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; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule Proposal

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This document supports the EPA's proposed 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 Standards and describes projected resource adequacy and reliability impacts of the proposed rules. The analysis presented in this TSD relies on the IPM modeling that was conducted to analyze the impacts of the requirements on existing coal-fired steam generating EGUs and the first two phases of the requirements on new natural gas fired EGUs, as outlined in Section 3 of the RIA. EPA did not conduct IPM modeling in order to evaluate the impacts of the requirements on existing natural-gas fired EGUs and the third phase of the requirements on new natural gas fired EGUs, relying instead on a spreadsheet-based analysis as outlined in section 8 of the RIA. The resource adequacy impacts of the spreadsheet-based analysis are addressed as a stand-alone section at the end of this TSD.

As used here, the term resource adequacy is defined as the provision of adequate generating resources to meet projected load and generating reserve requirements in each power region,[1] while reliability includes the ability to deliver the resources to the loads, such that the overall power grid remains stable. This document is meant to serve as a resource adequacy assessment of the impacts of the final rule and how projected outcomes under the final rule compare with projected baseline outcomes in the presence of the IRA.

Under the baseline, the impacts of the IRA result in an acceleration of the ongoing shift towards lower emitting generation and declining generation share for fossil-fuel fired generation. While this document is limited to an analysis of resource adequacy within the context of this rulemaking, a range of studies have outlined how reliability continues to be maintained under high variable renewable penetration scenarios. This includes the Eastern Renewable Generation Integration Study[2], which showed how the Eastern grid could accommodate upwards of 30% of wind and solar penetration, and the Western Wind and Solar Integration Study, which examined the reliability impacts of high levels of variable renewable penetration in the West.[3]

The proposed 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, 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 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.

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[1] As analyzed in this document, power regions correspond to aggregates of IPM regions corresponding to NERC assessment areas.
[2] Available at: https://www.nrel.gov/grid/ergis.html.
[3] Available at: https://www.nrel.gov/docs/fy15osti/62906.pdf.

The emission reduction requirements under this rule are based on adequately demonstrated cost-reasonable control measures that form the 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. However, the EPA also 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 revenues to support the EGU's continued operation until longer-term mitigation measures can be put in place. The Agency also expects that any resulting unit retirements will be carried out through an orderly process in which RTOs, balancing authorities, and state regulators use their powers to ensure that electric system reliability is protected.

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, a key planning metric that is necessary (but not sufficient) for grid reliability. It is important to recognize that the proposed rules provide multiple flexibilities that preserve the ability of responsible authorities to maintain electric reliability. For more detail on how the proposed rules address reliability concerns, see Section XV.F of the preamble. The results presented in this document show that the projected impacts of the proposed rules on preserving resource adequacy, are modest and manageable.

The results presented in this document further demonstrate, for the specific cases 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 proposed rules scenario from the RIA to a base case (absent the proposed requirements) that is assumed to be adequate and reliable. In this framework, we emphasize the incremental changes in the power system that are projected to occur under the presence of the rules in the 2030, 2035 and 2040 model run years[4]. The EPA uses the Integrated Planning Model (IPM) to project likely future electricity market conditions with and without the proposed rules.[5]

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 between the 78 IPM regions, based on current and planned transmission capacity, by

[4] 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 2029-2031 to run year 2030, calendar years 2032-2037 to run year 2035 and calendar years 2038-2041 to run year 2040. For model details, please see Chapter 2 of the IPM documentation, available at: https://www.epa.gov/airmarkets/power-sector-modeling.

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

setting limits to the ability to transfer power between regions using the bulk power transmission system, as well as the ability to endogenously expand these links based on relative economics. Within each model region, IPM assumes that adequate within-region transmission capacity exists or will be built to deliver any resources located in, or transferred to, the region. This document focusses on key regional results important to management of the power system. For a more complete presentation of the projected power sector impacts of the proposed rules, see the Regulatory Impact Analysis.

Overview

These rules establish CO_2 emission rate limits on covered fossil fuel-fired power plants (electric generating units or EGUs) in the US. As noted earlier, this analysis is limited to the impact of the requirements on existing coal-fired steam generation EGUs and the first two phases of the requirements on new natural gas fired EGUs as outlined in Section 3 of the RIA. A standalone analysis at the end of this TSD assesses the resource adequacy impacts of the proposed requirements for existing combustion turbines. The EGUs covered by the rules and subject to these limits are therefore 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 and X of the preamble.

The scenarios include a base case, and the proposed rules scenario. For purposes of this resource adequacy and reliability assessment, estimates and projections are taken from those same scenarios and years as shown in the RIA (2030, 2035, and 2040).

Summary of Changes in Operational Capacity

Total operational capacity remains similar between the base and policy scenarios. Operational generating capacity[6] changes from the base case in 2030, 2035 and 2040 are summarized below:

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

Table 1. Operational Capacity Summary (2030, 2035, 2040)[a]

Capacity (GW)	2030	2035	2040
Base Case Operational Capacity	1,338	1,632	1,908
Minus Retirements			
Coal	0.4	-22.2	-17.0
Oil/Gas	-0.5	-0.3	-0.3
NGCC	-0.1	0.0	0.0
NGCT	-0.3	-0.2	-0.2
Nuclear	0.0	0.0	0.0
Plus Additions			
NGCC	3.5	1.0	1.1
NGCT	0.3	23.1	18.2
Wind	0.4	2.0	-0.2
Solar	0.7	0.4	-1.0
Storage	-0.1	-2.2	-2.1
Other	0.0	0.0	0.0
Policy Case Operational Capacity	1,342	1,633	1,906

[a] Thermal additions include units with CCS.

Since the model must maintain adequate reserves in each region, projected retirements must be 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 the 2030 run year, an incremental 3.8 GW of NGCC/NGCT and an incremental 1.1 GW of incremental solar and wind builds occur relative to the baseline. By 2035, an incremental 22 GW of coal retirements occur, offset primarily by increases in incremental NGCT (23 GW) and renewable (2.4 GW) additions. By 2040, incremental coal retirements relative to the baseline (17 GW) are lower than in 2035 (22 GW), reflecting a convergence towards the long-term equilibrium level of remaining coal capacity.

While the table above reflects the total installed capacity, IPM assumes region-specific capacity credits for variable technologies (primarily solar and wind) to help meet target reserve margin constraints. Hence resources such as variable renewables receive a derate relative to nameplate capacity when solving for reserve margin.[7]

Reserve Requirements

The target reserve margin is a measure of the amount of accredited capacity available in excess of peak demand. Planners and reliability organizations set target reserve margins across a certain service territory as one of the steps to ensure resource adequacy and ensure that there is adequate supply to meet future demand. IPM uses a target reserve margin in each region[8] as the basis for determining how much accredited capacity to keep operational (or build) in order to preserve resource adequacy. IPM retires capacity if it is uneconomic and no longer needed to

[7] For model details, please see Chapters 3 and 4 of the IPM documentation, available at: https://www.epa.gov/airmarkets/power-sector-modeling.

[8] 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.

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 will 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. Projected reserve margins remain at or above target reserve margins under the baseline and proposal modeling for all years within the forecast period. For details on projected reserve margins under the base and policy scenarios, please see Appendix A-3, B-3 and C-3.[9]

Changes in Retirements and New Capacity Additions under the Proposed Rules

The incremental retirements in the proposal case are shown above in Table 1; the 22 GW of retirements in 2035 are in addition to 104 GW of coal and 15 GW of oil/gas retirements already occurring in the base case.

By 2035, the proposed rules 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). Renewable additions are higher under the policy case. The largest increases in new capacity are in NGCT (23 GW), followed by solar and wind (2.5 GW). 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 proposed 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.

Reserve Transfers

In cases where it is economic to transfer reserves from a neighboring region, rather than supply reserves from within a region, IPM will transfer reserves, 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 lower cost reserves 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 reserves sent to neighboring regions. In these cases, a positive value signifies the reserve capacity sent to other regions is larger than the reserve capacity received from other regions

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

(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 reserve transfers represent the use of the transmission system on a firm basis for at least a season.

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 proposed rules are below 2%, highlighting that reserve transfers under the proposal scenario are very similar to baseline levels. For details on projected transfers under the base and policy scenarios, please see Appendix A-6, B-6 and C-6.

Estimated Resource Adequacy Impact of Emission Guidelines on Existing Natural Gas Fired EGUS and Third Phase of Proposed New Source Performance Standards on New Natural Gas Fired EGUs

While the impacts were not modeled explicitly with IPM, the impact of the proposed emission guidelines for existing natural gas-fired EGUs and other elements of the proposed new source performance standards on new natural gas are estimated to have limited to no impact on the resource adequacy of the power system. As indicated in this TSD, resource adequacy is a core component of system reliability. The modeled proposal scenario in IPM maintained sufficient levels of resource adequacy across all years.

The proposed emission guidelines for existing natural gas-fired EGUs are estimated to have very little incremental impact on resource adequacy over the IPM modeled proposed scenario. As estimated above, the emission guidelines for existing gas would cover 36.8 GW of natural gas EGUs, which represents 7.7% of total natural gas capacity in 2035. However, only a fraction of this amount has a direct effect on resource adequacy. Resource adequacy is the generation capacity needed to meet peak demand. The total available capacity is needed, at most, for only a fraction of the year; most facilities can run at significantly less than full utilization throughout the year without any impact on resource adequacy or system reliability. Moreover, even those EGUs that operate at 50% annual capacity factor or below, and therefore avoid any requirements under the proposed emission guidelines for existing gas, could operate at higher utilization during periods of system need without exceeding a 50% capacity factor on an annual basis. Grid planners and system operators assign high capacity accreditation values to natural gas-fired EGUs that operate at a wide range of capacity factors. Therefore, those EGUs that choose to reduce utilization to at or under 50% would receive full capacity accreditation and would not negatively impact resource adequacy.

Similarly, for the 8.6 to 17.3 GW of EGUs estimated to install CCS, they would also still have full capacity accreditation and would contribute to resource adequacy. They would continue to operate, with CCS installed, and so would continue to offer capacity to the system at times of system need. The only impact on resource adequacy is due to the derate of the net-capacity from pre-retrofit to post-retrofit, which would reduce the maximum capacity available. EPA assumes an 18 percent derate based on the cost and performance assumptions developed by Sargent and Lundy and detailed in chapter 6 of the IPM documentation[10]. Applying this 18% derate to the 8.6 to 17.3 GW of EGUs installing CCS results in a total derate of 1.5 to 3.1 GW, representing 0.3% to 0.6% of the total natural gas capacity in 2035. Given the small relative magnitude of capacity derate to the size of the natural gas fleet, it is expected that this would have little to no impact on resource adequacy. At the same time, the analysis assumes that an incremental 4.6 to 5.5 GW of zero-emitting capacity is added or maintained nationwide. To fully offset the reduction of accredited capacity in NGCC would require that the zero-emitting resources were able to contribute 33 percent of their total capacity to reserve in the low scenario and 56 percent in the high scenario. To further put the capacity totals into context, total US projected peak demand in 2035 is 886 GW, and there are 58 GW of retirements and 332 GW of capacity additions projected between the 2030 and 2035 model run years under the Proposal modeling.

Moreover, grid planners, operators, and market participants can address the potential, marginal impact, through development of a similarly small increment of accredited capacity, whether from new natural gas simple cycle turbine deployment, new energy storage, or new sources of clean energy.

The same considerations apply to the incremental changes in capacity estimated in response to the other elements of the new source performance standards for new natural gas fired EGUs. For both the affected units that reduce capacity factor to 50% and those that increase hydrogen co-firing to 96% by volume, unit capacity accreditation and the amount that they contribute to resource adequacy is unchanged, as there is no capacity derate for hydrogen co-firing. Therefore the incremental impact of other elements of the proposed new source performance standards on new natural gas fired EGUs on resource adequacy and reliability in comparison to the modeled illustrative proposal is estimated to be negligible.

[10] Available at: https://www.epa.gov/power-sector-modeling.

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

A1. Projected Operational Capacity in GW (2030)

Region	All generation sources		Change from Base	Coal Only[a]		Change from Base
	Base	Policy		Base	Policy	
US	1,338	1,342	4	69	59	-10
ERCOT	142	141	-1	5	3	-2
FRCC	67	67	0	2	1	0
MISO	197	200	2	19	16	-3
ISONE	50	50	0	0	0	0
NYISO	54	54	0	0	0	0
PJM	222	222	0	16	15	-1
SERC	182	181	-1	13	12	-1
SPP	102	104	2	6	3	-3
WECC - non CAISO	212	211	-1	9	8	-1
CAISO	110	112	2	0	0	0

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

A2. 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	827	827	955	955
ERCOT	76	76	87	87
FRCC	53	53	63	63
MISO	133	133	156	156
ISONE	27	27	32	32
NYISO	33	33	38	38
PJM	155	155	179	179
SERC	132	132	151	151
SPP	55	55	63	63
WECC - non CAISO	109	109	124	124
CAISO	55	55	63	63

A3. 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%	15%	0%	0%
ERCOT	14%	14%	14%	0%	0%
FRCC	19%	19%	19%	0%	0%
MISO	17%	17%	17%	0%	0%
ISONE	18%	18%	18%	0%	0%
NYISO	15%	15%	15%	0%	0%
PJM	16%	16%	16%	0%	0%
SERC	15%	15%	15%	0%	0%
SPP	15%	15%	15%	0%	0%
WECC - non CAISO	14%	14%	14%	0%	0%
CAISO	14%	14%	14%	0%	0%

A4. Policy Case Retired Capacity Incremental to Base Case in GW (2030)

Region	CC	Coal	CT	Nuclear	OG Steam	Total
US	0.1	-0.4	0.3	0.0	0.5	0.5
ERCOT	0.0	0.4	0.0	0.0	0.0	0.4
FRCC	0.0	0.1	0.0	0.0	0.0	0.1
MISO	0.0	-1.1	0.0	0.0	0.0	-1.1
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	-0.3	0.0	0.0	0.0	-0.3
SERC	0.0	-0.3	0.0	0.0	0.0	-0.3
SPP	0.0	0.4	0.0	0.0	0.3	0.7
WECC - non CAISO	0.1	0.4	0.0	0.0	0.2	0.7
CAISO	0.0	0.0	0.3	0.0	0.0	0.3

A5. New Capacity in Policy Case Incremental to Base Case in GW (2030)

Region	CC	CT	Wind	Solar	Storage	Other	Total
US	4	0	0	1	0	0	5
ERCOT	0	0	0	0	0	0	0
FRCC	0	0	0	0	0	0	0
MISO	0	0	3	-1	0	0	2
ISONE	0	0	0	0	0	0	0
NYISO	0	0	0	0	0	0	0
PJM	0	0	1	0	0	0	0
SERC	2	1	-3	0	0	0	-1
SPP	0	0	1	1	0	0	2
WECC - non CAISO	1	0	-1	0	0	0	0
CAISO	0	0	0	2	0	0	2

A6. 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	-4.3	-4.3	0.0	0%
ERCOT	-0.9	-1.4	-0.5	-1%
FRCC	-1.8	-1.8	0.0	0%
MISO	-6.0	-6.0	0.0	0%
ISONE	-0.6	-0.6	0.0	0%
NYISO	-1.2	-1.2	0.0	0%
PJM	-0.2	-0.2	0.0	0%
SERC	7.3	7.3	0.0	0%
SPP	1.3	1.8	0.5	1%
WECC - non CAISO	-0.5	-0.5	0.1	0%
CAISO	-1.7	-1.7	0.0	0%

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

B1. Projected Operational Capacity in GW (2035)

Region	All generation sources		Change from Base	Coal Only [a]		Change from Base
	Base	Policy		Base	Policy	
US	1,632	1,633	2	44	13	-31
ERCOT	172	172	0	5	2	-3
FRCC	82	82	0	1	0	-1
MISO	259	258	-1	10	3	-7
ISONE	57	57	0	0	0	0
NYISO	65	65	0	0	0	0
PJM	262	264	2	12	3	-9
SERC	222	223	1	5	1	-4
SPP	127	127	0	4	0	-4
WECC - non CAISO	252	252	-1	6	4	-2
CAISO	133	133	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 (2035)

Region	Projected Reserve Margins			
	Peak Demand Base	Peak Demand Policy	Reserve Capacity Base	Reserve Capacity Policy
US	886	886	1,022	1,022
ERCOT	82	82	93	93
FRCC	57	57	68	68
MISO	140	140	164	164
ISONE	30	30	35	35
NYISO	34	34	39	39
PJM	164	164	189	189
SERC	140	140	161	161
SPP	58	58	67	67
WECC - non CAISO	120	120	137	137
CAISO	60	60	68	68

B3. 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%	15%	0%	0%
ERCOT	14%	14%	14%	0%	0%
FRCC	19%	19%	19%	0%	0%
MISO	17%	17%	17%	0%	0%
ISONE	18%	18%	18%	0%	0%
NYISO	15%	15%	15%	0%	0%
PJM	16%	16%	16%	0%	0%
SERC	15%	15%	15%	0%	0%
SPP	15%	15%	15%	0%	0%
WECC - non CAISO	14%	14%	14%	0%	0%
CAISO	14%	14%	14%	0%	0%

B4. Policy Case Retired Capacity Incremental to Base Case in GW (2035)

Region	CC	Coal	CT	Nuclear	OG Steam	Total
US	0.0	22.2	0.2	0.0	0.3	22.7
ERCOT	0.0	1.2	0.0	0.0	0.0	1.2
FRCC	0.0	1.0	0.0	0.0	0.0	1.0
MISO	0.0	4.8	0.0	0.0	0.0	4.8
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	8.4	0.0	0.0	0.0	8.4
SERC	0.0	3.2	0.0	0.0	0.0	3.2
SPP	0.0	1.5	0.0	0.0	-0.4	1.1
WECC - non CAISO	0.1	1.9	0.2	0.0	0.7	3.0
CAISO	-0.1	0.0	0.0	0.0	0.0	-0.1

B5. New Capacity in Policy Case Incremental to Base Case in GW (2035)

Region	CC	CT	Wind	Solar	Storage	Other	Total
US	1	23	2	0	-2	0	24
ERCOT	0	1	0	0	0	0	1
FRCC	0	1	0	0	0	0	1
MISO	0	4	-1	2	0	0	4
ISONE	0	0	0	0	0	0	0
NYISO	0	0	0	0	0	0	0
PJM	0	7	2	0	0	0	10
SERC	0	4	0	1	0	0	5
SPP	0	0	0	0	1	0	1
WECC - non CAISO	1	1	0	0	-1	0	2
CAISO	0	4	0	-2	-3	0	-1

B6. 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	-5.4	-5.9	-0.4	0%
ERCOT	-1.6	-1.4	0.2	0%
FRCC	-2.6	-2.4	0.3	0%
MISO	-3.1	-3.8	-0.7	-1%
ISONE	-2.7	-2.4	0.4	1%
NYISO	-0.4	-0.3	0.0	0%
PJM	-2.2	-2.6	-0.5	0%
SERC	6.9	6.9	0.0	0%
SPP	2.8	2.4	-0.4	-1%
WECC - non CAISO	1.0	-0.3	-1.2	-1%
CAISO	-3.6	-2.0	1.6	3%

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

C1. Projected Operational Capacity in GW (2040)

Region	All generation sources		Change from Base	Coal Only[a]		Change from Base
	Base	Policy		Base	Policy	
US	1,908	1,906	-1	35	10	-26
ERCOT	191	191	0	4	2	-2
FRCC	104	104	-1	1	0	-1
MISO	295	294	-1	7	2	-5
ISONE	69	69	0	0	0	0
NYISO	75	76	0	0	0	0
PJM	322	321	-1	9	1	-7
SERC	273	275	2	5	1	-4
SPP	139	139	0	4	0	-4
WECC - non CAISO	291	290	-1	5	3	-2
CAISO	149	149	0	0	0	0

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

C2. 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	954	954	1,101	1,101
ERCOT	88	88	100	100
FRCC	62	62	74	74
MISO	148	148	173	173
ISONE	33	33	39	39
NYISO	36	36	41	41
PJM	176	176	203	203
SERC	150	150	172	172
SPP	62	62	72	72
WECC - non CAISO	133	133	152	152
CAISO	65	65	74	74

C3. 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%	15%	0%	0%
ERCOT	14%	14%	14%	0%	0%
FRCC	19%	19%	19%	0%	0%
MISO	17%	17%	17%	0%	0%
ISONE	18%	18%	18%	0%	0%
NYISO	15%	15%	15%	0%	0%
PJM	16%	16%	16%	0%	0%
SERC	15%	15%	15%	0%	0%
SPP	15%	15%	15%	0%	0%
WECC - non CAISO	14%	14%	14%	0%	0%
CAISO	14%	14%	14%	0%	0%

C4. Policy Case Retired Capacity Incremental to Base Case in GW (2040)

Region	CC	Coal	CT	Nuclear	OG Steam	Total
US	0.0	17.0	0.2	0.0	0.3	17.4
ERCOT	0.0	0.7	0.0	0.0	0.0	0.7
FRCC	0.0	1.0	0.0	0.0	0.0	1.0
MISO	0.0	2.8	-0.1	0.0	0.0	2.7
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	6.5	0.0	0.0	0.0	6.5
SERC	0.0	3.0	0.0	0.0	0.0	3.0
SPP	0.0	1.6	0.0	0.0	-0.4	1.1
WECC - non CAISO	0.1	1.4	0.2	0.0	0.7	2.5
CAISO	-0.1	0.1	0.0	0.0	0.0	-0.1

C5. New Capacity in Policy Case Incremental to Base Case in GW (2040)

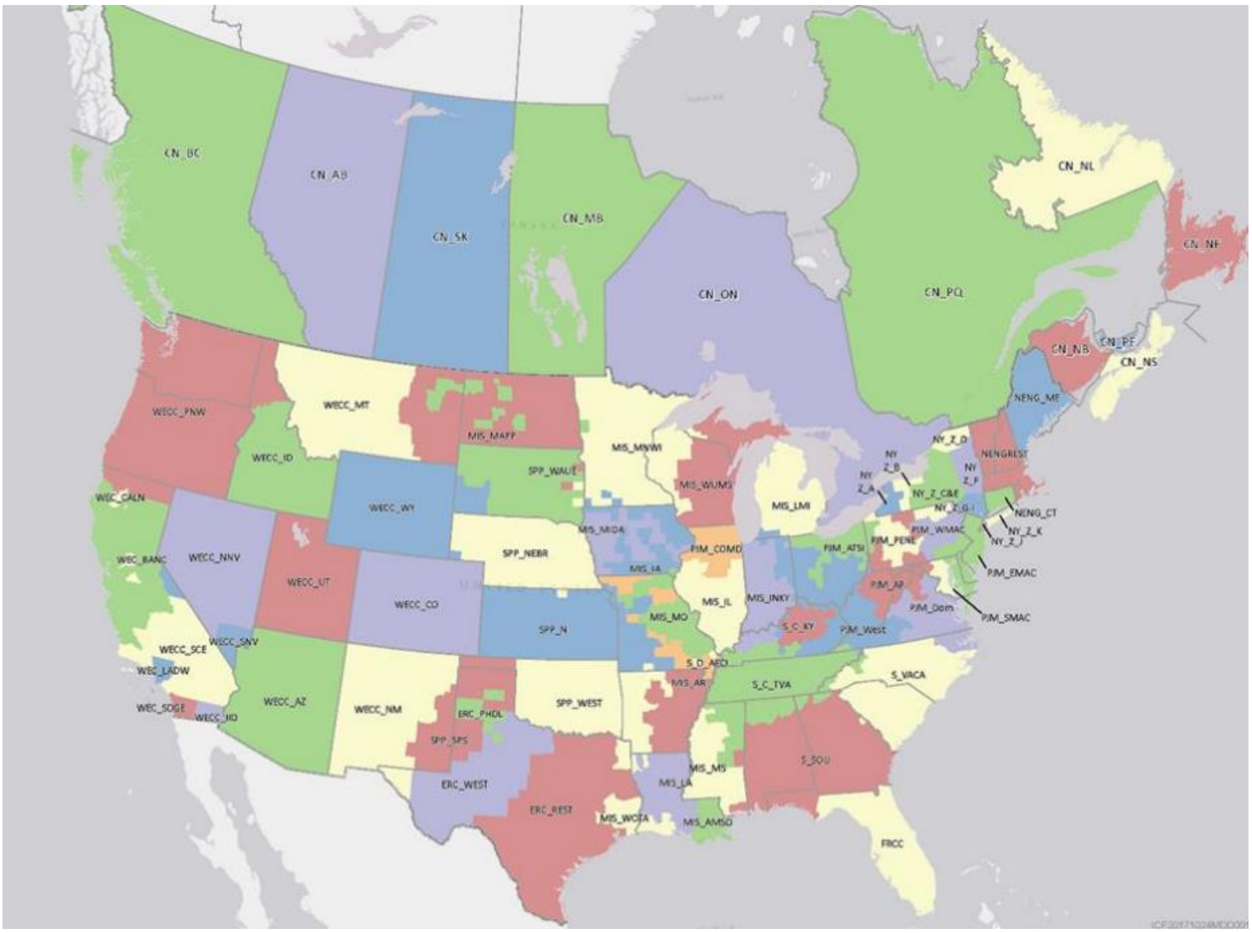
Region	CC	CT	Wind	Solar	Storage	Other	Total
US	1	18	0	-1	-2	0	16
ERCOT	0	1	0	0	0	0	1
FRCC	0	1	0	0	0	0	0
MISO	0	3	-2	0	0	0	2
ISONE	0	0	0	0	0	0	0
NYISO	0	0	0	0	0	0	0
PJM	0	6	0	0	0	0	6
SERC	0	3	1	2	0	0	6
SPP	0	1	0	0	0	0	1
WECC - non CAISO	1	2	1	-2	-1	0	2
CAISO	0	1	-1	-1	-1	0	-1

C6. 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	-6.9	-7.0	-0.1	0%
ERCOT	-0.9	-0.9	0.0	0%
FRCC	-2.0	-2.2	-0.2	0%
MISO	-4.1	-3.9	0.3	0%
ISONE	-2.5	-2.5	0.0	0%
NYISO	-2.0	-1.9	0.0	0%
PJM	-1.9	-2.1	-0.2	0%
SERC	7.3	7.4	0.0	0%
SPP	2.0	2.0	0.0	0%
WECC - non CAISO	-1.2	-2.0	-0.8	-1%
CAISO	-1.6	-0.8	0.8	1%

Appendix D: Maps

IPM v6 Map



D2: NERC Assessment Areas in Long Term Reliability Assessment.

Source: NERC 2022 Long-Term Reliability Assessment