Resource Adequacy Analysis

Technical Support Document

New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emissions Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule

Final Rule

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This document supports the EPA's Final New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units and the Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units, and describes projected resource adequacy impacts of the final rules.

This technical support document (TSD) describes EPA's analysis of the potential impacts of the final rules on the resource adequacy of the U.S. power grid. It was developed in consultation with the Department of Energy (DOE), drawing on the particular expertise and responsibilities of the agencies described in the March 9, 2023 *Joint Memorandum of Understanding on Interagency Communication and Consultation on Electric Reliability* signed by the EPA Administrator and the Secretary of Energy.[1] The objective of this analysis is to provide insight into the resource adequacy impacts of the rule. EPA's role in regulating emissions from electric generating units does not include specifying generation resource mixes or grid operations and planning practices. Thus, EPA does not conduct operational reliability studies. Rather, in this document, EPA describes its modeling of the projected impact of the final rules. The analysis includes both modeling of the power sector under reliability-protective constraints used by the North American Electric Reliability Corporation (NERC) and additional non-modeling considerations related to resource adequacy. EPA finds that projected impacts to the resource mix are relatively modest, and that strong institutional mechanisms exist to preserve resource adequacy.

Resource Adequacy in the Context of EPA's Final Rule

Resource adequacy is an important aspect of grid reliability.[2] As used here, the term resource adequacy is defined as the provision for adequate generating resources to meet projected load and generating reserve requirements in a power region.[3] Another key aspect of reliability is operational reliability, which includes the ability to withstand sudden electric system disturbances that can lead to blackouts.[4] This document is meant to serve as a resource adequacy assessment of the impacts of the final rules and how projected outcomes under the final rules compare with projected baseline outcomes in the presence of the Inflation Reduction Act (IRA). Under the baseline, the impacts of the IRA result in an acceleration of the ongoing shift towards lower emitting generation and a declining generation share for fossil-fuel fired generation. Studies such as the *Electricity Sector Emissions Impacts of the Inflation Reduction Act* demonstrate that EPA's projected outcomes under the IRA remain consistent with a range of peer-reviewed forecasts.[5]

Numerous additional national laboratory, academic, and industry-led studies have explored the resource adequacy impact of increasing clean electricity generation and decreasing power sector greenhouse gas emissions. Collectively, these studies demonstrate that meeting

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[1] *Joint Memorandum of Understanding on Interagency Communication and Consultation on Electric Reliability* (March 9, 2023). *https://www.epa.gov/power-sector/electric-reliability-mou*.
[2] For additional discussion of reliability, see https://www.nerc.com/AboutNERC/Documents/Terms%20AUG13.pdf.
[3] As analyzed in this document, power regions correspond to aggregates of Integrated Planning Model (IPM) regions corresponding to NERC assessment areas.
[4] Federal Energy Regulatory Commission (FERC) Reliability Explainer. https://www.ferc.gov/reliability-explainer.
[5] Available at https://www.epa.gov/inflation-reduction-act/electric-sector-emissions-impacts-inflation-reduction-act.

resource adequacy needs is achievable with current institutional mechanisms and known operational practices, under scenarios similar and that go beyond those expected due to IRA and this rulemaking. While this document is limited to an analysis of resource adequacy within the context of this rulemaking, EPA notes that many of these studies have also demonstrated how reliability, more generally, can continue to be maintained under scenarios with significantly reduced levels of power sector greenhouse gas emissions. Collectively, these studies find that: resource adequacy can be maintained during all hours of the year through a portfolio approach which that aggregates deployment of variable renewable resources with dispatchable resources, energy storage, and other technologies.[6] Beyond resource adequacy, these studies also evaluate aspects of operational reliability, finding that short-term variability and uncertainty in renewable generation can be cost effectively managed by increasing grid flexibility; increased utilization of power electronics can support frequency stability; and expanded transmission networks can help maintain and enhance reliability. Other studies have also evaluated highly decarbonized systems' ability to maintain operational reliability in the face of supply disturbances or extreme demand circumstances. For example, in its filing before the Colorado Public Utilities Commission, Tri-State Electric Cooperative submitted a proposed resource mix that achieves an 89% reduction in greenhouse gas emissions by 2030, compared to 2005 levels, reached 70% zero-emission generation by 2030, and includes a new combined cycle unit with carbon capture and sequestration by 2031.[7] Tri-State included an analysis that tested its proposed resource mix against extreme weather events and found that the proposed portfolio can meet a very high standard of reliability even in extreme circumstances.[8]

Examples of these studies include studies such as National Renewable Energy Laboratory's (NREL) 100% renewable power system study (2021) using the Regional Energy Deployment System (ReEDS) model published in the journal *Joule* [9], and the Net-Zero America study (2021) from Princeton University, which uses the Energy PATHWAYS-Regional Investment and Operations (EP-RIO) model.[10] These two studies demonstrate how even higher levels of renewables can be part of a grid that maintains resource adequacy. The North American Renewable Integration Study (2021) found multiple pathways can lead to 80% power-sector carbon reduction continent-wide by 2050 while maintaining resource adequacy.[11] The Solar Futures Study (2021) found existing technology portfolio approaches could maintain resource adequacy under high solar deployment and decarbonization scenarios.[12] Examples of regional grid operator studies that examine how reliability can be maintained with a changing generation

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[6] *Maintaining Grid Reliability – Lessons from Renewable Integration Studies.* National Renewable Energy Laboratory, April 2024. Available at: https://www.nrel.gov/docs/fy24osti/89166.pdf.

[7] https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=1011533&p_session_id=

[8] Reliability metrics included achieving: 1) less than or equal to 3 loss of load hours per year, 2) less than or equal to 12 loss of load hours across the study period from 2026-2031, and 3) expected unserved energy cannot exceed 20% of load in any hour. Tri-State found that its preferred scenario achieves 0 MWhs of unserved energy and 0 hours of low of load in all years from its extreme weather sensitivity.

[9] Cole et al., Quantifying the challenge of reaching a 100% renewable energy power system for the United States. Joule 5, 1732–1748 July 21, 2021. https://doi.org/10.1016/j.joule.2021.05.011.

[10] Larson, E. et al., 2021. Net-Zero America: Potential Pathways, Infrastructure, and Impacts, Final Report Summary, Princeton University, Princeton, NJ. https://netzeroamerica.princeton.edu/the-report.

[11] *The North American Renewable Integration Study: A U.S. Perspective.* National Renewable Energy Laboratory, June 2021. https://www.nrel.gov/docs/fy21osti/79224.pdf

[12] *Solar Futures Study.* U.S. Department of Energy, September 2021. https://www.energy.gov/sites/default/files/2021-09/Solar%20Futures%20Study.pdf

resource mix include ISO New England's Future Grid Reliability Study (2022)[13], Resource Adequacy in the Pacific Northwest (2019)[14], Energy Transition in PJM: Frameworks for Analysis (2021)[15], Midcontinent Independent System Operator's (MISO) Renewable Integration Impact Assessment (2021)[16], and Southwest Power Pool's Wind Integration Study (2016)[17]. In addition, the U.S. Department of Energy (DOE) finds that a portfolio approach that takes advantage of the full range of technology, planning, and operational solutions best ensures reliable power.[18]

The final rules establish emissions rate limits for covered electric generating units (EGUs). The stringency of these emission rate limits is set through assuming the installation of various greenhouse gas (GHG) emissions control technologies. Covered sources would therefore be able to comply with the rules with these within-the-fence technologies and are not required to reduce utilization or shift generation. Nonetheless, given the flexibility provided by performance-based standards and in light of the transition of the power sector toward less emitting generating resources, as highlighted by stakeholders, it is anticipated that some EGU owners and operators may pursue alternative compliance strategies. Should those strategies involve the curtailment or retirement of existing generating resources or the operation of new generating resources at lower capacity factors than they would have otherwise, stakeholders have separately raised concerns that this could impact the reliability of the power grid.

The emission reduction requirements under these rules are based on adequately demonstrated cost-reasonable control measures that comprise the best system of emissions reduction (BSER). Some EGU owners may conclude that, all else being equal, retiring a particular EGU and replacing it with cleaner generating capacity is likely to be a more economic option from the perspective of the unit's customers and/or owners than making substantial investments in new emissions controls at the unit. EPA understands that before implementing such a retirement decision, the unit's owner will follow the processes put in place by the relevant regional transmission organization (RTO), balancing authority, or state regulator to protect electric system reliability. These processes typically include analysis of the potential impacts of the proposed EGU retirement on electrical system reliability, identification of options for mitigating any identified adverse impacts, and, in some cases, temporary provision of any revenues necessary to compensate the EGU for the cost of continued operation until longer-term mitigation measures can be put in place. EPA expects that states will conduct meaningful engagement with relevant balancing authorities, grid operators, and reliability coordinators to

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[13] *2021 Economic Study: Future Grid Reliability Study Phase 1.* ISO New England, July 2022. https://www.iso-ne.com/static-assets/documents/2022/07/2021_economic_study_future_grid_reliability_study_phase_1_report.pdf
[14] *Resource Adequacy in the Pacific Northwest.* Energy and Environmental Economics, Inc., March 2019. https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf
[15] *Energy in Transition in PJM: Frameworks for Analysis.* PJM Interconnection LLC, December 2021. https://www.pjm.com/-/media/library/reports-notices/special-reports/2021/20211215-energy-transition-in-pjm-frameworks-for-analysis.ashx
[16] *MISO's Renewable Integration Impact Assessment*. MISO, February 2021. https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf
[17] *2016 Wind Integration Study.* Southwest Power Pool, January 2016. https://www.spp.org/documents/34200/2016%20wind%20integration%20study%20(wis)%20final.pdf
[18] *The Future of Resource Adequacy.* DOE. 2024. https://www.energy.gov/policy/articles/new-doe-report-outlines-solutions-meet-increasing-electricity-demand-and-cut

promote early and informed reliability planning to ensure that electric system reliability is maintained during and after any resulting unit retirements.

While such potential impacts would not be a direct result of these rules but rather of the compliance choices source owners and operators may pursue, we have analyzed whether the projected effects of the rules would in this regard pose a risk to resource adequacy. It is important to recognize that the final rules provide multiple flexibilities that preserve the ability of responsible authorities to maintain electric system reliability. For more detail on how the final rules address reliability concerns, see Section XII.F of the final rule preamble. The results presented in this document show that the projected impacts of the final rules on power system operations, under conditions preserving resource adequacy, are relatively modest and manageable.

Methodology

The results presented in this document further demonstrate, for the specific case illustrated in the Regulatory Impact Analysis (RIA), that the implementation of these rules can be achieved without undermining resource adequacy. The focus of the analysis is on comparing the illustrative final rules scenario from the RIA to a base case (absent the rule requirements) that is projected to be adequate and reliable. In this framework, the emphasis is on the incremental changes in the power system that are projected to occur under the presence of the rule in the 2028, 2030, 2035, 2040 and 2045 model run years[19]. The EPA uses the Integrated Planning Model (IPM) to project likely future electricity market conditions with and without the final rules.[20]

IPM is a state-of-the-art, peer-reviewed, multi-regional, dynamic, deterministic linear programming model of the contiguous U.S. electric power sector. It provides forecasts of least cost capacity expansion, electricity dispatch, and emissions control strategies while meeting energy demand and environmental, transmission, dispatch, and resource adequacy constraints. The EPA has used IPM for over two decades, including for prior successfully implemented rulemakings, to better understand power sector behavior under future business-as-usual conditions and to evaluate the economic and emissions impacts of prospective environmental policies. The model is designed to reflect electricity markets as accurately as possible. The EPA uses the best available information from utilities, industry experts, gas and coal market experts, financial institutions, and government statistics as the basis for the detailed power sector modeling in IPM. The model documentation provides additional information on the assumptions discussed here as well as all other model assumptions and inputs. The EPA relied on the same model platform at final as it did at proposal but made substantial updates to reflect public comments. Of particular relevance, the model framework relies on resource adequacy-related constraints that come directly from NERC. This includes NERC target reserve margins, NERC

[19] IPM uses model years to represent the full planning horizon being modeled. By mapping multiple calendar years to a run year, the model size is kept manageable. For this analysis, IPM maps the calendar years 2028-29 to run year 2028, calendar years 2030-31 to run year 2030, calendar years 2032-37 to run year 2035, calendar years 2038-41 to run year 2040 and calendar years 2042-47 to run year 2045. For model details, please see Chapter 2 of the IPM documentation, available at: https://www.epa.gov/power-sector-modeling.

[20] See final Regulatory Impact Analysis for more detail on the power sector impacts of the final rules.

Assessment regions, NERC Electricity Supply and Demand (ES&D) load factors, and NERC Generating Availability Data System. We note however that the targets and data collected by NERC do not reflect either mandatory reliability standards, tariff, or other obligations that registered entities are required to meet. Therefore, the model projections for the final rules are showing compliance pathways that respect these NERC reliability considerations and constraints. These results are discussed in the body of this report and demonstrate, for the specific case illustrated in the RIA, that the implementation of the final rules can be achieved without adversely affecting resource adequacy.[21]

Consistent with real-world decision making by utilities, RTOs, and state regulators, IPM's least-cost dispatch solution, in concert with the model's capacity expansion decision-making framework, is designed to ensure resource adequacy, either by using existing resources or through the construction of new resources. IPM addresses reliable delivery of generation resources for the delivery of electricity between the 78 IPM regions, based on current and planned transmission capacity, by setting limits on the ability to transfer power between regions using the bulk power transmission system. Within each model region, IPM assumes that adequate transmission capacity exists to deliver any resources located in, or transferred to, the region. The largest transmission constraints on the grid are represented in IPM using separate IPM regions, so each individual IPM region typically has relatively less internal transmission congestion (based on today's loads and resource mix).[22] Capacity expansion models often include transmission constraints only between selected regions (and not within them) because these models are designed to build out portfolios of generation resources and are not intended for detailed, local transmission planning.[23] While this analysis does not focus on local transmission availability, EPA notes that numerous federal actions are improving local transmission access and interconnection processes.[24] The model also includes constraints that adjust the reserve margin contribution of renewable resources and storage as a function of generation fraction.[25] Additionally, IPM models operating reserves at the regional level, and can account for the impact of solar and wind on operating reserves requirements.[26] This document focuses on key regional

[21] In respect to these resource adequacy requirements, the estimate of the compliance cost of the regulation accounts for any investment cost used to satisfy these requirements. That is, the compliance cost estimate in the corresponding RIA for the regulations includes any incremental cost of the need to install capacity that is available for use consistent with these resource adequacy retirements. For example, if a regulation would require a plant to install a particular control, the model in the policy scenario would fully capture the cost of either of those investments in the total cost estimates of the policy.

[22] IPM models separate regions that tend to align with the zones that ISOs and RTOs use for resource adequacy planning. For example, MISO plans for resource adequacy using 10 resource adequacy zones in its Planning Resource Auction, and each is separately modeled by one or more regions in IPM.

[23] https://www.energy.gov/sites/prod/files/2016/02/f30/EPSA_Power_Sector_Modeling_FINAL_021816_0.pdf

[24] These actions include the following: FERC Order 2023 is streamlining interconnection of new generation resources to the transmission grid. FERC published a NOPR to address transmission planning and cost allocation challenges. DOE's Grid Resilience and Innovations Partnerships (GRIP) program has $10.5 billion to enhance grid flexibility and improve resilience. GRIP funding supports grid modernization and deployment of innovative transmission projects that accelerate interconnection of clean energy, among other objectives. The Transmission Facilitation Program (TFP) has a revolving $2.5 billion to overcome financial hurdles for new and upgraded transmission line development by allowing DOE to be an anchor customer for new transmission projects.

[25] For details, please see Chapter 4 of the IPM documentation, available at: https://www.epa.gov/power-sector-modeling.

[26] For details, please see chapter 3 of the IPM documentation, available at: https://www.epa.gov/power-sector-modeling.

results important to management of the power system. For a more complete presentation of the projected power sector impacts of the final rules, see the Regulatory Impact Analysis.

Non-modeling Considerations Related to Resource Adequacy

The electricity sector also has numerous additional tools to maintain resource adequacy and grid reliability that are often not captured in models. A recent DOE report outlines various technology tools available to meet resource adequacy needs, including new generation and storage, transmission expansion and enhancement, and demand side resources. Key technologies not often captured in models and not included explicitly in IPM but available to utilities in planning processes include energy efficiency investments, deployment of virtual power plants leveraging distributed energy resources already being deployed, reconductoring existing transmission lines using advanced conductors, a suite of grid enhancing technologies like dynamic line ratings that can reduce congestion and help interconnect additional resources, deployment of energy storage at existing renewable energy generators to speed interconnection and permitting, and re-use of existing infrastructure such as through powering non-powered dams.[27]

EPA notes that resource adequacy is typically a state prerogative, with different states having different mandates and structures to ensure system generation is sufficient to meet demand (including participation in regional resource adequacy constructs overseen by federally-regulated RTOs). Power companies, grid operators, and regulators have well-established, adaptive procedures and policies in place to preserve electric reliability in response to system changes. Grid operators administer adaptive programs, such as capacity markets and resource adequacy programs, designed to require or incentivize medium- and long-term investment in the resources that will be needed to meet demand. In many states, regulators oversee long-term integrated resource planning by utilities to ensure that there is a diverse portfolio of generating resources with the qualities and attributes needed to reliably meet electricity demand. Integrated resource planning or an equivalent planning process is a critical tool available to states to help manage resource transitions. The Federal Energy Regulatory Commission (FERC), together with NERC and regional reliability organizations, establishes and enforces standards that transmission and generation utilities must meet to ensure operational reliability.

Over shorter time horizons, separate from mandatory reliability standards, grid operators and regulators have rules that require utilities to follow processes designed to protect reliability before making major plant modifications or retirement decisions. These typically include analysis of the potential impacts of retirement on reliability, identification of mitigating options, and, in some cases, temporary contracts to require operation until longer-term mitigation measures can be put in place. EPA has included compliance flexibilities in the final rules that allow states, power companies, and grid operators to ensure grid reliability. These compliance flexibilities including clarifying the appropriate use of remaining useful life and other factors (RULOF) to address reliability issues during state plan development and in subsequent state plan revisions; allowing emission averaging, trading, and unit-specific mass-based compliance mechanisms; and, for certain mechanisms, including a backstop emission rate and offering a compliance date extension for affected EGUs that encounter unanticipated delays with control

[27] *The Future of Resource Adequacy.* DOE. 2024. https://www.energy.gov/policy/articles/new-doe-report-outlines-solutions-meet-increasing-electricity-demand-and-cut

technology implementation. Additionally, EPA is finalizing two mechanisms, described in Section XII.F of the preamble for this rulemaking, to further address reliability concerns raised by commenters: a short-term reliability mechanism that allows affected EGUs to operate above their standard of performance for a limited time during periods of grid stress; and a long-term reliability assurance mechanism to ensure sufficient firm capacity is available. In addition to these measures, the DOE has authority to, on its own motion or by request, order, among other things, the temporary generation of electricity from particular sources in certain emergency conditions, including events that would result in a shortage of electric energy, when the Secretary of Energy determines that doing so will meet the emergency and serve the public interest. An affected source operating pursuant to such an order is deemed not to be operating in violation of its environmental requirements.

Overview of Resource Adequacy Impacts from RIA

These final rules establish CO_2 emission rate limits on covered fossil fuel-fired power plants (electric generating units or EGUs) in the U.S. The EGUs covered by the rules and subject to these limits are certain existing fossil-fuel fired steam generating units with >25-megawatt (MW) capacity, and new, modified, and reconstructed stationary combustion turbine EGUs. For details on the definition of the covered sources and the derivation of these emission rates, please see sections VII, VIII, IX and X of the final rule preamble.

This TSD uses the same scenario and years of analysis contained in the RIA.[28] The scenarios include a base case and the final rules scenario. For purposes of this resource adequacy assessment, estimates and projections are taken from those same scenarios and years as shown in the RIA (2028, 2030, 2035, 2040 and 2045).

Summary of Changes in Operational Capacity

Total operational capacity remains similar between the base and policy scenarios. Operational generating capacity[29] changes from the base case in 2028, 2030, 2035, 2040 and 2045 are summarized in Table 1 below. In Table 1, the total operational nameplate capacity from all resources is shown for the base case in the top row and for the policy case in the bottom row. The rows in between show the differences between the base case and policy case resource mixes in each year. The data is separated out by resource type and for retirements, de-rates, and additions.

[28] See Chapter 3 of the RIA for additional details on the scenarios examined.
[29] Operational capacity is any existing, new or retrofitted capacity that is not retired.

Table 1. Operational Capacity Summary (2028, 2030, 2035, 2040, 2045)

Capacity (GW)	2028	2030	2035	2040	2045
Base Case Operational Capacity	1,364	1,420	1,713	2,045	2,427
Minus Cumulative Incremental Policy Case Retirements					
Coal	-5	-4	-21	-14	-19
Oil/Gas	1	1	4	4	4
Natural Gas Combined Cycle (NGCC)	0	0	0	0	0
Natural Gas Combustion Turbines (NGCT)	0	0	0	0	0
Nuclear	0	0	0	0	0
Minus Cumulative Incremental Policy Case Derates					
Coal	0	0	-4	-4	-4
Plus Cumulative Incremental Policy Case Additions					
NGCC	0	-1	-1	-1	-1
NGCT	1	2	10	11	17
Wind	11	11	12	3	7
Solar	2	3	3	6	11
Storage	0	-2	9	2	2
Other	0	0	0	0	0
Policy Case Operational Capacity	1,374	1,431	1,725	2,052	2,444

Since the model is designed to maintain adequate reserves in each region, projected retirements are offset by reliance on existing baseline excess reserves, incremental builds, and the ability to shift transmission flows between regions in response to changing generation mix. In 2035, the illustrative compliance scenario shows an incremental 21 GW of coal retirement, 4 GW fewer oil/gas steam retirements, 9 GW of incremental gas-fired additions, 12 GW of incremental wind additions, 3 GW of incremental solar additions, and 9 GW of incremental battery storage additions. The coal retirements are in addition to 83 GW of coal retirements by 2035 under the baseline. In summary, out of more than 1,700 GW of operational nameplate capacity in the base case in 2035, illustrative compliance scenario shows replacement of 25 GW of coal capacity with 13 GW of gas and oil capacity and 24 GW of renewable and storage capacity. The incremental reduction in coal capacity represents 1.5 percent of total operational capacity of all types in 2035. The resulting resource mix meets all NERC reserve margins and other reliability requirements modeled in IPM, suggesting that the policy case resource mix meets resource adequacy requirements while complying with the final rules.

Planning Reserve Requirements

IPM uses a target reserve margin in each region[30] as the basis for determining how much capacity to keep operational in order to preserve resource adequacy. IPM retires capacity if it is no longer needed to provide energy for load or to provide capacity to meet reserve margin during the planning horizon of the projections. Since current regional reserves may be higher than the target reserve margin for a region, IPM may retire reserve capacity if it is not economic to use it to maintain adequate reserve margins. Existing resources may also be more expensive, compared to alternatives such as building new capacity or transferring capacity from another region. As a result, some of the plants that are projected to retire will not need to be replaced. Because some existing plants eventually retire in most regions, and IPM builds no more than what it needs to maintain a target reserve margin in each region, the actual reserve margins tend to approach the target reserve margins over time. For details on projected reserve margins under the base and policy scenario, please see Appendix A-3, B-3, C-3, D-3, and E-3.[31]

Changes in Retirements and New Capacity Additions under the Final Rules

The incremental retirements in the final rule case are shown above in Table 1 and are in addition to 83 GW of coal and 23 GW of oil/gas retirements already occurring in the base case through 2035.

By 2035, the final rule scenario as compared to the base case leads to higher levels of overall existing coal retirements and new capacity additions (shown regionally in Table A5, B5 and C5). These retirements and additions in the projections are the result of the model's optimization of economic planning for energy and capacity needs; they do not represent required outcomes for any individual units, which will be able to consider multiple compliance options in response to the final rules. In particular, new additions in a base case scenario that do not occur in the policy scenario projections might, in reality, be retained under a policy if local reliability conditions rendered this development the most appropriate choice. This rule does not prevent generation owners from shifting retirements and additions among specific sources to ensure reliability in such circumstances.

Firm Capacity Transfers for Meeting Planning Reserve Requirements

In cases where it is economic to transfer planning reserves from a neighboring region, rather than supply reserves from within a region, IPM will transfer firm capacity, subject to summer and winter limits that are designed to ensure that these reserves can be transferred reliably. The transfer of reserves can occur, for example, if a region retires capacity that was used in the base case to meet reserve requirements, but a neighboring region has excess lower cost firm capacity that are not needed for its own reserve requirements. To examine these transfers, the EPA analyzed the change in net transfers from each region, where the net transfer for the base and policy cases is measured by the firm capacity sent to neighboring regions. In

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[30] In IPM, reserve margins are used to represent the reliability standards that are in effect in each NERC region. Individual reserve margins for each NERC region are derived from reliability standards in NERC's electric reliability reports. The IPM regional reserve margins are imposed throughout the entire time horizon.

[31] See maps of IPM regions and NERC Assessment Regions, and the table of target and projected reserve margins in Appendix F. IPM regions are based on the regions NERC uses for regional assessments. These regions are used for the Appendix tables in this document.

these cases, a positive value signifies that the firm capacity sent to other regions is larger than the firm capacity received from other regions (sending and receiving regions can be different), while a negative value signifies that the capacity received is larger than the capacity sent. Thus, the value measures the degree to which resources in the region were reserved for use by other regions (positive value), or where the capacity to meet load in the region was served by resources in other regions (negative value). In each case these firm capacity transfers are limited within IPM by the firm Total Transfer Capabilities (TTC) between regions represent the use of the transmission system on a firm basis for at least a season. Firm or Capacity TTCs represent the aggregate transmission transfer capability between two regions after a single contingency loss. Limiting firm capacity transfers to the Firm TTCs ensures that transferred capacity can continue to support resource adequacy even under contingency conditions. IPM further imposes joint transmission capacity limits that limit the cumulative firm capacity transferred between groups of model regions. These limits represent additional transmission system constraints that affect the maximum simultaneous transfer of capacity over multiple interfaces.[32]

To look at the projected impact of the policy case on transfers, the measure used was the change in the summer reserves sent in the policy case compared to the base case. To develop a relative measure of the impact of the policy, the change in reserves was measured as a percentage of load in the sending region. This percentage gives an indication of the significance of the policy for changes in the grid. In general, the percentage changes in the final rules are below 1%, meaning that the modeled policy is projected to show little impact on any region's need to import capacity to maintain reserve margins. For details on projected transfers under the base and policy scenarios, please see Appendix A-6, B-6, C-6, D-6 and E-6.

[32] For details, please see chapter 3 of the IPM documentation, available at: https://www.epa.gov/power-sector-modeling.

Appendix A: Tables by IPM Region for Final Rules in 2028
(Note: All Results Cumulative through Projection Year)

A1. Projected Operational Capacity in GW (2028)[a]

Region	All generation sources		Change from Base	Coal Only		Change from Base
	Base	Policy		Base	Policy	
US	1,364	1,374	10	116	112	-4.5
ERCOT	168	175	7	5	4	-1.0
FRCC	69	69	0	4	4	0.0
MISO	197	197	0	34	34	-0.1
ISONE	46	46	0	0	0	0.0
NYISO	53	54	0	0	0	0.0
PJM	232	232	0	24	24	-0.1
SERC	177	176	-1	21	19	-1.9
SPP	98	100	2	13	11	-1.7
WECC - non CAISO	221	221	0	16	16	0.1
CAISO	103	103	0	0	0	0.0

[a] Coal category does not include coal to gas conversions

A2. Summary of Summer Peak Loads and Reserve Capacity in GW (2028)

Region	Projected Reserve Margins			
	Peak Demand Base	Peak Demand Policy	Reserve Capacity Base	Reserve Capacity Policy
US	808	808	934	934
ERCOT	73	73	85	85
FRCC	51	51	60	60
MISO	129	129	151	150
ISONE	25	25	28	28
NYISO	35	35	41	41
PJM	155	155	178	178
SERC	123	123	143	142
SPP	55	55	64	64
WECC - non CAISO	104	104	119	119
CAISO	57	57	67	67

A3. Summary of Target and Projected Reserve Margin % (2028)

Region	Target Reserve Margin	Base Case	Policy Case	Policy % Above Margin	Policy Change from Base
US		16%	16%	0%	0%
ERCOT	16%	16%	17%	1%	1%
FRCC	19%	19%	19%	0%	0%
MISO	17%	17%	17%	0%	0%
ISONE	11%	11%	11%	0%	0%
NYISO	15%	15%	15%	0%	0%
PJM	15%	15%	15%	0%	0%
SERC	15%	16%	15%	0%	-1%
SPP	16%	16%	16%	0%	0%
WECC - non CAISO	14%	14%	14%	0%	0%
CAISO	18%	18%	18%	0%	0%

A4. Policy Case Retired Capacity Incremental to Base Case in GW (2028)

Region	CC	Coal	CT	Nuclear	OG Steam	Total
US	-0.1	4.6	0.0	0.0	-1.3	3.2
ERCOT	0.0	1.0	0.0	0.0	-1.3	-0.4
FRCC	0.0	0.0	0.0	0.0	0.0	0.0
MISO	0.0	0.1	0.0	0.0	0.1	0.1
ISONE	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	0.0	0.0	0.0	0.0	0.0	0.0
PJM	0.0	0.1	0.0	0.0	-0.4	-0.3
SERC	0.0	1.9	0.0	0.0	0.0	1.9
SPP	0.0	1.7	0.0	0.0	0.4	2.1
WECC - non CAISO	0.0	-0.1	0.0	0.0	0.0	-0.1
CAISO	0.0	0.0	0.0	0.0	0.0	0.0

A5. New Capacity in Policy Case Incremental to Base Case in GW (2028)

Region	CC	CT	Wind	Solar	Storage	Other	Total
US	-0.2	1.0	10.7	1.9	0.0	0.1	13.5
ERCOT	0.0	0.0	7.0	0.0	0.0	0.0	7.0
FRCC	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MISO	-0.2	0.0	0.3	0.0	0.0	0.1	0.3
ISONE	0.0	0.0	0.4	0.0	0.0	0.0	0.4
NYISO	0.0	0.0	0.0	0.0	0.3	0.0	0.4
PJM	-0.4	0.0	0.3	0.1	-0.1	0.0	-0.1
SERC	1.0	0.4	0.0	0.0	0.0	0.0	1.3
SPP	0.0	0.0	2.0	1.9	0.0	0.0	3.9
WECC - non CAISO	-0.5	-0.1	0.8	0.0	0.1	0.0	0.3
CAISO	0.0	0.7	-0.3	0.0	-0.4	0.0	0.0

A6. Net Reserves Sent by NERC Assessment Region in GW (2028)

Region	Base	Policy	Change from Base to Policy	Change as a percent of summer peak
US	-6.5	-6.0	0.5	0%
ERCOT	2.6	2.6	0.0	0%
FRCC	-2.8	-2.8	0.0	0%
MISO	-9.0	-9.1	-0.1	0%
ISONE	1.3	1.6	0.3	1%
NYISO	-3.1	-2.8	0.2	1%
PJM	3.2	3.1	-0.1	0%
SERC	5.3	5.5	0.2	0%
SPP	-1.3	-1.3	0.0	0%
WECC - non CAISO	4.2	4.2	0.0	0%
CAISO	-7.0	-7.0	0.0	0%

Appendix B: Tables by IPM Region for Final Rules in 2030
(Note: All Results Cumulative through Projection Year)

B1. Projected Operational Capacity in GW (2030)[a]

Region	All generation sources		Change from Base	Coal Only		Change from Base
	Base	Policy		Base	Policy	
US	1,420	1,431	11	97	93	-4.3
ERCOT	174	181	7	5	4	-1.0
FRCC	72	71	0	4	4	0.0
MISO	207	210	3	25	24	-0.4
ISONE	50	51	0	0	0	0.0
NYISO	56	56	0	0	0	0.0
PJM	236	236	0	21	21	-0.1
SERC	187	186	0	19	18	-1.5
SPP	103	104	1	12	11	-1.3
WECC - non CAISO	222	223	1	11	11	0.0
CAISO	112	112	0	0	0	0.0

[a] Coal category does not include coal to gas conversions

B2. Summary of Summer Peak Loads and Reserve Capacity in GW (2030)

Region	Projected Reserve Margins			
	Peak Demand Base	Peak Demand Policy	Reserve Capacity Base	Reserve Capacity Policy
US	830	830	955	955
ERCOT	74	74	85	85
FRCC	53	53	63	63
MISO	132	132	154	154
ISONE	26	26	29	29
NYISO	36	36	42	42
PJM	159	159	182	182
SERC	126	126	145	145
SPP	56	56	65	65
WECC - non CAISO	108	108	122	122
CAISO	59	59	69	69

B3. Summary of Target and Projected Reserve Margin % (2030)

Region	Target Reserve Margin	Base Case	Policy Case	Policy % Above Margin	Policy Change from Base
US		15%	15%	0%	0%
ERCOT	14%	14%	15%	1%	1%
FRCC	19%	19%	19%	0%	0%
MISO	17%	17%	17%	0%	0%
ISONE	11%	11%	11%	0%	0%
NYISO	15%	15%	15%	0%	0%
PJM	15%	15%	15%	0%	0%
SERC	15%	15%	15%	0%	0%
SPP	16%	16%	16%	0%	0%
WECC - non CAISO	13%	13%	13%	0%	0%
CAISO	17%	17%	17%	0%	0%

B4. Policy Case Retired Capacity Incremental to Base Case in GW (2030)

Region	CC	Coal	CT	Nuclear	OG Steam	Total
US	-0.1	4.0	0.0	0.0	-1.1	2.9
ERCOT	0.0	1.0	0.0	0.0	-1.3	-0.4
FRCC	0.0	0.0	0.0	0.0	0.0	0.0
MISO	0.0	0.0	0.0	0.0	0.3	0.3
ISONE	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	0.0	0.0	0.0	0.0	0.0	0.0
PJM	0.0	0.1	0.0	0.0	-0.4	-0.3
SERC	0.0	1.5	0.0	0.0	0.0	1.5
SPP	0.0	1.3	0.0	0.0	0.4	1.7
WECC - non CAISO	0.0	0.0	0.0	0.0	0.0	0.0
CAISO	0.0	0.0	0.0	0.0	0.0	0.0

B5. New Capacity in Policy Case Incremental to Base Case in GW (2030)

Region	CC	CT	Wind	Solar	Storage	Other	Total
US	-1.1	2.4	11.0	2.9	-1.6	0.1	13.8
ERCOT	0.0	0.0	6.8	0.0	0.0	0.0	6.8
FRCC	0.0	0.0	0.0	0.0	-0.4	0.0	-0.4
MISO	-0.9	1.2	2.4	0.9	-0.2	0.1	3.4
ISONE	0.0	0.0	0.2	0.0	0.0	0.0	0.2
NYISO	0.0	0.0	-0.2	0.0	0.0	0.0	-0.2
PJM	-0.4	0.1	0.2	0.1	0.0	0.0	0.0
SERC	1.0	0.2	0.0	0.0	0.0	0.0	1.2
SPP	0.0	0.0	0.4	2.0	0.0	0.0	2.3
WECC - non CAISO	-0.6	0.2	1.2	0.0	-0.1	0.0	0.8
CAISO	0.0	0.7	0.0	0.0	-0.8	0.0	-0.2

B6. Net Reserves Sent by NERC Assessment Region in GW (2030)

Region	Base	Policy	Change from Base to Policy	Change as a percent of summer peak
US	-6.1	-6.1	0.0	0%
ERCOT	2.7	2.6	0.0	0%
FRCC	-2.8	-3.2	-0.4	-1%
MISO	-10.2	-9.1	1.2	1%
ISONE	1.8	1.8	0.0	0%
NYISO	-3.2	-3.4	-0.2	-1%
PJM	-0.4	-0.4	0.0	0%
SERC	8.4	8.0	-0.3	0%
SPP	0.7	0.5	-0.2	0%
WECC - non CAISO	0.0	0.2	0.2	0%
CAISO	-3.0	-3.1	-0.2	0%

Appendix C: Tables by IPM Region for Final Rules in 2035
(Note: All Results Cumulative through Projection Year)

C1. Projected Operational Capacity in GW (2035)[a]

Region	All generation sources		Change from Base	Coal Only		Change from Base
	Base	Policy		Base	Policy	
US	1,713	1,725	12	64	39	-25
ERCOT	201	201	0	5	3	-1
FRCC	88	88	0	1	1	-1
MISO	260	264	4	17	14	-4
ISONE	60	58	-2	0	0	0
NYISO	69	69	0	0	0	0
PJM	280	282	3	18	6	-12
SERC	222	223	1	9	7	-2
SPP	127	129	2	6	3	-4
WECC - non CAISO	259	261	2	8	6	-2
CAISO	148	149	1	0	0	0

[a] Coal category does not include coal to gas conversions

C2. Summary of Summer Peak Loads and Reserve Capacity in GW (2035)

Region	Projected Reserve Margins			
	Peak Demand Base	Peak Demand Policy	Reserve Capacity Base	Reserve Capacity Policy
US	890	890	1,026	1,026
ERCOT	78	78	89	89
FRCC	57	57	67	67
MISO	141	141	164	164
ISONE	29	29	33	33
NYISO	38	38	43	43
PJM	166	166	190	190
SERC	133	133	153	153
SPP	59	59	68	68
WECC - non CAISO	123	123	139	139
CAISO	66	66	78	78

C3. Summary of Target and Projected Reserve Margin % (2035)

Region	Target Reserve Margin	Base Case	Policy Case	Policy % Above Margin	Policy Change from Base
US		15%	15%	0%	0%
ERCOT	14%	14%	14%	0%	0%
FRCC	19%	19%	19%	0%	0%
MISO	17%	17%	17%	0%	0%
ISONE	11%	11%	11%	0%	0%
NYISO	15%	15%	15%	0%	0%
PJM	15%	15%	15%	0%	0%
SERC	15%	15%	15%	0%	0%
SPP	16%	16%	16%	0%	0%
WECC - non CAISO	13%	13%	13%	0%	0%
CAISO	18%	18%	18%	0%	0%

C4. Policy Case Retired Capacity Incremental to Base Case in GW (2035)

Region	CC	Coal	CT	Nuclear	OG Steam	Total
US	0.0	21.3	0.1	0.0	-4.2	17.1
ERCOT	0.0	1.0	0.0	0.0	-1.3	-0.4
FRCC	0.0	0.5	0.0	0.0	0.0	0.5
MISO	0.0	2.8	0.0	0.0	0.1	2.9
ISONE	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	0.0	0.0	0.0	0.0	0.0	0.0
PJM	0.0	10.9	0.0	0.0	-0.4	10.5
SERC	0.0	1.6	0.0	0.0	-0.1	1.5
SPP	0.0	3.4	0.1	0.0	-2.4	1.1
WECC - non CAISO	0.0	0.9	0.0	0.0	0.0	0.9
CAISO	0.0	0.1	0.0	0.0	0.0	0.1

C5. New Capacity in Policy Case Incremental to Base Case in GW (2035)

Region	CC	CT	Wind	Solar	Storage	Other	Total
US	-1.2	9.9	12.4	2.9	8.7	0.1	32.9
ERCOT	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FRCC	0.0	0.0	0.0	0.2	0.4	0.0	0.7
MISO	-0.9	1.2	3.4	-0.2	3.5	0.1	7.1
ISONE	0.0	0.0	1.0	-2.6	0.0	0.0	-1.6
NYISO	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PJM	-0.4	6.9	4.6	0.6	2.2	0.0	13.9
SERC	1.0	0.3	0.8	-0.2	1.3	0.0	3.1
SPP	0.0	0.0	1.4	2.2	0.0	0.0	3.6
WECC - non CAISO	-0.7	0.8	1.2	2.1	1.3	0.0	4.7
CAISO	0.0	0.7	0.0	0.8	0.0	0.0	1.4

C6. Net Reserves Sent by NERC Assessment Region in GW (2035)

Region	Base	Policy	Change from Base to Policy	Change as a percent of summer peak
US	-8.3	-8.4	-0.1	0%
ERCOT	-0.9	-0.9	0.0	0%
FRCC	-1.5	-1.5	0.0	0%
MISO	-6.2	-5.4	0.9	1%
ISONE	-1.7	-1.8	-0.1	0%
NYISO	-2.8	-2.8	0.0	0%
PJM	0.7	-0.6	-1.3	-1%
SERC	4.9	5.3	0.4	0%
SPP	2.0	2.0	0.0	0%
WECC - non CAISO	-2.0	-2.6	-0.6	0%
CAISO	-0.9	-0.3	0.6	1%

Appendix D: Tables by IPM Region for Final Rules in 2040
(Note: All Results Cumulative through Projection Year)

D1. Projected Operational Capacity in GW (2040)[a]

Region	All generation sources		Change from Base	Coal Only		Change from Base
	Base	Policy		Base	Policy	
US	2,045	2,052	7	54	36	-18
ERCOT	226	226	-1	5	3	-1
FRCC	108	107	-1	1	1	-1
MISO	328	326	-1	17	13	-4
ISONE	75	74	0	0	0	0
NYISO	89	89	0	0	0	0
PJM	341	342	1	11	6	-5
SERC	270	270	0	8	7	-2
SPP	138	140	2	6	3	-4
WECC - non CAISO	300	306	6	5	3	-2
CAISO	169	170	1	0	0	0

[a] Coal category does not include coal to gas conversions

D2. Summary of Summer Peak Loads and Reserve Capacity in GW (2040)

Region	Projected Reserve Margins			
	Peak Demand Base	Peak Demand Policy	Reserve Capacity Base	Reserve Capacity Policy
US	955	955	1,101	1,101
ERCOT	84	84	96	96
FRCC	61	61	73	73
MISO	148	148	173	173
ISONE	32	32	36	36
NYISO	42	42	48	48
PJM	175	175	201	201
SERC	141	141	163	163
SPP	63	63	73	73
WECC - non CAISO	134	134	152	152
CAISO	74	74	87	87

D3. Summary of Target and Projected Reserve Margin % (2040)

Region	Target Reserve Margin	Base Case	Policy Case	Policy % Above Margin	Policy Change from Base
US		15%	15%	0%	0%
ERCOT	14%	14%	14%	0%	0%
FRCC	19%	19%	19%	0%	0%
MISO	17%	17%	17%	0%	0%
ISONE	11%	11%	11%	0%	0%
NYISO	15%	15%	15%	0%	0%
PJM	15%	15%	15%	0%	0%
SERC	15%	15%	15%	0%	0%
SPP	16%	16%	16%	0%	0%
WECC - non CAISO	13%	13%	13%	0%	0%
CAISO	18%	18%	18%	0%	0%

D4. Policy Case Retired Capacity Incremental to Base Case in GW (2040)

Region	CC	Coal	CT	Nuclear	OG Steam	Total
US	0.0	13.6	0.1	0.0	-4.2	9.4
ERCOT	0.0	1.0	0.0	0.0	-1.3	-0.4
FRCC	0.0	0.5	0.0	0.0	0.0	0.5
MISO	0.0	3.1	0.0	0.0	0.1	3.2
ISONE	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	0.0	0.0	0.0	0.0	0.0	0.0
PJM	0.0	4.1	0.0	0.0	-0.4	3.7
SERC	0.0	1.0	0.0	0.0	-0.1	0.9
SPP	0.0	3.4	0.1	0.0	-2.4	1.1
WECC - non CAISO	0.0	0.4	0.0	0.0	0.0	0.4
CAISO	0.0	0.1	0.0	0.0	0.0	0.1

D5. New Capacity in Policy Case Incremental to Base Case in GW (2040)

Region	CC	CT	Wind	Solar	Storage	Other	Total
US	-1.2	11.1	3.0	5.8	1.8	0.1	20.6
ERCOT	0.0	0.0	-0.5	0.0	0.0	0.0	-0.5
FRCC	0.0	0.2	0.0	-0.6	0.0	0.0	-0.3
MISO	-0.9	3.5	-1.2	0.2	1.0	0.1	2.7
ISONE	0.0	0.0	0.2	-0.5	0.0	0.0	-0.3
NYISO	0.0	0.3	-0.1	0.1	-0.3	0.0	0.1
PJM	-0.4	4.7	0.2	1.1	0.2	0.0	5.8
SERC	1.0	-0.4	-0.4	0.7	1.1	0.0	2.0
SPP	0.0	0.0	0.9	2.2	0.0	0.0	3.1
WECC - non CAISO	-0.8	2.0	3.8	2.0	0.3	0.0	7.4
CAISO	0.0	0.7	0.0	0.5	-0.6	0.0	0.6

D6. Net Reserves Sent by NERC Assessment Region in GW (2040)

Region	Base	Policy	Change from Base to Policy	Change as a percent of summer peak
US	-5.9	-5.9	0.0	0%
ERCOT	-0.9	-0.9	0.0	0%
FRCC	-2.8	-3.1	-0.3	0%
MISO	-1.7	-1.7	0.0	0%
ISONE	-2.0	-2.0	0.0	0%
NYISO	-1.9	-1.9	0.0	0%
PJM	0.5	0.7	0.2	0%
SERC	3.7	3.8	0.1	0%
SPP	2.0	2.1	0.0	0%
WECC - non CAISO	-2.0	-2.0	0.0	0%
CAISO	-0.9	-0.9	0.0	0%

Appendix E: Tables by IPM Region for Final Rules in 2045
(Note: All Results Cumulative through Projection Year)

E1. Projected Operational Capacity in GW (2045)[a]

Region	All generation sources		Change	Coal Only		Change
	Base	Policy	from Base	Base	Policy	from Base
US	2,427	2,444	17	41	18	-23
ERCOT	254	255	1	4	2	-2
FRCC	144	145	1	1	0	-1
MISO	376	379	3	13	10	-3
ISONE	84	84	0	0	0	0
NYISO	96	96	0	0	0	0
PJM	407	411	4	9	3	-6
SERC	339	339	0	4	1	-3
SPP	160	163	3	5	1	-4
WECC - non CAISO	360	366	6	5	1	-4
CAISO	205	205	0	0	0	0

[a] Coal category does not include coal to gas conversions

E2. Summary of Summer Peak Loads and Reserve Capacity in GW (2045)

Region	Projected Reserve Margins			
	Peak Demand Base	Peak Demand Policy	Reserve Capacity Base	Reserve Capacity Policy
US	1,028	1,028	1,184	1,184
ERCOT	90	90	102	102
FRCC	66	66	79	79
MISO	157	157	183	183
ISONE	36	36	40	40
NYISO	45	45	51	51
PJM	188	188	215	215
SERC	151	151	174	174
SPP	67	67	77	77
WECC - non CAISO	148	148	167	167
CAISO	81	81	96	96

E3. Summary of Target and Projected Reserve Margin % (2045)

Region	Target Reserve Margin	Base Case	Policy Case	Policy % Above Margin	Policy Change from Base
US		15%	15%	0%	0%
ERCOT	14%	14%	14%	0%	0%
FRCC	19%	19%	19%	0%	0%
MISO	17%	17%	17%	0%	0%
ISONE	11%	11%	11%	0%	0%
NYISO	15%	15%	15%	0%	0%
PJM	15%	15%	15%	0%	0%
SERC	15%	15%	15%	0%	0%
SPP	16%	16%	16%	0%	0%
WECC - non CAISO	13%	13%	13%	0%	0%
CAISO	18%	18%	18%	0%	0%

E4. Policy Case Retired Capacity Incremental to Base Case in GW (2045)

Region	CC	Coal	CT	Nuclear	OG Steam	Total
US	0.0	18.8	0.0	0.0	-4.2	14.6
ERCOT	0.0	1.7	0.0	0.0	-1.3	0.4
FRCC	0.0	0.5	0.0	0.0	0.0	0.5
MISO	0.0	2.7	0.0	0.0	0.1	2.8
ISONE	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	0.0	0.0	0.0	0.0	0.0	0.0
PJM	0.0	5.5	0.0	0.0	-0.4	5.1
SERC	0.0	2.3	0.0	0.0	-0.1	2.2
SPP	0.0	3.6	0.0	0.0	-2.4	1.3
WECC - non CAISO	0.0	2.4	0.0	0.0	0.0	2.4
CAISO	0.0	0.0	0.0	0.0	0.0	0.0

E5. New Capacity in Policy Case Incremental to Base Case in GW (2045)

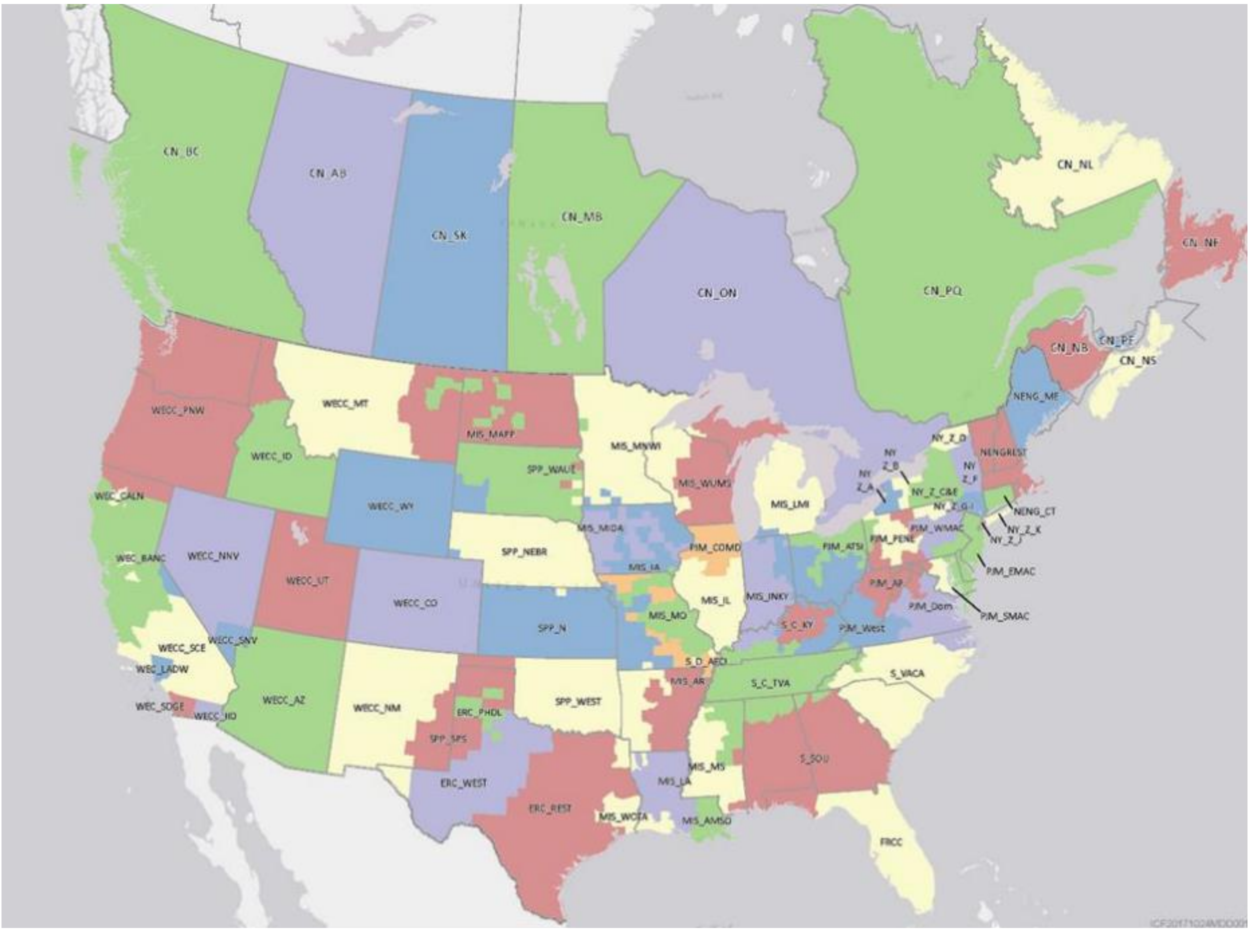
Region	CC	CT	Wind	Solar	Storage	Other	Total
US	-1	17	7	11	2	0	36
ERCOT	0	1	1	0	0	0	1
FRCC	0	0	0	1	0	0	2
MISO	-1	4	2	1	0	0	7
ISONE	0	0	0	0	0	0	0
NYISO	0	0	0	0	0	0	0
PJM	0	6	2	2	0	0	10
SERC	1	2	-2	2	0	0	3
SPP	0	0	3	1	0	0	4
WECC - non CAISO	-1	3	2	4	1	0	10
CAISO	0	1	0	0	-1	0	0

E6. Net Reserves Sent by NERC Assessment Region in GW (2045)

Region	Base	Policy	Change from Base to Policy	Change as a percent of summer peak
US	-5.6	-5.6	0.1	0%
ERCOT	-0.8	-0.8	0.0	0%
FRCC	0.0	0.0	0.0	0%
MISO	-4.0	-3.9	0.0	0%
ISONE	-2.7	-2.7	0.0	0%
NYISO	-1.5	-1.5	0.0	0%
PJM	-0.3	-0.2	0.1	0%
SERC	4.5	4.4	-0.1	0%
SPP	2.0	2.1	0.1	0%
WECC - non CAISO	-2.6	-2.5	0.0	0%
CAISO	-0.3	-0.4	-0.1	0%

Appendix F: Maps

IPM v6 Map



Reporting Region Definitions:

Reporting Region	IPM Model Region
ERCOT	ERC_REST
ERCOT	ERC_WEST
ERCOT	ERC_PHDL
ERCOT	ERC_GWAY
ERCOT	ERC_FRNT
FRCC	FRCC
MISO	MIS_WOTA
MISO	MIS_AMSO
MISO	MIS_AR
MISO	MIS_MS
MISO	MIS_LA
MISO	MIS_MAPP
MISO	MIS_IA
MISO	MIS_MIDA
MISO	MIS_MNWI
MISO	MIS_IL

MISO	MIS_LMI
MISO	MIS_INKY
MISO	MIS_WUMS
MISO	MIS_MO
ISONE	NENG_CT
ISONE	NENGREST
ISONE	NENG_ME
NYISO	NY_Z_F
NYISO	NY_Z_K
NYISO	NY_Z_J
NYISO	NY_Z_C&E
NYISO	NY_Z_G-I
NYISO	NY_Z_D
NYISO	NY_Z_A
NYISO	NY_Z_B
PJM	PJM_COMD
PJM	PJM_EMAC
PJM	PJM_SMAC
PJM	PJM_WMAC
PJM	PJM_West
PJM	PJM_Dom
PJM	PJM_PENE
PJM	PJM_ATSI
PJM	PJM_AP
SERC	S_SOU
SERC	S_C_TVA
SERC	S_C_KY
SERC	S_VACA
SERC	S_D_AECI
SPP	SPP_N
SPP	SPP_NEBR
SPP	SPP_WEST
SPP	SPP_SPS
SPP	SPP_WAUE
SPP	SPP_KIAM
WECC - non CAISO	WECC_AZ
WECC - non CAISO	WEC_LADW
WECC - non CAISO	WECC_ID
WECC - non CAISO	WECC_PNW
WECC - non CAISO	WECC_CO
WECC - non CAISO	WECC_SNV
WECC - non CAISO	WECC_IID
WECC - non CAISO	WECC_NM
WECC - non CAISO	WECC_NNV
WECC - non CAISO	WECC_UT
WECC - non CAISO	WECC_MT
WECC - non CAISO	WECC_WY
WECC - non CAISO	WEC_BANC
CAISO	WEC_CALN
CAISO	WEC_SDGE
CAISO	WECC_SCE

F2: NERC Assessment Areas in Long Term Reliability Assessment.

Source: NERC 2022 Long-Term Reliability Assessment