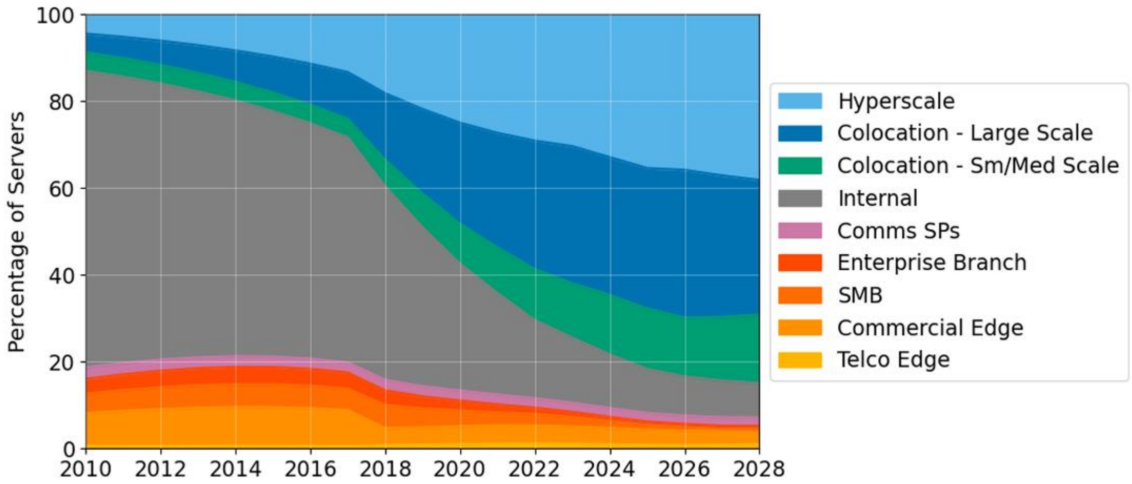


Data Center Feature 1: Agency and the split-incentive problem

Planning *and* operating *a data center* involves many decision-makers. *Some data centers (often called co-locations or "colos") are facilities where customers can rent space to house their servers and equipment or just run their software on provided equipment. This means the facility is developed and owned by a different company* from those *that rent rack space, buy* computing *capacity, and ultimately consume electricity. Multiple actors force complicated decisions around electricity supply.*

If we want new data centers to adapt their development approach to better integrate with the grid and increase their "speed-to-power," policymakers must understand the planning, construction, and operation of modern data centers. Many different actors are involved, creating a classic split-incentive problem. Loosely speaking, apart from the users or clients, three groups of actors dictate the energy and resource impacts of data centers: developers, facility operators, and service providers. These tend to be separate entities. Overlap sometimes occurs, but usually not enough to prevent split-incentive issues. More than half (and an even larger fraction of the current pipeline)[6] of data centers are categorized as co-location facilities—large facilities that rent out space to multiple separate entities.

Figure 3 Distribution of server types by data center type. 2024 United States Data Center Energy Usage Report[7]



We illustrate the split incentives by cataloguing some of the key concerns for each of the three types of decision-makers in the life of a data center. In early stages, data center development is mostly a real estate bet: developers acquire land, water, and electric connection rights and then these rights pass on to the projects they sell. The natural incentive for developers is to keep the range of future owners they could sell to as wide as possible. Hence, they are unlikely to want to enter contracts or agreements (or support legislation) that might prematurely impair any of the land, water, and power consumption rights for their projects. For example, they may not want to agree to be a flexible consumer in return for faster interconnection (load interconnection currently takes three to 11 years) because that might scare off some prospective buyers.

Similarly, owner/operators that lease capacity to data centers customers do not necessarily have much insight into how flexible these customers are or how their customers' usage pattern might change over time. They are conservative about aspects such as whether the tenant-user would be interested in avoiding on-peak usage, participating in time-varying rates, accessing clean energy tariffs, or participating in a demand-response program. Obviously, renters must abide by some rules (via master service agreements or service-level agreements[i]) about behavior that impacts power quality (voltage, frequency, harmonics, transients, etc.) or broader

[i] A master service agreement is an umbrella standardized contractual framework between a utility and the "customer of record" (which could be a data center owner/operator, a tenant/end-customer, or a special purpose entity created to hold the contract) across multiple facilities in the utility's territory. A load serving agreement is more specific to power delivery at a given site.

electrical concerns (like grounding, interference, and surge protection), but that still leaves a lot of uncertainty for the data center owner/operator. Violations may also pass undetected until a severe problem occurs.

Because data centers are also large electricity consumers, utilities will want to know if contracts are backed by the ultimate users (e.g., hyperscalers[ii]) or an intermediate company that could go bankrupt or disappear. Grid investments involve assets with multi-decadal lifetimes, while the service life of cutting-edge chips can be two to three years. Utilities and their regulators have a strong interest in recovering any incremental costs of investments needed to serve data centers and will look for contractual arrangements to make this happen.

Data Center Feature 2: Clustering, data centers are attracted by similar conditions or to each other

Data center locations tend to be concentrated in a few regions rather than evenly distributed. This clustering amplifies stress on already energy-dense grids. The main drivers are favorable conditions—reliable power, dense fiber, skilled workforce, tax regimes, and land—but anchor investments by hyperscalers or AI campuses could also accelerate the process. Policymakers should avoid treating projects as one-offs and consider the likelihood of a single facility snowballing into a larger cluster.

"Clustering" describes how data centers in the U.S. tend to collect in a handful of regions rather than being evenly distributed. Clustering creates stress for the bulk power system because it takes already energy-dense loads and adds even more load nearby. The easiest explanation for clustering is that it derives from favorable existing conditions: reliable electricity, dense fiber connectivity, neighboring trained workforce, supportive tax regimes, and land availability.

Large anchor projects also draw in more data center development: Once a hyperscaler or AI training facility establishes itself, it signals viability, brings new infrastructure, and lowers costs for additional entrants. Policymakers wanting to provide support for a big project by promises of jobs and tax revenue, risk underestimating the impacts of this attractive force as welcoming one project may quickly lead to a cascade of follow-on facilities, with both outsized benefits and mounting strains.[8]

Recent history reveals a pattern whereby anchor investments amplify favorable local conditions into enduring centers of digital infrastructure. Northern Virginia's "Data Center Alley" grew from early fiber and internet exchange into the world's largest concentration of data centers. Amazon Web Services (AWS) was an early and steady

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[ii] A hyperscaler is a cloud service provider or operator that builds and manages massive data center networks supporting millions of virtual servers and petabytes of data, operating globally and designed to scale seamlessly across regions. Examples might include Amazon Web Services (AWS), Microsoft Azure, Google Cloud Platform (GCP), Meta (Facebook), Apple, Alibaba Cloud, and Tencent Cloud.

investor in this cluster.[iii] Today, Data Center Alley reportedly handles roughly ~70 percent of the world's internet traffic, contains over 12 million square feet of commissioned data center space, and sustains hundreds of megawatts of power load.[9]. Reno's Tahoe-Reno Industrial Center became a global hub after Switch and Apple established major campuses, followed by Google and others[10]. Central Ohio offers a newer case: Google and AWS each invested in major builds, quickly attracting colocation providers.[11]. Atlanta and Phoenix look to be on similar paths[12].

In theory, diverse types of data centers should reinforce these patterns. Colocation facilities are drawn to network-dense hubs where they can maximize interconnection to other facilities. For example, enterprise servers might want to easily connect to multiple cloud providers—providers of cornerstone internet services stand to benefit from the reduced latency proximity affords, especially for content delivery like streaming video and games and so on. Hyperscalers could function as anchors, just like a department store in a shopping mall, investing billions into single campuses that create the vendor ecosystems others rely on. However, AI-focused facilities, with their unprecedented power needs, can also reshape the landscape by displacing other data centers competing for the same power network and generation resources.[13]

Electric power infrastructure both attracts and is stressed by clustering. Access to transmission lines and substations is a prerequisite, but as clusters grow, demand can overwhelm grids. Northern Virginia now faces multi-year waits for new hookups[14]. Reno's growth has raised water concerns and left Nevada utilities facing a potential doubling in necessary electrical infrastructure (also spurring them toward large renewable additions)[15]. Ohio illustrates the stakes most vividly: By March 2023, the utility AEP Ohio imposed a moratorium on new data center service agreements in Central Ohio, pending further study citing grid strain. Eventually regulators approved a new tariff[16] requiring data centers to pay for 85 percent of subscribed capacity whether it is used or not, with penalties for cancellation or under-performance and a four-year on-ramp[iv]. Clustering behavior can easily outrun planning and force regulators into reactive steps, introducing delays before more pro-active policies and tariffs can be put in place.

The policy lesson is not to avoid clusters—after all, they bring new jobs, tax revenue, and digital infrastructure—but to keep a skeptical eye on benefits claimed by developers and focus on smart planning. This should consider the multiple interests of stakeholders affected by a data center cluster and work in advance to align land use,

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[iii] AWS is certainly not the only part of this story but has been called out as a major player. Dan Swinhoe, "The Amazon Factor in Virginia," Data Center Dynamics, November 6, 2024, https://www.datacenterdynamics.com/en/analysis/the-amazon-factor-in-virginia/. Amazon also touts its $51.9 billion investment in Virginia between 2011 and 2021 (capital + operations) in its data center infrastructure in Fairfax, Loudoun, and Prince William counties. Roger Wehner, "Learn About AWS's Long-Term Commitment to Virginia," Amazon, June 7, 2023, https://www.aboutamazon.com/news/aws/aws-commitment-to-virginia.

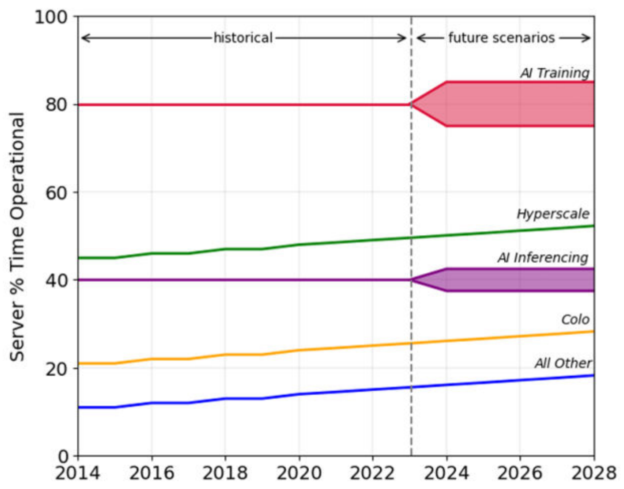
[iv] Under the decision, new data centers can access up to 50 percent capacity in the first year, 65 percent in the second, 80 percent in the third, and 90 percent in the fourth before getting full access to the grid.

grid upgrades, generation, flexible loads, and permitting frameworks, ensuring that benefits can be captured without bottlenecks or backlash once clusters grow.

Data Center Feature 3: Consumption profile

Data center electricity usage is not steady or 24/7. Up close, it can be quite choppy and challenging. Batteries could act as a buffer—a keystone solution to managing power quality.

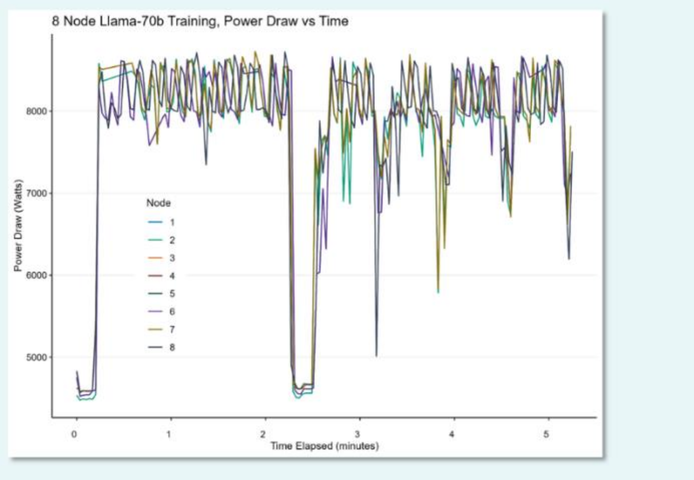
Figure 4 Server utilization by data center type. 2024 United States Data Center Energy Usage Report (LBNL).



Data centers exhibit considerable variability, especially going between operational and idle states. In Lawrence Berkeley National Laboratory's (LBNL) 2024 United States Data Center Energy Usage Report, the authors explain that in 2014 colos reported 21 percent utilization rates, hyperscalers 45 percent – rising to an estimated 35 percent and 50 percent respectively in 2027. The same report models AI learning centers and AI inferencing at 80 percent and 40 percent utilization rates, respectively. These don't directly translate into electricity consumption load factors because some electricity is used for other purposes like cooling that don't follow a 1:1 relationship with computing load.

Even looking at the whole power consumption profile of a data center, it's important to differentiate between actual load factor (the percentage of possible 24/7 full power use that a data center in fact uses) and availability (the percentage of maximum power a data center expects to have if it wants it, i.e., the *option* to use power). Whether power comes from on-site generation or from the grid, it needs to be prepared to provide power when the data center wants it, and back off when the data center doesn't.

Figure 5 8 Node trace of power consumption in an AI learning cluster. 2024 United States Data Center Energy Usage Report (LBNL).



Big swings in data center demand will clearly be a challenge, even for the most flexible on-site generation. Given the scale at which many data centers operate, these swings can still create problems for large regional grids [v]. The CEO of Hitachi Energy reportedly commented "there can be swings of 200, 300 MW within a ten-minute period as data centers move from learn vs stop learn mode, and that these types of swings would not be acceptable from other grid customers."

At smaller time scales, large numbers of similar chips in one place switch on and off and can create an aggregate resonance effect [vi]. Existing electrical standards are inadequate for screening out these behaviors, and utilities may not have sufficient sensors to properly trace back issues to a particular data center. In aggregate, the evidence points to data centers deteriorating power quality metrics in their environs.[17]

More research needs to be done that focuses on new large digital loads, including variable generation resources with inverters that center around things like low-voltage ride through or fault clearing. For more information, context, and solutions on some of the challenges with interconnecting these large loads, see GridLab's recent Practical Guidance and Considerations for Large Load Interconnections.

Data centers are not a "perfect baseload" fit to directly couple with large mechanical generators or even the grid, and they will need significant electrical equipment to buffer this connection and prevent extra wear and tear on co-located generation or nearby grid users. Even if some data centers can learn to be flexible, incorporating battery energy storage, especially as the hardware cost decreases, will likely become a key element in managing data center impacts on the grid. When good wind and solar resources are available nearby, batteries can play a dual role in managing both load and generation variability at multiple time scales. Consider the Lancium Clean Campus in under construction in Abilene, Texas: "In addition to the 1.2 GW grid interconnection,

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[v] See the GridLab report *Practical Guidance and Considerations for Large Load Interconnections*, with special attention to July 2024 Northern Virginia Data Center Event called out in Figure 1.2.

[vi] Some of these resonance issues can potentially be solved by on-chip energy management and storage. Rouslan Dimitrov et al., "How New GB300 NVL72 Features Provide Steady Power for AI," Nvidia, July 28, 2025, https://developer.nvidia.com/blog/how-new-gb300-nvl72-features-provide-steady-power-for-ai/?utm.

Lancium's power plan for the site includes large-scale behind-the-meter battery storage and solar resources, which serve to ensure grid reliability, and economic and carbon optimization."[18]

Data Center Feature 4: Flexibility, or the lack thereof

Flexibility could be key to quickly connecting new data centers, especially those involved with AI learning. Managed demand is possible, but on-site batteries may be a better solution where split incentives or onsite needs make demand control too rigid or complex.

Data centers can be flexible, but different functions involve different levels of flexibility. This is probably hardest to achieve for co-location data centers because the third-party owner which interfaces with the grid and with utilities is not the one deciding what servers inside its facility are doing. Additionally, data centers are tasked with fluctuating sets of applications, creating uncertainty about how reliable or persistent demand management can be as a means of providing flexibility.

Data centers fully owned by large hyperscalers provide a higher degree of control over the whole facility. But the diversity of services being provided, often with low latency (response times) needs, may create constraints on what the hyperscaler can do. Hyperscale data centers provide both regular services—like AWS' cloud computing—and AI workloads such as inference, which involves answering client queries using pre-processed AI models.

For AI learning data centers, which create these large learning models, the goal is to cram as many chips as possible into the same square mile with the fastest internal connectivity so that the collection can operate as one big parallel machine[19]. Much of the possible flexibility here comes from adjusting the timing of computing batches, yet matching these adjustments to power supply flexibility needs is not a given, especially when considering that data center operators will want to prioritize computation over flexibility. This is a consequence of the relatively larger size of the capital investment in computing hardware versus energy generation and distribution for most applications.

Flexibility is a particularly important quality for data centers because they are such a large component of load growth, and just a little flexibility would reduce the need for new peaking resources and speed up interconnection[20]. A 2025 analysis[21] by the Nicholas Institute for Energy, Environment & Sustainability at Duke University finds that just 0.5 percent to 1 percent flexibility opens significant space on the grid: 98 GW of new load could be integrated at an average annual load curtailment rate of 0.5 percent, and 126 GW at a rate of one percent. This level of flexibility is similar to what is provided by demand-response programs that exist today for other loads, but as far as speeding up interconnection, it may be the AI-driven hyperscalers and learning centers, acting more directly under their owners' control and schedules, that can achieve more.

AI loads are fundamentally more flexible than generic data center loads because they can be processed in batches, easily scheduled, and often internally orchestrated. For example, in a presentation[22] to the Texas grid operator Electric Reliability Council of Texas (ERCOT), the company Emerald AI demonstrated how it could implement flexibility at a data center. The company argued there is enormous potential to control AI data center load, and that "major hyperscalers are amenable to curtailing up to 25 percent for up to 200 hours in return for priority interconnection of 1 GW."

No one knows if any particular data center's operations will remain stable enough to guarantee a given level of flexibility or willingness to curtail over the lifetime of matching local grid upgrades. In some cases, the data center load can be flexible (willing to forgo some batches of work) but not exactly in the way that best serves the local grid. Some amount of local battery energy storage (providing multiple value streams like integrating local on-site variable energy, backup, and power quality services) could also help data centers be more flexible at their grid interface, especially those with less direct control over internal processes.

Data Center Feature 5: Backup needed for disturbances and outages

Most data centers require backup. Demand flexibility and short-duration batteries can either eliminate or lighten the load for traditional backup solutions.

Many data center customers aspire to high availability—as much as 99.999 percent uptime—hence the need for backup power to take over in case of any grid failure. The Uptime Institute, a widely followed source for industry tier certification in data center design, build, and operations,[23] defines four reliability tiers (I through IV) with increasing expectations for performance under challenging conditions, with an eye towards worst-case scenario planning. Many data centers serving enterprise needs require at least a Tier III level of reliability, either because of a direct need, like maintaining accessibility to data under adverse conditions, or as a proxy for operational trustworthiness. For mission-critical operations—major banks, stock exchanges, the military, or hyperscalers serving global customers—a Tier IV level of availability may be required.

Because Tier III and Tier IV facilities require 72 and 96 hours of on-site power capacity, respectively, simple economics dictate that backup is usually in the form of diesel generators with fuel storage on-site. Batteries can also be used to help ride-through disturbances in power supply,[vii] providing faster response times and reducing fuel and maintenance expenses on diesel. However, with today's technology, battery energy storage systems (BESS) that can cover critical needs for three to four days are not

[vii] In current facilities, this ride-through comes via the uninterrupted power system (UPS) usually provided by old-school lead-acid batteries, but modern lithium-ion battery energy systems can provide these services along-side the bulk of backup power needs.

economically feasible, especially without some form of on-site generation to sustain their state of charge.[viii]

However, diesel does not scale well: As data centers get much larger, massive tank farms for the generators' on-site fuel require complex fire protection, spill containment, and environmental risk mitigation. Furthermore, many air districts (e.g., Virginia, California, or Oregon) place strict caps on generator run time and cumulative emissions in a site or region. Placing more than a hundred diesel generators on one site creates a cumulative permitting challenge and may well face serious local resistance along with the prospect of delays or outright rejection from regulators. Somewhat cleaner gas generators (turbines[ix] or reciprocating engines) are usually connected to a pipeline and require large propane or liquefied natural gas storage facilities to satisfy on-site capacity requirements.

Some large hyperscalers are opting to target better up-time based on statistical estimates rather than explicit proxies for reliability. For example, Microsoft has publicly committed to reducing the use of diesel generators by 2030. To that end, it contracted with Saft, a subsidiary of TotalEnergies, to install four battery energy storage systems, each in groups of four megawatt hours (MWh) and capable of 80 minutes of on-site power, to replace diesel backup.[24] In the U.S., Microsoft's newest Azure region in San Jose, California is also being built diesel-free, but is using natural gas turbines for backup (plus batteries for ride-through). In general, the U.S. grid is quite reliable, with the one-in-ten reliability standard[x] mostly achieved at the transmission service level.[xi] Most outages that do occur are less than one or two hours, so a battery can carry enough of the backup burden to get the facility to a high level of reliability while hardly, if ever, using on-site generation.

As longer-duration storage solutions like Form's 100-hour battery[25] or thermal batteries[26] connected to local renewables and steam turbines in local energy parks[27] emerge, data centers will be able to free themselves from fossil fuel backups while taking advantage of integrated design to combine multiple uses of batteries for flexibility, power quality, and backup.

[viii] To see how this is done in detail, see the NREL Vulcan platform demonstration in collaboration with Verrus. Deepthi Vaidhynathan et al., "Vulcan Test Platform: Demonstrating the Data Center as a Flexible Grid Asset" (National Renewable Energy Laboratory, June 2025), https://www.nrel.gov/docs/fy25osti/94844.pdf.

[ix] Although gas turbines face significant supply chain cost and delivery challenges currently. GridLab, *Gas Turbine Cost Report*, https://gridlab.org/gas-turbine-cost-report/.

[x] The one-in-ten reliability standard is a standard that applies for the bulk power system (i.e. transmission level) requiring transmission planners, system operators and reliability planners to aim for nor more than one "event" of involuntary load-shedding in ten years. If one "event" was 24 hours, that is already 99.97 percent up-time.

[xi] Actual recent figures for grid performance are quite good (see table 1.1). North American Electric Reliability Corporation, *2024 State of Reliability*, June 2024, https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2024_Technical_Assessment.pdf.

Data Center Feature 6: Modularity—data centers are built in phases

Data centers expand in discrete phases, from racks to halls to entire campuses, with uncertain demand and rapidly rising power density. This modular growth pattern matches well with the modularity of renewables-plus-batteries deployment, which can be built in parallel to meet incremental load without the risks of lumpy firm power investments.

For utilities and data center developers, timing capital investments can be challenging. Matching these investments with energy supply for their increasingly electric power sub-components compounds the challenge. Building a new data center means committing to constructing a large building and grid capacity without knowing if consumers will come, how quickly they will deploy, or how their consumption will evolve over time. Tenants in a co-location situation, hyperscalers, and AI data centers may not immediately have all the chips available (or face some other bottleneck) so may want to deploy in phases: slowly building up electrical demand over time until reaching full capacity, if all the anticipated demand materializes. With a chip service life of around two to three years, the balance between increased efficiency and increased computing power may mean newer chips could either increase or decrease electricity demand in each physical asset footprint.[xii]

The digital world's infrastructure is itself modular—built from discrete, substitutable units. Data centers are not just abstract systems of bytes and tokens; they are also collections of tangible components: chips, servers, and, above all, racks. The rack is the main unit of reference: a cabinet holding multiple slender servers or "rack units." Racks are grouped into "pods" of 20–30, and an enterprise client might deploy a couple of pods at a time in either a dedicated or co-location facility. Some tenants lease only a handful of racks in a shared space, while hyperscalers may build entire halls of 200–400 racks, with multiple halls forming a single phase of expansion on a large campus[28].

The modular nature of data centers lets developers manage financial risk by building in phases, with the option to add new capacity quickly but in a planned way. Each phase, however, carries high stakes not only in capital cost but also in power demand. A 2024 Uptime Institute report[29], states finds that four- to six-kilowatt (kW) racks remain common, with a trend towards higher consumption today. Meanwhile, AI applications and high- performance computing are pushing the development of liquid-cooled racks with incredible increases in power density. Vertiv, an Ohio-based company that designs, manufactures, and services critical infrastructure for data centers, reported in its 2024 Investor Event Presentation[30] that extreme rack densities already reach 250 kW

[xii] This is certainly a question in flux. Google has reported that over a recent 12-month period, the energy footprint of the Median Gemini Apps text prompt dropped by 33x! At a given facility this can be achieved by increased throughput or reduced energy use, or both. Amin Vahdat and Jeff Dean, "Measuring the Environmental Impact of AI Inference," Google Cloud, August 21, 2025, https://cloud.google.com/blog/products/infrastructure/measuring-the-environmental-impact-of-ai-inference.

per rack today and could exceed one MW within five years. That means a space the size of a bedroom closet could consume more power than a thousand average homes. As a result, a single phase of development for a data center might range from on the low end at 250 kW (two-dozen at 10–12 kW per rack) on the low end to 250 MW at the high end (a 1,000 liquid-cooled 250 kW racks) at the high end, with extra overhead for cooling.

The extreme end of data center development is exemplified by data center developer Vantage's recently announced plans [31] to build its $25 billion Frontier campus situated on 1,200 acres in Shackleford County, Texas, with an eventual total consumption of 1.4 GWs—close to average total consumptions of the states of either Rhode Island or Delaware. And this project is not alone: a September 2025 ERCOT staff report [32] to ERCOT's board details 130 GW of non-crypto data center load in the interconnection queue through 2030.[33] In the last few years, Texas has met new additional load with new, mostly clean generation. Of the 428 GWs of generation requests as of August 31, 2025, 204 GWs are for wind and solar and 180 GWs are for energy storage (together 90 percent of all requests).

Data center development may come in all levels of power consumption. However, because developers rarely build, install, and commission data centers in a single phase, projects of all sizes need a power supply that can grow and expand with them. When covering the incremental energy demand from a new data center, a large new single firm resource is an unwieldy indivisible capital investment. A modular approach with renewables plus batteries reduces risk and provides better economics: You're not committing to a single lump-sum investment in a 500 MW gas turbine; you can phase investments, optimize based on real usage, and spread spending—and risk—over time.

With computing loads that grow unevenly, modular investments let operators respond dynamically—deploy more solar, wind, or storage as AI racks come online. As a bonus, you can avoid supply chain bottlenecks because incremental installation bypasses the big lead times and equipment backlogs associated with large generator orders, enabling continuous expansion without project delays. Just as data centers grow in discrete steps, modular renewables and batteries let the grid grow in parallel.

These six features highlight why data center demand is complex, not just a flat, 24/7 block of constant load. We now turn to how supply options can, and cannot, match this demand.

THE BEST WAY TO MEET DATA CENTER DEMAND IS DIVERSE RESOURCE PORTFOLIOS

When thinking about how to supply new demand from the rapidly growing data center industry, the key point to remember is **one-to-one matching with “firm” resources will not “solve” the load growth needs from data** centers.

In this section, we explain why single, stand-alone generation resource matching for any given industrial load has rarely been the historical course, and how and why that might change. We then describe the three resource buckets that new data center projects need to acquire to use the existing bulk power system. Finally, we discuss how the data center demand features described in the preceding section create further challenges and barriers in acquiring these resources.

Debunking the one-to-one matching myth

If you imagine data centers as large capital assets running power through expensive electronics 24/7, it seems natural to imagine a dedicated “captive” 24/7 power plant built to match this demand, with historical precedent for this one-to-one matching. For example, in the post-war era aluminum producer Alcoa built smelters near cheap grid sources of hydropower in New York and the Pacific Northwest along with captive coal plants in Indiana and Texas to feed the company’s aluminum smelters and mills. Today, industrial facilities use on-site combined-heat-and-power (CHP) plants to consume both the electricity and waste heat from fuel-driven power plants to operate industrial facilities with high end-use efficiency, and thus lower energy costs. According to the U.S. Energy Information Administration’s (EIA) latest Manufacturing Energy Consumption Survey from 2022, U.S. manufacturers produce around 17 percent of their electricity needs on-site (Table 11.1) and that on-site generation is 97 percent co-generation (Table 11.3).[xiii]

Single plants may not “play nice” with data centers

The demand characteristics of data centers described in the prior section raise immediate concerns regarding matching a captive plant with a data center. For example, while a data center may want 24/7 availability, its actual consumption will ramp up and down significantly with a profile that a large, single on-site generator might struggle to meet. Many fossil generators have a minimum dispatch level they cannot fall below, and “ramp rates” limits dictate how quickly they can adjust up and down. Furthermore, a modular, phased build-out does not lend itself to a single matching resource because in order to provide sufficient power for the full buildout,

[xiii] This survey defines co-generation as “the production of electrical energy and another form of useful energy, such as heat or steam, through the sequential use of energy. Cogeneration includes electricity generated from fossil fuels, such as natural gas, fuel oils, and coal; wood; and other biomass.” In practice, the steam/heat is the main other energy output, so co-generation is often used as synonymous with CHP.

the single resource would have to operate at lower, inefficient, dispatch levels during earlier phases of data center construction and operation.

Beyond a mismatch with the demand characteristics of data centers described in the prior section, there are additional reasons to question using a captive plant as a 1-1 match for a data center.

Captive power plants are not highly reliable alone

Table 4 from the North American Electric Reliability Corporation (NERC) 2024 State of Reliability Overview [34], shows the recent weighted forced outage rate (rate of unexpected failure) was 11.7 percent for coal, 7.7 percent for gas, 6.4 percent for hydro, and 2 percent for nuclear. Another relevant consideration is planned maintenance, like cleaning out coal boilers, maintaining and inspecting gas turbines, or refueling nuclear plants every 18-24 months.[xiv] This means a single supposedly "firm" plant will be unavailable for a double-digit percentage of time—not what data centers are looking for.

If an industry is set on self-supply, one strategy is to over-supply generation. Alcoa's Warrick, Indiana aluminum smelter and mill built three captive 144 MW coal plants alongside a 300 MW coal unit shared 50/50 with the local utility Vectren. With a total capacity of 732 MW but serving a local load of 550 MW,[35] the facility was clearly resilient to losing one unit and still running. But this effectively meant carrying 25 percent more capacity than necessary, without a guarantee of full reliability. Alcoa mitigated this extra cost by selling excess power to the grid and importing power from Unit 4 or the broader grid when necessary. This illustrates the general case that a grid connection remains both a sink for surplus and an important backup option; most on-site power is not fully independent and large loads will still want interconnection to the bulk power system. In fact, payment for grid backup (usually called "standby rates") is a common feature of CHP tariffs.[36].

What happens when the power plant is no longer needed?

An interesting postscript to the Alcoa Warrick plant story is that Alcoa announced it would shut down its aluminum smelter in 2016 (although it had partial restarts post 2018) because of poor market conditions [37] and transferred major rolling mill and finishing operations to Kaiser Aluminum in 2021.[38] It is now left with an unattractive coal generation asset, whose generation capacity now exceeds Alcoa's local demand and

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[xiv] This is on average a 32-day process. Aaron Larson, "Planning Is Key to Successful Nuclear Refueling Outages," POWER Magazine, September 1, 2023, https://www.powermag.com/planning-is-key-to-successful-nuclear-refueling-outages/.

will likely struggle to sell surplus capacity in the broader power market along with most coal assets,[39] which comes with significant environmental remediation liabilities.[xv]

This is always the risk with a captive power plant: One day the load will vanish because of changing economics. Investors will want to know if Plan B exists and that the captive plant is in and of itself an attractive asset with a bright future.

Co-location of prime power generation assets with data centers today

Grid bottlenecks create considerable talk about co-locating "prime power" generation[xvi] with new data centers. This might include leveraging existing nearby assets (for example, the Talen-Susquehanna deal which co-locates a data center next to a nuclear plant[40]), restarting mothballed generators, or building new on-site resources (such as gas plants). But these arrangements are not true one-to-one matches of generation with load, since they still depend heavily on a grid connection for full functionality, sometimes at the expense of other consumers.

For example, in the Talen-Susquehanna deal, the data center is physically adjacent to a pair of nuclear units. It is unlikely the units' output will ramp precisely in step with data center consumption. Therefore, matching local supply with demand creates net output—nuclear output minus on-site data center consumption—variability which must be managed by the grid operator. During the refueling of one nuclear unit, the other must pick up the data center load, thereby reducing exports to the grid. In effect, the grid acts as backup.

Hybrid arrangements using on-site power together with the grid can address bottlenecks. They combine physical and financial hedges. The Talen-Susquehanna deal, for instance, was eventually reshaped into a power purchase agreement after regulatory push-back.[41]. These hybrid deals share many of the properties—and many of the drawbacks—of other on-site generation deals discussed above.

If land is available, the best way to provide on-site prime power is not with a single firm resource but by using an energy park[42] with renewables and batteries, with backup from longer- duration storage and/or gas generators.[43] Then most of the generation is

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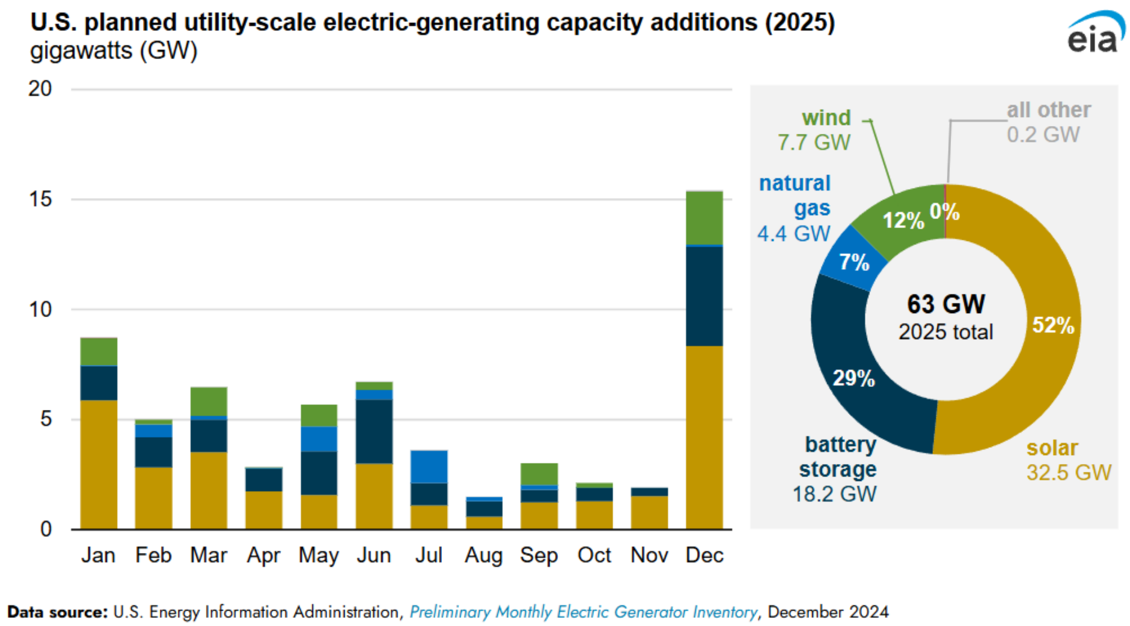
In 2024, Sierra Club and Environmental Integrity Project intervened in a case against Alcoa Warrick for "100+ permit violations" in 2022 and 2023, including releases of mercury, aluminum, chlorine, copper, fluoride, nickel, and zinc into the Ohio River. Environmental Integrity Project, "Groups Intervene in State Action to Stop Aluminum Smelting Plant's Illegal Dumping of Heavy Metals in Ohio River," February 21, 2024, https://environmentalintegrity.org/news/groups-intervene-in-state-action-to-stop-aluminum-smelting-plants-illegal-dumping-of-heavy-metals-in-ohio-river. There are also lingering questions regarding compliance for Warrick's "ash ponds" under the Environmental Protection Agency's Coal Combustion Residuals rules. Hoosier Environmental Council, "Today's EPA Action Means More Coal Ash Cleanup for Indiana" (press release), April 25, 2024, https://www.hecweb.org/wp-content/uploads/2024/04/PRESS-RELEASE-Todays-EPA-Action-Means-More-Coal-Ash-Cleanup-for-Indiana.pdf.

[xvi] Prime power is the continuous everyday power that powers the data center, as opposed to backup power There is also "bridge power" which is local generation which acts as prime power until a grid connection is put in place, and then becomes either backup or just a part of the supply portfolio.

clean, faster, and cheaper to deploy than other generation and helpful for hyperscaler emissions commitments. In addition, the combined resource is more reliable, with fewer large points of failure than a handful of fossil units – a good Plan B if load never fully materializes or decreases. Included energy park resources would reflect a microcosm of trends in the wider U.S. market where the large majority of generation coming online[44] and waiting in interconnection queues are renewables and batteries.[45]

Figure 6 Solar, battery storage to lead new U.S. generating capacity additions in 2025. US EIA.



Providing new electricity supply for data centers from the bulk power grid

Given that most data centers will need to get some, if not all, of their power from the bulk power system, it is helpful to review how large commercial or industrial loads do this. The power grid is a system of systems including physical transmission and distribution poles and wires, the generation and loads they connect, operations and dispatch, power markets, and power purchase agreements.

As soon as a large new load decides to connect to the bulk power system, its needs can be disaggregated and met in many ways.

The grid resources a new data center project must collect to successfully draw from the bulk power system fall into three broad buckets: connection, grid services, and bulk electricity.

New large data centers will require connection and network upgrades

How data centers connect to the grid depends on their size: scale matters. Smaller enterprise and co-location data centers (tens of MW or less) will often connect to a distribution system's high-end network (i.e., somewhere between 13.8 and 69 kilovolts) and may tie into an existing distribution substation with a new feeder. The utility typically owns and operates the primary substation equipment, while the data center customer owns the step-down transformer to its facility. The local utility conducts the impact studies and plans local upgrades to ensure compliance with NERC standards. Too many connections in the same area may trigger transmission upgrades and inclusion in transmission planning studies. In some geographies, like Virginia, this may involve an independent system operator (ISO) such as PJM [xvii] in planning and approving upgrades.

Larger data center campuses will have their own complex internal grid that connects directly to a bulk power system transmission substation. The data center must file a large load interconnection request with the local transmission owner or ISO. Tariffs and agreements will include matters like covering study costs, equipment ownership, and who pays for upgrades. The state may also require approvals for siting, environmental review, and cost recovery. The connection process can become long and painstaking once local capacity on the grid becomes tight. In Virginia's Dominion utility territory, data centers larger than 100 MW face up to a seven- year wait for power hookups.[46]

One important feature of new connection costs is that they are usually covered by the new load because cost causality is clear. Unfortunately, this may not hold true for more upstream transmission impacts where transmission upgrade costs are traditionally socialized more widely. A recent Natural Resources Defense Council (NRDC) report[47] tells the story in PJM: "Tight supply conditions led PJM to approve a $5 billion transmission expansion project to meet new data center demand in Virginia, where data centers already account for around a quarter of the state's electricity demand. The costs for this project were distributed by the Federal Energy Regulatory Commission (FERC), PJM, and utilities using varying cost allocation methods. Maryland residential customers were left with a bill of approximately $330 million, and Virginia residents had to foot $1.25 billion for transmission designed largely for a handful of data center customers in only a small region of the state."

Data centers create new stresses on a bulk power system planned around peak demand; they also consume other grid services

The main grid service data centers require regardless of size is peak capacity: the ability to serve up to their maximum interconnection rating during periods of system peak.

[xvii] Also referred to as a regional transmission operator, PJM covers 13 states in the mid-Atlantic and is one of the largest power markets in the world.

Going back to PJM (often a source of current examples because it already serves so many data centers), the ISO's board chair communicated about future reliability concerns because: "PJM's 2025 long-term load forecast shows a peak load growth of 32 GW from 2024 to 2030. Of this, approximately 30 GW is projected to be from data centers."[48]

PJM's conundrum is how to keep the grid reliable as data center demand grows faster than new generation. Its "non-capacity-backed load" proposal would classify very large new loads (less than 50 MW) as customers outside the capacity market.[49]. The idea is to avoid shifting costs to others, but critics say that the 50 MW cutoff is arbitrary, curtailment rules could distort market signals, and contract and siting decisions may be disrupted.[50]. PJM is still debating whether the non-capacity-backed load should be voluntary or mandatory in shortage zones before filing at FERC for the 2028/29 delivery year.[51]

One challenge with resources like peak capacity is that once a project has been approved for interconnection, been built, and paid its share of costs, it becomes a load like any other. At that point, it is very difficult for the market to discriminate against it without creating efficiency concerns or legal risks. Data centers do more than strain peak supply; like all large loads with some variation, they also draw on ancillary services and other grid management resources.

If incremental demand is not met with increased supply, prices and emissions will rise

As the recent Nicholas Institute report[52] points out, some amount of flexibility from data centers could significantly reduce costs and delays associated with connection and peak demand constraints from new data centers. The report estimates peak load bottlenecks could be avoided for around 100 GW of so-called "curtailment-enabled headroom" on the U.S. grid. However, even if data centers avoid consumption during the most problematic hours, they still need power the rest of the time. Absent new supply on those same grids, the extra generation available off-peak will be from more expensive, and typically dirtier, marginal generation units.

Data centers' need to draw most of their power from existing units is thus a problem for other electricity customers because absent new matching supply, it will drive up their wholesale electricity costs. It is also problematic for the data centers themselves, which frequently are tied to corporations that have carbon reduction goals which are incompatible with increased emissions from existing fossil power plants. Conversely, new supply (especially cheap and clean supply) arriving quickly enough to offset data center consumption without requiring a large amount of new grid infrastructure creates potential for "beneficial electrification[53]" where more power over the same wires reduces other consumers' costs[54].

Further consequences: Challenges and barriers specific to data centers

Connecting large new data center loads through the lens of three resource buckets faces three broad challenges required by all such loads. But these resource buckets also interact with the six more specific data center demand characteristics outlined in the preceding section.

Connection challenges specific to data centers

Because the source of many connection issues—or at least more expensive upgrades—come down to a limited set of hours and circumstances, flexibility is often cited as a master key for easing or speeding up connection. But flexibility is not always as simple to implement as first imagined, and other connection challenges specific to data centers are not necessarily circumvented with a touch of flexibility.

- **Agency:** Especially for co-location data centers, the operator is stuck between wanting to be more flexible to satisfy grid constraints and the imperative to be as generic as possible in contracts with tenants to accommodate as broad a class of customers as possible. Typical quality of service and service-level agreements also act as a barrier for to tapping flexibility.[55] Intervenors in public utility cases also question whether policies for ensuring new data centers cover all their incremental costs are effective[56].
- **Clustering:** Clustering leads to many data centers on the same part of the grid, necessitating more upstream transmission upgrades, as in the Virginia case mentioned cited by NRDC, mentioned above.
- **Consumption profile:** Big swings in power demand and power quality impacts on other consumers make data centers trickier for utilities and transmission providers to study and interconnect than simple 24/7 constant loads. Standard protection schemes and the collective behavior of 60 data centers recently caused a large reliability problem in Virginia in July 2024 when these data centers all dropped off the grid at once and caused a sudden surge in excess electricity that strained grid resources.[57]
- **Flexibility:** Some data centers are not flexible at all; others could be flexible but not in a manner consistent or predictable enough to satisfy the engineers running interconnection studies. These engineers are only likely to be satisfied after adding sophisticated energy management systems and large batteries, along with the promise of judicious backup power.
- **Backup:** As mentioned, backup power could be leveraged to facilitate connection or provide so-called "bridge power"[58] for data centers that cannot wait for interconnection. Unfortunately, backup power (used either for

flexibility or bridge power) tends to be dirty, leading to siting and local community environmental concerns.[59][60]

- **Modularity:** With a modular or phased build-out, a data center may ask up front for a large enough connection to accommodate all future phases, leading to stranded asset risk if all phases do not materialize.

Grid services challenges specific to data centers

Just as for solving connection issues, flexibility can help tamper the impact of new data centers on system-wide needs like peak capacity issues. A large overlap exists between local grid and larger grid issues with peak planning. However, as described in the prior section, flexibility is not always easy to implement or deploy in a manner which solves all challenges. Furthermore, the specific features of data centers tend to create additional challenges beyond help from simple load flexibility measures.

- **Agency:** Utilities often see new fossil resources like gas peakers as the easiest way to resolve new peak demand issues from data centers.[61] Because gas turbines are increasingly expensive, this may not be a good deal for other utility customers and may also entrench future emissions, working against many data center providers' and host states' clean power goals. Because eventual data center owner/operators tend to build where developers have prepared the ground, the fact that these developers may perceive emissions goals as secondary to "speed-to-power," and that utilities choose their own procurement path creates an agency mismatch.
- **Clustering:** The clustering of data centers tends to amplify their effects on the regional grid, with sharper surges in demand for grid services that cannot be accommodated fast enough through new resources builds.
- **Consumption profile:** While data centers don't run all the time, they plan their infrastructure for peak computing demand. This creates a knock-on effect for the bulk power system, which plans for peak power demand.
- **Flexibility:** Flexibility is not always a simple feature to implement or deploy.
- **Backup:** On-site backup power is a poor substitute for system resources because of expense as well as siting and local environmental concerns.
- **Modularity:** While the broader grid is in a good position to adjust to a phased build out of data center demand, this requires either coordination with the local utility or strong forward signals in the market to avoid disruptive demand shocks for grid services.

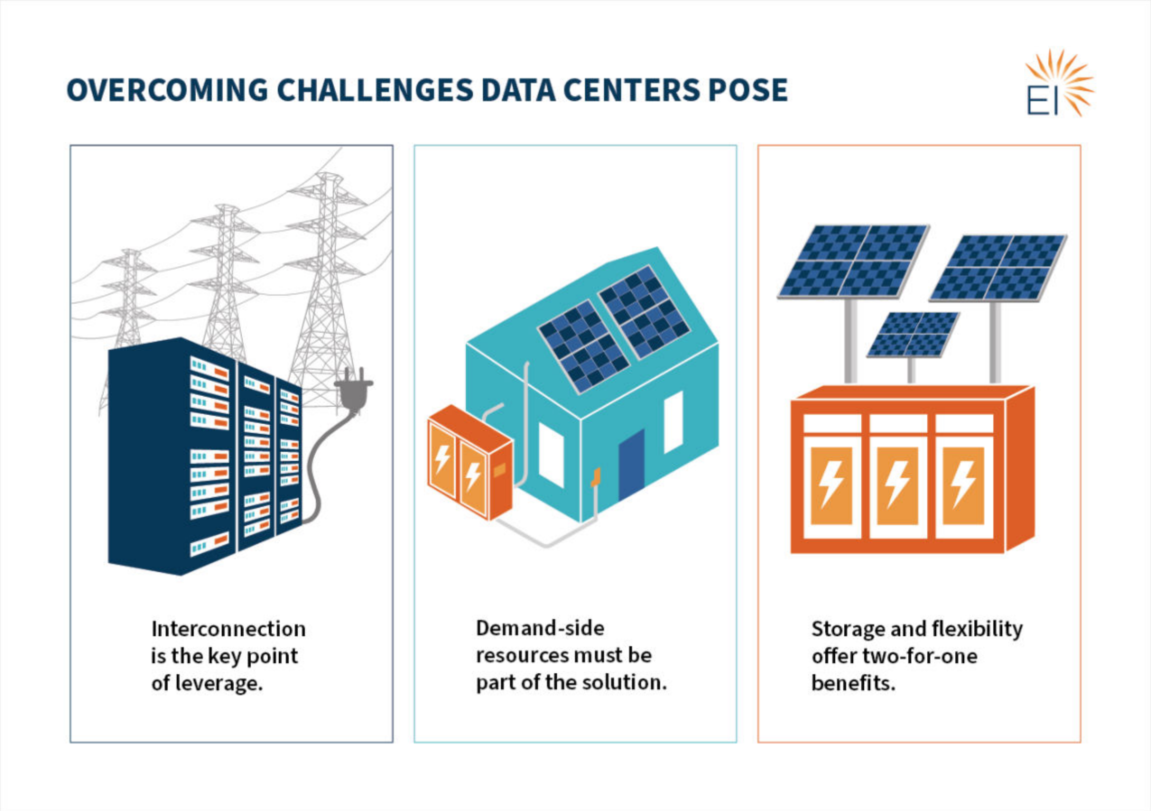
Bulk electricity challenges specific to data centers

Certain subcategories here (consumption profile, flexibility, modularity) concern time domains that do not apply when considering total annual consumption.

- **Agency:** As with grid connection and services, intermediate entities between electricity provisioners and data center owner/operators with emissions goals may not consider the environmental impacts of reliance on using spare capacity from existing marginal resources.
- **Clustering:** Clustering means more annual electricity drawn from the same grid. This creates a greater need for new supply, amplifying the problems of price and emissions increases.
- **Consumption profile:** A variable but not necessarily predictable profile for large data center loads could create new challenges for grid operators, even at off-peak times.
- **Flexibility:** Data center demand flexibility could potentially alleviate emission concerns by targeting off-peak consumption more towards time periods with lower marginal emissions. This requires an extra layer of control on top of whatever that data center might have already committed to ease grid connection and mitigate impacts on grid operational resources.
- **Backup:** Supplying too much of the actual annual electricity use from backup power creates problematic environmental impacts.

TAKEAWAYS FOR POLICYMAKERS AND OTHER STAKEHOLDERS

Figure 7 Three key takeaways



Many organizations (Clean Air Task Force/Brattle,[62] GridLab,[63] NRDC,[64] the Bipartisan Policy Center,[65] and the Regulatory Assistance Project[66]) have provided detailed and useful guides for coping with the challenges of meeting new data center loads.

This section distills the key lessons from the features and challenges discussed above.

Interconnection is the key point of leverage to influence when and how data centers join the grid

Accommodating large, dense new loads affects every grid participant, and the challenges show up at multiple scales. Geographically, they range from the substation where the data center connects to the entire interconnected system. In time, they span from sub-second transients to hours of local and bulk stress to the accumulation of annual demand.

When issues are tied directly to a data center's load or its immediate connection, cost-causation principles are easier to apply. But at larger scales, like meeting new annual demand or rising peaks across a region, the problem is less about the nature of data centers than the pace and size of their growth. At that point, they can reasonably argue for being treated like any other customer buying power "at the pump," without special obligations.

This tension is what policymakers need to keep in mind. Interconnection is the moment of maximum leverage: not to extract unreasonable concessions, but to ensure new entrants cover the infrastructure costs they trigger, and to nudge them toward implementing solutions like flexible demand or local storage that relieve local bottlenecks and support the broader grid. Likewise, developers and customers should lean toward local fixes that speed access to the grid, improve power quality, and ease broader impacts—reducing the likelihood of being saddled with extraordinary requirements later.

Using other demand-side resources

In one of our earlier reports on meeting the load growth challenge,[67] we pointed out the importance of using demand-side resources to meet this challenge most efficiently. Often the discussion of demand-side solutions focuses on direct measures at a data center, especially in the wake of the efficiencies revealed in the DeepSeek announcement.[68] However, data centers can meet their resource needs with other demand-side resources elsewhere on the grid. Recently, Voltus, an aggregator of distributed energy resources (DERs), announced a deal with Cloverleaf Infrastructure—a data center developer—to meet new capacity needs from data centers with market-accredited capacity from DERs.[69] This kind of transaction compensates other existing customers and thus helps accommodate the rapid rise of data center loads fairly, speedily, and equitably. Since connecting to the grid can involve mixing and matching resources to relieve bottlenecks, once a data center has invested in the flexibility and extra equipment needed to resolve local connection issues, there is no reason why more upstream connection issues, grid services bottlenecks, and the need for a large amount of annual electricity delivery cannot be resolved with demand-side solutions from other grid users.

A recent Rewiring America report proposes many of the resources to meet data center load growth could come from sponsoring household upgrades.[70] The report finds that if hyperscalers paid 50 percent of the up-front cost of installing heat pumps in the tens of millions of U.S. households that currently use inefficient electric heating, cooling, and water heating, they could free up a total 30 GW of capacity on the grid. In addition, if hyperscalers paid 30 percent of the up-front cost of rooftop solar and storage in every single-family household in the U.S., they could add 109 GW of capacity on the grid. The cost of these upgrades would be comparable to the report's estimate of $315/kW-year to build and operate a new gas power plant.

Storage and flexibility relieve data center challenges; they can also ease interconnection of new variable renewables

On-site prime generation solutions built around renewables and flexibility (modulating demand and using batteries) may provide cheaper, cleaner, and faster means for meeting new and existing data center demand. Because batteries are increasingly essential for buffering, backup, and power quality, they also provide a built-in solution for integrating variable renewables—offering a two-for-one advantage.

Furthermore, these renewable-plus-battery solutions can take advantage of existing surplus interconnection[71] to more quickly connect data centers to the grid in "power couples."[72]

By exploring the nuanced solutions, policymakers can avoid overcommitting to outdated firm resources and instead adopt strategies that embrace modularity, flexibility, and clean energy. Doing so will support both the digital economy's explosive growth and the clean energy transition.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

EXHIBIT 58

NARUC COAL REPORT

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

National Association of Regulatory Utility Commissioners | January 2020

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NARUC
National Association of Regulatory Utility Commissioners

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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.

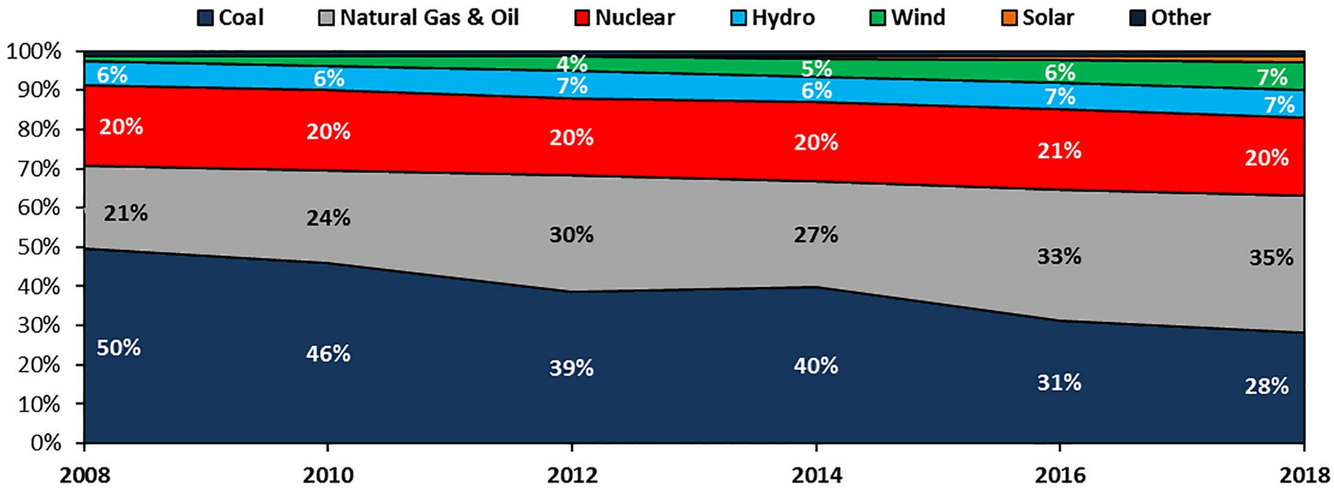
These conditions have resulted in new challenges for commissions. As economic regulators, they are charged with overseeing the reliable, safe, and affordable operation of the electricity generation and delivery system. The asset life for electric generation can span decades, making today's decisions 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

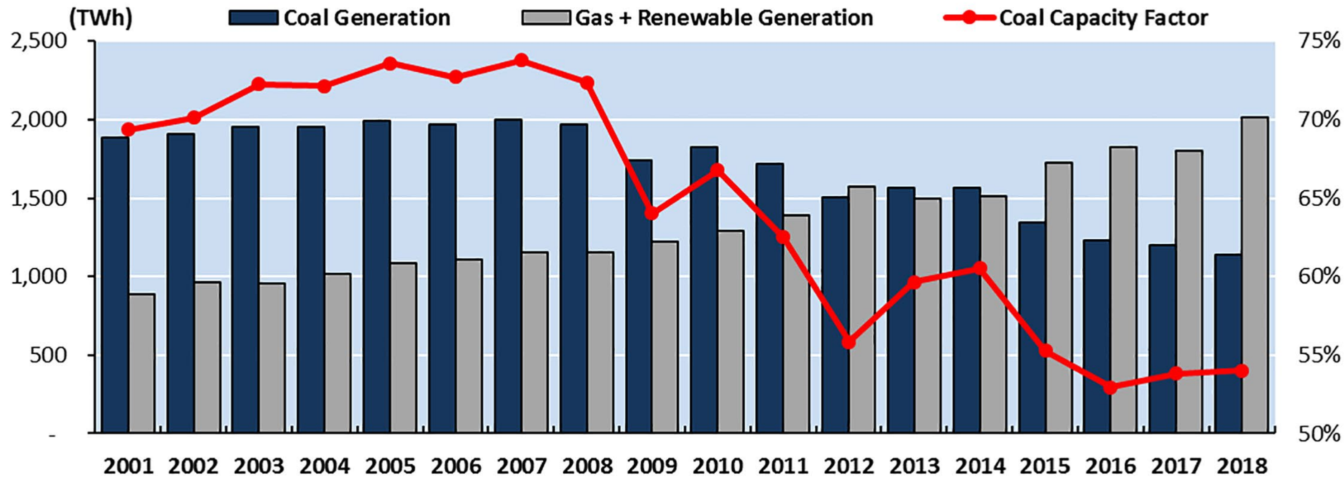
1 Generation throughout this report refers to the amount of electricity generated in a certain period measured MWh. Capacity refers to the maximum generation output a unit can generate in one hour, measured in MW.

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.

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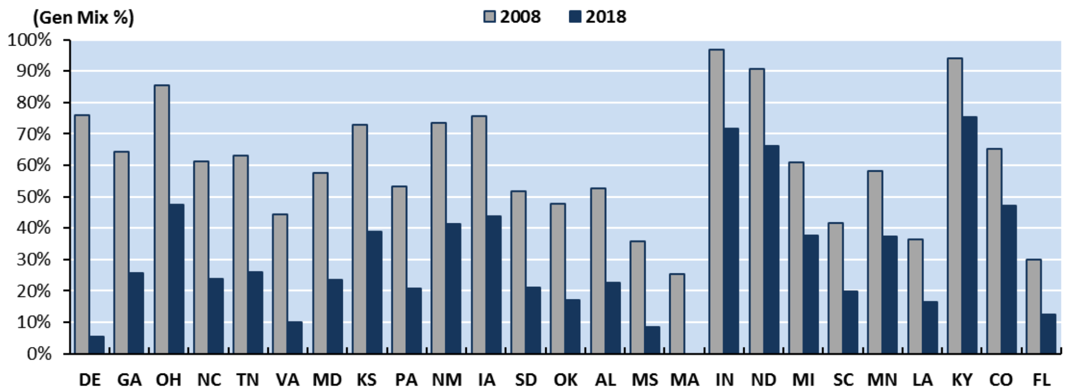
4 Capacity factor measures the utilization of a generating unit over time. For example, an electric generating unit with a generating capacity of 100 MW is capable of generating 100 MW per hour, or 876,000 MWh per year. If the same unit only generated 438,000 MWh during the year, it only generated 50%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

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

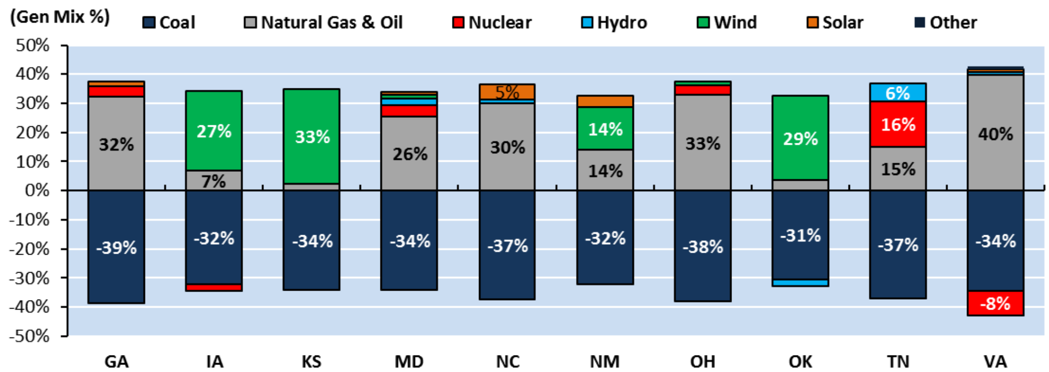
EXHIBIT 3: TOP 25 DECLINES IN COAL GENERATION SHARE BY STATE – 2008 VS. 2018[6]



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

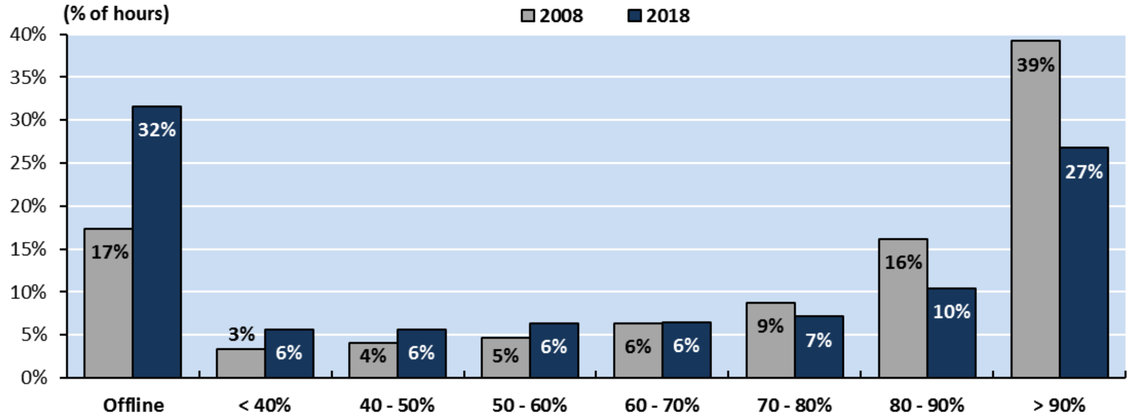
These dramatic changes in the generation mix have significant impacts on the operation of the remaining coal-fired generating fleet. To highlight these differences, this report presents an in-depth analysis of hourly gross generation data from EPA's Continuous Emission Monitoring System (EPA CEMS) for 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.

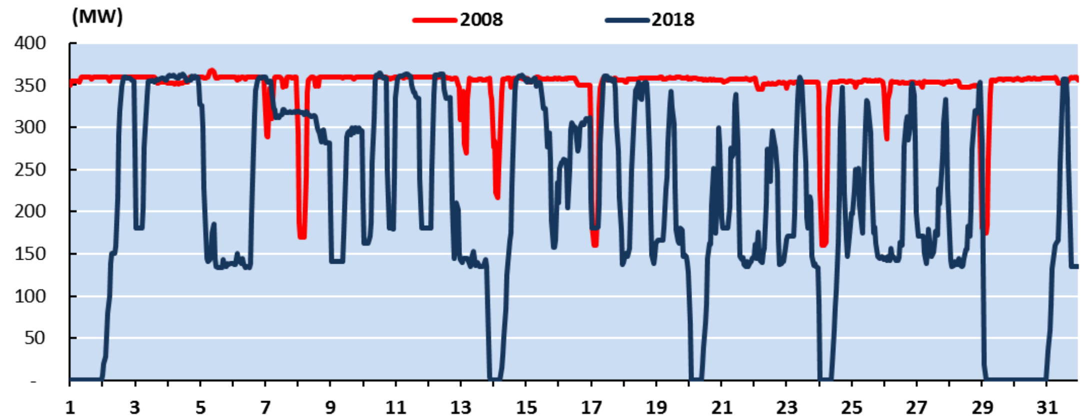
EXHIBIT 5: DISTRIBUTION OF HOURLY CAPACITY FACTOR FOR U.S. COAL-FIRED EGUS – 2008 VS. 2018[8]



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

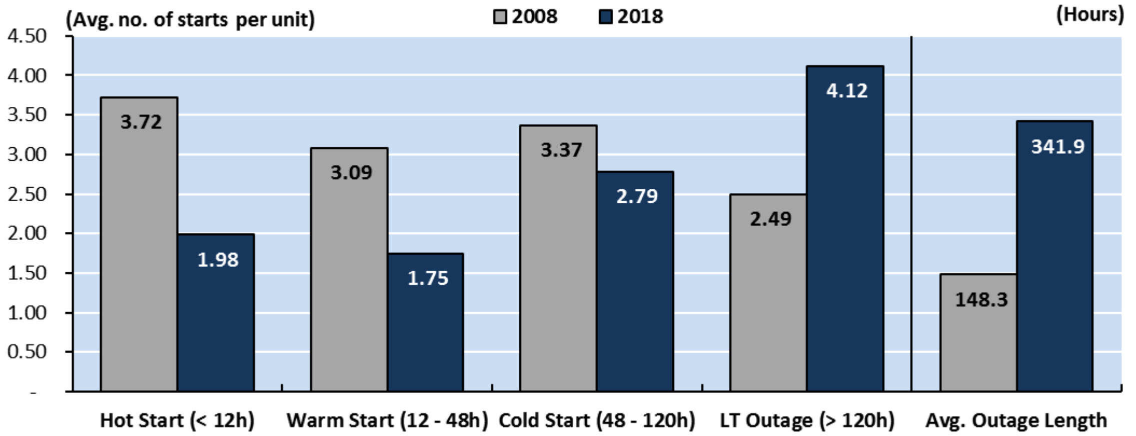
9 Source: EPA CEMS Hourly Data

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.

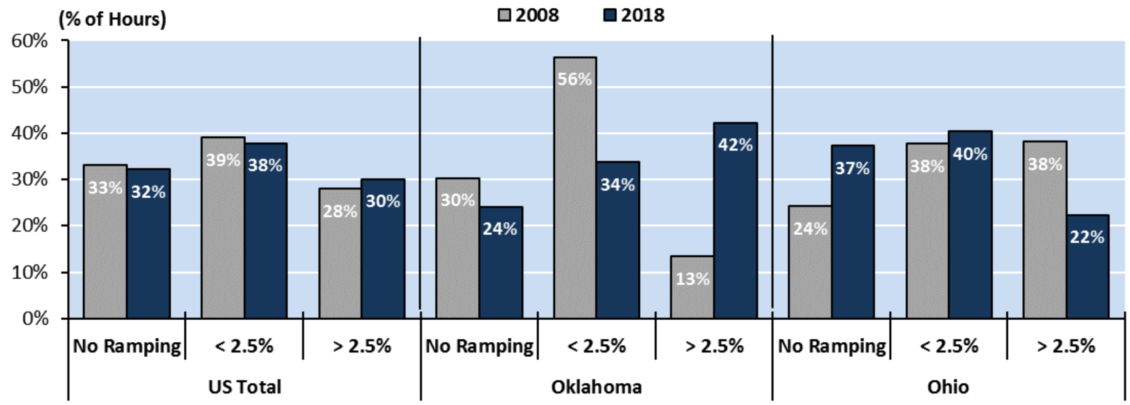
EXHIBIT 8: CAPABILITY OF DIFFERENT POWER GENERATING TECHNOLOGIES TO PROVIDE FLEXIBILITY[12]

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.*

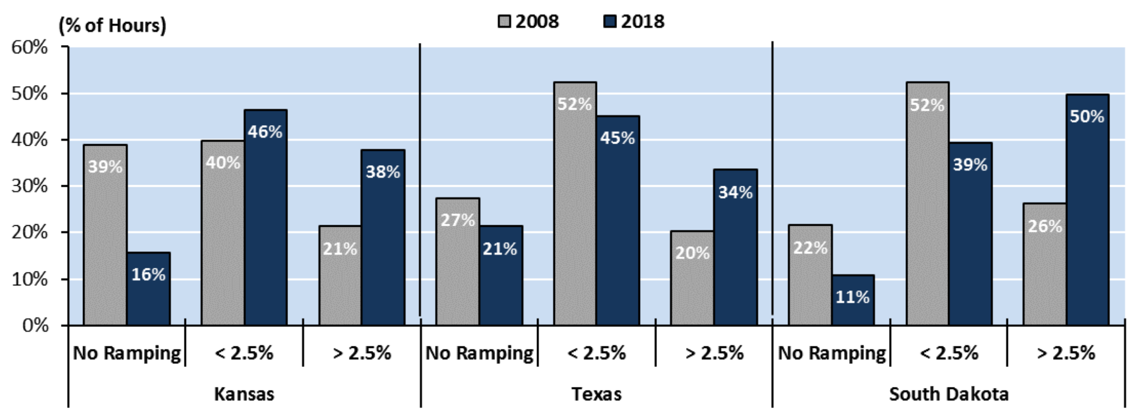
13 Source: EVA Analysis of EPA CEMS Data

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]

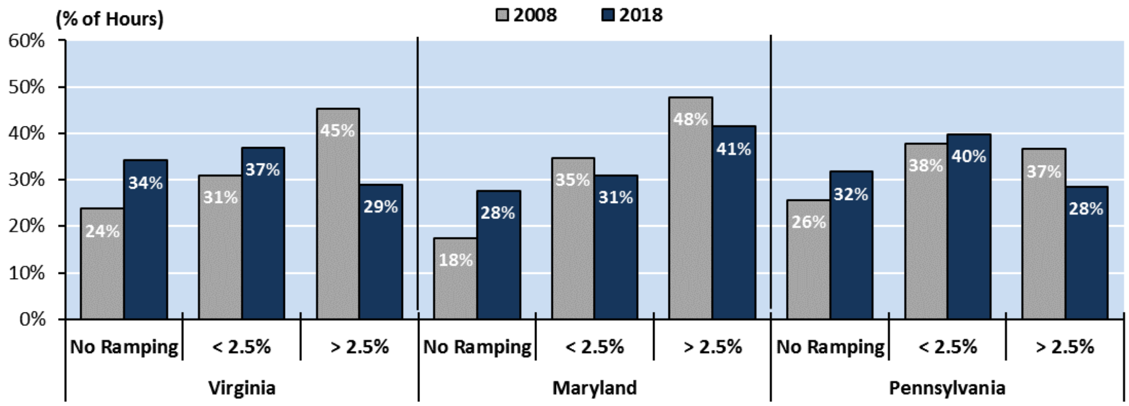


On the other hand, coal units in states where coal has been displaced mainly by new natural gas simple cycle and combined cycle power plants have been subject to less ramping at higher percentages. In Ohio, coal's generation share fell by 38 percentage points between 2008 and 2018, while natural gas's 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

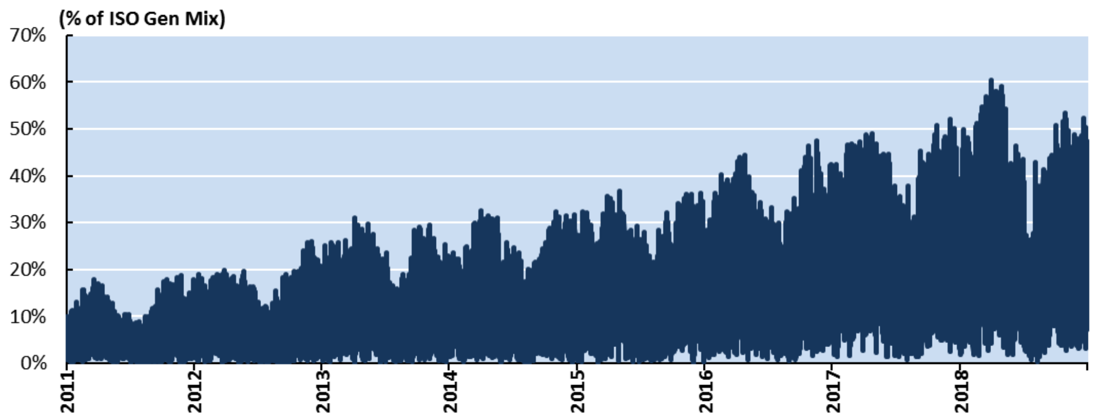
Again, states where electric generation shifted predominantly from coal to natural gas have seen similar developments, as shown in **Exhibit 11.** For example, in Virginia, another state where coal has been displaced mainly by natural gas, the share of ramp rates for coal units greater than 2.5% has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

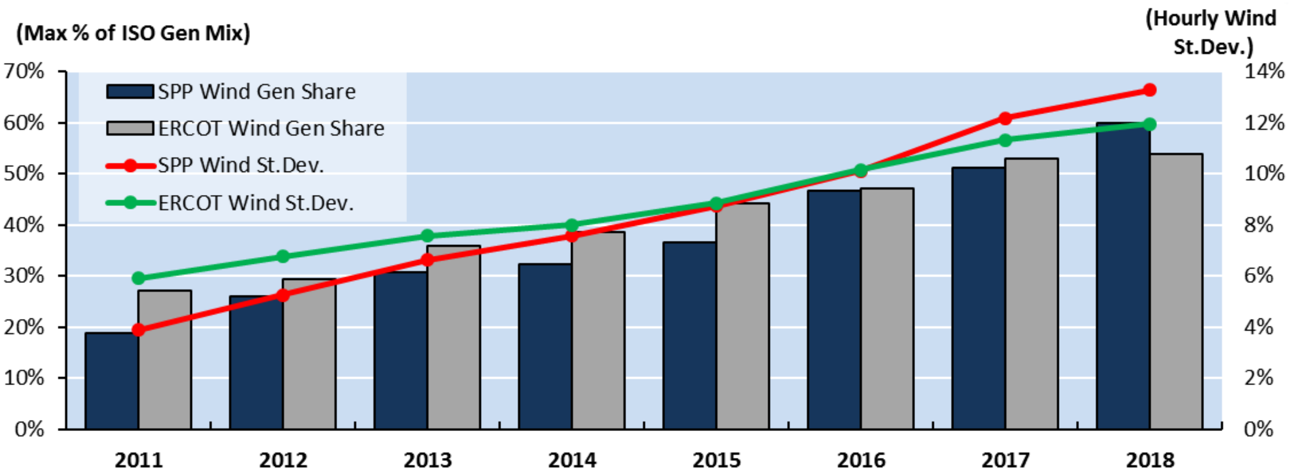


15 Source: EVA Analysis of EPA CEMS Data

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]

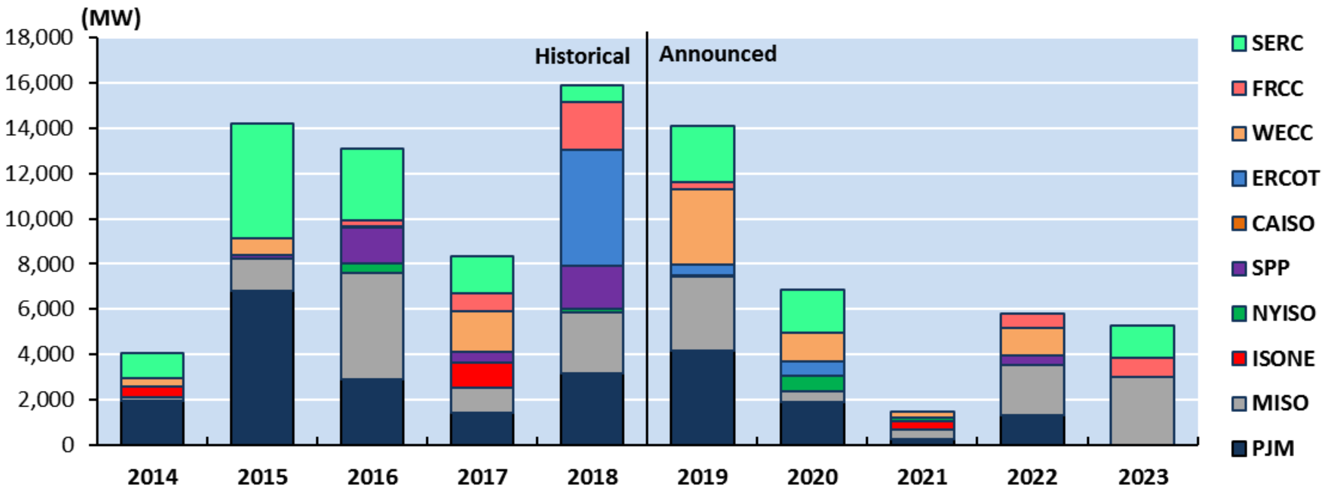


Despite the increased importance of flexible and dispatchable generation to balance the variability of a growing renewable fleet, more and more coal plants are being retired in power markets with an ever-increasing share of renewable generation. **Exhibit 14** shows historical and announced coal retirements 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

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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.

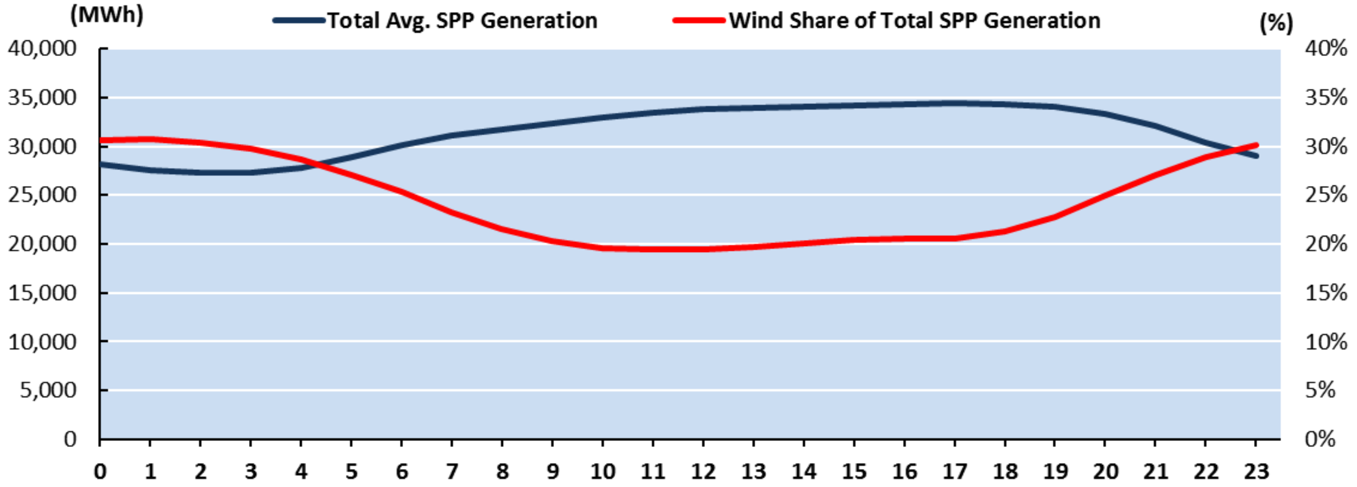
Other areas to minimize coal plant cycling costs, outside the control of coal plant owners, include increased deployment of energy storage and demand-side management resources to shift some of the renewable generation from wind and solar to peak demand hours or reduce the demand fluctuations over the 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.

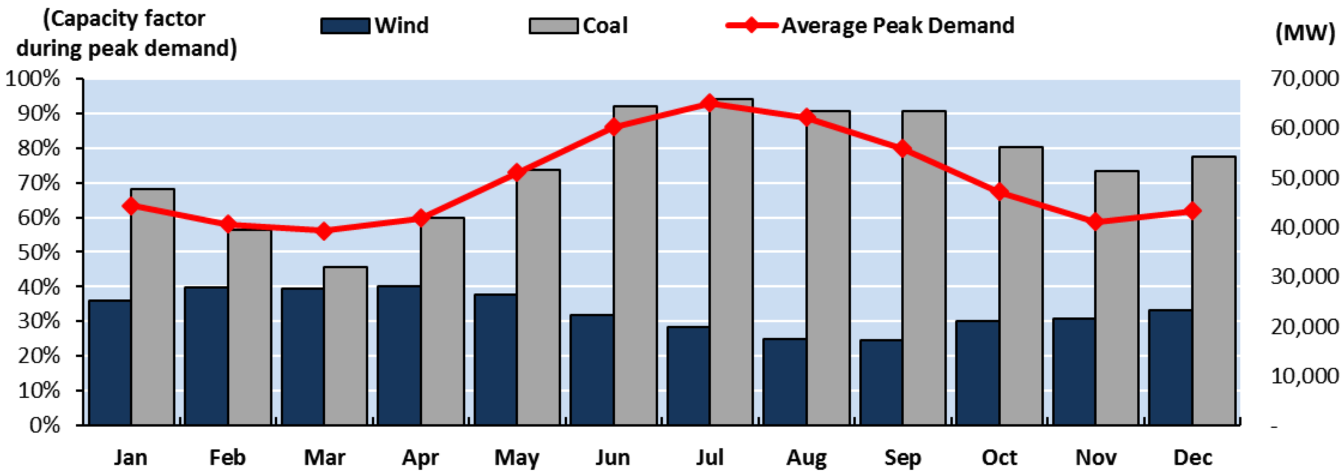
EXHIBIT 16: 2018 AVERAGE HOURLY SPP GENERATION VS. WIND GENERATION SHARE[21]



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."

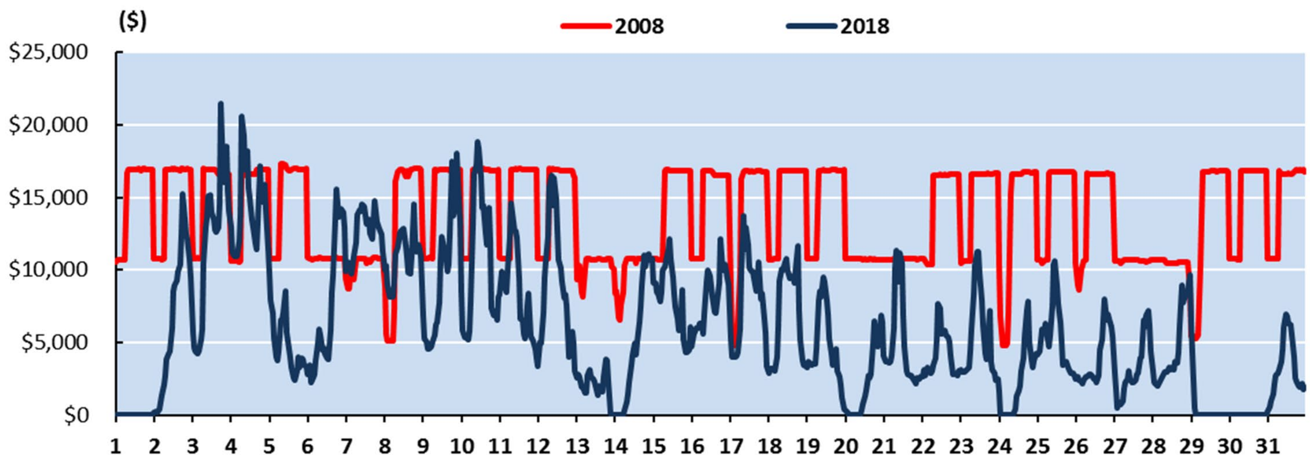
As a result, coal plants frequently find themselves in a vicious cycle. Due to the low revenue expectation during on-peak hours and to minimize losses during off-peak hours, coal plants more often shut down operations for longer periods and only return to service when more extended periods of profitability 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.

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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1889

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

EXHIBIT 59

IEA FLEXIBILITY REPORT

Increasing the flexibility of coal-fired power plants

Colin Henderson

September 2014

Increasing the flexibility of coal-fired power plants

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Preface

This report has been produced by IEA Clean Coal Centre and is based on a survey and analysis of published literature, and on information gathered in discussions with interested organisations and individuals. Their assistance is gratefully acknowledged. It should be understood that the views expressed in this report are our own, and are not necessarily shared by those who supplied the information, nor by our member countries.

IEA Clean Coal Centre is an organisation set up under the auspices of the International Energy Agency (IEA) which was itself founded in 1974 by member countries of the Organisation for Economic Co-operation and Development (OECD). The purpose of the IEA is to explore means by which countries interested in minimising their dependence on imported oil can co-operate. In the field of Research, Development and Demonstration over fifty individual projects have been established in partnership between member countries of the IEA.

IEA Clean Coal Centre began in 1975 and has contracting parties and sponsors from: Australia, Austria, Canada, China, the European Commission, Germany, India, Italy, Japan, New Zealand, Poland, Russia, South Africa, Thailand, the UK and the USA. The Service provides information and assessments on all aspects of coal from supply and transport, through markets and end-use technologies, to environmental issues and waste utilisation.

Abstract

Increasingly, coal-fired power plants are required to balance power grids by compensating for the variable electricity supply from renewable energy sources. For this, high flexibility is needed, in terms of possessing resilience to frequent start-ups, meeting major and rapid load changes, and providing frequency control duties. This report reviews the means available and under development for achieving flexibility. Potential damage mechanisms are well known, and the necessary flexibility can be achieved with acceptable impacts on component life, efficiency and emissions. Designs are being developed to enable flexibility in future plants.

Acknowledgement

Dr H-J Meier – VGB, Essen

Acronyms and abbreviations

ABS	ammonium bisulphate
ASU	air separation unit
A-USC	advanced ultra-supercritical
CFBC	circulating fluidised bed combustion
ESP	electrostatic precipitator
FDBR	Association of Plant Engineering for Energy, Environment and Process Industry (Germany)
FGD	flue gas desulphurisation
GW	gigawatts
HP	high pressure
IEA	International Energy Agency
IEA CCC	IEA Clean Coal Centre
IGCC	integrated gasification combined cycle
IP	intermediate pressure
LHV	lower heating value
LP	low pressure
MCR	maximum continuous rating
MPa	megapascals
MW	megawatts
PCC	pulverised coal combustion
PID	proportional integral derivative
RH	reheater
SCR	selective catalytic reduction
SH	superheater
SNG	substitute natural gas
USC	ultra-supercritical

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1 Introduction

A recent report from the IEA Clean Coal Centre discussed the growing capacity of renewable energy plants around the world and the effects of their intermittent and highly variable output on the operation of coal-fired plants (Mills, 2011). In the absence of sufficient large-scale electricity storage capability, the effect has been to force coal (and gas) fired units in some countries to deliver greatly varying output to enable the grid system to meet load at all times. The challenges presented by this situation will only increase and become more widespread in the future. For example, Hitachi Power Europe (now Mitsubishi Hitachi Power Systems) has estimated that fluctuations in supply in Germany from renewable power sources will double or triple by the end of the decade, while the demand for electricity from non-renewable sources will have decreased by 50% between 2010 and 2020 (Schultz, 2012). This is against a background of ever-changing system demand during each day (Balling, 2010). A comparison of the 2010 position in Germany with a projection for 2020 in Figure 1 illustrates the magnitude of the expected challenge (Busekrus, 2012).

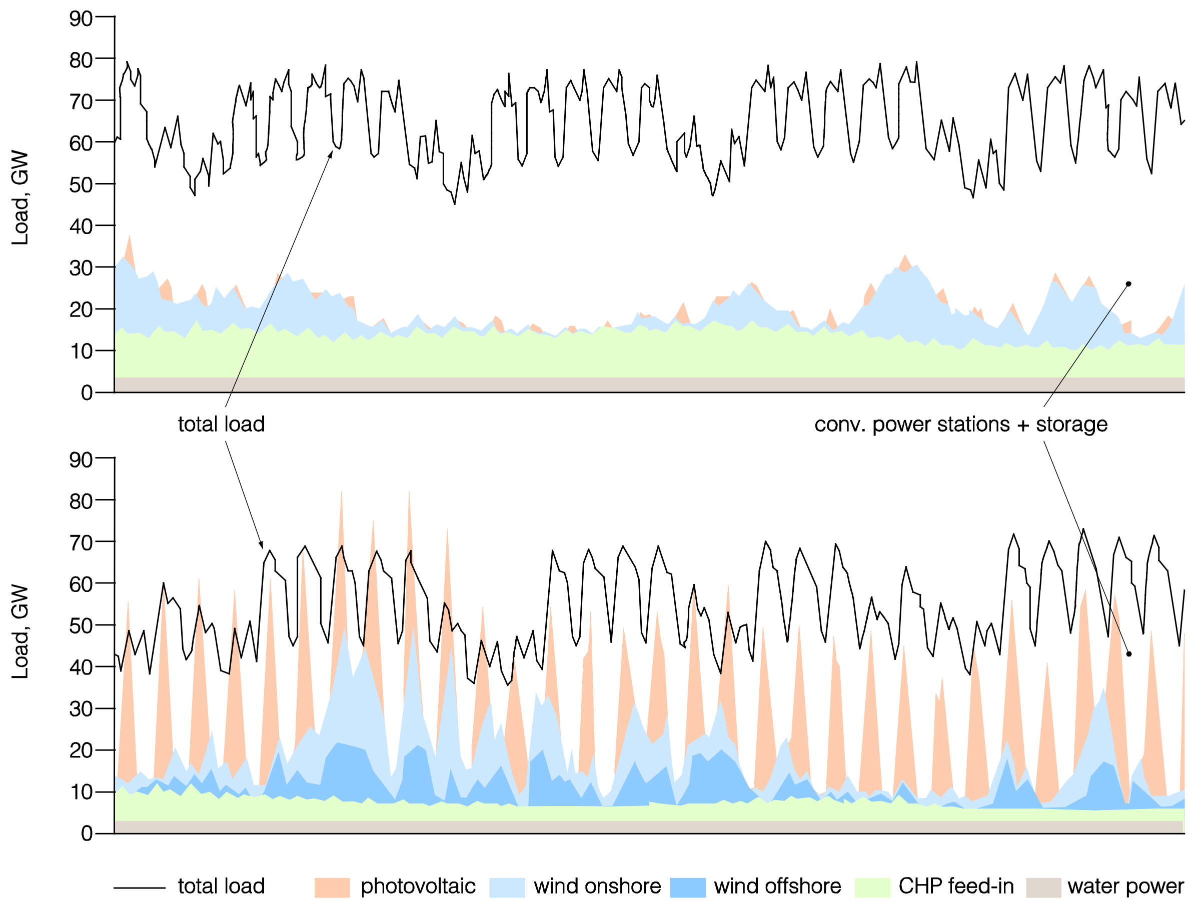

Figure 1 Monthly pattern of load and generation for Germany in 2010 (upper) with prediction for 2020 (lower) (Busekrus, 2012)

There is a wide range of reported values in the literature for the maximum load following rates of coal-fired units. One reason behind this may be that actual and design values can differ. Another reason is that some literature describes the characteristics of one major area of the plant only, for example the steam generator but not the turbine. Another contributing reason may be a lack of clarity sometimes in whether values refer to the normal load ramp rate capability as opposed to the capability for providing transient output changes to provide grid frequency control – *see later in this chapter*.

Once-through steam generators should in principle be capable of changing load more rapidly than boilers with steam drums. The twin Neurath 1.1 GW lignite-fired once-through USC units recently put into commercial operation in Germany can each change by 500 MW in 15 minutes (Fairley, 2013). This is about 3%/min based on MCR (maximum continuous rating). However, it can be possible to exceed this even with some existing plants, depending on design: 5% of maximum load/min was cited some years ago for a 220 MW unit in the USA after control system changes and tuning (Blankinship, 2003). In this report, as is normally the case in papers citing load change rates, % values are referring to % of maximum load. So, for example, a ramp rate of 2%/min on a 1000 MW plant is a linear 20 MW/min rate of change, whether from 400 MW or from 900 MW.

A presentation by Hitachi (now Mitsubishi Hitachi Power Systems) gives a rate of 7%/min from 40% to 100% output for the steam generators of new hard coal or lignite-fired plants (Busekrus, 2012), while brochures by the company suggest even 10%/min is possible (MHPS, 2014a,b). Babcock Power have reported 7%/min as a typical design value for a once-through boiler in the load range 50–90%, with demonstrated operating experience at this value with the 550 MW bituminous coal-fired unit at Rostock, Germany in two-shifting mode (Vitalis and others, 2000).

Some values from a survey and review conducted by Lindsay and Dragoon (2010) are shown in Table 1, to illustrate the potential for confusion in establishing a representative value for existing practical ramp rates. The EPRI data within that table were from a survey by that organisation of a large number of units in 1982, and, although old, do show considerable differences between maximum and average plant ramping rates, probably indicating a desire to limit plant wear, although there may be other influencing factors. In any case, it is likely that much higher load ramp rates will be required for future large units connected to grids for which the proportion of renewable generation sources continues to climb.

Table 1 Some design and reported plant load ramp rates for coal-fired units (Lindsay and Dragoon, 2010)

		Ramp rate, %/min	
Subcritical	Design	3–5	
Supercritical	Design	7–8	
Reported (EPRI)		**Average**	**Maximum**
Subcritical	180 MW	1.8	3.6
	300 MW	2.0	3.1
	420 MW	1.1	2.9
	540 MW	1.7	2.8
	660 MW	1.3	3.7
Supercritical	420 MW	1.3	4.3
	540 MW	1.1	3.6
	660 MW	1.2	2.0
	780 MW	0.9	3.5
	900 MW	1.0	2.0

The information shown in Table 2 on flexibility characteristics of modern USC PCC and IGCC plants is extracted from a table in a paper based on a study by Foster-Wheeler for the IEA Greenhouse Gas R&D Programme.

Table 2 Flexibility features of power plants (Domenichini and others, 2013)

	Turndown	Cycling capability, start-up to full load	Ramp rate
USC PCC	Minimum boiler load: 25–30%	Very hot start-up: <1h Hot start-up: 1.5–2.5 h Warm start-up: 3-5 h Cold start-up: 6-7 h	30-50% load: 2–3%/min 50-90% load: 4–8%/min 90-100% load: 3–5%/min
IGCC	Minimum environmental GT load: 60%. Process unit/air separation unit (ASU) cold box minimum load: 50%. ASU compressor minimum load: 70%	Cold start-up: 80-90 h Gasification hot start-up: 6-8 h ASU hot start-up: 6 h	Gasification ramp rate: 3–5%/min ASU ramp rate: 3%/min

The indications from the above review are that units can be supplied that can provide higher ramp rates than might commonly be supposed, and that part of the reason for this could be that owners have tended to operate their plants conservatively in this respect. However, an even greater degree of flexibility is expected to be required from coal-fired units in future. The present report focuses on the methods that have been developed to enable them to operate in this manner with least detriment to integrity, efficiency and emissions. It also describes means to achieve systems capable of operating at lower than current loads, so minimising the need for on/off operation or support firing.

Power grids have to maintain their alternating current frequency within defined limits. The synchronous capacity (coal, gas and nuclear) on a grid forms an inertial mass that provides a natural resistance to changes in that frequency when step changes in load or generator trips occur. However, the system also has to have active support to re-match supply to demand within seconds so that the system frequency can be quickly restored after it has begun to change. This primary frequency support function is provided by requiring some plants to be designed and operated in a manner to allow the supply of increased or reduced power on a very short-term reactive basis. This function has to be supplied by synchronous plants, typically some gas and some coal units. The high proportion of intermittent-service renewable energy plants on some grids is resulting in a reduction in the inertia of these grids because such plants do not normally deliver frequency control (Tielens and Van Hertem, no date). As a result, an increasing proportion of a decreasing body of fossil-fired units is now having to provide the service.

Primary frequency control requires extremely fast-changing output capability, for example approximately 1% of rated load per second, although it is needed only over short periods of time. Fossil-fired plants conventionally provide primary control through the turbine governors, which give a response to stabilise the frequency within 10 seconds to a minute, although there are other methods that can be even faster. Secondary control from other synchronous capacity within the grid system then restores frequency over a timeframe of 1–10 minutes (NERC, 2011). Providing frequency control capability in coal-fired units is discussed in Section 4.4.

This report mostly concentrates on pulverised coal (PC) plants, since these constitute the largest fraction of coal-fired generation capacity around the world. Circulating fluidised bed combustion (CFBC) plants form a much smaller, although growing, proportion. Many of the issues discussed around the steam cycle and steam turbine systems for PC plants are likely to be similar for CFBC. Integrated coal combined cycle (IGCC) systems are small in number, but further ones are planned. Later chapters in the report look at the expected flexibility of plants using these technologies.

The report is organised as follows. Chapter 2 considers the potential detrimental effects, particularly on the boiler and turbine areas, of plants operating flexibly. Chapter 3 describes technical measures that have been developed for increasing flexibility in boilers. Chapter 4 examines the turbine and water/steam systems with respect to means for increasing flexibility. Chapter 5 looks at other areas, including emissions control systems and auxiliaries. Chapter 6 covers control systems and flexibility, while Chapters 7, 8 and 9 consider other types of coal-fired plants: CFBC (circulating fluidised bed combustion), IGCC (integrated gasification combined cycles) and A-USC (advanced ultra-supercritical – 700°C and hotter – PCC systems). Chapter 10 discusses the potential flexibility of carbon capture plants. A summary and the main conclusions from this review are presented in Chapter 11.

2 Potential detrimental effects of flexible operation

There are different approaches that are available to minimise harmful or performance-degrading influences of frequent plant start-ups and fast load swings, but first, this chapter outlines how adverse impacts on equipment can arise. The major process areas of a pulverised coal-fired power generation unit are indicated in Figure 2. Of particular concern in looking at the detrimental effects of flexible operation are the high temperature and high pressure components of plants, but virtually all areas can be affected: plant cycling (on/off and variable output operation) has the potential to impinge on virtually every area. Other parts of the plant that are likely to be affected in various ways, mainly in reduced efficiency, are the auxiliary systems and emissions control systems. Where scope for modifications to better accommodate cyclic operation is limited, as in older plants designed for base load operation, the use of improved monitoring and prediction systems to enable accurate assessments of component lifetimes will become of increasing importance (*see, for example,* Kranz, 2013; Payten, 2012).

Areas with the greatest potential for adverse effects are the boiler and steam turbine systems. When the plant is called upon to operate frequently at rapidly variable output and with frequent shut-downs and start-ups, resultant changes in temperature and pressure give rise to increased stresses on their various components. The consequences are reduced life, reduced performance and increased costs. Nicol (2014) has produced an IEA Clean Coal Centre report recently on the steels used in coal-fired plants, summarising their development, compositions, assessment and performance.

Formerly, when most plants operated on base load, the principal, though not exclusive, mechanism for materials damage to the hot pressure parts was creep, but a combination of creep with other failure mechanisms is to be increasingly expected with rapidly cycling plants (Kranz, 2013). Fatigue is a major contributor, but other harmful processes will add to this.

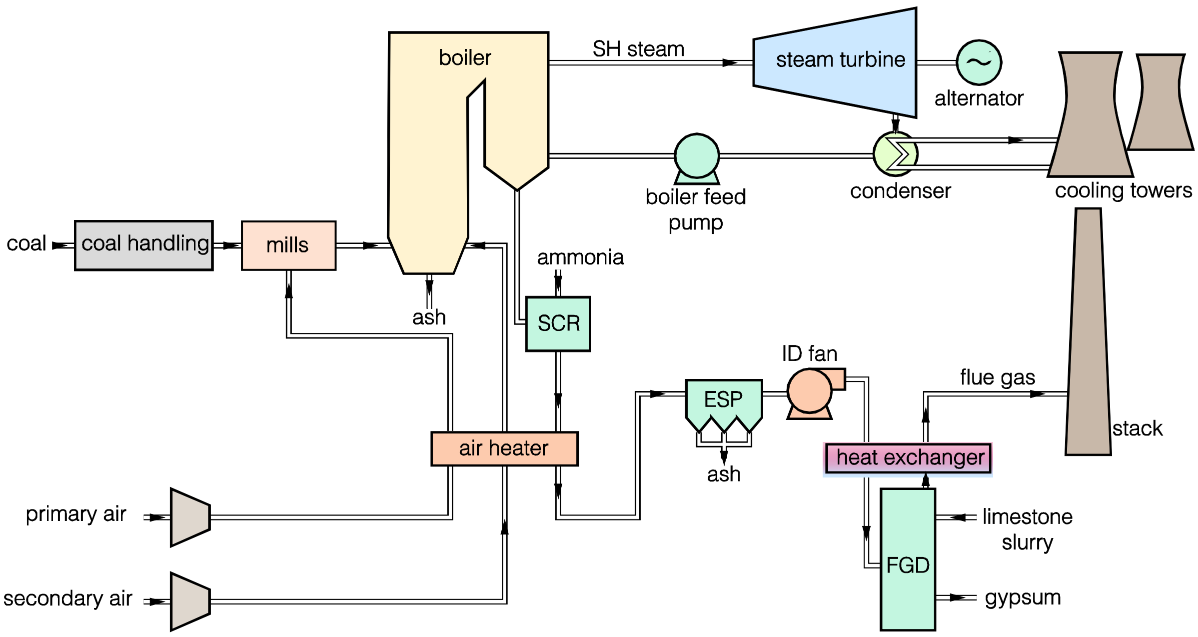

Figure 2 Major process areas of a pulverised coal-fired power plant

The main source of progressive deterioration that occurs when a material is subjected in the laboratory to on/off cycles or variations in loading is fatigue. In power plants, fatigue effects can be enhanced by their occurring in combination with other deterioration mechanisms, particularly creep and corrosion.

Fatigue occurs through the growth of existing flaws or incipient cracks in a material when the stress is applied cyclically. Eventually, if cracks reach a critical size, failure occurs. The number of applications of a given degree of cyclic stress to which a component can be subjected before failure is known as the fatigue life of the component. This is influenced by a variety of factors. Examples are the nature of the material from which it is composed, the temperature, the chemical environment, and the thickness of the component (which can affect temperature gradients). Fatigue is often classified as either high-cycle fatigue, where the number of cycles to failure is large, or low-cycle fatigue, where the number of cycles to failure is small. High-cycle fatigue is characterised by low amplitude, high frequency, elastic (that is, recoverable) strains, whereas low-cycle fatigue is characterised by high amplitude, low frequency, plastic (that is, non-recoverable) strains (DeLuca, no date).

Materials are tested for fatigue life using standard samples that are subjected to cyclic stresses of different amplitudes until they fail. Each test is carried out at a different stress amplitude, and the number of stress cycles to failure is recorded. Cyclic loading is represented in Figure 3, where σ_a is the stress amplitude, and the maximum (σ_{max}), minimum (σ_{min}) and mean (σ_m) stresses are shown.

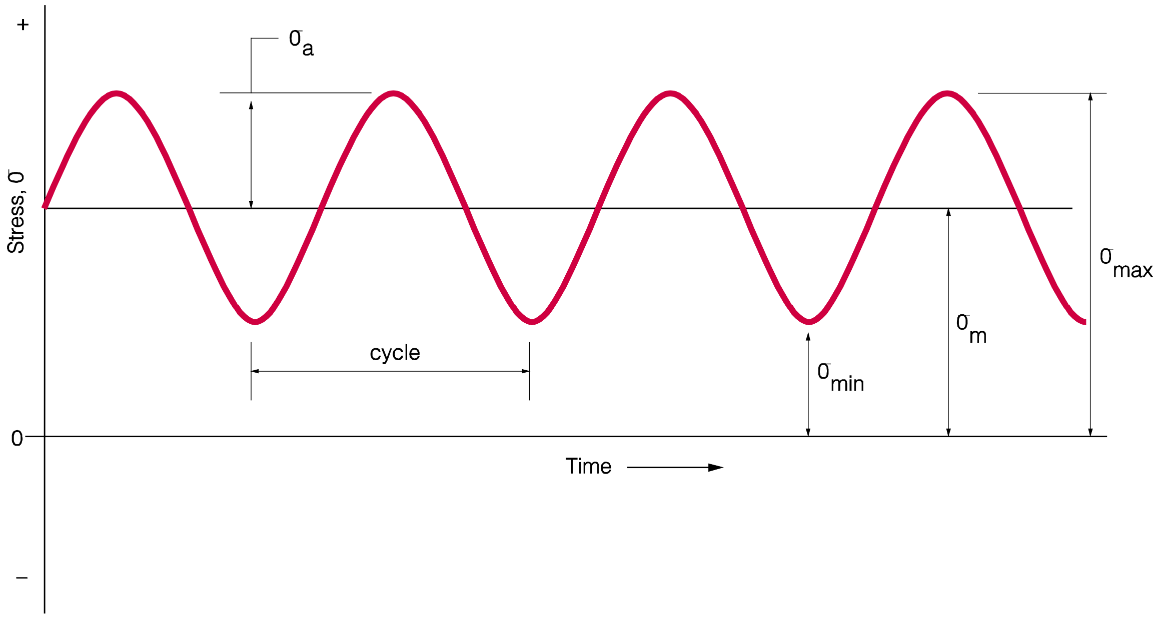

Figure 3 Stress life cycle (Danneman and Lefton, 2009)

From the test data, a graph of stress, S (which has the units of pressure), against the number of cycles to failure, N, known as an S-N curve, is then plotted. Figure 4 shows two examples. As would be expected intuitively, the greater the amplitude of the stress cycle, the shorter will be the life of the test sample. Because materials do not recover when the stress cycle is interrupted (the small cracks will not disappear), the damage to a component constructed from the material is cumulative. For a metal that has been welded or suffered corrosion or creep damage, the curve shows considerable scatter (Danneman and Lefton, 2009).

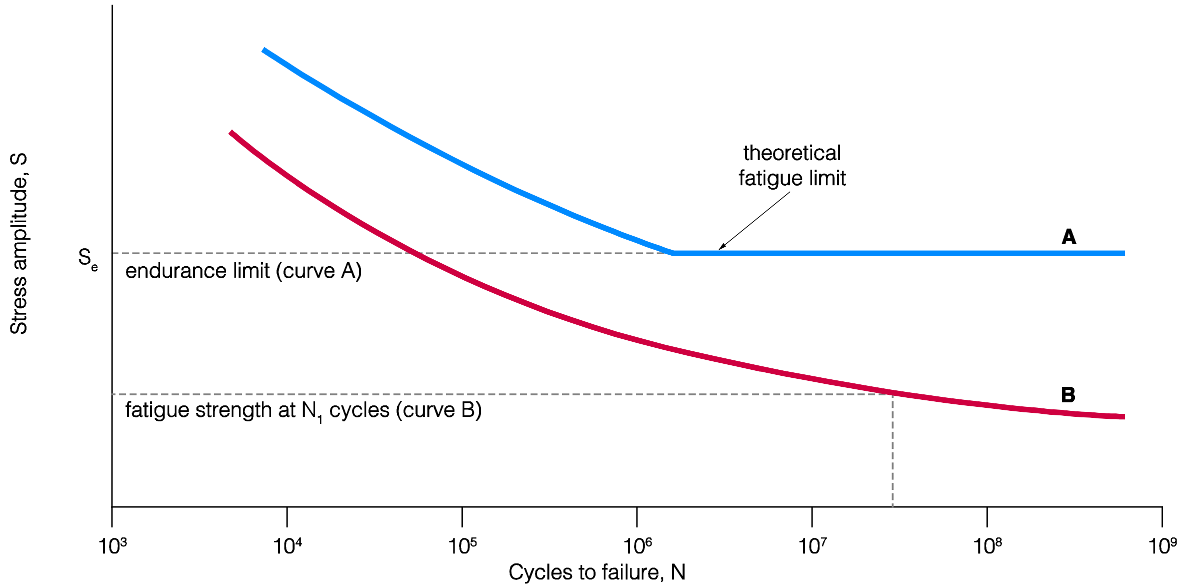

Figure 4 **Typical S-N curve of stress amplitude versus number of cycles to failure for two materials** (Danneman and Lefton, 2009)

There can be a magnitude of stress below which fatigue failure will not occur, regardless of the number of cycles. This is known as the endurance limit, or fatigue limit, and is shown on Figure 4 for material A. An endurance limit does not apply for certain materials, such as aluminium, which will fail eventually at any level of stress cycling. Steels do have a fatigue limit, but there is unfortunately no theoretical lower limit for *corrosion fatigue*, a damage mechanism that has been described as the dominant mode of failure for coal-fired power generation units operating in on/off cycling mode (Danneman and Lefton, 2009).

For thermal cycling fatigue, the number of cycles to failure (N) is related to the range of the temperature cycle (ΔT) thus:

$$N = C/(\Delta T)^{\gamma}.$$

C and γ are constants, characteristic of the material.

In a plant that has been cycling for a number of years, the residual fatigue-related life of the equipment is adequately calculated by taking into account the effects of all the different types of stress encountered. However, for a metal that has been welded, or suffered corrosion or creep damage, the S-N curve exhibits scatter, so predicted fatigue life is subject to more uncertainty (Danneman and Lefton, 2009).

2.1.1 Resultant effects of fatigue on pressure components

The most important areas of likely life-limiting deterioration from fatigue through cycling are the boiler pressure parts and the turbine and its associated equipment. Figure 5 (from Aptech Engineering Services) shows the different types of load cycles that a unit can suffer and, qualitatively, the relative levels of damage that can occur.

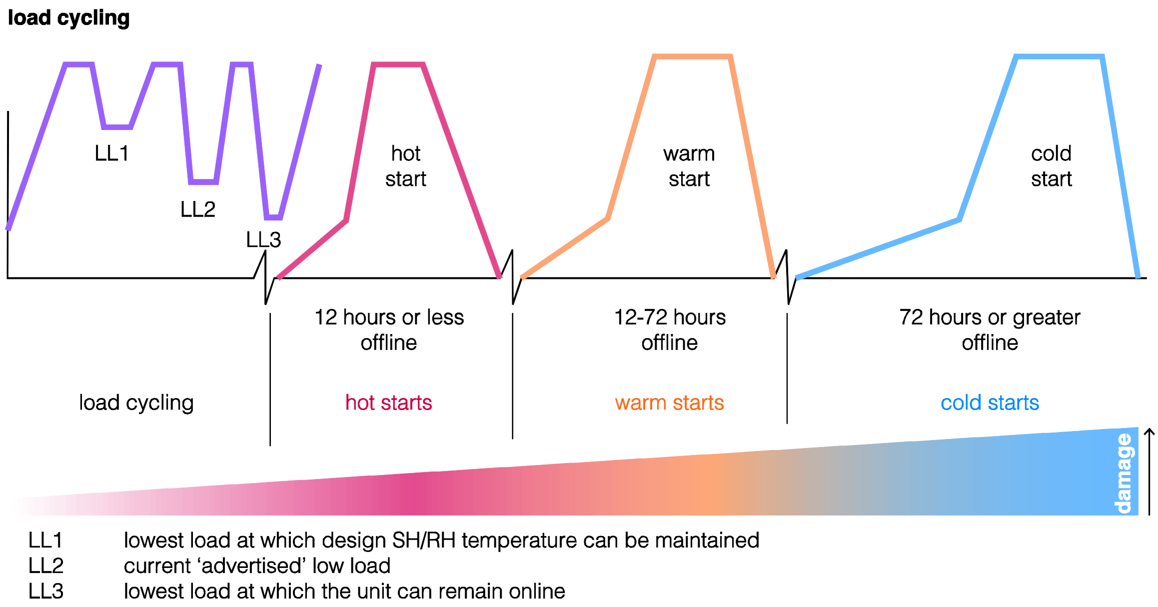

Figure 5 Types of load cycles that a unit can experience and potential relative damage levels (Danneman and Lefton, 2009)

Danneman and Lefton (2009) show that common fatigue-related failures from cycling of existing units in the USA include boiler tube corrosion fatigue, superheater and reheater tube attachment fatigue, turbine blade coating cracking extending into the base metal, and water wall tube membrane cracking. Thermal fatigue, from temperature changes, causes cracks between tube stubs of superheater and reheater headers, as well as damage to turbine rotors and thick-walled castings such as turbine valves and casings (Hesler, 2011).

2.2 Other damage mechanisms and effects of plant cycling

Thermal expansion can itself cause systems to expand so much compared with surrounding components that damage may occur. Examples are membrane wall sections, ductwork, and ties used to support superheat and reheat tubing. Differential expansion also contributes to tube-to-header cracking in superheaters and reheaters (Hesler, 2011).

Low load operation can reduce the flue gas exit temperature from the economiser. This can exacerbate air heater cold-end corrosion, leading to greater cross-leakage within the heater and so lower efficiency (Koza and others, 2011). The low flue gas temperature can also cause problems with maintaining correct conditions in selective catalytic reduction (SCR) systems. The latter is discussed in Section 5.1.

Maintaining boiler feedwater quality is always important, but operating a plant in a cycling mode necessitates additional vigilance. Steps that can be taken when designing or modifying a plant for cycling operation to avoid water quality induced problems include maintaining the correct chemical treatment programme, implementing condensate polishing, and installing on-line monitoring equipment (Koza and others, 2011).

An example of an operational problem that can arise in steam turbines at reduced load is ventilation. As the steam flow is reduced, a disturbance in the flow spreads upstream from the later stages of the turbine. In this mode, only the front turbine stages set performance, while the rear stages give off power to the fluid. In extreme cases, damage can result, but it is mainly a performance issue (Kwitschinski and others, 2013).

A survey by EPRI found that equipment modifications and changes to operational practice could reduce start-up times significantly. Examples were fitting natural-circulation boilers with circulating systems to pump water around the evaporator when off-load and addition of inter-stage drains to prevent condensate from earlier superheater stages reaching hot final stages (Hesler, 2011).

Mills (2011) has included a useful summary table of impacts of plant cycling, sourced from MMU (2010).

2.3 Summary

Normal power plant operation over time results in creep damage to high temperature and pressure components, but flexible operation introduces thermal and mechanical fatigue stresses also. These, together with corrosion, differential expansion, and other effects, often with synergisms, result in a reduction of the expected life of the pressure parts. The residual fatigue-related life of the equipment can be calculated approximately by taking into account the effects of the different types of stress encountered. Many other parts of plants can be affected by plant cycling in the form of either reduction in life, performance or energy efficiency. These include auxiliary systems and emissions control systems. Means to counter these difficulties have been, and are continuing to be, developed.

3 Increasing flexibility – boiler area

In Germany, where the power grid is already experiencing large variations in generation from the extensive capacity of renewable sources, an action plan for increased flexibility in the nation's coal-fired plants has been developed by the Association of Plant Engineering for Energy, Environment and Process Industry (FDBR, 2013). Among the technical suggestions are a large number concerned with the boiler-related parts of plants. These include, in respect of combustion, combustion system optimisation, retrofitting of replacement start-up and flame support burners that use solid fuels (dry lignite, pulverised coal, waste fuels) instead of expensive oil, and installation of indirect firing systems. These methods are discussed in Section 3.1. Some also target minimising emissions and maximising efficiency during changes in output. Other measures in the action plan concern the pressure parts of the boiler and water/steam and turbine systems. These are covered in Section 3.2 and Chapter 4.

Goerner (2012) has highlighted the following additional considerations in designing for high flexibility:

- extension of the acceptable fuel range;
- improved co-ordination of mill and burner systems;
- reduction of combustion chamber volume and height to facilitate fast-load change and high-efficiency at full and partial loads.

Means for reducing the minimum technical load and for increasing the permissible rate of load change are also needed in designing new plants. This additionally involves extending the primary control range (over which the design superheated and reheated steam parameters are maintained) and stretching the secondary control range down toward the revised, lower technical load – *see* Figure 6, from Vattenfall (Dirschauer, 2012).

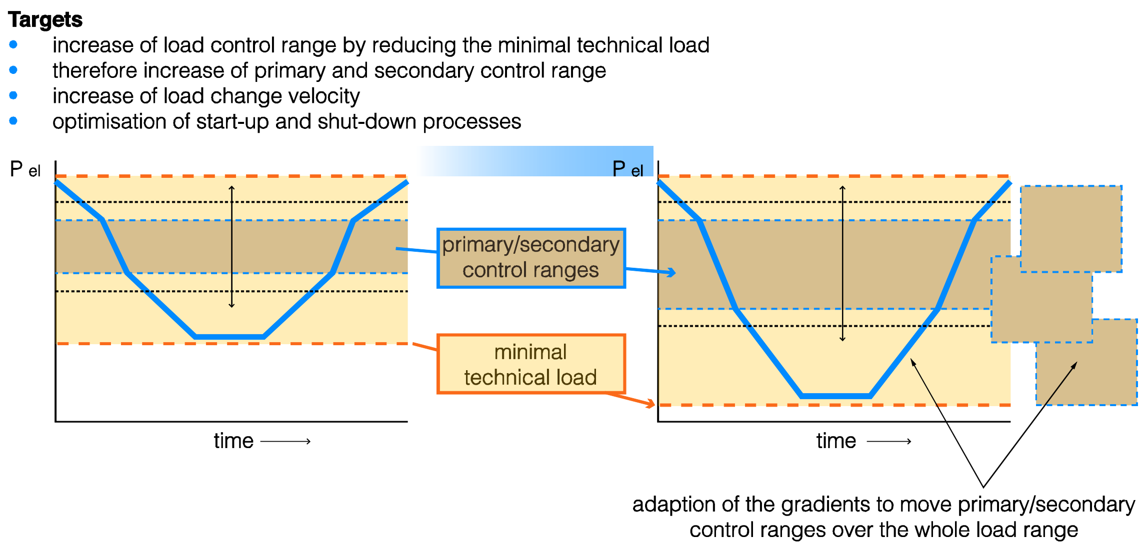

Figure 6 Increasing load range and ramp rate (Dirschauer, 2012)

A critical constraint during rapid ramping is matching steam and turbine metal temperatures. Modern supercritical units provided with sliding pressure operation have advantages in this respect over throttle control during start-up by establishing a flow to the turbine earlier in the sequence, with lower overall heat input and by retaining high temperatures on shut-down (Hesler, 2011; Lindsay and Dragoon, 2010). Sliding pressure is discussed in Section 4.2.

3.1 Firing systems

Among the various areas to consider in increasing boiler flexibility are changes that can be made to the firing systems. The following sections describe some of the means that can be applied.

3.1.1 Varying number of mills in operation to permit lower loads and greater load range

Providing the capability of very low-load running will minimise the number of cold start-up operations. The combustion system needs to play its part. Conventional firing systems for hard coals have permitted typically 40% boiler load without the need for back-up firing. That is far from the sort of performance that will be needed in future. However, it is possible through changes to mill size and burner operating range to achieve 25% load with two out of four mills operating (*see* Figure 7). Where four mills are supplying tangential corner-fired systems, the minimum load can be further reduced: in recent plants it has been shown that single-mill operation can be realised stably, with turndown to less than 20%, reducing the number of shut-down operations (Brüggemann and Marling, 2012). Provision for turndown to 15% has been provided in this way at Heilbronn Unit 7 (Starkloff and others, 2013).

These examples are from Alstom, but other suppliers also offer suitable burners and single-mill operation for very low load capability (*see, for example,* MHPS, 2014a, 2014b). Better instrumentation, combined with sophisticated control, will also improve minimum load capability (Schröck and Dürr, 2013).

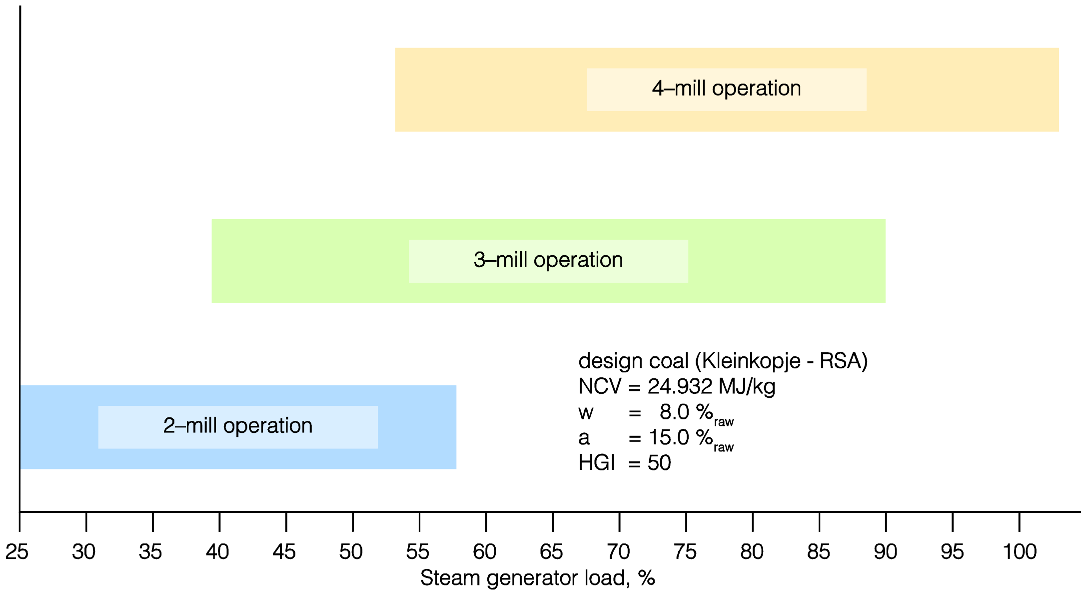

Figure 7 Burner operating range – design with four mills for hard coal (Brüggemann and Marling, 2012)

The use of tilting burners for corner firing gives flexibility in the position of the fireball relative to the heat transfer systems. Higher efficiencies at partial load are realised by reducing the need for reheat attemperation. Efficiency can be increased by 0.5–1% points. Figure 8 shows how adjustments to the reheat temperature can be made without attemperation.

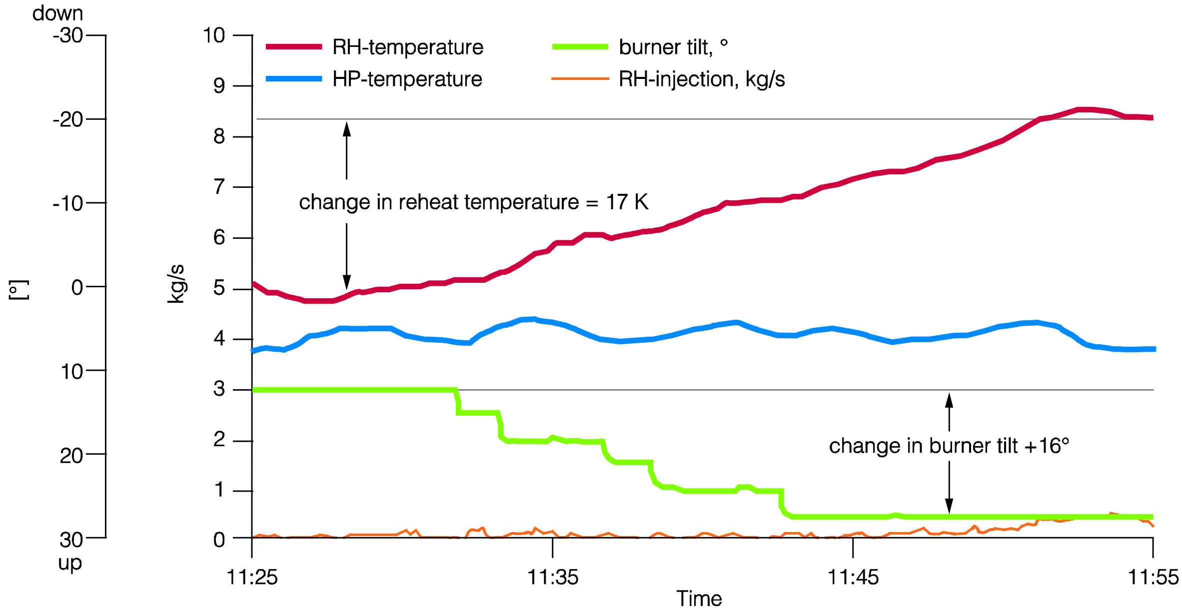

Figure 8 Use of tilting burners to avoid need for reheat attemperation at partial load (Brüggemann and Marling, 2012)

For lignite plants, which may typically have 6–7 beater mills operating at full output, systems are usually designed for a minimum load of 40% for new units (but only down to 50%, for older units), using burner air management and adjustments to the mills and firing systems. Four mills are normally in operation at the 40% load. However, it is possible to achieve a further reduction in minimum output by having only 3 mills in service with fine control of air supply and mill speed adjustments (to ensure flame stability). For example, tests at Vattenfall's lignite-fired Schwarze Pumpe supercritical power plant have indicated that a boiler minimum load of 37% is obtainable (Brüggemann and Schmidt, 2013). This was while the supercritical boiler was still in once-through mode – some water recirculation would also be needed for still lower loads. Reaching a minimum load as low as 35% in both new and existing units is considered possible using these means (Brüggemann and Marling, 2012; Reischke, 2012). Use of lignite after-burners will also reduce the minimum load, give improved stability and extend the permissible fuel range (Reischke, 2012).

Installation of indirect firing systems for hard coals, as well as introduction of lignite drying systems for new designs of lignite boilers, will also enable reductions in the achievable minimum firing and load change rates (Chen and others, 2012; Höhne and others, 2013; Jentsch and others, 2013). These are described in Section 3.1.3.

3.1.2 Increasing the acceptable fuel range with low load operation

Biomass is gaining in application as a cofiring fuel to reduce net CO_2 emissions. Single-mill operation for low load operation is compatible with 10% (thermal) biomass cofiring for large USC units (Brüggemann and Marling, 2012). Start-up can be optimised by putting mills into operation at an early stage, first at part-load, taking advantage of the measures described in Section 3.1.1. Further savings can be achieved with supplementary burners in the primary air system, to provide additional drying energy and allow mills to be loaded faster. Up to 90% of costly support fuel can be saved by switching very rapidly to minimum stable coal/biomass load during start-up (MHPS, 2014a).

For recent information on the influence of biomass cofiring on the design and operation of coal power plants, *see* a number of reports by the IEA Clean Coal Centre (Fernando, 2009, 2012; Dong, 2012; Barnes, 2012; Sloss, 2010).

In order to burn coals of higher moisture contents and lower caloric values than the design coal range for a plant, it is necessary to provide mills with increased drying capacity. In retrofit situations, this can take the form of larger mills with dynamic classifiers, new primary air fans with greater capacity, and means for additional heating of the primary air.

3.1.3 Installation of indirect firing systems

Indirect firing is a system that has been retrofitted successfully to pulverised coal-fired units in Germany to achieve reduced minimum boiler load, and so extend the operating load range. It can also enable increased ramp rates and better part load efficiency. Indirect firing involves installation of a pulverised coal hopper between the mill and burner, together with additional pipework and valves. By using such an arrangement, the instantaneous firing rate is not determined by the mill output at the time (*see* Figure 9). This separation of milling rate and burner feed rate results in a considerable reduction in the inertia of the firing system. The arrangement can allow a rate of change of firing of up to 10%/min (compared with conventional firing load ramps of 2–5%/min). Indirect firing can also stabilise the combustion process, avoid the need for oil as start-up fuel and enable more power to be usefully diverted to coal grinding when there is less demand for power to be sent out. When installed in conjunction with flexible burners, indirect firing can allow the minimum firing rate to be lowered to below 10% of MCR. Efficiency is also improved at low load as mills can continue to operate in their range of optimum power consumption (Reischke, 2012; FDBR, 2013; MHPS, 2014a,b; Busekrus, 2012).

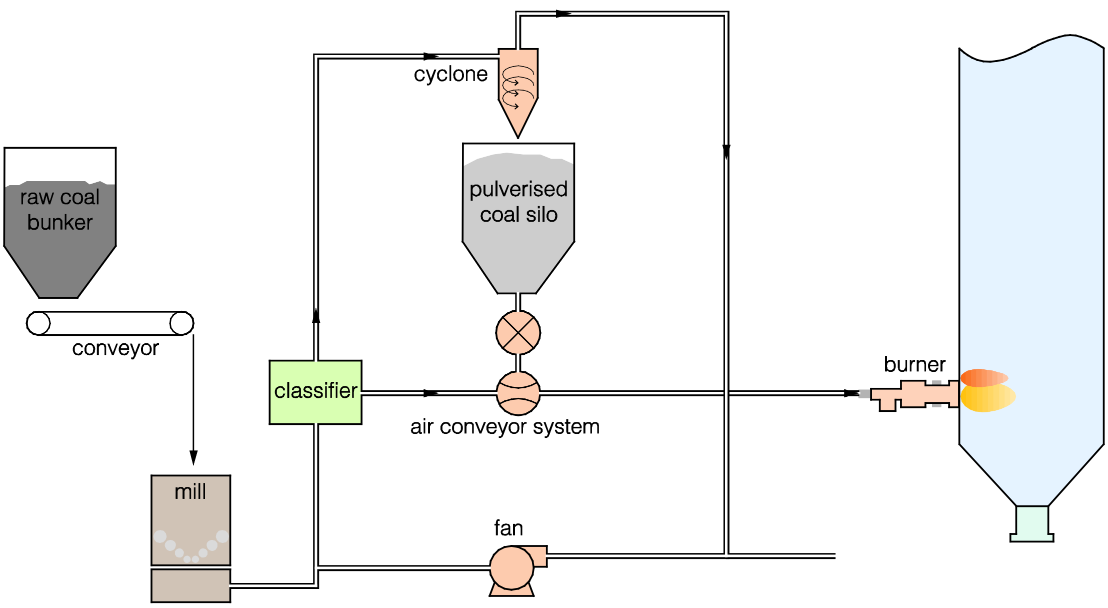

Figure 9 Indirect firing of pulverised coal (Busekrus, 2012)

There can be other benefits of indirect firing also (*see* Table 3).

Table 3 Beneficial effects of installing indirect firing (Busekrus, 2012)

	Direct firing	Indirect firing
Minimum load	25–30%	<10%
Ignition fuel demand	100%	5%
Excess air	15%	<12%
Grinding process	Mills operating at partial load	Mills operating at optimal load

Without installing an indirect firing system with its associated additional valves, pipework and hoppers, it is possible to a more limited extent to improve dynamic performance by simply controlling the coal flow in a conventional configuration that uses vertical spindle coal mills. By varying, within the acceptable range, the grinding pressure of such mills, pulverised coal output can be increased for periods of some minutes by increasing the grinding force. Because the coal feed to the mills cannot be accelerated as quickly, the mills act as energy storage devices (Lindsay and Dragoon, 2010).

Use of lignite pre-drying, while primarily intended to allow higher efficiency, would also provide a method for achieving indirect firing as the dried fuel would be fed to hoppers before firing. This system therefore also provides a capability for increased load change rates and reduced minimum load, as well as a fuel for start-up and combustion stabilisation without the need for fuel oil (Chen and others, 2012; Henderson, 2013; Höhne and others, 2013; Jentsch and others, 2013). The tangential firing arrangement would use corner mounting of the burners for better stability (wall-mounting is used in conventional lignite tangential-fired boilers), and so be akin to hard coal-burning tangential firing systems (Chen and others, 2012). A minimum load of around 30% is suggested by Pinkert and others (2013).

3.1.4 Monitoring and optimisation of combustion

Closer monitoring of the conditions in the furnace is especially important for a unit operating in cyclic mode and when very low loads need to be reached, perhaps with biomass addition. This can allow combustion efficiency to be maximised throughout. An example of the systems available is Zolo's ZoloBOSS technology, based on Tunable Diode Laser Absorption Spectroscopy (TDLAS). This passes laser beams through the furnace between a number of points and spectroscopically analyses the emerging light to monitor the concentrations of H_2O, CO, O_2, CO_2 and the temperature. One of the benefits from such monitoring is the fast response time and reduced need to derive large numbers of correlations (Dubert, 2013; Starke and Williams, 2013).

3.2 Pressure parts

3.2.1 Designing for faster load changes

Tubing and other pressure parts will better withstand the rapid and large changes in temperature associated with on/off and highly variable operation if the thermal gradients are reduced. For this, metal thicknesses need to be made thinner. The number of headers can also be increased. External steam heating or hot storage systems have also been used in Germany to reduce boiler start-up times, while, at Waigaoqiao No 3 in Shanghai, China, an identical adjacent unit can be used for steam heating to speed up start-up of a 1000 MW USC boiler (Henderson, 2013).

More advanced alloys have been developed to enable the metal thicknesses to be reduced, so that the stresses can be reduced in new plants. Former thick-sectioned components made using less advanced steels could only allow output to be adjusted up or down by up to about 3–4%/min. There are differing rates given by various sources, as mentioned earlier, but the highest load rate changes currently suggested by suppliers are as large as 10%/min (FDBR, 2013; MHPS, 2014a,b; Goerner, 2012).

Because the dominant failure mechanism of rapidly cycling units becomes not the development of creep voids, but rather a creep-fatigue interaction, the traditional basis of 200,000 h creep-based design standards is becoming increasingly regarded by plant designers as less applicable. A design life based on 100,000 h, or even less, rather than 200,000 h, without loss of actual plant life for cycling duty, becomes more appropriate due to the lower specific creep strain (Kranz, 2013; Reischke, 2012; Wolff, 2012). Figure 10, from Reischke (2012), shows how the creep lifetime consumption per cycle is significantly reduced by designing components for 100,000 h instead of 200,000 h at full load. Hence, more rapid cycles are possible.

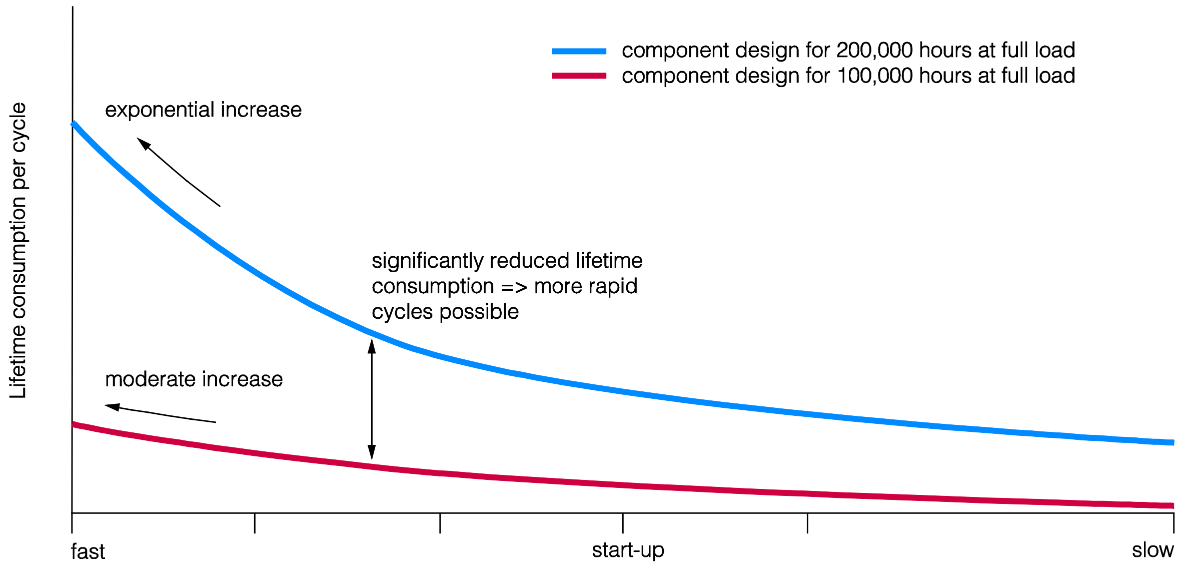

Figure 10 Comparison of lifetime consumption of superheater headers for design creep life of: a) 100,000 h; b) 200,000 h (Reischke, 2012)

Modern calculation methods, such as the Finite Elements Method (FEM) of the European Pressure Equipment Directive (PED), more closely simulate the real gradients in complex structures and facilitate the calculation of the (smaller) design wall thicknesses (Busekrus, 2012; Kranz, 2013). The dimensions and permissible temperature increase rates compatible with acceptable creep rates for a P92 header are shown in Table 4.

Table 4 Dimensions and creep performance of a P92 header (Busekrus, 2012)

Internal diameter, mm	Pressure rating, MPa	Temperature rating, °C	Required thickness according to EN12952-3, for 2.9 K/min gradient, mm	Required thickness, based on modern calculation methods, for 5.1 K/min, mm
255	29.5	615	100	77

3.2.2 Reducing the minimum load

Reducing a boiler's minimum load capability can be achieved through various approaches, for example, for new boilers, by paying special attention to evaporator design and, in existing systems, carrying out economiser modifications. Conditions in the economiser have to be correct, that is, such that there is an adequate degree of sub-cooling of the feedwater to prevent steaming. A reduction in minimum load has been found generally to be possible for existing boilers following assessment (Hamel and Nachtigall, 2012, 2013). The first step is to determine the current minimum technical load, based on thermal input, steam temperatures, flue gas temperatures and stability. This is followed by a feasibility study, involving modelling of the various boiler components, to permit a comparison of potential options. A detailed engineering study of the preferred option is then carried out to confirm costs before implementation.

An example from a case study referred to by Hamel and Nachtigall (2012, 2013) is the adjustment of a steam generator's flue gas temperature after the economiser to achieve the design value at loads down to

30% without economiser steaming. This was done by adding an economiser water-side bypass together with feedwater recirculation pumps and pipework. The same authors show, in another example, the approach adopted to achieve low (20%) load operation through the static and dynamic stabilisation of a spiral wound evaporator of a boiler (Hamel and Nachtigall, 2012, 2013). This included the following elements:

- creation of a thermal model of the boiler;
- analysis of operating data for full and partial load situations;
- calculations of the static and dynamic stability of the spiral evaporator;
- calculations of the static stability for all downstream heating surfaces;
- determination of the stable minimum load in the absence of modifications;
- comparative investigations of the potential advantages and limitations of different stabilisation concepts.

One way of designing for minimum load in designing new boilers is to use internally rifled or ribbed tubing within the evaporator (Reischke, 2012). This enables higher heat transfer rates at lower water flows. Circulating pumps may also be retrofitted to once-through boilers to reduce losses from steam escaping at low loads and during start-up (Schröck and Dürr, 2013). In drum boilers, it may be possible to increase the flow rates in the evaporator to achieve greater stability (FDBR, 2013).

3.3 Plant configuration choices

3.3.1 Using more than one boiler

Configuring a new plant to have more than one boiler supplying the steam to a single turbine will allow a greater degree of flexibility. RWE are developing a plant concept using 2 x 550 MW boilers connected to a single 1100 MW steam turbine for a possible future lignite plant in Germany. This would give high flexibility, with load change rates similar to those of modern gas-fired power plants. A turndown from 1,100 MW to around 175 MW would be possible (Wolff, 2012; Reischke, 2012).

3.3.2 Integrating gas turbines

In Germany, retrofitting of gas turbines equivalent to about 20% of the existing power plant capacity has been carried out at some plants, to enable output, efficiency and load change rate to be increased. They may be added either to create what is fairly similar to a conventional combined cycle or else to provide feedwater heating in a less integrated, lower efficiency, combination (MHPS, 2014b; Gurner, 2012; FDBR, 2013). The energy efficiency of usage of the additional natural gas can reach approximately 80% in some systems, compared with about 60% for a modern dedicated natural gas-fired combined cycle power plant (FDBR, 2013).

4 Increasing flexibility – turbine and water-steam systems

There is much that can be done to make these areas of a plant more durable, able to respond faster and suffer less efficiency losses. Examples are given in this chapter.

4.1 Reducing stresses during start-up

Start-up, especially from cold, places particularly large stresses on many parts of a coal-fired plant. The turbine is no exception in this regard. Very rapid temperature changes need to be kept to the minimum, while component designs can be adapted to suit. Lindsay and Dragoon (2010) have collected together data from published sources on start-up times for different plant conditions. They found that, generally, coal plants required approximately 12 hours to cold start, 4 hours to warm start, and 1 hour to hot start. There was considerable variation, and this was believed to stem from how hot, warm, and cold starts were defined, and whether those times were actually equipment-limited or not.

One of the requirements for flexibility in the turbine is that the very small clearances between stationary and moving components remain almost constant during output changes. This requires careful design, advanced sealing (*see also* Henderson, 2013) and measures for ensuring uniform thermal loading and applies especially during cold start-up operations (Quinkertz and others, 2008).

Turbine bypass systems are a necessity in plants designed for two-shift (on/off) and other flexible forms of operation. They allow all or part of the steam to bypass the HP turbine or LP turbine so that the rate of steam temperature change in the turbine can be managed as the boiler is starting up and shutting down. This allows thermal stresses in the turbine to be reduced (Lindsay and Dragoon, 2010). This is not to be confused with another type of bypass (HP stage bypass), that can be installed for frequency control in new plants and is described later.

The very high temperature and pressure conditions of USC systems necessitate use of thick-walled components so that they possess adequate strength. Unfortunately, this can limit the rate of temperature change consistent with reducing thermal fatigue to acceptable levels. In the turbine, one means used to counter this is steam cooling of the outer casing to keep its temperature 30–40°C lower than that of the inner casing at the corresponding position along the turbine during load changes. The steam for this is bled radially from points along the inner casing. The steam reduces temperature extremes in the outer casing and allows its thickness to be reduced. The result is that cold start-up time is reduced by almost 50% (Almstedt and others, 2007).

4.2 Load following using sliding pressure operation

While, traditionally, throttling has been used to vary output from a turbine while keeping the pressure constant (Lindsay and Dragoon, 2010), sliding pressure operation has become a commonly applied system in modern supercritical once-through systems (Henderson, 2004). A critical constraint on ramping operation is matching steam and turbine metal temperatures, and more rapid output changes can be achieved using sliding pressure. Sliding pressure also offers advantages over throttle control during start-up, by establishing a flow to the turbine earlier in the sequence, with lower overall heat input and by retaining high temperatures on shutdown.

This is a whole-plant design aspect, since it concerns the boiler as well as turbine systems. At the reduced pressure used for part load operation, when the system is operating subcritically, evaporation occurs in the boiler within a region of tubing that shifts with changes in load as the enthalpy increases in the boiler associated with preheating, evaporation and superheating change with pressure. The decrease in efficiency at reduced load is reduced, as better control of turbine temperatures and wetness is possible than when the governor valves are throttled. In addition, boiler feed pump power consumption is reduced and there are lower stresses on components such as valves.

In practice, a certain degree of throttling is usually also used to maintain some reserve steam to give the capability for meeting sudden increases in power demand (*see also* Section 4.4). Sliding pressure has been used for around twenty years in units in Denmark and in Germany, for example at the Rostock unit in Germany (Vitalis and others, 2000). Sliding pressure once-through boilers are provided with small steam drums for water and steam separation at the (subcritical) conditions of reduced load. Small separator vessels and a recirculating pump are in any case normally provided for start-up (Henderson, 2004).

4.3 Other ways to achieve greater load range and ramp rate

Addition of bypass pipework around feedwater heaters is a convenient modification to increase flexibility. The lower resultant temperature of the feedwater at the economiser inlet can then allow lower loads to be reached without economiser steaming (FDBR, 2013). Economiser steaming can be a problem limiting the extent to which water flow, and so plant load, can be turned down (*see also* Section 3.2.2).

Provision of bypasses around high pressure feedwater heaters, accompanied by the (necessary) closing of the HP bleed steam valves, can also be used to produce *additional* power over about 20-30 minutes. This occurs because the steam flow through the turbine is increased (Wechsung and others, 2012; Lindsay and Dragoon, 2010). Feedwater heater bypass used in this way can provide a means of very rapid response suited for frequency control (*see* Section 4.4).

Of relevance in considering new plant designs, separate HP and IP turbines, as opposed to combined HP/IP systems, are said to make faster load changes possible (Cozza, 2012).

4.4 Rapid response for frequency control

Many coal-fired power units already incorporate the means to provide very rapid output changes of 5% or even up to 10% within a time of no more than about 30 seconds (Reischke, 2012). These are plants that are designated and so designed to provide frequency stabilisation on the grid through primary frequency control. In addition to this very short-term response duty, other units are designated to operate to provide secondary (within several minutes) frequency control. The response of the latter frees up the primary frequency control units making them ready to provide immediate response again. Although not actually the same designated duty, providing secondary frequency control has similar implications for plant design to providing the capability for meeting large, rapidly changing supply/demand gaps, covered in other sections of this report, so this section concentrates on means for primary frequency control. Retaining some fossil-fired units for primary and secondary frequency control will remain very important in the future, as many renewable energy generators do not provide frequency control. Coal-fired plants designated for frequency control are kept on, and so synchronised, but operating below full load, ready to provide a response when needed.

Methods available for primary frequency control include the well-established means of opening of throttled main steam valves, but also, nowadays, condensate throttling, feedwater heater bypass (*see* Section 4.3) and HP stage bypass. Another alternative is to install a thermal storage system, which can also increase the load range. The latter is described in Section 4.5.

The three Torrevaldaliga North 660 MW USC units commissioned in Italy between 2009 and 2010 have been designed to provide primary frequency control through turbine throttling. Each 25.3 MPa/604°C/612°C (at boiler outlets) unit has the capability for producing a 4% change in power within 30 seconds. The turbines were supplied by MHI Ltd. The response time of the boilers, supplied by Ansaldo Caldaie S.p.A. and Babcock Hitachi Kure (BHK), is approximately 90 seconds. This allows the primary reserve provided by the turbine system to be recovered quickly, with provision of the power reserve for 15 minutes in accordance with the grid requirements (Penati and others, 2011).

The principle of condensate throttling is that the turbine control system opens the governor valves, if not fully open, to utilise the reserve steam storage capacity of the boiler (as in conventional throttling in absence of condensate throttling). The flow of condensate to the low pressure feedwater heaters is reduced at the same time by throttling the main condensate control valve (*see* Figure 11). The flows of extraction steam to the LP feedwater heaters and the deaerator/storage tank are therefore reduced. These actions leave additional steam flow in the turbine, generating the additional power. The response time can be optimised using additional fast acting valves in the extraction steam lines giving a maximum output after about 30 seconds (Cziesla and others, 2009; Quinkertz and others, 2008). The boiler fuel feed rate is also increased. At Waigaoqiao No 3 plant in Shanghai, China, a similar principle has been used on the Siemens turbine in adjusting condensate flow to vary indirectly the flows of extraction steam to enable transient demands to be met efficiently (Henderson, 2013).

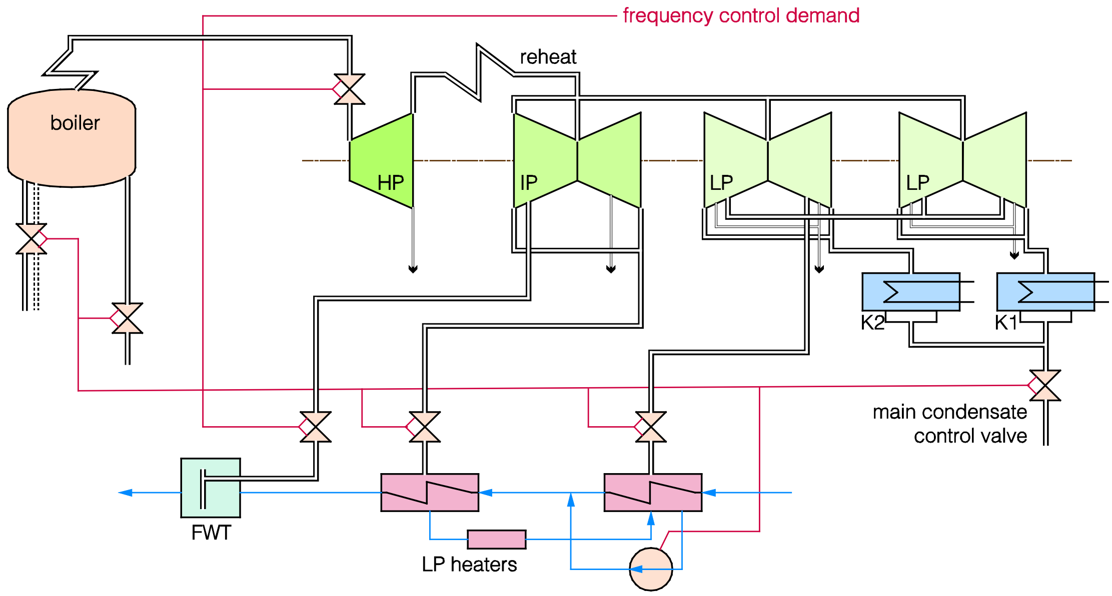

Figure 11 Condensate throttling for rapid response (Cziesla and others, 2009)

Another very rapid response system for primary frequency control that can be supplied with USC steam turbines is HP stage bypass. Figure 12 shows the system in Siemens 600-1200 MW turbines equipped with sliding pressure and full arc admission over the load range. It permits additional HP steam to be admitted to the HP turbine some stages after the first blade row when the bypass valve is opened, also to give full arc admission at that stage. The system is normally designed to give a short-term 5% increase in power. It is however possible to design such systems for an additional 10%, or even, if required, 15% increase in power (Almstedt and others, 2007; Wechsung and others, 2012). Normal operation at 100% MCR is achieved with the stage bypass valve closed. Efficiency falls upon opening it, but providing frequency control is a necessity to stabilise the grid. In any case, the HP stage bypass system is the most efficient means that is available for achieving rapid load increase (1% per second) because throttling losses are at a minimum at both points (Quinkertz and others, 2008). The stage bypass system is available for use within the whole load range. In contrast, throttling is normally operated at around fairly high load. Alstom supply similar systems (Alstom, no date).

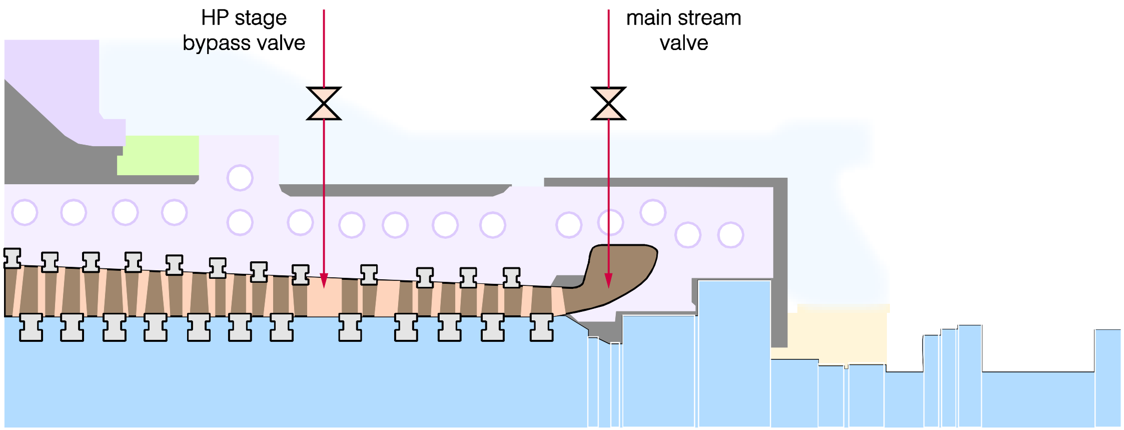

Figure 12 HP stage bypass system for very rapid response (Almstedt and others, 2007)

Alstom show a primary frequency control capability of 10% in 10 seconds as being under development for new and existing plants without expanding on the nature of the system (*see* Table 5) (Reischke, 2012).

Table 5 Flexibility capabilities of coal-fired units (Reischke, 2012)

	State of the art:	**Development (new and existing plants):**
Start-up:	2–6 hours depending on starting condition	1–4 hours depending on starting condition
Minimum load (hard coal)	New power plants: 25% Existing power plants: 40%	Conventional firing 15–20% Indirect firing 10–15%
Minimum load (Brown coal)	New power plants: 40% Existing power plants: 50%	Conventional firing 35–40% Indirect firing 10–15%
Load change cycles	Moderate	High to very high
(Primary frequency control)	2–5%/30 s possible to 5%/30 s	10%/10 s
(Secondary frequency control)	2–/min	10%/min
Biomass	10% cofiring	100% biomass

Modern control strategies have been said to permit a reduction of boiler inertia by more than 30%, reducing the turbine valve throttling needed for frequency control (Rech and others, 2009).

4.5 Thermal storage systems

Bypass of feedwater heaters has already been described as a way to increase steam flow for up to 30 minutes (*see* Section 4.3) and for frequency control, but even more flexibility can be achieved by installing storage systems for the low pressure or high pressure feedwater. An extended load range, increased ramp rate and provision of an alternative means for primary and secondary frequency control result (FDBR, 2013). Figures 13 and 14 show variants of a system that can be installed that is in principle capable of rapidly providing 5% more power at existing plants (Schuele and others, 2012).

The LP feedwater heaters are provided with a bypass which feeds upright cylindrical storage tanks (*see* Figure 13). These tanks contain both the cold and hot condensate, and any increase in storage of hot water displaces cold water and vice-versa. When power output needs to be reduced, the tanks are filled with hot condensate, taken from the outlet stream of the deaerator/feedwater storage tank. To achieve this, the condensate mass flow through the LP preheaters and the feed water tank is increased. This causes increased extraction of steam from the IP and LP turbines, reducing power output.

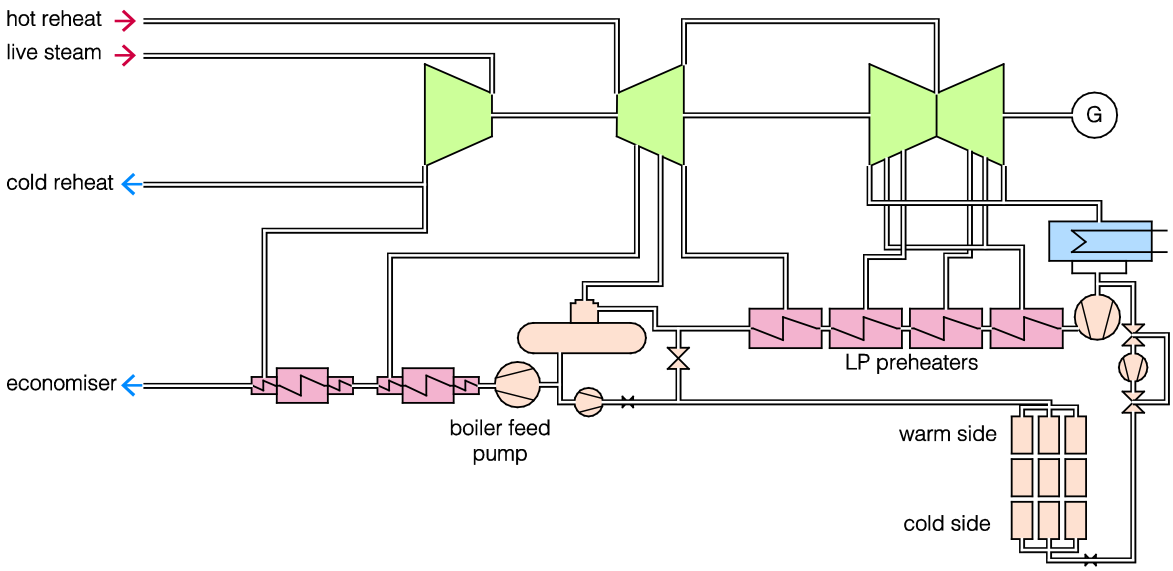

Figure 13 Thermal storage system for increasing plant flexibility (Schuele and others, 2012)

When additional generation is required, the LP feedwater preheaters are bypassed, and the cold condensate from the condenser displaces the hot condensate in the storage tanks. The hot condensate is introduced upstream of the deaerator/feedwater storage tank. Because the LP feedwater heaters are bypassed, they do not draw extraction steam. The hot condensate from the thermal storage tanks is at approximately the same temperature as that of the water in the feedwater tank, so no IP extraction steam is required at this point either. The steam flows through the final stages of the IP turbine and the LP turbine are consequently increased, raising electrical output.

The increase in output is greatest at full load, because then the impact of the reduced extraction steam mass flow is maximised. Approximately 5% of MCR can be produced. The associated capital cost is much lower and the efficiency associated with the system is much greater than for energy storage alternatives such as batteries or compressed air storage. The usable load range is also extended, as there is no need for other means, such as throttling, to provide frequency control (Schuele and others, 2012).

The more involved system in Figure 14, which utilises additional feedwater heaters, enables even greater flexibility. During heat storage, steam from the plant is used to heat the cold condensate from the tanks. In this case, the 'charging' condensate mass flow is independent of the water-steam cycle. The load reduction occurs because of the diversion of IP steam from the turbine. Adding the condensate from the storage preheater to the hot storage condensate reduces the 'charging' time. Power increase is achieved in the same way as for the simpler system, by cold condensate displacing stored hot condensate, which is re-introduced upstream of the feedwater tank.

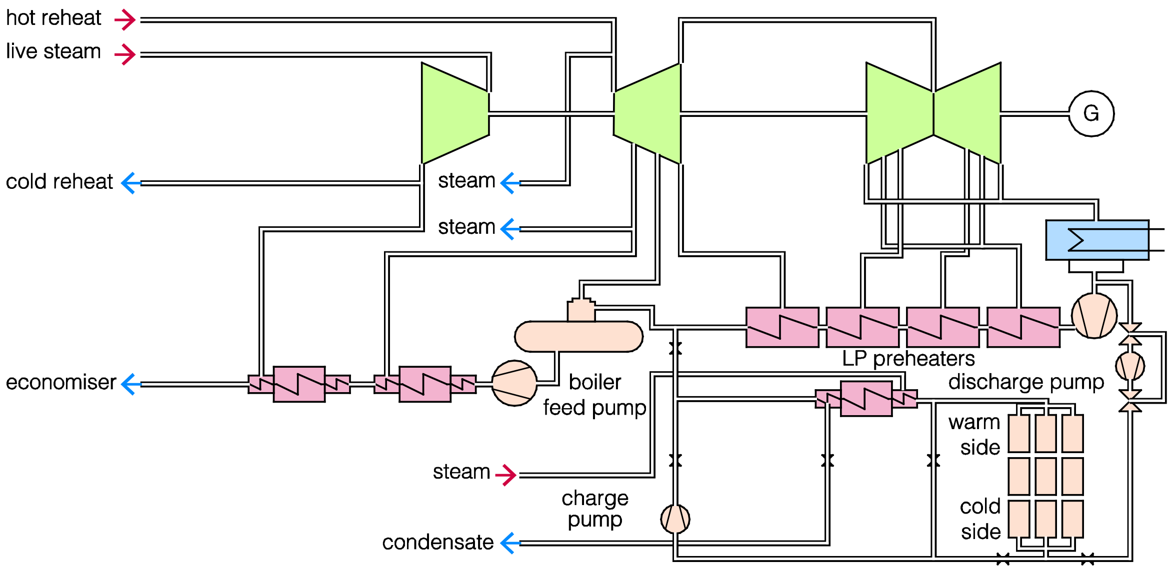

Figure 14 Thermal storage system for increasing plant flexibility (variant) (Schuele and others, 2012)

4.6 Water treatment

Poor water quality causes corrosion, and the likelihood of water quality deterioration is increased as a result of frequent load changes. For once-through boiler systems, all-volatile treatment and oxygenated treatment are used. Boilers operating in a cycling mode are best provided with all-volatile treatment together with full-flow condensate polishing. All-volatile treatment with oxygenating is preferable for ferrous-only based systems. It allows air in-leakage, resulting in dissolved oxygen levels of 1–10 ppb that form a ferric oxide hydrate layer on the magnetite (Nicol, 2014). The dissolved oxygen concentration is controlled by mechanical means, while chemicals such as ammonium hydroxide and hydrazine or other substances can be used as the pH adjuster (Koza and others, 2011). Condensate polishers remove dissolved contaminants, such as sodium and silica, and filter suspended particulates that become detached from heat exchanger internal surfaces during load transitions (Koza and others, 2011).

Operation of makeup water or wastewater clarifiers can be improved by the addition of recirculation lines to allow the maintenance of adequate flow through the clarifier at low load, keeping it ready for increased load operations (Koza and others, 2011).

5 Increasing flexibility – other plant areas

On/off and highly variable load operation affects other parts of the plant also. This chapter describes the potential problems that can arise and how they can be overcome.

5.1 NOx removal systems

The main potential issue with low load operation of plants with selective catalytic reduction (SCR) systems, which are usually placed after the economiser, is the possibility of lower flue gas temperatures occurring. SCR units often use ammonia as reagent, and ammonia control may become difficult during fast load swings, compounded by variable fuel properties. Excess ammonia can then leave with the exit gas stream. This so-called ammonia slip can then lead to ammonium bisulphate (ABS) formation as a sticky liquid that fills catalyst pores, reducing reactivity. ABS may also deposit in the air heater, increasing its pressure drop, and necessitating cleaning. It can even be blown from the air heater into boiler air ducts, where it can influence readings of air flow measurement devices.

To avoid problems with ABS formation, the conventional solution is for a flue gas or water-side economiser bypass to be installed to enable the flue gas temperature at low load to be kept at design value (FDBR, 2013). Such an arrangement can avoid plugging without sacrificing NOx removal performance (Rummenhohl and Davis, 2012; Koza and others, 2011; Moser, 2006). Where units are not, or cannot be, equipped with economiser bypass capabilities, other options are available. One is to monitor continuously the inlet NH_3 and SO_3 concentrations and temperature distribution in the SCR, and to compare these with design conditions. Other possibilities may be to change the fuel sulphur content or, if allowed, the NOx reduction levels at low load, or to modify the inlet temperature distribution using a static mixer (baffle). Adding a heating facility for hot gas carrying components can also be used to give shorter start-up times (FDBR, 2013). Whatever means is used, provided the correct temperature can be maintained, rapid rates of load change can generally be accommodated (Beckmann and Lerke, 2012).

5.2 FGD systems

The chemical processes involved in conventional wet flue gas desulphurisation (FGD) systems require precise control of the reaction conditions, which are influenced by reagent flow, water flow and flue gas temperature. Operation at varying power output can consequently affect the performance and reliability of these plants. The number of shut-downs and start-ups of FGD systems should also be minimised because of the need to purge to avoid slurry solidification. Reducing the number of shut-downs and start-ups is also needed to minimise the accumulation of start-up fuel oil residues on absorber linings, and to avert the lengthy warming up time that is needed by an FGD system.

It can be possible to obtain savings in energy consumption at part load by switching off some circulation pumps. Goerner (2012) suggests updating control systems to reduce the energy demand. However, at low-load, it will be difficult to maintain optimal performance if the reagent flow is fixed. Keeping within required emissions limits during rapid load changes requires sophisticated control concepts, and an increased liquid/gas ratio may be needed for sufficient SO_2 capture (Beckmann and Lerke, 2012).

5.3 Particulate removal systems

Particulate control systems can usually cope with a plant operating at partial load and rapid load changes without problems. Inlet gas temperatures need however to be watched – they must not fall so low that acidic moisture condenses on particles, causing adherence of solids to fabric filters or a resistivity that is too low for efficient ESP performance. At partial (or full) load, enhanced dust collection may be achieved in electrostatic precipitators by increasing residence time, while energy savings of up to 80% are possible using intelligent control systems for the power supply (Beckmann and Lerke, 2012). Goerner (2012) suggests that flexible plants include modern controls for electrostatic precipitators to reduce their energy consumption. A recent IEA Clean Coal Centre report describes developments in various types of particulate removal systems (Nicol, 2013a).

5.4 Auxiliary systems

During start-up and operation at reduced load, a power plant is at off-design conditions. Consequently, the thermal efficiency is reduced. It is desirable in flexible operation that any efficiency penalties be minimised. Apart from reduced boiler and turbine performance, a penalty can come from excessive power consumption by ancillary systems. Auxiliary systems on older plants designed for base load waste power at low load as drives still draw too much power. Examples are the major fans and the feedwater pumps. Flexible drive motors using variable frequency power supplies are now available for these large consumers in the power plant to reduce the energy losses from this source (FDBR, 2013; MHPS, 2014b; Hesler, 2011; Koza and others, 2011, Lindsay and Dragoon, 2010). Variable frequency drives for cooling tower fans can also help regulate condensate water temperature. Other suggested methods suggested by Goerner (2012) for flexible plants include using superconducting components. However, the latter technology is not widely used and is basically still developmental.

Supplying the auxiliary drives with power at varying frequency enables their operating efficiency to be improved when a plant is operating at reduced load, as mentioned above. At Waigaoqiao No 3 power plant in Shanghai, China, a novel means of achieving this has recently been developed and installed. It consists of a variable frequency turbine (manufactured by Siemens) driven by steam extracted from the main turbine. This follows the change of load to change the frequency supplied to the plant auxiliary systems and has been shown to save a considerable amount of power (Feng, 2014).

6 Control systems for improved flexibility

It is generally worthwhile replacing control and instrumentation systems in older plant to increase efficiency and flexibility. RWE has carried out such retrofits on its 300 MW and 600 MW lignite fired units to achieve greatly increased ramp rates and lower minimum loads. Figure 15 shows the demonstrated and predicted future improvements on a 600 MW unit (Eichholz and others, 2013).

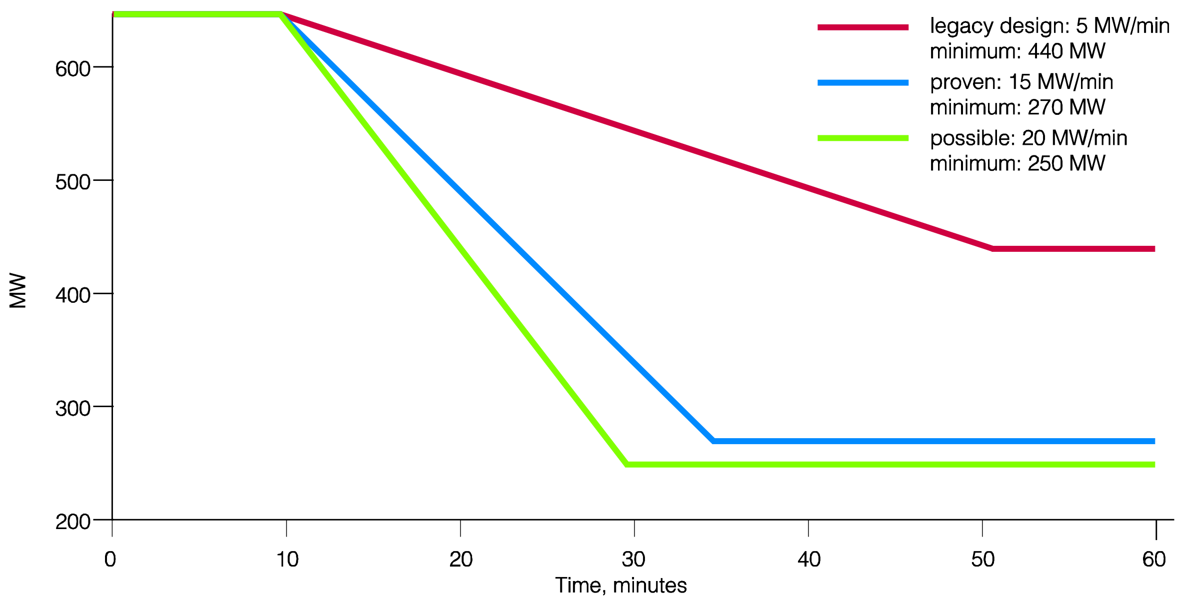

Figure 15 Demonstrated and predicted future improvements in minimum load and ramp rate on 600 MW lignite-fired units from retrofitting modern control systems (Eichholz and others, 2013)

6.1 Boiler control systems

Conventional control schemes are designed to provide responsive control within a unit's normal operating capacities. However, the boiler and steam-side response profiles are significantly affected at low load. Furthermore, conventional control systems may not be able to take into account changes such as those occurring as a plant ages (Wendelberger and others, 2009). Thus, if the dynamic response of the boiler changes over time, control performance will become degraded. In that case, the simple proportional integral derivative (PID) controller has to take corrective actions increasingly frequently. Eventually, the plant's stability and flexibility suffer. Modern systems available now can overcome such difficulties. For example, Siemens Energy has developed a system (advanced process controller – APC) for controlling the main steam pressure by adjusting the fuel flow (Figure 16). This controller is said to reduce commissioning time by more than 50%. The APC is able to stabilise non-stable loops so that it is not necessary to use the steam turbine to help stabilise steam pressure. As a result, the electrical load will follow its set point with a very high degree of accuracy and the APC can act as a full pressure controller, and dynamic tracking of the pressure set point in case of load changes or frequency disturbances is unnecessary (Wendelberger and others, 2009).

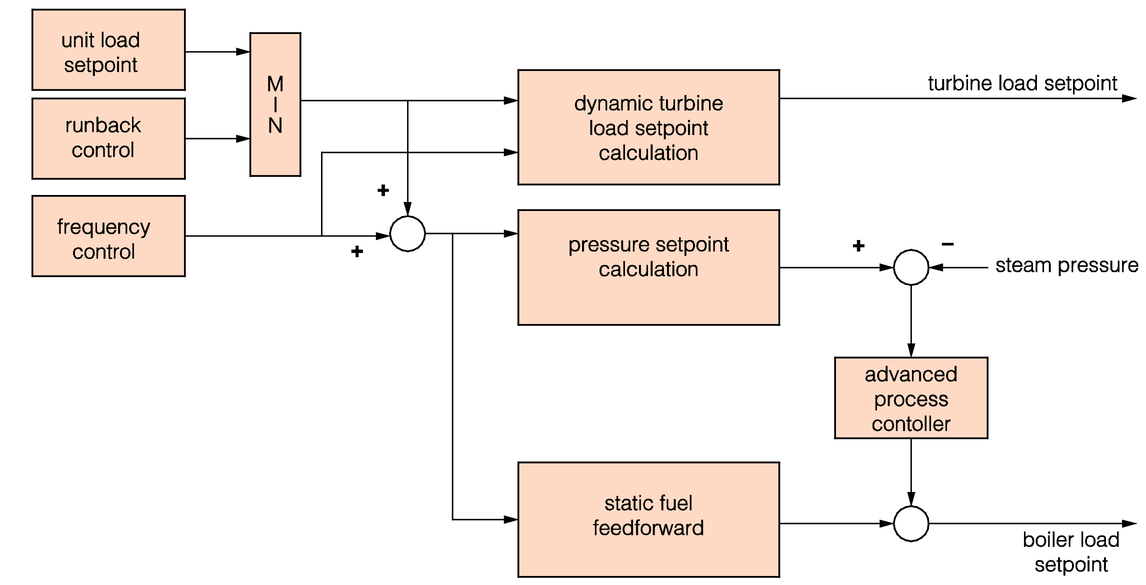

Figure 16 Unit control concept with APC. Source: Siemens AG (Wendelberger and others, 2009)

The authors describe how unit fitted with the APC responded when the load setpoint was increased and then reduced at a load change rate of approximately 5% per minute. The APC was able to stabilise the pressure quickly, and the load followed its set point closely. With the new control structure, control performance levels can be attained that were previously considered to be impossible (Wendelberger and others, 2009). Even further gains can be expected in the future with whole plant controls that use predictive algorithms. These are discussed in Section 6.3.

Schröck and Dürr (2013) describe how modern control systems can enable combining of the operation of multiple units to obtain faster ramp rates (*see* Figure 17) while keeping availability at a maximum. More sophisticated control and instrumentation will also improve minimum load capability, for example, through additional flame monitoring.

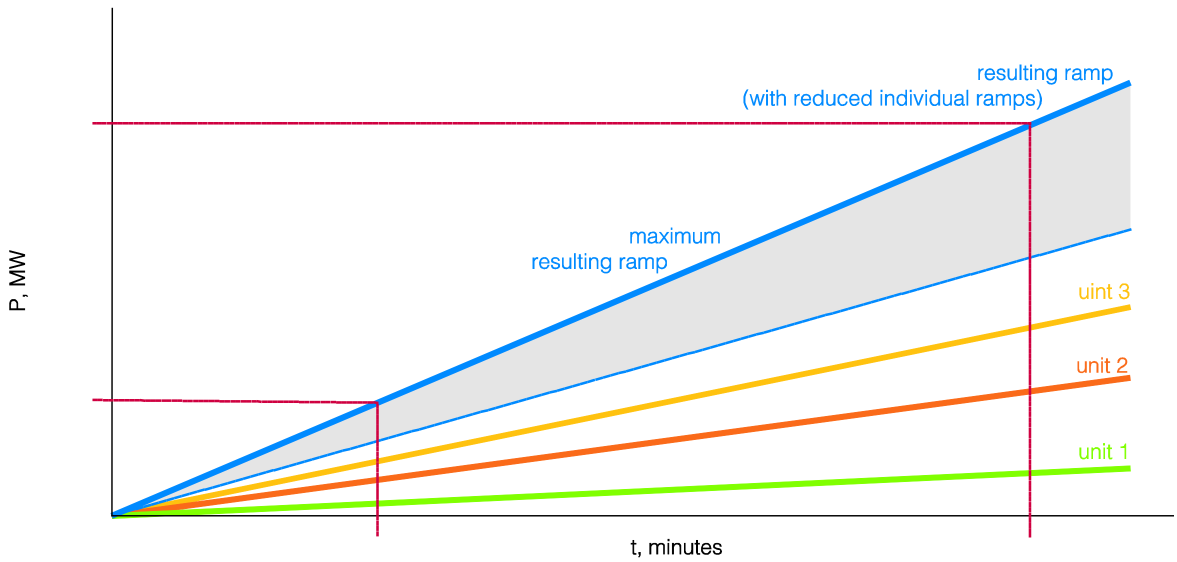

Figure 17 Using control systems to combine multiple units for greater ramp rates (Schröck and Dürr, 2013)

6.2 Turbine control systems

One of the functions of the turbine control system is to handle load changes while maintaining optimum efficiency and turbine life. Monitoring and control of the turbine are vital in preventing excessive thermal and creep-induced fatigue and also to prevent rubbing or excessive clearances resulting from differential expansion (Almstedt and others, 2007). Thus, the minimum requirement is to ensure that all temperatures and pressures remain within determined permitted ranges whatever the output or ramp rate.

Simple systems merely monitor the differential expansion between rotor and casing at a single point, then use a pre-set limit value to warn the operator to restrict conservatively the load change rate to ensure that no rubbing can occur. However, more sophisticated systems use monitored temperature and pressure data to calculate the expansion at different loads so that the associated clearances can be minimised at all times. This allows higher ramp rates, better efficiency and a total absence of rubs (Almstedt and others, 2007; FDBR, 2013).

To minimise thermal stresses, hot start-up has conventionally been carried out with the steam temperature higher than the turbine metal temperatures. However, this wastes steam, which has to be dumped to the condenser as the boiler is brought up to a sufficiently high outlet temperature (480–500°C). Modern units have control systems that enable the steam to be admitted at lower temperatures while the boiler is ramping. This allows the start-up time to be shortened by up to 15 minutes and less energy to be wasted (Quinkertz and others, 2008).

6.3 Plant control with self-learning predictive systems

There are advantages in installing comprehensive high level overall control systems that can co-ordinate the main plant systems by using predictive algorithms. Traditional control systems optimise the combustion process, steam cycle, steam turbine and emission control systems independently. Integration across the whole plant occurs through the actions of the plant operator. Modern automation systems now provide the ability to optimise the whole plant. This is highly beneficial in realising greater flexibility, in reducing stresses on the plant components while maximising efficiency and maintaining minimum emissions during load changes (Breeze, 2013a). Such systems, which are not yet widespread in power plants, may use mechanistic models to utilise the known principles of the various plant components, such as the furnace, boiler and turbine. Fuzzy logic may also be incorporated for less stable processes.

There are other situations where information on plant areas is not known or may not be available for other reasons. For these, a black box model may be used, which produces the predicted relationships from data inputs from around the plant without having access to specific detailed information (Breeze, 2013b). An example of a self-learning control system that operates in this way is ADEX's adaptive predictive technology that has recently been used in simulation of a CO_2 capture oxyfuel CFBC plant as part of a European FP7 project (Flexiburn). The high level control system was shown to work well without identification of the detailed dynamics of individual modules. Although this was a CO_2 capture application (and so is further discussed in Chapter 10), similar principles can be applied to non-capture coal-fired power plants (Slaven, 2013; Slaven and others, 2013).

6.4 Integration with other plants

Schröck and Dürr (2013) describe the emerging possibility of grids with greater flexibility, with operators employing remote monitoring of major units in an automated, closely co-ordinated mode, taking advantage of advanced control systems and the internet. For example, unavailability from component failure will be capable of being compensated through real-time data availability and forecasts, ultimately using neural networks for early identification of problems. Figure 18 shows the three principal elements of such a system envisaged by Siemens, embracing the local plant and central planning and diagnostics centres.

Marketing/generation planning with real time optimiser	marketing of current output excess and shortfall (real time) at each plant scheduling, taking account of current dynamic efficiencies of plants scheduling, taking account of current synchronisation point scheduling of the output forecast (day-ahead) supplied by power plant site and diagnostics and analysis centre scheduling of non-availabilities (already done).
Power plant site	communication of current output excess and shortfall (real time) advanced automatic checking program for starting drives and subordinate functional groups to ensure planned block start up time is met control system standby program to monitor drives and not ready for operation and implausible measured values to ensure planned block start-up time is met repair work/realisation of measures at economically favourable times (already done).
Diagnostics and analysis centre	monitoring of current dynamic efficiencies monitoring of current plant performance to ensure target output, gradients, control products and block start-up time, forecasting of load range between minimum technical and maximum (day ahead) in consultation with power plant site reporting of upcoming events.

Figure 18 Central and local elements and tasks of future power generation control systems (Schröck and Dürr, 2013)

7 Flexibility of CFBC plants

CFBC (circulating fluidised bed combustion) power plants use similar steam cycles to those of pulverised coal combustion plants, but the combustion system used in them is very different. The fuel is crushed, rather than pulverised, and combustion takes place at lower temperatures than in PCC systems in a highly mobile bed of ash and fuel supported on an upward current of combustion air. Most of the solids are continuously blown out of the bed then recirculated to the combustor. Heat is extracted for steam production from various parts of the system (*see* Figure 19). Limestone is also fed to the combustion system to control SO_2 emissions. Emissions of NOx are intrinsically lower than for PCC.

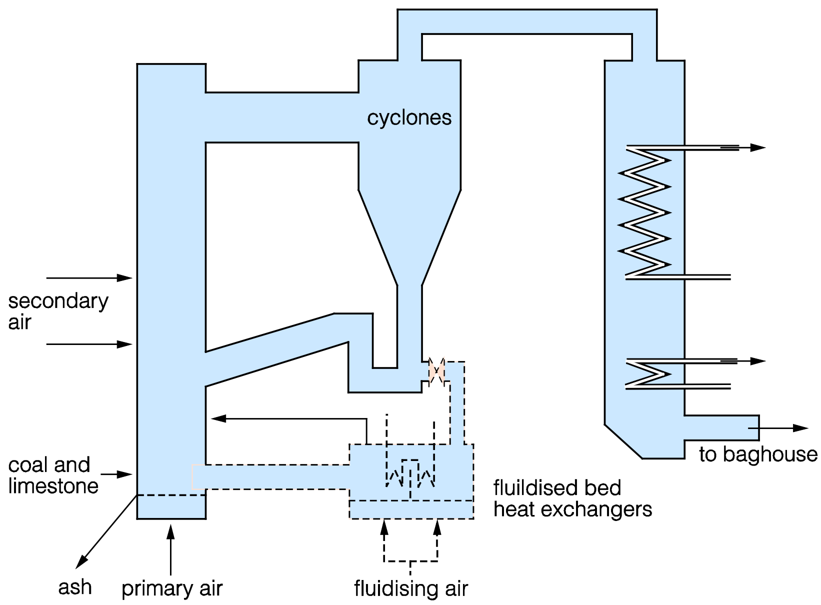

Figure 19 General schematic of a circulating fluidised bed boiler (Lockwood, 2013)

Refractory linings protect the tubing that forms the water-walls of the combustion chamber against erosion. Flue gases leaving the cyclones are generally sent to a conventional convective pass for steam superheating and other heat to the steam cycle. For more detailed descriptions of CFBC, *see* two recent IEA Clean Coal Centre reports, by Zhu (2013) and Lockwood (2013).

The flexibility issues of the turbine and water/steam cycle would be expected to be similar to those of pulverised coal plants. The essential differences from PCC units lie in the boiler and fuel feed and combustion systems. These can limit minimum load to about 40% of MCR in the absence of supplementary fuel. However, load following capabilities can be similar to those of PCC units: part loads down to 25% of MCR and load change rates of up to 7%/min are said to be possible (Mills, 2011).

Start-up times for some units can be longer than for similarly sized PCC plants. CFBC is less well suited to on/off cycling, as the bed temperature needs as far as possible to remain within normal operating range, and there can be potential for refractory damage (Zhu, 2013; Mills, 2011).

Wide or rapid temperature changes occurring during start-up, shut-down or load following can cause damage in the combustor and loop seal areas. However, a number of units have been cycled for some years, apparently without problems. Foster Wheeler offer for their Compact CFBC boilers a reheat steam bypass system for reheat steam temperature control during start-up and shut-down. The design also provides in-duct and over-grid start-up burners to shorten start-up times and save fuel (Mills, 2011).

8 Flexibility of IGCC plants

Coal-fuelled IGCC (integrated gasification combined cycle) power generation uses a combination of gas and steam turbines to produce electricity, rather than simply a steam turbine as in a PCC plant. Figure 20 shows the principle. The feed coal is converted to a fuel gas in a gasifier, which is generally of entrained flow design, fed with oxygen from an air separation plant. The fuel gas is subsequently cleaned of particulates and impurities before firing in the gas turbine to generate power. Hot exhaust gas from the gas turbine is passed through a waste heat boiler, where steam is generated for the steam turbine, which produces additional power. Steam available at suitable pressures from the gas production and cooling stages is also used at various points in the steam cycle.

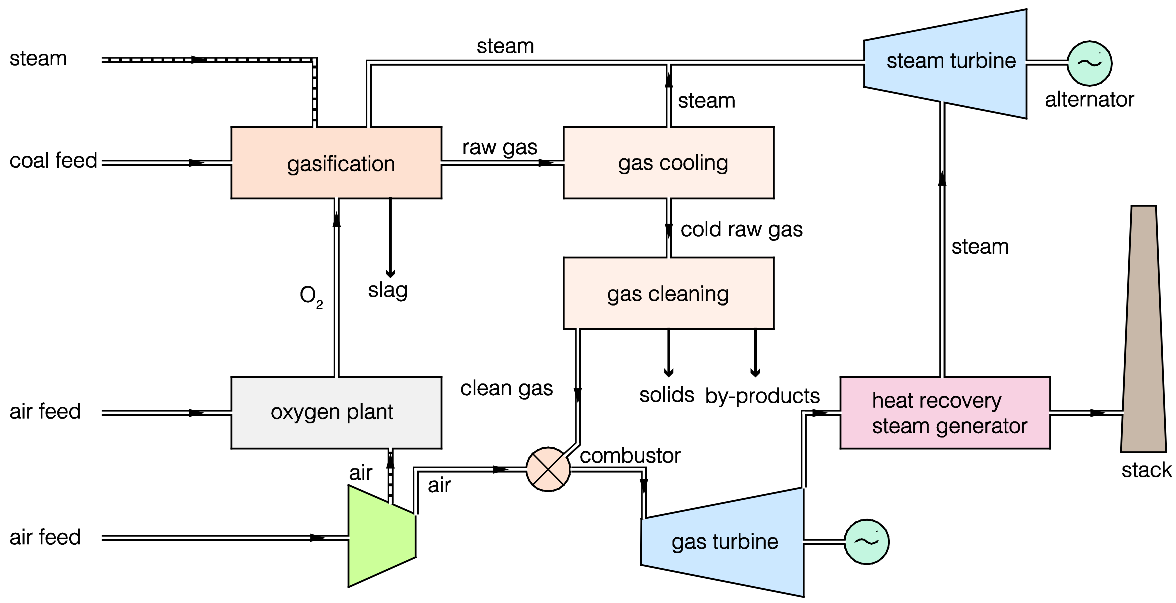

Figure 20 Integrated gasification combined cycle power generation (Henderson, 2008)

Some IGCC power plants supply the air separation unit (ASU) with air extracted from the gas turbine, while others use separate motor driven compressors. Alternatively, a combination of both may be used (partial integration). Higher degrees of integration favour higher thermal efficiencies, but start-up times can be longer, as individual process areas need to be brought on-stream in sequence. Partial integration is probably the best choice of ASU configuration for a standard IGCC as a starting point for achieving flexibility without sacrificing too much efficiency.

IGCC systems have not hitherto been designed specifically for high flexibility and the minimum load is conventionally about 40–50%, mainly determined by the achievable minimum outputs of the entrained flow gasifier and ASU. However, if two gas turbines are installed, this will give more scope for reduction, but the excess syngas needs to be used in some other way. One way is to make provision to store it at times of low load. It can then be fed to the turbine during periods of high electricity demand. Alternatively, at the expense of adding to the complexity, IGCC plants can be designed as polygeneration (multi-product) systems. These are able to vary the balance of multiple products, including electricity, liquids and synthetic natural gas (SNG). Polygeneration plants are discussed in Chapter 10, and an IEA Clean Coal Centre report is devoted to them (Carpenter, 2008).

Temporary storage of syngas and over-sizing the ASU to allow liquid oxygen and nitrogen storage, where integration allows, are potential means of increasing load range. At low demand, excess power would be used by the oxygen producing plant. Another suggestion has been that natural gas might be added to the syngas to increase ramp rate and output. The ramp rate of a straightforward IGCC system, as shown earlier in Table 2, will be determined by the gasifier and ASU ramp rates, and is, typically, about 3-5%/min, and so not very different from that of many older PCC units (Butler and others, 2013; Chalmers, 2010; Mills, 2011; Domenichini and others, 2013).

Some gasification systems use a largely air feed to the gasifier. An example is MHI's air-blown entrained gasification process. A 250 MW IGCC demonstration (now commercially operating) using the technology at Nakoso in Japan has achieved its design ramp rate of 3%/min and a minimum load of 36%. Start-up time was 15 h. There are plans to reduce the minimum load further (Watanabe, 2012).

Conceptual IGCC designs suggested for greater flexibility include some incorporating electrolysis. These could use excess power from the plant or from the grid, as appropriate, to provide additional hydrogen for the methanation of the syngas to SNG, while integrating heat from the exothermic SNG synthesis within the steam cycle (Butler and others, 2013; Wolfersdorf and others, 2013).

There has been relatively limited experience with IGCC power plants and these were not designed to meet rapidly changing and highly variable loads or rapid start-up or shut-down. It is therefore not yet clear how much operating flexibility will actually be obtainable with development. The fully-integrated Willem-Alexander IGCC plant at Buggenum in the Netherlands was operated as a commercial unit in load-following mode for over ten years until 2013. This plant was closed on 1 April 2013 on economic grounds (Barnes, 2013; Nuon, 2013). If IGCC plants start to be ordered in large numbers, designing for flexibility will become more important and further new approaches to achieving it may emerge.

9 Flexibility of future advanced USC technology

Manufacturers and utilities are working to achieve efficiencies of about 50% (LHV basis) and higher, by using steam conditions of 700–800°C at pressures of 35 MPa in advanced ultra-supercritical (A-USC) pulverised coal-fired plants. Superalloys based on nickel will be used in these systems. They are much more expensive than currently used steels, but only the highest temperature parts would be fabricated from them. Superalloys are already established in gas turbine systems, but component sizes in a coal plant are larger, the chemical environment is different, and pressure stresses are higher. Consequently, new formulations and fabrication methods are necessary. Activities to develop A-USC are in Europe, Japan, the USA, India, China and Russia. An IEA Clean Coal Centre report describes recent developments (Nicol, 2013b).

There is no experience with an operating A-USC plant, but such plants, like all other fossil-fired plants, will almost certainly need to have the capability to operate flexibly to be used in power grids with high capacities of renewable energy units on the system. However, nickel based alloys have the disadvantages of low thermal conductivity and a high thermal expansion coefficient (*see* Figures 21 and 22). These properties would potentially give rise to higher thermally induced stresses during changes of steam temperature than are encountered with the steels used in current plants. Work on the design and development of the superalloy components will have to overcome this if the A-USC plants are to achieve adequate flexibility for use in power markets such as in Europe (Gierschner and others, 2012).

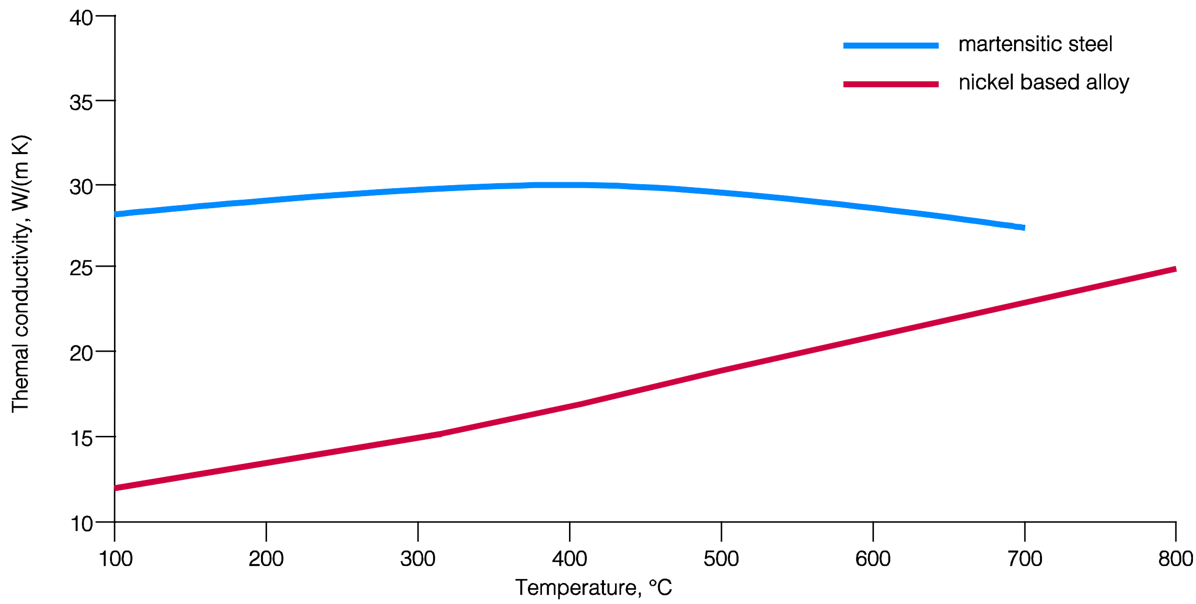

Figure 21 Thermal conductivity of a nickel based alloy and of a martensitic steel (Gierschner and others, 2012)

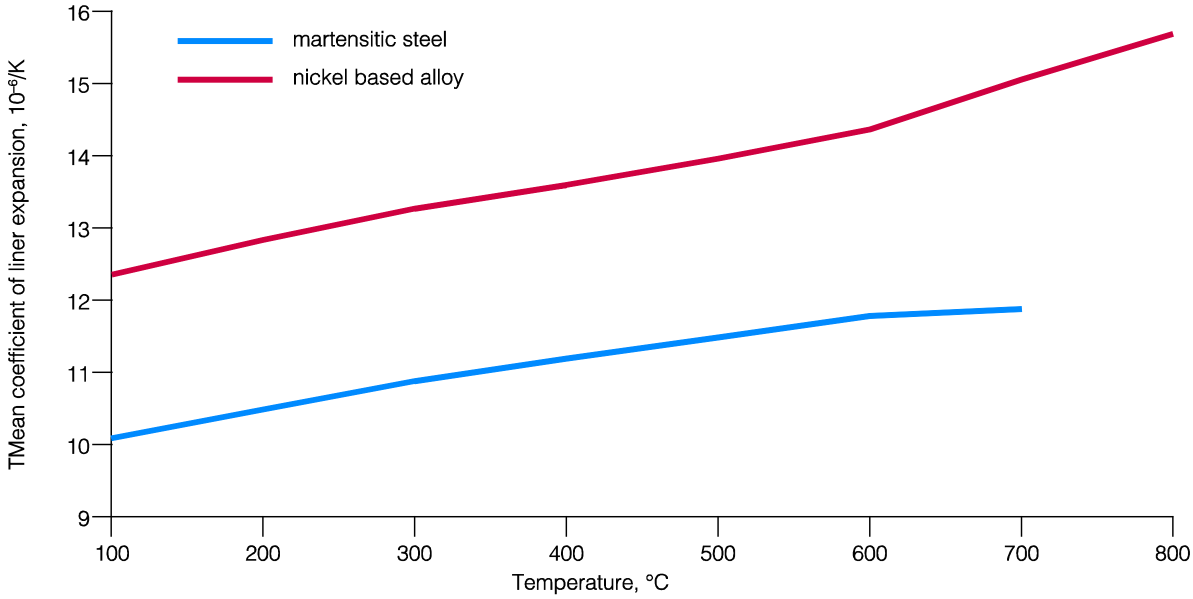

Figure 22 Thermal conductivity of a nickel based alloy and of a martensitic steel (Gierschner and others, 2012)

Table 6, taken from a graphical representation (in Busekrus, 2012), compares predicted start-up times for 600°C and 700°C technologies. A more detailed representation of the cold start-up metrics predicted for a 700°C, 35 MPa A-USC unit, is shown in Figure 23. This includes predictions of parameters such as the feedwater flow, steam flow, steam temperatures, steam pressures and turbine speed over the long run-up in the various areas of the plant. Laboratory test programmes using capacitive creep strain sensors, to assess the creep performance of superalloys, and modelling of creep-fatigue within the MACPLUS part of the A-USC programme in Europe are referred to by Kranz (2013) and Zanin (2013).

Table 6 Predicted start-up time for USC and advanced USC plants, minutes (Busekrus, 2012)

	600°C	700°C
Hot	120	130
Warm	200	300
Cold	320	430

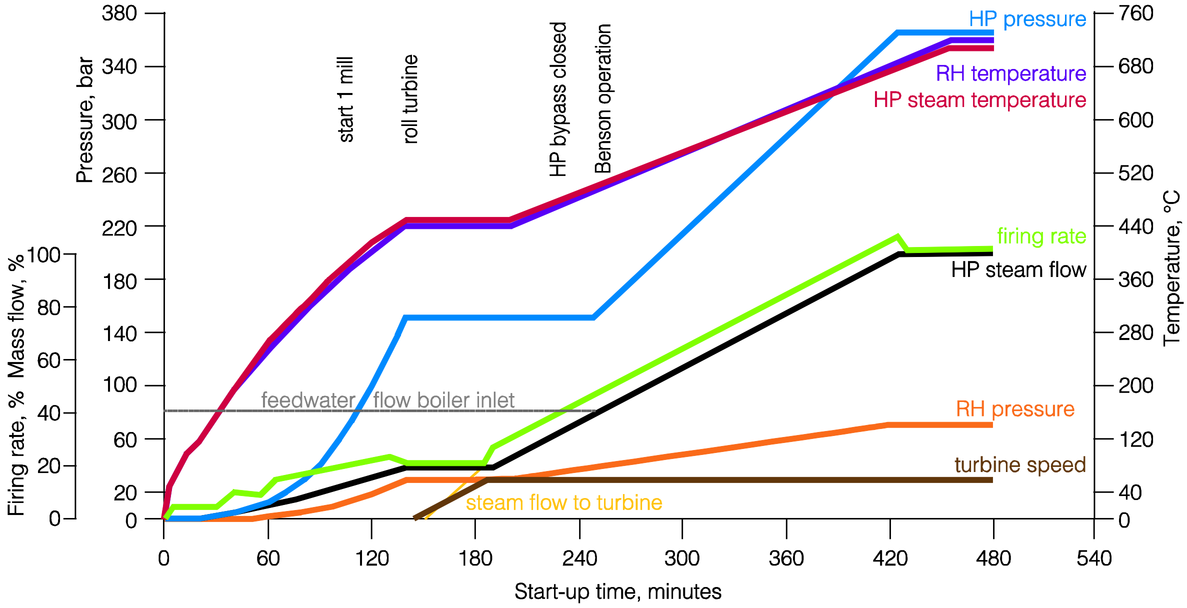

Figure 23 Predicted start-up dynamics for an A-USC (700°C) unit (Busekrus, 2012)

In summary, it not known at this stage for certain how much flexibility A-USC plants would be capable of in practice, but development of the required materials and their associated component fabrication techniques needs to be reconciled with the requirement for it (Wolff, 2012). If it turns out that sufficient flexibility cannot be achieved, such units will need to be restricted to base load application, which will leave them most suited to countries where higher, more stable capacity factors for coal-fired plants are likely to be sustainable, for example, in some Asian countries.

10 Flexibility of future coal-fired power plants with CO_2 capture

Predictions are that coal-fired plants incorporating CO_2 capture and storage (CCS) will be operating in significant numbers from about the mid-2020s, with major deployment during the 2030s (IEA, 2012). A number of IEA Clean Coal Centre reports from recent years described the technologies being developed (*see, for example,* Davidson, 2007, 2009, 2011, 2012). If and when carbon emissions prices become significant, CCS plants should be able to operate at higher capacity factors than plants without CO_2 capture because of their requiring fewer emissions allowances to be purchased. A proportion of these may provide base load, alongside nuclear plants (Davison, 2011). However, some CO_2 capture plants could need to operate flexibly, if wind and solar energy plants are called to operate first to maximise their usage.

Studies are providing indications of how flexible operation of coal-fired CCS plants could be realised, at a cost. Table 7, from a paper based on a study by Foster Wheeler for the IEA Greenhouse Gas R&D Programme, summarises the main techniques being considered.

Table 7 Techniques available for improving the flexibility of CO_2 capture plants (Domenichini and others, 2013)

	USC PCC	IGCC	Oxy-combustion
Turning off CO_2 capture	√	√	–
Co-production and storage of hydrogen	√	–	–
Storage of liquid oxygen	–	√	√
Storage of CO_2 capture solvent	√	–	–
Buffer storage of CO_2 (for constant flow to final storage)	√	√	√

For post-combustion capture plant, a rapid increase in output could be achieved by temporarily diverting the flue gas away from the CO_2 capture unit, if regulations permitted. At the same time, the flow of steam to the solvent regenerators would be turned off, increasing steam flow to the LP cylinders. At times of low demand, the CO_2 capture plant would be reconnected to the flue gas path. The steam cycle would need to be designed to accept the resultant higher flow. It is possible that the ability of such a plant to ramp up in output could be better than that of a plant without capture. However, large vessels for storage of CO_2-laden solvent would be needed if long periods of peak load were to be satisfied. Stored solvent would be regenerated at times of low power demand, when steam would be diverted to the regenerator, and achieving lower than normal minimum loads would then be possible. The large quantity of solvent that would have to be stored would mean that operating at peak output for long periods of time would not be attractive. Different variations would have different part-load efficiencies and economics (Lucquiaud and others, 2009; Chalmers and others, 2011; Mills, 2011; Domenichini and others, 2013; Mac Dowell, 2014).

Integrated gasification combined cycle (IGCC) power plants with CO_2 capture could be designed to allow hydrogen to be produced and stored, for firing in the turbine later. The gas production and power generation processes would thereby be decoupled. Both combined cycle and open cycle hydrogen-fired gas turbines could be used, further increasing flexibility. The gasification, CO_2 capture, transport and storage equipment would operate at base load, which would avoid potential practical difficulties of flexible operation and reduce costs. However, variable load operation of hydrogen gas turbines would need to be confirmed (Davison, 2012; Domenichini and others, 2013).

Oxygen production consumes considerable quantities of power, and it would be possible to develop IGCC plant designs allowing diversion of excess power to the oxygen producing plant, reducing net plant output, and thereby store the gas for use when demand is high, improving the economics (Chalmers, 2010; Mills, 2011; Butler and others, 2013; Domenichini and others, 2013). The latter could apply to non-capture IGCC plants and there was discussion of this in Chapter 8.

An IGCC plant design including two gas turbines and polygeneration could provide a turndown to 15-25%. This could improve utilisation, efficiency and, possibly, investment costs. If the chemical co-product were to be SNG, this could be stored in the natural gas grid. Figure 24 shows a version of such a system that allows pre-combustion CO_2 capture during operation of the gas turbine. This would require a dynamic operation of the synthesis plant, which is not usual practice (Butler and others, 2013). Variants of this concept, without CO_2 capture and incorporating an electrolysis cycle, were referred to in Chapter 8 (Butler and others, 2013; Wolfersdorf and others, 2013).

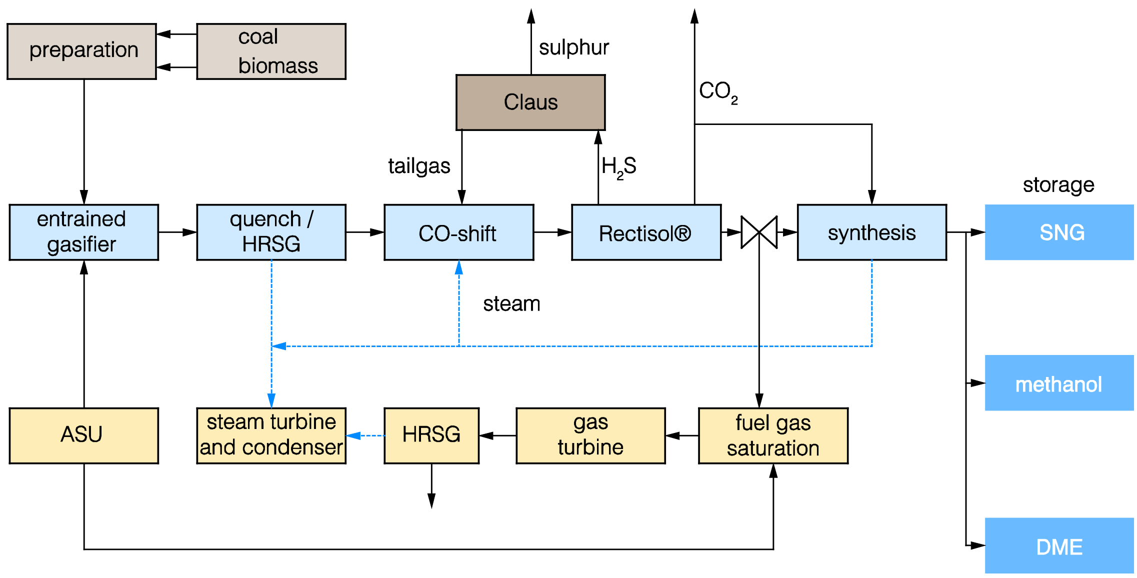

Figure 24 Simplified diagram of an IGCC polygeneration concept with dynamically driven synthesis and CO_2 capture (Butler and others, 2013)

Some gasification systems, such as MHI's process, use air for gasification. A feasibility study has been in progress on adding CO_2 capture after the wet gas clean-up at the 250 MW IGCC plant at Nakoso in Japan (*see* Chapter 8), but increasing the plant's flexibility is not mentioned as a specific aim of the CO_2 capture study (Watanabe, 2012; Barnes, 2013).

In oxy-coal systems, start-up on air will be followed by switching to oxygen plus recycle gas when the boiler has stabilised, which takes 20–30 minutes. Output flexibility within that timescale is likely to lie with temporarily switching off oxygen production and CO_2 capture (compression) and reintroducing air to the boiler. To add further flexibility and improve the economics there is also the possibility of employing oxygen storage with these plants (Chalmers, 2010; Domenichini and others, 2013).

Slaven and others (2013) have described the particular requirements of an oxy-fuel plant with respect to the control strategy to maintain close co-ordination of the various plant areas during load changes. These include managing:

- changes from oxy to air combustion or vice-versa at start-up, shut-down and as operating requirements vary;
- separate control of recirculating flue gas and oxygen to optimise combustion performance;
- balance between main components (air separation, boiler, CO_2 processing and turbine island) to maximise environmental and economic performance;
- control of flue gas composition prior to entering the gas processing unit.

A high level predictive control system across all plant modules would manage their functions and interfaces and adapt with precision and speed to changing dynamics, adjust appropriate variables to optimise efficiency and environmental performance, and so provide process stability. Such a control system would use adaptive predictive algorithms that would be able to anticipate and control the plant's changing dynamics.

Many of the systems described above could allow the flow of CO_2 to disposal to be maintained relatively constant. This is desirable because CO_2 compressors are typically limited to around 70% turndown. While greater turndown could be achieved by recycling compressed CO_2, this would impose a significant energy penalty (IEAGHG, 2012).

In summary, indications are that it may be possible to design plants incorporating CO_2 capture to have similar flexibility to their non-capture equivalents. However, cost considerations would influence the extent of flexibility realisable in practice. Some systems might allow high flexibility.

11 Summary and conclusions

A previous IEA Clean Coal Centre report considered the growing capacity of renewable energy plants around the world and the effects of their intermittent and highly variable output on the sort of role that coal-fired plants are having to fulfil (Mills, 2011). The effect is to force coal units in some countries to become swing suppliers. They have to deliver widely varying output so that total system supply matches load at all times. They also are being required, increasingly, to provide frequency control for grids because renewable power sources tend to be less well-suited to such duty, and grids are becoming of lower inertia. The challenges presented by this situation will only increase and become more widespread in the future. There is consequently a growing need for flexibility in coal-fired power plants for maintaining security of power supply. This present report focuses on the technical features that are available to enable plants to operate with rapid output changes with minimum detriment to integrity, efficiency and emissions.

There is a wide range of reported values for the load following rates of coal-fired power generation units, with ramp rates as high as 10% of maximum load/minute claimed to be achievable in some systems.

Flexible operation adds thermal and mechanical fatigue stresses to the creep damage that occurs anyway with time in the pressure parts of a coal-fired power plant. These, together with corrosion, differential expansion, and other effects, often synergistically, result in a reduction of the expected life of such components designed for base load. Operators and manufacturers have considered the mechanisms of these detrimental effects, and have come up with solutions. In addition, means of increasing flexibility that were constrained by non-life limiting considerations, such as better firing systems and better auxiliary motor drive systems, have been devised. The result is the availability of new and modified equipment, revised operating procedures, new specifications and further new ideas for making future plant designs more flexible while keeping efficiency as high as possible.

There are many features in specific plant areas that can be incorporated to give better flexibility. These include:

Boiler firing systems – changing to the size and number of mills and fitting of modern burners to achieve lower fuel feed rates to reduce number of shut-downs; introduction of lignite pre-drying (efficiency also improved); installation of hoppers and associated pipework to achieve indirect firing (efficiency at part load is then also improved)

Boiler pressure parts – use of alloys of improved strength to permit thinner section components; installation of external steam preheating to reduce start-up time; reducing minimum load through means such as modified evaporator designs, economiser water-side bypasses together with feedwater recirculation, and increasing the mass flow in the evaporator to achieve greater stability

Ensuring emissions control systems remain effective – installing means to maintain SCR exit temperature within specification at part load to avoid catalyst blocking and damage to the air heater;

minimising shut-downs and start-ups of FGD systems, and modernising control systems to reduce energy demand; for dust separation devices, ensuring adequate temperatures to avoid moisture condensation on particles

Turbine and water-steam systems – providing a turbine bypass so that the rate of steam temperature change can be managed as the boiler is starting up and shutting down, to reduce thermal stresses; use of a steam-cooled turbine outer casing to allow thinner sections for faster start-up; use of sliding pressure boiler-turbine systems for better control of turbine temperatures and reduced stresses; adding feedwater heater bypasses for greater load range; providing condensate throttling, feedwater heater bypass or HP stage bypass for frequency control; adding thermal (feedwater) storage systems for greater load range or frequency control

Control systems – installing new boiler control systems; installing new turbine monitoring and control systems; installing new self-learning control systems that co-ordinate the main plant systems by using predictive algorithms

Auxiliary plant – using flexible drives

Modifying plant configuration – retrofitting gas turbines integrated with the existing water-steam cycle for efficiency increase and increased output range and ramp rate.

The above measures are applicable to PCC (pulverised coal combustion) plants, but the flexibility aspects of the turbine and water-steam systems of CFBC (circulating fluidised bed combustion) plants are essentially the same as for PCC plants. The essential differences from PCC units lie in the boiler and fuel feed and combustion systems. The most flexible CFBC systems can have load change rates similar to those of similarly sized PCC plants, but start-up times can be longer than for PCC because of some tendency to suffer refractory damage from temperature changes.

IGCC (integrated gasification combined cycle) systems have not hitherto been designed specifically for high flexibility, and the minimum load and ramp rate are typically about 40–50% and 3–5%/min, respectively. These are comparable with older pulverised coal systems. Temporary storage of syngas is a possible way to provide more variable output. Another means could be to add facilities for oxygen storage. Some gasification systems use a largely air feed, but this does not appear to affect flexibility. Polygeneration (multi-product) IGCC systems would be able to vary the balance of different products and so allow greater load range, but it is uncertain whether response rate would be increased. There has been limited experience with IGCC power plants but, if they start to be ordered in large numbers, designing for flexibility will become more important and new approaches to achieving it may emerge.

Manufacturers and utilities are working to achieve efficiencies of about 50% (LHV basis) by using steam conditions of 700°C and above in advanced ultra-supercritical (A-USC) plants. There is no experience with an operating A-USC plant, but, like IGCC, they will almost certainly need to have the capability to operate flexibly. This could be difficult, as start-up time would be longer than for current USC units because of the properties of the superalloys that will be needed for the highest temperature components.

If necessary, it may be possible to design plants incorporating CO_2 capture to have similar flexibility to that of their non-capture equivalents, but cost considerations would influence the extent of flexibility realised in practice.

In summary, potential damage mechanisms from plant cycling duty are well known and the technical means exist for conventional combustion-based plants to achieve the necessary flexibility without unacceptable loss of plant life and thermal efficiency. Work is in progress on means to increase the flexibility of future systems. It is important that financial rewards are sufficient to cover the cost of maintaining grid balancing plants so that suitable fossil-fired capacity continues to be available to keep power supplies reliable.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

EXHIBIT 60

FL DEP LETTER TO US EPA RE REGIONAL HAZE PLAN FOR SECOND IMPLEMENTATION PERIOD

FLORIDA DEPARTMENT OF
Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Ron DeSantis
Governor

Jeanette Nuñez
Lt. Governor

Shawn Hamilton
Secretary

Via Electronic Mail and State Planning Electronic Collaboration System

October 8, 2021

Mr. John Blevins
Acting Regional Administrator
U. S. Environmental Protection Agency (EPA) – Region 4
61 Forsyth Street, SW – Mail Code: 9T25
Atlanta, GA 30303-8909

Re: Florida SIP Submittal: Regional Haze Plan for the Second Implementation Period

Dear Mr. Blevins:

In accordance with 40 CFR 51.103, the Department of Environmental Protection (Department) requests approval of a revision to Florida's Regional Haze State Implementation Plan (SIP) for the second implementation period of the U.S. Environmental Protection Agency's (EPA) Regional Haze Rule (RHR).

The SIP revision represents commitments and enforceable actions taken by the Department to address the requirements of the RHR during the second implementation period from 2019 to 2028, towards the goal of attaining natural visibility conditions in Florida's designated federal Class I areas and those federal Class I areas in other states that may be affected by emissions from Florida. Pursuant to 40 CFR 51.308(f), Florida's regional haze plan includes the following elements:

- Calculations of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress for each Class I area;
- Documentation of the technical analysis on which Florida is relying to determine reasonable progress, including modeling, emissions, and data analysis;
- Source-specific reasonable progress four-factor analyses and documentation of the source selection process;
- Long-term strategy for regional haze resulting from the reasonable progress analyses;
- Reasonable progress goals;
- A progress report addressing the requirements of 40 CFR 51.308(g)(1) through (5);
- Monitoring strategy and other implementation plan requirements; and

- Documentation of consultation with other states, EPA, and Federal Land Managers (FLMs).

These required elements are contained in the documents labeled *"Florida Regional Haze Plan for the Second Implementation Period"* and Appendices A through I. Appendices A through E include technical support materials and documentation used in developing the regional haze plan. Appendix F includes the documentation of the interagency consultation process. Appendix G includes documentation of the source-specific reasonable progress analyses conducted. Appendix H includes comments from the Federal Land Managers (FLMs) received during the 60-day FLM consultation period. Appendix I includes public comments received during the 30-day public comment period and the Department's response to public comments. The full Table of Appendices, which includes descriptions and file names for each appendix and sub-appendix and indicates which are Florida-specific and which are VISTAS-wide, is available in the *"Florida Regional Haze Plan for the Second Implementation Period"* document. The Florida-specific appendices are:

- Appendix F-1: Florida Consultation Letters to Other VISTAS States
- Appendix F-4: Florida Consultation with MANE-VU
- Appendix G-1: FL DEP Letters to Selected Facilities
- Appendix G-2: Responses Received from Selected Facilities
- Appendix G-3: Facility Permits and Documentation
- Appendix G-4: Florida Certified Smoke Management Plan
- Appendix G-5: Documentation of the Permanent Shutdown of BART and Reasonable Progress Units from the First Implementation Period
- Appendix H: Federal Land Manager Comment Summary
- Appendix I-1: Florida Clinicians for Climate Action Comments
- Appendix I-2: National Parks Conservation Association, Coalition to Protect America's National Parks and Sierra Club Public Comments
- Appendix I-3: Public Comment via Email Campaign
- Appendix I-4: Public Hearing Summary
- Appendix I-5: Response to Public Comments

All appendices are available on the Department's FTP site. The FTP site can be accessed using Windows File Explorer.

All documents, except for Appendices G-3 and G-4, are submitted for adoption into the nonregulatory portion of the SIP in 40 CFR 52.520, table (e). Appendix G-4, Florida's Smoke Management Plan, is included for reference only, and should not be adopted into Florida's SIP.

Appendix G-3 includes, for reference, the full air construction permits issued to Florida facilities to meet reasonable progress requirements. The document "Final 2021-01 - Regional Haze SIP" contains administrative items related to the SIP development process, including source-specific requirements to be incorporated into and removed from Florida's SIP. Through this SIP revision, the Department is requesting to incorporate into the regulatory portion of Florida's SIP at 40 CFR 52.520, table (d), certain source-specific SO_2 emission limits and permit conditions resulting from the reasonable progress analyses. Details of specific permit conditions to be incorporated into the regulatory portion of the SIP can be found in the SIP submittal.

The Department also requests that source-specific reasonable progress and best available retrofit technology (BART) limits from the first implementation period for specific units be removed from the SIP. These source-specific emission limits are applicable to units that have all permanently shutdown; therefore, removal of these limits from the SIP will not interfere with attainment of the national ambient air quality standards, visibility, or any other Clean Air Act requirement. Details of specific permit conditions to be removed from the regulatory portion of the SIP can found in the SIP submittal.

On June 9, 2021, the Department published in the Florida Administrative Register a notice of opportunity to submit comments regarding this SIP revision, and/or participate in a public hearing, which was held on July 15, 2021. The public hearing summary is included in Appendix I-4.

Attached please find the SIP submittal and *"Florida Regional Haze Plan for the Second Implementation Period"* documents. These two documents as well as all of the appendices have also been made available on the Department's Regional Haze website.

If you have any questions, please contact Ashley Kung at (850) 717-9041 or by email at Ashley.Kung@floridadep.gov.

Sincerely,

Jeffery F. Koerner

Jeffery F. Koerner, Director
Division of Air Resource Management

JFK/ak

cc:
Caroline Freeman, Division Director, Air & Radiation Division, EPA Region 4;
Lynorae Benjamin, Chief, Air Planning & Implementation Branch, EPA Region 4;
Pepa Sassin, Section Chief, Air Regulatory Management Section;
Pearlene Williams, Air Regulatory Management Section;
Michele Notarianni, Air Regulatory Management Section.

Enclosures:
Final 2021-01 - Regional Haze SIP; and
Florida Regional Haze Plan for the Second Implementation Period.