Resource Adequacy Analysis: Vehicle Rules, Final 111 EGU Rules, ELG and MATS RTR

Technical Memo

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

Final Rule

Docket ID No. EPA-HQ-OAR-2023-0072

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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 ("111 EGU Rules"). It describes projected resource adequacy impacts of the final 111 EGU Rules in conjunction with several other recently or nearly finalized EPA rulemakings: the LDV, HDV and MDV (collectively "Vehicle Rules"), Final 111 EGU Rules, ELG and MATS RTR (collectively "Power Sector Rules")[1]. **In doing so, it also demonstrates that the impacts of both the 111 EGU Rules alone and combined with other recent EPA actions related to electricity generating units are projected to result in anticipated power grid changes that (1) remain within the confines of key North American Electric Reliability Corporation (NERC) assumptions, (2) are consistent with peer reviewed projections for the power sector, and (3) are consistent with goals, planning efforts and Integrated Resource Plans (IRPs) of industry itself.[2,3] We project that the 111 EGU Rules, whether alone or combined with other Rules, are unlikely to adversely affect resource adequacy.**

This technical memo describes EPA's analysis of the potential impacts of the "Power Sector Rules" on the resource adequacy of the U.S. power grid. To best evaluate the impact of the Power Sector Rules on the power grid, the analysis includes the impacts of EPA's Vehicle Rules on demand for electricity in all scenarios. The objective of this analysis is to provide

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[1] As outlined in this document, the results of this analysis are based on specific model runs that capture the latest available information at the time of the analysis and cover the cumulative impacts of the power sector rulemakings described above. As such the specific results presented will not match the results presented as part of the record for the individual rulemakings.

[2] EPA actions considered here include final rules regulating the EGU sector at the time this analysis was performed, as well as several near final rules that commenters alleged could, in concert with the Vehicle Rules, negatively affect grid reliability and resource adequacy. These include the Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generation Point Source Category ("ELG Rule"), New Source Performance Standards for GHG Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired EGUs; Emission Guidelines for GHG Emissions from Existing Fossil Fuel-Fired EGUs ("111 EGU Rules");Rule"); Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generation Point Source Category ("ELG Rule"); and National Emissions Standards for Hazardous Air Pollutants: Coal-and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review ("MATS RTR Rule").

[3] Commenters also allege that certain other rules could affect the reliability of the power sector. We disagree. We did not see a need to consider these other rules in our quantitative analysis as these other rules do not regulate new or currently operational EGUs. Furthermore, commenters failed to explain how these other rules nonetheless would significantly impact the power sector and adversely affect resource adequacy or grid reliability. Specifically, on May 19, 2023, EPA proposed changes to the Coal Combustion Residual (CCR) regulations for inactive surface compounds at inactive electric generating units. 88 FR 31982. As these units are no longer operating and providing electricity to the grid, that proposal is not part of this assessment. Additionally, EPA also proposed to establish groundwater monitoring, corrective action, closure, and post closure care requirements for all CCR management units and allowed for a deferral of closure for all CCR management units (including OAF) if those units are above critical infrastructure. These components did not change EPA's need to incorporate the legacy/CCRMU rule into its cumulative impacts analysis because the CCR rule is not expected to impact current utility operations. The EPA finalized the Reconsideration of the National Ambient Air Quality Standards for Particulate Matter (PM NAAQS) on Feb. 7, 2024. The PM NAAQS rule itself does not regulate EGUs. It is also not possible to predict now what areas will be designated nonattainment for the PM NAAQS or what emissions control strategies states will adopt to attain and maintain the PM NAAQS, and EPA declines to speculate on how States might exercise their discretion. Further, the Administrator signed on Nov. 30, 2023, the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. This rule also does not regulate EGUs.

insight into the cumulative impacts on resource adequacy from EPA's rulemakings. 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 Vehicle and Power Sector Rules. The analysis includes both modeling of the power sector under reliability-protective constraints used by 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 Rules

Resource adequacy is an important aspect of grid reliability.[4] 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.[5] Another key aspect of reliability is operational reliability, which includes the ability to withstand sudden electric system disturbances that can lead to blackouts.[6] This document is meant to serve as a resource adequacy assessment of the cumulative impacts of the Power Sector Rules and how projected outcomes under the Power Sector Rules compare with projected baseline outcomes in the presence of the Inflation Reduction Act (IRA) and the Vehicle Rules. In the baseline, the impacts of the IRA result in an acceleration of the ongoing shift towards lower emitting generation and a declining 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 – inclusive of the IRA and Power Sector and Vehicle Rules - remain consistent with a range of peer-reviewed forecasts.[7]

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 resource adequacy needs is achievable with current institutional mechanisms and known operational practices, under scenarios similar to and beyond those expected due to IRA and these rulemakings. While this document is limited to an analysis of resource adequacy within the context of these rulemakings, 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 that aggregates deployment of variable renewable resources with dispatchable resources, energy storage, and other technologies.[8] Beyond resource adequacy, these studies also evaluate 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

[4] For additional discussion of reliability, see https://www.nerc.com/AboutNERC/Documents/Terms%20AUG13.pdf.
[5] As analyzed in this document, power regions correspond to aggregates of Integrated Planning Model (IPM) regions corresponding to NERC assessment areas.
[6] https://www.ferc.gov/reliability-explainer
[7] Available at https://www.epa.gov/inflation-reduction-act/electric-sector-emissions-impacts-inflation-reduction-act.
[8] *Maintaining Grid Reliability – Lessons from Renewable Integration Studies.* National Renewable Energy Laboratory, April 2024. Available at: https://www.nrel.gov/docs/fy24osti/89166.pdf.

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.[9] 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.[10]

Examples of these studies include 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* [11], and the Net-Zero America study (2021) from Princeton University, which uses the Energy PATHWAYS-Regional Investment and Operations (EP-RIO) model.[12] Both of these 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.[13] The Solar Futures Study (2021) found existing technology portfolio approaches could maintain resource adequacy under high solar deployment and decarbonization scenarios.[14] Examples of regional grid operator studies that examine how reliability can be maintained with a changing generation resource mix include ISO New England's Future Grid Reliability Study (2022)[15], Resource Adequacy in the Pacific Northwest (2019)[16], Energy Transition in PJM: Frameworks for Analysis (2021)[17], Midcontinent Independent System Operator's Renewable Integration Impact Assessment (2021)[18], and Southwest Power Pool's Wind Integration Study (2016)[19]. In addition, the U.S. Department of

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

[10] 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.

[11] 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.

[12] 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.

[13] https://www.nrel.gov/docs/fy21osti/79224.pdf

[14] https://www.energy.gov/sites/default/files/2021-09/Solar%20Futures%20Study.pdf

[15] *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

[16] *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

[17] *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

[18] *MISO's Renewable Integration Impact Assessment*. MISO, February 2021. https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf

[19] https://www.spp.org/documents/34200/2016%20wind%20integration%20study%20(wis)%20final.pdf

Energy (DOE) finds that a portfolio approach that takes advantage of the full range of technology, planning, and operational solutions best ensures reliable power.[20]

EPA's projected total load and variable renewable generation levels under this analysis[21] are comparable to the results of other studies which model the impacts of the IRA but not the Power Sector Rules as illustrated (see Figure 1). In this figure, the IPM horizontal line shows the projected total demand in the top panels together with the maximum projected share of variable renewable (solar and wind) generation in the bottom panels. IPM results shown are from EPA's cumulative impact assessment of its Power Sector and Vehicle Rules for 2030, 2035, 2040, and 2050. The multicolored points show the demand (top panels) and variable renewable share (bottom panels) from six other studies including single-model and multi-model studies of the electricity sector. Each of these other six studies present multiple loads and variable renewable shares resulting from different methods and assumptions. Two studies present results from multiple models and most report results from multiple scenarios. As evidenced in the figure, EPA's projected increase in demand and variable renewable share of generation incorporating the impacts of its Vehicle and Power Sector Rules (coupled with IRA and state policies) remains within the range and well below the upper bound of grid changes projected to be viable in other prominent models that respect resource adequacy constraints. The studies are approximately ordered from left to right in order of total load generation. **EPA finds its IPM projections align with the projections of other power sector models. Both the total projected demand and the projected variable renewable generation share are within the range of observed results from recent peer-reviewed research[22], reports from the Department of Energy[23] and the National Renewable Energy Laboratory.[24]** See Appendix Table H1 for details.

Figure 1: Cumulative IPM Demand and Variable Renewable (VR) Generation Projections Relative to Other Peer-reviewed Models (2030 - 2050)

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

[21] EPA Power Sector Rules do not require deployment of RE resources – these deployments are occuring based on the relative cost of these resources and the incentives afforded to them under the IRA.

[22] Bistline, J., et al., Emissions and energy impacts of the Inflation Reduction Act. Science, 2023. 380(6652): p. 1324-1327. DOI: 10.1126/science. adg3781. Available from: https://www.science.org/ doi/10.1126/science.adg3781

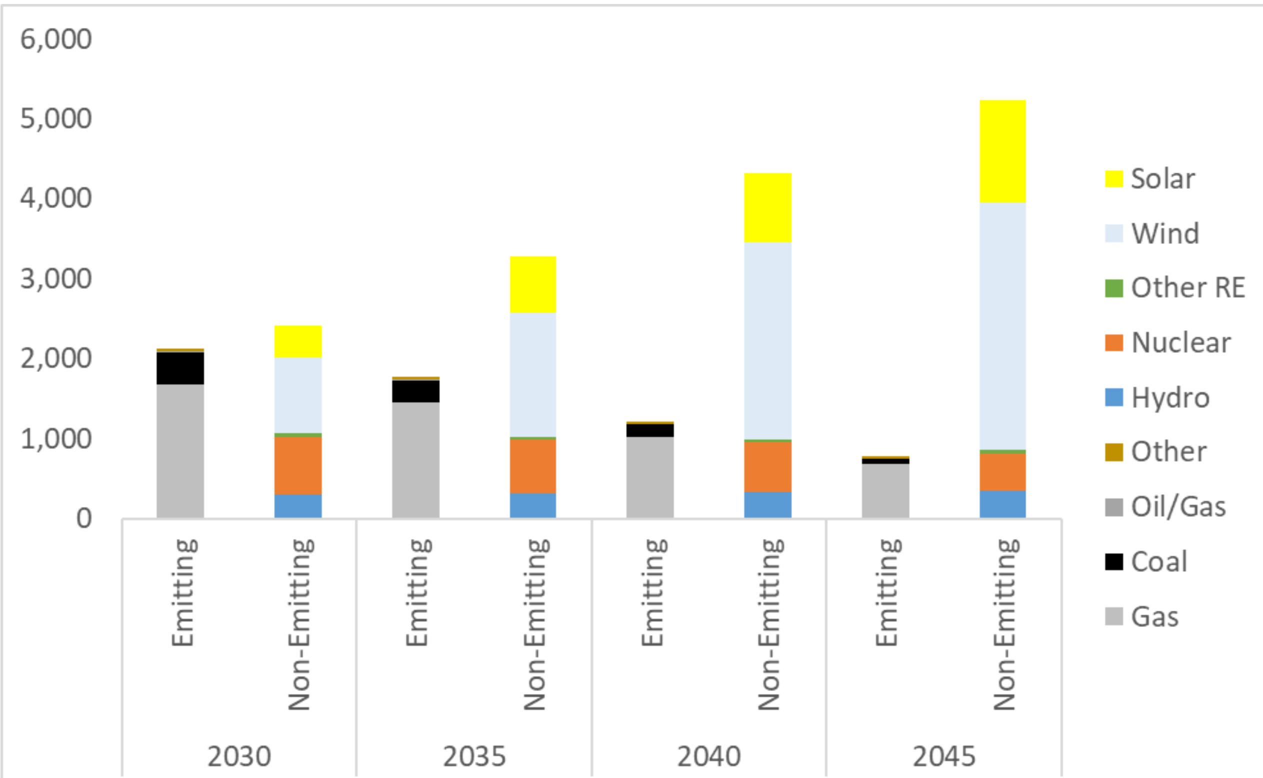
[23] U.S. Department of Energy, Investing in American Energy: Significant Impacts of the Inflation Reduction Act and Bipartisan Infrastructure Law on the U.S. Energy Economy and Emissions Reductions. 2023. Available from: https://www.energy.gov/ policy/articles/investing-american-energy-significant-impacts-inflation-reduction-act-and

[24] Steinberg, D.C., et al., Evaluating impacts of the Inflation Reduction Act and Bipartisan Infrastructure Law on the U.S. power system. 2023, National Renewable Energy Laboratory: Golden, CO. Available from: https://www.nrel.gov/docs/fy23osti/85242.pdf

The final 111 EGU 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 EGU owners and operators may also 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.

EPA notes that—consistent with long- term industry trends—the amount of projected baseline coal-fired generation affected by these air regulations comprises a relatively small and decreasing portion of expected capacity and generation over the forecast period, which further limits any potential grid impacts and resource adequacy implications of the Power Sector Rules. Figure 2 highlights the coal share of overall generation in a future with the Vehicle Rules but without implementation of any Power Sector Rules. This generating category – which is the predominant source of generation facing pollution mitigation measures in the Power Sector Rules – constitutes a relatively small share of the baseline generation in future years between 2030 and 2045. The fact that the most significant mitigation measures are concentrated within a small portion of baseline generation inherently limits any potential grid impacts related from regulatory compliance. While the full change in generation composition is examined, only a small portion of that change in generation is attributable to the Power Sector Rules.

Figure 2. Baseline Case Projected Generation Mix in TWh (2030, 2035, 2040, 2045)



Note: As outlined above, the baseline includes additional electricity demand from the vehicle rules. Coal and Gas categories include generation from units that are projected to install CCS.

The emission reduction requirements under these 111 EGU Rules are based on adequately demonstrated cost-reasonable control measures that constitute 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 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 111 EGU Rules provide multiple flexibilities that preserve the ability of responsible authorities to maintain electric system reliability. For more detail on how the final 111 EGU Rules address reliability concerns, see Section XII.F of the final 111 EGU 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 a specific set of cases illustrated in the IPM Sensitivity Analysis Memo – the "Sensitivity Vehicle Rules: Baseline" and "Sensitivity Vehicle Rules: Final 111 EGU Rules, MATS and ELG", that the implementation of these rules can be achieved without undermining resource adequacy. The focus of the analysis is on comparing the illustrative 111 EGU Final Rules scenario from the RIA in conjunction with other power sector rules to a base case without the power sector rules that is shown here to be consistent with other peer reviewed model projections. Both scenarios include the projected impacts of EPA's vehicle rules. Both cases also include existing legislation, such as the Inflation Reduction Act. Thus, this analysis focuses on the incremental changes in the power system that are projected specifically as a result of the Power Sector Rules. The EPA uses the Integrated Planning Model (IPM) to project likely future electricity market conditions with and without the power sector rules.[25] We evaluate the impacts of the rules in the 2028, 2030, 2035, 2040 and 2045 model run years.[26]

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

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[25] See "IPM Sensitivity Runs – Memo", available in the docket for this rulemaking for more detail on the power sector impacts of the final rules.

[26] 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.

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 rule 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 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. The model projections for the power sector rules are showing compliance choices that occur in an environment that respects these NERC reliability considerations and constraints listed. 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 vehicle rules and power sector rules can be achieved without adversely affecting resource adequacy.**[27]

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).[28] 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.[29] While this analysis does not focus on local transmission availability, EPA notes that numerous federal actions are improving local transmission access

[27] 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 those investments in the total cost estimates of the policy.

[28] 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.

[29] Boyd, Erin. Power Sector Modeling 101. U.S. Department of Energy. Available at: https://www.energy.gov/sites/prod/files/2016/02/f30/EPSA_Power_Sector_Modeling_FINAL_021816_0.pdf

and interconnection processes.[30] The model also includes constraints that adjust the reserve margin contribution of renewable resources and storage as a function of generation fraction.[31] Additionally, IPM models operating reserves at the regional level, and can account for the impact of solar and wind on operating reserves requirements.[32] This document focuses on key regional results important to management of the power system. For a more complete presentation of the projected power sector impacts of these rules, see the "IPM Sensitivity Runs – Memo" available in the docket for this rulemaking.

In order to conduct this analysis, EPA began by updating the baseline used to conduct the RIA for the 111 EGU Rules to account for the projected incremental electricity demand from the recently finalized MDV, HDV and LDV rules (vehicle rules). The policy scenario includes the impacts of the vehicle rules as well, and adds in the requirements under the final 111 EGU rules, MATS RTR and ELG (Power Sector Rules).[33]

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, and re-use of existing infrastructure such as through powering non-powered dams.[34]

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

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[30] 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.

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

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

[33] For details of policies modeled, please see Appendix section G.

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

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 111 EGU Rules that allow states, power companies, and grid operators to ensure grid reliability. These compliance flexibilities include 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 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 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. The Vehicle Rules, discussed below, also have timing and compliance flexibilities that allow industry to meet the standards in a phased approach and through the technology mix of their choosing.

Overview of Resource Adequacy Impacts from the Vehicle Rules, 111, MATS RTR and ELG

The final 111 EGU 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 analysis also includes the impacts of EPA's Greenhouse Gas Emissions Standards for Heavy-Duty Vehicles – Phase 3 (HDP3) rule and the Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles (LMDV) rule (collectively "Vehicle Rules"). The LMDV final rule establishes standards that will further reduce harmful air pollutant emissions from light-duty and medium-duty vehicles starting with model year 2027 and phasing in generally through model year 2032 and later. Similarly, the HDP3 final rule also establishes standards for model years (MYs) 2027 through 2032, building from the "Phase 2" greenhouse gas standards established in 2016. Both programs establish new standards that build upon EPA's previous regulations for federal emissions standards by setting more stringent performance-based emissions standards under which manufacturers choose the mix of vehicle and engine technologies to meet the standards given consumer preferences. The Vehicle Rule grid demands are based upon Alternative 3 from the proposed LMDV rule with the addition of heavy-duty vehicle charge demand based on an interim case for the HDP3 rule. We believe this analysis reasonably represents the projected effects of the final LDMV and HDP3 rules.[35] In addition, we note that the Vehicle Rules do not mandate manufacturers to follow specific technological pathways; to comply with the performance-based standards, manufacturers may pursue different technological pathways, for example with higher penetrations of clean internal combustion engine vehicles, that would result in significantly less electricity demand.

This analysis also reflects EPA's 2024 Effluent Limitation Guidelines, which strengthens the wastewater discharge standards that apply to coal-fired power plants, and the EPA's Final National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review (MATS RTR) which strengthens and update the MATS for power plants to reflect recent developments in control technologies and the performance of these plants. See Appendix G for a description of the emissions limitations modeled to reflect each Power Sector Rule.

This analysis uses the same scenario and years of analysis contained in the RIA for the final 111 EGU rules.[36] The scenarios include a base case (with Vehicle Rules) and a second scenario with the final Power Sector Rules and the Vehicle Rules. For purposes of this resource adequacy assessment, estimates and projections are taken from those same scenarios and years as shown in the RIA for the 111 EGU rules (2028, 2030, 2035, 2040 and 2045).

In order to conduct this analysis, EPA began by updating the baseline used to conduct the RIA to account for the projected incremental electricity demand from the recently finalized MDV, HDV and LDV rules (vehicle rules). The policy scenario includes the impacts of the vehicle rules as well, and adds in the requirements under the final 111 EGU rules, MATS RTR and ELG (Power Sector Rules).[37]

Summary of Changes in Operational Capacity

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[35] See LMDV RIA 5.1.1 for more information. Also, see Wood, E., B. Borlaug, K. McKenna, J. Keen, B. Liu, J. Sun, D. Narang, et al. 2024. *Multi-State Transportation Electrification Impact Study.* U.S. Department of Energy
[36] See Section 4 of the "Sensitivity IPM Runs – Memo" available in the docket for this rulemaking for descriptions of the other results projected under the scenarios examined.
[37] For details of policies modeled, please see Appendix section G.

Total operational capacity remains similar between the baseline and policy scenarios. Operational generating capacity[38] changes from the base case in 2028, 2030, 2035, 2040 and 2045 are summarized in Table 1 below.[39] 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 that includes the Final 111 EGU Rules, MATS RTR, and ELG 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.

[38] Operational capacity is any existing, new or retrofitted capacity that is not retired.

[39] This analysis is based on an updated IPM run (EPA's Power Sector Modeling Platform 2023 using IPM) which includes updated assumptions based on the latest available data including updates reflecting natural gas supply, RE cost and performance and demand. As such, the baseline results are not identical to those outlined in the earlier Vehicle Rule analysis.

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

Capacity (GW)	2028	2030	2035	2040	2045
Base Case Operational Capacity	1,378	1,431	1,737	2,139	2,570
Minus Cumulative Incremental Policy Case Retirements					
Coal	-9	-11	-24	-16	-21
Oil/Gas	2	1	5	5	5
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	-3	-3
NGCT	1	4	12	14	22
Wind	15	16	16	7	10
Solar	2	5	5	7	11
Storage	0	-1	8	2	1
Other	0	1	1	0	0
Policy Case Operational Capacity	1,390	1,446	1,760	2,156	2,595

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 for the collective rules shows an incremental 24 GW of coal retirement, 5 GW fewer oil/gas steam retirements, 11 GW of incremental gas-fired additions, 16 GW of incremental wind additions, 5 GW of incremental solar additions, and 8 GW of incremental battery storage additions. The coal retirements are in addition to 79 GW of coal retirements by 2035 under the baseline. In summary, out of the roughly 1,740 GW of operational nameplate capacity in the vehicle rules baseline scenario in 2035, the illustrative compliance scenario for the collective rules shows replacement of 24 GW of coal capacity with 16 GW of gas and oil capacity and 30 GW of renewable and storage capacity. The incremental reduction in coal capacity represents 1.4 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 111 EGU rules, MATS RTR, and ELG.

Planning Reserve Requirements

IPM uses a target reserve margin in each region[40] 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 nor 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 projected 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.[41]

Changes in Retirements and New Capacity Additions under the Final Power Sector Rules

The incremental retirements in the final rule case are shown above in Table 1 and are in addition to 79 GW of coal and 20 GW of oil/gas retirements already occurring in the baseline through 2035.

By 2035, the policy scenario as compared to the baseline 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. These rules do 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

[40] 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.

[41] 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. 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.[42]

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 power sector rules are below 2%, 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.

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

Appendix

Appendix A: Tables by IPM Region for Final Power Sector and Vehicle 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	1,378	1,390	12	112	103	-8.9
ERCOT	179	181	2	6	4	-1.8
FRCC	69	69	0	4	3	-0.4
MISO	197	200	3	34	34	-0.5
ISONE	46	46	0	0	0	0.0
NYISO	53	53	0	0	0	0.0
PJM	232	232	-1	22	20	-2.3
SERC	178	179	1	20	17	-2.3
SPP	101	106	5	11	10	-1.5
WECC - non CAISO	220	221	1	16	16	0.0
CAISO	103	103	1	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	805	805	933	932
ERCOT	73	73	86	86
FRCC	51	51	60	60
MISO	129	129	150	150
ISONE	25	25	27	27
NYISO	35	35	40	40
PJM	154	154	177	177
SERC	123	123	144	143
SPP	55	55	64	64
WECC - non CAISO	104	104	118	118
CAISO	56	56	66	66

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

Region	Target Reserve Margin	Base Case	Policy Case	Policy % Above Target	Policy Change from Base
US		16%	16%	16%	0%
ERCOT	14%	18%	18%	4%	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%	17%	16%	1%	-1%
SPP	16%	16%	16%	0%	0%
WECC - non CAISO	13%	14%	14%	1%	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	0.0	9.2	0.0	0.0	-2.2	7.0
ERCOT	0.0	1.8	0.0	0.0	-2.1	-0.3
FRCC	0.0	0.4	0.0	0.0	0.0	0.4
MISO	0.0	0.5	0.0	0.0	-0.2	0.4
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	2.5	0.0	0.0	-0.7	1.9
SERC	0.0	2.3	0.0	0.0	-0.3	2.0
SPP	0.0	1.5	0.0	0.0	1.1	2.7
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	0.4	1.2	15.4	2.4	-0.2	0.0	19.2
ERCOT	0.0	0.0	1.6	0.0	0.0	0.0	1.6
FRCC	0.0	0.1	0.0	0.0	0.3	0.0	0.4
MISO	-0.2	0.3	3.5	-0.1	0.0	0.0	3.5
ISONE	0.0	0.0	0.3	0.0	0.0	0.0	0.3
NYISO	0.0	0.0	0.0	0.0	0.1	0.0	0.1
PJM	1.1	0.0	0.0	0.0	-0.1	0.0	1.1
SERC	0.9	-0.2	2.4	0.0	0.0	0.0	3.1
SPP	0.0	0.0	4.9	2.4	0.0	0.0	7.4
WECC - non CAISO	-0.7	0.2	1.6	0.0	0.1	0.0	1.2
CAISO	-0.7	0.7	1.2	0.0	-0.6	0.0	0.5

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	-6.2	-5.9	0.3	0%
ERCOT	2.6	2.6	0.0	0%
FRCC	-2.7	-2.7	0.0	0%
MISO	-9.2	-9.0	0.2	0%
ISONE	1.4	1.7	0.2	1%
NYISO	-2.9	-2.8	0.1	0%
PJM	3.4	2.4	-1.0	-1%
SERC	5.2	6.0	0.8	1%
SPP	-1.3	-1.3	0.0	0%
WECC - non CAISO	3.8	4.2	0.4	0%
CAISO	-6.6	-7.0	-0.4	-1%

Appendix B: Tables by IPM Region for Final Power Sector and Vehicle 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	1,431	1,445	14	95	84	-11.5
ERCOT	183	186	3	6	4	-1.8
FRCC	72	72	0	4	3	-0.4
MISO	206	212	6	26	24	-2.4
ISONE	50	50	0	0	0	0.0
NYISO	56	56	0	0	0	0.0
PJM	238	237	-1	21	17	-4.0
SERC	188	189	1	17	15	-1.7
SPP	105	109	4	11	9	-1.2
WECC - non CAISO	223	224	1	11	11	0.0
CAISO	110	110	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	825	825	952	952
ERCOT	74	74	86	86
FRCC	53	53	63	63
MISO	132	132	153	153
ISONE	25	25	28	28
NYISO	36	36	41	41
PJM	158	158	181	181
SERC	127	127	146	146
SPP	56	56	65	65
WECC - non CAISO	107	107	121	121
CAISO	58	58	68	68

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

Region	Target Reserve Margin	Base Case	Policy Case	Policy % Above Target	Policy Change from Base
US		15%	15%		
ERCOT	14%	17%	17%	3%	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%

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

Region	CC	Coal	CT	Nuclear	OG Steam	Total
US	0.0	11.3	0.0	0.0	-1.5	9.8
ERCOT	0.0	1.8	0.0	0.0	-2.1	-0.3
FRCC	0.0	0.4	0.0	0.0	0.0	0.4
MISO	0.0	1.9	0.0	0.0	0.0	1.9
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	4.2	0.0	0.0	-0.7	3.5
SERC	0.0	1.7	0.0	0.0	0.2	1.9
SPP	0.0	1.2	0.0	0.0	1.1	2.4
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	-0.7	4.0	16.1	5.3	-1.3	0.9	24.3
ERCOT	0.0	0.0	2.3	0.0	0.0	0.0	2.3
FRCC	0.0	0.1	0.0	0.0	0.3	0.0	0.4
MISO	-1.4	1.3	5.2	2.9	-0.3	0.8	8.5
ISONE	0.0	0.0	0.1	0.0	0.0	0.0	0.1
NYISO	0.0	0.0	-0.1	0.0	0.0	0.0	-0.1
PJM	1.1	1.0	0.2	0.0	0.0	0.0	2.3
SERC	0.9	0.2	1.5	0.0	0.0	0.0	2.6
SPP	0.0	0.0	4.0	2.4	0.0	0.0	6.4
WECC - non CAISO	-0.6	0.6	1.1	0.0	0.1	0.0	1.2
CAISO	-0.7	0.7	1.8	0.0	-1.4	0.0	0.4

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	-6.0	0.1	0%
ERCOT	2.6	2.6	0.0	0%
FRCC	-2.7	-2.7	0.0	0%
MISO	-12.0	-10.0	2.0	2%
ISONE	1.9	2.0	0.1	0%
NYISO	-3.3	-3.4	-0.1	0%
PJM	1.5	0.0	-1.5	-1%
SERC	8.5	8.6	0.1	0%
SPP	0.3	-0.2	-0.6	-1%
WECC - non CAISO	0.8	1.4	0.6	1%
CAISO	-3.7	-4.3	-0.6	-1%

Appendix C: Tables by IPM Region for Final Power Sector and Vehicle 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	1,737	1,756	18	67	39	-28
ERCOT	205	204	-1	5	3	-2
FRCC	89	89	0	1	1	-1
MISO	265	272	7	19	14	-5
ISONE	60	60	0	0	0	0
NYISO	70	70	0	0	0	0
PJM	284	288	5	18	6	-12
SERC	229	229	0	10	7	-3
SPP	130	134	4	6	3	-3
WECC - non CAISO	262	265	3	8	6	-2
CAISO	144	145	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	896	896	1,032	1,032
ERCOT	79	79	90	90
FRCC	58	58	68	68
MISO	142	142	166	166
ISONE	29	29	32	32
NYISO	38	38	43	43
PJM	167	167	192	192
SERC	136	136	156	156
SPP	60	60	69	69
WECC - non CAISO	123	123	139	139
CAISO	65	65	76	76

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

Region	Target Reserve Margin	Base Case	Policy Case	Policy % Above Target	Policy Change from Base
US		15%	15%		
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	24.5	0.0	0.0	-5.4	19.0
ERCOT	0.0	1.8	0.0	0.0	-2.1	-0.3
FRCC	0.0	0.5	0.0	0.0	0.0	0.5
MISO	0.0	4.2	0.0	0.0	-0.1	4.0
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	12.0	0.0	0.0	-0.7	11.3
SERC	0.0	2.0	0.0	0.0	-0.1	1.9
SPP	0.0	3.0	0.0	0.0	-2.1	0.9
WECC - non CAISO	0.0	0.9	0.0	0.0	-0.4	0.6
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	-0.8	11.7	16.3	5.3	8.3	0.9	41.6
ERCOT	0.0	0.1	-0.7	0.0	0.0	0.0	-0.7
FRCC	0.0	0.1	0.0	0.0	0.0	0.0	0.1
MISO	-1.4	4.5	7.3	-2.1	3.0	0.8	12.1
ISONE	0.0	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	0.0
PJM	1.1	5.0	5.9	2.1	2.5	0.0	16.6
SERC	0.9	0.2	-1.3	0.9	1.9	0.1	2.7
SPP	0.0	0.0	2.7	2.0	0.0	0.0	4.7
WECC - non CAISO	-0.7	1.1	2.4	1.6	0.4	0.0	4.8
CAISO	-0.7	0.7	0.0	0.7	0.5	0.0	1.2

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	-7.3	-7.4	-0.1	0%
ERCOT	-0.9	-0.9	0.0	0%
FRCC	-1.9	-2.3	-0.4	-1%
MISO	-7.3	-5.0	2.3	2%
ISONE	-1.1	-1.1	0.0	0%
NYISO	-2.5	-2.5	0.0	0%
PJM	0.7	-1.0	-1.8	-1%
SERC	6.4	6.2	-0.2	0%
SPP	2.0	2.0	0.0	0%
WECC - non CAISO	-1.2	-1.6	-0.4	0%
CAISO	-1.7	-1.2	0.4	1%

Appendix D: Tables by IPM Region for Final Power Sector and Vehicle 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	2,139	2,152	13	57	37	-20
ERCOT	236	236	-1	5	3	-2
FRCC	109	110	1	1	1	-1
MISO	348	349	1	19	13	-5
ISONE	76	76	0	0	0	0
NYISO	91	91	0	0	0	0
PJM	358	360	2	11	6	-5
SERC	292	294	2	9	7	-2
SPP	146	148	2	6	3	-3
WECC - non CAISO	311	317	7	5	3	-2
CAISO	171	171	0	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	976	976	1,124	1,124
ERCOT	87	87	99	99
FRCC	63	63	75	75
MISO	152	152	178	178
ISONE	32	32	36	36
NYISO	42	42	48	48
PJM	179	179	205	205
SERC	146	146	168	168
SPP	65	65	75	75
WECC - non CAISO	136	136	154	154
CAISO	73	73	86	86

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

Region	Target Reserve Margin	Base Case	Policy Case	Policy % Above Target	Policy Change from Base
US		15%	15%		
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	15.6	0.0	0.0	-5.1	10.5
ERCOT	0.0	1.8	0.0	0.0	-2.1	-0.3
FRCC	0.0	0.5	0.0	0.0	0.0	0.5
MISO	0.0	4.4	0.0	0.0	-0.1	4.3
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	4.2	0.0	0.0	-0.7	3.6
SERC	0.0	1.2	0.0	0.0	-0.1	1.1
SPP	0.0	3.0	0.0	0.0	-2.1	0.9
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	-3.0	14.2	6.8	7.4	2.1	0.0	27.5
ERCOT	0.0	0.1	-0.9	0.0	0.0	0.0	-0.8
FRCC	-1.9	2.5	0.0	0.5	0.0	0.0	1.1
MISO	-1.4	5.9	0.3	-0.1	0.8	0.0	5.6
ISONE	0.0	0.0	-0.1	0.1	0.0	0.0	0.1
NYISO	0.0	-0.2	0.1	-0.5	0.2	0.0	-0.4
PJM	1.1	2.4	1.8	0.7	0.2	0.0	6.2
SERC	0.9	0.0	-0.4	2.5	0.9	0.0	3.9
SPP	0.0	0.0	1.4	1.6	0.0	0.0	3.1
WECC - non CAISO	-1.0	2.9	4.5	2.5	-0.4	0.0	8.6
CAISO	-0.7	0.7	0.0	-0.1	0.3	0.0	0.2

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	-6.2	-6.2	-0.1	0%
ERCOT	-0.8	-0.9	0.0	0%
FRCC	-3.5	-3.4	0.1	0%
MISO	-2.7	-2.4	0.3	0%
ISONE	-2.1	-2.1	0.0	0%
NYISO	-2.2	-2.2	0.0	0%
PJM	-1.1	-1.2	-0.1	0%
SERC	7.1	6.8	-0.3	0%
SPP	2.0	2.0	0.0	0%
WECC - non CAISO	-2.1	-2.2	-0.1	0%
CAISO	-0.7	-0.6	0.1	0%

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

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

Region	All generation sources		Change from Base	Coal Only		Change from Base
	Base	Policy		Base	Policy	
US	2,570	2,591	21	44	19	-25
ERCOT	268	269	1	5	2	-3
FRCC	148	148	0	1	0	-1
MISO	406	415	8	14	10	-4
ISONE	87	86	-1	0	0	0
NYISO	100	99	-1	0	0	0
PJM	428	428	0	10	3	-6
SERC	370	373	4	5	1	-4
SPP	174	177	3	5	2	-3
WECC - non CAISO	382	389	7	5	1	-4
CAISO	207	207	-1	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	1,058	1,058	1,219	1,219
ERCOT	93	93	106	106
FRCC	69	69	81	81
MISO	163	163	190	190
ISONE	36	36	40	40
NYISO	45	45	52	52
PJM	193	193	222	222
SERC	158	158	182	182
SPP	70	70	81	81
WECC - non CAISO	151	151	171	171
CAISO	81	81	95	95

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

Region	Target Reserve Margin	Base Case	Policy Case	Policy % Above Target	Policy Change from Base
US		15%	15%		
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	20.6	0.0	0.0	-5.1	15.5
ERCOT	0.0	2.3	0.0	0.0	-2.1	0.2
FRCC	0.0	0.5	0.0	0.0	0.0	0.5
MISO	0.0	3.3	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	5.9	0.0	0.0	-0.7	5.2
SERC	0.0	3.1	0.0	0.0	-0.1	3.0
SPP	0.0	3.2	0.0	0.0	-2.1	1.1
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)

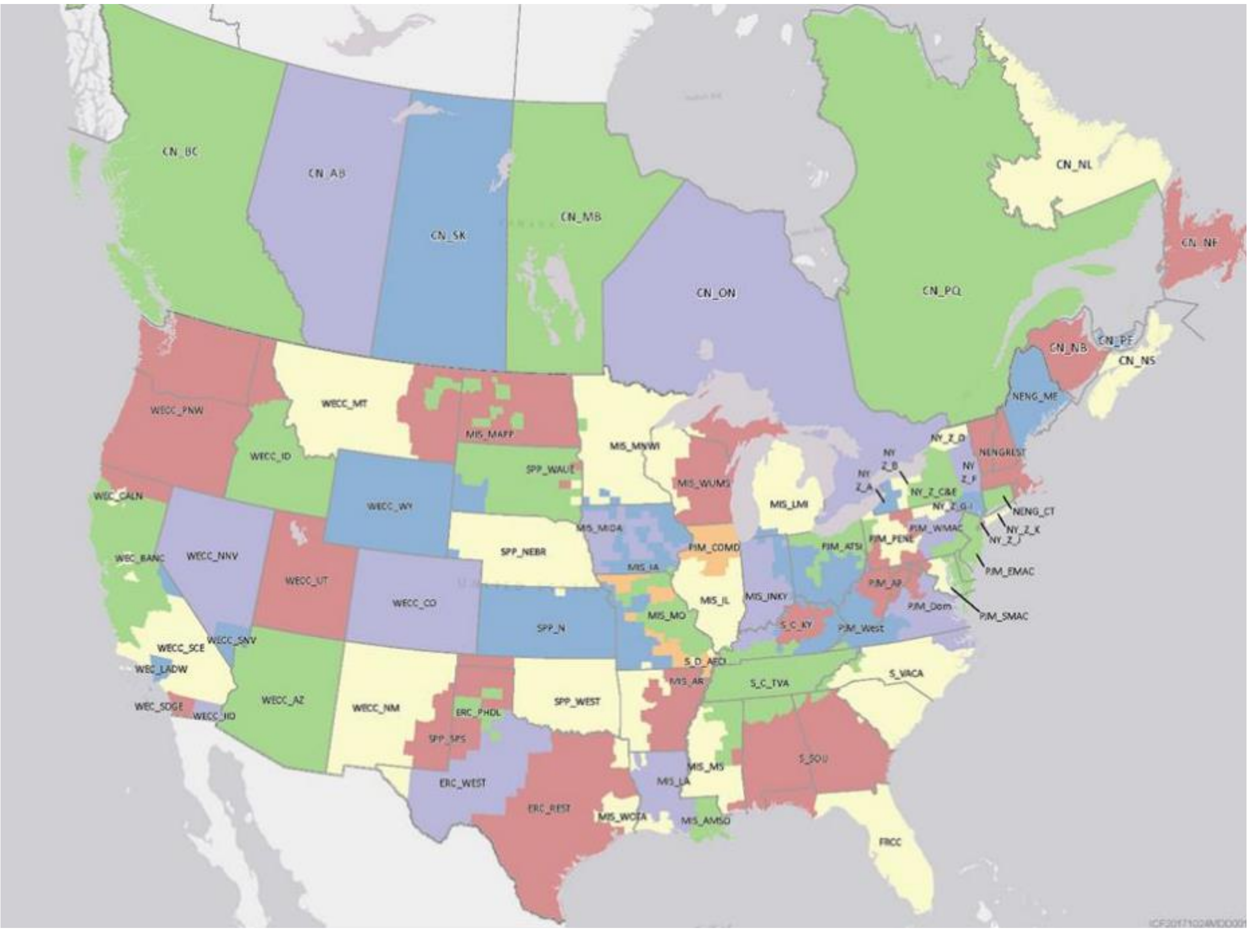
Region	CC	CT	Wind	Solar	Storage	Other	Total
US	-3	22	10	11	1	0	41
ERCOT	0	1	-1	1	0	0	1
FRCC	-2	2	0	0	0	0	1
MISO	-1	5	7	1	0	0	12
ISONE	0	0	0	0	0	0	-1
NYISO	0	1	-1	-1	0	0	-1
PJM	1	5	0	1	0	0	6
SERC	1	2	0	4	1	0	8
SPP	0	1	3	1	0	0	5
WECC - non CAISO	-1	4	1	5	1	0	11
CAISO	-1	1	0	-1	0	0	-1

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	-5.9	-5.9	0.1	0%
ERCOT	-0.8	-0.8	0.0	0%
FRCC	0.0	0.0	0.0	0%
MISO	-5.2	-5.2	0.0	0%
ISONE	-2.8	-3.2	-0.4	-1%
NYISO	-1.9	-1.5	0.4	1%
PJM	-1.3	-1.2	0.1	0%
SERC	6.9	6.9	0.0	0%
SPP	2.1	2.1	0.0	0%
WECC - non CAISO	-2.0	-1.7	0.2	0%
CAISO	-0.9	-1.1	-0.2	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

G1: Modeled MATS RTR Requirements

Provision	Regulatory Option Modeled
FPM Standard (Surrogate Standard for Non-mercury HAP metals)	Revised fPM standard of 0.010 lb/MMBtu
Mercury Standard	Revised mercury standard for lignite-fired EGUs of 1.2 lb/TBtu
Continuous Emissions Monitoring Systems (PM CEMS)	Require installation of PM CEMS to demonstrate compliance

G2: Modeled ELG Requirements

Wastestream	Subcategory	Technology Basis for BAT/PSES Regulatory Options[a]
FGD Wastewater	NA (default unless in subcategory)[b]	ZLD
	Boilers permanently ceasing the combustion of coal by 2028	SI
	Boilers permanently ceasing the combustion of coal by 2034	CP + Bio
	High FGD Flow Facilities or Low Utilization Boilers	NS
BA Transport Water	NA (default unless in subcategory)[b]	ZLD
	Boilers permanently ceasing the combustion of coal by 2028	SI
	Boilers permanently ceasing the combustion of coal by 2034	HRR
	Low Utilization Boilers	NS
CRL	NA (default)[b]	ZLD
	Discharges of unmanaged CRL	CP
	Boilers permanently ceasing the combustion of coal by 2034	CP
Legacy wastewater	Operate after 2024	CP

Abbreviations: BMP = Best Management Practice; CP = Chemical Precipitation; HRR = High Recycle Rate Systems; SI = Surface Impoundment; ZLD = Zero Liquid Discharge; NS = Not subcategorized (default technology basis applies); NA = Not applicable

a. See TDD for a description of these technologies (U.S. EPA, 2024f).

b. The table does not present existing subcategories included in the 2015 and 2020 rules as EPA did not reopen the existing subcategorization of oil-fired units or units with a nameplate capacity of 50 MW or less.

Source: U.S. EPA Analysis, 2024

G3: Modeled Final Power Sector Rules Requirements

Summary of Modeled GHG Mitigation Measures for Existing Sources by Subcategory under the Illustrative Final Rules [a,b,c]

Affected EGUs	Subcategory Definition	GHG Mitigation Measure
Long-term existing coal-fired steam generating units	Coal-fired steam generating units that have not elected to commit to permanently cease operations by 2040	CCS with 90% capture of CO_2, starting in 2035
Medium-term existing coal-fired steam generating units	Coal-fired steam generating units that have not elected to commit to permanently cease operations prior to 2035 but have committed to permanently ceasing operations by 2040	Natural gas co-firing at 40 percent of the heat input to the unit, starting in 2030

[a] All years shown in this table reflect IPM run years. Note that IPM run years encompass the specific calendar year requirements of BSER, details of which are available in Section VII of the preamble.
[b] Coal units that lack existing SCR controls must install these controls in addition to CCS to comply.
[c] Coal-fired EGUs that convert entirely to burn natural gas by 2030 are no longer subject to coal-fired EGU mitigation measures outlined above.

Summary of GHG Mitigation Measures for New Sources by Subcategory under the Illustrative Final Rules [a,b]

Affected EGUs	Subcategory Definition	Modeled Requirements During 1st Phase	Modeled Requirements During 2nd Phase (2035)	Baseload Definition: Final Rules Scenario
Baseload Economic NGCC Additions	NGCC units that commence construction after 2023 and operate at greater than baseload annual capacity factor	Efficient generation	CCS or co-fire hydrogen at sufficient level to meet CCS emission rate	40%
Intermediate Load Economic NGCC Additions	NGCC units that commence construction after 2023 and operate at an annual capacity factor of less than baseload	Efficient generation		
Intermediate load Economic NGCT Additions	NGCT units that commence construction after 2023 and operate at an annual capacity factor of more than 40%	Emission rate consistent with NGCC operation		
Peaking Economic NGCT Additions	NGCT units that commence construction after 2023 and operate at an annual capacity factor of less than 40%	Efficient generation		

[a] All years shown in this table reflect IPM run years. Note that IPM run years encompass the specific calendar year requirements of BSER, details of which are available in Section VII of the preamble.
[b] Delivered hydrogen price is assumed to be $1.15/kg in all years.

Appendix H:

Table H1: IPM Demand and Variable Renewable (VR) Generation Projections Relative to Peer-reviewed Studies

Source/Study	# of models / name	# scenarios reported	Type of Scenarios	2030 Total Demand (TWh)	2030 Share of VR Generation %
IPM	1 IPM	1	Described in the text of this memorandum	4,700	31%
Electricity Sector Impacts of IRA Study	14	1	IRA only	4,200 – 5,600	22% to 54%

National Climate Assessment Database	9	3	Reference, 2050 Net Zero CO_2, 2050 Net Zero CO_2 with advanced technologies	3,500 – 4,800	15% to 62%
Standard Scenarios 2023	1 ReEDS	53	Current Policies, 95% CO_2 Reduction by 2050, 100% CO_2 Reduction by 2035	4,400 – 5,200	45% to 58%
100% Renewable Study	1 ReEDS	7	Reference, 80%, 90%, 95%, 97%, 99%, 100%	4,200 – 4,700	22% to 81%
North American Renewable Integration Study	1 ReEDS	3	Reference, Medium Electrification, High Electrification	4,300 – 4,700	24% to 48%
Net-Zero America	1 EP-RIO	6	Reference, 100% Renewable, Renewable Constrained, High Biomass, Less-High Electrification, High Electrification	4,500 – 4,800	16% to 53%

Study	**2035 Total Demand (TWh)**	**2035 Share of Variable Renewable Generation %**	**2040 Total Demand (TWh)**	**2040 Share of Variable Renewable Generation %**	**2050 Total Demand (TWh)**	**2050 Shareof VR Generation %**
IPM	5,200	45%	5,700	59%	6,600	69%
Electricity Sector Impacts of IRA Study	4,200 – 6,300	21% to 80%	NA	NA	NA	NA
National Climate Assessment 5 Database	3,400 – 5.600	16% to 84%	3,800 – 6,700	15% to 86%	5,000 – 10,000	18% to 89%
Standard Scenarios 2023	4,700 – 7,300	51% to 74%	5,000 – 9,400	55% to 73%	5,600 – 12,300	56% to 76%
100% Renewable Study	4,400 – 5,300	24% to 82%	4,500 – 6,100	26% to 87%	5,000 – 7,500	35% to 90%
North American Renewable Integration Study	4,400 – 5,200	25% to 56%	4,600 – 5,900	27% to 64%	5,100 – 7,300	36% to 81%

Net-Zero America	4,700 – 6,200	19% to 75%	4,800 – 8,200	27% to 87%	5,300 – 16,000	38% to 98%

Note – TWh values for IPM here are rounded to nearest hundred for consistency when comparing across models.