BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-29
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-30

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

Exhibit 91
MISO ERAS Decision

192 FERC ¶ 61,064
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Mark C. Christie, Chairman;
David Rosner, Lindsay S. See,
and Judy W. Chang.

Midcontinent Independent System Operator, Inc.   Docket No. ER25-2454-000

ORDER ACCEPTING TARIFF REVISIONS, SUBJECT TO CONDITION

(Issued July 21, 2025)

1. On June 6, 2025, Midcontinent Independent System Operator, Inc. (MISO) submitted, pursuant to section 205 of the Federal Power Act (FPA)[1] and part 35 of the Commission's regulations,[2] proposed revisions to Attachment X in the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff), which contains MISO's Generator Interconnection Procedures (GIP), to establish the Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term.[3] In this order, we accept MISO's proposed Tariff revisions, subject to condition, effective August 6, 2025, as requested, as discussed below.

I. **Background**

2. In Order No. 2003,[4] the Commission required public utilities that own, control, or operate transmission facilities to file standard generator interconnection procedures and a standard agreement to provide interconnection service to generating facilities with a

[1] 16 U.S.C. § 824d.

[2] 18 C.F.R. pt. 35 (2024).

[3] MISO, FERC Electric Tariff, attach. X (Generator Interconnection Procedures (GIP)) (175.0.0); *id*. app. 1 (Interconnection Request for a Generating Facility)) (57.0.0); *id*. app. 6 (Generator Interconnection Agreement (GIA)) (108.0.0) (Proposed Tariff).

[4] *Standardization of Generator Interconnection Agreements & Procs.*, Order No. 2003, 104 FERC ¶ 61,103 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

capacity greater than 20 megawatts (MW). To this end, the Commission adopted the *pro forma* Large Generator Interconnection Procedures (LGIP) and *pro forma* Large Generator Interconnection Agreement (LGIA) and required all public utilities subject to Order No. 2003 to modify their tariffs to incorporate the *pro forma* LGIP and *pro forma* LGIA.[5]

3. The Commission permitted transmission providers to seek variations from the *pro forma* LGIP and *pro forma* LGIA if those variations were "consistent with or superior to" the terms of the *pro forma* LGIP and *pro forma* LGIA.[6] In addition, the Commission indicated that it would allow regional transmission organizations and independent system operators (RTO/ISO), such as MISO, to propose independent entity variations for pricing and non-pricing provisions, stating that RTOs/ISOs have different operating characteristics due to their sizes and locations and that an RTO/ISO is less likely to act in an unduly discriminatory manner than a transmission provider that is also a market participant.[7] The Commission found that RTOs/ISOs "shall therefore have greater flexibility to customize [their] interconnection procedures and agreements to fit regional needs."[8] Under the independent entity variation standard, an RTO/ISO must demonstrate that proposed deviations from the Commission's *pro forma* LGIP and *pro forma* LGIA are just and reasonable and not unduly discriminatory or preferential and accomplish the purposes of Order No. 2003.[9]

A. <u>**Overview of MISO's Generator Interconnection Process**</u>

4. Since the issuance of Order No. 2003, MISO has submitted several generator interconnection queue reform proposals. As relevant here, in January 2017, the Commission accepted MISO's proposal to implement a three-phase Definitive Planning

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[5] Order No. 2003, 104 FERC ¶ 61,103 at PP 1-2.

[6] *Id.* PP 825-826. The Commission also permitted transmission providers to justify a variation from the *pro forma* LGIP or *pro forma* LGIA based on regional reliability requirements and required transmission providers to submit these regional reliability variations to the Commission for approval under the relevant reliability standard. *Id.* PP 824, 826.

[7] *Id.* P 827.

[8] *Id.*

[9] *See, e.g.*, *Midcontinent Indep. Sys. Operator, Inc.*, 185 FERC ¶ 61,084, at P 11 (2023) (citing Order No. 2003, 104 FERC ¶ 61,103 at PP 26, 827).

Phase (DPP) process to study interconnection requests in clusters.[10] The DPP is based on a sequential review process that facilitates the structured study and restudy of proposed generating facilities.

5. Under the current procedures, MISO conducts one system impact study in each of the three DPP phases (i.e., a preliminary system impact study in DPP Phase I, a revised system impact study in DPP Phase II, and a final system impact study in DPP Phase III) to account for withdrawn interconnection requests and to refine and update the analysis.[11] During DPP Phases II and III, MISO also conducts a facilities study.[12] DPP Phases I and II are followed by interconnection customer decision points (Decision Point I follows DPP Phase I, and Decision Point II follows DPP Phase II).[13] The decision points provide interconnection customers opportunities to evaluate study results and decide whether to proceed with or withdraw their interconnection requests. On June 26, 2025, the Commission accepted in part MISO's Order No. 2023[14] compliance filing, which maintained its DPP process as an independent entity variation.[15]

6. On January 19, 2024, the Commission issued an order rejecting MISO's proposed revisions to its GIP to implement a cap on the total MW value of interconnection requests that may be studied in a cluster, as well as exemptions to that cap (2023 MISO Queue Cap Proposal).[16] The Commission found, among other things, that "the proposal to include cap exemptions has not been shown to be consistent with the Commission's open

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[10] *Midcontinent Indep. Sys. Operator, Inc.*, 158 FERC ¶ 61,003, *order on reh'g*, 161 FERC ¶ 61,137 (2017).

[11] MISO, Tariff, attach. X (GIP) (171.0.0), §§ 7 (Definitive Planning Phase), 7.3.1 (Definitive Planning Phase I), 7.3.2 (Definitive Planning Phase II), 7.3.3 (Definitive Planning Phase III).

[12] *Id.* §§ 7 (Definitive Planning Phase), 7.3.2 (Definitive Planning Phase II), 7.3.3 (Definitive Planning Phase III).

[13] *Id.* §§ 7 (Definitive Planning Phase), 7.3.1.4 (Interconnection Customer Decision Point I), 7.3.2.4 (Interconnection Customer Decision Point II).

[14] *Improvements to Generator Interconnection Procs. & Agreements*, Order No. 2023, 184 FERC ¶ 61,054, *order on reh'g*, 185 FERC ¶ 61,063 (2023), *order on reh'g*, Order No. 2023-A, 186 FERC ¶ 61,199, *errata notice*, 188 FERC ¶ 61,134 (2024).

[15] *Midcontinent Indep. Sys. Operator, Inc.*, 191 FERC ¶ 61,229 (2025).

[16] *Midcontinent Indep. Sys. Operator, Inc.*, 186 FERC ¶ 61,054 (January 2024 Order), *order on reh'g*, 187 FERC ¶ 61,031 (2024).

access requirements"[17] because, despite the purpose of the cap being to limit the total MW studied in a queue cycle, exempted interconnection requests could enter the cycle regardless of the cap value (i.e., there was no limit to the number of exempted interconnection requests), and thus "the cap exemptions create[d] priority access to the generator interconnection process for the exempted classes of interconnection requests."[18] The Commission further stated that it had "concerns that specific exemptions have not otherwise been shown to be just and reasonable and not unduly discriminatory."[19] As an example, the Commission stated that MISO's proposal lacked "sufficient basis to conclude that the RERRA exemption will be limited to interconnection requests needed to meet state resource adequacy or reliability requirements."[20] The January 2024 Order also accepted MISO's proposed revisions to its GIP, in Docket No. ER24-340-000, to increase milestone payments, adopt an automatic withdrawal penalty, revise certain withdrawal penalty provisions, and expand site control requirements for interconnection facilities (2023 Non-Cap Queue Reform Proposal).[21]

7. On November 21, 2024, in Docket No. ER25-507-000, MISO submitted another proposal to establish a queue cap (2024 MISO Queue Cap), which the Commission accepted on January 30, 2025.[22] Unlike the 2023 MISO Queue Cap Proposal, the 2024 MISO Queue Cap established a hard limit on the total MW that could be studied in a cluster. While the 2024 MISO Queue Cap allowed for exemptions, such exemptions counted toward the hard cap limit, and the Commission determined that the proposed exemptions did not create open access concerns.[23] Unlike the 2023 MISO Queue Cap Proposal, the 2024 MISO Queue Cap did not include a RERRA exemption.

B. Initial ERAS Proposal and May 2025 Order

8. On March 17, 2025, in Docket No. ER25-1674-000, MISO submitted proposed revisions to its GIP to establish an ERAS process to provide a framework for the

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[17] *Id.* P 170.

[18] *Id.* P 176.

[19] *Id.* P 178.

[20] *Id.* P 177 n.413.

[21] January 2024 Order, 186 FERC ¶ 61,054 at P 1.

[22] *Midcontinent Indep. Sys. Operator, Inc.*, 190 FERC ¶ 61,057 (2025) (January 2025 Order).

[23] *Id.* P 87.

expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term (Initial ERAS Proposal). On May 16, 2025, the Commission issued an order rejecting the Initial ERAS Proposal.[24]

9. In the Initial ERAS Proposal, MISO proposed to create a quarterly "first-come, first-served" serial study process to facilitate the rapid study of interconnection requests for generating resources that are committed to addressing specific, identified resource adequacy and/or reliability needs,[25] resulting in an Expedited Generator Interconnection Agreement (EGIA) within approximately 90 days of study kickoff. MISO proposed that an ERAS interconnection request must request Network Resource Interconnection Service (NRIS).[26] MISO further proposed that an ERAS interconnection request must demonstrate that it is required to meet an identified resource adequacy and/or reliability need by providing both: (1) a written notification from the RERRA, or its documented representative, where the load to be served by the generating facility is located, that certifies or determines that the generating facility should be considered for the ERAS process in order to meet a resource adequacy and/or a reliability need claimed by the RERRA, the Load Serving Entity (LSE), or the interconnection customer; and (2) an executed agreement evidencing that the ERAS project is intended to be used by the entity with the claimed resource adequacy or reliability need.[27]

10. MISO's Initial ERAS Proposal also included certain requirements and obligations for ERAS interconnection requests that would not apply to other interconnection requests, including commercial operation date requirements, greater site control requirements, a greater application fee and milestone payments, and a requirement to pay for all network upgrades documented in the EGIA, even if the interconnection customer withdrew its request after the EGIA was executed or filed unexecuted with the Commission.[28]

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[24] *Midcontinent Indep. Sys. Operator, Inc.*, 191 FERC ¶ 61,131 (2025) (May 2025 Order).

[25] *Id.* P 8.

[26] MISO's GIP defines NRIS, in relevant part, as "an Interconnection Service that allows Interconnection Customer to integrate its Generating Facility with the Transmission System in the same manner as for any Generating Facility being designated as a Network Resource. [NRIS] does not convey transmission service." MISO, Tariff, attach. X (GIP) (171.0.0), § 1 (Definitions).

[27] May 2025 Order, 191 FERC ¶ 61,131 at P 9.

[28] *Id.* P 10.

11. In the May 2025 Order, the Commission rejected MISO's Initial ERAS Proposal, finding that MISO had not shown the proposal to be just and reasonable and not unduly discriminatory or preferential.[29] The Commission agreed with MISO that ensuring reliability and resource adequacy is of critical importance. The Commission explained, however, that the Initial ERAS Proposal placed no limit on the number of projects that could be entered in the ERAS process, which could result in an ERAS queue with processing times for interconnection requests that are too lengthy to meet MISO's stated resource adequacy and reliability needs, similar to the challenges with the current DPP queue. The Commission also found that MISO had not demonstrated that the Initial ERAS Proposal will solve the identified reliability and resource adequacy needs.[30]

12. The Commission further stated that MISO's proposal to provide 14 opportunities to enter the ERAS process through 2028, "could further impede MISO's ability to process ERAS requests on an expedited basis," and would "exacerbate[] the potential for a volume of ERAS interconnection requests untethered to reliability or resource adequacy needs."[31] The Commission stated that this aspect of MISO's Initial ERAS Proposal made it difficult to determine whether the solution was narrowly tailored enough to fix the problem.

13. In addition, the Commission stated that MISO did not adequately describe how the ERAS process was sufficiently targeted to study only interconnection requests needed to meet the anticipated shortfall in generating capacity described by MISO.[32] The Commission further stated that MISO had not demonstrated that the proposed Tariff language was tailored to ensure that only those resources capable of addressing identified near-term resource adequacy or reliability needs would be eligible for expedited study through the ERAS process.[33]

II. <u>MISO's Filing</u>

14. MISO explains that it is facing urgent near-term resource adequacy and reliability concerns due to load growth, generation retirement, and delays in the interconnection

[29] *Id.* P 197.

[30] *Id.* PP 199, 201.

[31] *Id.*

[32] *Id.* P 201.

[33] *Id.* P 202.

process[34] and that it will experience a 4.7 gigawatt (GW) shortfall by 2028 if currently planned generating facility retirements occur.[35] MISO asserts that, while it has undertaken reforms to improve queue processing, the current processing presents a barrier to developing generation that can address these near-term needs. Therefore, MISO proposes revisions to its GIP and *pro forma* Generator Interconnection Agreement (GIA) to establish a revised ERAS process, which provides for accelerated study of interconnection requests that will address urgent resource adequacy and reliability needs in the near term (i.e., within the next five years) (Revised ERAS Proposal).[36] Specifically, under the Revised ERAS Proposal, MISO proposes to create a quarterly "first-come, first-served" serial study process to facilitate the rapid study of interconnection requests for generating resources that are committed to addressing specific, identified resource adequacy and/or reliability needs,[37] resulting in an EGIA within approximately 90 days of study kickoff.

15. MISO proposes to maintain that an ERAS interconnection request must meet capacity resource requirements and therefore must request NRIS.[38] Further, MISO proposes that an ERAS interconnection request must demonstrate that it is required to meet an identified resource adequacy and/or reliability need by providing both: (1) a written verification from the RERRA, or its documented representative, where the load to be served by the generating facility is located, that determines that the generating facility

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[34] Transmittal at 5.

[35] *Id.* at 6 (citing *NERC's 2024 Long-Term Reliability Assessment* (published December 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf).

[36] *Id.* at 1. *See* MISO, Proposed Tariff, attach. X (GIP) (175.0.0), §§ 1 (Definitions), 2.1 (Application of Generator Interconnection Procedures), 3.3.1 (Initiating an Interconnection Request), 3.4 (OASIS Posting), 3.9 (Expedited Resource Addition Study), 5.13 (Transition to ERAS Process), 7.2.1 (Requirements for Demonstrating Site Control for Generating Facility), 7.3.1.4 (Interconnection Decision Point I), 7.3.2.3.1 (Additional Analysis Applicable to Interconnection Requests in a JTIQ Screening Group), 11.1 (Tender), 11.2 (Negotiation), 11.2.1 (Optional negotiation period adjustment for Interconnection Facilities Study), and 11.3 (Execution and Filing); *id.* app. 1 (Interconnection Request for a Generating Facility) (56.0.0); *id.* app. 6 (GIA) (106.0.0), art. 1 (Definitions), 2.3.3, and 2.4 (Termination Costs).

[37] Transmittal at 4; Filing, Tab C (Testimony of Andrew Witmeier) at 51-52 (Witmeier Testimony).

[38] Transmittal at 36-37.

should be considered for the ERAS process in order to meet a resource adequacy and/or a reliability need that is not otherwise included in a resource plan, is claimed by the RERRA, or serves load in a retail choice state; and (2) an executed agreement evidencing that the ERAS project is intended to be used by the entity with the claimed resource adequacy or reliability need.[39]

16. MISO's proposal also maintains certain requirements and obligations on ERAS interconnection requests that would not apply to other interconnection requests, including commercial operation date requirements, greater site control requirements, a greater application fee and greater milestone payments, and a requirement to pay for all network upgrades documented in the EGIA, even if the interconnection customer withdraws its request after the EGIA is executed or filed unexecuted with the Commission.[40] MISO also states that the Revised ERAS Proposal contains new requirements for ERAS interconnection requests to better demonstrate the connection between a proposed generating facility and an identified resource adequacy and/or reliability need. MISO proposes to establish a cap of 68 interconnection requests that may be studied under ERAS. MISO proposes that of the 68 ERAS interconnection requests, 10 interconnection requests are carved out for independent power producers that have agreements with entities other than LSEs and eight interconnection requests are carved out for those serving retail choice loads. These requirements are described in more detail below in part IV of this order.

17. MISO requests an effective date of August 6, 2025 to ensure that the ERAS process will be in place prior to September 2, 2025, when MISO plans to start its first ERAS quarterly study period. MISO states that ERAS is meant as a short-term solution for a near-term problem, and it has written into its proposed Tariff revisions a sunset date of August 31, 2027, or the completion date of the sixty-eighth ERAS interconnection request study, whichever occurs first.[41] MISO states that it envisions ERAS as a temporary process needed until MISO is able to reduce the DPP study timeline to one year.[42]

III. <u>Notice and Responsive Pleadings</u>

18. Notice of the filing was published in the *Federal Register*, 90 Fed. Reg. 25042 (June 13, 2025), with interventions and protests due on or before June 16, 2025. Clean

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[39] *Id.* at 9, 27-30, 51-52.

[40] *Id.* at 56.

[41] *Id.* at 38-39; MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.9.

[42] Transmittal at 47.

Grid Alliance, Indicated Independent Power Producers (Indicated IPP),[43] NextEra, Public Interest Organizations (PIO),[44] and Trade Associations[45] each submitted a motion opposing the comment period of 10 days and requesting that the comment period be extended to 21 days. On June 11, 2025, the Office of the Secretary issued a notice denying the motions for extension of time.

19. Notices of intervention were filed by: the Minnesota Public Utilities Commission (Minnesota Commission); Organization of MISO States, Inc. (OMS); and the Public Utility Commission of Texas (Texas Commission).

20. Notices of intervention and comments were filed by: the Arkansas Public Service Commission (Arkansas Commission); the Illinois Commerce Commission (Illinois Commission); the Louisiana Public Service Commission and the Mississippi Public Service Commission (Louisiana and Mississippi Commissions); and the Missouri Public Service Commission (Missouri Commission).

21. A notice of intervention and limited protest was filed by the Michigan Public Service Commission (Michigan Commission).

22. Timely motions to intervene were filed by: Advanced Energy United; Alliant Energy Corporate Services, Inc. (AECS); American Clean Power Association and Clean Grid Alliance (jointly); Ameren Services Company, on behalf of Ameren Illinois Company d/b/a Ameren Illinois, Ameren Transmission Company of Illinois, and Union Electric Company d/b/a Ameren Missouri (collectively, Ameren); American Electric Power Service Corporation (AEP), on behalf of its affiliates AEP Energy Partners, Inc., AEP Indiana Michigan Transmission Company, Inc., and AEP Retail Energy Partners LLC; American Municipal Power, Inc.; Arevon; Big Rivers Electric Corporation (Big Rivers Electric); Calpine Corporation; Clean Energy Buyers Association; Clean Wisconsin; Clearway; Cleco Power LLC (Cleco); Coalition of Midwest Power Producers, Inc. (COMPP); Coalition of MISO Transmission Customers; Constellation

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[43] Indicated IPPs include: Arevon Energy, Inc. (Arevon); Clearway Energy Group LLC (Clearway); Cordelio Power LP (Cordelio); EDF Renewables, Inc. (EDF); Invenergy LLC; NextEra Energy Resources, LLC (NextEra); and Pine Gate Renewables, LLC (Pine Gate).

[44] For purposes of the motion opposing the 10-day comment period, PIOs include: Clean Wisconsin; Fresh Energy; Natural Resources Defense Council; Sierra Club; and Sustainable FERC Project.

[45] Trade Associations include: American Clean Power Association; Clean Grid Alliance; Electric Power Supply Association (EPSA); Solar Energy Industries Association (SEIA); and Southern Renewable Energy Association.

Energy Generation, LLC (Constellation); Consumers Energy Company (Consumers Energy); Cooperative Energy; Cordelio; DTE Electric Company (DTE Electric); Duke Energy Indiana, LLC (Duke Energy Indiana);[46] Earthrise MISO Companies;[47] East Texas Electric Cooperative, Inc.; EDF; EPSA; Enel Green Power North America, Inc. (Enel); Entergy Services, LLC (Entergy), on behalf of the Entergy Operating Companies;[48] Eolian, LP; Fresh Energy; Indiana Office of Utility Consumer Counselor; International Transmission Company d/b/a ITC*Transmission* (ITC*Transmission*); Invenergy Renewables, LLC (Invenergy); Large Public Power Council; Midwest TDUs;[49] MISO Transmission Owners (MISO TOs);[50] MN8 Energy LLC (MN8); New Leaf Energy, Inc. (New Leaf); NextEra; Northern Indiana Public Service Company LLC (NIPSCO); Ørsted Wind Power North America LLC; Otter Tail; Pine Gate; Public Citizen, Inc.; RWE Clean

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[46] Duke Energy Business Services LLC intervened on behalf of its affiliate Duke Energy Indiana.

[47] Earthrise MISO Companies include: Gibson City Energy Center, LLC; Shelby County Energy Center, LLC; and Tilton Energy LLC.

[48] The Entergy Operating Companies include: Entergy Arkansas, LLC; Entergy Louisiana, LLC; Entergy Mississippi, LLC; Entergy New Orleans, LLC; and Entergy Texas, Inc.

[49] Midwest TDUs include: Indiana Municipal Power Agency; The Missouri Joint Municipal Electric Utility Commission d/b/a the Missouri Electric Commission; Missouri River Energy Services; and WPPI Energy.

[50] For purposes of this filing, MISO TOs include: Ameren; American Transmission Company LLC; Big Rivers Electric; Central Minnesota Municipal Power Agency; Citizens Electric Corporation; City Water, Light & Power (Springfield, IL); Cleco; Cooperative Energy; Dairyland Power Cooperative; Duke Energy Business Services LLC for Duke Energy Indiana; East Texas Electric Cooperative, Inc.; Entergy Operating Companies; Great River Energy; GridLiance Heartland LLC; Hoosier Energy Rural Electric Cooperative, Inc.; Indiana Municipal Power Agency; Indianapolis Power & Light Company d/b/a AES Indiana; ITC*Transmission*; ITC Midwest LLC; Lafayette Utilities System; Michigan Electric Transmission Company, LLC (METC); MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; NIPSCO; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company (Otter Tail); Prairie Power, Inc.; Southern Illinois Power Cooperative; CenterPoint; Southern Minnesota Municipal Power Agency; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc.

Energy, LLC; SEIA; Shell Energy North America (US), L.P.; Sierra Club; Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (CenterPoint); Southern Renewable Energy Association; Southwest Power Pool, Inc. (SPP); Sustainable FERC Project and Natural Resources Defense Council (jointly); Treaty Oak Clean Energy, LLC; Union of Concerned Scientists; Vistra Corp. (Vistra); and Wisconsin Utilities.[51]

23. Timely comments were filed by: AECS; Ameren; Big Rivers Electric; CenterPoint; Consumers Energy; DTE Electric; Duke Energy Indiana; Entergy, Cleco, and Cooperative Energy (collectively, Entergy/Cleco/Cooperative Energy); EPSA; Indiana Energy Association;[52] ITC*Transmission*, METC, and ITC Midwest LLC (collectively, ITC); Midwest TDUs; MISO TOs; NIPSCO; Otter Tail; and Wisconsin Utilities.

24. Individual comments were filed by: Governor Mike Braun (Indiana Governor); Governor Mike Kehoe (Missouri Governor); Governor Jeff Landry (Louisiana Governor); Governor Tate Reeves (Mississippi Governor); Robert E. Rutkowski; and Governor Sarah Huckabee Sanders (Arkansas Governor).

25. Timely protests were filed by: Clean Energy Associations;[53] Clean Grid Alliance; COMPP; Constellation; Invenergy; MISO Independent Power Producers (MISO IPP);[54] PIOs;[55] and Vistra.

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[51] Wisconsin Utilities include: Wisconsin Electric Power Company; Wisconsin Public Service Corporation; and Upper Michigan Energy Resources Corporation.

[52] Indiana Energy Association filed comments on behalf of AES Indiana, CenterPoint Energy Indiana, Duke Energy Indiana, and NIPSCO.

[53] Clean Energy Associations include: Advanced Energy United; American Clean Power Association; Clean Grid Alliance; SEIA; and Southern Renewable Energy Association.

[54] MISO IPPs include: Arevon; Clearway; Cordelio; EDF; EDP Renewables North America, LLC; Enel; Invenergy LLC; MN8; New Leaf; NextEra; and Pine Gate.

[55] For purposes of the protest, PIOs include: Clean Wisconsin, Fresh Energy, Sierra Club, Sustainable FERC Project, and Union of Concerned Scientists.

26. On June 20, 2025, MISO filed a motion for leave to answer and answer (MISO Answer).[56] On June 26, 2025, MISO IPPs submitted an answer to the MISO Answer. On June 27, 2025, Clean Energy Associations and Clean Grid Alliance each submitted answers to the MISO Answer.

27. On June 23, 2025, the Texas Commission filed comments and a motion for leave to submit comments out-of-time.

28. On July 1, 2025, MISO filed a motion for leave to file supplemental answer and answer (MISO Supplemental Answer). On July 2, 2025, Vistra filed a motion for leave to respond and response to the MISO Supplemental Answer. On July 3, 2025, Clean Grid Alliance filed a motion for leave to answer and answer to the MISO Supplemental Answer. On July 7, 2025, PIOs filed a motion for leave to answer and answer. On July 9, 2025, Michigan Commission filed a motion for leave to answer and answer to the MISO Answer and MISO Supplemental Answer. On July 11, 2025, MISO filed a motion for leave to file a second supplemental answer and answer (MISO Second Supplemental Answer). On July 15, 2025, Invenergy filed a motion for leave to answer and answer to the MISO Supplemental Answer. On July 15, 2025, Clean Grid Alliance filed a motion for leave to answer and answer to apprise the Commission of new information.

IV. Discussion

A. Procedural Matters

29. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2024), the notices of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.[57]

30. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2024), prohibits answers to a protest unless otherwise ordered by the decisional authority. We accept the answers filed in this proceeding because they have provided information that assisted us in our decision-making process.

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[56] MISO attaches its previous transmittal letter, answers, and supporting testimonies from the Initial ERAS Proposal filing in Docket No. ER25-1674-000 as a supplement to its answer. *See* MISO Answer at 4, Tab B.

[57] Entities that filed comments or protests but did not file a notice of intervention or motion to intervene are not parties to this proceeding. *See* 18 C.F.R. § 385.211(a)(2) (2024) ("The filing of a protest does not make the protestant a party to the proceeding.").

B. Substantive Matters

31. As discussed below, we find that MISO's proposed Tariff revisions implementing the Revised ERAS Proposal are just and reasonable and not unduly discriminatory or preferential, and we accept the Tariff revisions, subject to condition, effective August 6, 2025, as requested.[58] We also find that MISO's proposed Tariff revisions accomplish the purposes of the Commission's final rules on generator interconnection, including Order Nos. 2003 and 2023, by helping to ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner.[59] Therefore, we find that MISO's proposed Tariff revisions meet the independent entity variation standard. Moreover, although several commenters argue for modifications to the Revised ERAS Proposal or suggest alternative solutions for addressing MISO's near-term resource adequacy and reliability needs, the Commission need only determine, under FPA section 205, whether the proposed filing is just and reasonable; the Commission is not obligated to consider whether the proposal is more or less reasonable than other alternatives.[60] We discuss the Revised ERAS Proposal in detail below.

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[58] *See NRG Power Mktg., LLC v. FERC*, 862 F.3d 108, 114-15 (D.C. Cir. 2017) (discussing the Commission's authority to propose modifications to a utility's FPA section 205 rate proposal).

[59] Order No. 2003, 104 FERC ¶ 61,103 at PP 26, 827; Order No. 2023, 184 FERC ¶ 61,054 at P 1.

[60] *See, e.g.*, *Cities of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984) (*Cities of Bethany*) (when determining whether a rate was just and reasonable, the Commission properly did not consider "whether a proposed rate schedule is more or less reasonable than alternative rate designs"). Thus, having found MISO's proposal just and reasonable, we need not consider alternative proposals.

1. Resource Adequacy Concerns

a. MISO's Filing

i. Resource Adequacy Concerns

32. MISO states that, as demonstrated by its Reliability Imperative Report,[61] the 2024 OMS-MISO Survey,[62] and the North American Electric Reliability Corporation (NERC) 2024 Long-Term Reliability Assessment,[63] MISO is facing urgent near-term resource adequacy and reliability concerns.[64] MISO states that its resource adequacy concerns are driven by unexpected significant load growth from large data center development, accelerated retirements of baseload generation, increased manufacturing, queue and supply chain delays, and permitting and financing issues. MISO also anticipates long-term load growth driven by increased cooling demands, electric vehicles, and cryptocurrency.[65] MISO states that its Futures Reports[66] have demonstrated the need for

[61] MISO, *MISO's Response to the Reliability Imperative*, Executive Summary 1 (updated Feb. 2024) (Reliability Imperative Report), https://cdn.misoenergy.org/Executive%20Summary%202024%20Reliability%20Imperative%20report%20Feb.%2021%20Final631825.pdf.

[62] OMS and MISO, *2024 OMS-MISO Survey Results* 2 (2024) (2024 OMS-MISO Survey) https://cdn.misoenergy.org/OMS%20MISO%20Survey%20Results%20Workshop%20Presentation628355.pdf.

[63] NERC, *2024 Long-Term Reliability Assessment* (2024) (NERC 2024 Long-Term Reliability Assessment), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[64] Transmittal at 13-16.

[65] *Id.* at 6.

[66] MISO's Futures Reports include forecasted scenarios designed to capture a range of system conditions over a 20-year planning horizon. The Futures Reports provide the foundation for MISO's local and regional long-term planning and represent "multiple possibilities for future system growth, fuel availability, market conditions, and regulatory environments." *See* MISO, *Future Plan Scenarios* (Apr. 15, 2025) https://www.misoenergy.org/planning/futures-development/.

MISO to take immediate action "to add almost twice the generation that MISO currently has online" over 20 years as a result of this unprecedented load growth.[67]

33. MISO states that the recently published 2025 OMS-MISO Survey[68] found that the near-term resource adequacy risks and uncertainties that MISO faces are intensifying.[69] MISO further states that the 2025 OMS-MISO Survey indicates that at least 3.1 GW of new resources are needed by the summer of 2026/2027 to avoid a resource deficit, and that future years will have greater needs.[70] MISO states that NERC's 2025 Summer Reliability Assessment identified MISO as having an elevated potential for insufficient operating reserves in above normal conditions for the 2025 summer season.[71] MISO adds that, in comments submitted to the Commission's June 2025 Technical Conference[72] regarding resource adequacy, it explained that, despite the rapid growth of wind and solar resources in its region, by 2042, MISO could face a net decline of about 32 GW in available electricity below the 2022 baseline due to the operating characteristics of these

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[67] Transmittal at 14 (citing MISO, *MISO Futures Report Series 1A*, at 2 (Nov. 1, 2023) (MISO Futures Report), at Series1A_Futures_Report630735.pdf). MISO predicts an increase of generating capacity from 732 terawatt hours in 2022 to 1,395 terawatt hours in 2042 under the Future 3A scenario. MISO Futures Report at 3.

[68] OMS and MISO, *2025 OMS-MISO Resource Adequacy Survey Results* (2025) (2025 OMS-MISO Survey), https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf

[69] Transmittal at 6 (citing OMS and MISO, *2025 OMS-MISO Resource Adequacy Survey Results*, Fact Sheet (2025 OMS-MISO Survey Fact Sheet), 20 https://cdn.misoenergy.org/2025%20OMS-MISO%20Survey%20Fact%20Sheet702641.pdf).

[70] *Id.* at 15 (citing 2025 OMS-MISO Survey Fact Sheet).

[71] *Id.* at 16.

[72] Technical Conference, *Meeting the Challenge of Resource Adequacy in RTO and ISO Regions*, Docket No. AD25-7-000 (June 4-5, 2025) (June 2025 Technical Conference) (Day 1 https://www.ferc.gov/news-events/events/day-1-commissioner-led-technical-conference-regarding-challenge-resource) (Day 2 https://www.ferc.gov/news-events/events/day-2-commissioner-led-technical-conference-regarding-challenge-resource).

resources.[73] MISO explains that it also highlighted projections that peak load in the region is expected to grow at a 1.6% compound annual growth rate and therefore threatens to outpace the addition of new generating facilities if urgent action is not taken.

34. MISO explains that it has pursued numerous avenues to address its near-term resource adequacy issues, including improving the GIP, implementing a queue cap, and making other queue improvements; however, these updates are unable to address or fill the identified near-term resource gap.[74] MISO adds that the recent queue improvements (i.e., those for increased milestone payments, site control requirements, withdrawal penalties, and the queue cap) are focused on long-term improvements to MISO's queue, and they will not be sufficient to address near-term resource adequacy needs.[75] MISO also asserts that, while interconnection customers can use provisional GIAs to achieve timely interconnection, that process is insufficient to address the need that MISO is facing, both in terms of scale and time frame.[76] MISO states that provisional interconnection service only provides for limited operation and is conditional on DPP studies for full deliverability. MISO states that DPP studies may not be available to recognize the new capacity and may still take years to finalize. MISO further notes that there may be risks associated with having a provisional GIA if the interconnection request is dependent on other interconnection requests in the queue, which may never reach commercial operation due to a lack of an off-taker or load to serve.[77] MISO states that some of the benefits of a provisional GIA are incorporated into ERAS, including increased financial commitments and an expedited timeline.[78] Finally, MISO asserts that only the proposed ERAS process will result in an EGIA that identifies all network upgrades on the MISO transmission system that are necessary to provide deliverability across the transmission system.

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[73] Transmittal at 15 (citing Comments of Todd Ramey, MISO, June 2025 Technical Conference, at 2 (filed May 28, 2025)). *See also* MISO Futures Report at 19.

[74] Transmittal at 36.

[75] *Id.* at 46 n.202.

[76] Witmeier Testimony at 19.

[77] *Id.* at 19-20.

[78] *Id.* at 20.

ii. Revised ERAS Proposal

35. MISO states that ERAS was developed in coordination with its stakeholders to address resource adequacy and reliability needs.[79] MISO further states that because its region is largely comprised of vertically integrated utilities, which are responsible for serving load within their service territories, MISO must partner with the states, their RERRAs, and LSEs to provide a way for the generation necessary for resource adequacy or reliability to be completed quickly.[80] MISO further explains that to incorporate the important jurisdictional interplay among the role of states, other RERRAs, and the Commission, the states in MISO have independent authority for resource adequacy. Due to this, MISO states that its ERAS proposal provides a vehicle for RERRAs to verify to MISO that there is a valid, new incremental load addition not identified in other resource plans or that the proposed generating facility will address an identified resource adequacy deficiency (RERRA verification).[81] MISO states that, following the May 2025 Order, it worked with stakeholders to address concerns about ERAS implementation and to address the Commission's guidance, which has resulted in the Revised ERAS Proposal.[82]

36. MISO proposes various eligibility requirements for interconnection requests seeking interconnection service through ERAS that must be met at the time of an application submission. MISO asserts that the proposed eligibility requirements reflect stakeholder feedback and additional analysis to ensure that a project could efficiently move through the study process while still being considered ready to commence construction, or "shovel ready."[83] MISO proposes the following eligibility requirements for an ERAS interconnection request:[84]

a. New capacity requesting NRIS service must identify the claimed resource adequacy and/or reliability need for which the interconnection request is being submitted and must include: (1) the location of any load to be served (e.g., county and state, electrical bus location(s), and the local resource

[79] Transmittal at 18-19.

[80] *Id.* at 13.

[81] *Id.* at 9.

[82] *Id.* at 25.

[83] Witmeier Testimony at 40.

[84] *Id.* at 40-41; Transmittal at 8, 36-39.

zone[85]) because a generating facility must be in the same local resource zone as the load to be served unless the identified need is included in a resource filing made to the RERRA; and (2) the peak demand for electricity expected over any one-hour period in MWs (the amount of interconnection service requested must not exceed 150% of the identified MW need).

b. Demonstration of a resource adequacy need through each of the following:

    i. A written verification from the RERRA that either:

        1. The new, incremental load addition is valid and not otherwise included in a resource plan or other process under the purview of the RERRA;

        2. The generating facility will address a resource adequacy deficiency as determined by the RERRA, state, LSE, or interconnection customer and can be supported by a range of documentation; or

        3. For a generating facility that will address a resource adequacy deficiency and serves retail choice load or a retail choice state (i.e., Illinois or Michigan), the interconnection customer will not be required to provide a RERRA verification, but the RERRA will have an opportunity to contest the interconnection request's inclusion in ERAS; and

    ii. An executed agreement evidencing that the proposed generating facility is intended to be used by the entity with the claimed resource adequacy or reliability need.

c. A non-refundable deposit (D1) of $100,000 and a refundable milestone payment (M2) of $24,000 per MW.

d. 100% site control for both the generator and interconnection customer's interconnection facilities.

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[85] Local Resource Zone is proposed to mean "a geographic area within the Transmission Provider Region that is prescribed by the Transmission Provider, based upon the criteria in Section 68A.3, to address congestion that limits Planning Resource deliverability." MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 1 (Definitions).

e. A requested commercial operation date that is no more than three years from the date of submission of an interconnection request, unless the interconnection request is deferred to a later ERAS quarterly study period.

37. MISO states that, in response to the Commission's findings in the May 2025 Order, it proposes requirements for an ERAS interconnection request to be located in the same Local Resource Zone as the resource adequacy or reliability need that it will address.[86] MISO states that adding this requirement better establishes a nexus between the load need and the ERAS interconnection request. MISO asserts that including this requirement will ensure that the proposed generating facility supports Local Clearing Requirements, which is the minimum amount of seasonal accredited capacity for a Local Resource Zone that is required to meet its seasonal loss of load expectation,[87] and will prevent the proposed generating facility from driving import or export concerns. MISO further asserts that requiring the interconnection request to serve a local load will negate the need for transmission investment, reduce import needs from other Local Resource Zones, and remove price divergences between load and generation.[88] MISO states that it will allow an ERAS interconnection request to be located in a different Local Resource Zone than the load it will address if the ERAS interconnection customer can demonstrate that the use of the proposed ERAS generating facility was included in a resource filing or other submission made to the RERRA.[89]

38. MISO explains that, under the current DPP process, an interconnection request may not become commercially operational for up to 11 years after the initial submission.[90] MISO argues that given the urgent near-term resource adequacy needs in

[86] Transmittal at 32.

[87] MISO defines Local Clearing Requirements as "The minimum amount of Seasonal Accredited Capacity for [a local resource zone] that is required to meet its LOLE for each Season while fully using the Zonal Import Ability for such [local resource zone] and accounting for controllable exports." *See* MISO, FERC Electric Tariff, § II, Module A, § 1 (Definitions-L) (47.0.0).

[88] Witmeier Testimony at 61.

[89] Transmittal at 33.

[90] Witmeier Testimony at 47. Specifically, Mr. Witmeier testifies that the maximum of 11 years can occur because: (1) a DPP interconnection customer may request a commercial operation date up to five years from the submission of the interconnection request; (2) during GIA negotiations, the commercial operation date may be extended up to three years based on specific circumstances set forth in GIP

its region, another mechanism is needed to ensure that ERAS generating facilities come online as soon as possible. MISO states that ERAS generating facilities will continue to have the additional three-year grace period from the commercial operation date listed in Appendix B of the EGIA to become commercially operational that is currently provided to interconnection customers under MISO's *pro forma* GIA.[91] MISO asserts that, in conjunction with the other eligibility requirements, the commercial operation date requirements will ensure that only "shovel ready" projects are submitted.[92]

b. **Responsive Pleadings**

i. **Comments in Support**

39. The Arkansas Governor, Indiana Governor, Louisiana Governor, Mississippi Governor, and Missouri Governor submitted comments in support of MISO's filing as a necessary temporary measure to address resource adequacy concerns. In their respective comments, the Governors cite concerns over resource adequacy that they believe the Revised ERAS Proposal will address, including unprecedented load growth, accelerated resource retirements, and delays in new resource additions.[93]

40. Several commenters assert that ERAS is necessary to address near-term resource adequacy needs in the MISO footprint.[94] In particular, several commenters argue that the

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section 4.4.4; and (3) MISO's *pro forma* GIA permits a three-year grace period for generating facilities to achieve commercial operation. *Id.*

[91] Transmittal at 50; Witmeier Testimony at 47. The proposed GIP states that the EGIA "shall take the form of MISO's *pro forma* GIA modified for the [ERAS]." MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 1 (Definitions).

[92] Witmeier Testimony at 31.

[93] Arkansas Governor Comments at 1; Indiana Governor Comments at 1; Louisiana Governor Comments at 1; Mississippi Governor Comments at 1; Missouri Governor Comments at 1.

[94] AECS Comments at 4; Ameren Comments at 1, 3; Arkansas Commission Comments at 3; Big Rivers Electric Comments at 3; CenterPoint Comments at 1, 4; Consumers Energy Comments at 2-3; Duke Energy Indiana Comments at 2; Entergy/Cleco/Cooperative Energy Comments at 9-10; ITC Comments at 3; Louisiana and Mississippi Commissions Comments at 5; Midwest TDUs Comments at 3-4; MISO TOs Comments at 3; Wisconsin Utilities Comments at 4; Texas Commission Comments at 13.

accelerated review of urgently needed, “shovel ready” projects will help alleviate near-term resource adequacy needs.[95]

41. Several commenters cite concerns about the ability of MISO’s DPP process to effectively meet resource adequacy needs and claim that ERAS provides an alternative mechanism to meet such needs.[96] Illinois Commission asserts that these queue problems will likely be compounded by rapid new load growth, especially resulting from the development of data centers throughout the region.[97]

42. Several commenters state that there is an urgent need to address resource adequacy and reliability challenges due to rapid load growth and that the ERAS process is a measure to address such large load growth.[98] More specifically, Big Rivers Electric and MISO TOs cite concerns over resource adequacy driven by a combination of electrification, a resurgence in manufacturing, rapidly growing demand from energy-intensive data centers, accelerated generating facility retirement, and a growing shift toward low or zero-carbon technologies.[99] MISO TOs and the Missouri Commission also note that ERAS can help address resource adequacy needs related to accelerated retirements.[100] Several commenters also state that they expect significant increases in demand on MISO’s transmission system because of potential state and

[95] AECS Comments at 4; Big Rivers Electric Comments at 3; CenterPoint Comments at 1; Entergy/Cleco/Cooperative Energy Comments at 9-10; ITC Comments at 3; Louisiana and Mississippi Commissions Comments at 5; Midwest TDUs Comments at 3-4; MISO TOs Comments at 3.

[96] AECS Comments at 2-3; Ameren Comments at 2; CenterPoint Comments at 4; Entergy/Cleco/Cooperative Energy Comments at 7-8; Illinois Commission Comments at 6; Louisiana and Mississippi Commissions Comments at 5; Midwest TDUs Comments at 3-4; Otter Tail Comments at 4.

[97] Illinois Commission Comments at 6-7.

[98] AECS Comments at 2-3; Ameren Comments at 1, 3-4; CenterPoint Comments at 4; Entergy/Cleco/Cooperative Energy Comments at 7-8; Louisiana and Mississippi Commissions Comments at 5; Missouri Commission Comments at 3.

[99] Big Rivers Electric Comments at 2; MISO TOs Comments at 12.

[100] MISO TOs Comments at 12; Missouri Commission Comments at 3.

regional economic growth opportunities in the form of large-scale industrial, manufacturing, and technology-driven projects.[101]

43. ITC and NIPSCO cite to expected capacity shortfalls predicted in the OMS-MISO Survey and the NERC Long-Term Reliability Assessment and Summer Reliability Assessment as evidence that MISO is facing significant resource adequacy risks in the near-term and as justification for the Revised ERAS Proposal. MISO TOs also cite to the OMS-MISO Survey's findings that at least 3.1 GW of additional capacity beyond committed capacity will be needed to meet the projected planning reserve margin forecast.[102] ITC also cites rising summer temperatures as a concern for reliability.[103]

44. DTE Electric asserts that MISO's Revised ERAS Proposal is a reasonable, well-intentioned resource adequacy stop-gap measure designed to shore up emergent needs across the MISO footprint.[104] Furthermore, DTE Electric asserts that this proactive planning measure is just and reasonable and will serve MISO's footprint effectively and efficiently in the near term because it is limited, flexible, and transparent.

45. The Indiana Energy Association argues that the Revised ERAS Proposal is a necessary and balanced approach to meeting the resource adequacy challenges of growing complexity in the energy landscape and ensuring resources are available to meet immediate and future demand.[105]

46. CenterPoint argues that the Revised ERAS Proposal provides a reasonable and appropriate tool to address potential unprecedented customer demand growth, the need to replace retired and retiring generation resources in a manner that does not compromise resource adequacy and reliability on the MISO transmission system, and existing delays and bottlenecks in MISO's current interconnection study process caused by an unprecedented number of interconnection requests.[106] Additionally, CenterPoint asserts that MISO's Revised ERAS Proposal is intentionally designed with significant

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[101] CenterPoint Comments at 4-5; Louisiana and Mississippi Commissions Comments at 5; NIPSCO Comments at 4.

[102] MISO TOs Comments at 12.

[103] ITC Comments at 4; NIPSCO Comments at 3.

[104] DTE Electric Comments at 4.

[105] Indiana Energy Association Comments at 2.

[106] CenterPoint Comments at 6-7.

safeguards to allow ERAS to meet urgently needed resource adequacy and reliability needs while preventing abuse of the ERAS process simply to avoid MISO's DPP.

47. Although Vistra and Michigan Commission filed protests to the Revised ERAS Proposal, they agree with MISO that there are urgent resource adequacy needs in MISO's footprint and generally agree that has MISO has made a good faith effort to create a solution.[107] Michigan Commission asserts that the Revised ERAS Proposal appropriately narrows the ERAS framework to address the Commission's concerns by requiring the identification of a specific load addition or resource adequacy deficiency.[108]

ii. Protests

(a) MISO's Identified Need

48. Several protesters argue that the studies that MISO relies on overstate the short-term risks and ignore near-term solutions in the existing queue, such as existing interconnection requests with signed GIAs or interconnection requests that can use the provisional GIA process.[109] Clean Energy Associations argue that MISO's reliance on the 2025 OMS-MISO Survey is flawed, similar to the Initial ERAS Proposal's reliance on the 2024 OMS-MISO Survey, which included an alternate projection that showed a surplus of 2.9 GW spring capacity in the 2025-2026 planning year.[110] Clean Energy Associations assert that the 2025 OMS-MISO Survey projects that MISO may need 3.1 GW of new resources by 2026/2027 and that MISO's queue and market reforms,

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[107] Vistra Protest at 5, 7; Michigan Commission Protest at 7.

[108] Michigan Commission Protest at 7 (citing Transmittal at 27-30).

[109] Clean Energy Associations Protest at 24; Clean Grid Alliance Protest at 9, 34-35; PIOs Protest at 29. *See also* Clean Energy Associations Protest, Ex. A; Clean Energy Associations Protest, Docket No. ER25-1674-000, at 48 (filed Apr. 7, 2025) (Clean Energy Associations Docket No. ER25-1674 Protest); MISO IPPs Protest, attach. A, MISO Independent Power Producers Protest, Docket No. ER25-1674-000, at 3-5, 26-29 (filed Apr. 7, 2025) (MISO IPPs Docket No. ER25-1674 Protest); MISO IPPs Protest, attach. B; NextEra Energy Resources, LLC Protest, Docket No. ER25-1674-000 (filed Apr. 7, 2025) (NextEra Docket No. ER25-1674 Protest; NextEra Docket No. ER25-2674 Protest at Ex. A-1, The Brattle Group Report, at 14-15 (2025 Brattle Group Report); PIOs Protest, attach. A, Public Interest Organizations Protest, Docket No. ER25-1674-000, at 28-35 (filed June 16, 2025) (PIOs Docket No. ER25-1674 Protest).

[110] Clean Energy Associations Protest at 25-26 (citing 2024 OMS-MISO Survey at 21).

improved resource deployment timelines, and other initiatives will help MISO maintain resource adequacy through 2031.[111] Clean Energy Associations further assert that the 2025 OMS-MISO Survey used new projections that showed a potential surplus between 1.4-6.1 GW in accredited capacity against the planning reserve margin requirement for both the winter and summer seasons, which further suggests that LSEs may have adequate resources to meet load reserve requirements in each zone over a five-year horizon.[112] Clean Energy Associations contend that the 2025 OMS-MISO Survey demonstrates that MISO's current trajectory can maintain resource adequacy and can achieve surplus capacity without ERAS.[113] Clean Grid Alliance also argues that MISO's reference to its own reports and comments in the June 2025 Technical Conference are insufficient to support its Revised ERAS Proposal.[114]

49. Several protesters argue that MISO's independent market monitor (IMM) has also affirmed their concerns that MISO's near-term resource adequacy needs are overstated.[115] Clean Energy Associations assert that the IMM stated that MISO is more than resource adequate going into the summer of 2025 and does not have substantial concerns about the MISO region in the near term.[116] Clean Grid Alliance further points out that the IMM stated that MISO's risks are "not nearly as daunting as portrayed by MISO planning reports."[117] Clean Energy Associations and PIOs further state that the IMM found that MISO planning reports and the NERC 2024 Long-Term Reliability Assessment significantly understate available capacity by failing to fully account for demand response, behind-the-meter generation, and firm capacity imports – where MISO has more than 8 GW of underrecognized capability.[118] PIOs add that MISO's reliance on the Commission's 2025 Summer Energy Market and Electric Reliability Assessment, as well

[111] *Id.* at 26 (citing 2025 OMS-MISO Survey at 2).

[112] *Id.* (citing 2025 OMS-MISO Survey at 7, 9).

[113] *Id.* at 26-27.

[114] Clean Grid Alliance Protest at 7-8.

[115] *Id.* at 8; Clean Energy Associations Protest at 27-29; PIOs Protest at 27-29.

[116] Clean Energy Associations Protest at 27 (citing Comments of David B. Patton, Ph.D., MISO Independent Market Monitor, June 2025 Technical Conference, at 2 (filed May 28, 2025) (Patton Technical Conference Comments)).

[117] Clean Grid Alliance Protest at 8.

[118] Clean Energy Associations Protest at 27-28 (citing Patton Technical Conference Comments at 2); PIOs Protest at 28 (citing same).

as the 2025 OMS-MISO Survey, are vulnerable to the same flaws pointed out by the IMM because such reports are based largely on the flawed NERC 2024 Long-Term Reliability Assessment.[119] PIOs also contend that MISO leans on historical interconnection rates, which do not reflect the various queue reforms the Commission has recently approved for MISO.

50. Several protesters argue that in analyzing near-term resource adequacy needs, MISO fails to consider its existing DPP, which they believe are adequate to meet MISO's near-term resource adequacy and reliability concerns.[120] Specifically, protesters aver that MISO ignores the 56 GW of generation in the DPP queue with GIAs, which are expected to come online before ERAS interconnection requests.[121] Additionally, PIOs assert that MISO fails to recognize that existing DPP interconnection requests may be able to meet its resource adequacy and reliability needs. PIOs claim that even if only 21% of the current DPP interconnection requests reach GIAs, then more than 64 GW of new capacity would have signed GIAs before ERAS is complete.[122] Protesters also point to MISO's existing provisional GIA process,[123] as well as its surplus interconnection and replacement generating facility processes,[124] as alternative processes that will help MISO meet its resource adequacy needs, which MISO fails to take into consideration. Clean Grid Alliance and PIOs also contend that MISO has demonstrated through its new automation software, Pearl Street's Suite of Unified Grid Analysis and Renewables (SUGAR), that the amount of time for an interconnection request to receive a GIA has been reduced to months, which undermines MISO's claims regarding the timing of DPP interconnection requests.[125]

51. Protesters therefore assert that MISO's capacity needs can be addressed by fully leveraging the resources already in the queue, improving interconnection timelines, and

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[119] PIOs Protest at 28 (citing, among others, FERC, *Summer Energy Market and Electric Reliability Assessment* (May 15, 2025), https://www ferc.gov/newsevents/news/ferc-releases2025-summer-assessment).

[120] Clean Energy Associations Docket No. ER25-1674 Protest at 50; NextEra Docket No. ER25-1674 Protest at 5.

[121] Clean Grid Alliance Protest at 9; PIOs Docket No. ER25-1674 Protest at 29-32.

[122] PIOs Protest at 31.

[123] Clean Grid Alliance Protest at 5-6.

[124] PIOs Protest at 29.

[125] *Id.* at 32; Clean Grid Alliance Protest at 9.

prioritizing surplus projects already in the interconnection queue that have on-shored their supply chains, making the ERAS proposal unnecessary.[126] Relatedly, Illinois Commission states that MISO should focus on improving the effectiveness and expeditiousness of the DPP queue, and ERAS should not be allowed to evolve into a second, parallel interconnection queue.[127]

52. Constellation asserts that the Revised ERAS Proposal does not address the Commission's concerns that ERAS is not narrowly tailored to only include interconnection requests capable of addressing identified near-term resource adequacy or reliability needs.[128]

(b) <u>Commercial Operation Date</u>

53. Clean Energy Associations assert that the Revised ERAS Proposal is not sufficiently tailored to ensure that only those resources capable of addressing identified near-term resource adequacy or reliability needs are eligible because of the commercial operation date.[129] Clean Energy Associations argue that the Revised ERAS Proposal does not address near-term issues because: (1) the requirement that the commercial operation date be achieved within three years can be extended if the interconnection request is deferred to a later quarterly study period, and (2) the three-year grace period further extends the commercial operation deadline. Clean Energy Associations thus assert that ERAS interconnection requests may come online as late as 2033. In response to MISO's contention that the commercial operation date provisions are necessary to account for delays outside of MISO's control, Clean Energy Associations assert that MISO has failed to tailor the aspects of its proposal that are within its control, such as using an ongoing quarterly study process rather than a one-time study.[130]

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[126] Clean Energy Associations Protest at 28; Clean Grid Alliance Protest at 3, 9, 34, 41; PIOs Protest at 29-32.

[127] Illinois Commission Comments at 7.

[128] Constellation Protest at 2-4.

[129] Clean Energy Associations Protest at 9.

[130] *Id.* at 9-10 (citing Transmittal at 13, 36).

54. Several protesters contend that the problem is the supply chain and not MISO's DPP, because all interconnection customers rely on the same supply chains.[131] Clean Grid Alliance further contends that these universal supply chain issues are evidenced by MISO's commercial operation date blanket waiver filed at the Commission in recent years.[132] These protesters argue that ERAS interconnection requests may still face these challenges and may not achieve commercial operation any faster than DPP interconnection requests.[133] According to Clean Energy Associations, the ERAS process may compound these issues for DPP interconnection customers if the ERAS interconnection customers deplete existing resources.[134] Clean Energy Associations assert that, while these delays may be beyond MISO's control, MISO's attention would be better suited to understanding and addressing those issues than the ERAS process. NextEra further argues that a lack of requirements or criteria for prioritizing resources that use existing transmission capacity or minimize the need for new network upgrades will make ERAS more susceptible to ongoing supply chain delays or may increase the time and costs for constructing required network upgrades; may constrain MISO staff resources; and/or may increase the risk of ERAS interconnection customers dropping out due to high network upgrade costs or long network upgrade construction schedules.[135]

55. Several protesters argue that the Revised ERAS Proposal is not appropriately tailored to timely meet MISO's resource adequacy needs because the commercial operation deadline requirements are too far out into the future.[136] COMPP contends that

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[131] Clean Energy Associations Docket No. ER25-1674 Protest at 46-47; Clean Grid Alliance Protest at 2; MISO IPPs Docket No. ER25-1674 Protest at 28; NextEra Docket No. ER25-1674 Protest at 25.

[132] Clean Grid Alliance Protest at 2. *See also Midcontinent Indep. Sys. Operator, Inc.*, 176 FERC ¶ 61,161 (2021) (granting waiver of the Tariff to allow a one or two-year extension of the commercial operation deadline for certain interconnection requests in MISO's August 2017 DPP West study group).

[133] Clean Energy Associations Docket No. ER25-1674 Protest at 46-47; MISO IPPs Docket No. ER25-1674 Protest at 28; NextEra Docket No. ER25-1674 Protest at 25; 2025 Brattle Group Report at 26.

[134] Clean Energy Associations Docket No. ER25-1674 Protest at 47.

[135] 2025 Brattle Group Report at 26.

[136] Clean Energy Associations Docket No. ER25-1674 Protest at 46; COMPP Protest at 4; Invenergy Protest at 9-10; Michigan Commission Protest 12-14; MISO IPPs Docket No. ER25-1674 Protest at 28; NextEra Docket No. ER25-1674 Protest at 21-22

the Revised ERAS Proposal does not address the Commission's concerns in the May 2025 Order and allows for ERAS interconnection requests to achieve commercial operation as late as 2035, when MISO forecasts a resource adequacy shortfall occurring between 2027 and 2030.[137] Similarly, Invenergy avers that the Revised ERAS Proposal weakens shovel readiness because the commercial operation date requirements would allow interconnection requests to be achieve commercial operation by as late as 2033.[138] MISO IPPs similarly argue that, instead of a three-year grace period, ERAS interconnection requests should be subject to higher penalties for delay or withdrawal than the DPP queue because they are given priority treatment in the ERAS process.[139] Michigan Commission additionally asserts that the Revised ERAS Proposal does not provide a stronger link between the interconnection request and the resource adequacy need because the Revised ERAS Proposal retains the three-year grace period for the commercial operation deadline, which does not narrowly tailor ERAS to only shovel-ready projects capable of meeting near-term resource adequacy challenges.[140] Michigan Commission argues that a three-year grace period, in addition to a three-year commercial operation date requirement for ERAS interconnection requests, is too long given the need for the addition of generating capacity by 2030 and belies the notion of the projects being "shovel ready," in contradiction to ERAS' stated purpose. Michigan Commission states that it is unclear why MISO appears reluctant to either eliminate the grace period or reduce it to one year and allow the Commission waiver process to handle longer lead time requests.

56. PIOs argue that MISO's Revised ERAS Proposal contains conflicting language with respect to the three-year grace period of the commercial operation date.[141]

(citing MISO Transmittal, Docket No. ER25-1674-000 at 21); PIOs Docket No. ER25-1674 Protest at 40-41.

[137] COMPP Protest at 4 (citing May 2025 Order, 191 FERC ¶ 61,131 at P 202). According to COMPP, MISO changed GIP section 4.4.4 to extend commercial operation deadlines for backlogged interconnection requests due to transmission owner construction delays by an additional 2.5 years beyond the three-year grace period, and some of these same transmission owners are seeking to interconnect generating facilities through ERAS. *Id.* n.7. *See Midcontinent Indep. Sys. Operator, Inc.*, 191 FERC ¶ 61,150 (2025).

[138] Invenergy Protest at 9-10.

[139] MISO IPPs Docket No. ER25-1674 Protest at 28.

[140] Michigan Commission Protest at 12-14.

[141] PIOs Protest at 37-38.

According to PIOs, MISO's transmittal states that "[a]ll ERAS projects are eligible to use the grace period of up to three years as documented in GIA Article 2.3.1." However, PIOs assert that Article 2.3.1 of the proposed *pro forma* EGIA does not directly describe a grace period, but instead refers to GIP section 4.4.4, which sets out the potential for a three-year grace period. Meanwhile, PIOs assert, the revised Tariff states that "[a]fter entering [ERAS], no changes to the In-Service Date or Commercial Operation Date of the Generating Facility is permitted via section 4.4.4."[142]

(c) <u>RERRA Verification Requirement</u>

57. Clean Energy Associations and EPSA aver that the RERRA verification does little to link the proposed ERAS interconnection request to the identified resource adequacy or reliability need.[143] Clean Energy Associations assert that the RERRA verification amounts to speculation by a group of states and local agencies that do not coordinate on resource adequacy and do not have the authority to determine the resource adequacy or reliability needs for the MISO-controlled transmission system.[144] Clean Energy Associations assert that proposed GIP section 3.9.1.1.ii allows projects to qualify based on support from a state integrated resource plan or similar mechanism, which directly contradicts the RERRA verification requirement in GIP section 3.9.1.1.i that an interconnection request not already be accounted for in an existing plan or procedure.[145] Clean Energy Associations further argue that the new provision that allows interconnection requests to bypass the Local Resource Zone requirement if an identified need appears in a RERRA's integrated resource plan or comparable document is similarly contradictory.

58. PIOs argue that despite MISO's proposal to change the RERRA requirement from a notification to a verification, it does not require the RERRA to explain its decision and how it compared similarly situated projects to choose the one best positioned to meet near-term resource adequacy needs.[146] PIOs add that nothing in the ERAS process requires a RERRA to consider whether a resource currently in the DPP is better suited to

[142] *Id.* at 38 (citing MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.8).

[143] Clean Energy Associations Protest at 11; EPSA Comments at 3.

[144] Clean Energy Associations Protest at 11.

[145] *Id.* at 11-12.

[146] PIOs Protest at 23 (quoting May 2025 Order, 191 FERC ¶ 61,131, (See, Comm'r, consenting at P 6).

meet the identified need.[147] PIOs contend that the first option for the RERRA verification focuses only on the load and not on the generation.

59. EPSA asserts that the Revised ERAS Proposal does not require RERRAs or others to explain why a given interconnection request is best positioned to meet near-term resource adequacy needs.[148] EPSA avers that the RERRA verification process is not objective or transparent enough to ensure that the interconnection requests are essential to addressing resource adequacy and reliability gaps.[149]

60. Several protesters argue that the Revised ERAS Proposal lacks specific criteria for how a RERRA will determine that a resource adequacy need exists and whether ERAS is necessary to meet such need.[150] Further, Invenergy argues that the proposal risks excluding projects that are best suited to meet resource adequacy needs.[151] Invenergy contends that the Revised ERAS Proposal is not narrowly tailored to resource adequacy needs because it lacks objective scoring criteria that the RERRAs will apply, such as was included in PJM Interconnection L.L.C.'s (PJM) Reliability Resource Initiative (RRI).[152] Similarly, EPSA contends that a more clear and specific qualitative scoring mechanism and/or selection process, such as part of the Interconnection Process Enhancements (IPE) that the Commission recently accepted for California Independent System Operator Corporation (CAISO), should be included in the Revised ERAS Proposal to ensure that resources proffered by RERRAs and the states are in fact essential to meet reliability and resource adequacy needs.[153] Invenergy asserts that MISO has not explained how an interconnection request will be evaluated, how a RERRA will target the most essential interconnection requests to address resource adequacy and reliability challenges, or how a

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[147] *Id.* at 24.

[148] EPSA Comments at 3.

[149] *Id.* at 3, 6-7.

[150] Clean Energy Associations Docket No. ER25-1674 Protest at 44-45 (citing January 2024 Order, 186 FERC ¶ 61,054 at P 174); Invenergy Protest at 10; 2025 Brattle Group Report at 28.

[151] Invenergy Protest at 14.

[152] *Id.* at 10 (citing *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084 (2025) (PJM RRI Order), (Phillips and Rosner, Comm'rs consenting at P 1)).

[153] EPSA Comments at 3, 7 (citing *Cal. Indep. Sys. Operator Corp.*, 188 FERC ¶ 61,225, at P 173 (2024) (CAISO IPE Order) (accepting amendments to the LGIP in CAISO's tariff)).

RERRA will compare interconnection requests to determine which are best positioned to meet near-term resource adequacy and reliability needs.[154]

61. Constellation argues that the new RERRA verification requirements exacerbate the problems that the Commission highlighted in the May 2025 Order.[155] Constellation asserts that the Revised ERAS Proposal's requirement that, in non-retail-choice states, RERRAs verify specific load additions that projects will support is illusory because the verification "may take any form that works for a specific state."[156] Constellation contends that any number of interconnection requests can meet an identified need, resulting in a RERRA connecting load growth to an interconnection request with little effort.[157] Constellation asserts that, without objective and transparent standards, a RERRA may reject or accept any given interconnection request for inclusion in ERAS because each RERRA will have the exclusive discretion to decide inclusion. Thus, Constellation avers that the Revised ERAS Proposal does not provide objective criteria for RERRA verification to ensure that interconnection requests are best suited to quickly and efficiently meet identified resource adequacy and reliability needs.

(d) <u>Other ERAS Eligibility Criteria</u>

62. Protesters raise several other arguments for why they believe the proposed ERAS eligibility requirements and framework are not tailored to achieve MISO's stated objectives of meeting near-term resource adequacy and reliability needs. PIOs and Invenergy contend that MISO's proposed requirements for site control and NRIS may help to prevent speculative interconnection requests but do not ensure that "shovel ready" interconnection requests enter the ERAS process, such as evidence that major equipment or project permits have been sought or secured.[158] PIOs further contend that because ERAS interconnection customers will be competing with DPP interconnection customers for parts, labor, and necessary services, ERAS interconnection requests are likely to add to the challenges interconnection customers are already facing in getting resources to achieve commercial operation.[159] Invenergy further asserts that the Revised ERAS

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[154] Invenergy Protest at 10-11 (citing May 2025 Order, 191 FERC ¶ 61,131 (See, Comm'r, consenting at P 6)).

[155] Constellation Protest at 2-3.

[156] *Id.* at 3 (citing Transmittal at 30).

[157] *Id.* (citing Transmittal at 13-18).

[158] Invenergy Protest at 9; PIOs Protest at 26.

[159] PIOs Protest at 26.

Proposal is not narrowly tailored due to is lack of objective criteria for interconnection requests to demonstrate shovel readiness.[160] Vistra asserts that the shortened timeline for the initial quarterly study period will likely limit independent power producer interconnection requests to smaller, less capital-intensive projects in order to meet the timeline, thus reducing their ability to meet regional resource adequacy needs.[161] Additionally, Constellation asserts that the serial nature of the ERAS study process means that interconnection requests will be studied on a first-come, first-served basis, which, Constellation contends, will have no bearing on an interconnection request's resource adequacy benefits.[162] According to Constellation, the quarterly study period will exclude interconnection requests within the same study area or impacting the same constraint, which may also harm resource adequacy.

63. Clean Grid Alliance asserts that MISO has not demonstrated how its proposal to study 68 ERAS interconnection requests will solve the claimed generating capacity shortfall or match such interconnection requests to locations where there are claimed needs.[163] Clean Grid Alliance argues that this contrasts with MISO's DPP queue cap, which has a "tether" based on non-coincident peak projections. Clean Grid Alliance further asserts that the Revised ERAS Proposal is not narrowly tailored because, unlike PJM RRI, ERAS will be processed in a separate queue.[164] PIOs contend that MISO's Revised ERAS Proposal, for which the closest comparison is the PJM RRI construct, includes a larger cap than PJM RRI despite MISO having less need for expedited interconnection than PJM.[165] Invenergy argues that MISO's proposed ERAS cap is untethered to resource adequacy or reliability needs due to its lack of scoring criteria.[166] Invenergy further argues that MISO's proposed carve out for independent power producers is not tied to any resource adequacy need or criteria, and as such, MISO may accept all 10 of the allotted independent power producer submissions in the first few

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[160] Invenergy Protest at 3, 8-9.

[161] Vistra Protest at 10.

[162] Constellation Protest at 3-4.

[163] Clean Grid Alliance Protest at 23-24.

[164] *Id.* at 26.

[165] PIOs Protest at 19 (citing FERC, *2024: State of the Markets Staff Report* (Mar. 20, 2025), at 28 (Figure 17)).

[166] Invenergy Protest at 13.

cycles regardless of whether later submitted interconnection requests could better meet an identified need.

iii. Answers

(a) MISO Answer

64. MISO reiterates that there is significant evidence supporting its stated resource adequacy and reliability needs.[167] MISO points to statements made by Commission Chairman Mark Christie, provided during the June 2025 Technical Conference on resource adequacy, that MISO has lost 95 GW of accredited capacity and that load driven by data centers is increasing.[168] At the conference, MISO stated that it is resource adequate today, but that it is also working to slow the decline of other resources in its footprint and that more work is needed to arrest this decline and maintain capacity.[169] MISO recognizes that there was a spectrum of perspectives on the imminency of resource adequacy needs expressed at the conference, but MISO asserts that the general consensus was that MISO's queue is backlogged, retirements are outpacing additions, and load growth is increasing in the near-term. MISO emphasizes that these challenges are being experienced by RTOs/ISOs across the United States.[170]

65. MISO acknowledges that NERC has downgraded the MISO region's risk category for capacity shortfalls to "elevated risk" in the corrected NERC 2024 Long-Term Reliability Assessment, but MISO asserts that this new risk category places the MISO region at the same risk level as the PJM and CAISO regions, both of which recently proposed similar expedited generator interconnection queue processes through the RRI and IPE initiatives, respectfully.[171] MISO states that the corrected NERC 2024

[167] MISO Answer at 5.

[168] *Id.* at 5-6 (citing June 2025 Technical Conference, Day 2, Panel 5 at 2:00-4:00).

[169] *Id.* at 5-6 (citing June 2025 Technical Conference, Day 2, Panel 5, at 4:00-5:30).

[170] *Id.* at 6 (citing PJM Pre-filed Statement of Manu Asthana, June 2025 Technical Conference, at 2-3 (filed May 20, 2025); Pre-filed Statement of Elliott Mainzer, CAISO, June 2025 Technical Conference, at 7-9 (filed May 28, 2025); Pre-filed Statement of Pallas Lee Van Schaick, ISO-NE External Market Monitor and NYISO Market Monitoring Unit, June 2025 Technical Conference, at 2-4 (filed May 28, 2025); Pre-filed Statement of Gordon van Welie and Stephen George, ISO-NE, June 2025 Technical Conference, at 2-4 (filed May 28, 2025)).

[171] *Id.* (citing NERC, *Statement on NERC's 2024 Long-Term Reliability Assessment* (June 17, 2025) (NERC Statement on 2024 Long-Term Reliability

Long-Term Reliability Assessment places the MISO region into the "high risk" category during the 2028-2031 timeframe, and MISO asserts that this supports its claim that it has imminent resource adequacy and reliability needs. In addition, MISO states that the NERC 2025 Summer Reliability Assessment, which was not impacted by NERC's correction, found that the MISO region has potential for insufficient operating reserves in above-normal conditions.[172]

66. MISO also disagrees with protesters' assertions that the 2024 and 2025 OMS-MISO Surveys do not support the Revised ERAS Proposal.[173] MISO states that there is a general trend of declining generation additions, increased generation retirements, and unexpected large spot load development in the near term; thus, the resource adequacy challenges are broadly recognized and do not depend on the specific findings of one study. MISO contends that it cannot predict where large load development will occur and that it is trying to address resource adequacy and reliability problems that will occur in the future to prevent foreseeable shortfalls.[174] MISO asserts that the Revised ERAS Proposal is necessary to ensure that generation is built in time to meet future resource adequacy needs, even if it is resource adequate today.

67. Further, MISO states that, while protesters argue that MISO's automation efforts will resolve DPP study delays, its automation efforts currently focus only on DPP Phase I, with implementation in the more in-depth DPP Phase II and Phase III studies to occur later.[175] MISO contends that it will take several years before MISO experiences the benefit of recent reforms such as SUGAR implementation, GIP improvements, and the

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Assessment) https://www.nerc.com/news/Pages/Statement-on-NERC%E2%80%99s-2024-Long-Term-Reliability-Assessment.aspx).

[172] *Id.* at 7 (citing NERC Statement on 2024 Long-Term Reliability Assessment; NERC, *2025 Summer Reliability Assessment* 6 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf).

[173] *Id.* (citing Clean Energy Associations Protest at 25-26; PIOs Protest at 29-33).

[174] *Id.* at 7-8.

[175] *Id.* at Tab B, Prepared Direct Testimony of Andrew Witmeier, Docket No. ER25-1674-000, at 10 (filed Apr. 21, 2025) (Witmeier Docket No. ER25-1674 Rebuttal Testimony).

2024 MISO Queue Cap, and ERAS is a separate process to address near-term resource adequacy needs.[176]

68. MISO also asserts that COMPP confuses the commercial operation date with the in-service date in arguing that the commercial operation date requirement was not appropriately tailored for ERAS interconnection requests to timely meet resource adequacy needs.[177] MISO explains that the Commission recently accepted, in Docket No. ER25-1758, revisions to its GIP that allow transmission owners to extend the in-service date during GIA negotiations for known construction delays, and to set a 180-day trial operation period after the in-service date. MISO contends that the 180-day trial operation period after the in-service date prevents the termination of an otherwise viable project in the very limited circumstance that the transmission owner had moved the in-service date for a facility that it was building and that was needed to allow a generating facility to provide its full output to the transmission system.[178] MISO states that these provisions do not allow the interconnection customer to extend its own commercial operation date grace period when the transmission system is ready to receive full output and do not impact commercial operation date timing requirements in GIP section 4.4.4 or *pro forma* GIA Article 2.3.1. MISO states that the grace period in the Revised ERAS Proposal is unchanged from the Initial ERAS Proposal and does not undercut the rationale for ERAS. MISO further asserts that any interconnection request can face in-service date and other delays and that arguments asserting that an interconnection request is not urgent because it may face in-service date delays are spurious. MISO asserts that the Revised ERAS Proposal accelerates those parts of the timeline that MISO can control.

69. Additionally, MISO states that the Revised ERAS Proposal better tailors the RERRAs' roles in ERAS to address resource adequacy needs because the new RERRA verification targets the resource adequacy need that an interconnection request is addressing and ensures that the interconnection request will address a new load addition or resource adequacy deficiency in the RERRA's footprint.[179] MISO explains that since resource adequacy determinations must be made in collaboration with the states, MISO relies on the RERRA to review and verify that the proposed interconnection request will

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176 MISO Answer, Tab B, MISO Answer, Docket No. ER25-1674-000, at 41 (filed Apr. 21, 2025) (MISO Docket No. ER25-1674 Answer).

177 MISO Answer at 8-9 (citing *Midcontinent Indep. Sys. Operator, Inc.*, 191 FERC ¶ 61,150; *see* MISO, Tariff, attach. X (GIP) (171.0.0), § 4.4.4.1).

178 *Id.* at 9-10.

179 *Id.* at 21.

address the identified need.[180] MISO states that the new verification requirement narrows ERAS interconnection requests to those that can address a resource adequacy need that a RERRA has verified is a valid, new, incremental load that is not already planned for, and for which an executed agreement exists connecting that need to the specific project.[181]

(b) <u>Additional Answers</u>

70. Clean Grid Alliance asserts that MISO's answer did not address the resource adequacy challenges that protesters raised and, instead, relied on NERC's new assessment downgrading MISO's risk to one similar to other RTOs/ISOs.[182] Clean Grid Alliance contends that, contrary to MISO's implications, the Commission did not grant exceptions to open access based on NERC capacity ratings. Further, Clean Grid Alliance reiterates that MISO has abundant generation because MISO has 56 GW of interconnection requests with GIAs and a large number of interconnection requests in the DPP 2021 and 2023 cycles that, according to MISO, will have GIAs in 2025 and 2026.[183] Clean Grid Alliance also contends that ERAS is unjustified and unnecessary because the provisional GIA process allows new generation to interconnect quickly.[184] Clean Grid Alliance further argues that MISO admits that ERAS projects may not be approved in state regulatory processes and may have to withdraw, which is contrary to MISO's claims that ERAS projects will be "shovel ready."[185]

71. Clean Grid Alliance reiterates that supply chain issues are the true cause of the DPP queue backlogs, which is evidenced by MISO's recent request for a blanket waiver to extend commercial operation deadlines for interconnection requests in the DPP 2018

[180] *Id.* at 22.

[181] *Id.* at 22-23.

[182] Clean Grid Alliance First Answer at 2-3 (citing Clean Grid Alliance Protest at 8; MISO Answer at 6). *See also* Clean Grid Alliance First Answer, attach. A (Clean Grid Alliance Answer), Docket No. ER25-1674-000 at 10 (filed May 2, 2025) (Clean Grid Alliance Docket No. ER25-1674 Answer).

[183] Clean Grid Alliance First Answer at 3; Clean Grid Alliance Docket No. ER25-1674 Answer at 11, 15.

[184] Clean Grid Alliance First Answer at 3, 5-6; Clean Grid Alliance Docket No. ER25-1674 Answer at 12-13.

[185] Clean Grid Alliance Docket No. ER25-1674 Answer at 13-14 (citing MISO Docket No. ER25-1674 Answer).

and 2019 cycles, citing supply chain issues.[186] Clean Grid Alliance avers that NERC also recognizes that supply chain issues are causing construction delays, resulting in a 2.7 GW shortfall in MISO's service territory.[187] Clean Grid Alliance asserts that establishing a separate ERAS study process is not going to solve the supply chain problem and may result in ERAS interconnection requests developing behind DPP interconnection requests with GIAs and those expected to finalize GIAs in 2025 and 2026.

72. Clean Grid Alliance asserts that LSEs and MISO correctly recognize that spot load is speculative and that there are only potential load growth issues.[188] Clean Grid Alliance avers that some LSEs identify specific generation needs but do not address why DPP interconnection requests cannot meet that load. Clean Grid Alliance also points out that other LSEs do not identify any specific needs.[189]

73. Finally, Clean Grid Alliance asserts that MISO is close to achieving a one-year processing time for its future DPP cycles due to implementing queue processing improvements, including the SUGAR software.[190] Clean Grid Alliance contends that MISO will be able to serve state load needs with resources in its DPP queue and that ERAS is thus unnecessary.

74. MISO IPPs aver that MISO's answer illustrates that the Revised ERAS Proposal is not narrowly tailored because MISO has not proffered any evidence connecting its proposed ERAS cap or carve outs with the magnitude of the anticipated resource adequacy shortfall, nor how the Revised ERAS Proposal will meet the timing of MISO's anticipated shortfall given that ERAS interconnection requests may not come online until 2032.[191]

75. Clean Energy Associations note that, in the time since MISO filed the Revised ERAS Proposal, NERC has revised the 2024 Long-Term Reliability Assessment to redesignate the MISO region from the "high risk" category to the "elevated risk"

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[186] Clean Grid Alliance First Answer at 4 (citing Clean Grid Alliance Protest at 2); Clean Grid Alliance Docket No. ER25-1674 Answer at 11.

[187] Clean Grid Alliance First Answer at 4-5 (citing the NERC 2024 Long-Term Reliability Assessment at 43).

[188] *Id.* at 5-6 (citing MISO Answer at 7; Clean Grid Alliance Protest at 33).

[189] *Id.* at 6-7.

[190] Clean Grid Alliance Docket No. ER25-1674 Answer at 15.

[191] MISO IPPs Answer at 15.

category.[192] Clean Energy Associations assert that MISO, despite acknowledging the downgrade in its answer, still relies on the NERC definition of "high risk" to support its claimed imminent resource adequacy and reliability concerns.[193] Therefore, Clean Energy Associations argue that MISO's rationale for ERAS is based on inaccurate and overstated resource adequacy projections.[194]

76. Clean Energy Associations note that the 2025 OMS-MISO Survey demonstrates that the MISO region can maintain resource adequacy through 2031 through DPP and market reforms, improved resource deployment timelines, and other initiatives.[195] Clean Energy Associations argue that MISO fails to provide any evidence to rebut this statement from the 2025 OMS-MISO Survey or similar statements made by its IMM.[196] Accordingly, Clean Energy Associations assert that MISO already has the processes needed to address future resource adequacy problems. Clean Energy Associations further assert that, absent clear evidence of a near-term shortfall, there is no basis to adopt a new, preferential interconnection process.[197]

77. PIOs assert that MISO has neither addressed that its need to demonstrate that near-term resource adequacy needs justify the Revised ERAS Proposal nor why existing processes in MISO's Tariff are insufficient to meet its resource adequacy needs.[198]

78. PIOs argue that MISO's answer dismisses evidence regarding its resource adequacy needs.[199] PIOs contend that despite MISO's recognition of NERC's downgrading of MISO's risk assessment, MISO does not propose any adjustment to its Revised ERAS Proposal. PIOs further contend that, in arguing that its resource needs are equivalent to those of PJM and CAISO, MISO ignores critical differences among the Revised ERAS Proposal, PJM's RRI, and CAISO's IPE. Specifically, PIOs explain that

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[192] Clean Energy Associations Answer at 3 (citing NERC Statement on 2024 Long-Term Reliability Assessment).

[193] *Id.* (citing MISO Answer at 7).

[194] *Id.* at 5.

[195] *Id.* at 3-4 (citing 2025 OMS-MISO Survey at 2).

[196] *Id.* at 4 (citing Clean Energy Associations Protest at 27-28).

[197] *Id.* at 5.

[198] PIOs Answer at 2.

[199] *Id.* at 3-4.

PJM has more significant issues with new entry and retirement of generating facilities compared to MISO, yet the RRI process has a smaller cap and stricter timeline criteria than the Revised ERAS Proposal. Further, PIOs state that CAISO's process prioritizes interconnection requests in the queue through scoring criteria rather than allowing new interconnection requests to "cut in line."[200]

79. PIOs argue that MISO continues to ignore significant timeline mismatches between its identified needs and the ERAS process. PIOs further argue that MISO's references to various timelines obfuscates the reality that ERAS interconnection requests are not more suited to meet near-term resource adequacy needs than interconnection requests in the DPP, particularly given the adoption of the SUGAR software through which MISO expects to process DPP backlogs by the end of 2026.[201]

80. PIOs argue that MISO's answer mistakes PIOs' and COMPP's concerns about the in-service date and commercial operation date to be solely about Tariff details and implementation, when the concern is more broadly that the Revised ERAS Proposal does not require ERAS interconnection requests to reach commercial operation in the near term.[202] PIOs contend that MISO's explanation that the Revised ERAS Proposal is only intended to accelerate the parts of the generator interconnection process that MISO can control demonstrates that the Revised ERAS Proposal does not include mechanisms to ensure that resources come online to meet near-term needs.[203] PIOs further contend that this explanation contradicts MISO's other statements that ERAS guarantees that only "shovel ready" interconnection requests will enter ERAS since MISO can only control certain aspects of the interconnection process, which will not be sufficient to ensure genuine shovel-readiness. PIOs assert that MISO's explanations also conflict with PJM's RRI, which includes indicators of readiness like a construction schedule and attestations of commercial operation timelines.[204]

c. <u>Commission Determination</u>

81. We find that MISO's Revised ERAS Proposal represents a just and reasonable and not unduly discriminatory or preferential approach for addressing MISO's urgent, near-term resource adequacy needs. MISO has authority to evaluate and maintain

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[200] *Id.* at 4.

[201] *Id.* at 4-5.

[202] *Id.* at 5.

[203] *Id.* at 6.

[204] *Id.* (citing PJM RRI Order, 190 FERC ¶ 61,084 at P 155).

resource adequacy under its Tariff mechanisms,[205] as well as to manage the processing of its queue.[206] We find that the Revised ERAS Proposal will allow MISO to accelerate the study of interconnection requests that are "shovel ready" and that will address an identified resource adequacy or reliability need in the same Local Resource Zone where the generating facility is to be located, with limited exceptions, thereby enabling resources to meet projected near-term resource adequacy needs more quickly than could be accomplished under MISO's current DPP process.

(a) MISO's Identified Need

82. We disagree with protesters that MISO has not sufficiently supported its near-term resource adequacy needs. While some protesters contend that MISO overstates its near-term resource adequacy needs, MISO cites several reports from different sources – MISO's Reliability Imperative Report, the 2024 and 2025 OMS-MISO Surveys, and the NERC 2024 Long-Term Reliability Assessment – as evidence of its near-term resource adequacy needs.[207] For example, while Clean Energy Associations assert that the 2025 OMS-MISO Survey projects a surplus of 1.4-6.1 GW, the next bullet in the survey results states that "at least 3.1 GW of additional capacity beyond the committed capacity will be needed to meet the projected planning reserve margin forecast."[208] Several commenters, both LSEs and state representatives, and some protesters have highlighted their near-term load-serving obligations and upcoming load needs.[209] MISO also asserts that the data it relies on, as well as the overall trends for

[205] *See Midcontinent Indep. Sys. Operator, Inc.*, 162 FERC ¶ 61,176, at P 59 (2018) ("MISO's resource adequacy construct ensures just and reasonable rates by creating a price signal that reflects the availability of capacity rather than by creating any particular price"); *see also* January 2024 Order, 186 FERC ¶ 61,054 at P 182 ("[A]ny future section 205 filing to propose a study cycle cap must demonstrate how the cap ensures that MISO can study new generation seeking to interconnect in a manner that appropriately accounts for its future resource adequacy needs.").

[206] *See* PJM RRI Order, 190 FERC ¶ 61,084 at P 54 (citing *Sw. Power Pool, Inc.*, 128 FERC ¶ 61,114, at PP 15, 32 (2009) (finding that an RTO is entitled to flexibility in proposing variations to Commission requirements under the independent entity variation standard and that the RTOs' temporal and geographic queue clustering proposal was a rational approach), *order on compliance*, 129 FERC ¶ 61,226 (2009), *order on compliance*, 133 FERC ¶ 61,139 (2010)).

[207] Transmittal at 5-6.

[208] 2025 OMS-MISO Survey at 2.

[209] *See, e.g.*, AECS Comments at 4; CenterPoint Comments at 1; Entergy/Cleco/Cooperative Energy Comments at 9-10; ITC Comments at 3; Louisiana

RTOs/ISOs throughout the country, support its claims about near-term resource adequacy needs.[210] While forecasting future resource adequacy needs necessarily involves uncertainty, we find that it is reasonable for MISO to act in recognition of the aforementioned reports. Further, we note that while NERC recently revised its 2024 Long-Term Reliability Assessment, MISO's risk classification for the years 2028-2031, remains in the "high risk" category.[211] ERAS provides a mechanism to accelerate the interconnection of resources to help address resource adequacy needs in MISO's footprint during this period. And as MISO points out, although NERC has downgraded the MISO region's risk category for capacity shortfalls to "elevated risk" before 2028, this new risk category places the MISO region at the same risk level as the PJM and CAISO regions, for which the Commission has also approved expedited generator interconnection study processes to address pressing resource adequacy needs.[212] We therefore find that MISO has sufficiently demonstrated that it has near-term resource adequacy needs in its region.

83. As for protesters' arguments about how the DPP process may meet MISO's identified resource adequacy needs in lieu of ERAS, we note that the Commission has extended RTOs/ISOs considerable flexibility in addressing region-specific interconnection study processing challenges.[213] In light of our finding that MISO's proposal is just and reasonable, we need not consider whether the proposal is more or less reasonable than the alternative solutions identified by protesters. Notwithstanding this, we disagree with arguments that MISO's recent interconnection study process reforms and study automation efforts will render the ERAS proposal unnecessary. While MISO's automation efforts may improve the overall DPP process,[214] those processing improvements are just now being implemented for the first time for the DPP 2022 cycle, which will not be completed for another year or more, and therefore are unlikely to be sufficient to meet MISO's near-term resource adequacy needs. At this time, only the system impact studies in the DPP process are being automated, while the ERAS

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and Mississippi Commissions Comments at 5; Michigan Commission Protest at 7; Midwest TDUs Comments at 3-4; MISO TOs Comments at 3; Mississippi Governor Comments at 1; Vistra Protest at 5, 7.

[210] MISO Answer at 5-8.

[211] Transmittal at 6 (citing the NERC 2024 Long-Term Reliability Assessment).

[212] *See* MISO Answer at 6.

[213] *See* PJM RRI Order, 190 FERC ¶ 61,084 at P 54.

[214] Witmeier Testimony at 64-65.

framework is designed to render EGIAs within 90 days,[215] with the entire ERAS process likely concluding well in advance of full implementation of DPP automation enhancement reforms.[216] Similarly, we agree with MISO that its interconnection study process reforms (e.g., the 2024 MISO Queue Cap) are focused on longer-term improvements to reduce speculative interconnection requests from entering the DPP queue and improve queue processing, not the objective of addressing near-term resource adequacy and reliability needs.

(b) <u>Commercial Operation Date</u>

84. Further, we disagree with protesters that MISO's proposed commercial operation date requirements undercut MISO's contention that ERAS interconnection requests will help resolve near-term resource adequacy needs. Under the Revised ERAS Proposal, interconnection customers must have a commercial operation date within three years of interconnection request submission, subject to an additional three-year grace period. Protesters argue that, as a result, ERAS generating facilities that will not come online for at least six years after interconnection request submission, and, for those submitted in 2027, as much as eight years from MISO's proposal, cannot address near-term resource adequacy or reliability needs. However, six years is the worst-case scenario, reflecting the maximum period for an ERAS generating facility to come online, which nevertheless is nearly half of the maximum 11-year commercial operation deadline that is used by some DPP interconnection requests.[217] Further, while there is no guarantee that all ERAS interconnection requests will achieve commercial operation, it is reasonable to conclude that ERAS interconnection requests are more likely to do so than DPP interconnection requests given the ERAS eligibility requirements designed to swiftly identify "shovel ready" projects. We agree with commenters that MISO's proposed coupling of its proposed commercial operation date requirements and stringent eligibility requirements will enable MISO to accelerate the study of urgently needed, "shovel ready" projects to help alleviate near-term resource adequacy needs.[218]

85. With respect to protester arguments that the proposed language in GIP section 3.9.8 may conflict with MISO's assertion that "[a]ll ERAS projects are eligible to

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[215] Transmittal at 8.

[216] *See* MISO Answer at 6-7.

[217] Witmeier Testimony at 47.

[218] Transmittal at 39; MISO Answer at 29; AECS Comments at 4; Big Rivers Electric Comments at 3; CenterPoint Comments at 1; Entergy/Cleco/Cooperative Energy Comments at 9-10; ITC Comments at 3; Louisiana and Mississippi Commissions Comments at 5; Midwest TDUs Comments at 3-4; MISO TOs Comments at 3.

use the grace period of up to three years as documented in GIA Article 2.3.1,"[219] we note that GIP section 3.9.8 addresses modifications to the ERAS interconnection request, and not to the EGIA.

(c) RERRA Verification Requirement

86. Contrary to Clean Energy Associations' assertions,[220] we do not believe that MISO's proposed GIP section 3.9.1 is contradictory. Rather, we find that proposed GIP section 3.9.1.1.i provides requirements for the RERRA's written verification with respect to "new, incremental load" whereas proposed GIP section 3.9.1.1.ii provides requirements for the RERRA's written verification with respect to "a resource adequacy deficiency" with multiple means by which such a determination can be supported.

87. For example, under proposed GIP section 3.9.1.1.ii, MISO provides examples of supporting materials that "can" support a determination that the proposed interconnection request will address an identified resource adequacy need, including integrated resource plans.

88. In response to PIOs' concerns that nothing in the ERAS process requires a RERRA to consider whether a resource currently in the DPP is better suited to meet the identified need, we note that the DPP is a MISO-specific process outside of a RERRA's purview. Further, nothing prohibits an interconnection customer with an interconnection request in the DPP from participating in the ERAS process if it satisfies the ERAS eligibility requirements.

(d) Other ERAS Eligibility Requirements

89. As further discussed below, we find that MISO has sufficiently detailed the parameters of ERAS eligibility in the proposed Tariff, and MISO has narrowly tailored the Revised ERAS Proposal to the identified near-term resource adequacy or reliability needs.[221] Moreover, as for protester suggestions that the RERRA verification should incorporate a scoring mechanism or other alternative approaches, we reiterate our earlier finding that the Commission affords MISO considerable flexibility in addressing region-specific interconnection queue processing challenges, and we need not consider whether

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[219] Transmittal at 50.

[220] Clean Energy Associations Protest at 11-12.

[221] *See* discussion *infra*, parts IV.B.2.c, 3.c., 4.c and 5.c.

MISO's proposal is more or less reasonable than the alternative solutions identified by protesters.[222]

2. Jurisdiction and Filed Rate Doctrine

a. MISO's Filing

90. MISO states that the FPA and Commission precedent recognize the authority of state regulators and their jurisdictional utilities to plan for adequate generation to address resource adequacy needs within their jurisdictional footprints.[223] MISO further states that the Revised ERAS Proposal incorporates the role of states and other RERRAs and "provides a vehicle for the RERRA to verify to MISO that there is a valid, new incremental load addition that is not incorporated in relevant plans or that the proposed Generating Facility will address an identified resource adequacy deficiency."[224] MISO's statement is a reference to the RERRA verification eligibility requirement in proposed GIP section 3.9.1, which provides that:

> 1. The Interconnection Request shall be accompanied by a written verification from the RERRA (or its documented representative) where the load to be served by the Generating Facility is located and, subject to the procedures the RERRA requires, that either:
>
>   a. The new, incremental load addition claimed by the interconnection customer is valid and not otherwise included in a resource plan or other process under the RERRA's purview; or
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>   b. The generating facility proposed by the interconnection customer will address a resource adequacy deficiency as determined by the RERRA, state, LSE, or interconnection customer as supported by certain documentation; or
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>   c. For generating facilities that will address a resource adequacy deficiency and either serves retail load or a retail choice state, the interconnection customer will

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[222] *See supra* P 82.

[223] Transmittal at 2.

[224] *Id.* at 9.

indicate the specific load as required in the interconnection request and provide evidence that the generating facility will address a resource adequacy deficiency as described in (b), but such interconnection customer will not be required to include a written verification from the RERRA.

b. Responsive Pleadings

i. Comments in Support

91. Some commenters assert that ERAS aligns with state jurisdictional authority as it relates to decision-making on resource adequacy.[225] AECS notes that the process respects state authority over resource procurement and ensures that RERRAs will determine the resources necessary to support LSEs under their jurisdiction.[226] Louisiana and Mississippi Commissions assert that the verification process accommodates the needs of the various MISO states, both regulated and those with retail access.[227] MISO TOs state that, according to Commission precedent, states have authority over resource adequacy, and ERAS intentionally empowers states and RERRAs with the ability to signal to MISO, through the RERRA verification process, that certain projects need the expedited treatment of the ERAS process. Additionally, MISO TOs note that MISO added Tariff language incorporating the retail access states into the ERAS process to address resource adequacy deficiencies in those states, recognizing the structural differences in those states.[228] Texas Commission asserts that there is a need to study interconnection requests that are necessary to meet nearer-term, state-determined resource adequacy needs because there is an increasing risk of a state's "needs determination" being unmet if an interconnection request is delayed in MISO's queue.[229]

[225] AECS Comments at 6; Entergy/Cleco/Cooperative Energy Comments at 3, 8; Louisiana and Mississippi Commissions Comments at 3, 9; MISO TOs Comments at 3, 10-11; Missouri Commission Comments at 2; Texas Commission Comments at 5-7.

[226] AECS Comments at 6.

[227] Louisiana and Mississippi Commissions Comments at 9.

[228] MISO TOs Comments at 10-11.

[229] Texas Commission Comments at 7.

ii. Protests

92. NextEra and MISO IPPs assert that the ERAS proposal unjustly and unreasonably allows states to set the terms and conditions of Commission-jurisdictional service, despite the FPA granting, and the courts upholding, exclusive jurisdiction over the rates, terms, and conditions for the transmission of electric energy in interstate commerce, including interconnection service, to the Commission.[230] Further, NextEra and MISO IPPs state that ERAS essentially grants RERRAs the authority to determine which interconnection customers will be granted interconnection service, which is a Commission-exclusive jurisdiction.[231] Additionally, NextEra asserts that MISO is required to provide nondiscriminatory open access to the transmission system in a manner that allows all resources to compete on equal footing, which will not infringe on states' authority over resource adequacy, so long as MISO does not mandate or prohibit any particular generating facility or resource mix.[232] In support of this, NextEra and MISO IPPs argue that the Commission rejected past proposals as unduly discriminatory when they prioritized resources that were being developed in connection with a state resource

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[230] *See* NextEra Docket No. ER25-1674 Protest at 6, 48-49 (citing *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 288 (2016); *Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 164 (2016) (*Talen*); and PJM RRI Order, 190 FERC ¶ 61,084 at P 75); MISO IPPs Docket No. ER25-1674 Protest, Affidavit of the Hon. Joseph T. Kelliher ¶ P 16 (Kelliher Aff.).

[231] MISO IPPs Docket No. ER25-1674 Protest at 13-14 (citing *FPL Energy Marcus Hook, L.P. v. FERC*, 430 F.3d 441, 443 (D.C. Cir. 2005); PJM RRI Order, 190 FERC ¶ 61,084 at P 75); NextEra Protest at 49.

[232] NextEra Docket No. ER25-1674 Protest at 50 (citing *Xcel Energy Operating Cos.*, 106 FERC ¶ 61,260, at P 23 (2004) (*Xcel*) (rejecting a proposal to provide priority queue access to interconnection requests that were part of a state-sponsored bidding process and finding that interconnection customers that did not take part in the state-sponsored bidding must be allowed to compete in the wholesale energy market on an equal footing); PJM RRI Order, 190 FERC ¶ 61,084 at P 76).

solicitation process[233] and rejected the RERRA exclusion in the 2023 MISO Queue Cap Proposal.[234]

93. NextEra asserts that, due to the non-delegation doctrine, neither MISO nor the Commission can delegate authority over the rates, terms, and conditions of interconnection service to RERRAs.[235] NextEra argues that there is a presumption against subdelegation, even if that subdelegation is to a state commission, which may be a RERRA under the ERAS process.[236] NextEra asserts that RERRAs are not subject to Commission oversight, so it is not clear that the Commission can exercise oversight of RERRA rates via FPA section 206[237] complaint proceedings, which would violate the non-delegation doctrine and the FPA.[238] Clean Energy Associations argue that "MISO is effectively delegating to states its responsibility for ensuring that its own Tariff is not unduly discriminatory or preferential, and thereby leaving the Commission without oversight."[239] Additionally, Clean Energy Associations state that MISO has failed to

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[233] MISO IPPs Docket No. ER25-1674 Protest at 7-8 (citing *Sw. Power Pool, Inc.*, 147 FERC ¶ 61,201, at P 124 (2014)); NextEra Docket No. ER25-1674 Protest at 8 (citing *Xcel*, 106 FERC ¶ 61,260 at PP 12-13, 22-24); *Midwest Indep. Transmission Sys. Operator, Inc*., 124 FERC ¶ 61,183, at P 143 (2008)).

[234] NextEra Docket No. ER25-1674 Protest at 9 (citing January 2024 Order, 186 FERC ¶ 61,054 at PP 176-177).

[235] *Id.* at 53.

[236] *Id.* (citing *U.S. Telecom Ass'n v. FCC*, 359 F.3d 554, 566 (D.C. Cir. 2004) (*U.S. Telecom*); *Texas v. Rettig*, 987 F.3d 518, 531 (5th Cir. 2021)); *see also* MISO IPPs Docket No. ER25-1674 Protest at 15 (citing Kelliher Aff. at 6-7).

[237] 16 U.S.C. § 824e.

[238] NextEra Docket No. ER25-1674 Protest at 53-54 (citing *La. Pub. Serv. Comm'n v. FERC*, 761 F.3d 540, 552 (5th Cir. 2014) (*Louisiana PSC*); *see Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. & Transmitting Utils.*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996) (cross-referenced at 75 FERC ¶ 61,080), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 (cross-referenced at 78 FERC ¶ 61,220), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Pol'y Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. N.Y. v. FERC*, 535 U.S. 1.

[239] Clean Energy Associations Docket No. ER25-1674 Protest at 22.

meet its obligations as an independent system operator under Order No. 888 to ensure fair and non-discriminatory access to transmission services and ancillary service for all users of the transmission system.

94. Finally, NextEra and MISO IPPs assert that ERAS violates the filed rate doctrine because a RERRA will establish the criteria used to determine ERAS participation without filing with the Commission and without providing uniform, objective, and non-discriminatory criteria in the tariff, which will circumvent the Commission's jurisdictional authority to ensure that the terms and conditions of receiving interconnection service in MISO are just and reasonable and not unduly discriminatory or preferential.[240] NextEra additionally argues that the fact that RERRAs can set their own criteria for resources to enter ERAS also will result in similarly situated interconnection customers within the MISO region being subject to arbitrary differences in the terms and conditions of interconnection service, depending on its applicable RERRA.[241] NextEra further argues that interconnection customers will not receive notice of the terms and conditions of the RERRA's criteria, as the FPA requires.[242] MISO IPPs assert that a lack of objective criteria in the Tariff will create an environment ripe for undue discrimination in the RERRA approval process, and thus the composition of the ERAS queue.[243]

95. Clean Grid Alliance argues that MISO's discussion of jurisdiction is intended to divert attention from the deficiencies in the Revised ERAS Proposal and that, while RERRAs should have a role over resource adequacy, MISO must still comply with open access requirements.[244] Similarly, COMPP asserts that though resource adequacy decisions rest within state jurisdiction, MISO's role is to meet the Commission's reliability standards while adhering to open access principles, and such principles are not being met by the Revised ERAS Proposal.[245] PIOs argue that MISO's refusal to exert

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[240] MISO IPPs Docket No. ER25-1674 Protest at 14; NextEra Docket No. ER25-1674 Protest at 52.

[241] NextEra Docket No. ER25-1674 Protest at 17-18.

[242] *Id.* at 52-53.

[243] MISO IPPs Docket No. ER25-1674 Protest at 15 (citing Kelliher Aff. at 6-7).

[244] Clean Grid Alliance Protest at 30.

[245] COMPP Protest at 7-8.

any oversight over the RERRA authority continues to go "beyond appropriate respect" for states' role in resource adequacy.[246]

iii. Answers

(a) MISO Answer

96. MISO asserts that the Revised ERAS Proposal reflects and respects the unique jurisdictional divide between the states, MISO, and the federal government. MISO reiterates that it is the states, not MISO, that have the power to determine the resources that will be used in states' jurisdictions.[247] MISO asserts that because there are a wide variety of RERRAs, it was required to design a flexible enough process to accommodate this variety. MISO argues that the additional eligibility requirements ensure that there are uniform, objective criteria in the Tariff.[248] MISO contends that states are not setting the rates, terms, and conditions of interconnection service; rather, RERRAs determine need within their jurisdictional processes, and that regardless of that determination, ERAS interconnection requests will still need to go through the approval process outside of ERAS.[249]

c. Commission Determination

97. We disagree with protesters that the Revised ERAS Proposal intrudes upon the Commission's exclusive FPA jurisdiction over generator interconnection. We disagree that the precedent cited by protesters indicates that the role of states, as RERRAs, in the ERAS process is impermissible.

98. Specifically, NextEra points to *Talen* to argue that even if states have authority over generating facilities, that does not permit them to "exercise control over the terms and conditions of interconnection service."[250] In *Talen*, incumbent generators brought suit to challenge a Maryland Public Service Commission (Maryland Commission) order that required LSEs in Maryland to buy capacity from a specific generator and pay the difference between the Commission-jurisdictional PJM interstate wholesale capacity auction clearing price and a price that the Maryland Commission guaranteed. The

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[246] PIOs Protest at 24 (quoting May 2025 Order, 191 FERC ¶ 61,13 (See, Comm'r, consenting at P 6)).

[247] MISO Answer at 4, 22, 25-26, 30.

[248] MISO Docket No. ER25-1674 Answer at 15.

[249] *Id.* at 16.

[250] NextEra Docket No. ER25-1674 Protest at 50 (citing *Talen*, 578 U.S. at 164).

Supreme Court of the United States (Supreme Court) rejected the Maryland program, stating that "[b]y adjusting an interstate wholesale rate, Maryland's program invades FERC's regulatory turf."[251] The Supreme Court stated that "[s]tates may not seek to achieve ends, however legitimate, through regulatory means that intrude on FERC's authority"[252] and that states "interfere with FERC's authority by disregarding interstate wholesale rates FERC has deemed just and reasonable, even when [s]tates exercise their traditional authority over . . . in-state generation."[253] The Supreme Court went on to say, however, that "[n]othing in this opinion should be read to foreclose . . . [s]tates from encouraging production of new or clean generation through measures 'untethered to a generator's wholesale market participation.'"[254]

99. We find that the Revised ERAS Proposal is permissible under *Talen* because RERRA participation in the ERAS process would be wholly pursuant to a Commission-jurisdictional process (i.e., the generator interconnection process), proposed by MISO and approved by the Commission—not by state authorities—and under which a GIP is on file with the Commission and any future revisions would be subject to Commission approval. Further, the ERAS process would remain subject to the Commission's authority pursuant to FPA sections 205 and 206. In contrast, in *Talen*, the Maryland Commission established a state program that operated outside a Commission-jurisdictional process and "interfered" with the Commission's authority to establish interstate wholesale rates. Nothing in the Revised ERAS Proposal deprives the Commission of its statutory jurisdiction as it applies to generator interconnection.

100. Similarly, we disagree with MISO IPPs' claim that, based on *U.S. Telecom*, the Revised ERAS Proposal impermissibly requires the Commission to subdelegate its FPA authority to the RERRAs. In that decision, which involved the Federal Communications Commission's (FCC) subdelegation to state commissions certain determinations that the FCC was required to make pursuant to the Telecommunications Act of 1996,[255] the United States Court of Appeals for the District of Columbia Circuit determined that the

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[251] *Talen*, 578 U.S. at 163.

[252] *Id.* at 164.

[253] *Id*. at 165.

[254] *Id.* at 166.

[255] 47 U.S.C. § 151 *et seq.*

FCC's subdelegation had, in some respects, given the state commissions "unlimited discretion."[256]

101. We find that *U.S. Telecom* is distinguishable from the Revised ERAS Proposal. The Revised ERAS Proposal does not subdelegate the Commission's authority but simply creates a role for RERRAs in a Commission-jurisdictional process.[257] In particular, the RERRA's role would be limited to assessing and verifying non-speculative interconnection requests that address an identified resource adequacy deficiency. In this way, the Revised ERAS Proposal also recognizes the states' jurisdictional authority over resource planning and the generation mix within their boundaries. Further, in *Louisiana PSC*, the United States Court of Appeals for the Fifth Circuit determined that it is not an unlawful subdelegation for the Commission to incorporate state-determined rate elements in Commission-jurisdictional rate proceedings.[258] According to the court, the Commission's "continuing review in Section 206 proceedings distinguishes it from the unease expressed in [*U.S.*] *Telecom,* of agencies' 'vague or inadequate assertions of final reviewing authority.'"[259] Similarly, under the Revised ERAS Proposal, the RERRA is given a limited role in verifying interconnection requests, and such requests, through the EGIA process, would be subject to Commission review under FPA sections 205 and 206.

102. We also disagree with NextEra and MISO IPPs that the Revised ERAS Proposal violates the filed rate doctrine. The filed rate doctrine and the rule against retroactive ratemaking are "the statutory requirements that bind regulated entities to charge only the rates filed with [the Commission] and to change their rates only prospectively."[260] The FPA requires public utilities to file with the Commission the rates, terms, and conditions

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[256] *U.S. Telecom*, 359 F.3d at 564.

[257] *See, e.g.*, *Participation of Distributed Energy Res. Aggregations in Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators*, Order No. 2222, 172 FERC ¶ 61,247, at P 64 (2020) (finding that small utilities may not participate in distributed energy resource aggregations unless the RERRA affirmatively allows such customers to participate in distributed energy resource aggregations), *order on reh'g*, Order No. 2222-A, 174 FERC ¶ 61,197, *order on reh'g*, Order No. 2222-B, 175 FERC ¶ 61,227 (2021).

[258] *Louisiana PSC*, 761 F.3d at 551-52 (holding that there was no unlawful subdelegation where the Commission exercised its role by reviewing and accepting a bandwidth formula that incorporated state agencies' depreciation rates).

[259] *Id*. at 552 (quoting *U.S. Telecom*, 359 F.3d at 568).

[260] *Okla. Gas & Elec. Co. v. FERC*, 11 F.4th 821, 829 (D.C. Cir. 2021); *see also PJM Power Providers Grp. v. FERC*, 96 F.4th 390, 394 (3rd Cir. 2024).

of the jurisdictional service they provide.[261] NextEra and MISO IPPs argue that the Revised ERAS Proposal violates the filed rate doctrine because it allows RERRAs to establish criteria that would not be on file with the Commission and that would determine whether or not an interconnection request is eligible for ERAS.[262] We disagree. We find that the Revised ERAS Proposal does not present a filed rate doctrine concern because it provides adequate notice of the ERAS eligibility requirements, including the RERRA verification requirement.[263] In particular, the RERRA verification requirement in proposed GIP section 3.9.1.1 has multiple sub-requirements that provide a level of uniformity among RERRAs, such as the requirement that the RERRA must be from the same location as the load to be served, and the requirement that the RERRA verification must include an explanation of how the generating facility associated with the interconnection request will address a resource adequacy need, among other things.[264] If the RERRA verification does not satisfy these requirements, then the interconnection request would not be eligible for ERAS. Thus, we find that MISO has sufficiently detailed the parameters of ERAS eligibility, including the RERRA verification requirement, to satisfy the filed rate doctrine.

3. **<u>ERAS Requirements and Open Access/Undue Discrimination Concerns</u>**

a. **<u>MISO's Filing</u>**

i. **<u>RERRA Verification</u>**

103. As noted above, MISO proposes to require that to qualify for ERAS, an interconnection request must include a written verification from the RERRA, or RERRA representative where the load to be served by the generating facility is located, that requires either:

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[261] 16 U.S.C. § 824d(c); *see* 18 C.F.R. § 35.1(a) (2024) (requiring that any "rates and charges . . . classifications, practices, rules and regulations affecting such rates, charges, classifications, services, rules, regulations or practices," be filed with the Commission).

[262] *See* MISO IPPs Docket No. ER25-1674 Protest at 14; NextEra Docket No. ER25-1674 Protest at 51-53.

[263] *See, e.g.*, *Consol. Edison Co. of N.Y. v. FERC*, 347 F.3d 964, 969 (D.C. Cir. 2003); *Columbia Gas Transmission Corp. v. FERC*, 895 F.2d 791, 795-97 (D.C. Cir. 1990).

[264] MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.1.

a. The new, incremental load addition claimed by the interconnection customer is valid and not otherwise included in a resource plan or other process under the RERRA's purview; or

b. The generating facility proposed by the interconnection customer will address a resource adequacy deficiency as determined by the RERRA, state, LSE, or interconnection customer, which can be supported by: (i) a state energy forecast, or other forward-looking forecast; (ii) commencement of a state proceeding; (iii) review of a RERRA, LSE, or other state resource plan or document, which may include, but is not limited to: integrated resource plans, procurement plans, or other plan or study types; (iv) response to a request for proposals; or (v) other process, or delegation of authority, as determined by the RERRA or RERRA regulations (including in retail choice states).

For generating facilities that will address a resource adequacy deficiency and either serve retail load or a retail choice state, the interconnection customer will not be required to include a written verification from the RERRA. Instead, the interconnection customer will indicate the specific load as required in the interconnection request and provide evidence that the generating facility will address a resource adequacy deficiency as described in (b).

104. MISO states that it changed this requirement, from the RERRA notification in the Initial ERAS Proposal,[265] to better target the resource adequacy driver that an ERAS interconnection request addresses and to ensure that the RERRA verifies that such interconnection request will address a new load addition or a resource adequacy deficiency in its footprint.[266] MISO further states that the revised requirement is critical to maintaining the limited scope of ERAS to address near-term resource adequacy and/or reliability need claimed by an interconnection customer in a RERRA. MISO explains

[265] In the Initial ERAS Proposal, MISO proposed to require that an ERAS interconnection request be accompanied by a written notification from the RERRA specifying where the load to be served is located and that the interconnection request should be included in ERAS.

[266] Transmittal at 30.

that the RERRA verification may take any form so long as it is made by the RERRA or RERRA representative.

105. MISO states that the third option related to the RERRA verification was added to incorporate retail choice states – Illinois and a portion of Michigan.[267] Under this option, rather than requiring RERRA verification, MISO proposes to notify the respective RERRA that an ERAS interconnection request was submitted and provide a copy of the interconnection request. MISO states that the RERRA will have 10 business days from the date of notification to state that the interconnection request should not be included in ERAS. MISO states that this aspect of its proposal recognizes that interconnection customers in retail choice states do not need to seek approval from a RERRA and that there are alternative retail electric suppliers that serve load. MISO asserts that this language better facilitates the use of ERAS in Illinois and the retail choice areas of Michigan without changing the role or requirements for RERRAs in other parts of MISO's footprint.

106. MISO asserts that it is not a resource planner, so it is reasonable to require a RERRA verification for consideration in the ERAS process.[268] MISO explains that, in fact, the FPA recognizes that the RERRAs have jurisdiction over resource adequacy needs.[269] Therefore, MISO states that including the RERRA verification requirement ensures that an ERAS interconnection request is tied to a specific resource adequacy or reliability need.[270] MISO adds that this requirement will prohibit the submission of speculative interconnection requests with no connection to a specific need.[271] MISO states, however, that the RERRA verification requirement is not intended to constitute a final determination on the need or suitability of the interconnection request. Rather, MISO emphasizes that the RERRA verification is only a condition for requesting that MISO study a proposed interconnection request in the ERAS process.[272]

[267] *Id.* at 31.

[268] Witmeier Testimony at 31.

[269] Transmittal at 2 (citing 16 U.S.C. § 824; *CXA La Paloma, LLC v. Cal. Indep. Sys. Operator Corp.*, 165 FERC ¶ 61,148, at P 70 (2018)).

[270] *Id.* at 30.

[271] Witmeier Testimony at 32. MISO states that verification is only needed from one RERRA for an application for ERAS participation. *Id.* at 35.

[272] Transmittal at 31, 52.

107. MISO states that due to its unique composition of almost entirely vertically integrated utilities, resource adequacy decisions must be made in collaboration with the states.[273] MISO explains that responsibility for addressing resource adequacy or reliability needs is a state responsibility and that it would be inappropriate for MISO to make selections to address these needs. MISO states that the Revised ERAS Proposal accounts for its unique composition and the division of jurisdictional authority by proposing that MISO only facilitate the ERAS process and that interconnection customers identify the specific needs their interconnection requests address, and that RERRAs (including states) verify to MISO which interconnection requests merit expedited study.

ii. <u>Executed Agreement Requirement</u>

108. MISO also proposes to require an ERAS interconnection customer to have an executed agreement evidencing that its interconnection request "is intended to be used by the entity with the claimed resource adequacy or reliability need" (executed agreement requirement).[274] MISO proposes that the required agreement can take the form of: (1) an LSE acknowledgement to self-supply; (2) a power purchase agreement (PPA) or a similar off-take agreement between the ERAS interconnection customer and the entity to be served (including, but not limited to, an alternative retail electric supplier or its LSE); (3) an agreement that provides for the transfer of ownership or control of the generating facility to the entity with the load to be served (including, but not limited to, an alternative retail electric supplier or its LSE) after such generating facility is developed by the interconnection customer; or (4) an "other" agreement between the ERAS interconnection customer and the entity with the load to be served (including, but not limited to, an alternative retail electric supplier or its LSE), stating that the ERAS interconnection request will be used to meet an identified resource adequacy deficiency.[275]

109. MISO states that this requirement will ensure that an ERAS interconnection request is intended to be used by the entity with the claimed resource adequacy or reliability need.[276] MISO explains that such a requirement prevents speculative interconnection requests with no commercial arrangements from participating in ERAS.

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[273] *Id.* at 19.

[274] *Id.* at 30; Witmeier Testimony at 39, 41; MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.1.2.

[275] Transmittal at 30-31; MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.1.2.

[276] Transmittal at 30.

MISO states that, for example, an interconnection customer that has an agreement with a data center developer for the generation to serve that load is differently situated from an interconnection customer that enters the queue with the hope of pitching their generation project to the developer. MISO adds that, based on stakeholder feedback, it expanded the ERAS process to allow independent power producers to participate through inclusion of an "other" type of executed agreement.[277] MISO asserts that the executed agreement requirement mitigates overuse concerns because it pairs an ERAS interconnection request with a specific need.[278]

iii. ERAS Cap and Carve Outs

110. MISO proposes to establish a limit on the total number of interconnection requests that can participate in the ERAS process to 68. Of the 68 total interconnection requests, MISO proposes to allow a maximum of 10 interconnection requests from independent power producers that have agreements with entities other than LSEs and a maximum of 8 interconnection requests to serve retail choice load.[279] MISO states that the remaining 50 interconnection requests allowed to participate in ERAS will be for the remaining applicants for non-retail choice states. In addition, MISO proposes to implement a limit on the total number of interconnection requests that may be studied in an ERAS quarterly study period to 10 interconnection requests. MISO states that the interconnection requests will be selected based on the time stamp of submission, and it will create a waitlist for interconnection requests beyond the tenth submission. MISO further states that it will screen the submitted interconnection requests to ensure that none are in the same geographical area or impacting the same constraint. MISO states that, if any of the interconnection requests are in the same geographical area or impact the same constraint, then the one with a later time submission will be deferred to the next available ERAS quarterly study period. MISO explains that in the event that an interconnection request is deferred to a future ERAS quarterly study period, it will review any ERAS interconnection requests on the waitlist to determine whether one can be moved up into the deferred interconnection request's spot. Accordingly, MISO states that it will confirm that an interconnection request from the waitlist is not in the same geographic area as those in the ERAS quarterly study period under review. MISO states that these proposed limitations are in response to the Commission's feedback in the May 2025 Order.

111. MISO states that these proposed limitations will enable MISO to complete the ERAS process more efficiently and will result in interconnection customers receiving an

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[277] *Id.* at 41.

[278] *Id.* at 31.

[279] *Id.* at 25-26; MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.2.

EGIA quickly. MISO further states that the proposed limitations will allow MISO to better plan for the number of interconnection requests requiring study each quarterly study period and to better coordinate internal resources.[280] MISO states that while it stands by its original assertions that the ERAS process will not affect DPP interconnection requests and that the strict eligibility requirements will limit interconnection request submissions, expressly capping the number of interconnection requests will further ensure that DPP interconnection customers are not harmed by the ERAS process.[281] MISO asserts that its proposed cap serves the same goal as PJM's RRI, to "reasonably balance the need to address … resource adequacy challenges with the need to avoid an influx of projects that could overwhelm … [MISO's] interconnection process," but that MISO's proposal is spread over a longer period of time than PJM's RRI in order to allow prospective interconnection customers time to fully prepare their interconnection requests.[282]

iv. Other ERAS Eligibility Requirements

112. MISO proposes several requirements for ERAS interconnection requests, in addition to the demonstrations discussed above. Specifically, MISO proposes that interconnection customers must provide a non-refundable \$100,000 D1 application fee and a refundable M2 amount of \$24,000/MW and meet a requirement for 100% site control for both the generating facility and interconnection customer's interconnection facilities.[283]

113. MISO states that the non-refundable \$100,000 D1 application fee, which is higher than the \$5,000 D1 amount (even as adjusted for inflation) in the DPP, is necessary to prevent speculative interconnection requests from applying to the ERAS process, implement the temporary ERAS process, and cover costs associated with processing ERAS interconnection requests.[284] MISO states that the M2 amount of \$24,000/MW (relative to \$8,000/MW in the DPP) is based on MISO's existing provisional interconnection service milestone requirements and represents the same level of upfront financial commitment for this "one phase" process that an interconnection customer otherwise would make cumulatively for the "three phase" M2, M3, and M4 milestones in

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[280] Transmittal at 26.

[281] *Id.* at 27.

[282] *Id.*

[283] *Id.* at 36.

[284] *Id.* at 49.

the DPP process.[285] MISO adds that in addition to the RERRA verification and executed agreement requirements, the milestone payments and deposits are required at the time of application to allow MISO to complete the ERAS process within the estimated 90-day timeframe.[286]

114. MISO states that it is reasonable to require 100% site control for both the generating facility and interconnection customer's interconnection facilities for ERAS interconnection requests because it ensures that MISO will not be inundated with speculative interconnection requests. MISO explains that this requirement is more stringent than the requirements for the DPP, which only requires a 100% site control demonstration for the generating facility and a 50% demonstration of site control for interconnection customer's interconnection facilities at the time of an application submission. MISO also asserts that its proposal to disallow financial security in lieu of the proposed site control requirements will deter speculative interconnection requests because it prohibits such requests from being eligible for the ERAS process if they are unable to obtain necessary permits or siting requirements.[287]

115. MISO proposes to require that an ERAS interconnection request identify the claimed resource adequacy and/or reliability need for which the interconnection request is being submitted.[288] MISO states that this must include the location of the generating facility, i.e., the county and state of the proposed generating facility, the electrical bus location(s), and the Local Resource Zone. MISO states that the ERAS interconnection request must identify the expected peak demand for electricity in MW over any one hour period and that the requested level of interconnection service must not exceed 150% of the identified MW need.

116. MISO states that it plans to publish an ERAS webpage that will include a significant amount of information related to each ERAS interconnection request.[289] MISO states that ERAS applications must include a non-confidential summary of the information contained in the interconnection requests for MISO to publish on its website. The summary will include the interconnection customer proposing the generating facility, the MW range of need that the ERAS interconnection request will address, the Local Resource Zone where the proposed generating facility will be located, and a general

[285] *Id.*; Witmeier Testimony at 45.

[286] Transmittal at 50.

[287] *Id.* at 59; Witmeier Testimony at 46.

[288] Transmittal at 34; MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.3.1.

[289] Transmittal at 34; Witmeier Testimony at 38-39.

description of the driver for the load need (e.g., a data center, manufacturing plant, etc.).[290] MISO states that in addition to the non-confidential summary, it will publish the RERRA that submitted a verification for each ERAS interconnection request, the specific group that the ERAS interconnection request falls within (i.e., LSE, independent power producer, or retail choice), and the specific ERAS quarterly study period in which the ERAS interconnection request will be studied once MISO has completed the screening process for each ERAS quarterly study period. Finally, MISO states that it plans to publish an information guide for potential ERAS interconnection customers that addresses common questions and problems that prospective ERAS interconnection customers may face.[291] MISO states that these additional requirements will increase the transparency of the ERAS process.

b. Responsive Pleadings

i. Comments in Support

117. Commenters argue that the Revised ERAS Proposal maintains open access[292] and is not unduly discriminatory or preferential.[293] As evidence of this, commenters raise several points regarding the Revised ERAS Proposal, including: (1) there are ERAS slots reserved specifically for independent power producers;[294] (2) projects that do not meet ERAS requirements or are not identified by the RERRA as necessary for resource adequacy may still proceed through the DPP;[295] and (3) DPP interconnection requests can

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[290] Transmittal at 34.

[291] *Id.* at 34-35.

[292] AECS Comments at 8; Big Rivers Electric Comments at 7; Consumers Energy Comments at 3; Entergy/Cleco/Cooperative Energy Comments at 13; ITC Comments at 5; Louisiana and Mississippi Commissions Comments at 8; MISO TOs Comments at 19; Missouri Commission Comments at 3-4; NIPSCO Comments at 8; Texas Commission Comments at 12.

[293] AECS Comments at 8; Big Rivers Electric Comments at 7; Consumers Energy Comments at 3; Louisiana and Mississippi Commissions Comments at 8; MISO TOs Comments at 17; Missouri Commission Comments at 3; NIPSCO Comments at 8; Texas Commission Comments at 9.

[294] AECS Comments at 8; Arkansas Commission Comments at 3; Big River Electric Comments at 8; Duke Energy Indiana Comments at 2; Entergy/Cleco/Cooperative Energy Comments at 13; MISO TOs Comments at 16-17.

[295] AECS Comments at 8.

transfer to ERAS.[296] Commenters also argue that ERAS is open to all project sponsors, and fuel and technology types, so long as the interconnection request satisfies the ERAS requirements.[297]

118. Commenters assert that with the revisions to require RERRA verification and the identification of a specific need in the same Local Resource Zone as the ERAS interconnection request, MISO's Revised ERAS Proposal is a just and reasonable solution to MISO's resource adequacy and reliability concerns.[298] Several commenters argue that the RERRA verification process reasonably balances MISO's need to verify projects that meet resource adequacy needs.[299] Further, Louisiana and Mississippi Commissions assert that the RERRA verification reasonably balances, "the state's need to not prejudge generation certifications."[300] Michigan Commission states that it supports MISO's proposed limit to study 10 interconnection requests per quarterly study period, the RERRA verification, and the other eligibility requirements for interconnection requests to participate in ERAS.[301] Michigan Commission adds that the executed agreement requirement provides a direct linkage from the resource adequacy need to the ERAS interconnection request.

119. Midwest TDUs state that they appreciate that the Revised ERAS Proposal will be implemented in a manner that allows municipal joint action agencies to meaningfully participate.[302] Midwest TDUs assert that joint action agencies can submit notifications as the documented representative of their municipal utility member RERRAs, consistent

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[296] Big River Electric Comments at 8; Louisiana and Mississippi Commissions Comments at 8.

[297] AECS Comments at 8; Arkansas Commission Comments at 3; Big Rivers Electric Comments at 8; Consumers Energy Comments at 3; Entergy/Cleco/Cooperative Energy Comments at 13; Louisiana and Mississippi Commissions Comments at 8; MISO TOs Comments at 17; NIPSCO Comments at 8.

[298] Big Rivers Electric Comments at 8; NIPSCO Comments at 7-8.

[299] Louisiana and Mississippi Commissions Comments at 10; Otter Tail Comments at 4; Texas Commission Comments at 8.

[300] Louisiana and Mississippi Commissions Comments at 10.

[301] Michigan Commission Protest at 7-9.

[302] Midwest TDUs Comments at 4.

with applicable laws and governance documents.[303] Midwest TDUs state that this provides assurance that they will not be foreclosed from, or unduly disadvantaged in, the ERAS process, which could be crucial to meeting their municipal utility members' resource adequacy and reliability needs.

120. Several commenters state that the Local Resource Zone requirement tightly ties the generating facility to the resource adequacy or reliability need.[304] Entergy, Cleco, and Cooperative Energy argue that the proposed requirement that resources be located in the same local resource zone as the associated resource adequacy or reliability need and the proposed limitation on the amount of interconnection service that may be requested through an ERAS interconnection request, providing reassurance that the ERAS interconnection requests studied by MISO will be limited to those that can meet anticipated generation capacity shortfalls.[305] AECS notes that the local resource zone requirement ensures that generating facilities can actually serve the load.[306]

121. Several commenters assert that the proposed cap on the number of ERAS interconnection requests that can studied for the entirety of the program and proposed cap on the number of interconnection requests that can be studied quarterly will better ensure that MISO studies interconnection requests in an accelerated time frame.[307] Commenters also note that the addition of a fixed "sunset date" ensures that ERAS is a temporary measure to address near-term resource adequacy needs.[308]

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[303] *Id.* at 7.

[304] AECS Comments at 5; Entergy/Cleco/Cooperative Energy Comments at 12; Louisiana and Mississippi Commissions Comments at 9.

[305] Entergy/Cleco/Cooperative Energy Comments at 12-13.

[306] AECS Comments at 5-6.

[307] AECS Comments at 7; Arkansas Commission Comments at 3; Consumers Energy at 3; Duke Energy Indiana Comments at 2; Entergy/Cleco/Cooperative Energy Comments at 9; MISO TOs Comment at 14; NIPSCO Comments at 8; Ottertail Comments at 4-5; Texas Commission Comments at 9-11; Wisconsin Utilities Comments at 4.

[308] Entergy/Cleco/Cooperative Energy Comments at 10; Otter Tail Comments at 4.

ii. Protests

(a) RERRA Verification Requirement

122. Protesters assert that the proposed Tariff, similar to the Initial ERAS Proposal, continues to lack any objective or transparent criteria to be used for the RERRA verification process and that it is not clear what would justify MISO's acceptance or rejection of ERAS submissions.[309] Michigan Commission argues that absent minimal RTO/ISO-level guardrails against discriminatory treatment and favoritism of certain projects over others, each RERRA must attempt to run its own screening process with incomplete information and without assistance from the RTOs/ISOs.[310] EPSA similarly argues that the proposed RERRA verification process gives RERRAs "significant power to delay [independent power producer] ERAS projects – or block them entirely in favor of ERAS submissions from the LSE in their respective service territory."[311]

123. Invenergy requests that MISO provide clarification on various proposed Tariff provisions, including the GIP section 3.9.1(ii) provision to explain what constitutes "other processes" or which among the LSE, RERRA, or interconnection customer is responsible to determine the resource adequacy need.[312] Invenergy also requests that MISO clarify what constitutes an "other agreement" under the executed agreement requirement because, without clarity, a RERRA could decide on its own accord what type of agreement qualifies.[313] Invenergy also states that MISO should clarify whether an ERAS interconnection customer keeps its EGIA if the agreement with the off-taker falls through.

124. With respect to the RERRA verification and retail choice, Michigan Commission strongly urges the removal of the proposed Tariff language stating that the RERRA verification can be supported by "a state energy forecast, or other forward-looking forecast."[314] According to Michigan Commission, this Tariff provision, in addition to

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[309] EPSA Comments at 3-4; Invenergy Protest at 3-5; Michigan Commission Protest at 11-12.

[310] Michigan Commission Protest at 11.

[311] EPSA Comments at 6.

[312] Constellation Protest at 6.

[313] Invenergy Protest at 7-8.

[314] Michigan Commission Protest at 16 (citing MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.1.1.ii.a).

being unnecessary, would allow nearly any project to be eligible for ERAS as long as there is some forecast to support it. Constellation argues that RERRAs are provided an unworkable and standardless veto power in retail choice states.[315]

125. Several protesters argue that the Revised ERAS Proposal, like the Initial ERAS Proposal before it, discriminates against independent power producers, and that additional time is required for independent power producers to meet the ERAS participation requirements.[316] Clean Grid Alliance argues that MISO's proposed carve out for independent power producers does not solve the discriminatory and preferential design of ERAS because MISO's proposal maintains its dependence on RERRA "validation."[317] Michigan Commission argues that the incumbent utilities' advantage over independent power producers results in inappropriately overburdening the RERRAs.[318] MISO IPPs assert that the Revised ERAS Proposal is distinguishable from the PJM RRI, which did not treat similarly situated interconnection customers differently.[319]

126. Vistra and COMPP assert that independent power producers contracting with customers other than LSEs will require additional time to meet the participation requirements compared to vertically integrated utilities in regulated states that already have participation documents and RERRA approvals in place.[320] According to Vistra, it will be extremely difficult for independent power producers to submit all required information and receive RERRA approval in the timeframe necessary to participate in the first ERAS quarterly study period, which begins on September 1, 2025. Vistra argues, among other things, that states are not similarly situated in their capacity to respond to the new verification requirements for independent power producer interconnection requests, and that it is possible that all 10 carve out slots are immediately filled by interconnection requests in the handful of states that are best positioned to implement the verification

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[315] Constellation Protest at 5.

[316] Clean Energy Associations Protest at 13-16; Clean Energy Associations Docket No. ER25-1674 Protest at 22, 43-44; Clean Grid Alliance Protest at 25, 63, 70, 72-78; COMPP Protest at 8-9; EPSA Protest at 4-6; MISO IPPs Docket No. ER25-1674 Protest at 9; NextEra Docket No. ER25-1674 Protest at 15-17; PIOs Protest at 5-9; PIOs Docket No. ER25-1674 Protest at 9-10; Vistra Protest at 6, 9-11.

[317] Clean Grid Alliance Protest at 25.

[318] Michigan Commission Protest at 10-11.

[319] MISO IPPs Docket No. ER25-1674 Protest at 8 (citing Kelliher Aff. at 3).

[320] COMPP Protest at 8; Vistra Protest at 6.

requirements quickly.[321] Vistra and COMPP propose that the initial independent power producer carve out application window begin in alignment with the second study period, starting on December 1, 2025.[322] Alternatively, COMPP requests that MISO reserves at least two study slots for independent power producers per ERAS cycle starting in December 2025.[323]

127. Similarly, Clean Grid Alliance asserts that LSEs have long-standing relationships with RERRAs while independent power producers do not, and this provides LSEs with an advantage in accessing ERAS. Clean Grid Alliance contends that LSE interconnection requests and independent power producer interconnection requests are similarly situated but that MISO's proposed carve out is evidence that ERAS caters to LSE participation.[324] Clean Grid Alliance further contends that, if MISO intended for independent power producers and LSEs to compete on equal footing, it would allow an equal number of spots for independent power producer ERAS interconnection requests and LSE ERAS interconnection requests.[325]

128. EPSA argues that it is often not possible for retail choice LSEs to indicate the specific load it will serve due to the nature of their agreements that often supply loads through a portfolio approach.[326] EPSA also states that competitive retailers often undertake a "demonstration of need" for corporate risk and hedging purposes to compare existing and expected future contractual obligations to load with the physical positions and market exposure of the LSE.[327] Accordingly, EPSA argues that MISO should clarify that an interconnection request that asserts the need for physical hedging of risks through

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[321] Vistra Protest at 10.

[322] *Id.* at 6, 9-11; COMPP Protest at 9.

[323] COMPP Protest at 9.

[324] Clean Energy Associations Docket No. ER25-1674 Protest at 17-18 (citing Order No. 2003, 104 FERC ¶ 61,103 at P 12); Clean Grid Alliance Protest at 24-25, 74, 78 (citing Order No. 2003, 104 FERC ¶ 61,103 at P 696); *see also* PIOs Docket No. ER25-1674 Protest at 9-10 (citing *Transmission Access Pol'y Study Grp. v. FERC*, 225 F.3d at 684).

[325] Clean Grid Alliance Protest at 26.

[326] EPSA Comments at 8-9.

[327] *Id.*

the addition of a resource is sufficient to meet the forward-looking forecast option contemplated in the proposed Tariff language.

129. PIOs argue that the Revised ERAS Proposal's selection criteria may make it challenging for merchant generators to benefit from ERAS interconnection service. PIOs allege that the proposal's requirement for merchant generators, such as independent power producers seeking to serve retail choice markets, to indicate the specific load that the generating facility will serve, differs from the requirement in non-retail choice markets, where the only requirement is to have RERRA verification that the ERAS interconnection request will address a resource adequacy deficiency without identifying specific customers to be served.[328] PIOs explain that, for example, in Illinois, an independent power producer may sell capacity credits to different counterparties each year or sell into the planning resource auction, which supports resource adequacy; however, an independent power producer that intends to participate in these markets will not be able to benefit from ERAS. PIOs add that, in Michigan, there is a 10% cap on the total amount of customer load that may take supply under retail choice, which is currently met and has been for several years. PIOs state that the cap on retail choice load cannot be increased until a new load joins a utility's system, which could make it difficult for an independent power producer to contract with a new large load for retail choice before such load joins the transmission system. PIOs further explain that once a new load joins the transmission system and the cap is increased, interconnection customers already in the queue would have the first opportunity on supplying the load.

130. Clean Energy Associations state that the Commission previously rejected a proposal by Xcel Energy Operating Companies to expedite interconnection requests selected through a state-sponsored procurement process, finding that this would discriminate against customers that "are not part of the state-sponsored bidding process" and would provide transmission owners "the power to discriminate against non-affiliated generation projects."[329]

(b) ERAS Cap and Carve Outs

131. Several protesters argue that MISO's proposed cap and carve outs are arbitrary.[330] PIOs and Invenergy argue that MISO has failed to demonstrate how the proposed limit of

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[328] PIOs Protest at 13-14.

[329] Clean Energy Associations Docket No. ER25-1674 Protest at 43-44 (citing *Xcel*, 106 FERC ¶ 61,260 at PP 21, 22).

[330] EPSA Protest at 7-8; Invenergy Protest at 13; PIOs Protest at 18-20; Vistra Protest at 8.

68 ERAS interconnection requests is tailored to ensure just and reasonable rates.[331] Several protesters also argue that MISO's proposed carve outs for independent power producers and retail choice loads are discriminatory.[332]

132. PIOs argue that MISO's proposed carve out of eight ERAS interconnection requests for retail choice load does not reduce discrimination for retail choice load in Illinois and Michigan.[333] PIOs argue that MISO has not demonstrated how eight interconnection requests is an equitable approximation of those customer bases' relative sizes and projected shortfalls. PIOs contend that not requiring RERRA approval in order for ERAS interconnection requests to move forward in retail choice markets may result in ERAS interconnection requests that are not well suited to meet the state's needs.[334] Further, PIOs assert that MISO's proposed 10-day window to allow the RERRA to veto an ERAS interconnection request in retail choice markets is not enough time for such RERRAs to adequately review the proposed interconnection request.

133. PIOs argue that MISO's Revised ERAS Proposal is also unduly discriminatory because it largely excludes independent power producers from the process.[335] PIOs state that while they agree that the proposed carve out of 10 ERAS interconnection requests for independent power producers without an LSE agreement lessens the discriminatory effect of ERAS somewhat, MISO's argument that the carve out provides independent power producers with comparable access to the ERAS process is not true. PIOs state that a truly non-discriminatory process would provide independent power producers with a fair opportunity to compete for 100% of the ERAS cap, rather than 15% of the cap with no support as to how the amount was determined. PIOs further claim that splitting a cap into smaller buckets for different types of interconnection customers does nothing to establish competition that can limit costs to consumers.

134. Invenergy argues that MISO's proposed carve out for independent power producers does not make participation easier for such entities because it does not alleviate the contracting challenges in MISO, which typically require an estimate of project costs

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[331] Invenergy Protest at 13; PIOs Protest at 18.

[332] Clean Energy Associations Protest at 30-31; Clean Grid Alliance Protest at 26; COMPP Protest at 9; Constellation Protest at 6 (citing Transmittal at 25); EPSA Protest at 4-5; Illinois Commission Comments at 4-5; Invenergy Protest at 15-16; PIOs Protest at 5-6; Vistra Protest at 8, 12.

[333] PIOs Protest at 12-13.

[334] *Id.* at 13-14.

[335] *Id.* at 5-6.

before finalizing off-taker agreements.[336] Invenergy adds that MISO's requirement to contract with an LSE will raise consumer prices because contracts will be executed without knowing the full costs of a project, and such costs will be passed on to consumers.

135. Several protesters argue that the Tariff should be clarified to explain that independent power producers are eligible to participate in the initial 50 project tranche if those independent power producers are serving LSEs.[337] EPSA states that the proposed Tariff language, which states that there is a "maximum of" eight interconnection requests for retail choice load and 10 interconnection requests for independent power producers, does not properly reflect MISO's intent to allow independent power producers the opportunity to compete for the other 50 non-carve out slots.[338] Vistra suggests that the words "a maximum of" in GIP section 3.9.2 be struck and the language in GIP section 3.8.2 be clarified to reflect MISO's intent to reserve a minimum number of slots for eligible independent power producer interconnection requests to participate in ERAS, rather than to cap independent power producer project participation.[339] EPSA and COMPP similarly urge the Commission to require MISO to clarify the Tariff language.[340]

136. Clean Energy Associations argue that, in the case where an ERAS interconnection request overlaps with more than one carve out, MISO's proposed Tariff language is unclear as to whether a slot from both carve outs would be eliminated.[341] Similarly, PIOs argue that it is unclear whether an independent power producer in Michigan or Illinois with a supply agreement, not with an LSE, would qualify for the independent power producer or retail choice carve out under MISO's proposal.[342]

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[336] Invenergy Protest at 15-16.

[337] *See, e.g.*, EPSA Protest at 4-5; Illinois Commission Comments at 4-5; Vistra Protest at 8, 12 (citing MISO, Proposed Tariff, attach. X (175.0.0), §§ 3.9.2, 3.8.2).

[338] EPSA Protest at 4 (citing Transmittal at 12); *see also* COMPP Protest at 9; Vistra Protest at 12.

[339] Vistra Protest at 12 (citing to MISO, Proposed Tariff, attach. X (175.0.0), §§ 3.9.2, 3.8.2).

[340] COMPP Protest at 9; EPSA Comments at 4-5.

[341] Clean Energy Associations Protest at 30.

[342] PIOs Protest at 15.

137. Clean Energy Associations also argue that it is unclear regarding whether independent power producers can compete on equitable terms for the remaining 50 spots in ERAS because MISO's proposed Tariff language is not clear on the types of agreements it will accept for the 50 slots.[343] Clean Energy Associations explains that the "other agreement" category for the executed agreement requirement suggests that independent power producers may have agreements with entities other than LSEs and asserts that MISO should clarify that such ERAS interconnection requests are not precluded from competing for the 50 slots.[344] Additionally, Illinois Commission states that MISO's proposed language in GIP section 3.9.2 is unclear as to whether "agreements with entities other than Load Serving Entities" is intended to mean large load end users such as data centers.[345]

(c) <u>Other ERAS Eligibility Requirements</u>

138. Several protesters argue that the Revised ERAS Proposal lacks stringent and objective eligibility criteria and differentiate the ERAS eligibility requirements from RTO/ISO generator interconnection proposals that the Commission has accepted.[346] For example, MISO IPPs argue that the CAISO IPE proposal's scoring criteria appropriately incorporated state and local regulatory authorities' interests, whereas ERAS fully delegates ERAS eligibility to RERRAs.[347] Similarly, MISO IPPs and Clean Energy Associations argue that the Commission found the PJM RRI proposal's specific scoring

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[343] Clean Energy Associations Protest at 30.

[344] *Id.* at 31.

[345] Illinois Commission Comments at 5.

[346] Clean Energy Associations Docket No. ER25-1674 Protest at 43; Clean Grid Alliance Protest at 11,15; MISO IPPs Docket No. ER25-1674 Protest at 19-21 (citing CAISO IPE Order, 188 FERC ¶ 61,225 at P 94); NextEra Docket No. ER25-1674 Protest at 24 (citing MISO, Tariff, attach. X (GIP) (171.0.0), §§ 3.6, 7.9.3).

[347] MISO IPPs Docket No. ER25-167 Protest at 20 (citing CAISO IPE Order, 188 FERC ¶ 61,225 at P 123).

criteria in the tariff to be facially neutral,[348] while ERAS criteria are not facially neutral because RERRAs determine eligibility.[349]

139. Additionally, Clean Grid Alliance and NextEra contend that the ERAS financial requirements are not sufficiently stringent, conflict with MISO's recent queue reforms, and do not disincentivize speculative interconnection requests from joining ERAS.[350] NextEra argues that an interconnection customer could submit a speculative interconnection request into ERAS to determine its liability for network upgrades, withdraw after seeing the results, and receive a refund of all the fees paid minus the $100,000 D1 application fee and study costs. NextEra states that the prospect of losing $100,000 is unlikely to act as a material deterrent to the submission of speculative interconnection requests or a reliable indicator of the commercial viability of a project.[351] Clean Grid Alliance argues that the M2 payment in ERAS should be forfeited if the interconnection customer withdraws to deter speculative interconnection requests and minimize late stage restudies.[352]

140. Clean Energy Associations argue that the $100,000 D1 application fee discriminates against independent power producers.[353] Clean Energy Associations assert that, while LSEs can afford high up-front costs that they can pass along to ratepayers, independent power producers do not have this same ability, particularly in the early stages of development before they have secured financing. Clean Energy Associations argue that ERAS incents LSEs to submit interconnection requests to ERAS regardless of readiness because their ratepayers will likely bear the risk responsibility for delays, cost overruns, or stranded assets.

141. Clean Grid Alliance contends that MISO's lack of requirement for a financial security for affected system upgrades and other studies not completed by the execution of

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[348] Clean Energy Associations Docket No. ER25-1674 Protest at 43; MISO IPPs Docket No. ER25-1674 Protest at 20 (citing PJM RRI Order, 190 FERC ¶ 61,084 at P 123).

[349] Clean Energy Associations Docket No. ER25-1674 Protest at 43; MISO IPPs Docket No. ER25-1674 Protest at 20.

[350] Clean Grid Alliance Protest at 11-12, 15; NextEra Docket No. ER25-1674 Protest at 25-26.

[351] NextEra Docket No. ER25-1674 Protest at 26.

[352] Clean Grid Alliance Protest at 80-81.

[353] Clean Energy Associations Docket No. ER25-1674 Protest at 19.

an EGIA is not stringent enough and may lead to late-stage withdrawals.[354] Clean Grid Alliance further contends that the Revised ERAS Proposal's lack of provisions to address potential ERAS restudies, based on an expectation that there will not be any, is a "gamble."[355]

142. Constellation argues that that the proposal appears to impose higher and unreasonable disclosure obligations on projects serving retail choice customers.[356] DTE Electric states that the Commission should clarify that the sunset provision in MISO's proposed Tariff language does not preclude it from revisiting the sunset date if circumstances require.[357]

143. NextEra asserts that the ERAS site control requirements are not more rigorous than those applied to DPP interconnection requests,[358] and even if they were, demonstrating 100% site control is insufficient to ensure that ERAS interconnection requests are "shovel ready," as other resources that demonstrate 100% site control still encounter challenges that delay commercial operation.[359] NextEra asserts that MISO did not propose objective criteria to ensure that interconnection requests are "shovel ready," and therefore there is no assurance that ERAS interconnection requests will not be delayed similarly to DPP interconnection requests.[360]

144. PIOs argue that MISO's proposed commercial operation date requirement fails to prevent preferential treatment towards ERAS interconnection requests, which may not

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[354] Clean Grid Alliance Protest at 13.

[355] *Id.* at 13-14.

[356] Constellation Protest at 5-6.

[357] DTE Electric Comments at 5.

[358] NextEra Docket No. ER25-1674 Protest at 24-25 (citing MISO, Proposed Tariff, attach. X(GIP) (175.0.0), § 7.2.2.1(ii) (requiring customers to demonstrate 100% site control for all "Interconnection Customer's Facilities (including demonstration of switchyard site control if requested by the Transmission Provider), and, if applicable (i.e., when the Interconnection Customer is providing the site for such facilities), the Transmission Owner's Interconnection Facilities and Network Upgrades at the [Point of Interconnection] that the Interconnection Customer will develop")).

[359] NextEra Docket No. ER25-1674 Protest at 25 (citing Witmeier Rebuttal Testimony at 14).

[360] NextEra Protest at 25.

reach commercial operation for another eight years following MISO's filing.[361] PIOs also point out that MISO's commercial operation date requirements differ from those in PJM RRI, which required RRI projects to waive the one-year milestone extension provided for in PJM's generator interconnection process.[362]

(1) <u>Executed Agreement Requirement</u>

145. Several protesters argue that the executed agreement requirement unduly discriminates against different classes of interconnection customers. As evidence, they point out that pursuant to this executed agreement requirement, non-LSEs and other competitive generation developers must obtain an offtake agreement to qualify, while LSEs can simply voice an intention to self-supply.[363] Michigan Commission states that while the carve out for 10 independent power producer interconnection requests is helpful, incumbent utilities can self-supply while independent power producers must take an additional step of having an executed agreement or work with an LSE to meet a resource adequacy need.[364] Several protesters similarly assert that the requirement for independent power producers contracting with LSEs to submit an executed agreement to achieve the first stage of eligibility fails to provide access to independent power producers on a comparable and sufficiently non-discriminatory basis.[365] Several protesters assert that this is an additional, unfair burden that limits competitive independent power producers' viability in ERAS.[366] EPSA requests that the Commission require MISO to remove these requirements for independent power producers or, at a minimum, that the Commission delay the due date for ERAS submission for the independent power producer carve outs, which would allow time for MISO states to

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[361] PIOs Protest at 25.

[362] *Id.* at 26 (citing PJM RRI Order, 190 FERC ¶ 61,084 at P 265).

[363] Clean Energy Associations Protest at 31; Clean Energy Associations Docket No. ER25-1674 Protest at 11-17; Clean Grid Alliance Protest at 26-27, 75; MISO IPPs Docket No. ER25-2674 Protest at 12-13; NextEra Docket No. ER25-1674 Protest at 36-38; PIOs Protest at 5; PIOs Docket No. ER25-1674 Protest at 10-12.

[364] Michigan Commission Protest at 10.

[365] Clean Energy Associations Docket No. ER25-1674 Protest at 11-17; EPSA Comments at 5; Invenergy Protest at 7; Michigan Commission Protest at 10; MISO IPPs Docket No. ER25-1674 Protest at 12-13; NextEra Docket No. ER25-1674 Protest at 37-38; PIOs Protest at 5; PIOs Docket No. ER25-1674 Protest at 11.

[366] Clean Energy Associations Docket No. ER25-1674 Protest at 11-17; Clean Grid Alliance Protest at 61-62.

determine the RERRA verification process for independent power producer interconnection requests, and for all independent power producers to negotiate the required agreements and meaningfully participate in the ERAS process.[367] Invenergy argues that it is unclear how independent power producers may present contracts to RERRAs under MISO's proposal, particularly where some state laws prohibit interconnection customers from making requests to RERRAs.[368]

146. MISO IPPs, Clean Energy Associations, Clean Grid Alliance, PIOs, and NextEra assert that independent power producers and load typically execute agreements after receiving cost estimates to appropriately price the agreement before execution.[369] Accordingly, these entities argue that the Revised ERAS Proposal discriminates against non-LSEs because ERAS is either non-viable for non-LSEs or is more stringent than the self-supply acknowledgement.[370] Clean Energy Associations assert that because some network upgrade costs will not be known in time to execute a durable offtake agreement, this may harm reliability needs and could cause disruption without benefit, as purchasers would sign a PPA that may lead to over-procurement to avoid contract termination or dropping out of ERAS altogether.[371]

147. NextEra and PIOs contend that independent power producers may not be able to enter ERAS unless an LSE grants the independent power producer an agreement or otherwise cooperates with the independent power producer, which, in effect, allows LSEs to choose which resources qualify for ERAS.[372] NextEra asserts that the CAISO IPE proposal gave independent power producers realistic opportunities to obtain interconnection service, but that ERAS does not have any of the CAISO IPE proposal's

[367] EPSA Comments at 5-6.

[368] Invenergy Protest at 5.

[369] Clean Energy Associations Docket No. ER25-1674 Protest at 12, 49; Clean Grid Alliance Protest at 74-75; MISO IPPs Docket No. ER25-1674 Protest at 13; NextEra Docket No. ER25-1674 Protest at 36-37; PIOs Docket No. ER25-1674 Protest at 11-12.

[370] Clean Energy Associations Protest at 13-16; Clean Grid Alliance Protest at 61-62; MISO IPPs Docket No. ER25-1674 Protest at 13; NextEra Docket No. ER25-1674 Protest at 36-37.

[371] Clean Energy Associations Docket No. ER25-1674 Protest at 13-15.

[372] NextEra Docket No. ER25-1674 Protest at 38; PIOs Docket No. ER25-1674 Protest at 10.

guardrails to ensure no undue discrimination against independent power producers.[373] Additionally, NextEra asserts that the risk of undue discrimination is exacerbated by ERAS allowing some entities, like cooperatives, to be both LSEs and RERRAs, which may incentivize the entity to prevent independent power producers from obtaining access to ERAS to protect the competitive advantage of its resources.[374] NextEra asserts that the Commission has historically rejected proposals that disadvantage independent power producers and other non-incumbents, citing to a PacifiCorp proposal that had different commercial readiness demonstration options for LSEs and independent power producers[375] and a Public Service Company of Colorado proposal that had commercial readiness criteria that were "likely too stringent for independent power producers to meet."[376] NextEra further asserts that, in Order No. 2023, the Commission declined to adopt requirements and criteria for demonstrating commercial readiness by submitting an executed term sheet or an executed PPA because these "may not be workable in markets where merchant sales are common."[377]

148. Clean Grid Alliance argues that independent power producers do not have access to information about load that "meet[s] an identified resource adequacy and/or reliability need," either at all or at the same time/level as LSEs.[378] Clean Grid Alliance also argues that the ERAS proposal will send the wrong market signals and stifle competition because it denies independent power producers' meaningful participation and restricts competition.[379]

149. Clean Grid Alliance further argues that ERAS unduly preferences LSEs because an LSE can submit an expedited process review as an exception to the standard MISO Transmission Expansion Plan (MTEP) process to include transmission to serve such spot load, which may make obtaining a RERRA certification easier, while an independent

[373] NextEra Docket No. ER25-1674 Protest at 39 (citing CAISO IPE Order, 188 FERC ¶ 61,225 at PP 174, 176).

[374] *Id.* at 38.

[375] *Id.* at 34 (citing *PacifiCorp*, 171 FERC ¶ 61,112, at PP 68-69 (2020)).

[376] *Id.* at 35 (citing *Pub. Serv. Co. of Colo.*, 183 FERC ¶ 61,166, at P 65 (2023) (*PSCo*)).

[377] *Id.* at 35-36 (citing Order No. 2023, 184 FERC ¶ 61,054 at PP 614-615, 696-98).

[378] Clean Grid Alliance Protest at 73.

[379] *Id.* at 61-62.

power producer cannot.[380] Additionally, Clean Grid Alliance contends that independent power producers will face greater barriers to exit the DPP due to the withdrawal penalties than LSEs, which have a safety net with costs backstopped through the state public utility commission.[381] Accordingly, protesters assert that the executed agreement requirement in ERAS is an additional, unfair burden that limits competitive independent power producers' viability.

(2) <u>Local Resource Zone</u>

150. PIOs argue that MISO's proposed requirement that an ERAS interconnection request must be located within the same Local Resource Zone as the load it will serve, unless the project was included in a resource filing or other submission to the RERRA, adds another element of discrimination.[382] Invenergy argues that the proposed Local Resource Zone requirement artificially constrains the number of eligible interconnection requests that might be suited to serve a resource adequacy need.[383]

151. PIOs further argue that the structural differences in relationship with the RERRA for independent power producers compared to LSEs will make it significantly harder for independent power producers to ensure that a project located outside of a Local Resource Zone is included in a resource filing or submission before the RERRA.[384] Relatedly, Constellation argues that it is "beyond dispute" that a generating facility in one Local Resource Zone can serve load in another, and it is therefore unduly discriminatory for MISO to propose excluding an interconnection request for consideration in ERAS simply because the proposed generating facility is located in a different Local Resource Zone.[385] Constellation asserts that MISO's proposed exception in this respect does not change that. Further, Constellation argues that MISO has not explained what "resource filing or other submission made to the RERRA" would satisfy this requirement, particularly in retail choice states.

[380] *Id.* at 73-74.

[381] *Id.* at 79.

[382] PIOs Protest at 9.

[383] Invenergy Protest at 12.

[384] PIOs Protest at 9.

[385] Constellation Protest at 7.

(3) Requested Interconnection Service May Not Exceed 150% of Identified Need

152. Michigan Commission and PIOs argue that, by capping interconnection requests at 150% of the identified need, the Revised ERAS Proposal effectively excludes renewable energy project participation and unfairly tilts the scales in favor of thermal generation.[386] PIOs explain that any new generation resource seeking interconnection needs interconnection service that matches its nameplate capacity, or it will be forced to curtail its output regularly.[387] PIOs argue that, as a result, ERAS effectively eliminates any resource receiving less than 67% capacity accreditation because such resources would have to request interconnection service in excess of 150% of the identified MW need to match the nameplate capacity.[388] PIOs further argue that MISO fails to engage with the fact that wind and solar resources receive significantly lower accreditation than other generation facility types and will therefore be uniquely impacted.[389] PIOs add that data presented at recent stakeholder meetings demonstrate that accredited values for renewable generation fell below 67%.[390] PIOs assert that MISO's discriminatory approach in the ERAS process cannot be justified because it is not tailored to meet MISO's stated resource adequacy and reliability needs.

153. Michigan Commission contends that the Initial ERAS Proposal, which capped interconnection requests at 125% of identified need and based the requirement on accredited capacity, instead of interconnection service, had a closer link to resource adequacy needs and was more equitable across fuel types. Michigan Commission asserts that in the alternative, if the amount remains based on interconnection service, the cap

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[386] Michigan Commission Protest at 14-15; PIOs Protest at 10-11.

[387] PIOs Protest at 10.

[388] *Id*. PIOs further explain that, for example, "To meet a resource adequacy need of 100 MW, a resource with, e.g., 50% capacity accreditation would need to build to 200 MW of nameplate capacity, but Interconnection Service at that level would exceed MISO's proposed 150% limit." *Id*.

[389] *Id.* at 11.

[390] *Id.* (citing MISO, Resource Adequacy Subcommittee (RASC), *LOLE Modeling Enhancements Storage Modeling* 19 (Apr. 9, 2025), https://cdn.misoenergy.org/20250409%20RASC%20Item%2008%20LOLE%20Modeling%20Enhancements%20St orage%20Modeling689245.pdf (using "even loss" values pursuant to MISO's proposed modeling approach in that presentation)).

should be raised to 200% to allow for renewable projects to participate and assuage discriminatory concerns.[391]

154. Clean Energy Associations also argue that the new requirement that the amount of interconnection service requested must not exceed 150% of the identified MW need will functionally cap intermittent resources and does not better link the claimed resource adequacy need and the proposed interconnection request, contrary to MISO's claim.[392]

iii. Answers

(a) MISO Answer

155. MISO states that it started with a base of 50 interconnection requests similar to the PJM RRI but ultimately proposed additional carve outs for 10 independent power producer interconnection requests and eight retail choice interconnection requests to reflect its unique environment that includes two retail choice states.[393] MISO argues that this cap, along with the 10 interconnection request limit per ERAS quarterly study period, will enable MISO to work efficiently on both ERAS and DPP studies. MISO explains that it determined a cap of eight interconnection requests for retail choice states based on internal analysis and discussion with retail choice states.[394] MISO asserts that a cap of eight interconnection requests for retail choice states strikes the right balance to proportionately allocate interconnection requests to retail choice states, based on the portion of MISO's footprint that those states represent.[395] MISO clarifies that the two carve outs are separate.

156. In response to protests that the 10-day RERRA review period is insufficient, MISO states that the 10-day timeframe, which was originally agreed to by stakeholders, is not intended to be a comprehensive review of the interconnection requests.[396]

157. MISO further clarifies, in response to Constellation, that the Revised ERAS Proposal does not impose higher obligations on interconnection requests serving retail

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[391] Michigan Commission Protest at 15.

[392] Clean Energy Associations Docket No. ER25-1674 Protest at 10.

[393] MISO Answer at 13-14.

[394] *Id.* at 15.

[395] *Id.* (citing Witmeier Testimony at 37).

[396] *Id.* at 16.

choice customers.[397] MISO states that it is requiring the same non-confidential information from all ERAS interconnection requests and has created a process to allow interconnection customers serving retail choice customers to participate in ERAS. MISO further states that while it recognizes that retail load in Michigan is already fully provided for, it cannot require the states to serve resource adequacy needs in certain ways and is simply providing a tool for states with resource adequacy needs.[398]

158. MISO asserts that the purpose of the independent power producer carve out is to address claims that LSEs could block independent power producers from participating in the ERAS process.[399] MISO clarifies that independent power producers may also submit interconnection requests in the remaining group of 50 ERAS interconnection requests so that the independent power producer carve out functions as a guaranteed floor of 10 independent power producer-only interconnection requests. MISO answers that it opposes a delay in the due date for ERAS submission for the independent power producer carve out because it is impractical and administratively burdensome.[400]

159. MISO asserts that a ranking or scoring process is not appropriate because MISO does not believe that it should prescribe to a state or RERRA which interconnection requests should be selected.[401] MISO states that a state or RERRA can implement their own scoring or ranking criteria, but it is ultimately the state's role, not MISO's, to determine the resources that will be utilized in their jurisdiction due to the unique jurisdictional divide under the FPA. Thus, MISO states that it will not specify a state process, regardless of protesters' arguments that doing so would be more transparent or otherwise preferable.

160. MISO contends that the new RERRA verification requirement provides states and RERRAs with different regulatory review processes necessary flexibility and does not supplant these review processes.[402] MISO states that an interconnection request approved to participate in ERAS must still receive approval through the state's corresponding regulatory review process, thus ensuring that the RERRA verification does not pre-determine any outcome of an applicable state process. MISO further asserts that it cannot

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[397] *Id.* at 17.

[398] *Id.* at 18.

[399] *Id.* at 19.

[400] *Id.* at 20.

[401] *Id.* at 24-25.

[402] *Id.* (citing Transmittal at 31; MISO Proposed Tariff, attach. X (GIP), § 3.9.1).

and should not mandate a set review process with pre-determined characteristics that supplant the RERRA's determinations with its own. MISO believes that RERRAs are the appropriate entity to select ERAS participants, especially with the Revised ERAS Proposal's guardrails. MISO disagrees with protesters that RERRAs will be incentivized to provide a verification for certain interconnection requests because the interconnection requests would need to receive approval through a full state review process. Finally, MISO states that the Revised ERAS Proposal balances respect for states' jurisdictions over their own resource mixes with requiring sufficient information and verification from the RERRA that the proposed interconnection requests is appropriate for ERAS.[403]

161. In response to Michigan Commission's opposition to a RERRA verification relying on a state energy forecast or other forward-looking forecast as support, and its contention that this is too broad as to allow nearly any interconnection request to qualify, MISO argues that it believes that it is a RERRA's prerogative to determine what supporting information to utilize.[404] MISO further argues that it believes that it is not appropriate for one state to dictate the supporting information that another state uses. MISO further explains that it is not the resource planner for the states within its footprint, and the RERRA verification requirement will tighten the nexus between the proposed ERAS interconnection request and an identified resource adequacy and/or reliability need. MISO additionally contends that the Local Resource Zone requirement will tighten the nexus between the RERRA-verified interconnection request and the resource adequacy need.[405] MISO asserts that the RERRA verification and executed agreement requirements provide strong evidence that an interconnection request's output will be used by the designated load.

162. In response to protesters' arguments regarding *Xcel*, MISO states that the Commission determined that the process in that case was unduly discriminatory because it excluded interconnection customers that did not participate in the state-sponsored bidding process.[406] MISO contends that this is not the case with the ERAS process because it is open to all applicants, not just those involved in a state solicitation process.

163. MISO states that the arguments that LSEs will exert undue influence over which resources qualify for ERAS by refusing to enter into agreements with competing

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[403] *Id.* at 25-26.

[404] *Id.* at 24.

[405] *Id.* at 26-27 (citing Tab A, (Witmeier Docket No. ER25-1674 Rebuttal Testimony, at 10).

[406] MISO Docket No. ER25-1674 Answer at 16-17 (citing *Xcel*, 106 FERC ¶ 61,260 at P 22).

interconnection customers assumes counterintuitive behavior from LSEs and load drivers that should reasonably select the most preferable project option.[407] MISO argues that ERAS does not require nor encourage the selection of an LSE's project over another equally beneficial project, and regardless, the executed agreement requirement will severely limit the possibility of this occurring. MISO also contends that while LSEs that own generation may self-supply, they still must receive approval from the RERRA.[408] Additionally, MISO states that any disadvantage experienced by independent power producers in this competition is not a result of ERAS.[409] MISO also notes that ERAS is not intended to work for the majority of interconnection requests but to be a unique, time-limited process for "shovel ready" projects to address near-term load needs.[410]

164. MISO argues that, contrary to protester assertions, the ERAS process is intended to be complementary to the state regulatory review process that ensures that projects are necessary, cost-effective, and in the public interest.[411] MISO further clarifies that while an interconnection request must include a RERRA verification to participate in ERAS, that does not guarantee acceptance into ERAS, and the other eligibility requirements will ensure that an interconnection request is "shovel ready."[412]

165. MISO states that while it considered a scoring approach, it ultimately determined that because of MISO's composition, states should be left to determine their own resource adequacy needs.[413] MISO additionally states that ERAS does not need scoring criteria because its strict eligibility requirements ensure that only projects that are truly commercially ready can participate.[414]

166. In response to concerns that the executed agreement requirement is unduly discriminatory toward independent power producers, MISO states that ERAS is structured to encourage negotiation and agreement to occur earlier in the planning

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[407] *Id.* at 25.

[408] *Id.* at 28.

[409] *Id.* at 25.

[410] *Id.* at 27.

[411] *Id.* at 18.

[412] *Id.* at 19.

[413] *Id.* at 31.

[414] *Id.* at 32.

process. MISO states that it has found that DPP interconnection customers without PPAs cited the lack of a PPA as the reason for their commercial operation date delay. MISO also states that it permits flexibility by not requiring detail in these agreements beyond that they will meet the load's identified resource adequacy need.[415]

167. MISO clarifies that it limited ERAS interconnection requests to 150% of the identified need based on the MW of interconnection service requested, not based on nameplate or accredited capacity.[416] MISO asserts that ERAS is focused on interconnection service rather than accredited capacity because it is resource neutral and only focused on "shovel ready" projects.[417]

168. In addition, MISO provides several clarifications regarding the purpose and use of proposed ERAS fees, milestones, and payments. MISO explains that, if an ERAS application is deemed ineligible, the non-refundable D1 application fee will be used for costs related to managing the ERAS process and that the application fee also serves to ensure only "shovel ready" projects are submitted.[418] MISO also clarifies that, with regard to proposed GIP provisions specifying that ERAS interconnection customers are eligible for a refund of the "remaining" M2 milestone upon withdrawal after GIA execution, the remaining M2 milestone would be what remains after meeting the initial milestone payment and/or the network upgrade costs memorialized in the EGIA.[419] MISO explains that any refund of the M2 milestone after GIA execution assumes that either the interconnection request did not result in network upgrades or that those network upgrades were less than the M2 milestone. In addition, MISO explains that an ERAS interconnection customer is liable for the network upgrade costs regardless of whether those costs are covered by the initial payment requirement under the EGIA or financial security rules. MISO reiterates that ERAS interconnection customers are responsible for any remaining network upgrade costs documented in the EGIA, and any corresponding facilities construction agreements or multi-party facilities construction agreements, even if the ERAS interconnection customer withdraws after EGIA execution.[420] Finally, MISO explains that, regarding whether transfer of ownership of

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[415] *Id.* at 28-29.

[416] MISO Answer at 28.

[417] *Id.* at 28-29.

[418] *Id.* at Tab B, MISO Supplemental Answer, Docket No. ER25-1674-000 (filed Apr. 29, 2025), at 3 (MISO Docket No. ER25-1674 Supplemental Answer).

[419] MISO Docket No. ER25-1674 Supplemental Answer at 6.

[420] *Id.* at 7 (citing MISO, Proposed Tariff, attach. X (GIP) (169.0.0), § 3.9.6.3).

ERAS projects after EGIA execution also transfers the load obligation, the commercial terms to address project transfer are outside the scope of the ERAS process.

(b) <u>Additional Answers</u>

169. In response to MISO's answer, Clean Grid Alliance argues that the ERAS process, unlike the DPP, is not an open or non-discriminatory process.[421] Instead, Clean Grid Alliance argues that the ERAS process makes LSEs, which "have an incentive to favor their own generation a gatekeeper for new generation."[422] Clean Grid Alliance further contends that FPA section 205 requires MISO to affirmatively demonstrate that its proposal is not unduly discriminatory and will not result in the unintended consequences discussed by protesters.[423] Clean Grid Alliance asserts that attempts to distinguish *Xcel* are unconvincing because the unduly discriminatory outcome that the Commission rejected there, where "Interconnection Customers that [did] not take part in . . . state-sponsored bidding [could not] compete . . . on an equal footing"[424] is "akin to" that presented by the ERAS proposal.[425] More specifically, Clean Grid Alliance claims that the executed agreement requirement, which requires "*some* kind of agreement in place with an LSE," prevents independent power producers from competing with LSEs on equal footing.[426] Clean Energy Alliance further avers that Order No. 2003 makes clear that the Commission should not approve deviations from its *pro forma* LGIP that provide "the mere opportunity for LSE (transmission owner) preference" and that the opportunity for undue discrimination is intrinsic to the ERAS proposal.[427]

170. Further, Clean Grid Alliance argues that MISO fails to support its claim that it worked closely with states to ensure that independent power producers have comparable

[421] Clean Grid Alliance Docket No. ER25-1674 Answer at 3-4.

[422] *Id.*

[423] *Id.* at 4 (citing *Midcontinent Indep. Sys. Operator, Inc.*, 154 FERC ¶ 61,247, at P 77 (2016)).

[424] *Id.* at 5 (citing *Xcel*, 106 FERC ¶ 61,260 at P 23).

[425] Clean Grid Alliance Docket No. ER25-1674 Answer at 5.

[426] *Id.* at 5-6 (quoting MISO Docket No. ER25-1674 Answer at 25 (emphasis in original)).

[427] *Id.* at 6 (citing Order No. 2003, 104 FERC ¶ 61,103 at P 696).

ability to participate in the ERAS process.[428] Additionally, Clean Grid Alliance asserts that it has cited "ample" precedent to support a finding that LSEs have an incentive to favor their own generation.[429] Clean Grid Alliance claims that the ERAS proposal is unduly discriminatory by providing an "exclusive preferential fast track for priority access to transmission headroom over DPP project to RERRA-anointed projects."[430] To this point, Clean Grid Alliance contends that ERAS interconnection requests enjoy penalty-free withdrawal during the study process, an advantage over DPP interconnection requests, and that relaxing DPP rules conflicts with MISO's claim that ERAS interconnection requests are "shovel ready." Further, Clean Grid Alliance argues that there is undue preference with respect to the ERAS power flow study dispatch over the DPP power flow study dispatch that "significantly lowers" the cost of interconnection for ERAS interconnection requests.[431]

171. Clean Grid Alliance asserts that MISO has not justified the proposed cap of 68 interconnection requests to be studied in ERAS. Specifically, Clean Grid Alliance avers that MISO's statement that it chose to cap LSE ERAS interconnection requests at 50, because that was the cap for the PJM RRI, is unreasonable because MISO has different resource needs than PJM and, further, that ERAS does not resemble the PJM RRI construct.[432]

172. Additionally, Clean Grid Alliance asserts that MISO does not justify allocating only 10 interconnection requests to independent power producers when LSEs have nearly unfettered access to the bulk of the ERAS interconnection request slots, to which LSEs can impose barriers to independent power producers' access.[433] Clean Grid Alliance asserts that RERRAs will not be able to verify ERAS interconnection requests submitted by independent power producers over those submitted by LSEs because LSEs will be able to deny agreements to independent power producers and reserve the 50 ERAS interconnection request slots for their own ERAS interconnection requests. Clean Grid Alliance avers that this is unduly discriminatory and preferential because independent

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[428] *Id.* at 7.

[429] *Id.* at 8 (citing *Nat. Ass'n of Reg. Util. Comm'rs v. FERC*, 475 F.3d 1277, 1279 (D.C. Cir. 2007); *Xcel Energy Servs., Inc. v. FERC*, 41 F.4th 548, at 561 (D.C. Cir. 2022)).

[430] *Id.* at 8-9.

[431] *Id.* at 9-10.

[432] Clean Grid Alliance First Answer at 10.

[433] *Id*. at 13-14.

power producers and LSEs are similarly situated because both entities seek to develop generation to serve load. Clean Grid Alliance adds that an LSEs' obligation to serve does not justify the undue discrimination created by the Revised ERAS Proposal.[434]

173. Clean Grid Alliance argues that, due to the reliability gaps resulting from MISO's proposed study modeling approach, the Revised ERAS Proposal conflicts with open access principles.[435]

174. MISO IPPs argue that the Commission cannot assume that there will be no undue discrimination or preference, or rely on RERRAs to see to that outcome, when MISO's Tariff language does not provide a reasoned basis for concluding that MISO has guarded against undue discrimination or preference.[436] MISO IPPs state that MISO's answer incorrectly defends that undue discrimination or preference as either a necessary feature or a harmless byproduct of its regulatory model.[437] More specifically, MISO IPPs argue that this proceeding is about interconnection service, which is within the Commission's exclusive jurisdiction under the FPA, and that the Commission is obligated to prevent undue discrimination or preference within its jurisdiction regardless of the MISO state's role in maintaining resource adequacy.[438] MISO IPPs also state that MISO's valid resource adequacy needs are a non-sequitur that does not excuse a violation of the statutory prohibition on treating similarly situated entities differently.[439] MISO IPPs aver that MISO's suggestion that RERRAs would not engage in discriminatory or preferential behavior because each ERAS project will still require state permits is not enough to meet MISO's burden under FPA section 205.[440]

175. MISO IPPs also state that the proposed carve out for 10 ERAS interconnection requests that may be submitted by independent power producers is unjustified and unduly discriminatory. MISO IPPs argue that MISO's answer, which states that independent power producers can also compete with the general group of 50 ERAS interconnection requests, does not resolve the undue discrimination concerns with the Revised ERAS

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[434] Clean Grid Alliance Docket No. ER25-1674 Answer at 14.

[435] Clean Grid Alliance First Answer at 8.

[436] MISO IPPs Answer at 4.

[437] *Id.* at 5.

[438] *Id.* at 5-7.

[439] *Id.* at 7-8.

[440] *Id.* at 8 (citing MISO Answer at 25).

Proposal's cap and carve outs because the 50 slots allotted for LSEs will be controlled by vertically integrated utilities.[441] MISO IPPs argue that MISO has not justified why LSEs should have five times as many slots to submit ERAS interconnection requests.[442]

176. MISO IPPs argue that the Local Resource Zone requirement is unduly discriminatory. Specifically, MISO IPPs argue that the proposed requirement that an ERAS interconnection request only be included in an integrated resource plan filing, instead of approved by a RERRA, is not relevant to the determination of whether the interconnection request is better situated than others to meet the resource adequacy or reliably need in question.[443] MISO IPPs aver that this requirement is susceptible to gaming by LSEs that can adjust their integrated resource plan filings.[444] MISO IPPs further argue that MISO's answer does not explain how the Local Resource Zone requirement will address import-export concerns simply because the interconnection request is proposed in an integrated resource plan.[445]

177. Clean Energy Associations assert that the extent to which MISO will permit independent power producers to compete on equitable terms for the remaining 50 ERAS interconnection request spots remains unresolved by MISO's answer.[446] Clean Energy Associations state that MISO clarifies that, although independent power producers can compete for the 50 ERAS interconnection request spots, "projects submitted by [independent power producers] without LSEs are maxed out at 10 projects."[447] Clean Energy Associations assert that MISO's interpretation does not align with the plain language of the Tariff because the proposed Tariff language does not state that an entity must be an LSE to be eligible to compete for the 50 ERAS interconnection request spots.[448]

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[441] *Id.* at 9-10 (citing MISO Answer at 19).

[442] *Id.* at 10.

[443] *Id.* at 12.

[444] *Id.*

[445] *Id.* (citing MISO Answer at 27).

[446] Clean Energy Associations Answer at 5-6 (citing Clean Energy Associations Protest at 30).

[447] *Id.* at 6 (citing MISO Answer at 19).

[448] *Id.* at 6-7 (citing MISO, Proposed Tariff, attach. X (175.0.0), § 3.9.1(2)(b)).

178. Clean Energy Associations argue that the 10 ERAS interconnection request carve out for independent power producers without an LSE contract is a permission structure for discrimination that contradicts well-established open access principles.[449] Clean Energy Associations assert that, under MISO's interpretation of the Tariff language, independent power producer interconnection requests will be at a disadvantage relative to LSE-owned or affiliated interconnection requests because the requirement to have a contract with an LSE puts the LSE in a gatekeeper role.[450] Furthermore, Clean Energy Associations argue that, by requiring that ERAS generating facilities must serve new load not accounted for in a resource plan or address a resource adequacy deficiency, independent power producers will be at an additional disadvantage because only the RERRA and LSE are likely to know what new load is unaccounted for in a resource plan.[451] Clean Energy Associations assert that the disadvantage faced by independent power producer interconnection requests relative to LSE-owned or affiliated interconnection requests results in a failure by MISO to address the preferential treatment for LSE projects and undue discrimination against independent power producer projects without LSE involvement.[452]

179. Clean Energy Associations contend that MISO's answer did not sufficiently respond to their claim that the 150% nameplate cap would only allow thermal resources to participate in ERAS; rather, MISO merely stated that its approach is resource neutral.[453] Clean Energy Associations assert that MISO ignores that the eligibility of planning resources to provide resource adequacy benefits depend on interconnection service in addition to capacity accreditation. Accordingly, Clean Energy Associations assert that, while remaining facially neutral as to which resources request it, the 150% limitation will operate as a functional bar on certain resources meeting an identified need. Clean Energy Associations argues that this approach will likely prevent non-thermal resources from being considered to meet identified needs because RERRAs and project sponsors are unlikely to consider solutions that would leave a substantial amount of capacity unstudied and incapable of being delivered.[454]

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[449] *Id.* at 8.

[450] *Id.* at 7 (citing Clean Energy Associations Protest at 27-30).

[451] *Id.* (citing Clean Energy Associations Protest at 14).

[452] Clean Energy Associations Answer at 7.

[453] *Id.* at 10 (citing MISO Answer at 29).

[454] *Id.* at 11.

180. PIOs argue that MISO's proposal requiring an ERAS interconnection customer to request interconnection service of no more than 150% of the identified need discriminates against renewable generating resources because it would require such resources to interconnect at a level that prevents them from full economic dispatch. PIOs further argue that this is true even if a renewable generator is paired with battery storage, which PIOs allege would become a prerequisite for renewable generators' participation in ERAS in practice. PIOs contend that this requirement would result in renewable generators being limited in their ability to fully participate in times of increased demand and could impact utilities' future resource planning if renewable generators are limited in their output.[455]

181. PIOs argue that MISO's answer does not address PIOs' concern regarding the adequacy of oversight for the RERRA verification requirement.[456] PIOs contend that MISO did not make meaningful changes to the RERRA role in the Revised ERAS Proposal compared to the Initial ERAS Proposal.[457] PIOs further contend that, in its answer, MISO continues to refuse the adoption of any standard for the RERRA verification to explain how it weighs the merits of similarly situated interconnection requests for participation in ERAS, despite concerns raised by protesters and in Commissioner See's concurrence.[458] PIOs argue that the Revised ERAS Proposal may create reliance on a state or other forward-looking energy forecast as a supporting factor.[459] PIOs further argue that, as the Michigan Commission notes, this aspect of MISO's proposal would allow any interconnection request to be eligible for ERAS as long as a forecast supports it. PIOs contend that, as a result, utility-funded analyses could be utilized to support such forecasts with no quality standards in place. PIOs assert that MISO's inclusion of "other forward-looking forecast" in its Tariff obliges MISO to accept a RERRA verification based on such a forecast.[460]

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[455] PIOs Answer at 7.

[456] *Id.* at 9.

[457] *Id.* at 10.

[458] *Id.* at 10-11 (citing MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.1).

[459] *Id.* at 12.

[460] *Id.* (citing 18 C.F.R. § 35.1(e) (2024) ("No public utility shall, directly or indirectly, demand, charge, collect or receive any rate, charge or compensation for or in connection with electric service subject to the jurisdiction of the Commission, or impose any classification, practice, rule, regulation or contract with respect thereto, which is different from that provided in a rate schedule required to be on file with this

iv. Supplemental Answers

(a) MISO Supplemental Answer

182. MISO states that it intends for independent power producers to be able to compete for the 50 ERAS interconnection request spots regardless of whether the independent power producer's proposed interconnection request includes an agreement with an LSE.[461] MISO states that each of the proposed carve out groups are separate from each other and independent power producers may submit interconnection requests in each group.[462] MISO states that independent power producers without agreements with LSEs that submit interconnection requests to ERAS will first be counted towards the 10 independent power producer-only ERAS interconnection request carve out before being counted to the 50 ERAS interconnection request slots shared with LSEs serving non-retail choice loads.[463]

183. MISO states that the Revised ERAS Proposal is crafted to ensure that all interconnection customers can submit interconnection requests to ERAS for all states in the MISO footprint.[464] MISO explains that the carve out for independent power producers provides a safety net for independent power producers to ensure that they have access to at least 10 spots. MISO further explains that it adopted this carve out in the Revised ERAS Proposal to address stakeholder concerns that independent power producers could be precluded from participating in ERAS by LSEs fully subscribing the cap before independent power producers could submit their interconnection requests or by LSEs refusing to execute agreements with independent power producers.

184. MISO acknowledges that some commenters continue to interpret the proposed Tariff language in GIP section 3.9.2 as capping the number of ERAS interconnection requests that may be submitted by independent power producers, that do not have an agreement with an LSE, to 10. Therefore, MISO states that it would welcome a

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Commission unless otherwise specifically provided by order of the Commission for good cause shown.")).

[461] MISO Supplemental Answer at 3.

[462] *Id*. MISO also clarifies that ERAS interconnection requests addressing retail choice loads may only apply for the retail choice carve out regardless of the entity submitting the interconnection request.

[463] *Id.* at 4.

[464] *Id.*

compliance directive from the Commission requiring MISO to include in its GIP section 3.9.2, in relevant part, the following clarifying revisions:[465]

> The Transmission Provider will evaluate Expedited Resource Addition Study requests in the order in which they are submitted using the time stamp from submission. The Transmission Provider will limit the maximum number of the ERAS Interconnection Requests studied in the ERAS process to no more than 68 projects total until the sunset date noted in Section 3.9.9. The Transmission Provider has carved out a maximum of 8 Interconnection Requests of the total 68 Interconnection Requests that may be submitted in accordance with 3.9.1.1(iii) to serve retail choice load and ~~a maximum of~~ 10 Interconnection Requests of the total 68 Interconnection Requests that may be submitted by Independent Power Producers (IPPs) with agreements with entities other than Load Serving Entities to ERAS until the sunset date noted in Section 3.9.9. <u>The remaining 50 Interconnection Requests of the total 68 Interconnection Requests may be submitted by IPPs or Load Serving Entities (LSEs) to serve non-retail choice load. Interconnection Requests submitted by IPPs with agreements with entities other than LSEs to ERAS will be counted first towards the 10 Interconnection Requests cap of the total 68 Interconnection Requests before the 50 Interconnection Requests to serve non-retail choice load. After the 10 Interconnection Requests submitted by IPPs with agreements with entities other than LSEs are accepted by the Transmission Provider, any subsequent Interconnection Request submitted by IPPs will count toward the remaining 50 Interconnection Requests to serve non-retail choice load.</u>[466]

(b) <u>Additional Supplemental Answers</u>

185. Vistra states that it supports MISO's proposed Tariff language regarding the carve out for independent power producer interconnection requests and asserts that the Commission should direct MISO to adopt such language on compliance. However, Vistra reiterates its argument that the timeline for independent power producers contracting with non-LSEs is too aggressive for such independent power producers to meaningfully participate in ERAS. Specifically, Vistra states that independent power producers contracting with non-LSEs would have to obtain an executed agreement and a RERRA verification by August 11, 2025, which is only days after the requested effective

[465] The strikeout text represents MISO's proposed deletions while the underlined text represents MISO's proposed additions.

[466] MISO Supplemental Answer at 5-6.

date for the instant filing.[467] Vistra contends that this timeline will result in the ten ERAS interconnection spots for independent power producers contracting with non-LSEs to be immediately filled by projects in states that can provide RERRA verifications immediately or by smaller projects that can complete applications quickly.[468] Vistra argues that MISO provides no explanation for its position that extending the timeline for independent power producers contracting with non-LSEs is impractical and burdensome.[469] Vistra further argues that adjusting the timeline would have no effect on the other categories of ERAS interconnection requests or the overall pace of ERAS and that adjusting the timeline would make ERAS more effective.[470]

186. Clean Grid Alliance argues that the MISO Supplemental Answer and proposed Tariff language demonstrates that the Revised ERAS Proposal violates the FPA's competition mandates. Clean Grid Alliance asserts that MISO has not addressed why 10 ERAS interconnection requests are reserved for independent power producers, while 50 ERAS interconnection requests are reserved for LSEs.[471] Clean Grid Alliance further contends that MISO has not addressed the potential for LSEs to unilaterally veto contracts with an independent power producer that apply for the 50 ERAS interconnection requests spots and instead prioritize their own generation resources for ERAS.[472] Clean Grid Alliance argues that the Revised ERAS Proposal lacks a requirement for RERRAs to openly consider proposals from independent power producers, allowing unilateral and unchecked applications by LSEs.

187. Michigan Commission argues that a "retail choice load" and "retail choice state" should be considered separate and distinct classifications for ERAS purposes. Michigan Commission notes that retail choice accounts for a very small portion of the state's electrical supply in the state of Michigan. Michigan Commission asserts that treating all

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[467] Vistra Answer at 4- 5.

[468] *Id.* at 6.

[469] *Id.* (citing MISO Answer at 20; Witmeier Docket No. ER25-1674 Rebuttal Testimony at 7-8).

[470] *Id.* at 6-7.

[471] Clean Grid Alliance Second Answer at 1; *see also* Clean Grid Alliance Third Answer at 1-2.

[472] Clean Grid Alliance Second Answer at 2.

interconnection requests originating in Michigan as falling under the umbrella of a "retail choice state" is a clumsy simplification that would lead to unjust outcomes.[473]

188. Michigan Commission notes that in MISO's answer and the MISO Supplemental Answer, MISO uses the terms "retail choice states" and "retail choice load" interchangeably in a number of instances.[474] Michigan Commission compares this to MISO's statements in its transmittal, where MISO offered clear distinction between the terms.[475] Michigan Commission explains that Michigan statutory limitations prevent retail choice from exceeding 10% of an electric utility's average weather-adjusted retail sales.[476] Michigan Commission contends that classifying all interconnection requests from the state of Michigan as being located in a "retail choice state," as opposed to classifying each interconnection request based on whether it serves "retail choice load," would severely limit participation from interconnection requests located in Michigan.

189. Michigan Commission requests that the Commission clarify that interconnection requests serving "retail choice load" located in Michigan would be included in the eight-interconnection request retail choice carve out, but that the other 90% of the Michigan load will be eligible to participate in the 10-interconnection request independent power producer carve out or 50-interconnection request "non-retail choice" cap.[477]

190. Invenergy and Clean Grid Alliance raise concerns about certain information included in MISO's "Informational Guide" issued to stakeholders, which states in part that "[a]greements that are not legally binding, such as Letters of Intent, Memorandums of Understanding, or Term Sheets, will not be considered sufficient to meet the off-take agreement requirement."[478] Invenergy argues that this restriction violates the proposed

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[473] Michigan Commission Answer at 3.

[474] *Id.* at 4-5 (citing MISO Supplemental Answer at 3; MISO Answer at 13).

[475] *Id.* at 5-6 (citing Transmittal at 8, 52-53).

[476] *Id.* at 6-7.

[477] *Id.* at 7.

[478] Invenergy Answer at 3-5 (citing MISO, *Expedited Resource Addition Study*, at 7 (posted July 11, 2025), https://cdn.misoenergy.org/ERAS%20Informational%20Guide707493.pdf ?v=20250711150053); Clean Grid Alliance Third Answer at 2-3 (citing same). Invenergy also attaches the ERAS Informational Guide as Exhibit A to its answer.

Tariff language and MISO's statements in this proceeding.[479] Both Invenergy and Clean Grid Alliance also argue that not allowing letters of intent and similar contracts to be included within the scope of "other agreements" under the proposed Tariff[480] raise a barrier to independent power producer participation in ERAS.[481]

(c) <u>MISO Second Supplemental Answer</u>

191. MISO states that any conflation of the terms "retail choice load" and "retail choice state" in its answers was inadvertent. MISO states that the Michigan Commission's understanding, that ERAS interconnection requests serving retail choice load located in Michigan would be included in the eight ERAS interconnection request carve out for retail choice, is correct. MISO further explains that interconnection requests intending to serve the remaining 90% of Michigan load can apply to the 10 ERAS interconnection request spots for independent power producers or the 50 ERAS interconnection request spots for non-retail choice loads.[482]

c. <u>Commission Determination</u>

192. MISO has proposed several eligibility requirements for the ERAS process. We accept these requirements and find them to be just and reasonable and not unduly discriminatory or preferential. Taken together, this comprehensive package of eligibility requirements will deter speculative interconnection requests from entering the ERAS process and minimize disruption to DPP interconnection requests.

193. At the outset, we review the Commission's consideration of open access matters in the context of Order Nos. 888 and 2003. In Order No. 888, the Commission first required open access requirements on a generic basis to address potential discrimination on the transmission system. By requiring an open access transmission tariff, the Commission applied–generically–a comparability standard to jurisdictional transmission providers as it had done previously on a case-by-case basis.[483] Under the comparability standard,

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[479] *Id.* at 4-5.

[480] *See* MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.1(2)(d).

[481] Invenergy Answer at 4; Clean Grid Alliance Third Answer at 3.

[482] MISO Second Supplemental Answer at 2-3.

[483] The Commission therefore required "that all public utilities must offer . . . services on a non-discriminatory open access basis" and explained that "[a]n open access tariff that is not unduly discriminatory or anticompetitive should offer third parties access on the same or comparable basis, and under the same or comparable terms and

transmission service was to be offered to third parties on the same or comparable basis as that used by the transmission provider.[484] To implement its requirements, the Commission issued with Order No. 888 a *pro forma* open access transmission tariff and required public utilities to meet the new *pro forma* tariff non-price minimum terms and conditions.[485]

194. In Order No. 2003, the Commission applied Order No. 888's open access requirements to the generator interconnection process in recognition of the fact that generator interconnection is a "critical component of open access transmission service and thus is subject to the requirement that utilities offer comparable service under the [*pro forma* open access transmission tariff]."[486] The Commission found that it was appropriate to establish a standard set of generator interconnection procedures to "minimize opportunities for undue discrimination and expedite the development of new generation, while protecting reliability and ensuring that rates are just and reasonable."[487] To this end, the Commission adopted the *pro forma* LGIP and *pro forma* LGIA and amended its regulations to require all transmission providers to incorporate these standard procedures and agreement into their tariffs.[488]

195. More recently, the Commission rejected MISO's Initial ERAS Proposal because, first, it "place[d] no limit on the number of projects that could be entered in the ERAS process," and second, MISO did "not sufficiently describe how the ERAS process is sufficiently targeted to study only interconnection requests needed to meet the anticipated shortfall in generating."[489] Here, we find that MISO's Revised ERAS Proposal sufficiently addresses these concerns identified in the May 2025 Order by capping the number and size of ERAS projects, strengthening the RERRA verification requirement, requiring ERAS interconnection requests to be located in the same Local Resource Zone as the resource adequacy or reliability need that it will address, absent reasonable

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conditions, as the transmission provider's uses of the system." Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,647 (quoting *Am. Elec. Power Serv. Corp.*, 67 FERC ¶ 61,168, at 61,489 (1994)).

[484] *Id.*

[485] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at app. D, para. 13.6.

[486] Order No. 2003, 104 FERC ¶ 61,103 at PP 9, 12.

[487] *Id*. P 11.

[488] *See* 18 C.F.R. 35.28(f)(1) (2024).

[489] May 2024 Order at P 199-201.

exceptions, and making additional changes, as discussed further below. Collectively, these changes ensure the ERAS process is sufficiently limited in scope to swiftly address discrete, demonstrated resource adequacy needs in a narrowly tailored fashion, and on a temporary, time-limited basis. Additionally, we note that the limited, one-time design of the process weighed significantly on our decision here.

196. While interconnection requests that qualify for the ERAS process will have the ability to interconnect on a priority basis, ERAS does not present open access concerns because it is "open, competitive, technology/fuel agnostic, and does not involve MISO favoring or selecting certain projects over others."[490] The Revised ERAS Proposal also applies identical eligibility criteria across all potential interconnection requests. This is similar to the PJM RRI construct, which allows for potential inclusion of any resource regardless of technology.[491] Furthermore, the Revised ERAS Proposal does not restrict or change interconnection customers' access to the DPP process.

197. We note that MISO's specific requirements for ERAS interconnection requests (e.g., location information for the load the ERAS interconnection request will serve, the limitation on the size of ERAS interconnection requests based on the identified resource adequacy shortfall, specific commercial readiness requirements, etc.), strengthened RERRA verification requirements, and MISO's commitment to publicly post detailed information about each ERAS interconnection request and its corresponding type of load served, establishes a clear and transparent process. Therefore, we disagree with protesters that MISO's Revised ERAS Proposal lacks objective and transparent criteria for participation in ERAS.

(a) <u>RERRA Verification Requirement</u>

198. We find that the proposed RERRA verification requirement is just and reasonable and not unduly discriminatory or preferential. We find that MISO has demonstrated that its proposal to require RERRAs to verify that either: (i) the new, incremental load addition is valid and not otherwise included in a resource plan or other process under the RERRA's purview, or (ii) that the generating facility will address a resource adequacy deficiency, is just and reasonable and not unduly discriminatory or preferential.[492]

199. We agree with MISO that the proposed RERRA verification requirement provides the necessary flexibility to recognize the different regulatory review processes across the

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[490] Transmittal at 32.

[491] PJM RRI Order, 190 FERC ¶ 61,084 at PP 118, 121, 123.

[492] *See* Transmittal at 2.

states and RERRAs in the MISO region.[493] MISO has strengthened what was a "notification" requirement in its Initial ERAS Proposal to better ensure that RERRAs affirmatively verify interconnection requests will address specific resource adequacy needs that are not otherwise being addressed. We also find that it is reasonable and appropriate for MISO to allow RERRAs to determine which projects should be selected for ERAS, and to implement their own processes for making such determinations, as this approach strikes a reasonable balance between state authority over resource procurement and Commission authority over generation interconnecting to the interstate transmission system. Accordingly, we find that it is not necessary for MISO to establish scoring criteria or a ranking process for proposed ERAS projects, as protesters suggest. We note that here, we must evaluate whether MISO's Revised ERAS Proposal before us is just and reasonable, and we need not consider alternative proposals. Further, we agree with MISO that RERRAs are uniquely positioned to evaluate the needs in their regions and projects proposed by a developer or LSE[494] and that the Revised ERAS Proposal strikes a reasonable balance between ensuring that an ERAS interconnection request will serve a valid new load or meet a resource adequacy deficiency in MISO while respecting the state's jurisdiction over their own resource mix to address resource adequacy.[495] We disagree with EPSA, Invenergy, and other protesters[496] that state regulators, which are obliged to serve the public interest in accordance with state law, will not be objective in their RERRA verifications. We further find that MISO's reliance on RERRAs in the selection process for ERAS is a practical and expedient solution for each RERRA to identify ways to meet their specific resource adequacy challenges. We note that, as MISO explains, studying an interconnection request through the ERAS process does not pre-determine the outcome of an ERAS interconnection request, as any project must still obtain state approval through the state's corresponding regulatory review process.[497] As several commenters explain, the RERRA verification process balances MISO's need to verify projects that meet resource adequacy needs and the RERRAs' need to not prejudge generation certifications.[498]

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[493] MISO Answer at 24-25.

[494] *Id.* at 22.

[495] *Id.* at 25-26; Southern Regulators Comments at 3.

[496] *Supra* at P 59, P 118.

[497] *See* Transmittal at 31.

[498] Louisiana and Mississippi Commissions Comments at 10; Otter Tail Comments at 4; Texas Commission Comments at 8.

200. We disagree with arguments that the RERRA verification requirement restricts open access by unduly discriminating against interconnection customers in retail choice jurisdictions, such as Illinois and Michigan. Rather, the Revised ERAS Proposal is available to interconnection customers regardless of whether they propose to operate in retail choice or non-retail choice jurisdictions. As MISO explains, the Revised ERAS Proposal was designed to be flexible to accommodate the various RERRA processes and regulatory constructs in the MISO region.[499] Further, the Revised ERAS Proposal adopts a carve out for eight interconnection requests serving retail choice loads (more than 10% of the total number of ERAS interconnection requests allowed under the program) to be studied in ERAS, which was added for the specific purpose of accommodating retail choice loads. Indeed, the Revised ERAS Proposal affords significant flexibility to accommodate interconnection customers in retail choice regions, including by permitting them to participate in ERAS without RERRA verification– a structural accommodation designed specifically to enable retail choice states and regions to participate fairly.[500] We also acknowledge that a significant majority of MISO's load is served through traditional vertically integrated processes.[501] Regarding Michigan Commission's request that MISO remove the proposed Tariff language in GIP section 3.9.1 that RERRA verification can be supported by "a state energy forecast, or other forward-looking forecast," we agree with MISO that the Tariff language is simply included as part of a list of potential information that RERRAs may use and that each RERRA will ultimately determine what information will be required for the ERAS project verification.[502]

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[499] *See* MISO Answer at 25.

[500] Witmeier Testimony at 35-36. We note that Michigan Commission raises concerns with imprecise language in MISO's Answer and MISO's Supplemental Answer regarding retail choice loads and retail choice states; however, we find the proposed Tariff language, as revised by MISO's Supplemental Answer, is clear that the carve out for eight ERAS interconnection requests is for retail choice loads, which would include the 10% limit in Michigan, and the remaining ERAS interconnection requests slots are for non-retail choice load. Further, we note MISO's affirmation of this interpretation, and its explanation that interconnection requests serving the remaining 90% of load in Michigan can apply to ERAS under the 10 ERAS interconnection request spots for independent power producers or the 50 ERAS interconnection request spots for non-retail choice load. MISO Second Supplemental Answer at 2-3.

[501] Transmittal at 22 (citing *Midcontinent Indep. Sys. Operator, Inc.*, 162 FERC ¶ 61,176 at P 67).

[502] MISO Answer at 24.

201. We find unpersuasive protester arguments that the RERRA verification is more difficult to satisfy for certain subcategories of interconnection requests. The record does not demonstrate that certain classes of interconnection customers will necessarily find it more difficult to receive a RERRA verification. RERRA verification may be triggered in numerous ways, not just through participation in one specific state-sponsored process. MISO's proposed GIP section 3.9.1.1 provides that the RERRA verifies that there is a valid, new incremental load addition that is not incorporated in relevant plans or that the proposed generating facility will address an identified resource adequacy deficiency; thus, MISO permits flexibility in satisfying this requirement.[503]

202. Further, we agree with MISO that the precedent in *Xcel* does not require rejection of the Revised ERAS Proposal. First, we note that *Xcel* involved the tariff of a non-independent transmission provider, and the Commission gives such transmission providers less flexibility than RTOs/ISOs to depart from the *pro forma* generator interconnection procedures and *pro forma* generator interconnection agreement.[504] Additionally, the proposal in *Xcel* required an interconnection customer taking part in a state-sponsored bidding process to drop out of the generator interconnection queue if the customer did not win the contract.[505] The *Xcel* proposal also appeared to allow projects submitted as part of the state process to jump ahead of other projects in the queue that were filed first.[506] In contrast, the Revised ERAS Proposal, though it provides an expedited process for certain interconnection requests, does not replace or interfere with the existing DPP process, which remains available to all interconnection requests.

(b) <u>ERAS Cap and Carve Outs</u>

203. We find that MISO's proposal to limit the total ERAS participation to 68 interconnection requests, with a carve out of eight interconnection requests to serve retail choice load and 10 interconnection requests for independent power producers, is just and reasonable and not unduly discriminatory or preferential. We agree with MISO that the Revised ERAS Proposal is narrowly tailored to meet MISO's near-term resource

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[503] MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.1.1(a)-(d).

[504] *See* Order No. 2003, 104 FERC ¶ 61,103 at P 26 (allowing RTOs/ISOs to submit LGIP and LGIA terms and conditions that meet an "independent entity variation" standard, which is more flexible than the "consistent with or superior to" and "regional differences" standards). As discussed *supra* in part IV.B.2(c), the parameters of the RERRA verification requirement are clearly stated in MISO's Proposed Tariff.

[505] *Xcel*, 106 FERC ¶ 61,260 at P 22.

[506] *Id*.

adequacy and/or reliability needs.[507] We find that the Revised ERAS Proposal, including the proposed cap and carve outs, strikes a reasonable balance between ensuring broader participation and addressing the resource adequacy needs of the region, while providing reasonable limitations on the number of interconnection requests that will be studied through the ERAS process. Additionally, the proposed cap minimizes the potential for the types of delays that have occurred in the DPP queue to also manifest in the ERAS queue. MISO developed the 68 interconnection request cap in response to the May 2025 Order to limit ERAS participation to a manageable number of interconnection requests that MISO determined it can efficiently study in the short-term consistent with what the Commission approved for PJM's RRI process by design, with adjustments made to accommodate retail choice states and independent power producers in the MISO footprint.[508] Specifically, MISO explains that they coupled the cap with the two respective carve outs to ensure that independent power producers and entities in retail choice states have the exclusive opportunity to participate in ERAS. Therefore, we disagree with protesters' arguments that MISO's proposed cap and carve outs are arbitrary and unsupported.

204. We disagree with protesters' arguments that MISO's proposed cap and carve outs impede open access. Rather, as discussed above, we find that the proposed ERAS process is "open, competitive, technology/fuel agnostic, and does not involve MISO favoring or selecting certain projects over others."[509] Additionally, we find that the carve outs for independent power producers and entities in retail choice states ensure that all interconnection customers will have comparable ability to seek to participate in the ERAS process, regardless of location and ownership type.[510] We also find that MISO's proposed cap is directly responsive to the Commission's concerns in the May 2025 Order that the Initial ERAS Proposal was not just and reasonable because it placed no limit on the number of projects that could be entered in the ERAS process.[511] Our acceptance of

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[507] Transmittal at 35, 47.

[508] MISO Answer at 13.

[509] *See supra* P 190.

[510] *See* PJM RRI Order, 190 FERC ¶ 61,084 at P 123 (finding that PJM's proposal does not violate open access requirements because it provides all interconnection customers the comparable ability to submit an interconnection request for projects with at least 10 MW UCAP to be evaluated under PJM's proposed criteria). *See also* CAISO IPE Order, 188 FERC ¶ 61,225 at P 94 (finding that CAISO's proposal does not present open access issues because all interconnection customers are provided a "comparable ability" to join the cluster).

[511] May 2025 Order, 191 FERC ¶ 61,131 at P 199.

MISO's proposal, including the proposed cap of 68 interconnection requests, is consistent with that precedent.

205. We also disagree with protesters' contention that the Revised ERAS Proposal unduly discriminates against independent power producer interconnection requests with non-LSE agreements. In its answer, MISO provides clarification that the 10 ERAS interconnection request carve out for independent power producers with non-LSE agreements is not a cap on independent power producer interconnection requests, and independent power producers may *also* submit interconnection requests in the general group of 50 ERAS interconnection requests.[512] MISO explains that the purpose of the carve out is to address claims that LSEs could block independent power producers from participating in the ERAS process. We disagree with Clean Energy Associations' arguments that it is unclear whether independent power producers can compete on equitable terms for the general group of 50 spots in ERAS because MISO's proposed Tariff language is not clear on the types of agreements it will accept for those spots. MISO's proposed GIP section 3.9.1.2, which details the various types of acceptable executed agreements, applies to all ERAS interconnection customers regardless of whether they apply for the general 50 spots or the carve out spots for independent power producers and retail choice loads. Further, in its supplemental answer, MISO provides additional detail and sample Tariff provisions to clarify the carve out for independent power producers and states that it would welcome a directive to include such language in its Tariff on compliance.[513] We find that the Tariff provisions described by MISO in its supplemental answer will provide clarity to its Tariff. Therefore, we direct MISO to submit, within 30 days of the date of this order, revisions to its Tariff to incorporate the clarifying language included in its supplemental answer.

206. We further disagree with protesters' arguments that MISO should delay the implementation date, or otherwise provide more time, for independent power producer interconnection requests. Rather, we agree with MISO that creating separate start dates for different groups of ERAS interconnection requests may be impractical, administratively burdensome, and inappropriate.[514] Further, we find that MISO's proposed carve out to accommodate 10 independent power producer interconnection requests, in addition to MISO's clarification that independent power producer interconnection requests may also be included in the general group of 50 ERAS interconnection requests, ensures that independent power producers have comparable

[512] MISO Answer at 19.

[513] MISO Supplemental Answer at 4.

[514] MISO Answer at 20-21.

access to ERAS.[515] We therefore do not agree with protesters that additional processes for independent power producer interconnection requests are necessary to render the proposal just and reasonable.

(c) Other ERAS Eligibility Requirements

207. We find that the proposed ERAS executed agreement requirement is just and reasonable and not unduly discriminatory or preferential. Protesters argue that, to satisfy this requirement, the options for independent power producers necessarily require more effort than the self-supply option for LSEs.[516] We disagree that this potential distinction renders MISO's proposal unjust and unreasonable and find that MISO's proposal strikes a reasonable balance between reducing speculative projects and ensuring that certain types of interconnection requests or interconnection customers are not excluded from participating in ERAS. We find that the executed agreement requirement will help ensure that only truly "shovel ready" projects are proposed. As MISO states, this requirement ensures that some form of commercial arrangement exists pairing the ERAS project with the specified load and demonstrates that the ERAS project is not merely submitted in the hope of being selected to serve that need,[517] which would not support the objective of identifying more commercially ready projects in ERAS. We note that LSEs that meet the executed agreement requirement through a commitment to self-supply must still be verified by a RERRA, as is the case with the other types of executed agreements that independent power producers may use. We agree with MISO that this requirement prevents participation by speculative entities that "do not have buy in from the need driver."[518] Consequently, we agree that the proposed Tariff language indicates greater commercial readiness, thereby ensuring ERAS projects can meet MISO's urgent, near-term reliability and resource adequacy needs. While protesters may object to this requirement, MISO provides multiple options for interconnection customers to satisfy the executed agreement requirement.[519]

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[515] *Id*. at 19 (citing Witmeier Docket No. ER25-1674 Rebuttal Testimony at 6-7); MISO Supplemental Answer at 4.

[516] *See, e.g.,* Clean Energy Associations Protest at 31; Clean Grid Alliance Protest at 26-27; EPSA Comments at 5; PIOs Protest at 5.

[517] Transmittal at 30-31.

[518] Witmeier Testimony at 42.

[519] MISO, Proposed Tariff, attach. X (GIP) (1750.0), § 3.9.1.2.

208. One such option is the eligibility of interconnection requests with "other agreements" to be included in the ERAS process.[520] By including such an option, MISO provides considerable flexibility for interconnection customers, including independent power producers and RERRAs seeking to procure supply from independent power producers, to satisfy this requirement.[521] We disagree with Clean Energy Associations that it is unclear which agreements apply to the 50 ERAS interconnection spots because the executed agreement requirements of proposed GIP section 3.9.1.2 apply to all ERAS interconnection requests. Further, as noted by both MISO and protesters, CAISO's IPE,[522] PJM's RRI,[523] and the 2024 MISO Queue Cap[524] proposals all incorporate aspects that encourage commercial readiness and, in each of those proceedings, the Commission found that those proposals were not in violation of open access requirements or otherwise unduly discriminatory. We find here that the Revised ERAS Proposal is largely consistent with these proposals, and likewise just and reasonable.

209. Finally, we find that the executed agreement requirement is tailored to achieve MISO's expressed objective for proposing ERAS, that is, meeting urgent, near-term resource adequacy or reliability needs by requiring interconnection customers to have

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[520] *Id.* § 3.9.1.2(d). In response to stakeholder feedback that the executed agreement requirement may prove too onerous, MISO added this option to establish "a minimum requirement that an arrangement exists between the driver of the need and the project to address that need." Witmeier Testimony at 42.

[521] We disagree with Invenergy's and Clean Grid Alliance's arguments that agreements that are not legally binding should satisfy the "other agreement" requirement, as that would have the effect of rendering the "other agreement" requirement meaningless, thereby allowing projects that may not actually be needed to meet an identified resource adequacy need to be included in the ERAS process.

[522] CAISO IPE Order, 188 FERC ¶ 61,225 at P 174 ("[W]e find that CAISO's proposal to account for commercial interest in its evaluation of interconnection requests will help enable CAISO to prioritize the study of the most viable and needed interconnection requests under Cluster Study Criteria.").

[523] PJM RRI Order, 190 FERC ¶ 61,084 at P 155 ("We find PJM's proposed commercial operation date viability criteria . . . reasonably prioritize projects that have a reasonable likelihood of coming online in the near term to meet PJM's resource adequacy needs.").

[524] January 2025 Order, 190 FERC ¶ 61,057 at P 90 ("We also find that . . . [t]hese exempted interconnection requests [which count first towards the MW cap] are associated with generating facilities that are already in service or already have an executed GIA and, therefore, demonstrate a higher degree of commercial readiness.").

entered into agreements to serve specific load needs.[525] MISO has adequately demonstrated that this executed agreement eligibility criterion, along with the RERRA verification requirement, will help ensure that "shovel ready" projects that can meet RERRA-identified, near-term capacity needs are included in the ERAS process. Further, we find that MISO has provided consistent terms and conditions (and multiple avenues) for satisfying this requirement, and the record does not demonstrate that independent power producers, as a class, will be unable to satisfy this uniform requirement.

210. We find that MISO's proposed application fee, site control, milestone, commercial operation date, and Local Resource Zone requirements for ERAS interconnection requests are just and reasonable and not unduly discriminatory or preferential.[526] We agree with MISO that the proposed requirements will help prevent speculative projects from applying to the ERAS process, which will help ensure "shovel ready" projects that meet specific, near-term resource adequacy needs will be studied. While commenters argue that certain requirements, such as milestone payments, could be made more rigorous or stringent to better deter speculative projects from applying to the ERAS process, the Commission is not obligated to consider whether the ERAS proposal is more or less reasonable than other alternatives.[527] We note, however, that even if some protesters would prefer more stringency, the proposed ERAS application fee, site control, milestone, and commercial operation date requirements are all considerably stricter than those established for the DPP and thus designed to strictly limit participation in the ERAS process, which is both appropriate and consistent with MISO's objectives. Further, while other protesters argue that, for example, the $100,000 application fee and withdrawal penalties could be a barrier for them to enter ERAS,[528] we find that these requirements serve as meaningful deterrents against speculative projects.

211. Additionally, with ERAS, like PJM's RRI and CAISO's IPE proposals, MISO has tailored the requirements toward the goal of satisfying near-term reliability and resource adequacy needs by emphasizing "shovel readiness" and commercial readiness. Taken as a whole, MISO has proposed requiring ERAS interconnection customers to post greater financial and non-financial commercial readiness requirements and greater site control requirements, compared to DPP interconnection customers, as well as an NRIS requirement and RERRA verification and executed agreement requirements. We find

[525] PJM RRI Order, 190 FERC ¶ 61,084 at P 123; CAISO IPE Order, 188 FERC ¶ 61,225 at P 94.

[526] *Supra* PP 36, 38.

[527] *Supra* P 31.

[528] Clean Energy Associations Docket No. ER25-1674 Protest at 19; Clean Grid Alliance Protest at 79.

that, taken together, MISO has proposed a comprehensive package of eligibility requirements that will considerably deter speculative projects from applying to the ERAS process.

212. We disagree with protesters' arguments that MISO's proposed requirement that an ERAS interconnection request's level of requested interconnection service be no more than 150% of the identified MW need is unduly discriminatory. In the May 2025 Order, the Commission rejected MISO's Initial ERAS Proposal because it was not narrowly-tailored to ensure that only those resources capable of addressing identified near-term resource adequacy or reliability needs would be eligible for expedited study through the ERAS process.[529] We find that capping ERAS interconnection requests at 150% of the identified resource adequacy need is responsive to the May 2025 Order. MISO's proposal caps the ratio of interconnection service requested to needed generation in order to prevent gaming of the ERAS process, where the MW of a potential ERAS request could far exceed the identified MW need for new generation. Without such a cap, the ERAS request could be oversized and even a small MW need could be used for large new generating facilities to bypass the normal queue. MISO's proposal, as it states, is fuel-type agnostic, meaning there are no prohibitions on any specific fuel type from entering the ERAS process and that MISO does not take into account what type of generating facility is associated with an ERAS interconnection request. To the extent that an ERAS project would benefit economically from obtaining interconnection service over and above what is needed to address the RERRA-verified resource adequacy need, that project may seek additional interconnection service through the DPP process.[530] We acknowledge that there are practical limitations on what types of projects can compete for the ERAS process. However, we find that in this instance, where the ERAS process is limited to a small number of projects, and those projects are identified to meet a very specific need, MISO's proposal to ensure that there is a limitation to avoid any gaming concerns is a reasonable protection to put into place. As a result of this limitation, we disagree with protesters that the Local Resource Zone requirement is unduly discriminatory.[531] As noted above, MISO's addition of this requirement helps address the Commission' concern in the May 2025 Order that the ERAS proposal might not be tailored to addressing specific resource adequacy needs. Further, neither LSE nor independent power producer projects will be limited by this zonal requirement if they are included in an integrated resource plan. We find that MISO's Revised ERAS Proposal is therefore just and reasonable and not unduly discriminatory or preferential.

[529] May 2025 Order, 191 FERC ¶ 61,131 at P 202.

[530] Transmittal at 44; Witmeier Testimony at 68.

[531] *Supra* P 171.

4. ERAS Study Process

a. MISO's Filing

213. MISO proposes to study ERAS interconnection requests quarterly in a regional, serial "first-come, first-served" fashion using the existing engineering study process used in the DPP for ensuring full generator deliverability to load.[532] MISO explains that while both ERAS and DPP studies will use the same MTEP base case (i.e., the most current MTEP base case at the time of the DPP study cycle or the ERAS quarterly study process kickoff), they will include different generator assumptions. Specifically, MISO explains that, while the DPP will continue to include all prior-queued interconnection requests in base case models, the ERAS study will include only generating facilities with an executed GIA in such models.[533]

214. MISO states that the serial study is a key feature of ERAS and that it affords ERAS interconnection requests a better understanding of their impact on the transmission system when looking to address the needs of load. MISO also states that the traditional challenges related to reviewing interconnection requests on a serial basis are not present with ERAS because there will be a smaller number of interconnection requests to process, and they are expected to be geographically and electrically dispersed across the MISO footprint.[534] MISO states that if several ERAS interconnection requests are submitted in one geographical area at the same time, it will study the interconnection requests with the earliest submission time first, and the subsequent interconnection requests will be studied in the next available ERAS quarterly study period. However, MISO states that it does not anticipate this occurring very often due to the 10-interconnection request cap on ERAS interconnection requests per quarterly study period, its large footprint, and the strict eligibility requirements to enter the ERAS process.

215. Additionally, MISO proposes that existing DPP interconnection requests that have not reached Decision Point II in the DPP 2022, 2023, and later cycles will be eligible to transfer to ERAS.[535] MISO states that it is aware of several existing DPP interconnection requests that could apply to participate in ERAS. MISO explains that these DPP interconnection requests may remain in their DPP study group while applying for ERAS, and once admitted to ERAS, the interconnection requests must withdraw from the DPP

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[532] Transmittal at 7-8; Witmeier Testimony at 52.

[533] Transmittal at 39; Witmeier Testimony at 52.

[534] Transmittal at 37-38.

[535] *Id.* at 37.

and will be subject to MISO's automatic withdrawal penalties and harm penalties. MISO asserts that the penalties are necessary because when interconnection requests drop out of the queue, the withdrawal causes harm to other interconnection requests in that study group. MISO explains that if a DPP interconnection request is deemed ineligible for ERAS, then it will forfeit the $100,000 D1 payment required with the ERAS application and will remain in its original DPP queue position.

216. MISO asserts that the Revised ERAS Proposal has been crafted to avoid supplanting the DPP or harming interconnection requests in the DPP interconnection queue.[536] MISO states that it plans to coordinate the ERAS, DPP, and expedited project review studies to maximize efficiency and reduce any impacts among these studies. MISO explains that network upgrades identified in ongoing MTEP studies that mitigate congestion in DPP and ERAS studies will remove the need for DPP and ERAS network upgrades once the MTEP project is approved. MISO contends that ERAS interconnection requests will not harm interconnection requests currently studied in the DPP process by taking existing transmission capacity headroom from active DPP interconnection requests. According to MISO, this is because the ERAS and DPP processes use the same MTEP base case as a starting point, and any headroom used by an ERAS interconnection request is not deducted from the DPP model, as ERAS interconnection requests will not be included in ongoing DPP studies.[537] MISO explains that the output of the DPP and ERAS models will be reconciled in the next MTEP, consistent with how MISO reconciles currently effective parallel processes through the next MTEP base case.[538]

217. MISO further explains that if transmission capacity is overallocated due to approved interconnection requests in both the ERAS and DPP processes, such

[536] *Id.* at 39.

[537] *Id.* at 42-43; Witmeier Testimony at 52. MISO explains that the DPP process uses the most up-to-date MTEP base case when the DPP study is kicked off and is not subsequently modified to include later-approved MTEP projects or ERAS interconnection requests after that kickoff. Witmeier Testimony at 53. For example, MISO explains that if it approves an ERAS interconnection request that will use the transmission capacity in MTEP 2024, and the DPP 2023 cycle is using MTEP 2023, the ERAS interconnection customer will not take away transmission capacity from any interconnection request in the DPP 2023 cycle. MISO also asserts that ERAS interconnection requests will not have early access to the newly available transmission headroom related to Long Range Transmission Plan Tranche 2.1 projects and will not disadvantage interconnection requests from the DPP 2025 cycle. Transmittal at 43.

[538] Transmittal at 43.

overallocation will be identified and mitigated in the next MTEP cycle.[539] In such a scenario, MISO explains that the transmission capacity overallocation would be discovered as part of the MTEP Deliverability Analysis, which ensures continued deliverability of generating facilities with NRIS.[540] MISO further contends that, even in an overallocation scenario, there will be no negative implications for either a DPP or ERAS interconnection request because both types of interconnection requests will be allowed to proceed, and neither will be required to pay additional costs due to the overallocation. MISO explains that the cost of the MTEP project needed to resolve overallocation will be allocated based on the existing Tariff rules, which will likely allocate the costs of the project to load within the transmission pricing zone where the transmission upgrade is located.[541] MISO explains that this will include the load that is benefiting from the ERAS and DPP interconnection requests, and this load will benefit from the network upgrades that were funded by the interconnection customers that went through those processes. Further, MISO asserts that the cost shift is consistent with existing processes. MISO explains that it has multiple planning processes, many performed in parallel with their own unique modeling assumptions and cost allocation methodologies.[542] MISO states that after projects are approved through their relevant processes, they are included in the base cases of subsequent studies based on the modeling assumptions for those studies. MISO states that it is not uncommon for new constraints to arise in subsequent studies driven by approved transmission and generation projects, as well as new load growth and generation retirement, and that, as new constraints are identified, new mitigation is identified, which could include another new transmission project necessary to ensure reliability.[543]

218. Finally, MISO asserts that the Revised ERAS Proposal meets the standard for an independent entity variation from the requirements of Order Nos. 2003 and 2023 because it fosters the increased development of economic generation by reducing interconnection

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[539] *Id.*; Witmeier Testimony at 54.

[540] Witmeier Testimony at 54.

[541] *Id.* at 54-55.

[542] MISO references, for example, baseline reliability projects, market efficiency projects, multi-value projects, transmission deliverability service projects, interregional transmission projects, other projects, generator interconnection projects, and new generating facilities that are approved through the DPP, generator surplus, or generator replacement processes. *Id.* at 55-56.

[543] *Id.* at 56.

costs and time.[544] MISO asserts that because ERAS is a standalone process, it should be viewed as one large independent entity variation with a defined set of rules, rather than individual independent entity variations for the various differences between the cluster study process outlined in Order Nos. 2023 and 2023-A and the proposed serial-based study approach in ERAS.[545] MISO argues that using serial studies for ERAS accomplishes the purposes of Order Nos. 2003 and 2023 by minimizing the restudy risk that is inherent to multi-phase cluster studies so that ERAS generating facilities can be built quickly, without the risk of cascading restudies.[546] MISO contends that although the use of cluster studies is appropriate for the large queue volume seen in MISO's DPP process, the use of serial studies for ERAS will allow MISO to quickly study ERAS interconnection requests to address resource adequacy and/or reliability concerns and to meet the goals of the temporary ERAS process.

b. Responsive Pleadings

i. Comments in Support

219. Texas Commission argues that the Revised ERAS Proposal will not negatively impact DPP interconnection customers.[547] Texas Commission asserts that allowing interconnection customers in the DPP to transfer their interconnection request to ERAS before Decision Point II protects remaining DPP interconnection requests by preventing unplanned restudies that could result from late-stage transfers. Texas Commission adds that any interconnection requests that transfer from the DPP to ERAS must pay all applicable withdrawal penalties.

ii. Protests

(a) Serial Studies

220. Several protesters raise concerns with MISO's proposal to study ERAS interconnection requests serially. Clean Grid Alliance argues that ERAS represents a high-risk deviation that threatens to create ongoing disruptions to the DPP by destabilizing study models that interconnection customers rely on and causing cost shifts,

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[544] Transmittal at 23-24 (citing Order No. 2003, 104 FERC ¶ 61,103 at PP 11-12).

[545] Witmeier Testimony at 5, 67.

[546] Transmittal at 24.

[547] Texas Commission Comments at 11.

resulting in cascading restudies in ERAS and the DPP.[548] Relatedly, Clean Grid Alliance argues that despite MISO's proposal to adopt a cap of 10 ERAS interconnection requests per quarterly study period, the risk of cascading restudies is still present, as with any serial study approach.[549]

221. Invenergy argues that the Revised ERAS Proposal violates Order No. 2023's requirement that interconnection requests be studied in clusters.[550] Invenergy points to the Commission's language in the May 2025 Order that a serial interconnection study process may contribute to delays if multiple interconnection requests are submitted in the same quarter in the same area of the transmission system.[551] PIOs argue that in Order No. 2023, the Commission established the cluster study process as the cornerstone on which other reforms were oriented, and a separate serial study process would lead to unjust and unreasonable rates by diverting resources and causing delays to the existing DPP process, thereby undermining MISO's ability to identify the most efficient set of shared network upgrades for a DPP study group.[552] PIOs state that a serial study process also fails to realize the benefit of the efficient identification of shared network upgrades, and this will result in the under-identification of network upgrades assigned to ERAS interconnection requests, leading to reliance on the MTEP process to identify smaller, but more expensive, discrete technology solutions.[553] PIOs argue that ERAS is also not limited or transitional because its sunset date exceeds the full shift to cluster studies required by Order No. 2023 and may delay the realization of the benefits from Order No. 2023.[554]

222. PIOs argue that the serial study approach will detract staff resources from the DPP and that the Commission has previously denied requests to operate serial studies parallel to cluster studies.[555] PIOs contend that running serial studies for ERAS for multiple

[548] Clean Grid Alliance Protest at 5.

[549] *Id.* at 16-17.

[550] Invenergy Protest at 17 (citing Order No. 2023, 184 FERC ¶ 61,054 at PP 177-178; Invenergy Docket No. ER25-1674 Protest at 3-6).

[551] *Id.* (citing Order No. 2023, 184 FERC ¶ 61,054 at P 178).

[552] PIOs Docket No. ER25-1674 Protest at 22-23.

[553] *Id.* at 28.

[554] *Id.* at 25.

[555] PIOs Protest at 20 (citing Order No. 2023, 184 FERC ¶ 61,054 at PP 177-178).

years will delay MISO's processing of the DPP for those years.[556] PIOs further argue that MISO's serial study approach for ERAS will result in many network upgrade needs being identified for the first time in the MTEP process and that MISO's use of MTEP to build upgrades for ERAS interconnection requests does not achieve efficient transmission development.[557]

223. Invenergy argues that MISO has not justified the need for ERAS to span multiple study cycles rather than it occurring over one cycle.[558]

224. PIOs argue that MISO's proposed cap of 68 interconnection requests to be studied through the ERAS process does not address how the ERAS quarterly study period timeline will intersect with the DPP process.[559]

(b) <u>Withdrawals</u>

225. Clean Grid Alliance and Invenergy raise concerns about the effects of withdrawals from ERAS. Invenergy states that Order No. 2023 established withdrawal penalties to encourage interconnection customers to submit viable interconnection requests, discourage late-stage withdrawals, and reduce harm to other interconnections customers from withdrawals. Invenergy argues that ERAS does not accomplish the purposes of Order No. 2023 because the non-refundable D1 application fee and refundable M2 payment do not address the risk of restudies and delays nor the harms to other interconnection customers that would result from late-stage withdrawals from ERAS.[560] Clean Grid Alliance argues that interconnection customers in the DPP need an off-ramp without financial penalties when an ERAS interconnection request emerges and creates a negative financial impact.[561]

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[556] *Id.* at 22.

[557] *Id.* at 18.

[558] Invenergy Protest at 14.

[559] PIOs Protest at 17.

[560] Invenergy Protest at 17-18.

[561] Clean Grid Alliance Protest at 23.

226. Clean Grid Alliance argues that if an ERAS interconnection request withdraws, restudies must occur in both ERAS and the DPP.[562] Clean Grid Alliance adds that such withdrawals would also impact the MTEP models because such models include ERAS interconnection requests after an EGIA is executed and a withdrawal after that point would render the MTEP models inaccurate. Further, Clean Grid Alliance asserts that such models are not designed to address interconnection requests.[563] PIOs add that they strongly oppose the creation of a "two-track" system in which ERAS interconnection requests are not fully studied until the MTEP.[564] Further, Clean Grid Alliance avers that if an ERAS EGIA is terminated, then the MTEP models that the DPP utilizes would no longer be accurate.[565]

227. Clean Grid Alliance argues that despite MISO's claims that withdrawals in ERAS will have little impact on DPP interconnection customers, any withdrawal will require restudies and administrative tasks. Clean Grid Alliance also notes that ERAS should consider the impacts to an ERAS interconnection request if the load it is intended to serve does not materialize.[566]

228. Invenergy asserts that MISO has not clarified how the withdrawal of an ERAS interconnection request from the ERAS queue may impact the DPP cluster study and DPP interconnection customers.[567] Invenergy argues that it is not just and reasonable to assign network upgrade costs to interconnection customers that are not the "but for"[568]

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[562] *Id.* at 18. Clean Grid Alliance asserts that MISO's DPP 2023 models may include ERAS projects and that later DPP cycles would certainly include ERAS projects. *Id.*

[563] *Id.* at 17.

[564] PIOs Protest at 17-18.

[565] Clean Grid Alliance Protest at 18.

[566] *Id.* at 20.

[567] Invenergy Protest at 22.

[568] For generator interconnection-related network upgrades identified through the generator interconnection process, the Commission has accepted proposals by RTOs/ISOs to allocate the cost of such network upgrades solely to individual, or clusters of, interconnection customers. Through the generator interconnection process, the transmission provider studies individual or clusters of interconnection requests and identifies specific network upgrades needed to accommodate each interconnection request on an incremental basis (i.e., by determining whether a network upgrade is

cause of those costs, or that do not reflect their contribution to a needed network upgrade. Invenergy asserts that MISO should clarify its approach to ensure interconnection customers are paying for costs that they actually necessitate.

(c) **Harm to Interconnection Customers**

229. Several protesters argue that the Revised ERAS Proposal will harm DPP interconnection customers because it is a multi-year proposal.[569] They further argue that the Revised ERAS Proposal will delay the DPP because the serial studies in the ERAS process could detract from transmission providers' efforts to efficiently process cluster studies in the DPP and would not ensure reliable, efficient interconnection.[570] Several protesters assert that, unlike MISO's Revised ERAS Proposal, PJM's RRI and CAISO's IPE proposals were one-time, emergency proposals that were narrowly tailored to minimize harm and disruption to other interconnection customers.[571] Clean Grid Alliance further argues that MISO's proposed cap and carve outs are dissimilar from PJM's RRI because projects in PJM's RRI are processed under the same study cycle under PJM's standard interconnection queue, whereas MISO proposes to process ERAS interconnection requests in a separate queue.[572]

230. Several protesters argue that the Revised ERAS Proposal poses significant harm to DPP interconnection customers by diverting needed resources to conduct interconnection studies, such as limited staffing, and contend that implementing ERAS in parallel to the DPP will exacerbate these challenges, delay DPP processing, and increase network upgrade costs.[573] Invenergy asserts that MISO has failed to explain how the establishment

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needed "but for" the interconnection of a generating facility). *See Sw. Power Pool, Inc.*, 122 FERC ¶ 61,060 (2008); *Sw. Power Pool, Inc.*, 171 FERC ¶ 61,272 (2020).

[569] Clean Grid Alliance Protest at 17, 51-53; Invenergy Protest at 20-21; NextEra Docket No. ER25-1674 Protest at 26-27.

[570] Clean Grid Alliance Protest at 16-19; Invenergy Protest at 20; NextEra Docket No. ER25-1674 Protest at 31 (citing Order No. 2023, 184 FERC ¶ 61,054 at PP 177-178, 1347).

[571] MISO IPPs Docket No. ER25-1674 Protest at 7-8 (citing Kelliher Aff. at 5-6); NextEra Docket No. ER25-1674 Protest at 26-27; PIOs Docket No. ER25-1674 Protest at 42-43.

[572] Clean Grid Alliance Protest at 26, 67.

[573] Clean Energy Associations Docket No. ER25-1674 Protest at 31; Clean Grid Alliance Protest, attach. A (Declaration of Jennifer Ayers-Brasher) at 6 (Ayers-Brasher

of a second interconnection queue will not increase the interconnection delays already common in the existing queue.[574] Invenergy states that it applauds MISO for its commitment to hire additional staff to assist with the backlogged queue; however, this could be implemented independent of the ERAS proposal to address existing queue delays. Clean Grid Alliance further argues that MISO has not demonstrated how staffing challenges that have impacted DPP processing are not also present in facilitating ERAS.[575]

231. Clean Energy Associations assert that MISO's promise to prevent resources and staff time devoted to ERAS from being utilized to speed the DPP process is unfair to developers that have been waiting their turn to get through a backlogged queue.[576] Clean Energy Associations argue that, in spite of changes to the MISO proposal, such as the cap on ERAS participation and locational restrictions, ERAS still exists as a parallel process. Additionally, Clean Energy Associations argue that the task of studying ERAS interconnection requests while also studying DPP interconnection requests will further stretch MISO's already strained resources, risking delay to both the ERAS queue and the DPP queue.[577]

232. Clean Grid Alliance contends that a better approach to address large load additions is to allow large loads and interconnection customers to move through the existing processes in a coordinated fashion to create a net-zero impact on resource adequacy.[578]

233. Several protesters argue that the Revised ERAS Proposal allows for queue jumping.[579] PIOs argue that ERAS interconnection requests are effectively jumping the DPP queue, and much of the costs for ERAS interconnection customers to connect to the

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Testimony); MISO IPPs Docket No. ER25-1674 Protest at 23-24; NextEra Docket No. ER25-1674 Protest 31-32; PIOs Docket No. ER25-1674 Protest at 15-16, 22, 26.

[574] Invenergy Protest at 20.

[575] Clean Grid Alliance Protest at 28.

[576] Clean Energy Associations Protest at 23.

[577] *Id.* (MISO, Transmittal Letter, Docket No. ER25-507-000, at 3 (Nov. 21, 2024); Witmeier Testimony at 13).

[578] Clean Grid Alliance Protest at 19.

[579] Clean Energy Associations Protest at 10; MISO IPPs Docket No. ER25-1674 Protest at 24; NextEra Docket No. ER25-1674 Protest at 3, 8, 10, 36, 41; PIOs Protest at 15, 20; PIOs Docket No. ER25-1674 Protest at 1-3, 8-9.

transmission system will be borne by DPP interconnection customers or unaffiliated load.[580] PIOs further argue that MISO's lack of a post hoc analysis to true up costs may result in ERAS interconnection customers paying less than their fair share.[581] PIOs assert that the advantages for projects that make it into ERAS, in addition to the lack of oversight from MISO, will create an incentive for RERRAs to approve as many in-state projects as possible.[582]

234. Clean Energy Associations assert that the Revised ERAS Proposal still allows for queue jumping from MISO's DPP to ERAS and interconnection requests, especially thermal resources proposed by LSEs, to offer additional capacity as surplus to be provided to an affiliate, effectively bypassing the DPP queue a second time.[583]

235. Additionally, Invenergy states that it has concerns that ERAS interconnection requests will have priority over DPP interconnection requests in the existing queue because ERAS interconnection requests will be studied first and can incorporate up-to-date information about available transmission capacity.[584] Invenergy also states that it has concerns about the unintended consequences of using two different base cases for ERAS and DPP interconnection requests that are being studied simultaneously.[585]

(d) <u>Transmission Overallocation</u>

236. Several protesters assert that MISO's Revised ERAS Proposal will allow ERAS interconnection customers to receive earlier access to transmission capacity. Protesters contend that ERAS interconnection requests will be studied faster than DPP interconnection requests, which will necessarily take up transmission capacity from the DPP, leading to increased costs for later queued DPP interconnection requests as ERAS interconnection requests queue jump the DPP.[586] MISO IPPs and NextEra assert that

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[580] PIOs Protest at 15, 20.

[581] *Id.* at 15-16.

[582] *Id.* at 24-25.

[583] Clean Energy Associations Protest at 10.

[584] Invenergy Protest at 20-21.

[585] *Id*. at 21.

[586] Clean Grid Alliance Protest at 43-46; MISO IPPs Docket No. ER25-1674 Protest at 23-24; NextEra Docket No. ER25-1674 Protest at 42-43; 2025 Brattle Group Report at 26-27; PIOs Docket No. ER25-1674 Protest at 8-9,15-16.

once MISO incorporates ERAS interconnection requests with EGIAs into the MTEP model, which MISO has represented will occur for the DPP 2026 cycle, it will reduce the amount of transmission capacity available to DPP interconnection requests and subject those interconnection customers to higher network upgrade costs, potentially threatening the viability of their projects.[587] PIOs, NextEra, and Clean Grid Alliance similarly assert that the ERAS interconnection customers may pay less to interconnect through the ERAS process than if they had been studied as part of the DPP study group because ERAS interconnection requests: (1) will be double-counting the same headroom used by parallel DPP study groups; (2) will be advantaged in their use of existing headroom by excluding prior-queued interconnection requests from their interconnection study; and (3) will be arbitrarily less likely to trigger violations than DPP study groups because they will be evaluated serially and therefore gain disproportionately from existing headroom on the transmission system.[588]

237. MISO IPPs and NextEra further argue that faster study of ERAS interconnection requests may create contingent facilities that DPP interconnection requests are reliant upon, which may be delayed and subsequently harm reliant DPP interconnection requests.[589] Furthermore, Clean Grid Alliance argues that MISO's proposal to study ERAS interconnection requests and existing DPP study groups in parallel could ultimately lead to interconnection customers being subject to limited operations while MISO resolves capacity overallocation through the MTEP process.[590]

238. Several protesters raise concerns regarding reliability issues arising from interactions between ERAS projects and other interconnection customers, as the study model will exclude higher-queued interconnection customers without an interconnection agreement.[591] Clean Grid Alliance further argues that using the MTEP process to later address reliability concerns resulting from transmission capacity overallocation will not effectively address reliability concerns due to the limitations of NRIS and Energy

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[587] MISO IPPs Docket No. ER25-1674 Protest at 24; NextEra Docket No. ER25-1674 Protest at 42-43.

[588] Clean Grid Alliance Protest at 43-46; 2025 Brattle Group Report at 26-27; PIOs Docket No. ER25-1674 Protest at 16.

[589] MISO IPPs Docket No. ER25-1674 Protest at 24-25; NextEra Docket No. ER25-1674 Protest at 43.

[590] Clean Grid Alliance Protest, Ayers-Brasher Testimony at 9.

[591] Clean Grid Alliance Protest at 20 (citing Clean Energy Associations Docket No. ER25-1674 Protest, Aff. of Warren Hess at ¶ 2, (filed Apr. 7, 2025)); NextEra Docket No. ER25-1674 Protest at 44.

Resource Interconnection Service studies.[592] Clean Grid Alliance argues that MISO's proposal to address transmission capacity overallocation through the next MTEP is unreasonable because there is no guarantee that the MTEP will produce the needed transmission, and it would shift ERAS-related costs to MTEP.[593]

239. Clean Energy Associations assert that, as with the Initial ERAS Proposal, the Revised ERAS Proposal fails to include late-stage DPP generating facilities in ERAS studies and will result in reduced network upgrades due to lower line loadings.[594] Clean Energy Associations aver that this will result in reliability gaps because MISO will not model all known near-term system changes that will occur when the ERAS generating facility reaches commercial operation. Clean Energy Associations assert that ERAS already departs from MISO's standard practice and that ERAS interconnection requests will be studied only with interconnection requests that have already achieved a GIA (i.e., interconnection requests from prior DPP cycles or completed ERAS cycles), while DPP interconnection requests will share headroom with all other interconnection requests in the DPP cycle.[595] Clean Energy Associations thus contend that ERAS will effectively push current reliability gaps onto future interconnection requests that are not in ERAS.[596]

240. Clean Energy Associations argue that the use of the annual MTEP reliability study process to resolve over-allocation of transmission headroom across ERAS and the DPP will not effectively address reliability concerns, as the annual MTEP reliability study process sets local balancing area constraints to limit power flows between local balancing areas, masking constraints that would otherwise show up in the DPP process.[597] Clean Energy Associations assert that, if MTEP does not capture the constraints caused by overallocated headroom due to not including all the expected projects coming online at the same time, the resulting unaddressed constraints will fall to subsequent DPP cycles.

241. Furthermore, Clean Energy Associations argue that, even with a numerical cap on the total number of interconnection requests and the number of interconnection requests per zone, ERAS interconnection requests could still trigger significant reliability impacts

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[592] Clean Grid Alliance Protest at 20 (citing Clean Energy Associations Protest, Docket No. ER25-1674, Aff. at P 2).

[593] *Id.* at 22.

[594] Clean Energy Associations Protest at 12, 21.

[595] *Id.* at 12-13.

[596] *Id.* at 13.

[597] *Id.* at 22.

that require substantial network upgrades, if they are large and located in areas where they have a high impact on a highly congested part of the transmission system.[598] Clean Energy Associations assert that the cap on the number of interconnection requests and interconnection requests per zone quarterly does not negate the potential for overlapping allocation of headroom that is insufficiently reconciled via MTEP.

242. Relatedly, NextEra argues that the MTEP process may not be able to resolve issues caused by ERAS because: (1) timing issues between ERAS and MTEP processes may limit the efficacy of the MTEP to prevent costs of network upgrades needed to resolve issues missed in the ERAS process from being passed on to interconnection customers in the DPP; (2) the MTEP and DPP processes use different underlying assumptions, including dispatch assumptions; and (3) MISO assesses deliverability differently in the MTEP and DPP processes.[599]

243. Furthermore, several protesters raise concerns regarding cost allocation for network upgrades that are identified in the MTEP process. MISO IPPs argue that the ERAS study process will not identify the need for required upgrades, possibly leaving customers that entered DPP prior to the ERAS interconnection requests left to foot the bill.[600] Furthermore, MISO IPPs assert that allocating costs for network upgrades triggered by ERAS interconnection requests through MTEP could run afoul of the Commission's cost allocation requirements and be inconsistent with cost causation requirements.[601]

244. Some protesters assert that the Revised ERAS Proposal will violate cost causation principles by allocating costs of such upgrades to load.[602] NextEra states that MISO claims that costs will be allocated to load in the same transmission pricing zone where a network upgrade is located and expects that "this load will include the load that is

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[598] *Id.* at 24.

[599] NextEra Docket No. ER25-1674 Protest at 45 (citing Cody Doll Aff. at 7-9).

[600] Clean Energy Associations Docket No. ER25-1674 Protest at 28-29; MISO IPPs Docket No. ER25-1674 Protest at 23; NextEra Docket No. ER25-1674 Protest at 45-48; PIOs Docket No. ER25-1674 Protest at 19-21.

[601] MISO IPPs ERAS 1.0 Protest at 47.

[602] Clean Energy Associations Docket No. ER25-1674 Protest at 28-29; NextEra Docket No. ER25-1674 Protest at 46-48.

benefiting from the ERAS and DPP interconnection requests;[603] however, NextEra argues that interconnection requests frequently trigger the need for network upgrades in neighboring transmission zones, meaning that transmission customers and ratepayers in one transmission pricing zone may be required to subsidize the costs of serving other transmission customers and ratepayers.[604] NextEra argues that this subsidization may be exacerbated because the claimed need leading to issuance of a RERRA verification for an ERAS interconnection request may be limited to a locality or municipality, but that ERAS interconnection request may eventually create a need for significant upgrades through the MTEP process, requiring a transmission pricing zone to subsidize the cost of upgrades to meet a locality's need.[605] PIOs contend that while there are circumstances in which it is appropriate for load to pay the costs of new transmission rather than generation, that is not the case for the proposed cost shifts driven by ERAS.[606] PIOs argue that the proposed shift in costs driven by ERAS projects to load would be haphazard and would not necessarily ensure that the portion of load that shoulders any such costs is also the portion of load that benefits from the ERAS and DPP generating facilities whose full impact was not captured in their parallel studies.[607] Thus, PIOs argue that the ERAS proposal moves transmission planning in the opposite direction from the Commission's policies established in Order Nos. 1000[608] and 1920.[609]

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[603] NextEra Docket No. ER25-1674 Protest at 47 (citing Witmeier Docket No. ER25-1674 Rebuttal Testimony at 38:5-9).

[604] *Id*. at 47-48.

[605] *Id.* at 48.

[606] PIOs Docket No. ER25-1674 Protest at 21.

[607] *Id.* (citing PIOs Docket No. ER25-1674 Protest, attach. A (Testimony of Houtan Moaveni) at 14-16).

[608] *Id.*; *Transmission Plan. & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 136 FERC ¶ 61,051 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g & clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

[609] PIOs Docket No. ER25-1674 Protest at 21; *Bldg. for the Future Through Elec. Reg'l Transmission Plan. & Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068, *order on reh'g & clarification*, Order No. 1920-A, 189 FERC ¶ 61,126 (2024), Order No. 1920-B, 191 FERC ¶ 61,026 (2025), *appeal docketed sub nom. Appalachian Voices v. FERC*, No. 24-1650 (4th Cir. pet. consolidated Aug. 8, 2024).

245. Clean Grid Alliance argues that MISO's proposal to allow "backfilling" of a quarterly study period is unjust and unreasonable.[610]

iii. Answers

(a) MISO Answer

246. MISO asserts that the Revised ERAS Proposal will not take resources away from DPP processing because it will use the ERAS application fee and study deposit to cover costs related to processing ERAS interconnection requests, including improving study tools and hiring additional staff.[611] MISO further asserts that it has carefully crafted the Revised ERAS Proposal to avoid supplanting the DPP or harming DPP interconnection customers.[612]

247. MISO contends that, as the Commission noted in the PJM RRI Order, arguments that separate study processes like ERAS will harm existing interconnection customers are speculative. MISO asserts that it is not proposing to delay the DPP queue processing schedule as a result of the ERAS proposal, that no DPP milestones have been altered, and that no interconnection customer will lose its queue position.[613] MISO also argues that it has taken steps to ensure that current DPP interconnection requests are protected from losing available transmission capacity.[614] MISO states that it will build the ERAS model based on the existing MTEP model, which will not remove any available transmission system headroom from DPP interconnection requests.[615] MISO explains that ERAS will only incorporate approved generating facilities, while the DPP will incorporate all higher and equally-queued interconnection requests, which includes speculative projects.[616] MISO explains that it will follow its existing processes to determine if already planned projects can alleviate constraints. MISO also argues that by not updating the base case for each DPP cycle once the study process starts, except for changes due to withdrawals

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[610] Clean Grid Alliance Protest at 28.

[611] MISO Docket No. ER25-1674 Answer at 47.

[612] MISO Answer at 29.

[613] MISO Docket No. ER25-1674 Answer at 17 (citing PJM RRI Order, 190 FERC ¶ 61,084 at P 245).

[614] MISO Answer at 29-30; MISO Docket No. ER25-1674 Answer at 39.

[615] MISO Docket No. ER25-1674 Answer at 39-40.

[616] MISO Answer at 2.

or generator retirements, transmission capacity available for DPP interconnection requests is not being taken away by ERAS interconnection requests approved outside the DPP cycle.[617] MISO also argues that using the latest, approved MTEP base case to reconcile the models insulates existing DPP interconnection requests from costs shifts due to the ERAS process. MISO argues that there is no evidentiary support to protesters' arguments that ERAS interconnection requests will result in higher network upgrade costs for DPP interconnection requests and that ERAS requires interconnection customers to pay all network upgrade costs associated with their proposed interconnection requests.[618] MISO further states that network upgrades approved through the ERAS process can be used to mitigate constraints in the DPP process, which will have a positive impact on the DPP.

248. Regarding concerns about whether the ERAS proposal will protect DPP interconnection customers from ERAS interconnection customer withdrawals prior to EGIA execution, MISO asserts that DPP interconnection requests are adequately protected from ERAS withdrawals because an ERAS interconnection request that does not reach EGIA execution will never be modeled in DPP cycles and therefore cannot impact the DPP.[619] Further, MISO asserts that the proposed ERAS study process will ensure that a withdrawal will not cause restudies in the ERAS process, as ERAS interconnection requests will be studied serially, or in the DPP process, as the parallel ERAS and DPP studies are done in tandem. MISO clarifies that a DPP interconnection request that moves to ERAS will be liable for any harm caused to other DPP interconnection requests in the study group and will be subject to automatic withdrawal penalties.

249. In response to concerns about ERAS not being a one-time process, MISO states that it does not want to limit participation to a one-time opportunity if some interconnection customers or RERRAs take more time to identify projects that could participate in ERAS.[620] MISO contends that it would need to do a cluster study for a one-time process, which would prevent interconnection customers from more timely knowing their full network upgrade costs, as those costs would be contingent on the decisions made by all the other ERAS interconnection requests in the cluster.

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[617] *Id.* at 29-30; MISO Docket No. ER25-1674 Answer at 40 (citing Witmeier Docket No. ER25-1674 Rebuttal Testimony at 35).

[618] MISO Docket No. ER25-1674 Answer at 40.

[619] MISO Docket No. ER25-1674 Supplemental Answer at 5.

[620] MISO Docket No. ER25-1674 Answer at 35-36.

250. MISO also argues that the ERAS proposal will not result in queue jumping because the ERAS process is open to all interconnection customers that meet the eligibility criteria, and any interconnection request selected to participate is not similarly situated to other interconnection requests because that request has a greater ability to meet near-term resource adequacy needs.[621] MISO contends that, similar to the Commission's findings when accepting PJM's RRI proposal, no DPP interconnection requests will be displaced by ERAS, no DPP milestones have been altered, and no DPP interconnection customer will lose its queue position as a result of ERAS.[622]

251. MISO states that, because the Revised ERAS Proposal establishes a cap on the number of interconnection request that will be studied under ERAS and will occur over a limited timeframe, the DPP is further protected.[623] MISO asserts that addressing the ongoing delays in the DPP to reach a study processing time of one year remains a priority for MISO, and ERAS is a separate process needed to address near-term reliability and resource adequacy needs.

(b) <u>Additional Answers</u>

252. Clean Grid Alliance argues that MISO's contention that its staffing resources will not be diverted from processing the DPP queue to support the ERAS process is unsupported.[624] Clean Grid Alliance also disagrees with MISO's arguments that the ERAS proposal would not enable queue jumping and states that the Commission has previously rejected such queue jumping proposals.[625]

253. Clean Grid Alliance argues that MISO has not addressed protesters' arguments that ERAS will harm DPP interconnection customers through disrupting modeling, causing cascading restudies, and shifting costs.[626] In addition, Clean Grid Alliance disagrees with MISO's arguments that the ERAS process will not take headroom from

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[621] *Id.* at 34.

[622] *Id.* (citing PJM RRI Order, 190 FERC ¶ 61,084 at P 245).

[623] MISO Answer at 30.

[624] Clean Grid Alliance Docket No. ER25-1674 Answer at 24-25.

[625] *Id.* at 16 (citing MISO Docket No. ER25-1674 Answer at 34; *Sw. Power Pool, Inc.*, 147 FERC ¶ 61,201 at P 124).

[626] Clean Grid Alliance First Answer at 8-9.

DPP interconnection requests.[627] Clean Grid Alliance argues that MISO has not explained how the implementation of ERAS will not result in the same transmission capacity being allocated twice in concurrent DPP (i.e., DPP 2023 cycle) and ERAS studies, and then not result in interconnection requests in the next DPP cycle (i.e., DPP 2025 cycle) having to address any overallocations as pre-existing conditions. Clean Grid Alliance argues that if ERAS interconnection customers are interconnecting to, or depend on, the same transmission lines as DPP interconnection customers, then, given ERAS interconnection customers' priority to that transmission headroom, the DPP interconnection customers will be harmed.[628] Clean Grid Alliance argues that such a scenario is likely because MISO will not model DPP interconnection requests, even late-stage DPP Phase III interconnection requests, in ERAS interconnection studies.[629] In addition, Clean Grid Alliance claims that the ERAS process may harm DPP interconnection requests because serial restudies will absorb MISO staff time, given that restudies are necessary when an interconnection request withdraws, regardless of network upgrades remaining, due to the potential for counterflows.[630] In addition, Clean Grid Alliance raises concerns that MISO's proposal does not require ERAS interconnection customers to provide 100% of network upgrade costs as an initial payment, arguing that MISO may have to initiate legal action to collect funds from an ERAS interconnection customer with an EGIA that withdraws absent such protection.[631]

254. Clean Energy Associations argue that MISO fails to refute arguments that the ERAS study process will harm DPP interconnection customers stemming from: (1) uncertainty regarding the dispatch model that would be used for ERAS studies; (2) MISO's proposal to not include late-stage DPP interconnection requests in ERAS studies; and (3) use of the annual MTEP process to resolve over-allocation of transmission headroom across ERAS and DPP processes.[632] Clean Energy Associations argue that MISO's proposal will systematically advantage ERAS interconnection

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[627] *Id.* at 17.

[628] Clean Grid Alliance Docket No. ER25-1674 Answer at 18.

[629] Clean Grid Alliance First Answer at 8 (citing Clean Grid Alliance Protest at 21); Clean Grid Alliance Docket No. ER25-1674 Answer at 18. Clean Grid Alliance argues that MISO's submissions in prior filings before the Commission have noted that interconnection requests in DPP Phase III have a 90% success rate. *Id.*

[630] Clean Grid Alliance Docket No. ER25-1674 Answer at 19.

[631] *Id.* at 26.

[632] Clean Grid Alliance First Answer at 8 (citing Clean Grid Alliance Protest at 21); Clean Grid Alliance Docket No. ER25-1674 Answer at 10.

requests and lead to unresolved constraints, which will fall to subsequent DPP interconnection requests to address if the MTEP does not capture them. Clean Grid Alliance further asserts that LSEs have not committed to paying the cost for additional transmission capacity that MISO proposes to shift to MTEP.[633]

255. Clean Grid Alliance argues that MISO's admission, that ERAS interconnection requests "could be included in the ERAS process but ultimately not be approved in the state regulatory process and thus may not be completed at that point in time," conflicts with MISO's assertions that restudies in the ERAS process will not be an issue.[634]

256. MISO IPPs state that MISO did not respond to MISO IPPs' arguments that different study assumptions for ERAS and DPP interconnection requests will cause MISO to underestimate network upgrades for ERAS interconnection requests and shift the costs of those network upgrades to other entities.[635]

257. Clean Grid Alliance argues that MISO fails to address the Revised ERAS Proposal's harm to the DPP by allowing queue jumping and introducing reliability gaps caused by transmission capacity overallocation. Clean Grid Alliance avers that the Revised ERAS Proposal will only mitigate reliability impacts within the local balancing area where an ERAS interconnection request is located, while the DPP mitigates reliability impacts across the entire MISO footprint. Clean Grid Alliance contends that the Revised ERAS Proposal's approach is discriminatory. Clean Grid Alliance asserts that these harms are unnecessary because MISO already has the provisional GIA process through which interconnection customers can pursue an expedited interconnection and GIA.[636]

258. PIOs argue that MISO's answer does not address PIOs' concern that ERAS interconnection requests will receive more favorable study assumptions, which will likely enable ERAS interconnection requests to pay less for interconnection service than similarly situated DPP interconnection requests. PIOs contend that MISO's reliance on the fact that ERAS will incorporate only approved generating facilities, while the DPP includes all prior queued interconnection requests, is a key characteristic that is creating

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[633] Clean Grid Alliance First Answer at 9 (citing Clean Grid Alliance Protest at 22).

[634] Clean Grid Alliance Docket No. ER25-1674 Answer at 13-14 (citing MISO Docket No. ER25-1674 Answer at 16).

[635] MISO IPPs Answer at 13.

[636] Clean Grid Alliance Second Answer at 3.

the undue preference for ERAS interconnection requests.[637] PIOs aver that a process that subjects interconnection requests to two different baseline study assumptions will not eliminate inherent risks present when multiple interconnection requests rely on the same transmission infrastructure.[638]

c. **Commission Determination**

259. We find that MISO's proposal to evaluate ERAS interconnection requests in a separate, serial study process is just and reasonable and not unduly discriminatory or preferential and accomplishes the purposes of Order Nos. 2003 and 2023. Further, we find that MISO's Revised ERAS Proposal will not harm DPP interconnection customers and that the cap on the number of ERAS interconnection requests that may be studied provides a further guardrail to ensure ERAS is a limited process.

260. MISO seeks variations from the *pro forma* LGIP and *pro forma* LGIA under the independent entity variation standard, which provides that the proposed variations must be just, reasonable, not unduly discriminatory or preferential, and accomplish the purposes of Order Nos. 2003 and 2023.[639] MISO proposes to study ERAS interconnection requests using its existing NRIS modeling standards and the most recent MTEP base case that includes all generating facilities with executed GIAs. While protesters argue that limiting ERAS to 10 serial studies per quarterly study period does not alleviate the concern that the proposed serial study process is inconsistent with the requirements of Order No. 2023, we find that MISO's proposed approach is just and reasonable and accomplishes the purposes of Order Nos. 2003 and 2023. MISO's proposal to use a serial study process here does not present concerns related to queue withdrawals and restudies traditionally raised by serial cluster processes[640] because, as discussed above, interconnection projects in the ERAS process are less likely to be speculative and withdraw due to the enhanced commercial readiness requirements. MISO represents that there will not be any DPP or ERAS restudies associated with any ERAS projects that do withdraw.[641] Further, withdrawing ERAS interconnection customers are also responsible for any network upgrade costs assigned to them in an EGIA, which would mitigate risks regarding any potential cost impacts to lower-queued

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[637] PIOs Answer at 8-9.

[638] *Id.* at 9.

[639] *See* Transmittal at 23.

[640] Order No. 2023, 184 FERC ¶ 61,054 at P 47.

[641] MISO Docket No. ER25-1674 Supplemental Answer at 5.

interconnection customers.[642] Moreover, MISO's proposal to study ERAS interconnection requests using its existing NRIS modeling standards and the most recent MTEP base case while including all generating facilities with executed GIAs is just and reasonable because it will allow MISO to expedite the ERAS studies through a serial process that excludes DPP interconnection requests that are more likely to withdraw, e.g., those DPP interconnection requests that have not executed GIAs, because including such resources would create uncertainty in the ERAS study process.

261. We find protesters' claims that the implementation of ERAS will delay MISO's processing of the DPP to be speculative. As MISO explains, it will use the ERAS non-refundable application fee to support the necessary staffing and resources to allow MISO to process both the DPP and ERAS studies without negative impacts to the DPP queue.[643] We also note MISO's stated commitment to ensure proper staffing and resource allocation to avoid any delays to DPP study processing.[644]

262. Further, protesters argue that interconnection customers in future DPP cycles may be subject to higher network upgrade costs or curtailments under a potential scenario where the MTEP process does not identify network upgrades sufficient to resolve issues created by parallel DPP and ERAS studies. We find protesters' argument that MTEP might not address needed reliability upgrades to be speculative, and so we disagree with protesters that the potential for such an outcome renders MISO's proposal unjust and unreasonable. The Commission has previously found that interconnection customers have no legal rights to a given system topology or to whether upgrades may be required.[645] Further, given the way MISO's interconnection queue has been designed to encourage orderly withdrawals, lower-queued interconnection customers are frequently faced with changing network upgrade costs. Moreover, MISO explains that its proposed ERAS study will identify network upgrades and other facilities necessary for the interconnection of ERAS interconnection customers, and we therefore disagree that ERAS projects will

[642] MISO, Proposed Tariff, attach. X (GIP) (171.0.0), § 3.9.6.3.

[643] MISO Answer at 141; MISO Docket No. ER25-1674 Answer at 47.

[644] MISO Docket No. ER25-1674 Answer at 47. Specifically, MISO states that the non-refundable $100,000 D1 application fee will allow MISO "to hire additional staff, as needed, to ensure that adoption of the ERAS process does not create harmful effects to the DPP interconnection process" and that it "is committed to making other resource or staffing changes to ensure that this remains true throughout the ERAS process." *Id.*

[645] PJM RRI Order, 190 FERC ¶ 61,084 at P 192.

either be inappropriately assigned network upgrade costs or not assigned network upgrade costs at all.

263. We do not find persuasive protesters' arguments that interconnection customers currently in the DPP queue will be harmed as a result of ERAS and will be subject to higher network upgrade costs due to the ERAS proposal. As MISO explains, DPP studies use the most recent MTEP model at the time that MISO commences the DPP study cycle as the base case, and that model will not be updated to include ERAS interconnection requests. Furthermore, as Texas Commission explains, the Revised ERAS Proposal protects interconnection customers currently in the DPP queue by preventing late-stage transfers, which could lead to unplanned restudies, and by requiring interconnection requests that transfer to ERAS to pay withdrawal penalties.[646] Therefore, interconnection customers currently in the DPP process will not see higher assigned network upgrade costs because their interconnection requests will continue to be studied without accounting for ERAS interconnection requests. In addition, we note that interconnection customers that submit interconnection requests into future DPP cycles will have notice of the existence of the ERAS process prior to submitting their interconnection requests and could factor the ERAS process into their commercial decisions. Furthermore, we note that DPP interconnection requests that have not reached Decision Point II in the 2022, 2023, and later cycles are eligible to transfer to the ERAS process, if they meet the eligibility requirements.[647]

264. In response to protesters' arguments that MISO's proposal will result in cost allocation inconsistent with cost causation, and that there is the potential for needed network upgrades to be identified in the MTEP process because ERAS interconnection requests may not be assigned their full "but for" costs, we find MISO's proposal to address through its existing processes any deliverability issues identified as a result of differences between the models used in the ERAS and DPP studies to be just and reasonable. As MISO explains, its current Tariff allocates to load the costs of network upgrades identified through its MTEP process, as needed, to maintain resource deliverability. Therefore, MISO's proposal is consistent with its existing, Commission-approved process for addressing deliverability issues identified outside of its process for studying interconnection requests.[648]

265. Protesters contend that the ERAS process is not a "one time" process because it includes multiple, quarterly study periods over several years. We do not find this concern

[646] Texas Commission Comments at 11.

[647] Transmittal at 22.

[648] MISO Answer at Tab B, MISO Transmittal, Docket No. ER25-1674, at 30 (filed Apr. 21, 2025); Witmeier Docket No. ER25-1674 Rebuttal Testimony at 38-39.

persuasive. The Revised ERAS Proposal is timebound and will sunset at the earlier of August 31, 2027 or when MISO has studied 68 ERAS interconnection requests. We disagree with the arguments that the Revised ERAS Proposal must be a one-time cluster study, such as PJM's RRI proposal, to be just and reasonable. The Commission's acceptance of PJM's RRI does not preclude the Commission from accepting a different RTO or ISO proposal, such as MISO's proposal, which is not only tailored to address the specific needs of the MISO region but also considers the distinct characteristics of the MISO region.[649]

5. **Affected Systems**

a. **MISO's Filing**

266. MISO explains that, regarding affected system studies, neighboring transmission providers will have the right to evaluate the impact of ERAS interconnection requests on their transmission systems, just as with DPP interconnection requests.[650] MISO further explains that any ERAS interconnection request that meets the Joint Targeted Interconnection Queue (JTIQ) criteria will be subject to JTIQ study procedures.[651] MISO notes that the Revised ERAS Proposal was designed with the expectation that MISO would use existing affected system study processes and that it is actively working with multiple seams partners to develop additional seams procedures to incorporate the ERAS process.[652]

267. MISO proposes that ERAS interconnection requests will adhere to the same affected system screening criteria as applicable to DPP interconnection requests, with the following exceptions:

a. The transmission provider will submit all necessary information for an affected system to study an ERAS interconnection request no later than 10 calendar days prior to the applicable ERAS study kickoff;

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[649] *See* Order No. 2003, 104 FERC ¶ 61,103 at P 826 (stating that RTOs/ISOs "shall have greater flexibility to customize [their] interconnection procedures and agreement to fit regional needs").

[650] Transmittal at 38.

[651] *Id.* at 38, 48, 51, 55, 59-60; MISO, Proposed Tariff, attach. X (GIP) (175.0.0), §§ 1, 3.9.5, 7.3.1.4, 7.3.2.3.1.

[652] Witmeier Testimony at 64.

b. The transmission provider will provide any affected system analysis received from the affected system to the ERAS interconnection customer promptly upon receipt;

c. If affected system study results and cost information are not available at the time an EGIA is tendered, then such EGIA will include an obligation to execute any agreements for the study, construction, or funding of network upgrades identified by the affected system within 15 calendar days after such an agreement is tendered to the interconnection customer;

d. The transmission provider will submit ERAS interconnection request information to the affected system operator individually and request that the affected system operator study the ERAS interconnection request serially; and

e. When MISO and the affected system operator use a specified point in the DPP, such as a decision point or a DPP phase kickoff date, to establish the queue priority date of a MISO interconnection request, MISO will assert a queue priority date for ERAS interconnection requests as of the date that MISO commences the ERAS system impact study unless the controlling agreement between MISO and the affected system operator provides for an alternative queue priority date. Additionally, for interconnection requests with an earlier queue priority date, "in accordance with this section 9.4.3 (a) will have a higher relative queue priority than those with a later queue priority date."[653]

268. MISO states that it will provide affected system study results in the final ERAS study report, in the draft EGIA, or when they are received from the affected system operator, if they are not available at the time of the final ERAS study results and/or at the time of EGIA execution.[654] MISO explains that, in the event that an interconnection customer withdraws its ERAS interconnection request and terminates its EGIA after execution of the EGIA or after requesting that the EGIA be filed unexecuted, the interconnection customer will be liable for the network upgrades arising from the affected system study process.[655]

[653] MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.5.2.

[654] Transmittal at 38; MISO, Proposed Tariff, attach. X (GIP) (175.0.0), §§ 3.9.3, 3.9.5; *see also* Witmeier Testimony at 65.

[655] Witmeier Testimony at 66.

269. MISO contends that this process will ensure a timely affected system study appropriate for the ERAS process while still providing necessary flexibility for MISO and individual seams partners.[656]

b. <u>Responsive Pleadings</u>

i. <u>Protests</u>

270. MISO IPPs argue that the Revised ERAS Proposal fails to adequately address how MISO will manage affected system studies for ERAS interconnection requests and how such affected system studies may impact DPP interconnection requests.[657] MISO IPPs argue that affected system studies are time-consuming and can cause substantial delays, yet MISO largely ignores the issue of affected system studies, merely stating that MISO will include affected system study results in the ERAS study if available, and if not available, MISO will provide them separately when received from the applicable affected system. MISO IPPs argue that this leaves questions, including whether affected system studies will cause delays in processing ERAS interconnection requests and/or DPP interconnection requests.[658]

271. Invenergy argues that ERAS does not align with Order No. 2023's requirement that affected system studies be completed in clusters in order of queue priority based on when the affected system study agreement was executed. Invenergy states that while MISO has filed provisions for its JTIQ with SPP, it does not explain how the serial nature of ERAS would interface with the affected system cluster study process.[659]

272. Clean Grid Alliance argues that information regarding the affected system process remains unclear and lacks critical details on MISO's coordination with its seams partners.[660] Clean Grid Alliance asserts that MISO has not explained how neighboring transmission systems would be able to individually process 10 ERAS interconnection requests quarterly through 2027, as well as how those studies would align with the affected system operator's study of DPP interconnection requests and its own queue.

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[656] Transmittal at 51.

[657] MISO IPPs Docket No. ER25-1674 Protest at 25 (citing MISO, Docket No. ER25-1674, Proposed Tariff, attach. X (GIP) (169.0.0), § 3.9.3).

[658] MISO IPPs Docket No. ER25-1674 Protest at 25 (citing MISO, Docket No. ER25-1674, Proposed Tariff, attach. X (GIP) (169.0.0), § 3.9.3).

[659] Invenergy Protest at 18.

[660] Clean Grid Alliance Protest at 27.

Similarly, MISO IPPs argue that it is unclear whether affected system studies will cause delays in processing DPP interconnection requests.[661] Clean Grid Alliance argues that affected system coordination has been a significant source of queue processing delays, and such delays are misaligned with meeting MISO's claimed near-term resource adequacy and reliability needs.[662]

273. Clean Energy Associations contend that ERAS interconnection customers may be put in the position to sign an EGIA before receiving information about affected system networks upgrades and argues that this conflicts with the requirement adopted in Order No. 2023 for a host transmission provider to delay the deadline for an interconnection customer to file its LGIA, at an interconnection customer's request, if the affected system study results have not been received.[663]

274. Clean Energy Associations argue that the risk of limited information on affected system study results might deter independent power producers' interconnection requests that are well suited to meet near-term resource adequacy needs from applying for the ERAS process, while posing relatively little risk to LSE-owned or affiliated generation that can pass along unexpected affected system network upgrade costs to consumers.[664]

ii. Answers

(a) MISO Answer

275. In response to concerns regarding the lack of detail on the affected system study process for ERAS interconnection requests, MISO explains that ERAS interconnection requests will be subject to the same affected system process as DPP interconnection requests, including the same criteria used by MISO's seams partners.[665]

276. Further, in response to protesters' arguments that LSEs can pass along affected system costs to consumers without bearing the same risk as independent power producers, MISO states that differences in risk profiles already existed between LSEs and

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[661] MISO IPPs Docket No. ER25-1674 Protest at 25 (citing MISO, Docket No. ER25-1674, Proposed Tariff, attach. X (GIP) (169.0.0), § 3.9.3).

[662] Clean Grid Alliance Protest at 28.

[663] Clean Energy Associations Docket No. ER25-1674 Protest at 24-25.

[664] Clean Energy Associations Protest at 24-25 (citing Clean Energy Associations Docket No. ER25-1674 Protest at 25, 48-51).

[665] MISO Docket No. ER25-1674 Answer at 41.

independent power producers prior to the Revised ERAS Proposal and are not a result of that proposal.[666]

(b) **Additional Answers**

277. Clean Grid Alliance argues that MISO fails to explain how the Revised ERAS Proposal would lead to an expedited process to bring new generation online if ERAS and DPP interconnection requests are subject to the same affected system processes.[667] Clean Grid Alliance also argues that MISO does not provide sufficient information about how it will coordinate affected system studies with all seams partners and that the lack of information does not satisfy MISO's burden under FPA section 205.[668] Further, Clean Grid Alliance argues that MISO's statement that it will merely request that an affected system operator study ERAS interconnection requests on a serial basis is contrary to the Commission's reforms in Order No. 2023 to firm-up the affected system study process and draw clearly defined parameters.[669]

c. **Commission Determination**

278. We find that MISO's proposed process to notify affected system operators of potential impacts to their transmission systems from ERAS interconnection requests in a serial fashion, as well as MISO's requirements regarding affected system network upgrade obligations on ERAS interconnection customers, to be just and reasonable and not unduly discriminatory or preferential and accomplishes the purposes of Order Nos. 2003 and 2023. MISO's proposal will ensure that ERAS interconnection requests are evaluated for impacts on affected systems like other interconnection requests, consistent with Commission precedent.[670] As MISO states, the ERAS interconnection requests are subject to the same affected system study process as DPP interconnection requests, including the same criteria currently used by MISO's seams partners, albeit MISO will notify those seams partners of potential impacts in a serial manner. MISO's proposal to use a serial study process here does not present concerns related to queue

[666] *Id.* at 29-30.

[667] Clean Grid Alliance Docket No. ER25-1674 Answer at 10.

[668] *Id.* at 20-21.

[669] *Id.* at 22 (citing MISO Answer at 44; Order No. 2023, 184 FERC ¶ 61,054 at P 1111).

[670] Order No. 2003, 104 FERC ¶ 61,103 at P 118.

withdrawals and restudies traditionally raised by serial study processes[671] because, as discussed above, interconnection projects in the ERAS process are less likely to be speculative and withdraw due to the enhanced commercial readiness requirements.

279. We disagree with protesters that requiring ERAS interconnection customers to execute an EGIA, or request that it be filed unexecuted, prior to receiving affected system study results is unjust and unreasonable. The proposed ERAS eligibility criteria and requirements are intended to ensure that non-speculative, "shovel ready" projects enter the ERAS process and move expeditiously to EGIA execution. To the extent that an interconnection customer is not willing to execute an EGIA without affected system study results, the interconnection customer may withdraw from the ERAS process.[672] Additionally, as the Commission noted in Order No. 2023-A, there is no requirement for affected system network upgrade costs to be known at the time of LGIA execution, which in ERAS would be at the time of EGIA execution or requesting that it be filed unexecuted.[673]

280. Finally, we disagree with the concerns raised by certain protesters that MISO's Revised ERAS Proposal provides vague information regarding affected system studies. We find that MISO's proposed Tariff language provides sufficient detail regarding the process in which MISO will notify affected system operators of potential impacts from ERAS interconnection requests, as well as how MISO will relay the results of affected system analysis to ERAS interconnection customers.

6. <u>Miscellaneous</u>

a. <u>MISO's Filing</u>

281. MISO states that following the Commission's rejection of the Initial ERAS Proposal, it re-engaged with stakeholders to develop the Revised ERAS Proposal.[674] MISO states that it presented the Revised ERAS Proposal at the Planning Action Committee meeting on May 28, 2025 and received feedback from stakeholders through

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[671] Order No. 2023, 184 FERC ¶ 61,054 at P 47.

[672] We note that withdrawing ERAS interconnection requests that withdraw prior to executing an EGIA will forfeit their non-refundable $100,000 D1 payment. *See* MISO, Proposed Tariff, attach. X (GIP) (175.0.0) § 3.9.2.

[673] Order No. 2023-A, 186 FERC ¶ 61,199 at P 494.

[674] Transmittal at 19.

its informal feedback tool.[675] MISO also asserts that it held "dozens" of calls with stakeholders.[676]

a. Responsive Pleadings

i. Comments in Support

282. Big Rivers Electric asserts that the Revised ERAS Proposal underwent extensive review and discussion through MISO's stakeholder process, and MISO adopted many stakeholder recommendations to enhance the proposal's effectiveness. Big Rivers Electric further states that MISO has provided extensive opportunity for all interested parties to participate in stakeholder processes and that the Revised ERAS Proposal reflects substantial stakeholder input gathered over the past several months.[677]

283. CenterPoint states that MISO's Revised ERAS Proposal enjoys widespread support from the State of Indiana, as expressed by a concurrent resolution passed by the Indiana House of Representatives and Senate urging reform processes to expedite the approval of electric transmission and generation projects and a letter from Indiana Governor Mike Braun expressing his strong support for MISO's efforts to address pressing resource adequacy challenges.[678] Furthermore, CenterPoint notes that Indiana Energy Association has expressed its support for the Revised ERAS Proposal, as it will help account for the growing complexity of the energy landscape and ensure that sufficient resources are available to meet immediate and future demand.

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[675] *Id.* (citing MISO, *Expedited Resource Addition Study (ERAS) Next Steps* (May 28, 2025), https://cdn.misoenergy.org/20250528%20PAC%20Item%2008%20Expedited%20Resource%20Addition%20St udy%20(ERAS)%20Next%20Steps%20(PAC-2023-1)699836.pdf. ; Informal Feedback (2025), MISO, https://www.misoenergy.org/engage/stakeholder-feedback/2025/informalfeedback-2025/).

[676] Witmeier Testimony at 23.

[677] Big Rivers Electric Comments at 5-6.

[678] CenterPoint Comments at 5-6.

ii. **Protests**

284. Several protesters raise concerns over the stakeholder process that preceded the Revised ERAS Proposal.[679] Clean Grid Alliance states that MISO never informed stakeholders of its plan to request a shortened comment period.[680] PIOs contend that the silence from some states likely reflects the inadequate time to respond under the shortened comment period rather than their support.[681] Illinois Commission and PIOs assert that pre-filing stakeholder engagement on the Revised ERAS Proposal was limited due to MISO's quick refiling of its ERAS proposal, and there was no formal stakeholder feedback requested by MISO prior to filing the revisions.[682] PIOs and Clean Grid Alliance assert that MISO did not publicly share its proposed Tariff language prior to filing with the Commission.[683] PIOs state that they have had conversations with Minnesota State Commissioners who have expressed concern over the Revised ERAS Proposal.[684]

285. PIOs argue that this lack of stakeholder engagement renders the Revised ERAS Proposal legally vulnerable. According to PIOs, the record is insufficient for the Commission to make a reasoned decision, and MISO violated Order No. 719,[685] by which an RTO/ISO must be responsive to the needs of its customers and stakeholders.[686] PIOs allege that because MISO bypassed its normal stakeholder process and rushed the revision of the ERAS proposal, MISO failed to "make well-informed decisions that

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[679] Clean Grid Alliance Protest at 3-4; Illinois Commission Comments at 3; PIOs Protest at 1, 32-37.

[680] Clean Grid Alliance Protest at 3-4.

[681] PIOs Protest at 40.

[682] *Id.* at 34; Illinois Commission Comments at 3.

[683] Clean Grid Alliance Protest at 3; PIOs Protest at 35.

[684] PIOs Protest at 40-41 (citing Minnesota Commission, *MISO Quarterly Update Meeting* (June 6, 2025)). PIOs include quotes from Minnesota State Commissioners Hwikwon Ham and Joseph Sullivan, who voiced concerns over MISO's Revised ERAS Proposal process at the Minnesota Commission meeting on June 6, 2025.

[685] *Wholesale Competition in Regions with Organized Elec. Mkts*, Order No. 719, 125 FERC ¶ 61,071 (2008), *order on reh'g*, Order No. 719-A, 128 FERC ¶ 61,059, *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[686] PIOs Protest at 37-38.

reflect the full range of competing interests that may be affected," and also failed to meet the ongoing responsiveness requirements of Order No. 719.[687] PIOs contend that MISO has also arguably failed to meet the remaining criteria outlined in Order No. 719 to ensure a balancing of diverse interests and representation of minority interests because the Revised ERAS Proposal has not gone before the MISO Board of Directors.[688]

286. Finally, PIOs assert that MISO's rushed process to submit the Revised ERAS Proposal has resulted in numerous errors in its filing. PIOs state that, for example, the proposed Tariff language includes references in the EGIA to the three-year grace period provided for under GIP section 4.4.4 but that this conflicts with the language in proposed GIP section 3.9.8, which states that no changes to the commercial operation date are permitted once an interconnection request enters ERAS.[689]

iii. <u>Answers</u>

(a) <u>MISO Answer</u>

287. MISO states that it worked to quickly file the Revised ERAS Proposal to address the failures identified by the Commission in the May 2025 Order and to create a fully workable process that could be implemented this year.[690] MISO disagrees with protesters that the stakeholder process was rushed.[691] MISO asserts that it made targeted changes to its Initial ERAS Proposal, which was crafted with extensive stakeholder input, and that the changes were not created in a vacuum. MISO asserts that the Revised ERAS Proposal applied lessons learned from the original stakeholder process, considered the Commission's findings, and engaged with stakeholders on an individual basis to receive feedback on the proposed changes. Thus, MISO states that the Revised ERAS Proposal is the result of MISO responding to input from a variety of parties, stakeholder protests to the Initial ERAS Proposal, and feedback from individual stakeholders on the Revised ERAS Proposal. MISO asserts that it was necessary to quickly file the Revised ERAS

[687] *Id.* at 37 (citing Order No. 719, 125 FERC ¶ 61,071 at PP 506-509).

[688] *Id.*

[689] *Id.* at 38 (citing MISO, Proposed Tariff, attach. X (GIP) (175.0.0), §§ 4.4.4, 3.9.8; *id.* app. 6 (GIA) (106.0.0), art. 2.3.1.

[690] MISO Answer at 11.

[691] *Id.* (citing Clean Energy Associations Protest at 5-6; COMPP Protest at 6-7; Illinois Commission Comments at 2-3; Michigan Commission Protest at 2; PIOs Protest at 3).

Proposal to enable MISO to begin ERAS this year and to address its short-term resource adequacy and reliability needs.[692]

288. MISO states that it acknowledges the diverse interests of the stakeholder community but argues that developing a proposal that satisfies every interest of each stakeholder is not possible, nor should that be the benchmark.[693]

(b) <u>Additional Answers</u>

289. PIOs contend that MISO has not explained how holding a full stakeholder process to implement their suggestions would hinder the intended benefits of the Revised ERAS Proposal.[694] PIOs point out that OMS has not provided input on the Revised ERAS Proposal and that the Commission should not assume parties that supported the Initial ERAS Proposal also support the instant filing. PIOs argue that MISO's statements that it reached out to certain stakeholders are indicative of a secretive and exclusive process that falls short of the standards for stakeholder engagement outlined in Order No. 719. PIOs further argue that it is concerning that many of the revisions following the May 2025 Order appear to be at the request of individual stakeholders.[695]

b. <u>Commission Determination</u>

290. We disagree with protesters' contention that MISO's stakeholder process for the Revised ERAS Proposal is a basis to reject the filing. We find that MISO's stakeholder process for the Revised ERAS Proposal, though it entailed a more targeted approach than the one taken for the Initial ERAS Proposal, was sufficiently responsive to stakeholder feedback within the context of the revisions that MISO sought to make in its Revised ERAS Proposal, and consistent with MISO's existing governance procedures and stakeholder processes that the Commission has already approved as compliant with Order No. 719.[696] MISO states that the Revised ERAS Proposal focused on limited modifications to the Initial ERAS Proposal in order to be responsive to the May 2025 Order, and as such, MISO engaged with stakeholders on a targeted basis to refine an

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[692] *Id.* at 11-12.

[693] *Id.* at 30.

[694] PIOs Answer at 13 (citing Witmeier Docket No. ER25-1674 Rebuttal Testimony at 5).

[695] *Id.*

[696] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 133 FERC ¶ 61,068, at P 44 (2010).

existing prior proposal, as compared to the more extensive stakeholder process for the Initial ERAS Proposal, which included discussions, presentations, and numerous opportunities for stakeholder input.[697] According to MISO, following the May 2025 Order, MISO re-engaged with its stakeholders at the May 28, 2025 Planning Action Committee meeting, and thereafter, MISO received feedback from stakeholders through its informal feedback tool.[698] In addition, MISO states that the Revised ERAS Proposal incorporates feedback that was received for the Initial ERAS Proposal.[699] Thus, MISO asserts that the Revised ERAS Proposal responds to the Commission's guidance, stakeholder protests to the Initial ERAS Proposal, input from a variety of parties, and feedback from individual stakeholders on the Revised ERAS Proposal.[700]

<u>The Commission orders</u>:

(A) MISO's proposed Tariff revisions are hereby accepted, subject to condition, effective August 6, 2025, as requested, as discussed in the body of this order.

(B) MISO is hereby directed to submit a further compliance filing within 30 days of the date of this order, as discussed in the body of this order.

By the Commission. Commissioner Chang is concurring with a separate statement attached.

(S E A L)

Debbie-Anne A. Reese,
Secretary.

[697] *See* Transmittal at 18.

[698] *Id.* at 19.

[699] Witmeier Docket No. ER25-1674 Rebuttal Testimony at 5.

[700] MISO Answer at 11.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc.   Docket No. ER25-2454-000

(Issued July 21, 2025)

CHANG, Commissioner, *concurring*:

1. I concur in today's order accepting Midcontinent Independent System Operator, Inc's (MISO) Expedited Resource Addition Study (ERAS) proposal as just and reasonable, and not unduly discriminatory or preferential, because it is sufficiently tailored to reflect the specific needs that are rapidly arising in the MISO region. I write separately, given my prior dissent on PJM Interconnection, L.L.C.'s (PJM) Reliability Resource Initiative (RRI) proposal.[1]

2. Regulators and the utilities we oversee are responsible for ensuring that customers' needs are reliably and affordably met. For more than two decades, the Commission and the industry have relied on non-discriminatory interconnection procedures to facilitate access for new generation of all types. It is no secret that queues around the country, and particularly in the regional transmission organizations, are strained, which has significantly delayed the interconnection of new resources needed to serve new and existing loads. In response, the Commission, grid operators, and utilities are searching for solutions to process backlogged queues and expedite the interconnection of new resources.[2]

3. As a general matter, when faced with the challenge of the existing queue backlogs, I disfavor temporary solutions that do not help resolve the underlying problem. One-off short-term fixes can create additional problems and at times beget further one-off fixes. Developing these types of temporary proposals can detract from our collective efforts to address the more fundamental underlying issues. Furthermore, interconnection queue proposals that grant priority access to the system are, at minimum, in tension with

[1] *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084 (2025) (Chang, Comm'r, dissenting).

[2] *See, e.g.*, *Improvements to Generator Interconnection Procs. & Agreements*, Order No. 2023, 184 FERC ¶ 61,054, *order on reh'g*, 185 FERC ¶ 61,063 (2023), *order on reh'g*, Order No. 2023-A, 186 FERC ¶ 61,199, *errata notice*, 188 FERC ¶ 61,134 (2024); *Midcontinent Indep. Sys. Operator, Inc.*, 190 FERC ¶ 61,057 (2025) (approving MISO's generator interconnection queue cap).

competition and open access to the transmission system, which I believe have served customers well and should not be lightly discarded. Any deviations from the traditional Commission policy or existing, generally applicable queue procedures have a very high bar to clear.

4. Nonetheless, to meet the challenge of resource adequacy, as I explained in my dissent on PJM's RRI proposal, I am open to considering region-specific deviations from generally applicable interconnection queue procedures, given the Commission's paramount obligation to ensure that system operators can reliably serve their loads. Consistent with my analysis there, I assess here (1) whether MISO has demonstrated a sufficient reliability need to justify its proposed deviation, and (2) whether its proposed solution to that need is sufficiently tailored to address it. As discussed below, I find that MISO has satisfied both showings and I therefore approve its filing.

5. In the MISO region, most of the states and load serving entities (LSEs) have full responsibility over their own resource adequacy. These entities must ensure that sufficient supply and demand-side resources will be able to meet the growing load, and they do so through resource planning processes that state regulators oversee. Those resource planning processes are used to determine the utilities' investments in and contracts with new resources. MISO's proposal, which gives states a voice in which projects are selected for ERAS, codifies that selection decision into MISO's tariff for a limited set of projects that can most readily meet the specific needs identified by the states. MISO's ERAS process essentially moves the timing of when a proposed resource is selected by a state or an LSE from the after the interconnection process to before it, while maintaining the responsibility of the states and LSEs to ensure their footprints are resource adequate.

6. To facilitate such role for the state and the LSEs, each ERAS interconnection request must be accompanied by a written verification from a state entity that there is a need for the resource to interconnect to the MISO system. Along with that verification, the resource must have a power purchase agreement or other agreement to ensure that the resource has a commercial off-taker that plans to use the generation as soon as it is in commercial operation. The state and the LSE must identify a specific load addition or resource adequacy need that the planned resource will meet. These factors ensure that the ERAS projects are needed, supported by state entities, and sufficiently commercially viable to ensure the projects are actually constructed.

7. MISO has put in place significant requirements for the interconnection customers seeking to use the ERAS process. First, the proposal allows for an addition of only 68 projects to an expedited interconnection process. Of those 68, eight are reserved for restructured states, ten are reserved for independent power producers, and the remaining 50 are available to any type of interconnection customer, whether they are affiliated with the interconnecting transmission owner or not. While limiting the number of projects that

can participate is a minimum requirement to avoid creating a perpetual process under which certain resources can bypass the existing queue, it is not only the limited number of projects that makes MISO's ERAS proposal acceptable. Next, each project must demonstrate full site control and must provide several financial payments to enter the process. Both of these requirements will limit the projects that seek to enter the ERAS queue and will limit withdrawals from the ERAS process and other queue disruptions.

8. MISO's proposal requires that it study all of the ERAS requests by the earlier of the completion of all 68 studies or August 31, 2027. This ensures that this process does not linger past the time where MISO explains it needs the new generation the most and ensures that the ERAS process is truly a one-time exception to the traditional interconnection process as required by Orders No. 2003 and 2023. It is extremely important that this process is limited to a short term, one-time fix, and I appreciate MISO's revised requirements to ensure it completes the ERAS process by August 31, 2027.

9. MISO also explains that it will study no more than 10 projects per quarter, which will necessarily limit the staffing needed to process the ERAS studies. While MISO is implementing various computational solutions to improve the processing of interconnection requests, it is still constrained by the number of personnel that can work on the studies. By limiting to studying only 10 projects per quarter, MISO's ERAS proposal should help ensure that MISO's staff has enough bandwidth to continue the important work on processing the existing interconnection queue.[3]

10. Overall, I am persuaded that MISO's ERAS proposal is a just and reasonable solution to, in the short term, add resources that can address imminent demand growth and locational resource adequacy challenges. I truly hope this process is a successful bridge to the more durable and equitable implementation of MISO's latest interconnection reforms and the reforms required by Order No. 2023, which should provide better long-term outcomes under the Commission's traditional open access framework.

For these reasons, I respectfully concur.

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Judy W. Chang
Commissioner

[3] *Midcontinent Indep. Sys. Operator, Inc.*, 192 FERC ¶ 61,064, at P 110 (2025).

Document Content(s)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-29
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-30

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

Exhibit 92
Energy Emergency EO

Federal Register
Vol. 90, No. 18
Wednesday, January 29, 2025

Presidential Documents

Title 3—

The President

Executive Order 14156 of January 20, 2025

Declaring a National Energy Emergency

By the authority vested in me as President by the Constitution and the laws of the United States of America, including the National Emergencies Act (50 U.S.C. 1601 *et seq.*) (''NEA''), and section 301 of title 3, United States Code, it is hereby ordered:

Section 1. *Purpose.* The energy and critical minerals (''energy'') identification, leasing, development, production, transportation, refining, and generation capacity of the United States are all far too inadequate to meet our Nation's needs. We need a reliable, diversified, and affordable supply of energy to drive our Nation's manufacturing, transportation, agriculture, and defense industries, and to sustain the basics of modern life and military preparedness. Caused by the harmful and shortsighted policies of the previous administration, our Nation's inadequate energy supply and infrastructure causes and makes worse the high energy prices that devastate Americans, particularly those living on low- and fixed-incomes.

This active threat to the American people from high energy prices is exacerbated by our Nation's diminished capacity to insulate itself from hostile foreign actors. Energy security is an increasingly crucial theater of global competition. In an effort to harm the American people, hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets. An affordable and reliable domestic supply of energy is a fundamental requirement for the national and economic security of any nation.

The integrity and expansion of our Nation's energy infrastructure—from coast to coast—is an immediate and pressing priority for the protection of the United States' national and economic security. It is imperative that the Federal government puts the physical and economic wellbeing of the American people first.

Moreover, the United States has the potential to use its unrealized energy resources domestically, and to sell to international allies and partners a reliable, diversified, and affordable supply of energy. This would create jobs and economic prosperity for Americans forgotten in the present economy, improve the United States' trade balance, help our country compete with hostile foreign powers, strengthen relations with allies and partners, and support international peace and security. Accordingly, our Nation's dangerous energy situation inflicts unnecessary and perilous constraints on our foreign policy.

The policies of the previous administration have driven our Nation into a national emergency, where a precariously inadequate and intermittent energy supply, and an increasingly unreliable grid, require swift and decisive action. Without immediate remedy, this situation will dramatically deteriorate in the near future due to a high demand for energy and natural resources to power the next generation of technology. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy and the integrity of our Nation's electrical grid. Our Nation's current inadequate development of domestic energy resources leaves us vulnerable to hostile foreign actors and poses an imminent and growing threat to the United States' prosperity and national security.

These numerous problems are most pronounced in our Nation's Northeast and West Coast, where dangerous State and local policies jeopardize our Nation's core national defense and security needs, and devastate the prosperity of not only local residents but the entire United States population. The United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy. In light of these findings, I hereby declare a national emergency.

Sec. 2. *Emergency Approvals.* (a) The heads of executive departments and agencies (''agencies'') shall identify and exercise any lawful emergency authorities available to them, as well as all other lawful authorities they may possess, to facilitate the identification, leasing, siting, production, transportation, refining, and generation of domestic energy resources, including, but not limited to, on Federal lands. If an agency assesses that use of either Federal eminent domain authorities or authorities afforded under the Defense Production Act (Public Law 81–774, 50 U.S.C. 4501 *et seq.*) are necessary to achieve this objective, the agency shall submit recommendations for a course of action to the President, through the Assistant to the President for National Security Affairs.

(b) Consistent with 42 U.S.C. 7545(c)(4)(C)(ii)(III), the Administrator of the Environmental Protection Agency, after consultation with, and concurrence by, the Secretary of Energy, shall consider issuing emergency fuel waivers to allow the year-round sale of E15 gasoline to meet any projected temporary shortfalls in the supply of gasoline across the Nation.

Sec. 3. *Expediting the Delivery of Energy Infrastructure.* (a) To facilitate the Nation's energy supply, agencies shall identify and use all relevant lawful emergency and other authorities available to them to expedite the completion of all authorized and appropriated infrastructure, energy, environmental, and natural resources projects that are within the identified authority of each of the Secretaries to perform or to advance.

(b) To protect the collective national and economic security of the United States, agencies shall identify and use all lawful emergency or other authorities available to them to facilitate the supply, refining, and transportation of energy in and through the West Coast of the United States, Northeast of the United States, and Alaska.

(c) The Secretaries shall provide such reports regarding activities under this section as may be requested by the Assistant to the President for Economic Policy.

Sec. 4. *Emergency Regulations and Nationwide Permits Under the Clean Water Act (CWA) and Other Statutes Administered by the Army Corps of Engineers.* (a) Within 30 days from the date of this order, the heads of all agencies, as well as the Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works shall:

(i) identify planned or potential actions to facilitate the Nation's energy supply that may be subject to emergency treatment pursuant to the regulations and nationwide permits promulgated by the Corps, or jointly by the Corps and EPA, pursuant to section 404 of the Clean Water Act, 33 U.S.C. 1344, section 10 of the Rivers and Harbors Act of March 3, 1899, 33 U.S.C. 403, and section 103 of the Marine Protection Research and Sanctuaries Act of 1972, 33 U.S.C. 1413 (collectively, the ''emergency Army Corps permitting provisions''); and

(ii) shall provide a summary report, listing such actions, to the Director of the Office of Management and Budget (''OMB''); the Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works; the Assistant to the President for Economic Policy; and the Chairman of the Council on Environmental Quality (CEQ). Such report may be combined, as appropriate, with any other reports required by this order.

(b) Agencies are directed to use, to the fullest extent possible and consistent with applicable law, the emergency Army Corps permitting provisions to facilitate the Nation's energy supply.

(c) Within 30 days following the submission of the initial summary report described in subsection (a)(ii) of this section, each department and agency shall provide a status report to the OMB Director; the Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works; the Director of the National Economic Council; and the Chairman of the CEQ. Each such report shall list actions taken within subsection (a)(i) of this section, shall list the status of any previously reported planned or potential actions, and shall list any new planned or potential actions that fall within subsection (a)(i). Such status reports shall thereafter be provided to these officials at least every 30 days for the duration of the national emergency and may be combined, as appropriate, with any other reports required by this order.

(d) The Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works, shall be available to consult promptly with agencies and to take other prompt and appropriate action concerning the application of the emergency Army Corps permitting provisions. The Administrator of the EPA shall provide prompt cooperation to the Secretary of the Army and to agencies in connection with the discharge of the responsibilities described in this section.

Sec. 5. *Endangered Species Act (ESA) Emergency Consultation Regulations.* (a) No later than 30 days from the date of this order, the heads of all agencies tasked in this order shall:

(i) identify planned or potential actions to facilitate the Nation's energy supply that may be subject to the regulation on consultations in emergencies, 50 CFR 402.05, promulgated by the Secretary of the Interior and the Secretary of Commerce pursuant to the Endangered Species Act (''ESA''), 16 U.S.C. 1531 *et seq.;* and

(ii) provide a summary report, listing such actions, to the Secretary of the Interior, the Secretary of Commerce, the OMB Director, the Director of the National Economic Council, and the Chairman of CEQ. Such report may be combined, as appropriate, with any other reports required by this order.

(b) Agencies are directed to use, to the maximum extent permissible under applicable law, the ESA regulation on consultations in emergencies, to facilitate the Nation's energy supply.

(c) Within 30 days following the submission of the initial summary report described in subsection (a)(ii) of this section, the head of each agency shall provide a status report to the Secretary of the Interior, the Secretary of Commerce, the OMB Director, the Director of the National Economic Council, and the Chairman of CEQ. Each such report shall list actions taken within the categories described in subsection (a)(i) of this section, the status of any previously reported planned or potential actions, and any new planned or potential actions within these categories. Such status reports shall thereafter be provided to these officials at least every 30 days for the duration of the national emergency and may be combined, as appropriate, with any other reports required by this order. The OMB Director may grant discretionary exemptions from this reporting requirement.

(d) The Secretary of the Interior shall ensure that the Director of the Fish and Wildlife Service, or the Director's authorized representative, is available to consult promptly with agencies and to take other prompt and appropriate action concerning the application of the ESA's emergency regulations. The Secretary of Commerce shall ensure that the Assistant Administrator for Fisheries for the National Marine Fisheries Service, or the Assistant Administrator's authorized representative, is available for such consultation and to take such other action.

Sec. 6. *Convening the Endangered Species Act Committee.* (a) In acting as Chairman of the Endangered Species Act Committee, the Secretary of the Interior shall convene the Endangered Species Act Committee not less than quarterly, unless otherwise required by law, to review and consider any lawful applications submitted by an agency, the Governor of a State, or any applicant for a permit or license who submits for exemption from obligations imposed by Section 7 of the ESA.

(b) To the extent practicable under the law, the Secretary of the Interior shall ensure a prompt and efficient review of all submissions described in subsection (a) of this section, to include identification of any legal deficiencies, in order to ensure an initial determination within 20 days of receipt and the ability to convene the Endangered Species Act Committee to resolve the submission within 140 days of such initial determination of eligibility.

(c) In the event that the committee has no pending applications for review, the committee or its designees shall nonetheless convene to identify obstacles to domestic energy infrastructure specifically deriving from implementation of the ESA or the Marine Mammal Protection Act, to include regulatory reform efforts, species listings, and other related matters with the aim of developing procedural, regulatory, and interagency improvements.

Sec. 7. *Coordinated Infrastructure Assistance.* (a) In collaboration with the Secretaries of Interior and Energy, the Secretary of Defense shall conduct an assessment of the Department of Defense's ability to acquire and transport the energy, electricity, or fuels needed to protect the homeland and to conduct operations abroad, and, within 60 days, shall submit this assessment to the Assistant to the President for National Security Affairs. This assessment shall identify specific vulnerabilities, including, but not limited to, potentially insufficient transportation and refining infrastructure across the Nation, with a focus on such vulnerabilities within the Northeast and West Coast regions of the United States. The assessment shall also identify and recommend the requisite authorities and resources to remedy such vulnerabilities, consistent with applicable law.

(b) In accordance with section 301 of the National Emergencies Act (50 U.S.C. 1631), the construction authority provided in section 2808 of title 10, United States Code, is invoked and made available, according to its terms, to the Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works, to address any vulnerabilities identified in the assessment mandated by subsection (a). Any such recommended actions shall be submitted to the President for review, through the Assistant to the President for National Security Affairs and the Assistant to the President for Economic Policy.

Sec. 8. *Definitions.* For purposes of this order, the following definitions shall apply:

(a) The term ''energy'' or ''energy resources'' means crude oil, natural gas, lease condensates, natural gas liquids, refined petroleum products, uranium, coal, biofuels, geothermal heat, the kinetic movement of flowing water, and critical minerals, as defined by 30 U.S.C. 1606 (a)(3).

(b) The term ''production'' means the extraction or creation of energy.

(c) The term ''transportation'' means the physical movement of energy, including through, but not limited to, pipelines.

(d) The term ''refining'' means the physical or chemical change of energy into a form that can be used by consumers or users, including, but not limited to, the creation of gasoline, diesel, ethanol, aviation fuel, or the beneficiation, enrichment, or purification of minerals.

(e) The term ''generation'' means the use of energy to produce electricity or thermal power and the transmission of electricity from its site of generation.

(f) The term ''energy supply'' means the production, transportation, refining, and generation of energy.

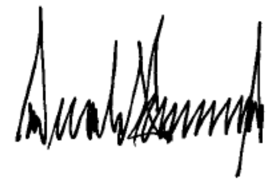
Sec. 9. *General Provisions.* (a) Nothing in this order shall be construed to impair or otherwise affect:

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

(ii) the functions of the Director of OMB relating to budgetary, administrative, or legislative proposals.

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

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



THE WHITE HOUSE,
January 20, 2025.

[FR Doc. 2025–02003
Filed 1–28–25; 11:15 am]
Billing code 3395–F4–P

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-29
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-30

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Exhibit 93
Grid EO

Presidential Documents

Executive Order 14262 of April 8, 2025

Strengthening the Reliability and Security of the United States Electric Grid

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

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

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

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

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

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

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

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

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

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

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

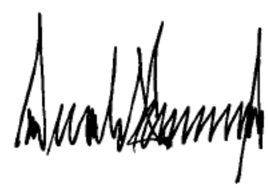
Sec. 4. *General Provisions.* (a) Nothing in this order shall be construed to impair or otherwise affect:

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

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

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

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



THE WHITE HOUSE,
April 8, 2025.

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

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-29
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-30

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Exhibit 94
New York Times Coal Article

Trump Signs Orders Aimed at Reviving a Struggling Coal Industry

The moves include loosening environmental rules, but it is unclear how much they can help reverse the sharp decline in coal power over the last two decades.

Listen to this article · 7:58 min Learn more


By Brad Plumer and Mira Rojanasakul
Reporting from Washington

April 8, 2025

President Trump signed a flurry of executive orders Tuesday aimed at expanding the mining and burning of coal in the United States, in an effort to revive the struggling industry.

One order directs federal agencies to repeal any regulations that “discriminate” against coal production, to open new federal lands for coal mining and to explore whether coal-burning power plants could serve new A.I. data centers. Mr. Trump also said he would waive certain air-pollution restrictions adopted by the Biden administration for dozens of coal plants that were at risk of closing down.

In a move that could face legal challenges, Mr. Trump directed the Energy Department to develop a process for using emergency powers to prevent unprofitable coal plants from shutting down in order to avert power outages. Mr. Trump proposed a similar action in his first term but eventually abandoned the idea after widespread opposition.

Flanked by dozens of miners in white hard hats at the White House, Mr. Trump said he was also instructing the Justice Department to identify and fight state and local climate policies that were “putting our coal miners out of business.” He added that he would issue “guarantees” that future administrations could not adopt policies harmful to coal, but did not provide details.

“This is a very important day to me because we’re bringing back an industry that was abandoned despite the fact that it was the best, certainly the best in terms of power, real power,” Mr. Trump said.

In recent weeks, Mr. Trump, Chris Wright, the energy secretary, and Doug Burgum, the interior secretary, have all spoken about the importance of coal. The two cabinet members sat in the front row at the White House ceremony, which was attended by members of Congress from Wyoming, Kentucky, West Virginia and other coal-producing states.

“Beautiful clean coal,” Mr. Trump told the gathering. “Never use the word ‘coal’ unless you put ‘beautiful, clean’ before it.”

Coal is the most polluting of all fossil fuels when burned, and accounts for roughly 40 percent of the world’s industrial carbon dioxide emissions, the main driver of global warming. It releases other pollutants, including mercury and sulfur dioxide, that are linked to heart disease, respiratory problems and premature deaths. Coal mining and the resulting coal ash from power plants can also present environmental problems.

Over the past two decades, the use of coal has fallen precipitously in the United States, as utilities have switched to cheaper and cleaner electricity sources like natural gas, wind and solar power. That transition has been the biggest reason for the drop in U.S. emissions since 2005.

Coal power has declined sharply — and more retirements are coming.

Coal capacity retired each year

Capacity (megawatts)
300,000

More capacity retired under Trump's first term than under Biden.

200,000

Operating coal plants

Planned retirements

About half of remaining coal capacity is set to retire.

100,000

Projections

2000 2025 2050

G.W. BUSH **OBAMA** **TRUMP** **BIDEN** **TRUMP**

Source: Global Energy Monitor and New York Times reporting. • Note: Includes coal capacity added. • By Mira Rojanasakul/The New York times

It is unclear how much Mr. Trump could reverse that decline. In 2011, the nation generated nearly half of its electricity from coal; last year, that fell to just 15 percent. Utilities have already closed hundreds of aging coal-burning units and have announced retirement dates for roughly half of the remaining plants.

In recent years, growing interest in artificial intelligence and data centers has fueled a surge in electricity demand, and utilities have decided to keep more than 50 coal-burning units open past their scheduled closure dates, according to America's Power, an industry trade group. And as the Trump administration moves to loosen pollution limits on coal power — including regulations applied to carbon dioxide and mercury — more plants could stay open longer, or run more frequently.

"You know, we need to do the A.I., all of this new technology that's coming on line," Mr. Trump said on Tuesday. "We need more than double the energy, the electricity, that we currently have."

Yet a major coal revival is unlikely, some analysts said.

"The main issue is that most of our coal plants are older and getting more expensive to run, and no one's thinking about building new plants," said Seth Feaster, a data analyst who focuses on coal at the Institute for Energy Economics and Financial Analysis, a research firm. "It's very hard to change that trajectory."

During his first term, Mr. Trump sought to prevent unprofitable coal plants from closing, using emergency authority that is normally reserved for fleeting crises like natural disasters. But that idea brought a fierce blowback from oil and gas companies, grid operators and consumer groups, who said it would drive up electricity bills, and the administration eventually backed away from the idea.

If the idea was tried again today, it would be likely to lead to lawsuits, said Ari Peskoe, director of the Electricity Law Initiative at Harvard Law School. "But there's not a lot of litigation history here," he said. "Typically these emergency orders last for no longer than 90 days."

Ultimately, Mr. Trump struggled to fulfill his first-term pledge of rescuing the coal industry. Despite the fact that his administration repealed numerous climate regulations and appointed a coal lobbyist to lead the Environmental Protection Agency, 75 coal-fired power plants closed, and the industry shed about 13,000 jobs during his presidency.

Coal's decline continued under President Joseph R. Biden Jr., who sought to move the country away from the fossil fuel altogether in an effort to fight climate change. Last year, his administration issued a sweeping E.P.A. rule that would have forced all of the nation's coal plants to either install expensive equipment to capture and bury their carbon dioxide emissions or shut down by 2039.

This year, upon returning to office, Mr. Trump ordered the E.P.A. to repeal that rule. And Trump administration officials have repeatedly warned that shutting down coal plants would harm power supplies. Unlike wind and solar energy, coal plants can run at any hour of the day, making them useful when electricity demand spikes.

Some industry executives who run the nation's electric grids have also warned that the country could face a greater risk of blackouts if too many coal plants retire too quickly, especially since power companies have faced delays in bringing new gas, wind and solar plants online, as well as in adding battery storage and transmission lines.

"For decades, most people have taken electricity and coal for granted," said Michelle Bloodworth, chief executive of America's Power. "This complacency has led to damaging federal and state policies that have caused the premature retirement of coal plants, thus weakening our electric grid and threatening our national security."

Yet coal opponents say that keeping aging plants online can worsen deadly air pollution and increase energy costs. Earlier this year, PJM Interconnection, which oversees a large grid in the Mid-Atlantic, ordered a power plant that burns coal and another that burns oil to stay open until 2029, four years past their planned retirement date, to reduce the risk of power outages. The move could ultimately cost utility customers in the area of more than $720 million.

"Coal plants are old and dirty, uncompetitive and unreliable," said Kit Kennedy, managing director for power at the Natural Resources Defense Council, an environmental group. "The Trump administration is stuck in the past, trying to make utility customers pay more for yesterday's energy. Instead, it should be doing all it can to build the electricity grid of the future."

Brad Plumer is a Times reporter who covers technology and policy efforts to address global warming.

Mira Rojanasakul is a Times reporter who uses data and graphics to cover climate and the environment.

A version of this article appears in print on , Section A, Page 15 of the New York edition with the headline: Trump Signs Orders Aimed At Reviving Coal Industry

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Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-29
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Public Interest Organizations

Exhibit 95
EIA Table 8.4

U.S. Energy Information Administration

Table 8.4. Average Power Plant Operating Expenses for Major U.S. Investor-Owned Electric Utilities, 2014 through 2024 (Mills per Kilowatthour)

	Operation				Maintenance			
Year	Nuclear	Fossil Steam	Hydro-electric	Gas Turbine and Small Scale	Nuclear	Fossil Steam	Hydro-electric	Gas Turbine and Small Scale
2014	12.41	4.55	7.30	2.63	6.67	5.11	4.59	2.90
2015	11.17	5.16	8.37	2.34	7.06	5.41	5.06	2.68
2016	10.90	5.05	6.65	2.49	7.01	5.53	4.34	2.74
2017	10.27	5.01	6.33	2.45	6.63	5.13	3.96	2.83
2018	10.78	5.19	6.69	2.37	5.93	5.27	3.96	2.71
2019	10.63	5.52	6.86	2.58	6.29	6.85	3.94	2.64
2020	10.05	6.40	7.72	2.38	5.78	5.60	5.00	2.51
2021	10.55	5.70	7.98	2.12	5.88	5.32	4.33	2.28
2022	10.51	6.75	7.68	2.20	6.10	5.09	4.76	2.36
2023	9.52	6.48	9.18	2.16	6.36	5.61	5.53	2.12
2024	9.87	6.98	8.97	2.25	6.84	5.81	6.10	2.11

	Fuel				Total			
Year	Nuclear	Fossil Steam	Hydro-electric	Gas Turbine and Small Scale	Nuclear	Fossil Steam	Hydro-electric	Gas Turbine and Small Scale
2014	7.71	29.39	--	37.06	26.79	39.04	11.90	42.60
2015	7.48	26.70	--	28.22	25.71	37.26	13.42	33.24
2016	7.45	25.50	--	24.97	25.36	36.08	10.98	30.19
2017	7.47	25.27	--	26.48	24.38	35.41	10.29	31.76
2018	7.15	25.40	--	27.35	23.86	35.86	10.65	32.43
2019	6.81	24.28	--	23.11	23.73	36.66	10.80	28.33
2020	6.10	22.87	--	19.65	21.92	34.86	12.71	24.55
2021	6.31	24.64	--	25.78	22.74	35.66	12.30	30.18
2022	6.12	32.04	--	38.72	22.73	43.88	12.44	43.28
2023	6.12	30.58	--	22.19	22.00	42.67	14.71	26.47
2024	6.37	28.52	--	18.59	23.08	41.32	15.07	22.95

Hydroelectric category consists of both conventional hydroelectric and pumped storage.
Gas Turbine and Small Scale category consists of gas turbine, internal combustion, photovoltaic, and wind plants.
Notes: Expenses are average expenses weighted by net generation. A mill is a monetary cost and billing unit equal to 1/1000 of the U.S. dollar (equivalent to 1/10 of one cent).
Total may not equal sum of components due to independent rounding.
Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others via Ventyx Global Energy Velocity Suite.

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Public Interest Organizations

Exhibit 96
July 2025 Resource Adequacy Report

U.S. DEPARTMENT of ENERGY

Resource Adequacy Report

Evaluating the Reliability and Security of the United States Electric Grid

July 2025

Acknowledgments

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

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

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

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

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List of Acronyms

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

Background to this Report

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

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

Executive Summary

Our Nation possesses abundant energy resources and capabilities such as oil and gas, coal, and nuclear. The current administration has made great strides—such as deregulation, permitting reform, and other measures—to enable addition of more energy infrastructure crucial to the utilization of these resources. However, even with these foundational strengths, the accelerated retirement of existing generation capacity and the insufficient pace of firm, dispatchable generation additions (partly due to a recent focus on intermittent rather than dispatchable sources of energy) undermine this energy outlook.

Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation. A failure to power the data centers needed to win the AI arms race or to build the grid infrastructure that ensures our energy independence could result in adversary nations shaping digital norms and controlling digital infrastructure, thereby jeopardizing U.S. economic and national security.

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

Key Takeaways

- **Status Quo is Unsustainable**. The status quo of more generation retirements and less dependable replacement generation is neither consistent with winning the AI race and ensuring affordable energy for all Americans, nor with continued grid reliability (ensuring "resource adequacy"). Absent intervention, it is impossible for the nation's bulk power system to meet the AI growth requirements while maintaining a reliable power grid and keeping energy costs low for our citizens.

- **Grid Growth Must Match Pace of AI Innovation**. The magnitude and speed of projected load growth cannot be met with existing approaches to load addition and grid management. The situation necessitates a radical change to unleash the transformative potential of innovation.

- **Retirements Plus Load Growth Increase Risk of Power Outages by 100x in 2030**. The retirement of firm power capacity is exacerbating the resource adequacy problem. 104 GW of firm capacity are set for retirement by 2030. This capacity is not being replaced on a one-to-one basis and losing this generation could lead to significant outages when weather conditions do not accommodate wind and solar generation. In the "plant closures" scenario of this analysis, annual loss of load hours (LOLH) increased by a factor of a hundred.

- **Planned Supply Falls Short, Reliability is at Risk**. The 104 GW of retirements are projected to be replaced by 209 GW of new generation by 2030; however, only 22 GW would come from firm baseload generation sources. Even assuming no retirements, the model found increased risk of outages in 2030 by a factor of 34.

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

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

Developing a Uniform Methodology

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

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

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

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

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

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

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

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

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

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

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

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

Reliability Standard

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

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

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

Achieving Reliability Standard

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

Key Results Summary

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

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

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

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

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

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

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

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

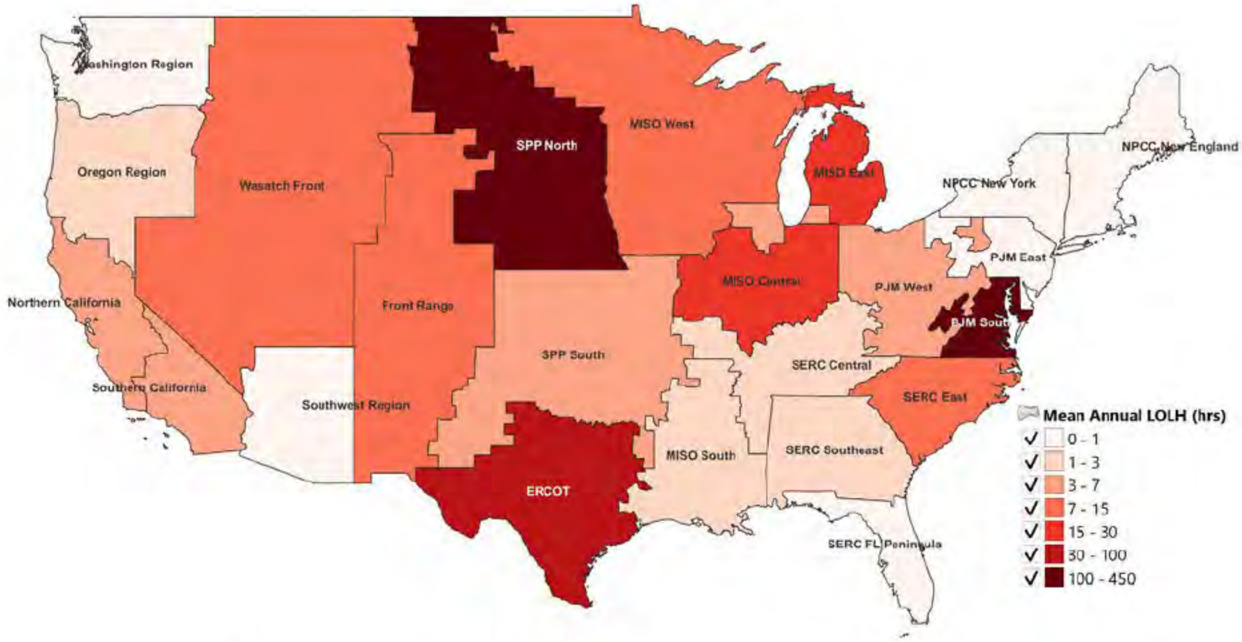

Figure 1. Mean Annual LOLH by Region (2030) – Plant Closures

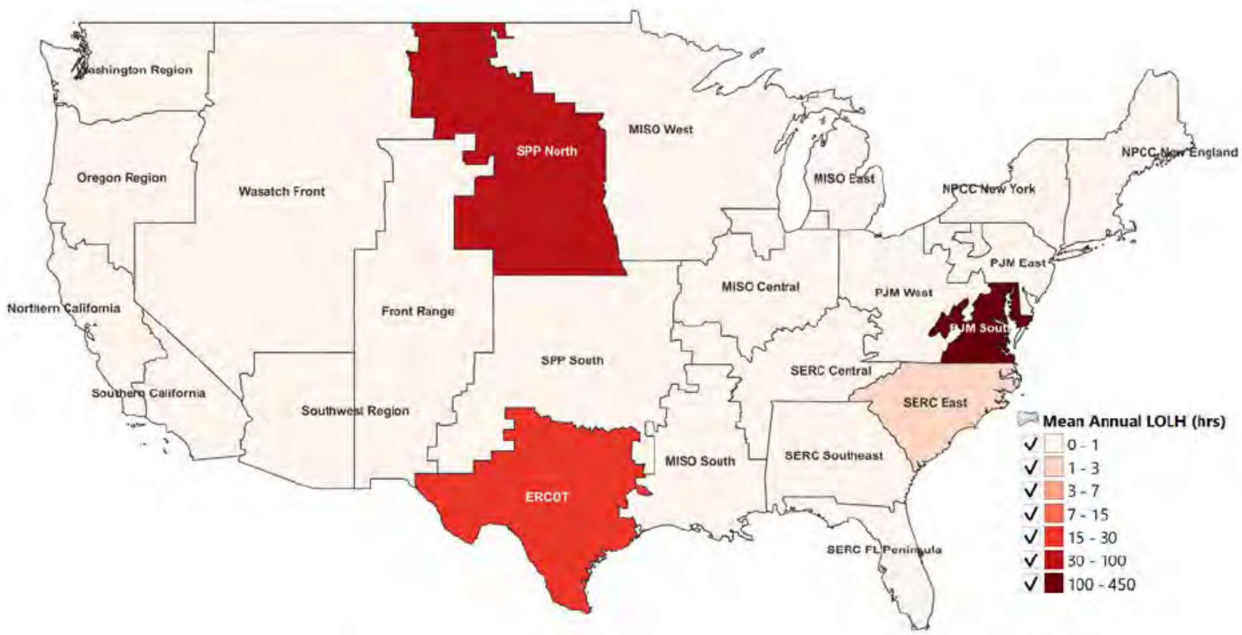

Figure 2. Mean Annual LOLH by Region (2030) – No Plant Closures

Table 1. Summary Metrics Across Cases

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

Current System Analysis

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

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

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

2030 Model Results

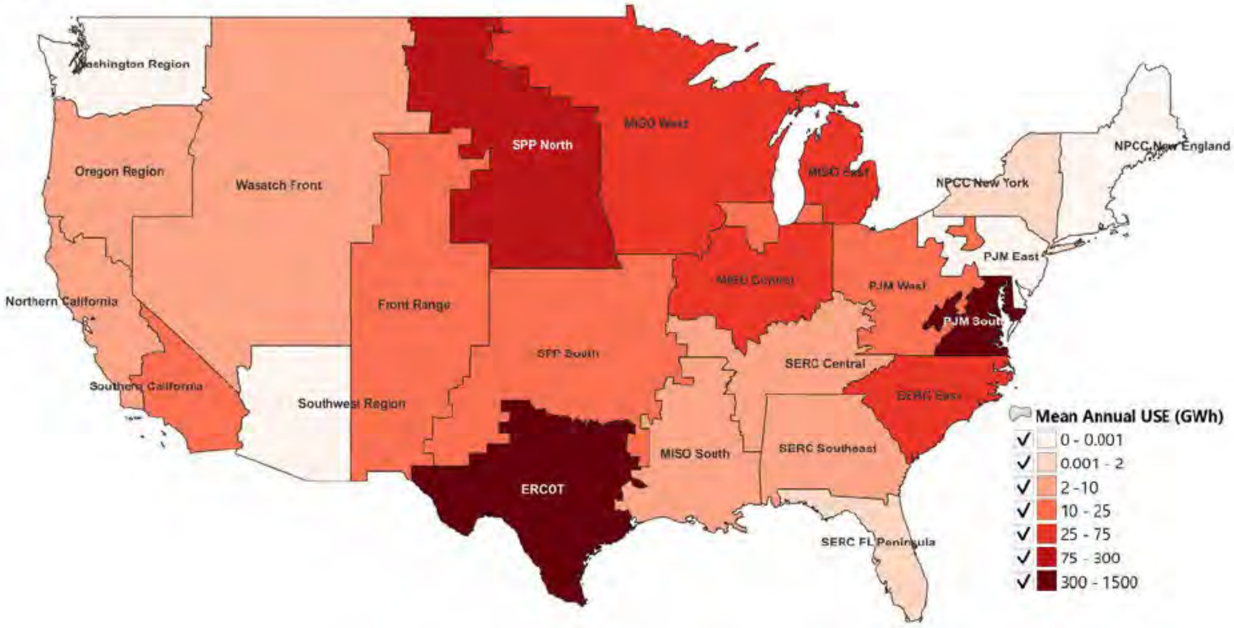

Figure 3. Mean Annual NUSE by Region (2030) -Plant Closures

Key Findings – Plant Closures Case:

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

Key Findings – No Plant Closures Case:

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

- **PJM**: 214 hours/year average, 0.066% normalized unserved energy, 644 hours in worst year, max 36% of load lost.
- **SPP**: 48 hours/year average, 0.008% normalized unserved energy, max 19% load lost.
- **ERCOT**: 20 average hours, 0.028% normalized unserved energy, 101 max hours/year, peak shortfall of 27%.
- **SERC-East**: Generally adequate (avg. 1 hour/year, 0.0003% NUSE), but Elliot storm in 2022 caused 42 hours of shortfall.

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

Required Build

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

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

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

Perfect Capacity/Additions

Figure 4. Tuned Perfect Capacity (MW) By Region

1 Modeling Methodology

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

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

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

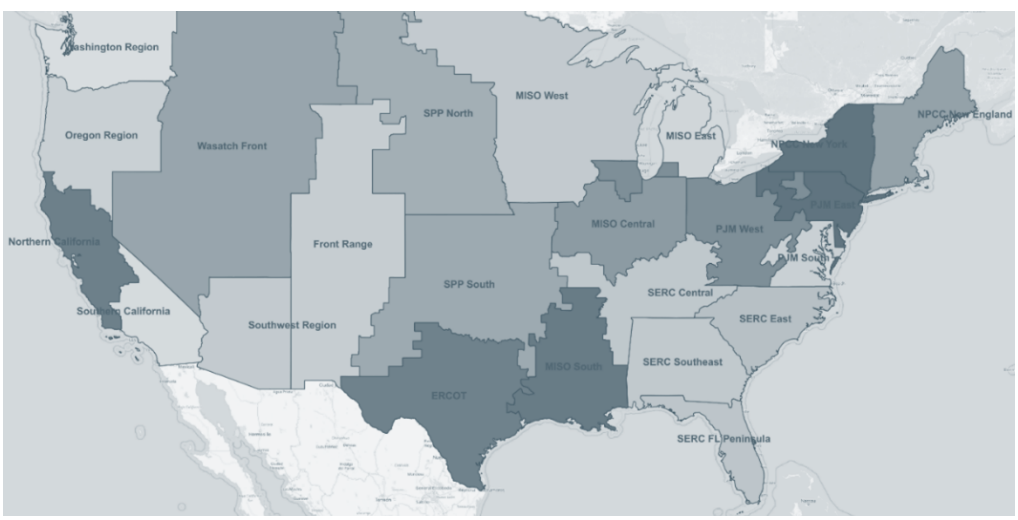

Figure 5. TPRs used in NERC ITCS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

1.1 Modeling Resource Adequacy

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

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

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

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

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

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

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

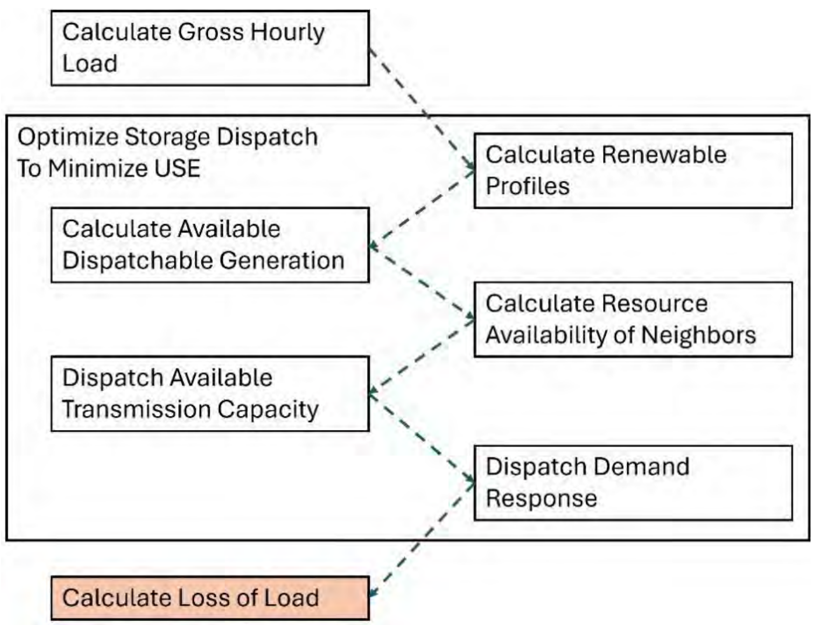

Figure 6. Simplified Overview of Model

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

1.2 Planning Years and Weather Years

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

1.3 Load Modeling

Data Center Growth

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

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

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

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

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

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

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

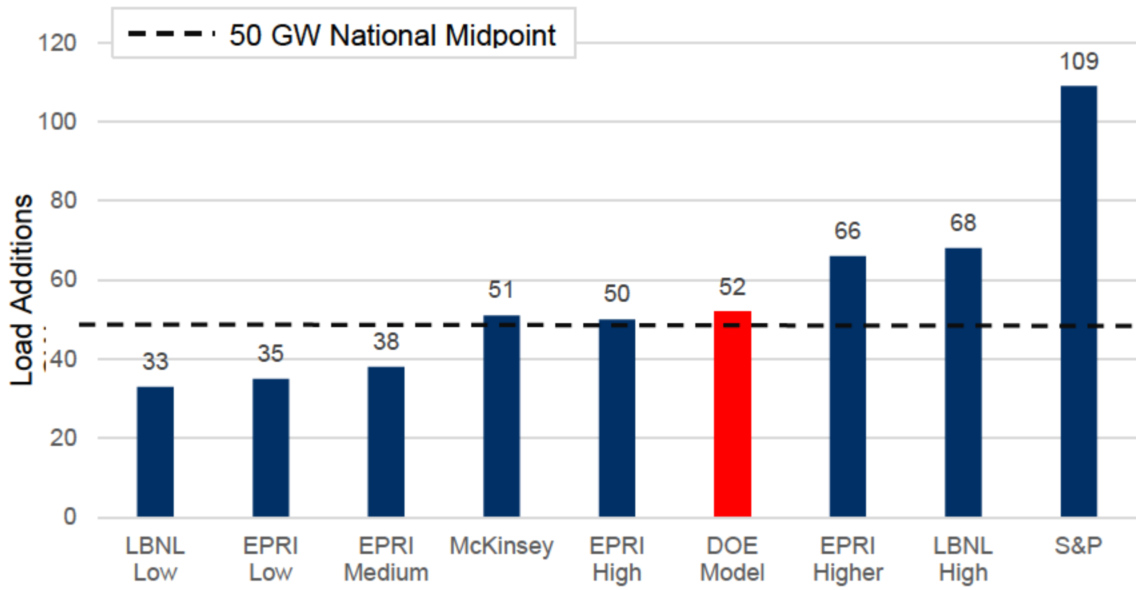

Figure 7. 2024 to 2030 Projected Data Center Load Additions

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

Data Center Allocation Method

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

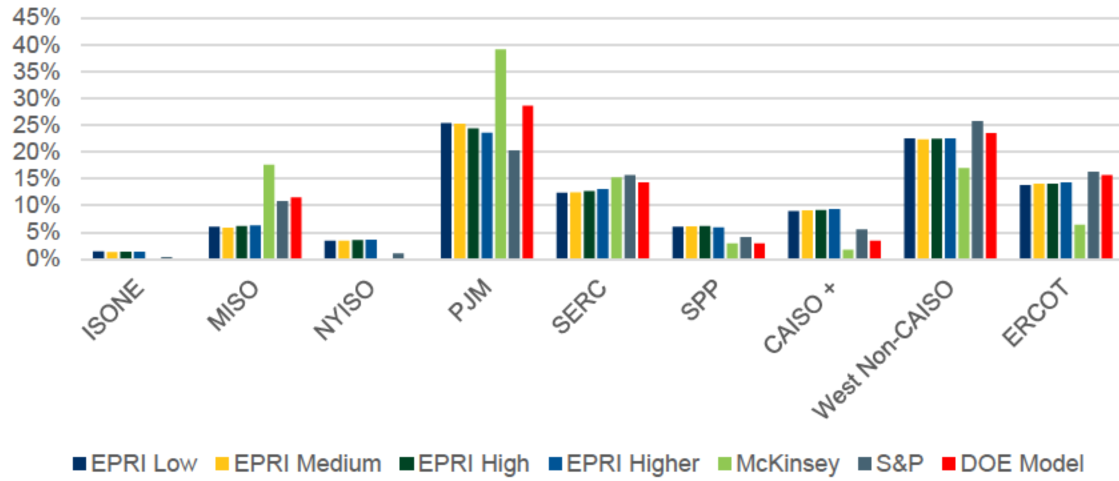

Figure 8. New Data Center Build (% Split by ISO/RTO) (2030 Estimated)

Non-Data Center Load Modeling

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

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

Overall Impact on Projected Peak Load

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

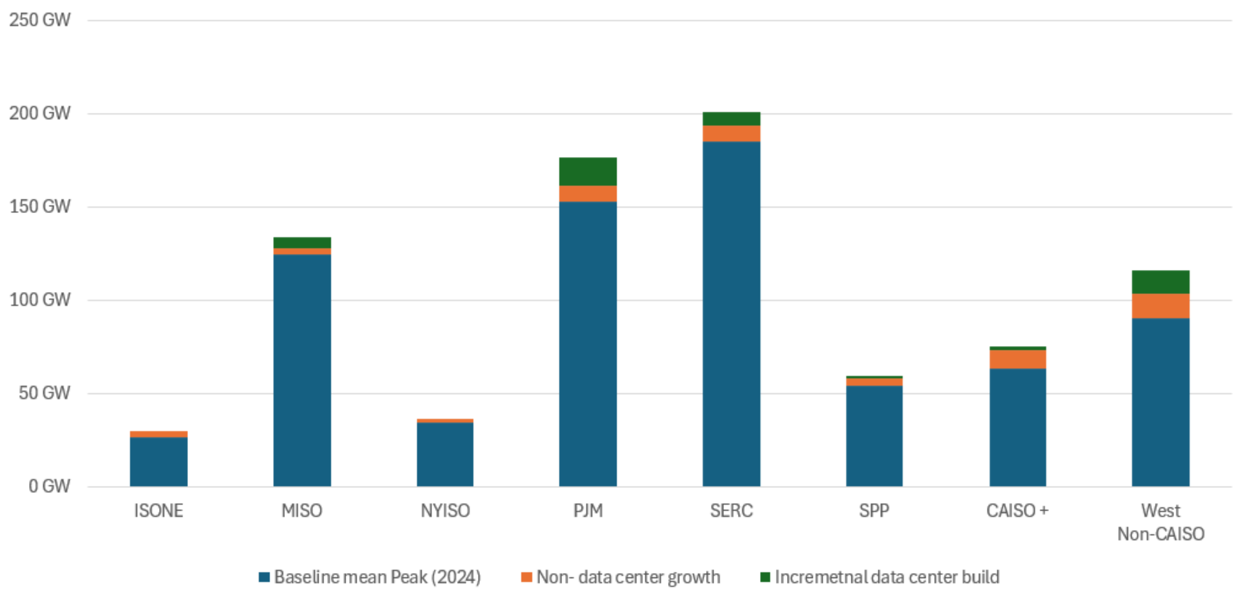

Figure 9. Mean Peak Load by RTO (Current Case vs 2030 Case)

1.4 Transfer Capabilities and Import Export Modeling

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

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

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

1.5 Perfect Capacity Additions

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

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

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

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

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

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

2 Regional Analysis

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

2.1 MISO[25]

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

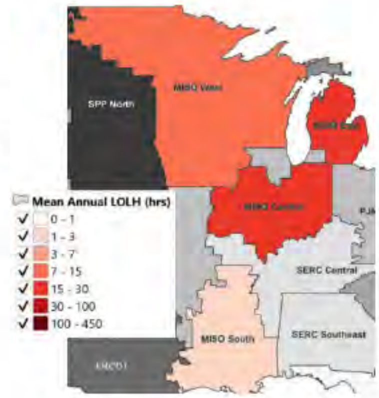


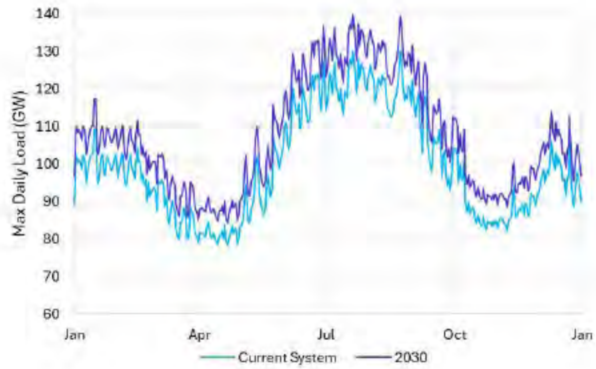
Table 2. Summary of MISO Reliability Metrics

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

Load Assumptions

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

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



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

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

Generation Stack

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

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

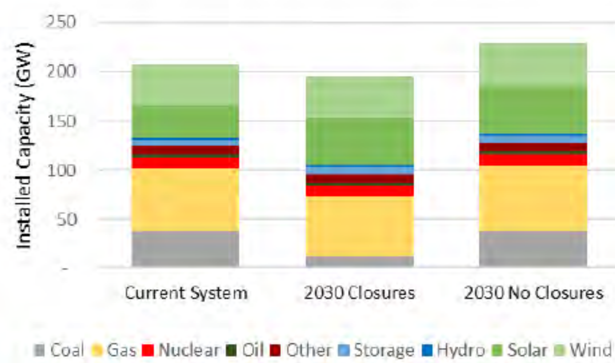


Figure 11. MISO Generation Capacity by Technology and Scenario

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

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

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

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

2.2 ISO-NE

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

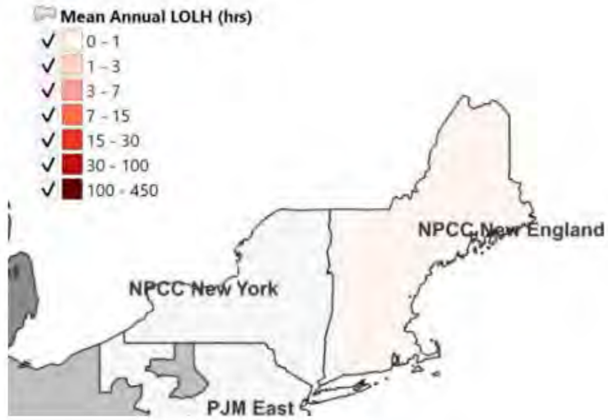
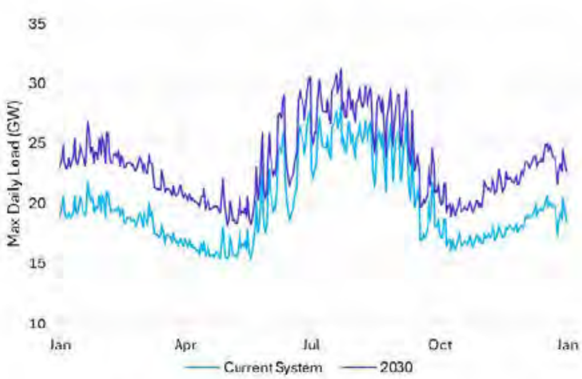


Table 4. Summary of ISO-NE Reliability Metrics

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

Load Assumptions

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



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

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

Generation Stack

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

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

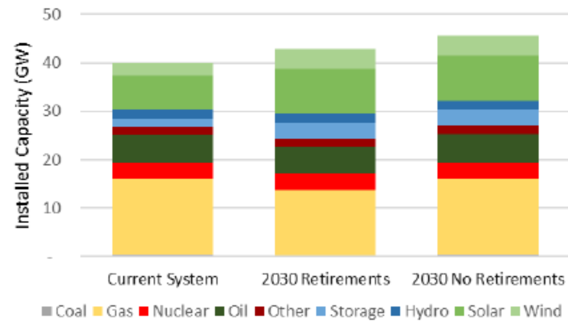


Figure 13. ISO-NE Generation Capacity by Technology and Scenario

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

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

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

2.3 NYISO

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

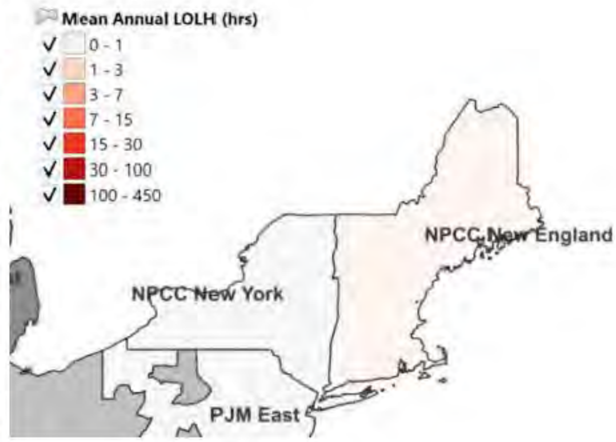
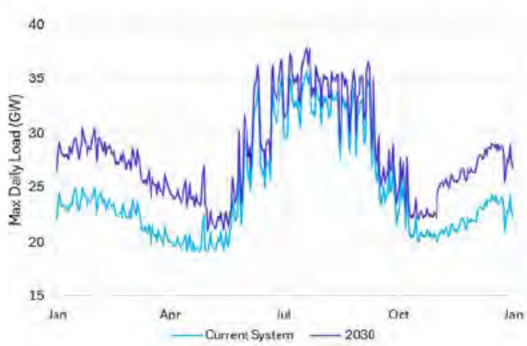


Table 6. Summary of NYISO Reliability Metrics

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

Load Assumptions

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



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

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

Generation Stack

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

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

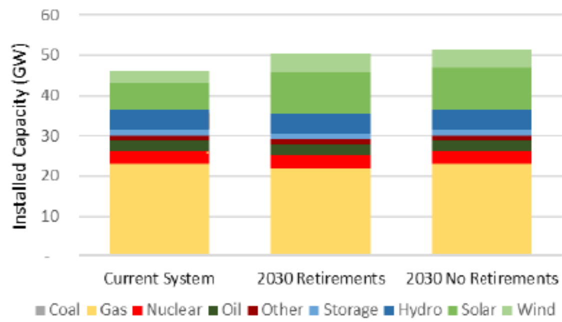


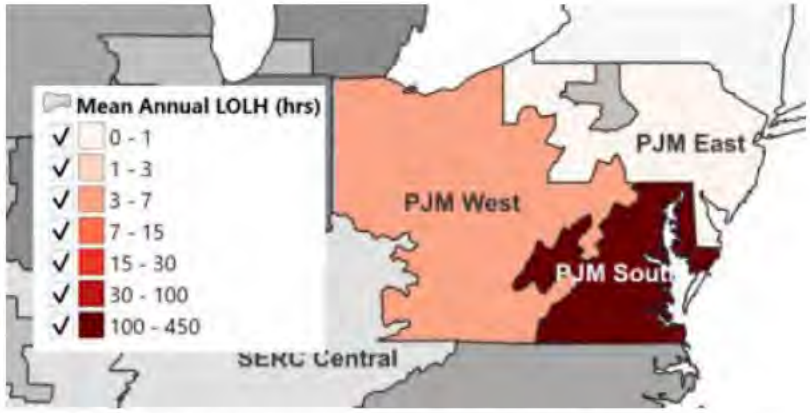
Figure 15. NYISO Generation Capacity by Technology and Scenario

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

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

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

2.4 PJM



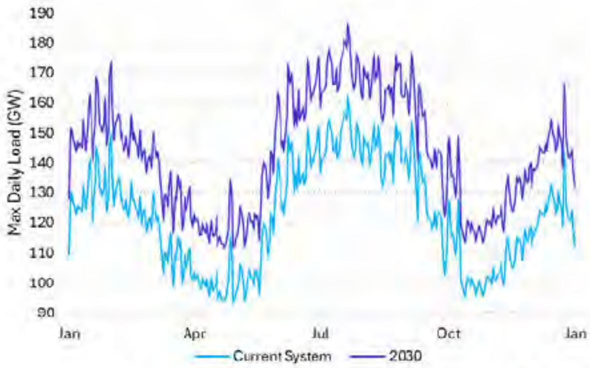
In the current system model, PJM experienced shortfalls, but they were below the required threshold. In the No Plant Closures case, shortfalls increased dramatically, with 214 average annual LOLH and peak unserved load reaching 17,620 MW, indicating growing strain even without retirements. In the Plant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

Table 8. Summary of PJM Reliability Metrics

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

Load Assumptions

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



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

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

Generation Stack

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

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

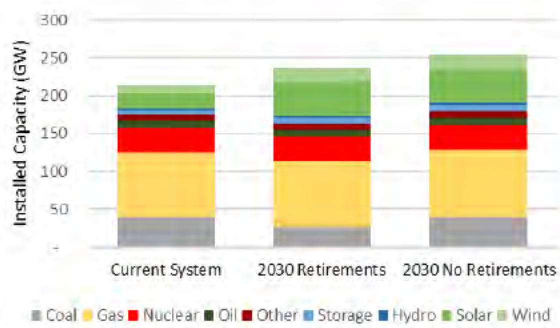


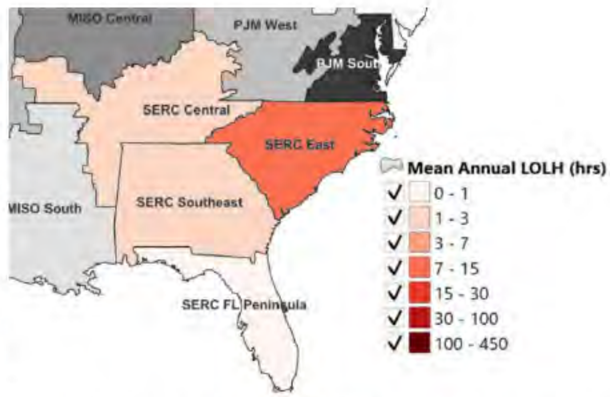
Figure 17. PJM Generation Capacity by Technology and Scenario

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

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

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

2.5 SERC



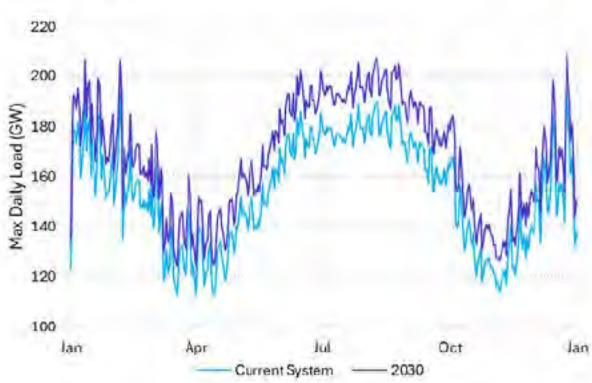
In the current system model and the No Plant Closures case, SERC maintained overall adequacy, though some subregions—particularly SERC-East—faced emerging winter reliability risks. In the Plant Closures case, shortfalls became more severe, with SERC-East experiencing increased unserved energy and loss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

Table 10. Summary of SERC Reliability Metrics

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

Load Assumptions

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



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

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

Generation Stack

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

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

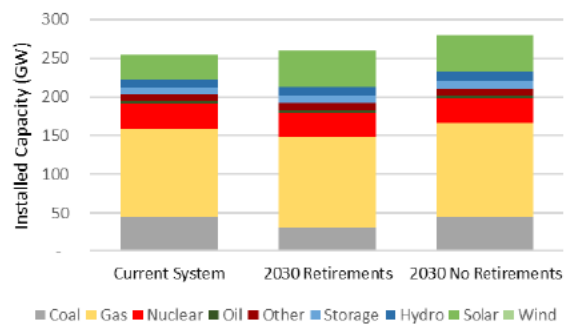


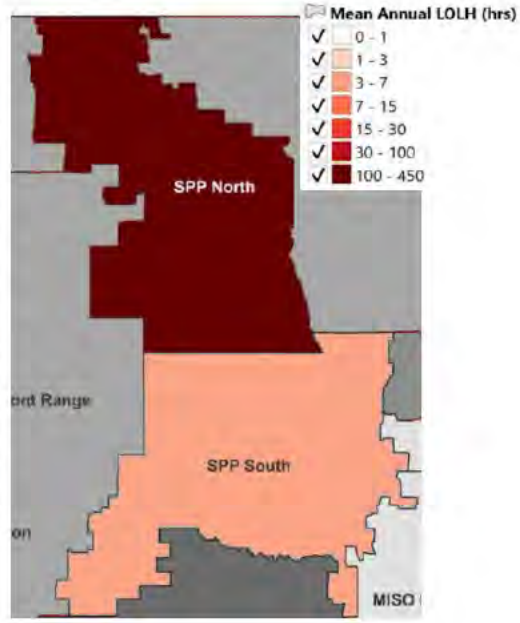
Figure 19. SERC Generation Capacity by Technology and Scenario

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

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

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

2.6 SPP



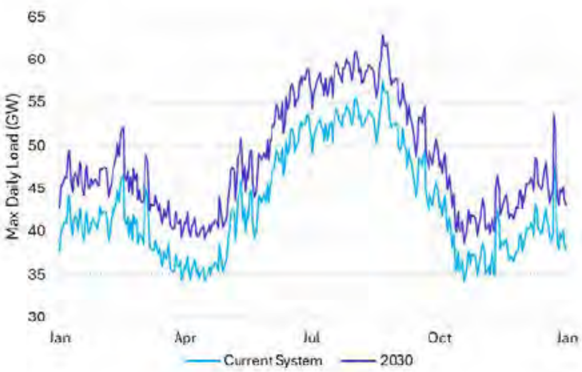
In the current system model, SPP experienced shortfalls, but they were below the required threshold. Adequacy was preserved through reliance on imports. In the No Plant Closures case, SPP experienced persistent reliability challenges, with average annual LOLH reaching approximately 48 hours per year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

Table 12. Summary of SPP Reliability Metrics

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

Load Assumptions

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



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

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

Generation Stack

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

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

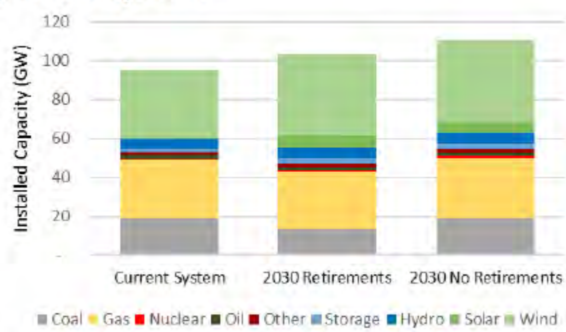


Figure 21. SPP Generation Capacity by Technology and Scenario

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

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

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

2.7 CAISO+

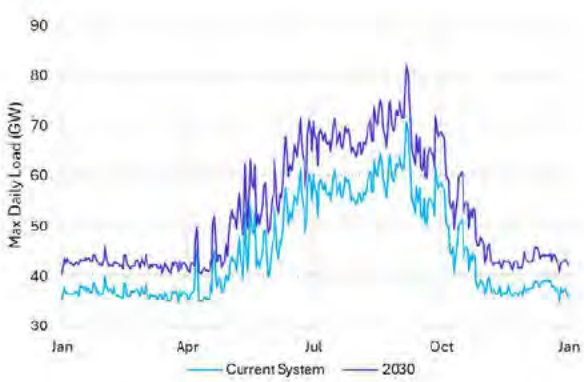
In the current system and No Plant Closures cases, CAISO+ did not experience major reliability issues, though adequacy was often maintained through significant imports during tight conditions. In the Plant Closures case, however, the region faced substantial shortfalls, particularly during summer evening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

Table 14. Summary of CAISO+ Reliability Metrics

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

Load Assumptions

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



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

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

Generation Stack

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

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

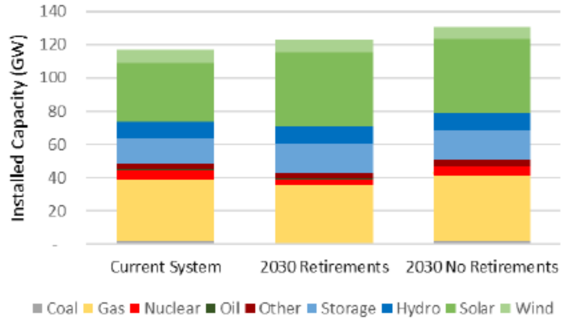


Figure 23. CAISO+ Generation Capacity by Technology and Scenario

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

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

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

2.8 West Non-CAISO

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

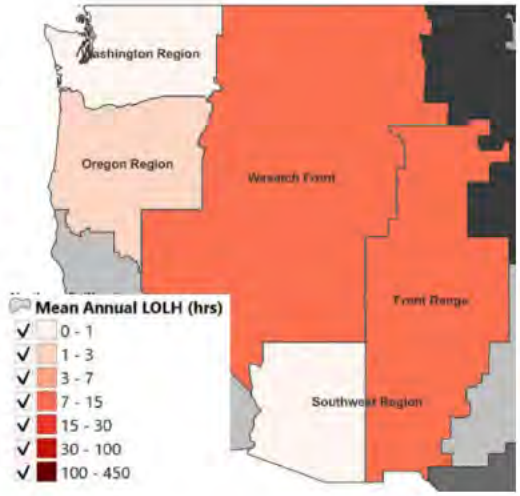
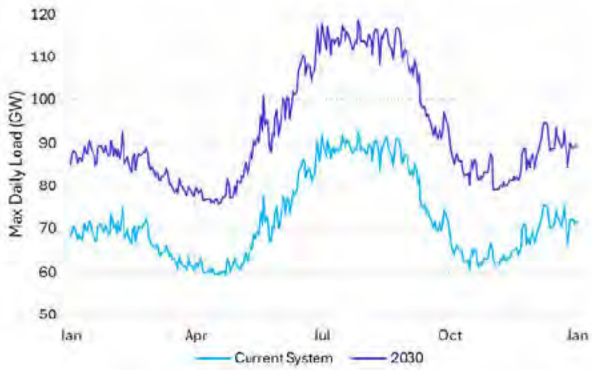


Table 16. Summary of West Non-CAISO Reliability Metrics

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

Load Assumptions

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



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

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

Generation Stack

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

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

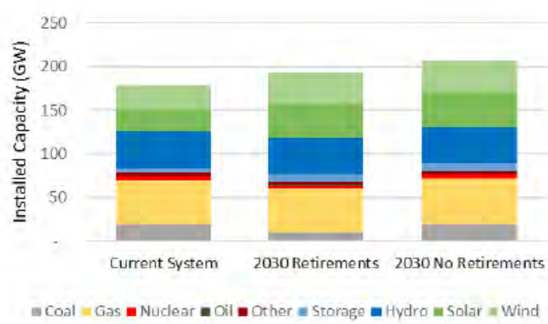


Figure 25. West Non-CAISO Generation Capacity by Technology and Scenario

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

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

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

2.9 ERCOT

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

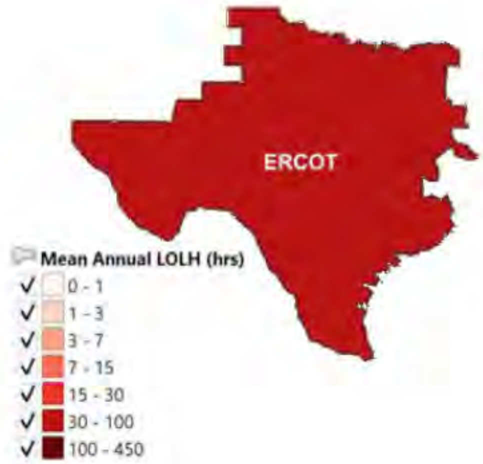
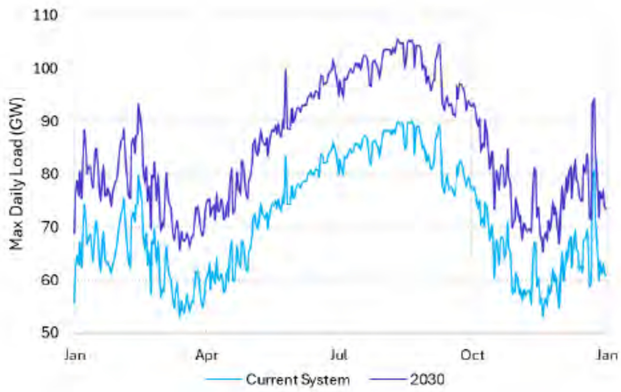


Table 18. Summary of ERCOT Reliability Metrics

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

Load Assumptions

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



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

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

Generation Stack

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

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

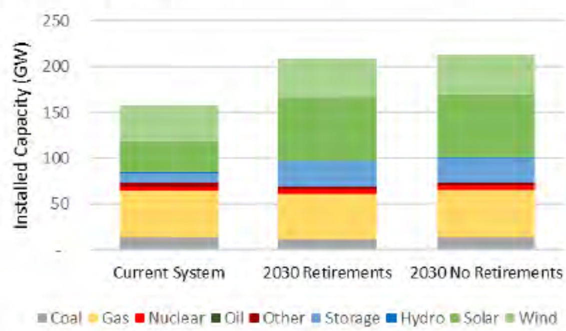


Figure 27. ERCOT Generation Capacity by Technology and Scenario

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

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

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

Appendix A - Generation Calibration and Forecast

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

2024 Resource Mix

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

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

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

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

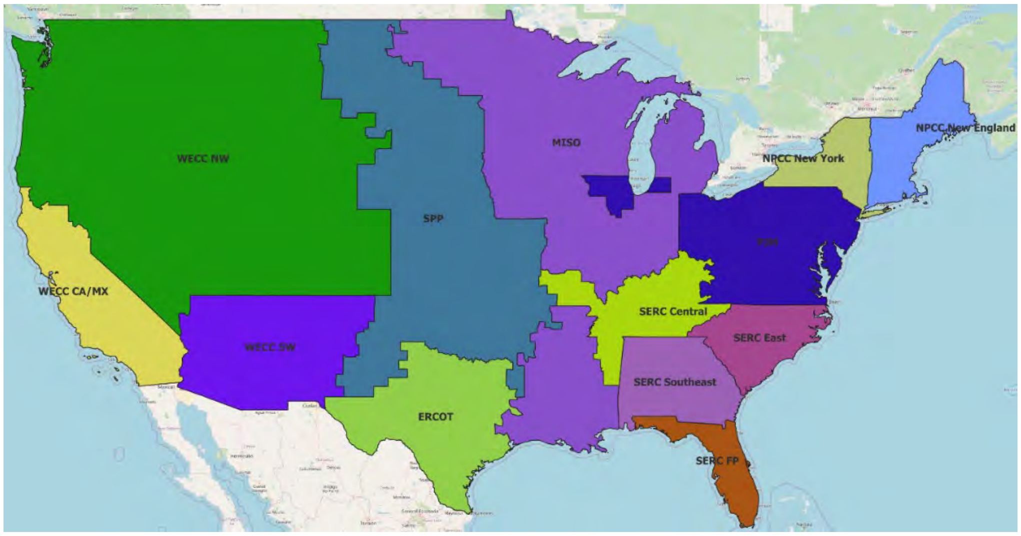


Figure A.1. NERC assessment areas.

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

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

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

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

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

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

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

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

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

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

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

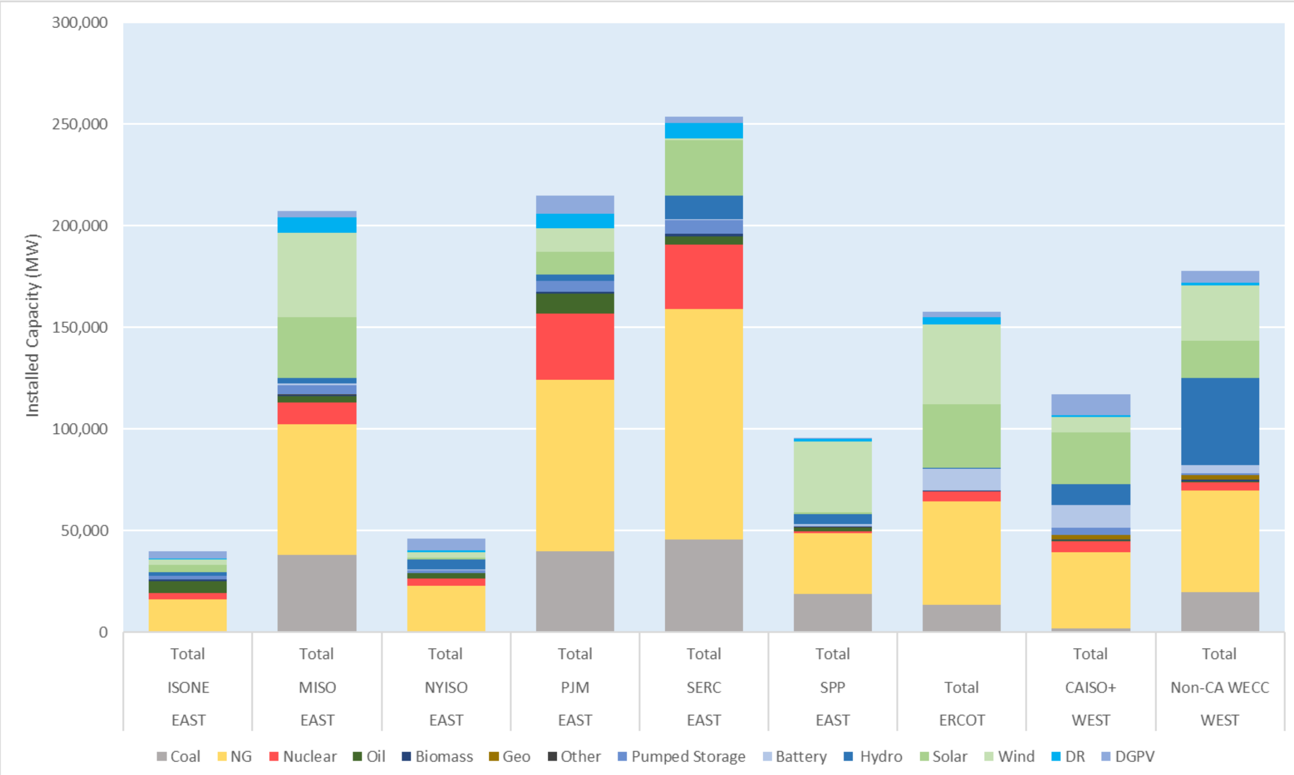


Figure A.2. Existing and Tier 1 capacities by NERC assessment area in 2024.

Forecasting 2030 Resource Mixes

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

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

Retirements

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

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

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

Generation Stack for Each Scenario

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

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

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

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

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

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

Appendix B - Representing Canadian Transfer Limits

Introduction

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

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

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

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

Methodology

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

Dataset Collection and Preparation

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

Underlying Hypothesis

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

Regression Model

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

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

Model Training, Validation, and Assessment

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

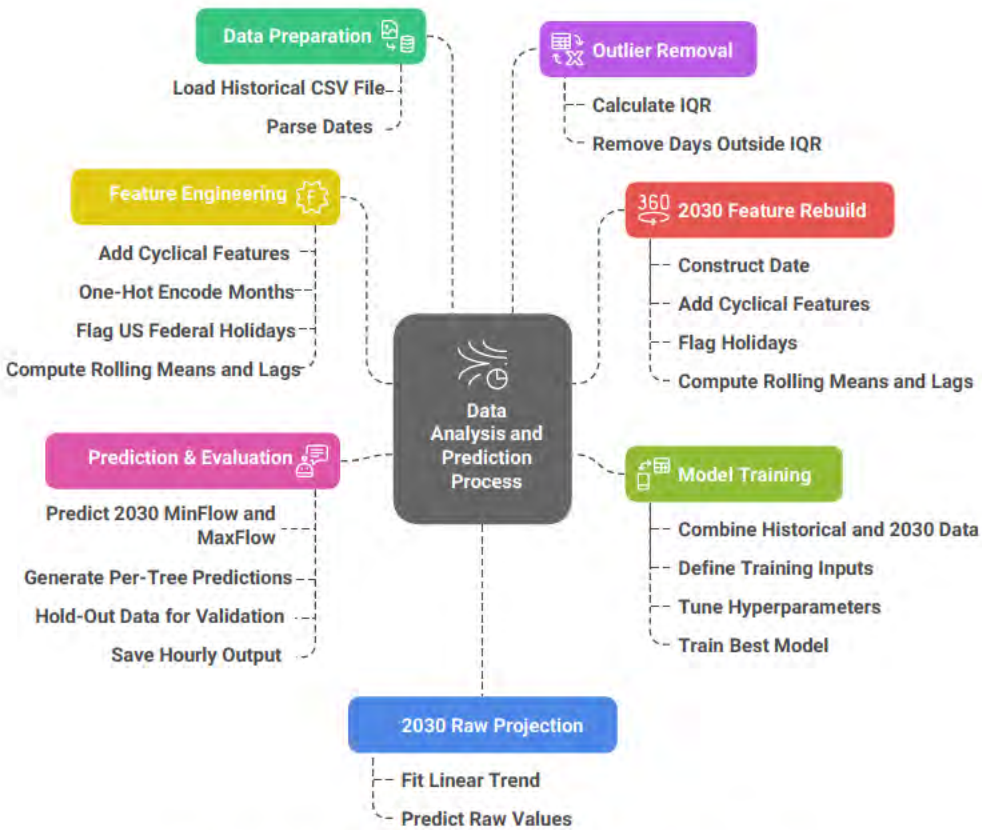


Figure B.1. Data analysis and prediction process.

Example Feature Importance for Predicting MaxFlow from Ontario to NYISO

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

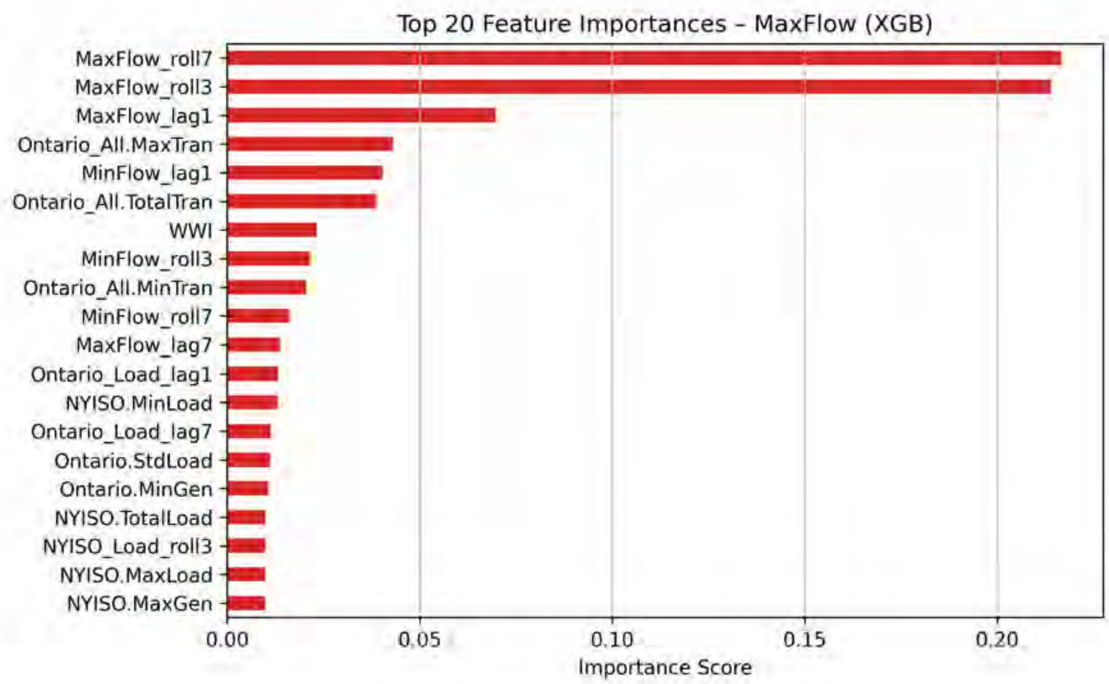


Figure B.2. Feature importance for predicting the hourly maximum energy transfer (MaxFlow) between NYISO and Ontario. XGB = eXtreme Gradient Boosting.

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

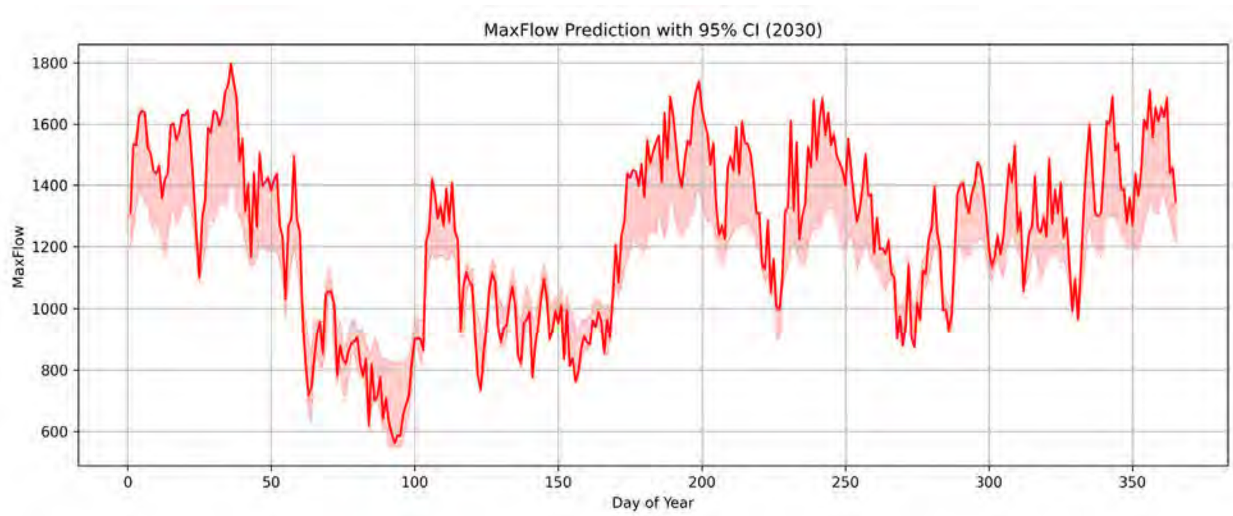


Figure B.3. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI).

Model Performance

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

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

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

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

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

Maximum flow predictions: Ontario to New York

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

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

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

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

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

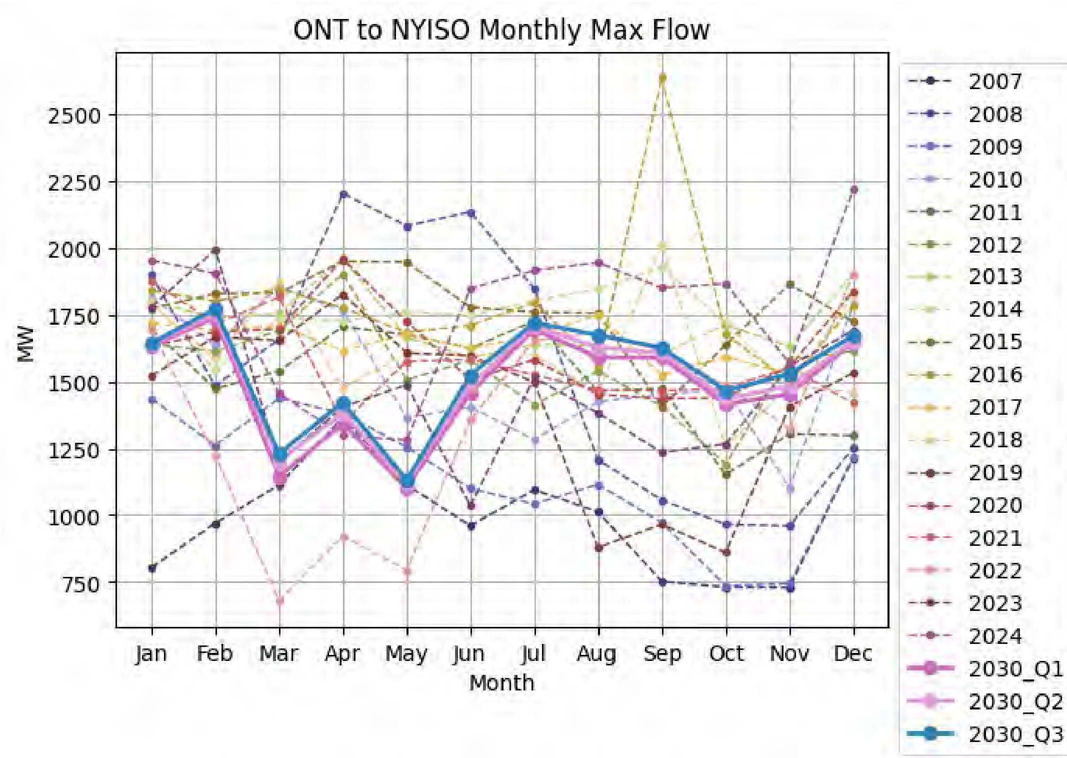


Figure B.4. Monthly maximum energy transfer between Ontario (ONT) and New York (NYISO).

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

Discussion

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

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

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

Supplementary Plots for Additional Transfers

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

(iii) Pacific Northwest to British Columbia

(iv) Alberta to Montana

(v) Manitoba to MISO West

(vi) Ontario to MISO West

(vii) Ontario to MISO East

(viii) Ontario to New York

(ix) Hydro-Quebec to New York

(x) Hydro-Quebec to New England

(xi) New Brunswick to New England

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

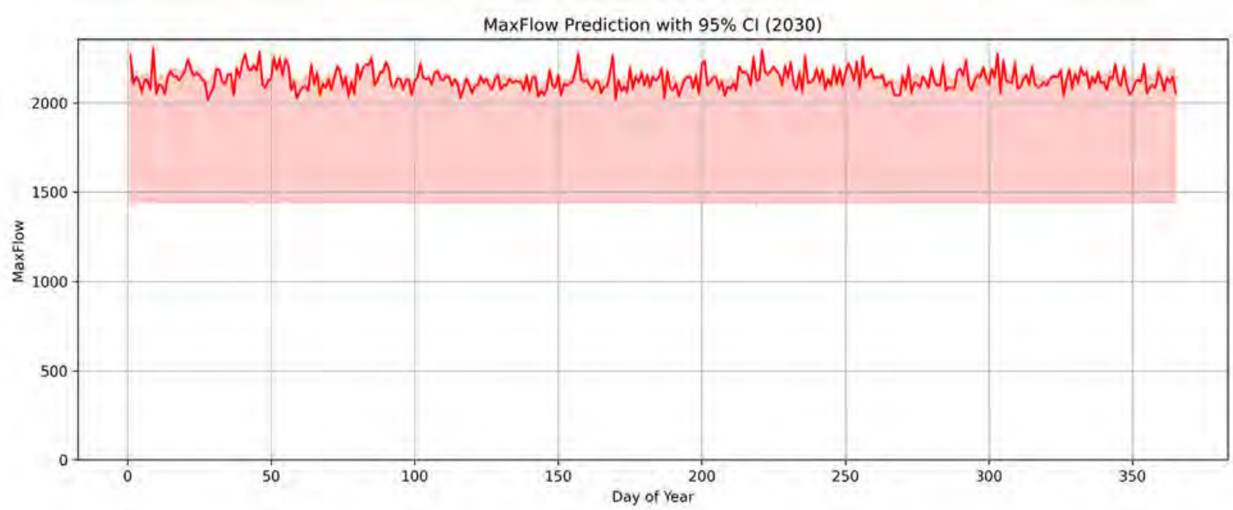


Figure B.5. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between British Columbia and the Pacific Northwest.

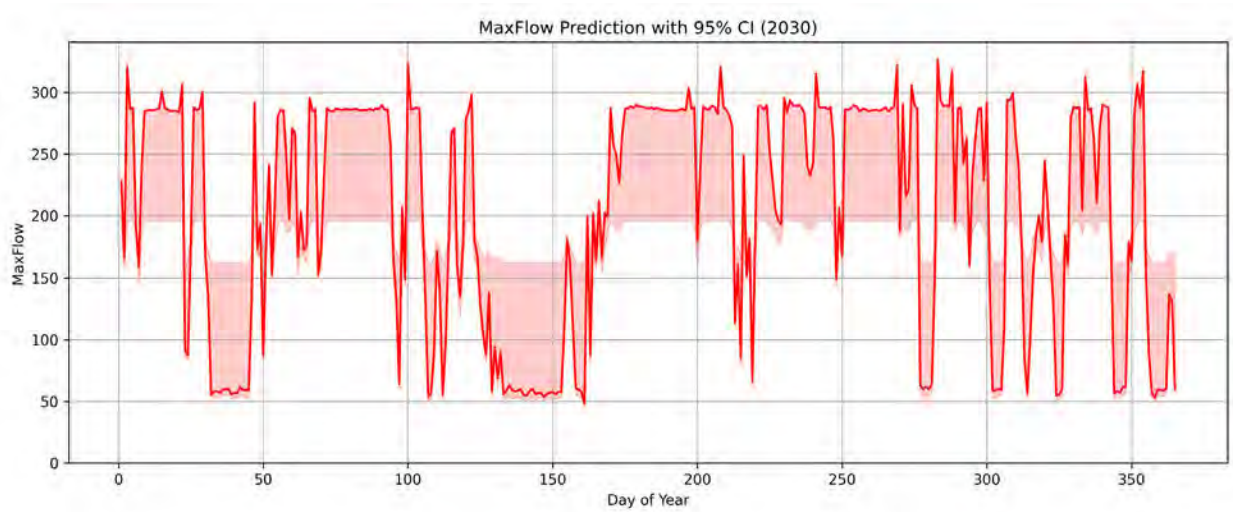


Figure B.6. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between AESO and Montana.

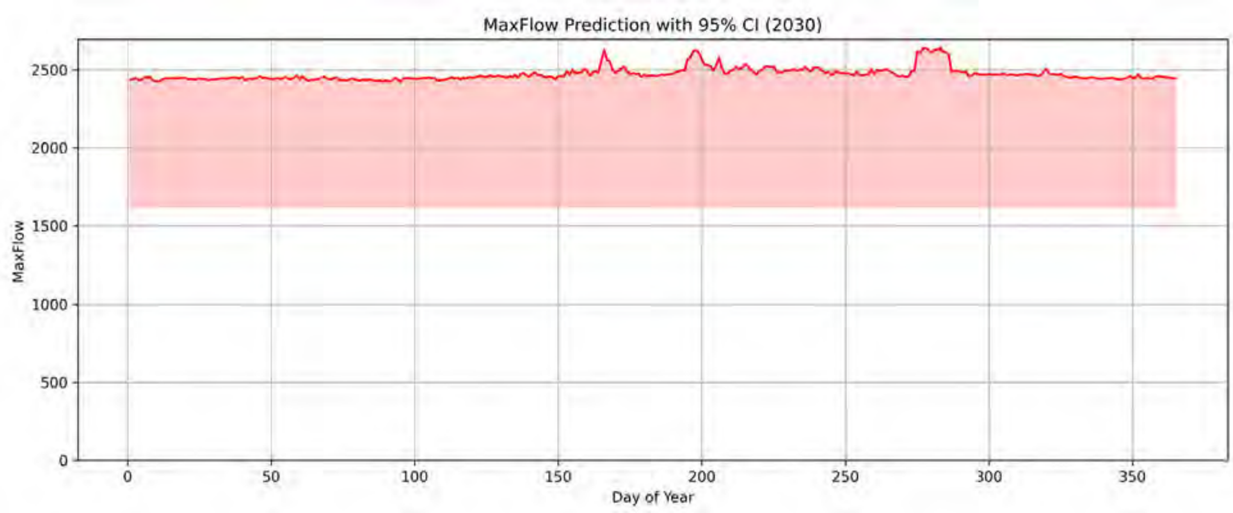


Figure B.7. Projected 2030 maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Manitoba and MISO.

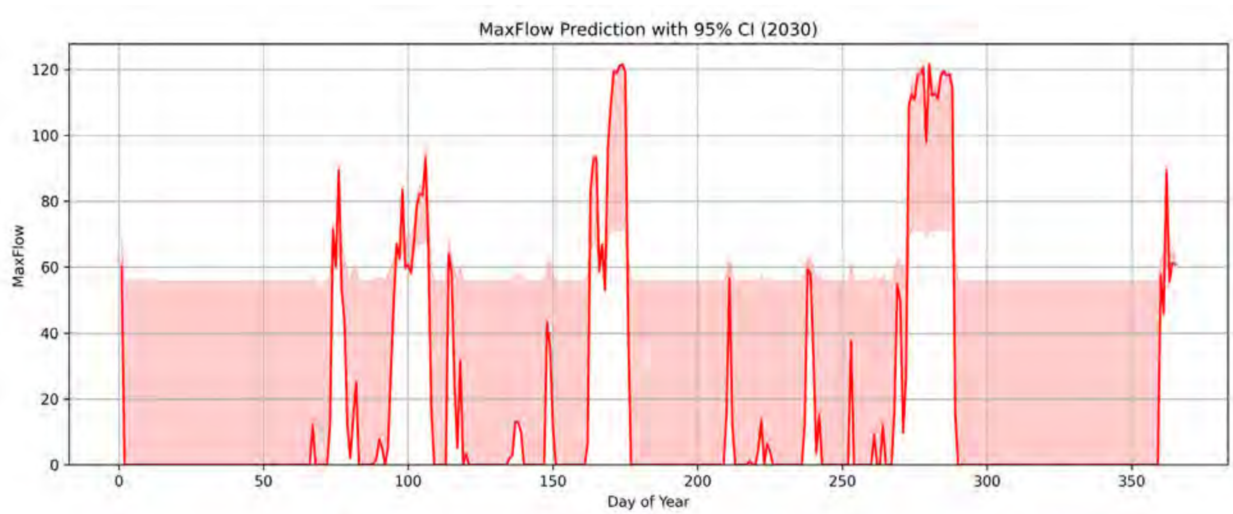


Figure B.8. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO West.

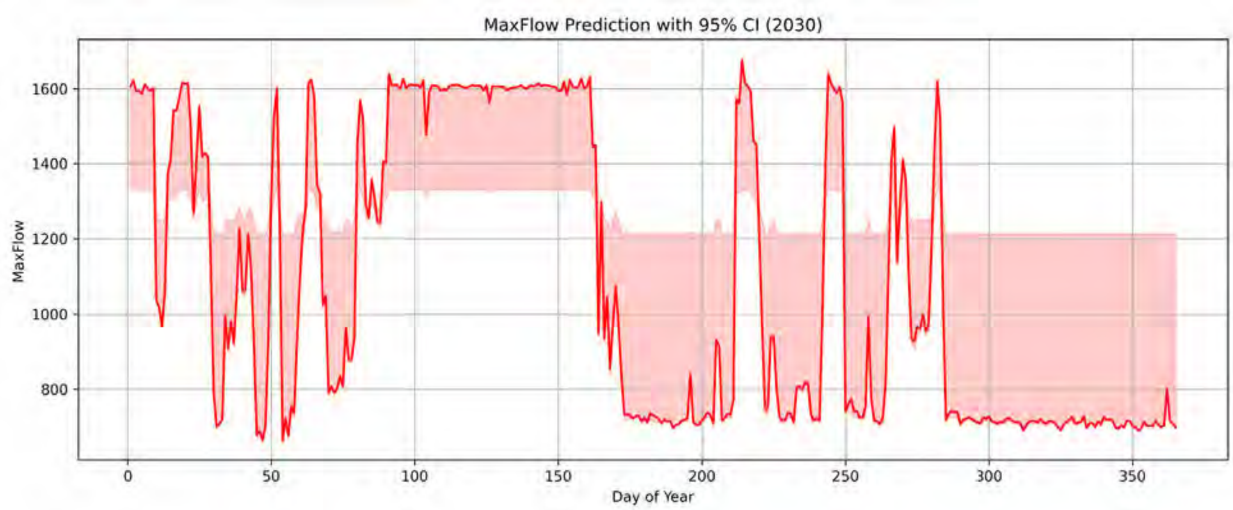


Figure B.9. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO East.

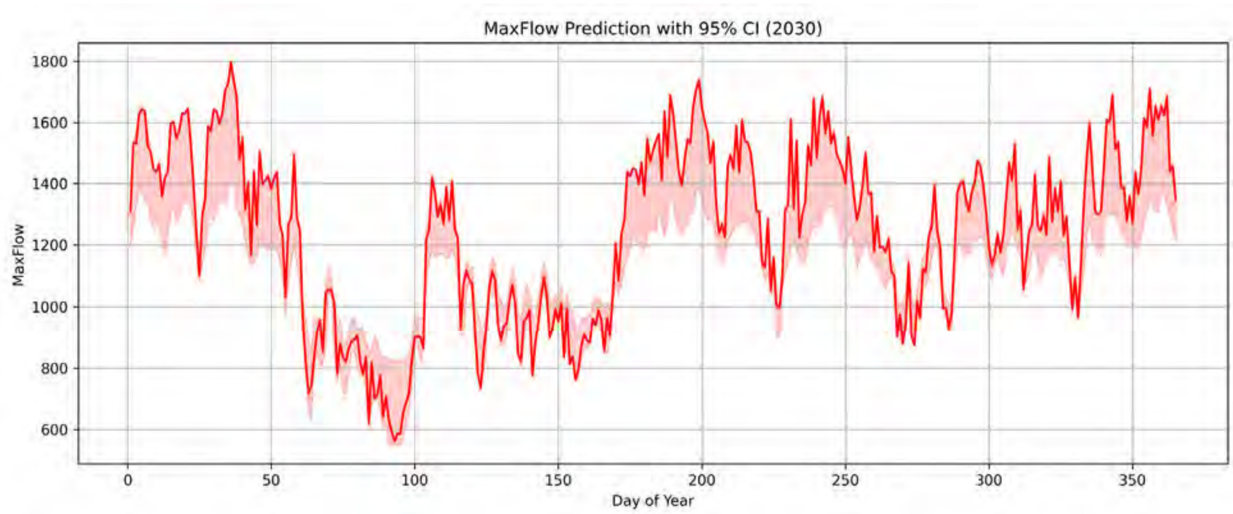


Figure B.10. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and New York.

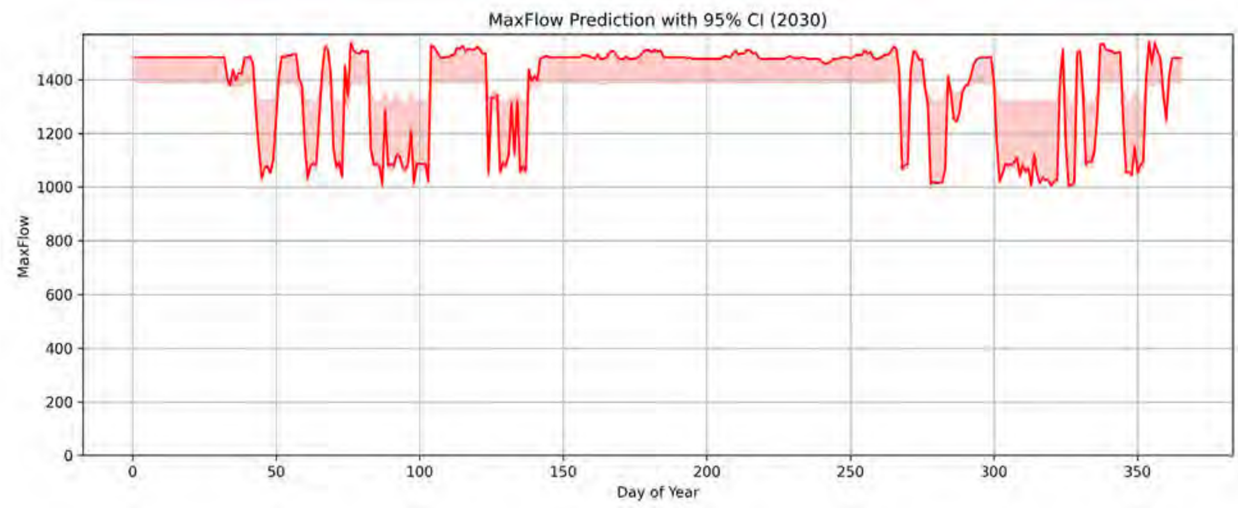


Figure B.11. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New York.

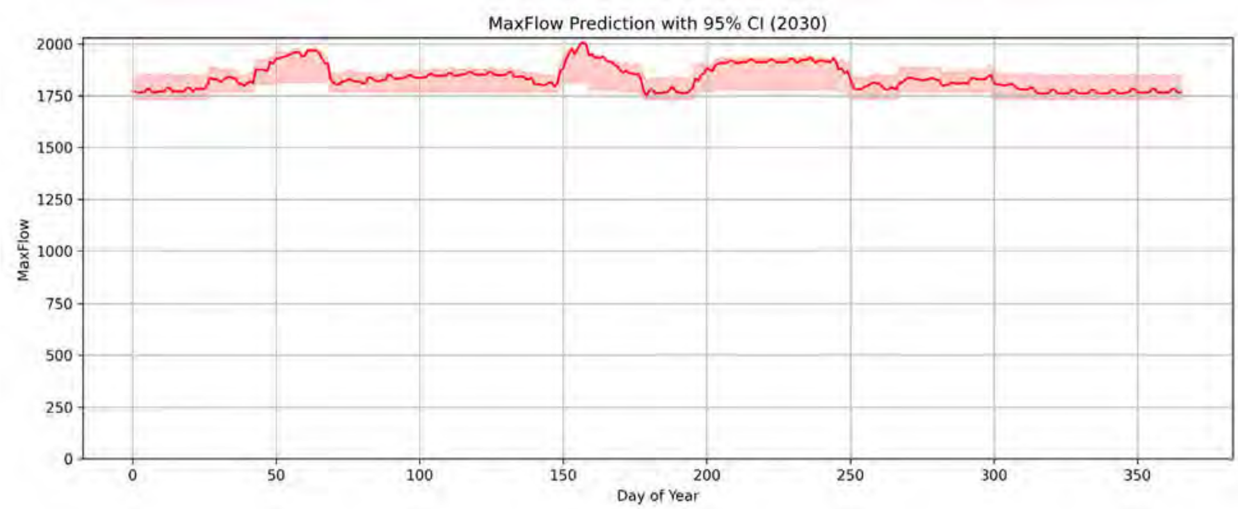


Figure B.12. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New England.

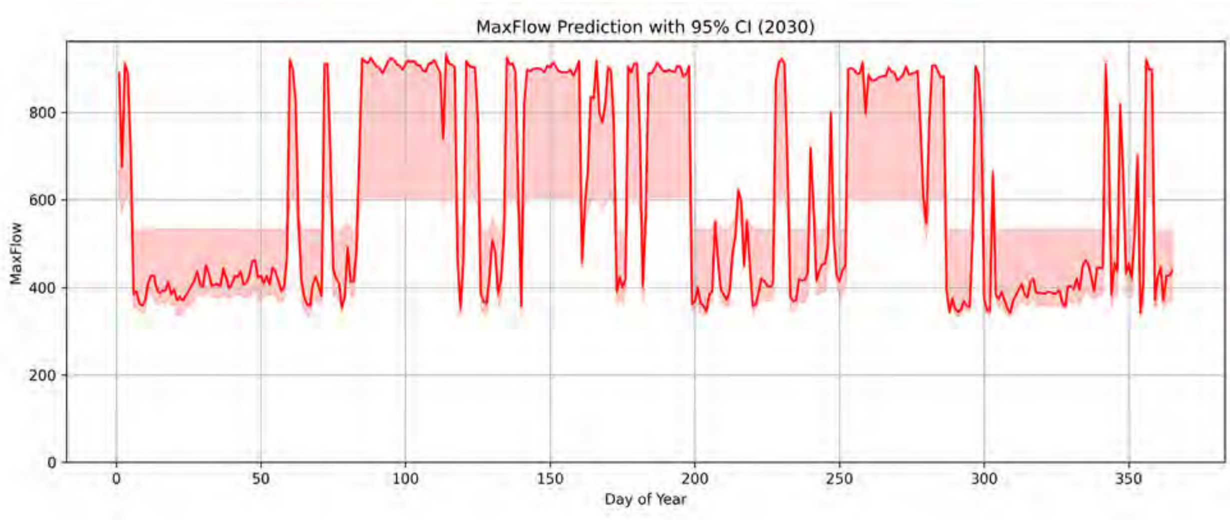


Figure B.13. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between New Brunswick and New England.

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EO 14262

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

Presidential Documents

Executive Order 14262 of April 8, 2025

Strengthening the Reliability and Security of the United States Electric Grid

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

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

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

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

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

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

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

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

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

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

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

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

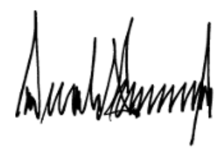
Sec. 4. *General Provisions*. (a) Nothing in this order shall be construed to impair or otherwise affect:

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

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

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

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



THE WHITE HOUSE,
April 8, 2025.

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

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

U.S. DEPARTMENT of ENERGY

For more information, visit:
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DOE/Publication Number • July, 7 2025

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-29
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-30

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

Exhibit 97
DOE July 7, 2025 Press Release

Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security

The Department of Energy warns that blackouts could increase by 100 times in 2030 if the U.S. continues to shutter reliable power sources and fails to add additional firm capacity.

Energy.gov

July 7, 2025

4 min

The Department of Energy warns that blackouts could increase by 100 times in 2030 if the U.S. continues to shutter reliable power sources and fails to add additional firm capacity.

WASHINGTON— The U.S. Department of Energy (DOE) today released its Report on Evaluating U.S. Grid Reliability and Security. The report fulfills Section 3(b) of President Trump's Executive Order, *Strengthening The Reliability And Security Of The United States Electric Grid*, by delivering a uniform methodology to identify at-risk regions and guide Federal reliability interventions.

The analysis reveals that existing generation retirements and delays in adding new firm capacity, driven by the radical green agenda of past administrations, will lead to a surge in power outages and a growing mismatch between electricity demand and supply, particularly from artificial intelligence (AI)-driven data center growth, threatening America's energy security.

"This report affirms what we already know: The United States cannot afford to continue down the unstable and dangerous path of energy subtraction previous leaders pursued, forcing the closure of baseload power sources like coal and natural gas," Secretary Wright said. "In the coming years, America's reindustrialization and the AI race will require a significantly larger supply of around-the-clock, reliable, and uninterrupted power. President Trump's administration is committed to advancing a strategy of energy addition, and supporting all forms of energy that are affordable, reliable, and secure. If we are going to keep the lights on, win the AI race, and keep electricity prices from skyrocketing, the United States must unleash American energy."

Highlights of the Report:

- **The status quo is unsustainable.** DOE's analysis shows that, if current retirement schedules and incremental additions remain unchanged, most regions will face unacceptable reliability risks within five years and the Nation's electrical power grid will be unable to meet expected demand for AI, data centers, manufacturing and industrialization while keeping the cost of living low for all Americans. Staying on the present course would undermine U.S. economic growth, national security, and leadership in emerging technologies.

- **Grid growth must match the pace of AI innovation.** Electricity demand from AI-driven data centers and advanced manufacturing is rising at a record pace. The magnitude and speed of projected load growth cannot be met with existing approaches to load addition and grid management. Radical change is needed to unleash the transformative potential of innovation.
- **With projected load growth, retirements increase the risk of power outages by 100 times in 2030.** Allowing 104 GW of firm generation to retire by 2030—without timely replacement—could lead to significant outages when weather conditions do not accommodate wind and solar generation. Modeling shows annual outage hours could increase from single digits today to more than 800 hours per year. Such a surge would leave millions of households and businesses vulnerable. We must renew a focus on firm generation and continue to reverse radical green ideology in order to address this risk.
- **Planned supply falls short, reliability at risk.** The 104 GW of plant retirements are replaced by 209 GW of new generation by 2030; however, only 22 GW comes from firm baseload generation sources. Even assuming no retirements, the model found outage risk in several regions rises more than 30-fold, proving the queue alone cannot close the dependable-capacity deficit.
- **Old tools won't solve new problems.** Traditional peak-hour tests to evaluate resource adequacy do not sufficiently account for growing dependence on neighboring grids. At a minimum, modern methods of evaluating resource adequacy need to incorporate frequency, magnitude, and duration of power outages, move beyond exclusively analyzing peak load time periods, and develop integrated models to enable proper analysis of increasing reliance on neighboring grids.

DOE's report identifies regions most vulnerable to outages under various weather and retirement scenarios and offers capacity targets needed to restore acceptable reliability. The methodology also informs the potential use of DOE's emergency authority under Section 202(c) of the Federal Power Act.

Click here for a fact sheet on the report.

###

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Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-30

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

Exhibit 98
Culley East Ash Pond Closure Plan

AECOM

Submitted to
Southern Indiana
Gas & Electric Company
Inc. (SIGECO)
One Vectren Square
Evansville, IN 47708

Submitted by
AECOM
1300 East 9th Street
Suite 500
Cleveland, Ohio 44114

September 10, 2021

CCR Certification: Written Closure Plan §257.102 (b) & (d)

for the

East Ash Pond

at the

F.B. Culley Generating Station

Revision 1

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Appendices

Executive Summary

This Coal Combustion Residuals (CCR) Written Closure Plan (Closure Plan) for the East Ash Pond at the Southern Indiana Gas & Electric Company Inc., F.B. Culley Generating Station has been prepared in accordance with the requirements specified in the USEPA CCR Rule under 40 Code of Federal Regulations §257.102. These regulations require that the specified documentation, assessments and plans for an existing CCR surface impoundment be prepared by October 13, 2016. The Initial Closure Plan proposed a Closure-in-Place (CiP) methodology and was prepared in accordance with these requirements. This Closure Plan (Rev. 1) represents an update to the Initial Closure Plan (Rev. 0) considering recent developments to implement a closure by removal (CbR) methodology for closure of the East Ash Pond.

This Closure Plan meets the regulatory requirements as summarized in **Table ES-1.**

Table ES-1 – Certification Summary

Report Section	CCR Rule Reference	Requirement Summary	Requirement Met?	Comments
Closure Plan				
2.1	§257.102 (b)	*A written closure plan must be prepared that describes the steps necessary to close the unit*	Yes	This Closure Plan has been prepared based on a closure design. All steps necessary to close the unit and information as required concerning the unit are included in the Closure Plan.
2.2	§257.102 (c)	*Closure by Removal*	Yes	This Closure Plan has been prepared based on a closure by removal design. All steps necessary to close the unit and information as required concerning the unit are included in the Closure Plan.

The East Ash Pond at the F.B. Culley Generating Station is currently an active surface impoundment. Upon decision and/or requirement to close this surface impoundment, a Notification of Intent to Initiate Closure will be placed in the Operating Record, closure operations will commence, and the surface impoundment will be closed within the time frame as allowed in the CCR Rule. It is anticipated that the East Ash Pond will initiate closure by March 2023.

1 Introduction

1.1 Purpose of this Report

The purpose of the Closure Plan is to document that the requirements specified in 40 Code of Federal Regulations (CFR) §257.102 have been met to support the certification required under each of the applicable regulatory provisions for the East Ash Pond at F.B. Culley Generating Station. The East Ash Pond is an existing coal combustion residuals (CCR) surface impoundment as defined by 40 CFR §257.53. The CCR Rule requires that the Initial Written Closure Plan for an existing CCR surface impoundment be prepared by October 13, 2016. The Initial Closure Plan proposed a Closure-in-Place (CiP) methodology and was prepared in accordance with these requirements. This Closure Plan (Rev. 1) represents an update to the Initial Closure Plan (Rev. 0) considering recent developments to implement a closure by removal (CbR) methodology for closure of the East Ash Pond.

The following table summarizes the documentation required within the CCR Rule and the sections that specifically respond to those requirements of this plan.

Table 1-1 – CCR Rule Cross Reference Table		
Report Section	Title	CCR Rule Reference
2.1	Content of the Plan	§257.102 (b)(1)
2.2	Achievement of Performance Standards	§257.102 (c)

1.2 Brief Description of Impoundment

The Culley station is located in Warrick County, Indiana, southeast of Newburgh, Indiana, and is owned and operated by Southern Indiana Gas and Electric Company (SIGECO). The Culley station (Culley) is located along the north bank of the Ohio River and the west bank of Little Pigeon Creek along the southeast portion of the site. Culley historically has had two CCR surface impoundments, identified as the West Ash Pond and the East Ash Pond. The East Ash Pond actively receives CCR materials and the West Ash Pond has since closed and no longer receives or manages CCR materials. This Closure Plan has been developed for the East Ash Pond. The East Ash Pond is approximately 10 acres in size.

The history of construction report for the East Ash Pond indicates that the pond construction commenced in the 1971. The original design plans indicate that earthen embankments for the East Ash Pond were constructed by placing fill along the south side (adjacent to the Ohio River) and the east side (adjacent to Little Pigeon Creek), and tying into existing high ground at the north and west sides. Prior to the construction of the generating station, Little Pigeon Creek originally ran through the footprint of the East Ash Pond, continuing through the current location of the generating station and the former West Ash Pond. During the construction of the generating station in the 1950s, Little Pigeon Creek was re-routed to the Ohio River east of the Culley Station. The top of the East Ash Pond embankment was constructed to an approximate elevation of 397 feet. Interior side slopes of the pond vary, but original design documents indicate that the slopes are approximately 2.5H:1V (horizontal to vertical) from the top of the dike to approximately halfway down the interior slope until a flat bench. From the bench to the bottom of the pond, the slope is approximately 2H:1V. The embankment of the East Ash Pond is approximately 1,200 feet long, 15 feet wide at the crest, 30 feet high, and has approximately 2.5H:1V exterior side slopes covered with trees, riprap, concrete rubble and undergrowth vegetation. The surface area of the impoundment is approximately 9.8 acres. Within the pond, there are two small pools. One is being utilized as a settling basin for the discharge from the FGD wastewater treatment system. The ponded water has a surface area of approximately 7 acres and has a normal operating level of 386.5 feet.

A Site Location Map showing the area surrounding the station is included as **Figure 1** of **Appendix A**. **Figure 2** in **Appendix A** presents the F.B. Culley Site Map.

2 Written Closure Plan

Regulatory Citation: 40 CFR §257.102 (b); Written closure plan—

- *(1) Content of the plan. The owner or operator of a CCR unit must prepare a written closure plan that describes the steps necessary to close the CCR unit at any point during the active life of the CCR unit consistent with recognized and generally accepted good engineering practices. The written closure plan must include, at a minimum, the information specified in paragraphs (b)(1)(i) through (vi) of this section.*

The Written Closure Plan for the East Ash Pond is described in this section. Information about operational and maintenance procedures was provided by Culley plant personnel. The Culley station follows an established maintenance program that quickly identifies and resolves issues of concern.

2.1 Content of the Plan

2.1.1 Closure Plan Description

Regulatory Citation: 40 CFR §257.102 (b)(1);

- *(i) Narrative description of how the CCR unit will be closed in accordance with this section.*

The entire footprint of the East Ash Pond will be excavated to remove CCR to historical/pre-development grades. The East Ash Pond will be dewatered to facilitate CCR excavation. Excavated CCR materials will be either beneficially reused or disposed at a third party disposal site. The existing southern embankment will be breached to direct stormwater to an NPDES permitted outfall. Closure operations will involve:

1) Dewatering the impoundment;

2) Excavation and removal of all CCR materials;

3) Dike breach & outfall construction; and

4) Seeding and final vegetative stabilization

In accordance with §257.102(b)(3), this Closure Plan will be amended as needed to provide additional details after the final engineering design is completed. This Closure Plan reflects the information available to date.

Regulatory Citation: 40 CFR §257.102 (b)(1);

- *(ii) If closure of the CCR unit will be accomplished through removal of CCR from the CCR unit, a description of the procedures to remove the CCR and decontaminate the CCR unit in accordance with paragraph (c) of this section.*

Excavation in the East Ash Pond footprint will advance until historical/pre-development grades have been achieved and all CCR has been removed from within the CCR unit. Upon attaining pre-development grades, a visual inspection will be conducted to identify any remnant CCR materials. Remnant CCR materials identified by this inspection will subsequently be removed by additional excavation. This process may be supplemented by analytical testing to satisfy state-specific closure protocols, as appropriate. Following completion of this process and consistent with current regulatory provisions, groundwater monitoring will be conducted until it can be confirmed that concentrations do not exceed the groundwater protection standard established pursuant to §257.95(h) for constituents listed in Appendix IV.

Regulatory Citation: 40 CFR §257.102 (b)(1);

- *(iii) If closure of the CCR Unit will be accomplished by leaving CCR in place, a description of the final cover system and methods and procedures used to install the final cover.*

Not applicable.

2.1.2 Inventory and Area Estimates

Regulatory Citation: 40 CFR §257.102 (b);

- *(iv) An estimate of the maximum inventory of CCR ever on-site over the active life of the CCR unit.*

An estimate of the maximum inventory of CCR ever on-site over the active life is 349,000 cubic yards.

Regulatory Citation: 40 CFR §257.102 (b);

- *(v) An estimate of the largest area of the CCR unit ever requiring a final cover as required by paragraph (d) of this section at any time during the CCR unit's active life.*

Not applicable.

2.1.3 Closure Schedule

Regulatory Citation: 40 CFR §257.102 (b)(1);

- *(vi) Schedule for completing all activities necessary to satisfy the closure criteria in this section, including an estimate of the year in which all closure activities for the CCR unit will be completed.*

The milestones and the associated timeframes are initial estimates. Some of the activities associated with the milestones will overlap. Amendments to the milestones and timeframes will be made as more information becomes available.

Table 2-1 – Closure Schedule

Milestone	Schedule
Initial Written Closure Plan (Rev. 0)	October 13, 2016
Written Closure Plan (Rev. 1)	September 10, 2021
Notification of Intent to Close Placed in Operating Record	March 2023 or no later than the date closure of the CCR unit is initiated. Closure to commence in accordance with the applicable timeframes in 40 CFR 257.102(e).

Table 2-1 – Closure Schedule	
Milestone	**Schedule**
Agency coordination and permit acquisition – Coordinating with state agencies for compliance. – Acquiring state permits.	2021-2023 2022-2023
Mobilization	March 2023
Closure Construction Activities CCR – Complete dewatering, as necessary – Complete excavation of CCR – Final Dike Breach/Final Stabilization	 June 2024 June 2024 December 2024
Estimate of Year in which all closure activities will be completed.	2024-2025

2.2 Achievement of Closure by Removal

Regulatory Citation: 40 CFR §257.102 (c); Closure by removal of CCR

An owner or operator may elect to close a CCR unit by removing and decontaminating all areas affected by releases from the CCR unit. CCR removal and decontamination of the CCR unit are complete when constituent concentrations throughout the CCR unit and any areas affected by releases from the CCR unit have been removed and groundwater monitoring concentrations do not exceed the groundwater protection standard established pursuant to §257.95(h) for constituents listed in appendix IV to this part.

Excavation in the East Ash Pond footprint will advance until historical/pre-development grades have been achieved and all CCR has been removed from within the CCR unit. Upon attaining pre-development grades, a visual inspection will be conducted to identify any remnant CCR materials. Remnant CCR materials identified by this inspection will subsequently be removed by additional excavation. This process may be supplemented by analytical testing to satisfy state-specific closure protocols, as appropriate. Following completion of this process and consistent with current regulatory provisions, groundwater monitoring will be conducted until it can be confirmed that concentrations do not exceed the groundwater protection standard established pursuant to §257.95(h) for constituents listed in Appendix IV.

2.3 Amendment to Initial or any Subsequent Written Closure Plan

The Initial Written Closure Plan (Rev. 0) dated October 13, 2016 is hereby being amended by this Written Closure Plan (Rev. 1) on September 10, 2021 as required by §257.102 (b)(3).

3 Certification

This Certification Statement documents that the East Ash Pond at the F.B. Culley Generating Station meets the Written Closure Plan requirements specified in 40 CFR §257.102 (b) and the closure by removal requirements as specified in 40 CFR §257.102 (c). The East Ash Pond is an existing CCR surface impoundment as defined by 40 CFR §257.53. The CCR Rule requires that the Initial Written Closure Plan for an existing CCR surface impoundment be prepared by October 13, 2016. An amendment to the Initial Written Closure Plan is provided herein, dated September 10, 2021.

CCR Unit: Southern Indiana Gas & Electric Company; F.B. Culley Generating Station; East Ash Pond

I, Jay Mokotoff, being a Registered Professional Engineer in good standing in the State of Indiana, do hereby certify, to the best of my knowledge, information, and belief that the information contained in this certification has been prepared in accordance with the accepted practice of engineering. I certify, for the above referenced CCR Unit, that the Initial Written Closure Plan dated October 13, 2016 and hereby amended on September 10, 2021 meets the requirements of 40 CFR § 257.102.

Jay D. Mokotoff
Printed Name

September 10, 2021
Date

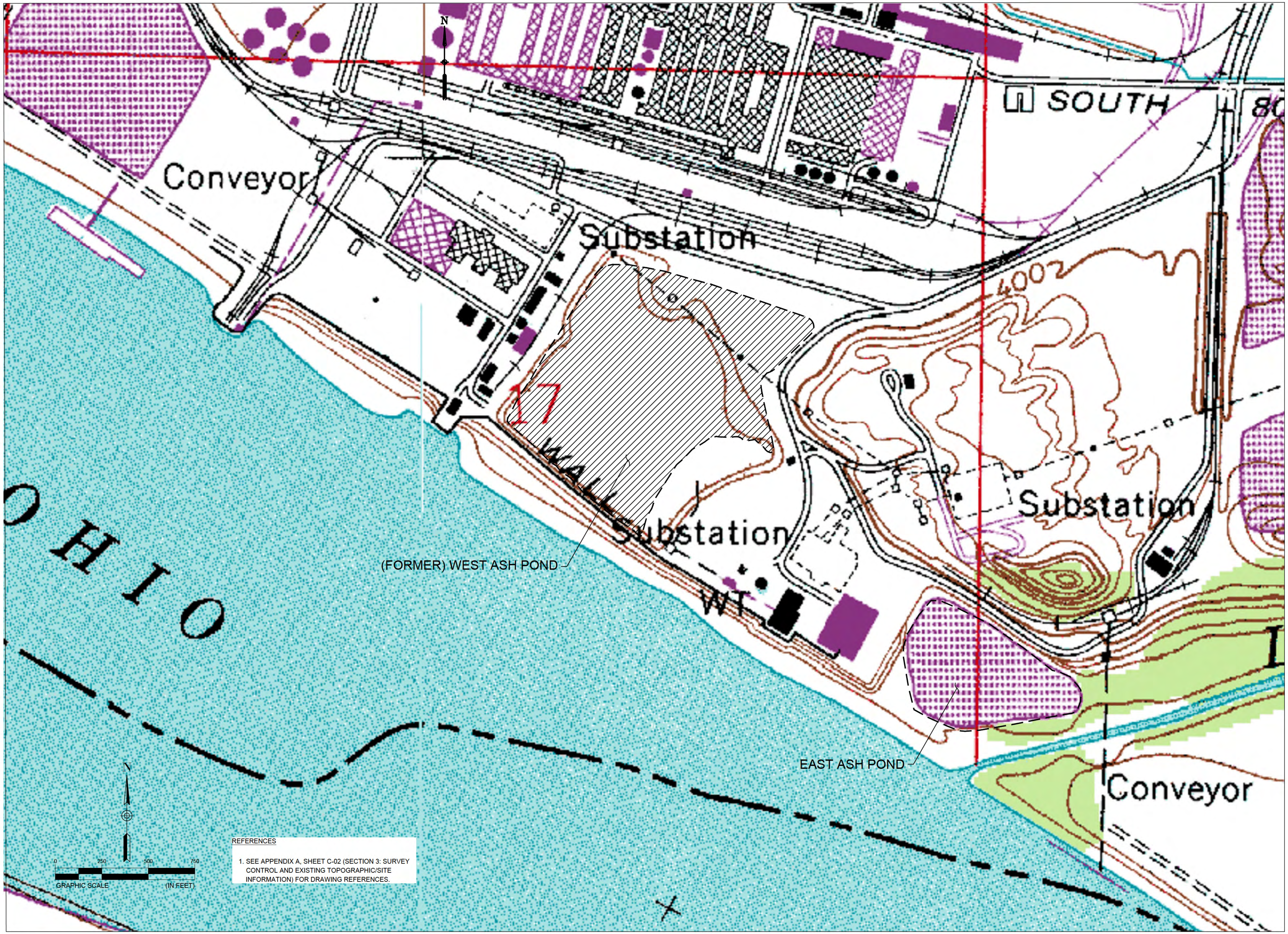
4 Limitations

Background information, design basis, and other data which AECOM has used in preparing this report have been furnished to AECOM by SIGECO. AECOM has relied on this information as furnished and is not responsible for the accuracy of this information. Our recommendations are based on available information from previous and current investigations. These recommendations may be updated as future investigations are performed.

The conclusions presented in this report are intended only for the purpose, site location, and project indicated. The provisions and recommendations presented in this report should not be used for other projects or purposes. Conclusions or recommendations made from these data by others are their responsibility. The conclusions and recommendations are based on AECOM's understanding of current plant operations, maintenance, stormwater handling, and ash handling procedures at the station, as provided by SIGECO. Changes in any of these operations or procedures may invalidate the findings in this report until AECOM has had the opportunity to review the findings and revise the report if necessary.

This development of the Closure Plan was performed in accordance with the standard of care commonly used as state-of-practice in our profession. Specifically, our services have been performed in accordance with accepted principles and practices of the engineering profession. The conclusions presented in this report are professional opinions based on the indicated project criteria and data available at the time this report was prepared. Our services were provided in a manner consistent with the level of care and skill ordinarily exercised by other professional consultants under similar circumstances. No other representation is intended.

Appendix A
Figures



REFERENCES

1. SEE APPENDIX A, SHEET C-02 (SECTION 3: SURVEY CONTROL AND EXISTING TOPOGRAPHIC/SITE INFORMATION) FOR DRAWING REFERENCES.

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F.B. CULLEY
GENERATING STATION
NEWBURGH, INDIANA

CLOSURE BY REMOVAL
OF EAST ASH POND

CLOSURE PLAN

NOT FOR
CONSTRUCTION

ISSUED FOR BIDDING ____ DATE BY

ISSUED FOR CONSTRUCTION ____ DATE BY

REVISIONS

NO.	DESCRIPTION	DATE
△		
△		
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AECOM PROJECT NO:	60586569
DRAWN BY:	WCPP
DESIGNED BY:	AG
CHECKED BY:	JDM
DATE CREATED:	
PLOT DATE:	07/29/2021
SCALE:	NOTED
ACAD VER:	2019

SHEET TITLE

SITE LOCATION

FIGURE 1

SHEET 1 OF 2

AECOM DRAWING PATH: C:\Users\Wadson.Phanord\Desktop\Culley East\IDEM Version\Appendices\Figures\Figure 2 – Site Aerial.dwg

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F.B. CULLEY GENERATING STATION
NEWBURGH, INDIANA

CLOSURE BY REMOVAL OF EAST ASH POND

CLOSURE PLAN

NOT FOR CONSTRUCTION

ISSUED FOR BIDDING ______ DATE BY

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REVISIONS

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ACAD VER:	2019

SHEET TITLE

AERIAL SITE MAP

FIGURE 2

SHEET 2 OF 2

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More information on AECOM and its services can be found at www.aecom.com.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-29
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-30

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

Exhibit 99
RFR of July Resource Adequacy Report

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

	)
In re	)
Resource Adequacy Report	)
Evaluating the Reliability and Security	)
Of the United States Electric Grid	)
	)

Motion to Intervene and Request for Rehearing of
Natural Resources Defense Council, the Ecology Center, Environmental Defense Fund, Environmental Law and Policy Center, Public Citizen, Sierra Club, and Vote Solar

I. INTRODUCTION

Pursuant to section 313 of the Federal Power Act ("the Act"), 16 U.S.C. § 825*l*, Natural Resources Defense Council, the Ecology Center, Environmental Defense Fund, Environmental Law and Policy Center, Public Citizen, Sierra Club, and Vote Solar ("Public Interest Organizations") hereby move, to the extent necessary, to intervene and request rehearing of the Department of Energy's ("Department" or "DOE") "Resource Adequacy Report: Evaluating the Reliability and Security of the United States" ("RAR").[1] The Department issued the RAR in response to Executive Order 14,262 *Strengthening the Reliability and Security of the United States Electric Grid,* April 8, 2025 ("Grid EO"),[2] and claims that the RAR is a "uniform methodology to identify at-risk region(s) and guide reliability interventions" as directed by the Grid EO.[3] But the Department simultaneously disclaims the utility of the RAR to guide interventions uniformly, acknowledging on the very first page that the various "entities responsible for the maintenance and operation of the grid" have information "that could further enhance the robustness of reliability decisions" in their parts of the grid.[4]

The flaws in the RAR continue. The Department overstates assumptions about demand growth and likely retirements while understating likely new entry, building into the RAR an inherent bias toward a finding of inadequate resource adequacy. The Department also departs from best practices by using a

[1] July 7, 2025, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf (attached as Ex. 1) (hereinafter, the "RAR").

[2] 90 Fed. Reg. 15521 (Apr. 8, 2025) (hereinafter "Grid EO").

[3] *Id.* at vi.

[4] *Id.* at i.

deterministic approach, which fails to account for necessary uncertainties and demonstrates that the RAR's findings should not be taken as conclusive or form the basis for further extraordinary actions. And on some critical aspects of the RAR analysis, the Department simply fails to explain its own methodology; while the Department describes two thresholds at which the RAR projects outages will occur, it fails to explain when it applies the standard threshold and when it applies the elevated one. These flaws render any reliance on the RAR to "guide reliability interventions" arbitrary and capricious.

While the Department acknowledges that the RAR is unsuitable to guide reliability interventions uniformly and provided no notice or opportunity to comment, the Department nevertheless does not clarify how it will use the RAR, creating confusion as to whether the RAR, in conjunction with the Grid EO, is intended to function as a final rule. Public Interest Organizations believe that the RAR should not be used as the basis for future action by the Department. We submit this request for rehearing in an abundance of caution, to the extent the Department later argues that any of these issues must have been raised in a request for rehearing within 30 days of the publication of the RAR, 16 U.S.C. § 825*l*. We also reserve our right to argue in later proceedings that 16 U.S.C. § 825*l* does not apply.

In sum, the RAR is a poorly crafted solution in search of a problem; there is no "energy emergency" and the regulatory bodies who actually possess authority to ensure resource adequacy are doing their jobs. Consequently, the RAR serves no useful purpose and should simply be withdrawn. By DOE's own admission, the RAR cannot reasonably be relied on to guide DOE interventions, nor, given the false premise and multiple mistaken assumptions, does it provide any value even as a purely informational report. On the contrary, it will only cause confusion for grid operators, energy providers, and members of the public. In the alternative, the Department should not use the RAR as support for any reliability intervention or other action until and unless it (1) provides notice of the statutory authority under which DOE issued the RAR and publishes all data underlying the RAR, (2) explains in detail the specific uses for the methodology, and (3) allows interested parties to comment on the RAR before finalizing it.

II. STATEMENT OF ISSUES

1. The Department intrudes on Federal Energy Regulatory Commission ("FERC" or "the Commission") and state authority. 16 U.S.C. §§ 824a(c),824o-1; 42 U.S.C. § 7113.
2. The RAR's findings, even if accurate, do not demonstrate any emergency allowing the Department to compel generation under the Federal Power Act. 16 U.S.C. § 824a(c); S. Rep. No. 74-621 (1935); 10 C.F.R. § 205.371; 10 C.F.R. § 205.375; 46 Fed. Reg. 39,985.

3. The RAR is analytically flawed and does not rely upon substantial evidence. 16 U.S.C. 824a(a); 16 U.S.C. § 824o(a)(3).
4. The Department cannot use the RAR as a "uniform methodology" without giving notice and taking public comment. 5 U.S.C. §§ 552, 553; 10 C.F.R. §§ 205.371; 205.373.
5. The Department cannot use the RAR as a "uniform methodology" without following National Environmental Policy Act procedural requirements. 42 U.S.C. § 4332(C).

III. INTERVENTION

Each of the Public Interest Organizations has interests that may be directly and substantially affected by the use of this RAR as a "uniform methodology" to guide "reliability interventions," including the issuance of Emergency Orders under Section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c).[5] To the extent that the RAR is determined to be an Order or Rule, each party may intervene in this proceeding.[6] And to the extent the Department treats the RAR as binding and uses it to guide reliability interventions, each of the Public Interest Organizations and their members will suffer concrete injuries that are redressable through rehearing.[7] Each organization is therefore aggrieved if the RAR is a "uniform methodology" for use in guiding interventions, as the Department purports, and each organization may properly apply for rehearing, assuming without conceding that the rehearing procedures apply.[8]

A. Natural Resources Defense Council

Natural Resources Defense Council ("NRDC") is a national non-profit membership organization whose mission includes ensuring the rights of all people to clean air, clean water, and healthy communities. NRDC has a longstanding organizational commitment to protect the interests of its members and to reducing pollution caused by fossil fuel fired power plants. NRDC works to achieve clean

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[5] *See* RAR, Ex. 1 at iv.

[6] *See* U.S. Dep't of Energy, DOE 202(c) Order Rehearing Procedures, https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures (last visited June 18, 2025) (archived version attached as Ex. 2) (hereinafter "DOE Rehearing Procedures"). This website was altered after June 18, 2025, and the procedures were removed. *Compare* https://web.archive.org/web/20250604093213/https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures with the current website. *See also* Email from Lot Cooke, U.S. Dep't of Energy to Linda Alle-Murphy Re: Rehearing procedures for DOE Order No. 202-05-3 (December 30, 2005) (recommending that "a party seeking rehearing can look for procedural guidance to [Federal Energy Regulatory Commission's ("FERC")] Rules of Practice and Procedure, 18 CFR Part 385.") (attached as Ex. 3).

[7] *See, e.g. Alcoa Inc. v. FERC*, 564 F.3d 1342, 1346 (D.C. Cir. 2009).

[8] *See* 16 U.S.C. § 825*l*(a); *Wabash Valley Power Ass'n, Inc. v. FERC*, 268 F.3d 1105, 1112-13 (D.C. Cir. 2001); *NextEra Energy Res. v. ISO New Eng., Inc.*, 157 FERC ¶ 61,059, at P 5 (2016).

energy solutions that will lower consumer energy bills, meet greenhouse gas emission reduction goals, accelerate the use of energy efficiency and renewable energy, and ensure that clean energy is affordable and accessible to all. NRDC has hundreds of thousands of members across the United States. These NRDC members are harmed by orders to operate fossil fuel powered generation past planned retirement dates because continued operation will subject NRDC members to air and water pollution in the areas where they live, work, and recreate. NRDC members are also exposed to the noise and visual impacts of these facilities' operations. In addition, NRDC members are ratepayers in regions who will be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. For that reason, NRDC filed requests for rehearing of DOE's 202(c) orders issued to the J.H. Campbell and Eddystone plants, the latter of which explicitly stated that it would be reexamined following publication of the methodology. NRDC has five U.S. offices that also will be subject to higher electric bills as a result of "reliability interventions" undertaken as a result of the RAR's "uniform methodology." Moreover, NRDC has a sustainable operations plan with a goal of reducing net creation of greenhouse gas emissions derived from building operational activity to zero. NRDC and its members therefore have a strong interest in promoting actions that displace less cost-effective fossil generation with more cost-effective clean energy.

B. The Ecology Center

The Ecology Center is a Michigan-based non-profit organization headquartered in Ann Arbor, Michigan, with additional offices in Detroit, Michigan. Ecology Center is a public interest organization with more than 50 years of experience advocating for clean energy production, healthy communities, environmental justice, and a sustainable future. Ecology Center works at the local, state, and federal level. Its programs address systemic sources of poor health and environmental degradation through unique partnerships with environmental health and environmental advocates. Ecology Center has over 6,000 members and supporters, that live, use electricity, and pay electric bills in Michigan and could be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. In addition, Ecology Center members are harmed by orders to operate fossil fuel powered generation past planned retirement dates because continued operation will subject Ecology Center members to air and water pollution in the areas where they live, work, and recreate.

C. Environmental Defense Fund

The Environmental Defense Fund ("EDF") is a non-profit membership organization with hundreds of thousands of members nationwide whose mission is to build a vital Earth for everyone by preserving the natural systems on which all life depends. Guided by expertise in science, economics, law, and business partnerships, EDF seeks practical and lasting solutions to address environmental problems and protect human health, including in particular by addressing pollution from the power sector. On behalf of its members, EDF works with partners across the private and public sectors to engage in utility regulatory forums at the federal level and throughout the United States to advocate for policies that will create an affordable, reliable, and low pollution energy system. Recent 202(c) Orders issued by the DOE have harmed members of EDF by causing increases in pollution, which impact the health of people and nature, and in energy costs. EDF has submitted requests for rehearing regarding the DOE Orders related to the J.H. Campbell and Eddystone power plants and a Petition for Review regarding the DOE Order regarding the J.H. Campbell plant. Further 202(c) Orders issued as a result of the RAR, including extensions of the J.H. Campbell and Eddystone orders and orders directed at other generators, will result in further pollution and cost impacts that will harm EDF members.

D. Environmental Law and Policy Center

Environmental Law and Policy Center ("ELPC") is a not-for-profit environmental organization with members, contributors, and offices throughout the Midwest. Among other things, ELPC advocates before state public service commissions and the Federal Energy Regulatory Commission for clean, reliable energy generation in order to reduce ratepayer costs and improve environmental outcomes. ELPC members in the Midwest live, work, and recreate near power plants that burn coal or other fossil fuels and are directly impacted by their pollutants. In addition, ELPC members are ratepayers in regions who could be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. ELPC and its members could be subject to higher electric bills and impacted by additional pollution as a result of "reliability interventions" undertaken as a result of the RAR's "uniform methodology." ELPC has a longstanding organizational commitment to protect the interests of its members, to reduce pollution caused by fossil fuel-fired power plants, and to promote clean, reliable energy generation.

E. Public Citizen

Public Citizen, Inc. hereby intervenes in these proceedings. Public Citizen, Inc. is an active intervenor and participant before the Federal Energy Regulatory Commission in Federal Power Act proceedings, as well as before the U.S. Department of Energy in both electricity export and natural gas export dockets to ensure just and reasonable rates and that utilities' operations are consistent with the public interest. Established in 1971, Public Citizen, Inc. is a national, not-for-profit, non-partisan, research and advocacy organization representing the interests of American household consumers. Public Citizen has members in all 50 states and represents the interests of consumers, not represented by any other party in this proceeding. Financial details about our organization are on our website: www.citizen.org/about/annual-report/.

F. Sierra Club

Sierra Club is a national environmental non-profit whose purpose is to explore, enjoy, and protect the wild places of the earth; to practice and promote the responsible use of the earth's ecosystems and resources; to educate and enlist humanity to protect and restore the quality of the natural and human environment; and to use all lawful means to carry out these objectives. To those ends, the Sierra Club and its members have worked to limit pollution caused by fossil-fuel-fired power plants through public education and advocacy at the local, state, and federal level. Sierra Club represents over 640,000 members nationwide, many of whom reside and recreate in the regions in which the RAR purports to identify resource shortfalls requiring the continued operation of coal- and gas-fired generation. Sierra Club members in those areas would be harmed by the pollution and the increased utility rates caused by any such continued operation.

G. Vote Solar

Vote Solar is an independent 501(c)(3) non-profit working to re-power the U.S. with clean energy by making solar power more accessible and affordable through effective policy advocacy. In over half of the country, Vote Solar seeks to promote the development of solar at every scale, from distributed rooftop solar to large utility-scale plants. Vote Solar has over 90,000 members nationally. Vote Solar members are ratepayers in regions who could be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. Vote Solar is not a trade organization, nor does it have corporate members. Vote Solar is committed to promoting clean, renewable energy and transitioning away from coal generation.

IV. BACKGROUND

A. Executive Orders

The genesis of the RAR lies in the President's unsupported day one declaration of a national energy emergency: *Declaring a National Energy Emergency* ("Energy Emergency EO").[9] That declaration's lack of factual underpinning was highlighted in a recent report by DOE's independent statistics and analysis arm, the Energy Information Administration ("EIA"). The EIA report highlights how U.S. energy production and exports are currently at an all-time high.[10] Nonetheless, the Energy Emergency EO was cited as a basis for the

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[9] Exec. Order No. 14,156, 90 Fed. Reg. 8433 (January 20, 2025) (hereinafter "Energy Emergency EO") (attached as Ex. 4). *See* also RAR, Ex. 1 at vi (explaining that the Grid EO "builds on" the Energy Emergency EO).

[10] *See* U.S. EIA, *U.S. primary energy production, consumption, and exports increased in 2024* (June 20, 2025), https://www.eia.gov/todayinenergy/detail.php?id=65524.

President's follow-up grid-specific executive order, the Grid EO, that led to DOE's publication of the RAR.[11]

The Grid EO directed DOE to take three steps to address the President's assertion that there may be lack of grid reliability in the future, including: 1) to streamline the processes to issue orders pursuant to Federal Power Act Section 202(c);[12] 2) to develop a reserve margin assessment methodology and use it to identify at risk regions and critical energy resources within those regions and to publish that methodology within 90-days of the Grid EO;[13] and 3) to establish a protocol for identifying critical generating resources and taking action to prevent retirement or conversion of the fuel source of such resources.[14]

Notably, the Grid EO was issued in conjunction with a series of actions by President Trump and DOE designed explicitly to prop up the coal and gas industries, including: 1) Executive Order 14,261, *Reinvigorating America's Beautiful Clean Coal Industry,*[15] which seeks to restart coal leasing and expand coal mining on federal lands, in addition to making these processes easier by offering loans and streamlining permitting;[16] 2) a Presidential Proclamation entitled *Regulatory Relief for Certain Stationary Sources to Promote American Energy* that exempts coal plants from complying with the U.S. Environmental Protection Agency's updated Mercury and Air Toxics Standards;[17] and 3) Executive Order 14,260, *Protecting American Energy from State Overreach*,[18] which directs the U.S.

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[11] Nor does the Energy Emergency EO supply legal support for the Grid EO. Under the National Emergencies Act, 50 U.S.C. § 1631, a declaration of national emergency does not authorize the exercise of emergency powers "unless and until the President specifies the provisions of law under which he proposes that he, or other officers will act." But as Congress made clear, the statute "is not intended to enlarge or add to Executive power" such as authority under Section 202(c), only to "establish clear procedures and safeguards for the exercise by the President of emergency powers conferred on him by other statutes." S. Rep. No. 94-1168, 3 (1976).

[12] Grid EO Section 3(a).

[13] *Id.* Section 3(b).

[14] *Id.* Section 3(c).

[15] *See* Exec. Order No. 14,261, 90 Fed. Reg. 15,517 (Apr. 8, 2025).

[16] DOE simultaneously announced several initiatives to subsidize the coal industry, including loan guarantees for coal-fired power plant projects. Dep't of Energy, *Energy Department Acts to Unleash American Coal by Strengthening Coal Technology and Securing Critical Supply Chains* (Apr. 8, 2025), https://www.energy.gov/articles/energy-department-acts-unleash-american-coal-strengthening-coal-technology-and-securing.

[17] Proclamation No. 10914, 90 Fed. Reg. 16777 (Apr. 8, 2025).

[18] Exec. Order No. 14,260, 90 Fed. Reg. 15513 (Apr. 8, 2025).

Department of Justice to take action to block states' exercises of their police powers to protect their residents from pollution caused by coal and fossil-fuel sources.[19]

B. RAR

On July 7, 2025, DOE published the RAR on its website. The RAR includes a deterministic analysis of the resource adequacy of the current electric system and three 2030 cases: (1) the Plant Closure case includes 104 GW of coal and gas retirements plus 100% of NERC's Tier 1 additions; (2) the No Plant Closures case includes no retirements but 100% of NERC's Tier 1 additions; and (3) the Required Build case begins with the Plant Closures scenario and projects what additional added perfect capacity would be needed to meet the RAR's determined reliability standards.[20] Each of the three 2030 scenarios assume 50 GW of load growth from data centers and an additional 51 GW of load growth from other sources.[21] The Department finds in the RAR that, under the current system, only ERCOT fails to achieve DOE's selected resource adequacy targets,[22] but that, based on the methodology used to forecast the 2030 scenarios, there will be broader resource adequacy issues in 2030.[23] And, notwithstanding the RAR's upfront acknowledgement that the analysis used "could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level,"[24] the Department proceeds to make broad declarations of future need based on its findings in the RAR.[25]

DOE explained that the RAR was being issued pursuant to the Grid EO. The RAR incorporates a full copy of the Grid EO and explains that "[t]his report serves as DOE's response to [the Grid EO's] Section 3(b) … by delivering the required uniform methodology to identify at-risk region(s) and guide reliability

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[19] These actions mimic President Trump's failed efforts to prop up the coal industry during his first term, including DOE's proposed rule, soundly rejected by FERC, that would have provided assured cost recovery (including a return on equity) for coal and nuclear plants (*see* 162 FERC ¶ 61,012), and the President's unfulfilled directive that DOE use Section 202(c) and the Defense Production Act to block closure of uneconomic coal plants while requiring grid operators to bear the costs. *See* Draft Memorandum (May 29, 2018), https://embed.documentcloud.org/documents/4491203-Grid-Memo/.

[20] RAR, Ex. 1 at 4-5.

[21] *Id.* at 2-3, 15-17.

[22] *Id.* at 7.

[23] *Id.* at 6-9.

[24] *Id.* at i.

[25] *Id.* at 1-2. *See also*, DOE Fact Sheet, https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf; DOE Press Release, https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security.

interventions."[26] DOE's statement that it intends to use the methodology "to guide reliability interventions" and that DOE will continue to use the RAR "on a regular basis to ensure its usefulness for effective action among industry and government decision-makers across the United States" suggests that the RAR may be intended to also serve as the protocol called for by Section 3(c) of the Grid EO.[27] But the RAR fails to clarify this, or, if the RAR does not also serve as DOE's response to Section 3(c), whether a protocol has been or will be developed, or whether any protocol will be made public. The RAR does not include any discussion of Section 3(a) of the Grid EO. To the extent that the Department addressed that portion of the Grid EO's directions, it has not made any process changes public. On the contrary, the Department has made its processes under Section 202(c) even less transparent by removing the existing process guidance from the DOE website.[28]

Notwithstanding the statement in the RAR that DOE intends to use the "methodology to identify at-risk region(s) and guide reliability interventions," e.g., Section 202(c) Orders,[29] other portions of the RAR make clear that it can't and shouldn't be used as a basis for interventions, specifically not issuance of 202(c) Orders. First and foremost, the reliability projections in the RAR focus on conditions five years from now and concede that there are not current grid conditions that fit within Section 202(c)'s definition of an "emergency." Second, the Department candidly concedes the RAR's lack of robustness: "DOE acknowledges that the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level. The DOE study team built the methodology and analysis upon the best data that was available. However, entities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience."[30]

C. Section 202(c) Orders

Section 202(c) of the Federal Power Act allows the Secretary of Energy, in certain emergency situations, to require by order temporary connections of facilities, and generation, delivery, interchange, or transmission of electricity as the Secretary

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[26] RAR, Ex. 1 at vi.

[27] *Id.*

[28] *Compare* https://web.archive.org/web/20250604093213/https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures with the current website.

[29] *See* Dep't of Energy, *Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security* (July 7, 2025), https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security ("The methodology also informs the potential use of DOE's emergency authority under Section 202(c) of the Federal Power Act.").

[30] RAR, Ex. 1 at i.

determines will best meet the emergency and serve the public interest. Section 202(c) has an important purpose: to mitigate electricity shortages caused by war, drought, and other emergencies. In granting DOE the authority that Section 202(c) provides, Congress considered the severe societal consequences of blackouts and determined that avoiding those consequences justified allowing DOE to act without notice and to require operations that override environmental laws. But Congress was also very careful to narrowly limit DOE's use of that authority, as the title of the provision makes clear, to "temporary" "emergency" situations.[31] And while the statute doesn't define "emergency," DOE's regulations include a lengthy definition which reinforces the key element in the statute: 202(c) orders are for situations that are sudden and unexpected, not for longer term grid management.[32]

1. DOE's Past Use of 202(c) Orders

The Department's application of Section 202(c) consistently confirms the urgency of the conditions necessary to invoke the provision and underscores the lack of authority for the planned implementation scheme described in the Grid EO and RAR.[33] The Department's predominant practice has been to use Section 202(c) to address specific, imminent, and unexpected shortages—not to address longer-term reliability concerns or demand forecasts.[34]

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[31] *See, e.g., Richmond Power & Light,* 574 F.2d at 617 (Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply and not at those in which supply is adequate but a means of fueling its production is in disfavor.").

[32] 10 C.F.R. § 205.371: "'Emergency,' as used herein, is defined as an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected 'entity' to prevent. An emergency also can result from a sudden increase in customer demand, an inability to obtain adequate amounts of the necessary fuels to generate electricity, or a regulatory action which prohibits the use of certain electric power supply facilities. Actions under this authority are envisioned as meeting a specific inadequate power supply situation. Extended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated in these regulations. In such cases, the impacted 'entity' will be expected to make firm arrangements to resolve the problem until new facilities become available, so that a continuing emergency order is not needed. Situations where a shortage of electric energy is projected due solely to the failure of parties to agree to terms, conditions or other economic factors relating to service, generally will not be considered as emergencies unless the inability to supply electric service is imminent. Where an electricity outage or service inadequacy qualifies for a section202(c) order, contractual difficulties alone will not be sufficient to preclude the issuance of an emergency order."

[33] *See FTC v. Bunte Brothers, Inc.*, 312 U.S. 349, 352 (1941) ("[J]ust as established practice may shed light on the extent of power conveyed by general statutory language, so the want of assertion of power by those who presumably would be alert to exercise it, is equally significant in determining whether such power was actually conferred.").

[34] *See, e.g.,* Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) (responding to ongoing severe winter storm producing immediate and "unusually high peak load" between December 23 and

The law also requires the Department to narrowly tailor the remedies in Section 202(c) orders to ensure that the orders only address the stated emergency, limit the order to "only [the] hours necessary to meet the emergency," be "consistent with any applicable Federal, State, or local environmental law or regulation," and to "minimize[] any adverse environmental impacts.[35] Up until recently, the Department has routinely followed these provisions of the law.[36]

2. DOE's Recent Misuse of Section 202(c)

Prior to issuance of the RAR but consistent with the direction in the Grid EO, DOE issued two Section 202(c) orders blocking the planned closures of two fossil-fuel fired generation resources that were unreliable, uneconomic, and at the end of their useful lives: the J.H. Campbell coal-fired plant in West Olive Michigan,[37] and units 3 and 4 of the Eddystone oil and gas fired plant in Eddystone, Pennsylvania.[38] The Eddystone 202(c) Order stated that "DOE plans to use this methodology [i.e., the RAR] to further evaluate Eddystone Units 3 and 4," thus raising questions about DOE's intentions as to the legal status and efficacy of the RAR.

Public Interest Organizations filed requests for rehearing for both the J.H. Campbell and Eddystone 202(c) Orders.[39] In both cases DOE failed to identify conditions that would qualify as "emergencies" for the purpose of issuance of Section 202(c) Orders. And both Section 202(c) Orders impose significant costs on ratepayers,[40] while increasing emissions of air pollutants and providing no

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December 26) (attached as Ex.5); Department of Energy Order 202-20-2 (Sept. 6, 2020) at 10-2 (responding to shortages produced by ongoing extreme heat and wildfires) (attached as Ex.6); *see also* Benjamin Rolsma, *The New Reliability Override*, 57 CONN. L. REV. 789, 803-4 (describing "sparing[]" use of Section 202(c) outside of wartime shortages during the twentieth century) (attached as Ex. 7).

[35] 16 U.S.C.§ 824a(c)(2).

[36] *See, e.g.,* Ex.5, Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) at 4-7 (limiting order to the 3 days of peak load, directing PJM to exhaust all available resources beforehand, requiring detailed environmental reporting, notice to affected communities, and calculation of net revenue associated with actions violating environmental laws); Ex.6, Dep't of Energy Order 202-20-2 (Sept. 6, 2020) at 3-4 (limiting order to the 7 days of peak load, directing CAISO to exhaust all available resources beforehand, requiring detailed environmental reporting).

[37]Dep't of Energy Order No. 202-25-3 (May 23, 2025) (attached as Ex. 8).

[38]Dep't of Energy Order No. 202-25-4 (May 30, 2025) (hereinafter "Eddystone 202(c) Order") (attached as Ex. 9).

[39] Mot. to Intervene and Request for Rh'g and Stay of Pub. Int. Orgs., DOE Ord. No. 202-25-3 (June 18, 2025) (hereinafter "Campbell RFR") (attached as Ex.10);Mot. to Intervene and Request for Rh'g and Stay of Pub. Int. Orgs., DOE Ord. No. 202-25-4 (June 27, 2025) (hereinafter "Eddystone RFR") (attached as Ex.11).

meaningful corresponding reliability benefit.[41] The Department denied both of Public Interest Organization's requests for rehearing by operation of law.[42]

D. Existing Mechanisms Ensure Resource Adequacy

In the United States, how electricity is bought and sold varies by region. Electric utilities can be either traditionally regulated and operate as vertically integrated monopolies, or they can operate in deregulated, competitive markets where electric energy prices are set by the market. Both vertically integrated utilities and utilities in deregulated markets are subject to federal oversight, and in some of the deregulated states, the state nonetheless exercises oversight over the terms of retail supply offers, especially for retail customers. And all utilities are subject to reliability standards developed by the North American Electric Reliability Corporation ("NERC") and approved by FERC. In sum, FERC, Regional Transmission Organizations ("RTOs"), States, and NERC all play a hand in ensuring resource adequacy.

1. Vertically integrated utilities

Until the 1990s, utilities were generally vertically integrated such that generation, transmission, and distribution resources were all held by the same entity.[43] Vertically integrated utilities must seek state approval for power plant investments.[44] Many state regulators require utilities to demonstrate the necessity of proposed investments through an integrated resource planning process.[45] This process is used for long-term planning and requires the utility to justify its investments and demonstrate how it plans to meet customer electricity demand.[46] Even though vertically integrated utilities generate their own electricity, many

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[40] *See e.g.* U.S. Sec. and Exch. Comm'n, Form 10-Q, Consumers Energy Company Quarterly Report For the Quarterly Period Ended June 30, 2025, at 39, 62, 92 (2025) https://d18rn0p25nwr6d.cloudfront.net/CIK-0000201533/10a900b7-263b-4ccd-82a0-4162ba7ae5f2.pdf (describing costs of $29 million to operate Campbell through June 30, 2025); FERC Docket No. ER25-2653-000 (PJM proposed cost allocation to implement DOE Order 202-25-4).

[41] *See* Campbell RFR, Ex. 10 at 11-14; Eddystone RFR, Ex. 11 at 56-60. 87-88.

[42] Dep't of Energy, Notice of Denial of Reh'g by Operation of Law and Providing for Further Consideration of Ord. No. 202-25-3A (July 28, 2025) (attached as Ex. 12); Dep't of Energy, Notice of Denial of Reh'g by Operation of Law and Providing for Further Consideration of Ord. No. 202-25-4A (Aug. 1, 2025) (attached as Ex. 13).

[43] *See* Kathryne Cleary and Karen Palmer, *US Electricity Markets 101* (March 17, 2022), Resources for the Future, https://www.rff.org/publications/explainers/us-electricity-markets-101/.

[44] *Id.*

[45] *Id.*

[46] *Id.*

trade with other utilities during times of need. These wholesale market transactions are subject to regulation by FERC.[47]

2. Competitive markets

Advances in technology and statutory changes led to the development of energy markets and merchant generation that is not owned by incumbent utilities.[48] In the 1990s, FERC fostered competitive markets through rules that allowed the establishment of independently-operated voluntary RTOs that determine the prices for energy, capacity, and ancillary services based on procurement and dispatch of least-cost resources through Order Nos. 888, 890, and 2000.[49] As RTO markets expanded, many states deregulated their utility monopolies and required them to join RTOs. Deregulated states use markets to determine which power plants are necessary for electricity generation.[50] Even in deregulated states, the state sites new generation. Market price signals encourage new investment when supply is tight and encourage the retirement of facilities that are no longer competitive when capacity is plentiful. RTOs now account for approximately 2/3 of all electricity sales in the U.S. and have saved consumers billions of dollars, increased reliability, and reduced environmental harm.[51]

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[47] *See* FERC, *Electric Power Markets* (last updated March 27, 2025), https://www.ferc.gov/electric-power-markets.

[48] *See, e.g.,* Order Terminating Rulemaking Proceeding, Initiating New Proceeding, And Establishing Additional Procedures, 162 FERC ¶ 61,012, PP 7-11 (2018); Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,639-31,645 (1996), order on reh'g, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. *New York v. FERC*, 535 U.S. 1 (2002).

[49] Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 638-41 (1996), Order No. 890, FERC Stats. & Regs. ¶ 31,241, at 124-352 (1997), Order No. 2000, FERC Stats. & Regs. ¶ 31,089, at 99-130 (1999).

[50] State regulators in competitive markets still practice oversight over utilities. For example, some states, such as Michigan, use both the market and integrated resource planning. *See* Michigan Public Service Commission, *Phase III – Integrated Resource Plan* (last visited Aug. 4, 2025), https://www.michigan.gov/mpsc/commission/workgroups/mi-power-grid/phase-iii-integrated-resource-plan-mirpp-filing-requirements-demand-response-study-energy-waste-red. Other state legislatures or commissions have enacted subsidies to keep nuclear plants alive, such as in New York, Illinois, Ohio, and New Jersey. *See* U.S. EIA, Five states have implemented programs to assist nuclear power plants (Oct. 7, 2019), https://www.eia.gov/todayinenergy/detail.php?id=41534.

[51] *See, e.g.*, Judy Chang et al., The Brattle Group, Potential Benefits of a Regional Wholesale Power Market to North Carolina's Electricity Customers, 1, 3-7 (April 2019) https://www.brattle.com/wp-content/uploads/2021/05/16092_nc_wholesale_power_market_whitepaper_april_2019_final.pdf (discussing billions of dollars in estimated cost saving); Jennifer Chen & Devin Hartman, *Why wholesale market benefits are not always apparent in customer bills*, R Street (Nov. 10, 2021), https://www.rstreet.org/commentary/why-wholesale-market-benefits-are-not-always-apparent-in-

As explained by FERC, its "support of competitive wholesale electricity markets has been grounded in the substantial and well-documented economic benefits that these markets provide to consumers."[52] In addition to billions of dollars of consumer savings, FERC found that competitive markets protect consumers by "providing more supply options, encouraging new entry and innovation, spurring deployment of new technologies, promoting demand response and energy efficiency, improving operating performance, exerting downward pressure on costs, and shifting risk away from consumers."[53]

3. FERC and NERC Reliability Regulation

As part of its role in regulating the wholesale electric industry, FERC has implemented Congressional mandates to ensure system reliability, including establishing NERC as the Electric Reliability Organization, which sets industry standards for grid reliability that are approved by FERC;[54] coordination requirements for the natural gas and electricity market scheduling;[55] investigation and improvements required in light of the grid's response to extreme weather events;[56] and reviewing capacity accreditation processes to ensure that capacity markets generate reliable results.[57]

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customer-bills/ (same); Jeff St. John, *A Western US energy market would boost clean energy. Will it happen?*, Canary Media (Jun. 10, 2024), https://www.canarymedia.com/articles/utilities/a-western-us-energy-market-would-boost-clean-energy.-will-it-happen; John Tsoukalis et al., Assessment of Potential Market Reforms for South Carolina's Electricity Sector, at 6, 46, 77-78 (Apr. 27, 2019), https://www.scstatehouse.gov/CommitteeInfo/ElectricityMarketReformMeasuresStudyCommittee/2022-04-27%20-%20SC%20Electricity%20Market%20Reform_Brattle%20Report.pdf (discussing cost savings across regional wholesale markets).

[52] Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures, 162 FERC ¶ 61,012, P 11 (2018).

[53] *Id.* (citation omitted).

[54] PJM, NERC and Reliability Fact Sheet (Jan. 5, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/nerc-and-reliability-fact-sheet.pdf. *See also* PJM, PJM Ensures a Reliable Grid (Jan. 29, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/reliability-fact-sheet.pdf.

[55] PJM, PJM Promotes Gas/Electricity Industry Coordination (Jan. 29, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/gas-electric-coordination-fact-sheet.pdf. *See also* Order 787, 145 FERC ¶ 61,134 (2013); Order 809, 151 FERC ¶ 61,049 (2015).

[56] *See e.g.,* Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, 149 FERC ¶ 61,145 (2014) (order addressing technical conferences on, among other things, the 2014 Polar Vortex); Order Approving Extreme Cold Weather Reliability Standards EOP-011-3 and EOP-012-1 and Directing Modification of Reliability Standard EOP-012-1, 182 FERC ¶ 61094 (2023); Order Approving Extreme Cold Weather Reliability Standard EOP-012-2 and Directing Modification, 187 FERC ¶ 61,204 (2024). *See also* FERC, NERC and Regional Staff, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott (Oct. 2023), https://www.ferc.gov/sites/default/files/2023-11/24_Winter-Storm_Elliot_1107_1300.pdf; FERC, NERC and Regional Entity Joint Staff, The February 2021 Cold Weather Outages in Texas and the

V. ARGUMENT

A. The Department Is Intruding on FERC and State Authority.

The Department's authority over reliability is strictly circumscribed to respond to imminent emergencies;[58] this authority does not extend to regulating long-term or overarching aspects of the electricity sector. Rather, Congress reserved to the states and FERC the authority to regulate the electric sector generally and to regulate resource adequacy and reliability specifically. Recent actions—starting with the Energy Emergency EO and culminating in the RAR—indicate, however, that DOE is not remaining in its designated lane.[59] The RAR lays bare the Department's agenda to prop up fossil fuel businesses by utilizing emergency authority in a systematic fashion that goes well beyond the scope of DOE's authority under the Federal Power Act and illegally intrudes upon authorities that Congress has explicitly reserved to the states or given to FERC.

The authority to maintain a reliable electric system in the United States has evolved over the years to include parties at the federal, regional, state, and local levels.[60] But the Department of Energy has never been granted primary regulatory authority over either reliability or resource adequacy of the grid. Rather, the Department of Energy Organization Act of 1977 ("Organization Act")[61] and the

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South Central United States (Nov. 2021), https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/FERC%20Presentation-Phase%202.pdf; PJM, Winter Storm Elliott Event Analysis and Recommendation Report (2023), https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.pdf.

[57] *Id.*; *see also* Order Accepting Tariff Revisions Subject to Condition, 186 FERC ¶ 61,080 (2024).

[58] *See* 16 U.S.C. §§ 824a(c),824o-1.

[59] *See* Energy Emergency EO, Ex. 4; Grid EO Sec. 3 (RAR, Ex. 1 at C); RAR Ex. 1; DOE, DOE Fact Sheet, https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf; DOE Press Release, https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security; Eddystone 202(c) Order, Ex. 9; Dep't of Energy Order No. 202-25-3 (May 23, 2025), Ex. 8.

[60] *New York v. FERC*, 535 U.S. 1, 5-8 (2002) ("Prior to 1935, the States possessed broad authority to regulate public utilities"). *See generally* Nat'l Ass'n of Reg. Util. Comm'rs ("NARUC"), *Resource Adequacy for State Utility Regulators: Current Practices and Emerging Reforms* (Nov. 2023) https://pubs.naruc.org/pub/0CC6285D-A813-1819-5337-BC750CD704E3?_gl=1*oyp366*_ga*MTc1NzM0NTE0LjE3NTM5ODk1NDA.*_ga_QLH1N3Q1NF*czE3NTM5ODk1NDAkbzEkZzEkdDE3NTM5ODk1NzUkajI1JGwwJGgw; NARUC, *Resource Adequacy Primer for State Regulators* (July 2021), https://pubs.naruc.org/pub/752088A2-1866-DAAC-99FB-6EB5FEA73042?_gl=1*1mituzu*_ga*MTc1NzM0NTE0LjE3NTM5ODk1NDA.*_ga_QLH1N3Q1NF*czE3NTM5ODk1NDAkbzEkZzAkdDE3NTM5ODk1NDAkajYwJGwwJGgw.

[61] 42 U.S.C. § 7111 *et seq.*

Federal Power Act[62] give to the Department only narrow, emergency authority over the electric system—for example through Federal Power Act Sections 202(c) and 215A.[63] The President's declaration of an energy emergency (even if it were legitimate) and other executive orders cannot expand these statutorily defined authorities.[64] And while the Department may of course analyze policy implications and issue reports on various topics—as it has done since its founding—DOE's statements indicate that the RAR is not simply a policy analysis. The Department states—without limitation—that it will use the RAR "to identify at-risk region(s) and guide reliability interventions."[65] Thus, taking DOE at its word, the RAR is beyond the Department's authority.

Further, to the extent that it is an indication of the Department's broader scheme, in the RAR, the Department ignores the limitations on its authority and the comparative breadth of authority explicitly reserved to the states and FERC over the Department. "States are responsible for resource adequacy in siting of electric facilities, establishing retail electric rates, and overseeing the reliability of the distribution system."[66] State public utility commissions review utility proposals for long-term impacts to the system's reliability. "Most states address resource adequacy by requiring large investor-owned utilities to file long-term planning documents like integrated resource plans that include strategies for reliably meeting future demand."[67]

The structure and language of the Organization Act and Federal Power Act reflect Congress's deliberate choices to preserve this traditional state authority over generating facilities and to circumscribe the Department's emergency authority in light of the states' role. Congress noted in the Organization Act that "[n]othing in this chapter shall affect the authority of any State over matters exclusively within its jurisdiction."[68] And the first sentence of the Federal Power Act declares that

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[62] Subsequent legislation has also amended and updated these authorities. *See e.g.* Fixing America's Surface Transportation Act (FAST Act), Pub. L. No. 114–94, 129 Stat. 1312 (2015); Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005).

[63] 16 U.S.C. §§ 824a(c), 824o-1.

[64] *See Biden v. Nebraska*, 600 U.S. 477, 500-01 (2023); *see also* S. Rep. No. 94-1168, 3 (1976), (the National Emergencies Act "is not intended to enlarge or add to Executive power. Rather, the statute is an effort by Congress to establish clear procedures and safeguards for the exercise by the President of emergency powers *conferred on him by other statutes*.") (emphasis added).

[65] RAR, Ex. 1 at vi.

[66] NARUC, *Resource Adequacy Primer for State Regulators*, at 9 (July 2021) https://pubs.naruc.org/pub/752088A2-1866-DAAC-99FB-6EB5FEA73042?_gl=1*1mituzu*_ga*MTc1NzM0NTE0LjE3NTM5ODk1NDA.*_ga_QLH1N3Q1NF*czE3NTM5ODk1NDAkbzEkZzAkdDE3NTM5ODk1NDAkajYwJGwwJGgw.

[67] Nat'l Renewable Energy Lab'y, *Explained: Fundamentals of Power Grid Reliability and Clean Electricity*, at 4 (Jan. 2024) https://docs.nrel.gov/docs/fy24osti/85880.pdf.

[68] 42 U.S.C. § 7113.

federal regulation extends "only to those matters which are not subject to regulation by the States."[69] Section 201(b)(1) further states that, except as otherwise "specifically" provided, federal jurisdiction does not attach to "facilities used for the generation of electric energy."[70] The courts have held that Section 201(b)(1) reserves to the states authority over electric generating facilities,[71] including the authority to order their closure.[72] Congress also recognized the states' exclusive authority over generating facilities in Section 202(b), which provides that FERC's interconnection authority does not include the power to "compel the enlargement of generating facilities for such purposes."[73] And when Congress added new authority regarding reliability to the Federal Power Act in 2005, it also still explicitly clarified that "[n]othing in this section shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any reliability standard…."[74]

The RAR also intrudes upon authority that Congress explicitly and repeatedly gave exclusively to FERC, not the Department. In 1935, Congress passed the Federal Power Act, creating the Federal Power Commission to engage in "federal regulation of electricity in areas beyond the reach of state power."[75] However, until the 1970s, the federal government played a very limited role in energy policy and generally left to private industry and state and local governments the task of establishing energy policies and planning.[76] In 1977, Congress passed the Organization Act,[77] creating both the Department and FERC. The Organization Act transferred most of the authority for overseeing the electric system in the

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[69] 16 U.S.C. § 824(a).

[70] *Id.* § 824(b)(1).

[71] *See, e.g., Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 154 (2016).

[72] *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (2009) (under Section 201(b), states retain the right "to require retirement of existing generators" or to "take any other action in their role as regulators of generation facilities."). *See also Devon Power LLC et al.*, 109 FERC ¶ 61,154, P 47 (2004) ("Resource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there. States have traditionally designated the entities that are responsible for procuring adequate capacity to serve loads within their respective jurisdictions.").

[73] 16 U.S.C. § 824a(b).

[74] 16 U.S.C. § 824o.

[75] *New York v. FERC*, 535 U.S. 1, 6 (2002).

[76] DOE, *A Brief History of the Department of Energy,* https://www.energy.gov/lm/brief-history-department-energy. *See also* DOE, *Department of Energy 1977-1994, A Summary History* (Nov. 1994), https://www.energy.gov/sites/prod/files/2017/09/f36/DOE%201977-1994%20A%20Summary%20History_0.pdf.

[77] Public Law 95–91 (1977), 42 U.S.C. § 7101 *et seq.*

Federal Power Act to FERC, not the Department;[78] the Department retained primary authority only over "emergency interconnection."[79]

While FERC is housed within the Department, FERC is an independent agency with distinct authority from the Department that the Department may not modify or supersede.[80] Generally the Department "is authorized to establish, alter, consolidate or discontinue such organizational units or components within the Department as [the Secretary] may deem to be necessary or appropriate."[81] But this authority explicitly does not extend to FERC. The Organization Act explains that the Department may not abolish "organizational units or components established by" the Organization Act, nor may it "transfer [] functions vested by this chapter in any organizational unit or component."[82] Because the Organization Act created[83] and transferred specific authority to FERC,[84] the Department has no authority to alter FERC itself nor to seize FERC's statutorily prescribed authority.

Further, "the decision of the Commission involving any function within its jurisdiction . . . shall be final agency action . . . and *shall not be subject to further review by the Secretary* or any officer or employee of the Department."[85] While the Department can propose rules under FERC's jurisdiction, FERC maintains "exclusive jurisdiction . . . to take final action on any proposal made by the Secretary."[86] And when the Department proposes a rule in the exercise of its own functions that FERC determines significantly affects any function within FERC's jurisdiction, FERC can insist on changes that DOE must adopt if DOE wants to issue the rule.[87]

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[78] 42 U.S.C. § 7172 (transferring functions from Federal Power Commission to FERC); 42 U.S.C. § 7151 (the function of the Federal Power Commission is transferred to the Secretary except as provided to FERC). The Department and FERC share authority over certain parts of the Federal Power Act that primarily address recordkeeping and administration. 42 U.S.C. § 7172(a)(2) ("The Commission may exercise any power under the following sections to the extent the Commission determines such power to be necessary to the exercise of any function within the jurisdiction of the Commission: (A) sections 4, 301, 302, 306 through 309, and 312 through 316 of the Federal Power Act.").

[79] *See* 42 U.S.C. § 7172(a)(1)(B).

[80] *See* 42 U.S.C.A. § 7112 (Congressional declaration of purpose in establishing Department); 42 U.S.C. § 7171 (establishment of FERC).

[81] 42 U.S.C. § 7253.

[82] 42 U.S.C. § 7253.

[83] 42 U.S.C. § 7171 (establishment of FERC).

[84] 42 U.S.C. § 7172(a) (transferring functions from Federal Power Commission to FERC).

[85] 42 U.S.C. § 7172(g) (emphasis added).

[86] 42 U.S.C. § 7173. *See* 162 FERC ¶ 61,012.

[87] 42 U.S.C. § 7174.

In 2005, Congress expanded FERC's authority to specifically encompass reliability by updating the Federal Power Act in the 2005 Energy Policy Act.[88] While "FERC had previously addressed electric grid reliability in an indirect manner, such as allowing the cost recovery of public utility expenditures that address discrete reliability matters,"[89] there had been no mandatory reliability standards adopted by any federal regulator. When providing recommendations on reliability in 1998, the Department had concluded "that the U.S. Congress should explicitly assign oversight of bulk-power reliability to the FERC."[90] The new Section 215 followed the Department's suggestion and "tasked FERC [—not the Department—] with a direct role over an entire new field of activity."[91] Section 215 authorizes FERC to certify an electric reliability organization; FERC designated NERC. It is therefore NERC that develops reliability standards that FERC reviews to ensure consistency with federal law.[92] The broad reliability authority Congress granted to FERC contrasts with the very narrow, emergency authority in Section 215A that Congress granted to the Department.[93] The RAR appears to duplicate FERC and NERC's reliability efforts, impermissibly intruding upon authority Congress chose to give FERC —subject to elaborate procedural and substantive limitations—not the Department.

[88] Pub. L. No. 109-58, 119 Stat. 594 (2005).

[89] FERC, *Reliability Primer*, at 5 (2020) https://www.ferc.gov/sites/default/files/2020-04/reliability-primer_1.pdf.

[90] DOE, *Maintaining Reliability in a Competitive U.S. Electricity Industry* at vii-viii, xiv (Sept. 29, 1998), https://certs.lbl.gov/sites/all/files/basic-page/maintainting-reliability-in-competitive-electricity-industry-1998_0.pdf ("The Administration has proposed legislation that would provide the federal oversight necessary to make reliability standards mandatory. The NERC has begun to reinvent itself to respond to the changing needs of the industry. In addition, the FERC has undertaken several reliability initiatives. However, much more is needed. The Congress, for example, urgently needs to clarify the FERC's authority over an electric industry self-regulating reliability organization and expand the FERC's jurisdiction for reliability over the bulk-power system.") ("The Task Force is confident that the electricity industry, overseen by the Federal Energy Regulatory Commission (FERC) and a restructured self-regulating reliability organization (such as the planned North American Electric Reliability Organization [NAERO]), can and will maintain today's high levels of reliability."). *See also* S. Rep. No. 106-324, Electric Reliability 2000 Act (proposals from Congress such as this one gave FERC the authority over reliability).

[91] FERC, *Reliability Primer*, at 5 (2020) https://www.ferc.gov/sites/default/files/2020-04/reliability-primer_1.pdf.

[92] FERC, Reliability Explainer (Aug. 16, 2023) https://www.ferc.gov/reliability-explainer#:~:text=Both%20NERC%20and%20FERC%20have,blackouts%20or%20systematic%20compliance%20failures.

[93] The 2015 amendment to Federal Power Act creating Section 215A (16 U.S.C. 824o-1(d)) gives DOE the authority to issue orders to address emergencies related to malicious acts resulting from physical attacks to the grid at limited 15-day increments.

Finally, the Department arbitrarily and capriciously assumes that the existing systems are not working. The states and FERC have—pursuant to their authority—established systems to maintain resource adequacy and reliability including integrated resource planning processes and capacity markets. These existing systems are designed to signal to build more energy generation when energy demand rises.[94] Recently, as the Department notes in the RAR, energy demand has been rising; but the Department fails to acknowledge that the state and FERC systems already are appropriately responding, negating claims of an emergency or the need for the Department to interfere, as discussed *infra* in Section C.[95] For example, PJM's, SPP's, and MISO's new "fast track" processes—adopted to address concerns of resource adequacy—"alone would add roughly twice what the DOE assumed for the entire nation."[96] The RAR is written arbitrarily and capriciously incorporating the implicit assumption that capacity market results are not reliable, and that market-driven generator retirement is cause for alarm.

In sum, Congress has explicitly reserved to the states and FERC primary regulatory authority over resource adequacy and reliability. The Department's only authority to directly regulate reliability of the electric grid is narrow emergency authority such as Federal Power Act Sections 202(c) and 215A. The Department does not have broader authority to interfere with resource adequacy or reliability regulations. To the extent that the RAR is the confirmation of the attempt to usurp that authority from the states and FERC, via a "uniform methodology" in the RAR, it is outside of DOE's statutory authority and contrary to law.

B. The Department's Findings in the RAR, Even if Accurate, Do Not Demonstrate Any Emergency Allowing the Department to Compel Generation Under the Federal Power Act.

Even if the findings in the RAR were accurate (which they are not, as explained in Section C below), they would not empower the Department to exercise any statutory authority, under "section 202 of the Federal Power Act" or otherwise, to override state- or market-driven changes to the electricity generating facilities supplying the grid.[97] As discussed in Section A above, the Federal Power Act gives the Department tightly circumscribed authority over resource adequacy planning, to address "emergency" conditions through "such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy" as

[94] *See e.g.* DOE, A Primer on Electric Utilities, Deregulation, and Restructuring of U.S. Energy Markets, at 3.8 (May 2002); GridLab, GridLab Analysis: Department of Energy Resource Adequacy Report, at 4 (July 11, 2025) (hereinafter "GridLab Analysis") (attached as Ex. 14).

[95] GridLab Analysis, Ex. 14 at 2-3.

[96] GridLab Analysis, Ex. 14 at 3.

[97] Grid EO at Sec. 3 (RAR, Ex. 1 at C-3).

"will best meet the emergency and serve the public interest."[98] The statutory text, structure, and history, as well as case law interpreting Section 202(c), the Department's regulations, and its historic use of Section 202(c), all establish that its "emergency" authority is confined to sudden, unexpected, imminent, and specific electricity shortfalls. The information in the RAR, at most, expresses the Department's view that bulk-power system reliability will be insufficient in 2030. The Department's conclusions in the RAR—even if assumed to be accurate for the sake of argument—consequently provide no basis for the Department to manipulate the electricity market.

1. The Federal Power Act only permits the Department to intervene when necessary to address an imminent, unexpected, and specific electricity shortfall.

The Federal Power Act's text, context, and structure, as well as caselaw and the Department's longstanding regulations, all establish that it does not permit the Department to "prevent" generating facilities "from leaving the bulk-power system" or "converting" from one fuel-source to another based on the Department's view of long-term reliability needs.[99] The Act provides the Department only authority to intervene in electricity markets when necessary to address imminent, near-term, and exigent electricity supply shortfalls requiring immediate response, through the cabined authority provided by Section 202(c) of the Act.

a. The Text of Section 202(c) Narrowly Limits the Department's Authority to Emergencies: Imminent, Unexpected, and Certain Shortfalls in Electricity Supply.

The Act's text empowers the Department to require generation only in an "emergency;"[100] the Act primarily reserves authority over generation to the states, allocating more limited federal regulatory power to different agencies, *see section* A above. The statute itself does not define "emergency." At the time Congress enacted Section 202(c), Webster's New International Dictionary of the English Language (1930) defined "emergency" as a "*sudden* or *unexpected* appearance or occurrence . . . An *unforeseen* occurrence or combination of circumstances which calls for *immediate* action or remedy; *pressing* necessity; exigency."[101] Contemporary dictionaries similarly define "emergency" as demanding imminence: an emergency

[98] 16 U.S.C. 824a(c).

[99] Grid EO at Sec. 3(c)(ii) (RAR, Ex. 1 at C-4).

[100] 16 U.S.C. § 824a(c).

[101] Emphasis added.

is "an *unforeseen* combination of circumstances or the resulting state that calls for *immediate* action."[102]

The remainder of Section 202(c) underscores the exigency inherent in the governing term "emergency." The authority granted by Section 202(c) is, in the first instance, a war-time power.[103] An "emergency" under the statute is limited to circumstances of similar urgency: "a *sudden* increase in the demand for electric energy," for example.[104]

The text's use of the present tense also underscores that focus on imminent and certain shortfalls: it empowers the Department to act only where "an emergency *exists*."[105] That near-term focus along with the statute's strictly "temporary" authority[106] precludes use of Section 202(c) to pursue long-term policy goals, such as "fear of overdependence" on foreign oil supplies,[107] or "energy independence."[108]

Section 202's overall structure further highlights Section 202(c)'s emphasis on imminent, near-term concerns. The preceding subsections 202(a) and (b) together define and limit the tools by which the federal government may pursue "abundant" energy supplies in the normal course.[109] The resulting statutory "machinery for the

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[102] Merriam Webster's Dictionary 407 (11th ed. 2009) (emphasis added); *see* 3 Oxford English Dictionary 119 (1st ed. 1913) (defining emergency similarly as "a state of things *unexpectedly* arising, and urgently demanding *immediate* action" (emphasis added)); *see also* Rolsma, Ex. 7 at 812 n.147 (noting that dictionaries have given the term "emergency" the "same meaning for many years").

[103] 16 U.S.C. § 824a(c) (beginning with "[d]uring the continuance of any war in which the United States is engaged"); *see Jarecki v. G.D. Searle & Co.*, 367 U.S. 303, 307 (1961) (noting that statutory terms should be interpreted in the context of nearby parallel terms "in order to avoid the giving of unintended breadth to the Acts of Congress").

[104] 16 U.S.C. § 824a(c) (emphasis added); *see Richmond Power & Light,* 574 F.2d at 615 (holding that Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances"); S. Rep. No. 74-621, at 49 (1935) (explaining that Section 202(c) provides "temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose").

[105] 16 U.S.C. § 824a(c) (emphasis added).

[106] 16 U.S.C. § 824a(c).

[107] *Richmond Power & Light*, 574 F.2d at 617.

[108] RAR, Ex. 1 at 1. *See Richmond Power & Light*, 574 F.2d at 614 (Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply and not those in which supply is adequate but a means of fueling its production is in disfavor.").

[109] 16 U.S.C. § 824a(a) (seeking "abundant supply of electric energy" by directing the federal government to "divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy") & 824a(b)

promotion of the coordination of electric facilities" comprises the following: in subsection (a), an instruction to establish a general framework meant to facilitate "coordination by voluntary action;" in subsection (b), "limited authority to compel interstate utilities to connect their lines and sell or exchange energy," subject to defined procedural and substantive requirements, when "interconnection cannot be secured by voluntary action;" and in subsection (c), "much broader" but "temporary" authority "to compel the connection of facilities and the generation, delivery, or interchange of energy during times of war or other emergency."[110]

That tiered structure—relying on voluntary action for quotidian energy planning, specifying limited authority where that voluntary system fails, and allowing for "temporary" central command-and-control only in case of "emergency"—requires that Section 202(c) remain narrowly bounded to instances of an immediate and unavoidable "break-down in electric supply,"[111] rather than mere want of more abundant supply in the future.[112] Interpreting Section 202(c)'s "emergency" powers to encompass longer-term concerns—e.g., potential shortfalls years into the future, or an expected "expansion of artificial intelligence data centers and an increase in domestic manufacturing,"[113]—would unwind the careful balance of voluntary, market-driven action and federal power set out in subsections 202(a) and 202(b). Such an interpretation cannot be squared with the statutory text and structure.[114]

b. *Congress' Enactment of a Specific, Cabined Scheme to Address Reliability Concerns Confirms that Section 202(c) Cannot be Expanded to Impose Requirements Related to Long-Term Reliability.*

That the Department's Section 202 powers may not be used to enforce the Department's view of long-term reliability needs is confirmed by Section 215 of the Federal Power Act—which specifically and directly delineates the scope of federal power to enforce mandatory long-term reliability requirements for the bulk-power system.[115] Congress added Section 215 to the Federal Power Act in 2005 precisely because the Act as it then existed—including Section 202—did not provide the

(allowing federal government to order "physical connection … to sell energy or to exchange energy" upon application, and after an opportunity for hearing).

[110] S. Rep. No. 74-621 at 49 (1935).

[111] *Id.*

[112] *cf.* Eddystone 202(c) Order, Ex. 9 at 2 (imposing responsibility on PJM "to ensure maximum reliability on its system").

[113] Grid EO at Sec. 1 (RAR, Ex. 1 at C-4).

[114] *See Otter Tail Power Co. v. Fed. Power Comm.*, 429 F.2d 232, 233-34 (1970) (holding that Section 202(c) "enables the Commission to react to a war or national disaster," while Section 202(b) "applies to a crisis which is likely to develop in the foreseeable future").

[115] 16 U.S.C. § 824o.

federal government with the power to enforce measures designed to ensure broad, long-term reliability.[116]

By enacting Section 215, Congress provided a comprehensive and carefully circumscribed scheme to empower the federal government to enforce long-term reliability requirements. That statutory scheme strikes a careful balance between state and federal authority, and between private, market-driven decisions and top-down control. Reliability standards are devised by NERC independent "of the users and operators of the bulk-power system" but with "fair stakeholder representation."[117] FERC may approve or remand those standards (but not replace them with its own) and is required to "give due weight" to NERC's "technical expertise" while independently assessing effects on "competition."[118] Section 215 provides specified enforcement mechanisms and procedures for reliability standards—which mechanisms conspicuously exclude the power to command specific generation resources to remain operational.[119] And Section 215 carefully preserves state authority over "the construction of additional generation" and in-state resource adequacy, establishing regional advisory boards to ensure appropriate state input on the administration of reliability standards.[120]

Interpreting Section 202(c) to permit the Department to mandate generation based on its own unfettered assessment of long-term bulk-system reliability would effectively allow the Department to bypass Section 215's procedural safeguards, constraints on federal authority, and protection of state power. Such a bypass would impermissibly "contradict Congress' clear intent as expressed in its more recent," reliability-specific "legislation," enacted "with the clear understanding" that the Department had "no authority" to address long-term reliability through Section

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[116] *See* 70 Fed. Reg. 53,118 ("In 2001, President Bush proposed making electric Reliability Standards mandatory and enforceable," leading to enactment of Section 215 in 2005); RAR of the National Energy Policy Development Group (May 2001) at p. 7-6, https://www.nrc.gov/docs/ml0428/ml042800056.pdf (noting that "[r]egional shortages of generating capacity and transmission constraints combine to reduce the overall reliability of electric supply in the country" and that "one factor limiting reliability is the lack of enforceable reliability standards" because "the reliability of the U.S. transmission grid has depended entirely on *voluntary* compliance," and then recommending "legislation providing for enforcement" of reliability standards (emphasis added)); S. Rep. No. 109-78 at 48 (2005) (Section 215 "changes our current voluntary rules system" for long-term reliability "to a mandatory rules system."). *See Alcoa, Inc. v. FERC*, 564 F.3d 1342, 1344 (D.C. Cir. 2009) (noting that prior to the Energy Policy Act of 2005, "the reliability of the nation's bulk-power system depended on participants' voluntary compliance with industry standards").

[117] 16 U.S.C. § 824o(c)-(d). *See also id.* 824o(a)(3) (defining reliability standards as "a requirement … to provide for reliable operation of the bulk-power system").

[118] *Id.* § 824o(d)(2)-(4).

[119] *Id.* § 824o(e).

[120] *Id.* § 824o(i)-(j).

202(c).[121] Congress has, in Section 215, directly established the mechanisms (and limitations) by which the federal government may compel action to ensure long-term electric-system reliability. In so doing, it has confirmed that the Department may not, through Section 202(c) "emergency" orders, use long-term reliability concerns to mandate the generation it views as required to address long-term reliability needs.

c. DOE's Regulations Similarly Establish that Section 202(c) Emergency Authority Can Only Be Invoked to Address Imminent, Certain Supply Shortfalls Requiring Immediate Response.

The Department's regulations demonstrate its own long-standing understanding that Section 202(c)'s authority is confined to imminent and unavoidable resource shortages, rather than a mechanism to address long-term concerns as to the reliability of the bulk-power system. The regulations define an emergency as "an *unexpected* inadequate supply of electric energy which may result from the *unexpected* outage or breakdown" of generating or transmission facilities—not a means of planning against distant expectations or risks.[122] Emergencies "may result" from a number of events.[123] The use of the verb "result," defined as "arise as a consequence, effect, or conclusion," suggests that the event triggering the emergency has already happened rather than that there is a speculation that it could occur.[124]

Moreover, the events are characterized by those produced by "weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected 'entity' to prevent."[125] Where the culprit is increased demand, it must be "a *sudden* increase in customer demand" producing a "*specific* inadequate power supply situation,"[126] rather than long-term demand projections producing general reliability concerns. The need for both specificity and certainty is repeated in the Department's regulations defining an inadequate energy supply: "A system may be considered to have" inadequate supply when "the projected energy deficiency . . . *will* cause the applicant [for a 202(c) Order] to be unable to meet its

[121] *See FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 142 & 149 (2000); s*ee also Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 401–02 (D.C. Cir. 2004) ("Congress's specific and limited enumeration of [agency] power" over a particular matter in one section of the Federal Power Act "is strong evidence that [a separate section] confers no such authority on [agency].").

[122] 10 C.F.R. § 205.371 (emphasis added).

[123] *Id.* ("may result from the unexpected outage," "may be the result of weather conditions," "can result from a sudden increase in customer demand").

[124] Merriam-Webster's Collegiate Dictionary (11th ed. 2003) 1063.

[125] 10 C.F.R. § 205.371

[126] *Id.* (emphasis added).

normal peak load requirements based upon use of all of its otherwise available resources so that it *is* unable to supply adequate electric service to its customers."[127]

And while the regulations suggest that "inadequate planning or the failure to construct necessary facilities *can result* in an emergency," they recognize that the Department may not utilize a "continuing emergency order" to mandate long-term system planning.[128] An emergency may exist where past planning failures produce an immediate, present-tense shortfall (that is where, a shortfall *results* from insufficient planning); the Department has no authority to commandeer bulk-system reliability planning merely because it deems current plans inadequate to meet far-distant needs.[129] As the Department stated when it promulgated those regulations, the statute allows the Department to provide "assistance [to a utility] during a period of unexpected inadequate supply of electricity," but does not empower it to "solve long-term problems."[130]

d. Courts Have Uniformly Held that Section 202(c) Can Be Invoked Only in Immediate Crises.

Two courts have addressed the scope of authority under Section 202(c), and both determined that this Section applies only when there is a sudden, unexpected, imminent, and specific emergency.

Richmond Power and Light of City of Richmond, Indiana v. FERC, 574 F.2d 610 (D.C. Cir. 1978), arose out of the 1973 oil embargo. The Federal Power Commission needed to decide how to respond to oil shortages, and decided to call for the voluntary transfer for electricity from non-oil power plants to areas of the country that relied heavily on oil, such as New England.[131] The New England Power Pool was not convinced that the voluntary program would work and petitioned the Commission for a 202(c) order.[132] The Commission instead facilitated an agreement between state commissions and supplying utilities, which satisfied the New England Power Pool and it withdrew its petition.[133] A dissatisfied utility

[127] 10 C.F.R. § 205.375 (emphasis added).

[128] 10 C.F.R. § 205.371 (also recognizing that "where a shortage of electricity is projected due solely to the failure of parties to agree to terms, conditions, or other economic factors" there is no emergency "unless the inability to supply electric service is *imminent*" (emphasis added)).

[129] *See* 10 C.F.R. § 205.375 (requiring present inability to meet demand to demonstrate inadequate energy supply).

[130] 46 Fed. Reg. at 39,985–86.

[131] 574 F.2d at 613.

[132] *Id.*

[133] *Id.*

sought judicial review of the Commission's decision to allow the withdrawal of the Section 202(c) petition.[134]

The court easily upheld the Commission's decision not to invoke Section 202(c).[135] Though the oil embargo had ended, the utility argued that the "high cost and uncertain supply of imported oil" justified an emergency order.[136] The Commission countered that the voluntary program had worked, the New England Power Pool never interrupted service, there was no need for a Section 202(c) order, and the court agreed.[137]

Trying another tactic, the utility argued that "dependence on imported oil leaves this country with a *continuing* emergency."[138] The court observed that Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances."[139] Interpreting this statutory language, the court upheld the Department's view that Section 202(c) cannot be used when "supply is adequate but a means of fueling its production is in disfavor."[140] Section 202(c) is not an appropriate means to implement long-term national policy to switch fuels. It is only a temporary fix for a temporary problem.

The Eighth Circuit has similarly held that Section 202(c) can only be used to respond to immediate crises. In *Otter Tail Power Co. v. Federal Power Commission*, 429 F.2d 232 (8th Cir. 1970), a utility insisted that the only way for the Federal Power Commission to properly order the utility to connect to a municipal power provider was to issue a Section 202(c) order. Demand for electricity in the city had increased, and the peak load of the municipal power provider was getting to be so high that both of its two generators would likely need to be used simultaneously in the near future, "causing a possible loss of service should one malfunction during a peak period."[141] To avoid this possible loss of service, the Federal Power Commission issued a Section 202(b) order, requiring the utility to connect the municipal power provider. The utility argued that the Federal Power Commission used the wrong section and should have used Section 202(c) instead.

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[134] *Id.* at 614.

[135] *Id.*

[136] *Id.*

[137] *Id.* at 615.

[138] *Id.* (emphasis added).

[139] *Id.*

[140] *Id.*

[141] *Id.* at 233-34.

The court explained that Section 202(c) "enables the Commission to react to a war or national disaster" by ordering "immediate" interconnection during an "emergency."[142] For non-emergency situations, "[o]n the other hand, Section 202(b) applies," including when there is a "crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission."[143] The court upheld the Commission's use of Section 202(b) instead of Section 202(c) because there was no immediate emergency.

The case law uniformly supports the interpretation that Section 202(c) can only be used in acute, short-term, urgent emergencies.

e. *The Department's Prior Orders Recognize that Section 202(c) Does Not Confer Plenary Authority Over Long-Term Resource Adequacy.*

The Department's past applications of Section 202(c) corroborate the urgency of the emergency conditions that are the necessary predicate for any Department intervention under that section.[144] The Department's predominant practice outside of wartime has been to use Section 202(c) to address specific, imminent, and unexpected shortages—not to address longer-term reliability concerns or demand forecasts.[145] The Department has also narrowly tailored the remedies in Section 202(c) orders to ensure that the orders only address the stated emergency, to limit the order to the minimum period necessary, and to mitigate violations of environmental requirements and impacts to the environment.[146]

Public Interest Organizations are not aware of any instance in which the Department has utilized Section 202(c) to mandate generation the Department

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[142] *Id.* at 234 (citing 16 U.S.C. § 824a(c)).

[143] *Id.*

[144] *See FTC v. Bunte Brothers, Inc.*, 312 U.S. 349, 352 (1941) ("[J]ust as established practice may shed light on the extent of power conveyed by general statutory language, so the want of assertion of power by those who presumably would be alert to exercise it, is equally significant in determining whether such power was actually conferred.").

[145] *See, e.g.,* Ex. 5, Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) (responding to ongoing severe winter storm producing immediate and "unusually high peak load" between Christmas Eve and Boxing Day); Ex. 6 Dep't of Energy Order 202-20-2 (Sept. 6, 2020) at 10-2 (responding to shortages produced by ongoing extreme heat and wildfires); *see also* Ex.7 Rolsma, 57 Conn. L. Rev. at 803-4 (describing "sparing[]" use of Section 202(c) outside of war-time shortages during the twentieth century).

[146] *See, e.g.*, Ex. 5, Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) at 4-7 (limiting order to the 3 days of peak load, directing PJM to exhaust all available resources beforehand, requiring detailed environmental reporting, notice to affected communities, and calculation of net revenue associated with actions violating environmental laws); Ex. 6 Dep't of Energy Order 202-20-2 (Sept. 6, 2020) at 3-4 (limiting order to the 7 days of peak load, directing CAISO to exhaust all available resources beforehand, requiring detailed environmental reporting).

views as necessary to ensure long-term resource sufficiency—and for good reason.[147] Any such use would exceed the Department's statutory authority.

2. In the RAR, DOE purports to identify only long-term, uncertain, and generalized concerns with bulk-power system reliability, which do not enable the Department to compel generation pursuant to Section 202(c).

Given the statutory limitations described above, the RAR provides no basis for the Department to use Section 202(c) to require that particular "generation resources" are "retained as an available generation resource," or to "prevent . . . an identified generation resource . . . from leaving the bulk-power system or converting" its fuel source.[148] Nor does the Department identify any other source of legal authority for DOE to impose such requirements. In the RAR, the Department only purports to identify capacity shortages that might affect bulk-system reliability in 2030.[149] The Department acknowledges that all but one region—ERCOT—currently meet its criteria.[150] Its claim that shortages might arise five years from now, even if it were correct—would present no "emergency" under Section 202(c). Those non-imminent resource needs are, rather, precisely the long-term reliability and resource adequacy matters over which Congress allocated responsibility to FERC and NERC.

Second, the Department identifies only a "risk of power outages" even in 2030[151] based on the Department's projected "AI and data center load growth under the given assumptions for generator build outs by 2030, generator retirements by 2030, reserve requirements, and potential load growth."[152] The Department acknowledges, meanwhile that its analysis "is not an indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system."[153] The RAR—even by its own terms—thus does not specify any shortfall that is certain enough to justify invocation of the Department's emergency powers under Section 202(c). Its numbers are, rather, "indicators to determine where it may be beneficial to encourage increased generation and transmission capacity to meet an expected need."[154] Section 202(c) does not authorize the Department to order generation based on such non-certain shortfalls; it provides distinct, and

[147] *See Richmond Power and Light,* 574 F.2d at 616.

[148] Grid EO at 2.

[149] *E.g.,* RAR, Ex. 1 at 1, 20, 27, 30, 32, 40.

[150] RAR, Ex. 1 at 7.

[151] *Id.* at 1.

[152] *Id.* at 7.

[153] *Id.*

[154] *Id.*

much more limited powers, by which the Department may facilitate "an abundant supply of electric energy throughout the United States."[155]

And third, the Department does not claim to identify any particular location in which a shortfall might occur, or the specific resources that might best serve to address such shortfall. Instead, in the RAR, the Department provides aggregate estimates of potential loss-of-load under "varied grid conditions and operating scenarios based on historical data."[156] But those estimates do not demonstrate that any single generating facility would best meet the resulting shortfall, and could not therefore justify an emergency order directing a facility to remain available.

Consequently—even setting aside methodological flaws—the Department asserts resource risks in the RAR that are neither imminent, certain, nor specific. Those risks do not describe an emergency that would permit the Department to intervene pursuant to Section 202(c). They represent, rather, the Department's view as to measures that might "assur[e] an abundant supply of electric energy throughout the United States."[157] Section 202 does not permit the Department to compel generation on that basis. The Department also describes in the RAR the measures the Department believes "necessary to provide for reliable operation of the bulk-power system."[158] But Section 215 gives FERC, not the Department, the power to provide for reliable operation of the bulk power system, and specifies the procedures by which such measures must be developed and enforced; the Federal Power Act does not permit the Department to end-run those limitations by deeming long-term reliability an emergency. The RAR consequently could not form the basis of any action by the Department to compel generation under Section 202 of the Federal Power Act.

C. The RAR Is Analytically Flawed and Does not Rely Upon Substantial Evidence.

The RAR is severely flawed and does not meet DOE's own information quality standards. There are significant informational and methodological limitations and clear analytical and data errors. Any reliance on the RAR to "guide interventions" or to serve as a basis for any DOE decisionmaking would be arbitrary and capricious and not based on substantial evidence, in violation of the Administrative Procedure Act.

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[155] 16 U.S.C. § 824a(a).

[156] RAR, Ex. 1 at 2. *See, e.g., id.* at 21.

[157] 16 U.S.C. § 824a(a).

[158] 16 U.S.C. § 824o(a)(3).

1. The RAR falls woefully short of informational and methodological best practices.

DOE admits the RAR was hastily thrown together without sufficient information. At the outset, DOE acknowledges the resource adequacy analysis in the RAR "could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level."[159] Indeed, "[h]istorically, the nation's power system planners would have shared electric reliability information with DOE through mechanisms such as EIA-411, which has been discontinued."[160] DOE continues to explain that a key takeaway of the RAR is the need for "strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our collective economic and national security."[161] The candor in these comments is revealing; these limitations prove that the RAR does not meet the requirements of the Information Quality Act ("IQA") or DOE's guidelines thereunder.[162] The RAR should be withdrawn so that the Department does not continue to disseminate this poor-quality information, and the RAR should not be relied on in any decisionmaking. In the alternative, the Department should not use the RAR as support for any final action until and unless it (1) provides notice of the statutory authority under which DOE issued the RAR and publishes all data underlying the RAR, (2) explains in detail the specific uses for the methodology, and (3) allows interested parties to comment on the RAR before releasing a final version that incorporates and responds to public comment.

The IQA directs agencies to "ensur[e] and maximiz[e] the quality, objectivity, and integrity of information (including statistical information) disseminated by Federal Agencies."[163] Office of Management and Budget ("OMB") guidelines issued

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[159] RAR, Ex. 1 at i.

[160] *Id.*

[161] *Id.*

[162] *See* Pub. L. 106-554 Sec. 515, 114 Stat. 2763A-153.

[163] *Id.* OMB's government-wide information quality guidelines direct agencies to issue their own implementing guidelines. Agencies must provide the public a way to administratively seek and obtain correction of information disseminated by the agency that does not comply with OMB or agency guidelines. *See* Office of Management and Budget, Guidelines for Ensuring and Maximizing the Quality, Objectivity, Utility, and Integrity of Information, 67 Fed. Reg 8452 (Feb. 22, 2002); Office of Management and Budget, Memorandum for the Heads of Executive Departments and Agencies (Apr. 24, 2019) (hereinafter "OMB Guidelines 2019 Update"), https://www.whitehouse.gov/wp-content/uploads/2019/04/M-19-15.pdf.

Pursuant to the OMB directive, DOE has issued its own agency-specific information quality guidelines. *See* Dep't of Energy, Final Report Implementing Office of Management and Budget Information Dissemination Quality Guidelines (Oct. 1, 2002), no. 6450-01-p, https://www.energy.gov/sites/prod/files/cioprod/documents/finalinfoqualityguidelines03072011.pdf; Dep't of Energy, Final Report Implementing Updates to the Department of Energy's Information pursuant to the IQA require agencies to ensure that scientific information including "factual inputs, data, models, analyses . . . related to such disciplines as . . . engineering, or physical sciences" undergo certain review procedures to maintain quality standards.[164]

To that end, agencies must "choose a peer review mechanism that is adequate, giving due consideration to the novelty and complexity of the science to be reviewed, the relevance of the information to decisionmaking, the extent of prior peer reviews, and the expected benefits and costs of additional review."[165] Agencies must "strive to ensure that their peer review practices are characterized by both scientific integrity and process integrity," including the "rationale and supportability" of the agency's findings and ensuring "avoidance of real or perceived conflicts of interest" and "a workable process for public comment and involvement."[166] Agencies are encouraged to "have the choice of input data and the specification of the model reviewed by peers before the agency invests time and resources in implementing the model and interpreting the results," in order to "focus attention on data inadequacies in time for corrections . . . before the agency becomes invested in a specific approach."[167] Additionally, peer reviewers must "ensure that scientific uncertainties are clearly identified and characterized," and "ensure that the potential implications of the uncertainties for the technical conclusions drawn are clear."[168] OMB IQA guidelines also require agencies to evaluate "the sensitivity of the agency's conclusions to analytic assumptions."[169] These steps of peer review determine a report's "fitness . . . for policy purposes."[170]

DOE IQA guidelines further note that "in disseminating certain types of information to the public, other information must also be disseminated in order to ensure an accurate, clear, complete, and unbiased presentation."[171] Agencies should provide open access to data and modeling information underlying a report.[172]

Quality Act Guidelines (2019) (hereinafter "DOE IQA Guidelines 2019 Update"), available at https://www.energy.gov/cio/articles/2019-final-updated-version-doe-information-quality-guidelines.

[164] OMB, Final Information Quality Bulletin for Peer Review, 70 Fed. Reg. 2664, 2667 (Jan. 14, 2005); *see also* OMB Guidelines 2019 Update at 4.

[165] OMB Information Quality Bulletin for Peer Review, 70 Fed. Reg. at 2668.

[166] *Id.*

[167] *Id.*

[168] *Id.* at 2669.

[169] OMB Guidelines 2019 Update at 4.

[170] *Id.*

[171] DOE IQA Guidelines 2019 Update at 16.

[172] OMB Guidelines 2019 Update at 8; *See also*, e.g., *Chem. Mfrs. Ass'n v. U.S. EPA*, 870 F.2d 177, 200 (5th Cir. 1989) ("fairness requires that the agency afford interested parties an opportunity to challenge the underlying factual data relied on by the agency."); *United States v. Nova Scotia Food*

Additionally, DOE is "responsible for ensuring that the information [being disseminated in a report] is consistent with the OMB and DOE guidelines and that the information is of adequate quality for dissemination."[173] For reports containing "influential financial, scientific, or statistical information," DOE must "identify for the [Chief Information Officer] a high ranking official" who is responsible for higher level review of the report's conclusions.[174]

OMB's IQA guidelines recognized that the "[f]ederal government's assessment of risk can directly or indirectly influence the response actions of state and local agencies or international bodies."[175] Thus, under the OMB and DOE guidelines, influential information—information routinely embargoed because of "potential effect on markets" or information "on which a regulatory action with a $100 million per year impact is based"—must meet the highest standards of quality and transparency, and should undergo the rigorous review procedures outlined above.[176]

Here, the RAR does not comply with IQA requirements, rendering any further reliance on it to be arbitrary and capricious. For example, the RAR appears to be inconsistent with internal review processes required: it should have undergone peer review because of its "influential" nature, particularly if the RAR is, as it purports to be, a "uniform methodology" to guide reliability interventions, such as Federal Power Act Section 202(c) orders, which have outsize economic impacts. However, there is no evidence that the RAR underwent any peer review, and, given the time constraints, it is unlikely it did. The Department further failed to make available all underlying data and modeling information used to create the RAR. Additionally, as described in detail below, the RAR relies on improper analytic assumptions, including overstated demand and understated supply forecasts. The RAR includes faulty analysis based on these improper assumptions despite DOE's acknowledgment of significant informational limitations regarding regional- and utility-level engineering data. In addition, the RAR contains numerous errors, such as referring to appendices that do not exist or incorrect appendices,[177] stating

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Prods. Corp., 568 F.2d 240, 251-53 (2d Cir. 1977) (holding that regulation was promulgated in arbitrary and capricious manner where agency failed to disclose data on which it relied).

[173] DOE IQA Guidelines 2019 Update at 22.

[174] *Id.* at 22-23.

[175] OMB Information Quality Bulletin for Peer Review, 70 Fed. Reg at 2667.

[176] DOE IQA Guidelines 2019 Update at 7.

[177] *See* RAR, Ex. 1, at 12 (referring to nonexistent "Outputs" section of an unnamed appendix); *id.* (referring to Appendix B for further detail regarding retirement assumptions, whereas Appendix B describes Canadian transfer limits).

inaccurate units for generation capacity,[178] and falsely asserting bulk power system load shedding occurred in regions during certain events.[179]

2. In the RAR, the Department overstates assumptions about demand.

In the RAR, the Department assumes 101 GW of load growth by 2030—a 15% increase over 2025 load. This increase is more than double the high case in the U.S. EIA 2025 Annual Energy Outlook, which forecasts 6% growth.[180] This extraordinarily high assumed load growth contributes substantially to the findings of low resource adequacy under the Plant Closures scenario in the RAR. As explained below, in the RAR, the Department omits consideration of many factors that will likely dampen load growth in the coming 5 years, thus undermining the validity and usefulness of its results.

The Department assumes 50 GW of load growth from data centers by 2030, which it characterizes as the midpoint among other available forecasts.[181] However, it does not appear that DOE's forecast accounts for load flexibility at these data centers, which would significantly reduce the overall demand that these centers place upon the grid during the periods of peak system risk. While certain data centers may not be capable of load curtailment due to their purpose, many can be flexible. Even a small amount of data center load flexibility provides significant benefits. A recent study by experts at Duke University found that curtailment at data centers during only 0.25% of the year would enable 76 GW of data center power demand to be added to the system today, without triggering resource adequacy problems or requiring further expansion.[182] The White House recently issued an AI Action Plan endorsing demand flexibility as a means to maintain resource adequacy as data center capacity expands: "the United States should investigate new and novel ways for large power consumers to manage their power consumption during critical grid periods to enhance reliability and unlock additional power on the system."[183]

The Electric Power Research Institute has begun an initiative to enhance data center flexibility in light of its benefits for grid reliability, under which

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[178] *Id.* at 9 (text stating that PJM has a shortfall of 2.4 MW).

[179] *See infra* subsection C.6.

[180] *See* GridLab Analysis, Ex. 14 at 2.

[181] RAR, Ex. 1 at 2.

[182] Norris, T. H., T. Profeta, D. Patino-Echeverri, and A. Cowie-Haskell. 2025. Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems at 20. Durham, NC: Nicholas Institute for Energy, Environment & Sustainability, Duke University, https://nicholasinstitute.duke.edu/publications/rethinking-load-growth (attached as Ex. 15).

[183] White House, Winning the Race: America's AI Action Plan 15 (July 2025), https://www.whitehouse.gov/wp-content/uploads/2025/07/Americas-AI-Action-Plan.pdf.

demonstration projects were set to deploy in the first half of 2025.[184] Early results from other projects to test data center flexibility have been promising.[185] Evaluations of the RAR by GridLab and the NYU Institute for Policy Integrity ("IPI") both have concluded that the Department's failure to account for data center load flexibility renders its findings of elevated reliability risk in 2030 suspect.[186] This is particularly true for DOE's findings concerning the ERCOT region, considering that in June 2025, Texas enacted a law allowing curtailment of these loads during grid emergencies.[187]

Furthermore, it is unclear whether the RAR's data center load forecasts account for potential constraints on the growth of data centers, such as shortages of critical semiconductor chips,[188] and other grid equipment like transformers and switchgears.[189] In addition to the Texas policy mentioned above, states and utilities are proposing new tariff designs for data centers to ensure that data centers don't

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[184] Elec. Power Rsch. Inst., EPRI Launches Initiative to Enhance Data Center Flexibility and Grid Reliability (Oct. 29, 2024), https://perma.cc/75LY-PSP5 ("Led by EPRI, DCFlex will coordinate real-world demonstrations of flexibility in a variety of existing and planned data centers and electricity markets, creating reference architectures and providing shared learnings to enable broader adoption of flexible operations that benefit all electricity consumers. Specifically, DCFlex will establish five to ten flexibility hubs, demonstrating innovative data center and power supplier strategies that enable operational and deployment flexibility, streamline grid integration, and transition backup power solutions to grid assets. Demonstration deployment will begin in the first half of 2025, and testing could run through 2027.").

[185] *See* Anuja Ratnayake, Unlocking AI Potential with Data Center Flexibility, ENERGYCENTRAL (June 12, 2025), https://www.energycentral.com/intelligent-utility/post/unlocking-aipotential-with-data-center-flexibility-PtPoXIAuRMzs5Ff ("In a preliminary test of the depth of computational flexibility possible in an AI data center, the Arizona demonstration site experienced some early success. It showcased the potential for an AI data center to provide grid relief during a peak system event—such as a hot summer day with high power demand—by temporarily and precisely ramping down its electricity consumption without compromising data center performance.").

[186] NYU Institute for Policy Integrity, *Enough Energy*, at 25 (attached as Ex. 16) (hereinafter "IPI Report"); *see also* GridLab Analysis, Ex. 14 at 2 ("It does not address flexibility of this load, however, which was recently demonstrated in a report from Duke University to allow for 100 GW of large load additions today with minimal grid impact.").

[187] S.B. No. 6 § 4, 89th Legislature (Tex. 2025) (to be enacted at Tex. Util. Code § 39.170), https://perma.cc/4Z7H-9XKQ; Brian Martucci, Texas Law Gives Grid Operator Power to Disconnect Data Centers During Crisis, UTILITY DIVE (June 25, 2025), https://perma.cc/SYK3-V4XX; Waleed Aslam & Robin Hytowitz, Elec. Power Rsch. Inst., Texas SB6 Explained: Addressing Large Load Impacts (2025), https://perma.cc/QD8S-3M5C.

[188] *See, e.g.* London Economics International LLC, *Uncertainty and Upward Bias Are Inherent in Data Center Electricity Demand Projections* at 39 (July 7, 2025) (attached as Ex. 17), https://www.selc.org/wp-content/uploads/2025/07/LEI-Data-Center-Final-Report-07072025-2.pdf.

[189] How big tech plans to feed AI's voracious appetite for power, The Economist (July 28, 2025), https://www.economist.com/business/2025/07/28/how-big-tech-plans-to-feed-ais-voracious-appetite-for-power.

pose risks to the distribution system or shift costs to other consumers, all of which could slow or redirect the forecasted data center load growth.[190] The Department fails to evaluate any of these dynamics in the RAR.

In addition to the overall rate of data center load growth, the Department also uses a poorly described and supported methodology to allocate data center load to different regions. As the IPI observes, DOE used state-level growth ratios to allocate the projected data center load across regions, "[b]ut it is unlikely that all the computing demand needs to be processed close to load centers (i.e., proportional to a region's current electric load)."[191] IPI posits that "some computing demand may be served from other regions if it will be cheaper to integrate the data center elsewhere," and observes that "[g]iven the scale of DOE's projected data center load compared to the relatively small resource adequacy shortfalls that the study identifies, these assumptions may have made the difference between whether a region achieves DOE's resource adequacy targets."[192] Figure 8 in the RAR (New Data Center Build) shows that DOE's estimates for the percentage of data center load growth that will be built in various RTOs in some cases differs substantially from the percentages in the various forecasts that DOE used to calculate its overall data center load growth estimate. DOE does not explain why it discards these studies' more geographically specific estimates and instead relies on a single state-level growth ratio derived from a different study.

The Department's approach to estimating non-data center load growth by 2030 is also poorly explained in the RAR and likely flawed. DOE relies upon NERC's 2024 Long-Term Reliability Assessment forecast for overall load growth, but because the Department otherwise seeks to include elevated levels of data center load growth in the RAR, it must back out an estimate of data center load growth from the overall forecast.[193] The estimate that DOE chooses to back out is a "low-growth" case for data center load from a different source (which DOE presents in volumetric consumption terms, rather than peak demand). This approach, without further information to understand DOE's analysis, could have resulted in DOE over-estimating non-data center load growth. This effect is likely exacerbated by recent changes in federal law that will reduce electricity consumption from

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[190] Jason Plautz, *Rulemakers play catch-up as data centers multiply*, E&ENews by Politico (July 18, 2025), https://www.eenews.net/articles/rulemakers-play-catch-up-as-data-centers-multiply/.

[191] IPI Report, Ex. 16 at 26.

[192] *Id.*

[193] RAR, Ex. 1 at 17 ("Given the rapid emergence of AI/DC loads, additional steps were taken to account for this category of demand. It is difficult to determine how much AI/DC load is already embedded in NERC [Long-Term Reliability Assessment] forecast, for example, the 2024 [Long-Term Reliability Assessment] saw more than 50GW increase from 2023, signaling a major shift in utility expectations. To benchmark existing AI/DC contribution, DOE assumed base 2023 AI/DC load equaled the EPRI low-growth case of 166 TWh.").

specific sectors, including vehicles and hydrogen electrolysis. The utility forecasts included in the NERC Long-Term Reliability Assessment included projections of vehicle and building electrification that depend in part on tax credits and incentives that were revoked prior to publication of the RAR as part of the One Big Beautiful Bill Act ("OBBBA"). Recent analysis shows that the elimination or reduction of tax credits that supported new sources of electricity load growth will have a meaningful effect by 2030.[194] As a result, DOE's non-data center load growth projections are likely overstated.

3. Assumptions about supply are unsupported.

a. In the RAR, the Department Overstates Likely Retirements.

The Department finds the most dire resource adequacy shortfalls occur in the Plant Closures case, in which it assumes 104 GW of retirements by 2030.[195] This estimate is much higher than the most recent data from the EIA released in June 2025 in its authoritative Form 860, which shows 50 GW fewer retirements than assumed in the RAR.[196] As GridLab experts explained, DOE assumed not only "these 50 GW of likely retirements, but [also] included another 50 GW of *announced* retirements."[197] While it may be appropriate to include announced retirements in certain long-term planning exercises, it is unreasonable to assume such retirements will happen as the basis for extraordinary emergency actions. Without more detail about any formal or binding characteristics of those announcements, or the factors purportedly driving those announcements, it is impossible to verify the validity of this input that doubles the amount of otherwise projected resource retirements. Even EIA's Annual Energy Outlook, which does model projected retirements beyond those already formally noticed, finds 10 GW fewer thermal retirements by 2030 than does DOE.[198] Without further support for the 50 GW assumed retirement

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[194] *See, e.g.,* Princeton NetZero Lab and Evolved Energy Research, A Fork in The Road: Impacts of Federal Policy Repeal on the U.S. Energy Transition, at Tab 12 (last updated July 3, 2025), https://public.tableau.com/app/profile/evolvedenergyresearch/viz/AForkinTheRoad_ImpactsofFederalPolicyRepealontheU_S_EnergyTransition_June/1Title (showing approximately 100 TWh annual energy use reduction in 2030 compared to mid-range estimates of the status quo ante).

[195] RAR, Ex. 1 at 5.

[196] U.S. EIA, Annual Energy Outlook 2025: Table 9. Electricity generating capacity (March 2025), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2025&region=0-0&cases=ref2025&start=2025&end=2030&f=A&linechart=ref2025-d032025a.4-9-AEO2025&map=&sourcekey=0. *See also* GridLab Analysis, Ex. 14 at 2.

[197] GridLab Analysis, Ex. 14 at 2; *see also* IPI Report, Ex. 16 at 24 (explaining that DOE's "number includes both 'confirmed' retirements—resources that have notified their system operators of their impending retirements and begun the retirement process—and 'announced' retirements—which are publicly stated but not officially noticed.").

[198] According to the U.S. EIA's 2025 Annual Energy Outlook, coal-fired generating capacity is projected to decline by 93.6 GW between 2025 and 2030 in the Reference case, approximately 10

value, the Plant Closures case is nothing more than speculation about what might happen if certain assumptions were to come true.

Such assumptions are particularly unjustified given that, as GridLab notes, "[m]ost likely many plants will choose not to retire due to the changing regulatory and economic landscape."[199] The IPI makes a similar point in their critique of DOE's retirement assumptions, noting that "the economics of energy production have changed since 2024. The combined effect of new demand from data centers and the elimination of federal tax credits for new wind and solar resources improves the financial outlook for thermal resources."[200] As one snapshot of this trend, high capacity prices in the PJM region led to 1.1 GW of resources withdrawing formal deactivation notices since last summer.[201] IPI also observes that the Trump Administration is seeking to rescind or reexamine many federal environmental regulations that would have required thermal resources to make investments reducing their pollution or else retire before 2030, "which could cause resources to delay their retirements."[202]

b. *In the RAR, the Department Understates Likely New Entry by 2030 and Other Sources of Supply.*

Among the most impactful and unsupported assumptions in the RAR is that "only [generation] projects that are very mature in the pipeline (such as those with a signed interconnection agreement) will be built" by 2030.[203] DOE thus constrains its analysis to include only projects designated as Tier 1 in the NERC 2024 Long Term Resource Assessment, which it then maps to Interregional Transfer Capability Study regions. Because Tier 1 includes only resources that are already under construction, have signed construction service agreements, and similar

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fewer GW of retirements than modeled in the DOE report. No other fossil fuel technology shows a net decrease in generating capacity in the 2025 Annual Energy Outlook analysis. U.S. EIA, Annual Energy Outlook 2025: Table 9. Electricity generating capacity (March 2025), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2025&region=0-0&cases=ref2025&start=2025&end=2030&f=A&linechart=ref2025-d032025a.4-9-AEO2025&map=&sourcekey=0.

[199] GridLab Analysis, Ex. 14 at 2.

[200] IPI Report, Ex. 16 at 24.

[201] PJM Inside Lines, PJM Auction Procures 134,311 MW of Generation Resources; Supply Responds to Price Signal (July 22, 2025) https://insidelines.pjm.com/pjm-auction-procures-134311-mw-of-generation-resources-supply-responds-to-price-signal/ ("Since the 2025/2026 Base Residual Auction results were posted on July 30, 2024, 17 generating units totaling approximately 1,100 MW worth of Capacity Interconnection Rights have withdrawn their retirements").

[202] IPI Report, Ex. 16 at 24-25.

[203] RAR, Ex. 1 at 12.

characteristics,[204] this assumption "results in minimal capacity additions beyond 2026."[205] As experts at GridLab observe, the assumption that "no projects are built post 2026, [] is not realistic for a report forecasting to 2030."[206] This is especially true given rising energy prices due to increased demand, which is attracting more investment to the market and driving new construction of generation resources.

The Department also states in the RAR that of these Tier 1 additions, just 22 GWs of generator additions are "firm" (thermal) resources, which severely underestimates new gas generation compared to other projections. According to GridLab, "a more reasonable assumption for forecasted capacity additions is the EIA 860 released in June 2025, which has 35 GW of gas additions, and another 53 GW of batteries [for a total of] 88 GW of firm additions by 2030."[207] Other federal government projections are even higher: EIA's 2025 Annual Energy Outlook projects 90 GWs of new fossil generators added to the system through 2030.[208] 80 GWs of the EIA-projected natural gas growth are in earlier development stages and likely did not meet the 2024 NERC Long-Term Reliability Assessment Tier 1 criteria to be included in the RAR.

As researchers at the IPI conclude, DOE departed from best practice in declining to include any resources classified by NERC as "Tier 2" resources[209] in the overall resource adequacy analysis for 2030, even those at advanced stages of the interconnection process.[210] A reasonable process could have involved "examin[ing]

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[204] *See* IPI Report, Ex. 16 at n.155 (citing NERC, 2024 Long Term Reliability Assessment, 137 (last updated July 15, 2025) https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf).

[205] RAR, Ex. 1 at A-5.

[206] GridLab Analysis, Ex. 14 at 3.

[207] *Id.*

[208] According to the U.S. EIA, the policy-neutral reference case projects a 93.29 GW increase in combined cycle, fossil steam, and combustion turbine capacity between 2025 and 2030. U.S. EIA, Annual Energy Outlook 2025: Table 9. Electricity generating capacity (March 2025), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2025&region=0-0&cases=ref2025&start=2025&end=2030&f=A&linechart=ref2025-d032025a.4-9-AEO2025&map=&sourcekey=0.

[209] NERC defines Tier 2 resources as those having one of the following characteristics: "Signed/approved Completion of a feasibility study, Signed/approved Completion of a system impact study, Signed/approved Completion of a facilities study, Requested Interconnection Service Agreement, Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)." NERC, 2024Long Term Reliability Assessment, 137 (Dec. 2024, updated July 15, 2025) https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[210] IPI Report, Ex. 16 at 23.

historical statistics of interconnection queue time by region, resource type, and resource size, along with differentiated queue withdrawal rates, estimating Tier 2 resource additions for each region."[211] For example, for the PJM region, the Independent Market Monitor's analysis shows that 15% of generation projects (on an energy basis) successfully enter service.[212] As of late 2024, PJM had over 44 GW of accredited capacity in its interconnection queue.[213] To assume that none of this capacity would enter service by 2030, as DOE's analysis does, is unreasonable.

Such an analysis should also consider factors pointing towards even faster queue times than those seen in the historical data, given factors now expediting interconnection queues such as implementation of FERC Order 2023, streamlining of tools to better utilize existing points of interconnection (e.g., surplus interconnection service), and various interconnection fast tracks that FERC has recently approved.[214] For example, it is unreasonable for DOE to exclude from consideration the over 9 GW of accredited capacity that PJM selected in May 2025 to participate in its Reliability Resource Initiative—the vast majority of these projects (primarily gas and battery energy storage systems) are committed to be online by 2030,[215] but are omitted in DOE's analysis because they do not yet have a signed interconnection agreement. DOE paints an inaccurate picture of new entry by ignoring recently adopted policies designed to address the very same tightening supply and demand conditions that DOE describes.

DOE also underestimates the extent to which interregional transfers of energy could help to prevent or address any shortfalls. Noting that it relies upon the interregional transfer capacities identified by NERC in its Interregional Transfer Capability Study, DOE explains that "[i]mports are assumed to be available up to the minimum total transfer capacity and spare generation in the

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[211] *Id.*

[212] Monitoring Analytics, 2024 State of the Market Report, at 705 (2024) https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024q2-som-pjm-sec12.pdf (noting 14.9% completion rate).

[213] PJM, Reliability Resource Initiative MRC Update, at slide 6 (Nov. 7, 2024) https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2024/20241107-special/item-04---reliability-resource-initiative---presentation.ashx.

[214] *Id. See also* Prefiled Statement of Manu Asthana on Behalf of PJM Interconnection, L.L.C., FERC Docket No. AD25-7, at 4 (May 27, 2025), https://www.ferc.gov/media/manu-asthana-pjm-president-and-ceo (touting recent improvements to PJM's interconnection queue by noting that "[a]n additional approximately 18 GW is being processed to move to the final study phase for completion this year, and an additional 56 GW (including projects from Transition Cycle 2 and Reliability Resource Initiative) will be through the queue by late 2026.").

[215] PJM, Reliability Resource Initiative Results Summary, at slide 9 (May 6, 2025) https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250506/20250506-item-06---reliability-resource-initiative---summary-results.pdf.

neighboring subregion."[216] Because the Interregional Transfer Capability Study calculated interregional transfer capacities for both summer and winter, and for each direction of flow, it is unclear what DOE means regarding allowing transfers up to the minimum. As the IPI observes: "If DOE picked the lesser of the summer and winter transfer capacities and applied that annually, doing so would inaccurately underestimate the amount of interregional transfer capacity."[217] This is yet another example of where DOE fails to explain its methodology with sufficient detail to enable an evaluation of whether its approach is reasonable, or is supported by substantial evidence.

4. DOE's use of a deterministic analysis provides an incomplete and inaccurate picture.

For the RAR, DOE employs a deterministic approach in examining resource adequacy; that is one that "evaluate[s] resource adequacy using relatively stable or fixed assumptions about the representation of the power system," rather than a probabilistic approach that "incorporate[s] data and advanced modeling techniques to represent uncertainty that require more computing power."[218] DOE explains it chose a deterministic approach "for transparency and to model detailed historic system conditions."[219] However, deterministic approaches have significant limitations; as NERC explained in the Interregional Transfer Capability Study on which DOE otherwise heavily relies, because that study did not employ a probabilistic approach, it "should not be considered a North American resource adequacy assessment."[220] The problem, as IPI explains, is that "[b]y examining whether regions would be resource adequate only under conditions that resemble the recent past, DOE's study does not sufficiently account for uncertainty."[221] Furthermore, as NERC itself has explained, under a deterministic approach, "some regions may look resource adequate because they happened to do well during the twelve years of data, while others look resource inadequate but be unlikely to perform as poorly in the future."[222] As IPI concludes, neither of DOE's professed reasons for using a deterministic approach justifies departing from best practices, as "DOE could document a probabilistic approach in a transparent way, and relying on a small sample of historic years is less accurate than a probabilistic approach."[223]

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[216] RAR, Ex. 1 at 12.

[217] IPI Report, Ex. 16 at 26.

[218] RAR, Ex. 1 at 2 n.2.

[219] *Id.*

[220] IPI Report, Ex. 16 at 21 (citing NERC, Interregional Transfer Capability Study, at 4 (2024) (hereinafter "NERC ITCS")).

[221] IPI Report, Ex. 16 at 21.

[222] *Id.* (citing NERC ITCS at 138).

[223] *Id.* at 21.

DOE may have chosen a less sophisticated and rigorous approach given the limited amount of time in which the Grid EO required this analysis to be completed, but regardless of the reason, the limitations inherent in DOE's deterministic methodology mean that its findings should not be taken as conclusive or form the basis for further extraordinary actions.[224]

5. DOE uses an elevated threshold for determining when outages will occur.

In the RAR, the Department projects a shortfall if "the remaining capacity after transmission and demand response falls below the 6 percent or 3 percent needed for error forecasting and ancillary services, depending on the scenario."[225] This approach, and the particular values used as thresholds, come from the NERC Interregional Transfer Capability Study, which uses 3% as the default threshold and 6% only in a sensitivity analysis. NERC explains that the 3% value "was established based on an evaluation of average reserve requirements where load shed may occur" in order for a Balancing Authority to continue to hold the minimum reserves needed to protect the system from cascading or widespread outages.[226] In the sensitivity examined by NERC, using the 6% threshold "significantly altered the existence and extent of predicted outages in many regions, such as producing a 690% increase in the size of the maximum outage event in SERC-Florida."[227]

As the IPI analysis notes, DOE provides no further explanation for when and how it uses 6% as a threshold versus 3%.[228] While the Department directs readers to an appendix with further detail, the appendices do not in fact provide any further information regarding this critical assumption.[229] Furthermore, "the fact that DOE listed 6% first may suggest that 6% was not limited to a sensitivity analysis," and that if "DOE's model instead identifies shortage events even when a region still has 6% of load available as spare capacity, then DOE's results depart from NERC's practice and may overstate the extent of expected outages."[230] DOE's failure to explain its own methodology concerning such a critical input to its analysis, including through the failure to provide information in an appendix that the RAR states exists, renders the RAR arbitrary and capricious. Insofar as the RAR's results for 2030 scenarios depend upon the 6% threshold, DOE must explain why

[224] *Id.* ("Given the high stakes associated with resource adequacy planning, any future DOE resource adequacy assessment should prioritize accuracy over expediency.")

[225] RAR, Ex. 1 at 12.

[226] IPI Report, Ex. 16 at 22 (citing NERC ITCS, at 91 n.90, 85).

[227] IPI Report, Ex. 16 at 22 (citing NERC ITCS at 105 tbl.8.4); *see also id.* ("Under the 6% sensitivity, NERC also recommended 58 GW of transmission additions to address resource adequacy instead of 35 GW, illustrating the sizable influence of shifting this assumption from 3% to 6%.")

[228] IPI Report, Ex. 16 at 22.

[229] *Id.*

[230] *Id.*

such a threshold is appropriate, given the departure from NERC's practice and the evidence in the NERC report considering the propriety of a far lower threshold.

6. DOE inconsistently applies its own methodology.

Several of the findings in the RAR are inconsistent with the methodology that DOE develops. For instance, DOE states that "[a]nalysis of the current system shows all regions except ERCOT have less than 2.4 hours of average loss of load per year and less than 0.002% NUSE" (the standards DOE developed for this study).[231] DOE further explains that "[w]hen looking at metrics in the worst weather years, regions meet or exceed additional criteria. All regions experienced less than 20% of lost load in any hour."[232] Despite these clear findings, DOE goes on to state that "PJM, ERCOT, and SPP experienced significant loss of load events during 2021 and 2022 winter storms Uri and Elliot which translated into more than 20 hours of lost load," and asserts that this "results in a concentration of lost load within certain years such that some regions exceeded 3-hours-per-year of lost load."[233] As an initial matter, the PJM system did not experience any lost load due to resource inadequacy during Winter Storms Uri or Elliott.[234] Second, DOE's focus on whether a region had lost load or a risk of lost load in a particular weather year is inconsistent with DOE's own articulation of its resource adequacy standards, as "average indicators" assessed across all scenarios and years.[235] As the IPI notes, these standards are "not a requirement that must be achieved in each and every scenario."[236]

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[231] RAR, Ex. 1 at 7.

[232] *Id.*

[233] *Id. See also Id.* at 9 ("For the current system, this analysis identifies an additional 2.4 MW of capacity to meet the NUSE target for PJM, which experiences shortfalls due to the winter storm Elliot historical weather year.").

[234] PJM Inside Lines, PJM Releases Winter Storm Elliott Report (July 17, 2023) https://insidelines.pjm.com/pjm-releases-winter-storm-elliott-report/ ("PJM maintained system reliability and served customers throughout the extreme weather that affected the region Dec. 23–25 [2022], and even was able to support its neighbors during certain periods."); *see also* FERC, NERC and Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (Nov. 16, 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and (noting that PJM was exporting power to neighboring regions during Winter Storm Uri, and investigating rolling blackouts only in Texas and south central states).

[235] RAR, Ex. 1 at 5.

[236] IPI Report, Ex. 16 at 20.

D. Notice and Comment Procedures Are Required for Any "Uniform Methodology" the Department Uses to Guide Reliability Interventions.

Under the Administrative Procedure Act, federal agencies must provide notice and an opportunity for public comment when issuing rules, with limited exceptions not applicable here.[237] If the RAR is, as the Department claims on page vi, a "uniform methodology" for agency decisionmaking on reliability interventions, then the Department needed to provide notice and seek and respond to public comment on this methodology. The Department cannot slip in "entirely new information critical" to its "determination[s]" without taking and responding to public comment.[238]

In the past, when the Department sought to create uniform triggers for reliability intervention within its authority, it issued notice and sought comment.[239] If the RAR is a "uniform methodology" for reliability interventions, then the Department has effectively amended those prior regulations on reliability interventions without following legally required procedures. For example, the Department has regulations defining "emergency" and setting forth procedures for an applicant to demonstrate an "emergency" in the context of Federal Power Act Section 202(c) orders.[240] If the RAR is now a mandatory factor in determining whether there is an "emergency," the Department has changed its existing regulations without following required notice and comment procedures.

E. NEPA Procedures Must Be Followed for Any RAR on Legislative Proposals or "Uniform Methodology" the Department Uses to Guide Reliability Interventions.

Under the National Environmental Policy Act ("NEPA"), agencies must include a "detailed statement" on the environmental impacts of a proposed action "in every recommendation or report on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment."[241] If the RAR is a "uniform methodology" for agency decisionmaking on reliability interventions, it qualifies as a major federal action requiring, at a minimum, an Environmental Assessment and most likely, under the circumstances, a full

[237] 5 U.S.C. §§ 553(b), (c).

[238] *Am. Pub. Gas Assoc. v. DOE*, 72 F.4th 1324, 1338 (D.C. Cir. 2023) (cleaned up).

[239] *See* Grid Security Emergency Orders: Procedures for Issuances, 83 Fed. Reg. 1174 (Jan. 10, 2018) (final rule on Federal Power Act section 215A procedures issued after notice and comment); Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39,984 (Aug. 6, 1981) (final rules concerning emergency interconnections under Federal Power Act sections 202(c) and 202(d) issued after notice and comment).

[240] 10 C.F.R. §§ 205.371; 205.373.

[241] 42 U.S.C. § 4332(C).

Environmental Impact Statement. However, the RAR does not contain any statement whatsoever, and certainly no "detailed statement," on environmental impacts.

Yet the RAR purports to guide "government decisionmakers" on one of the most significant issues that affect the environment—electricity generation. The electricity sector is responsible for wide-ranging environmental impacts—from smog to greenhouse gas emissions to toxic metals to acid rain.[242] Uniform rules on reliability interventions would significantly affect the environment because some of these reliability interventions allow environmental rules for electricity generators to be waived.[243]

VI. CONCLUSION

For the reasons set forth above, the undersigned Public Interest Organizations respectfully request that the Department withdraw the RAR. In the alternative, the Department should not use the RAR as support for any reliability intervention or other action until and unless it (1) provides notice of the statutory authority under which DOE issued the RAR and publishes all data underlying the RAR, (2) provides a detailed explanation of the specific uses for the methodology, and (3) allows interested parties to comment on the RAR before finalizing it.

Dated: August 8, 2025

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[242] *See* EPA, Human Health & Environmental Impacts of the Electric Power Sector (Feb. 6, 2025) https://www.epa.gov/power-sector/human-health-environmental-impacts-electric-power-sector.

[243] *See* 16 U.S.C. § 824a(c)(4)(A).

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