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APPENDIX A

United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 24-1120 **September Term, 2023**

EPA-89FR39798

Filed On: July 19, 2024

State of West Virginia, et al.,

Petitioners

v.

Environmental Protection Agency and Michael S. Regan, Administrator, United States Environmental Protection Agency,

Respondents

Louisiana Public Service Commission, et al.,
Intervenors

Consolidated with 24-1121, 24-1122, 24-1124, 24-1126, 24-1128, 24-1142, 24-1143, 24-1144, 24-1146, 24-1152, 24-1153, 24-1155, 24-1222, 24-1226, 24-1227, 24-1233

BEFORE: Millett, Pillard, and Rao, Circuit Judges

ORDER

Upon consideration of the motions for stay, the oppositions thereto, the replies, the Rule 28(j) letter, and the responses thereto; and the motions to participate as amici curiae and the lodged amicus briefs, it is

ORDERED that the motions of the Chamber of Commerce, the Sierra Club, the Environmental Defense Fund, and Professor Rachel Rothschild to participate as amici curiae be granted. The Clerk is directed to file the lodged amicus briefs. It is

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FURTHER ORDERED that the motions for stay be denied. Petitioners have not satisfied the stringent requirements for a stay pending this court's review. *See Nken v. Holder*, 556 U.S. 418, 434 (2009); D.C. CIRCUIT HANDBOOK OF PRAC. AND INTERNAL PROCS. 33 (2021).

On the merits, petitioners dispute whether the Environmental Protection Agency ("EPA") acted arbitrarily or capriciously in determining that carbon capture and other emission control technologies are adequately demonstrated, or that specific degrees of emission mitigation are achievable with those technologies. But petitioners have not shown they are likely to succeed on those claims given the record in this case. Nor does this case implicate a major question under *West Virginia v. EPA*, 142 S. Ct. 2587 (2022), because EPA has claimed only the power to "set emissions limits under Section 111 based on the application of measures that would reduce pollution by causing the regulated source to operate more cleanly[,]" a type of conduct that falls well within EPA's bailiwick, *id.* at 2610.

On irreparable harm, actual compliance deadlines do not commence until 2030 or 2032—years after this case will be resolved. Though the first deadline for States to submit state implementation plans is May 2026, the only consequence of failing to submit a state plan is the promulgation of a federal plan—which the States can replace with their own plans later. EPA Opp., Ex. 1, Goffman Decl. ¶ 100. To the extent petitioners claim harm due to the need for long-term planning, a stay will not help because the risk remains that the distant deadlines in EPA's rule will come back into force at the end of the case.

EPA has suggested that this case be expedited as an alternative means of protecting all parties' interests. Accordingly, to ensure this case can be argued and considered as early as possible in the court's 2024 term, it is

FURTHER ORDERED that the parties submit, within 14 days from the date of this order, proposed formats and schedules for the briefing of these cases. The parties are strongly urged to submit a joint proposal and are reminded that the court looks with extreme disfavor on repetitious submissions and will, where appropriate, require a joint brief of aligned parties with total words not to exceed the standard allotment for a single brief. Whether the parties are aligned or have disparate interests, they must provide detailed justifications for any request to file separate briefs or to exceed in the

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aggregate the standard word allotment. Requests to exceed the standard word allotment must specify the word allotment necessary for each issue.

<u>Per Curiam</u>

FOR THE COURT:
Mark J. Langer, Clerk

BY: /s/
Selena R. Gancasz
Deputy Clerk

APPENDIX B

Pub. L. 95–95, §107(b), added subsec. (g) relating to Governor's authority to issue temporary emergency suspensions.

Subsec. (h). Pub. L. 95–190, §14(a)(5), redesignated subsec. (g), added by Pub. L. 95–95, §108(g), as (h). Former subsec. (h) redesignated (i).

Subsec. (i). Pub. L. 95–190, §14(a)(5), redesignated subsec. (h), added by Pub. L. 95–95, §108(g), as (i). Former subsec. (i) redesignated (j) and amended.

Subsec. (j). Pub. L. 95–190 §14(a)(5), (6), redesignated subsec. (i), added by Pub. L. 95–95, §108(g), as (j) and in subsec. (j) as so redesignated, substituted ''will enable such source'' for ''at such source will enable it''.

1974—Subsec. (a)(3). Pub. L. 93–319, §4(a), designated existing provisions as subpar. (A) and added subpar. (B).

Subsec. (c). Pub. L. 93–319, §4(b), designated existing provisions as par. (1) and existing pars. (1), (2), and (3) as subpars. (A), (B), and (C), respectively, of such redesignated par. (1), and added par. (2).

EFFECTIVE DATE OF 1977 AMENDMENT

Amendment by Pub. L. 95–95 effective Aug. 7, 1977, except as otherwise expressly provided, see section 406(d) of Pub. L. 95–95, set out as a note under section 7401 of this title.

PENDING ACTIONS AND PROCEEDINGS

Suits, actions, and other proceedings lawfully commenced by or against the Administrator or any other officer or employee of the United States in his official capacity or in relation to the discharge of his official duties under act July 14, 1955, the Clean Air Act, as in effect immediately prior to the enactment of Pub. L. 95–95 [Aug. 7, 1977], not to abate by reason of the taking effect of Pub. L. 95–95, see section 406(a) of Pub. L. 95–95, set out as an Effective Date of 1977 Amendment note under section 7401 of this title.

MODIFICATION OR RESCISSION OF RULES, REGULATIONS, ORDERS, DETERMINATIONS, CONTRACTS, CERTIFICATIONS, AUTHORIZATIONS, DELEGATIONS, AND OTHER ACTIONS

All rules, regulations, orders, determinations, contracts, certifications, authorizations, delegations, or other actions duly issued, made, or taken by or pursuant to act July 14, 1955, the Clean Air Act, as in effect immediately prior to the date of enactment of Pub. L. 95–95 [Aug. 7, 1977] to continue in full force and effect until modified or rescinded in accordance with act July 14, 1955, as amended by Pub. L. 95–95 [this chapter], see section 406(b) of Pub. L. 95–95, set out as an Effective Date of 1977 Amendment note under section 7401 of this title.

MODIFICATION OR RESCISSION OF IMPLEMENTATION PLANS APPROVED AND IN EFFECT PRIOR TO AUG. 7, 1977

Nothing in the Clean Air Act Amendments of 1977 [Pub. L. 95–95] to affect any requirement of an approved implementation plan under this section or any other provision in effect under this chapter before Aug. 7, 1977, until modified or rescinded in accordance with this chapter as amended by the Clean Air Act Amendments of 1977, see section 406(c) of Pub. L. 95–95, set out as an Effective Date of 1977 Amendment note under section 7401 of this title.

SAVINGS PROVISION

Section 16 of Pub. L. 91–604 provided that:

''(a)(1) Any implementation plan adopted by any State and submitted to the Secretary of Health, Education, and Welfare, or to the Administrator pursuant to the Clean Air Act [this chapter] prior to enactment of this Act [Dec. 31, 1970] may be approved under section 110 of the Clean Air Act [this section] (as amended by this Act) [Pub. L. 91–604] and shall remain in effect, unless the Administrator determines that such implementation plan, or any portion thereof, is not consistent with applicable requirements of the Clean Air Act [this chapter] (as amended by this Act) and will not provide for the attainment of national primary ambient air quality standards in the time required by such Act. If the Administrator so determines, he shall, within 90 days after promulgation of any national ambient air quality standards pursuant to section 109(a) of the Clean Air Act [section 7409(a) of this title], notify the State and specify in what respects changes are needed to meet the additional requirements of such Act, including requirements to implement national secondary ambient air quality standards. If such changes are not adopted by the State after public hearings and within six months after such notification, the Administrator shall promulgate such changes pursuant to section 110(c) of such Act [subsec. (c) of this section].

''(2) The amendments made by section 4(b) [amending sections 7403 and 7415 of this title] shall not be construed as repealing or modifying the powers of the Administrator with respect to any conference convened under section 108(d) of the Clean Air Act [section 7415 of this title] before the date of enactment of this Act [Dec. 31, 1970].

''(b) Regulations or standards issued under this title II of the Clean Air Act [subchapter II of this chapter] prior to the enactment of this Act [Dec. 31, 1970] shall continue in effect until revised by the Administrator consistent with the purposes of such Act [this chapter].''

FEDERAL ENERGY ADMINISTRATOR

''Federal Energy Administrator'', for purposes of this chapter, to mean Administrator of Federal Energy Administration established by Pub. L. 93–275, May 7, 1974, 88 Stat. 97, which is classified to section 761 et seq. of Title 15, Commerce and Trade, but with the term to mean any officer of the United States designated as such by the President until Federal Energy Administrator takes office and after Federal Energy Administration ceases to exist, see section 798 of Title 15, Commerce and Trade.

Federal Energy Administration terminated and functions vested by law in Administrator thereof transferred to Secretary of Energy (unless otherwise specifically provided) by sections 7151(a) and 7293 of this title.

§ 7411. Standards of performance for new stationary sources

(a) Definitions

For purposes of this section:

(1) The term ''standard of performance'' means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

(2) The term ''new source'' means any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.

(3) The term ''stationary source'' means any building, structure, facility, or installation which emits or may emit any air pollutant. Nothing in subchapter II of this chapter relating to nonroad engines shall be construed to apply to stationary internal combustion engines.

(4) The term ''modification'' means any physical change in, or change in the method of

operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.

(5) The term ''owner or operator'' means any person who owns, leases, operates, controls, or supervises a stationary source.

(6) The term ''existing source'' means any stationary source other than a new source.

(7) The term ''technological system of continuous emission reduction'' means—

(A) a technological process for production or operation by any source which is inherently low-polluting or nonpolluting, or

(B) a technological system for continuous reduction of the pollution generated by a source before such pollution is emitted into the ambient air, including precombustion cleaning or treatment of fuels.

(8) A conversion to coal (A) by reason of an order under section 2(a) of the Energy Supply and Environmental Coordination Act of 1974 [15 U.S.C. 792(a)] or any amendment thereto, or any subsequent enactment which supersedes such Act [15 U.S.C. 791 et seq.], or (B) which qualifies under section 7413(d)(5)(A)(ii)[1] of this title, shall not be deemed to be a modification for purposes of paragraphs (2) and (4) of this subsection.

(b) List of categories of stationary sources; standards of performance; information on pollution control techniques; sources owned or operated by United States; particular systems; revised standards

(1)(A) The Administrator shall, within 90 days after December 31, 1970, publish (and from time to time thereafter shall revise) a list of categories of stationary sources. He shall include a category of sources in such list if in his judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.

(B) Within one year after the inclusion of a category of stationary sources in a list under subparagraph (A), the Administrator shall publish proposed regulations, establishing Federal standards of performance for new sources within such category. The Administrator shall afford interested persons an opportunity for written comment on such proposed regulations. After considering such comments, he shall promulgate, within one year after such publication, such standards with such modifications as he deems appropriate. The Administrator shall, at least every 8 years, review and, if appropriate, revise such standards following the procedure required by this subsection for promulgation of such standards. Notwithstanding the requirements of the previous sentence, the Administrator need not review any such standard if the Administrator determines that such review is not appropriate in light of readily available information on the efficacy of such standard. Standards of performance or revisions thereof shall become effective upon promulgation. When implementation and enforcement of any requirement of this chapter indicate that emission limitations and percent reductions beyond those required by the standards promulgated under this section are achieved in practice, the Administrator shall, when revising standards promulgated under this section, consider the emission limitations and percent reductions achieved in practice.

(2) The Administrator may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards.

(3) The Administrator shall, from time to time, issue information on pollution control techniques for categories of new sources and air pollutants subject to the provisions of this section.

(4) The provisions of this section shall apply to any new source owned or operated by the United States.

(5) Except as otherwise authorized under subsection (h) of this section, nothing in this section shall be construed to require, or to authorize the Administrator to require, any new or modified source to install and operate any particular technological system of continuous emission reduction to comply with any new source standard of performance.

(6) The revised standards of performance required by enactment of subsection (a)(1)(A)(i) and (ii)[1] of this section shall be promulgated not later than one year after August 7, 1977. Any new or modified fossil fuel fired stationary source which commences construction prior to the date of publication of the proposed revised standards shall not be required to comply with such revised standards.

(c) State implementation and enforcement of standards of performance

(1) Each State may develop and submit to the Administrator a procedure for implementing and enforcing standards of performance for new sources located in such State. If the Administrator finds the State procedure is adequate, he shall delegate to such State any authority he has under this chapter to implement and enforce such standards.

(2) Nothing in this subsection shall prohibit the Administrator from enforcing any applicable standard of performance under this section.

(d) Standards of performance for existing sources; remaining useful life of source

(1) The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 7410 of this title under which each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source for any air pollutant (i) for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) of this title or emitted from a source category which is regulated under section 7412 of this title but (ii) to which a standard of performance under this section would apply if such existing source were a new source, and (B) provides for the implementation and enforcement of such standards of performance. Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan sub-

[1] See References in Text note below.

mitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.

(2) The Administrator shall have the same authority—

(A) to prescribe a plan for a State in cases where the State fails to submit a satisfactory plan as he would have under section 7410(c) of this title in the case of failure to submit an implementation plan, and

(B) to enforce the provisions of such plan in cases where the State fails to enforce them as he would have under sections 7413 and 7414 of this title with respect to an implementation plan.

In promulgating a standard of performance under a plan prescribed under this paragraph, the Administrator shall take into consideration, among other factors, remaining useful lives of the sources in the category of sources to which such standard applies.

(e) Prohibited acts

After the effective date of standards of performance promulgated under this section, it shall be unlawful for any owner or operator of any new source to operate such source in violation of any standard of performance applicable to such source.

(f) New source standards of performance

(1) For those categories of major stationary sources that the Administrator listed under subsection (b)(1)(A) of this section before November 15, 1990, and for which regulations had not been proposed by the Administrator by November 15, 1990, the Administrator shall—

(A) propose regulations establishing standards of performance for at least 25 percent of such categories of sources within 2 years after November 15, 1990;

(B) propose regulations establishing standards of performance for at least 50 percent of such categories of sources within 4 years after November 15, 1990; and

(C) propose regulations for the remaining categories of sources within 6 years after November 15, 1990.

(2) In determining priorities for promulgating standards for categories of major stationary sources for the purpose of paragraph (1), the Administrator shall consider—

(A) the quantity of air pollutant emissions which each such category will emit, or will be designed to emit;

(B) the extent to which each such pollutant may reasonably be anticipated to endanger public health or welfare; and

(C) the mobility and competitive nature of each such category of sources and the consequent need for nationally applicable new source standards of performance.

(3) Before promulgating any regulations under this subsection or listing any category of major stationary sources as required under this subsection, the Administrator shall consult with appropriate representatives of the Governors and of State air pollution control agencies.

(g) Revision of regulations

(1) Upon application by the Governor of a State showing that the Administrator has failed to specify in regulations under subsection (f)(1) of this section any category of major stationary sources required to be specified under such regulations, the Administrator shall revise such regulations to specify any such category.

(2) Upon application of the Governor of a State, showing that any category of stationary sources which is not included in the list under subsection (b)(1)(A) of this section contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare (notwithstanding that such category is not a category of major stationary sources), the Administrator shall revise such regulations to specify such category of stationary sources.

(3) Upon application of the Governor of a State showing that the Administrator has failed to apply properly the criteria required to be considered under subsection (f)(2) of this section, the Administrator shall revise the list under subsection (b)(1)(A) of this section to apply properly such criteria.

(4) Upon application of the Governor of a State showing that—

(A) a new, innovative, or improved technology or process which achieves greater continuous emission reduction has been adequately demonstrated for any category of stationary sources, and

(B) as a result of such technology or process, the new source standard of performance in effect under this section for such category no longer reflects the greatest degree of emission limitation achievable through application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impact and energy requirements) has been adequately demonstrated,

the Administrator shall revise such standard of performance for such category accordingly.

(5) Unless later deadlines for action of the Administrator are otherwise prescribed under this section, the Administrator shall, not later than three months following the date of receipt of any application by a Governor of a State, either—

(A) find that such application does not contain the requisite showing and deny such application, or

(B) grant such application and take the action required under this subsection.

(6) Before taking any action required by subsection (f) of this section or by this subsection, the Administrator shall provide notice and opportunity for public hearing.

(h) Design, equipment, work practice, or operational standard; alternative emission limitation

(1) For purposes of this section, if in the judgment of the Administrator, it is not feasible to prescribe or enforce a standard of performance, he may instead promulgate a design, equipment, work practice, or operational standard, or combination thereof, which reflects the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any non-

air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. In the event the Administrator promulgates a design or equipment standard under this subsection, he shall include as part of such standard such requirements as will assure the proper operation and maintenance of any such element of design or equipment.

(2) For the purpose of this subsection, the phrase ''not feasible to prescribe or enforce a standard of performance'' means any situation in which the Administrator determines that (A) a pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State, or local law, or (B) the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations.

(3) If after notice and opportunity for public hearing, any person establishes to the satisfaction of the Administrator that an alternative means of emission limitation will achieve a reduction in emissions of any air pollutant at least equivalent to the reduction in emissions of such air pollutant achieved under the requirements of paragraph (1), the Administrator shall permit the use of such alternative by the source for purposes of compliance with this section with respect to such pollutant.

(4) Any standard promulgated under paragraph (1) shall be promulgated in terms of standard of performance whenever it becomes feasible to promulgate and enforce such standard in such terms.

(5) Any design, equipment, work practice, or operational standard, or any combination thereof, described in this subsection shall be treated as a standard of performance for purposes of the provisions of this chapter (other than the provisions of subsection (a) of this section and this subsection).

(i) Country elevators

Any regulations promulgated by the Administrator under this section applicable to grain elevators shall not apply to country elevators (as defined by the Administrator) which have a storage capacity of less than two million five hundred thousand bushels.

(j) Innovative technological systems of continuous emission reduction

(1)(A) Any person proposing to own or operate a new source may request the Administrator for one or more waivers from the requirements of this section for such source or any portion thereof with respect to any air pollutant to encourage the use of an innovative technological system or systems of continuous emission reduction. The Administrator may, with the consent of the Governor of the State in which the source is to be located, grant a waiver under this paragraph, if the Administrator determines after notice and opportunity for public hearing, that—

(i) the proposed system or systems have not been adequately demonstrated,

(ii) the proposed system or systems will operate effectively and there is a substantial likelihood that such system or systems will achieve greater continuous emission reduction than that required to be achieved under the standards of performance which would otherwise apply, or achieve at least an equivalent reduction at lower cost in terms of energy, economic, or nonair quality environmental impact,

(iii) the owner or operator of the proposed source has demonstrated to the satisfaction of the Administrator that the proposed system will not cause or contribute to an unreasonable risk to public health, welfare, or safety in its operation, function, or malfunction, and

(iv) the granting of such waiver is consistent with the requirements of subparagraph (C).

In making any determination under clause (ii), the Administrator shall take into account any previous failure of such system or systems to operate effectively or to meet any requirement of the new source performance standards. In determining whether an unreasonable risk exists under clause (iii), the Administrator shall consider, among other factors, whether and to what extent the use of the proposed technological system will cause, increase, reduce, or eliminate emissions of any unregulated pollutants; available methods for reducing or eliminating any risk to public health, welfare, or safety which may be associated with the use of such system; and the availability of other technological systems which may be used to conform to standards under this section without causing or contributing to such unreasonable risk. The Administrator may conduct such tests and may require the owner or operator of the proposed source to conduct such tests and provide such information as is necessary to carry out clause (iii) of this subparagraph. Such requirements shall include a requirement for prompt reporting of the emission of any unregulated pollutant from a system if such pollutant was not emitted, or was emitted in significantly lesser amounts without use of such system.

(B) A waiver under this paragraph shall be granted on such terms and conditions as the Administrator determines to be necessary to assure—

(i) emissions from the source will not prevent attainment and maintenance of any national ambient air quality standards, and

(ii) proper functioning of the technological system or systems authorized.

Any such term or condition shall be treated as a standard of performance for the purposes of subsection (e) of this section and section 7413 of this title.

(C) The number of waivers granted under this paragraph with respect to a proposed technological system of continuous emission reduction shall not exceed such number as the Administrator finds necessary to ascertain whether or not such system will achieve the conditions specified in clauses (ii) and (iii) of subparagraph (A).

(D) A waiver under this paragraph shall extend to the sooner of—

(i) the date determined by the Administrator, after consultation with the owner or operator of the source, taking into consideration the design, installation, and capital cost of the technological system or systems being used, or

(ii) the date on which the Administrator determines that such system has failed to—

(I) achieve at least an equivalent continuous emission reduction to that required to be achieved under the standards of performance which would otherwise apply, or

(II) comply with the condition specified in paragraph (1)(A)(iii),

and that such failure cannot be corrected.

(E) In carrying out subparagraph (D)(i), the Administrator shall not permit any waiver for a source or portion thereof to extend beyond the date—

(i) seven years after the date on which any waiver is granted to such source or portion thereof, or

(ii) four years after the date on which such source or portion thereof commences operation,

whichever is earlier.

(F) No waiver under this subsection shall apply to any portion of a source other than the portion on which the innovative technological system or systems of continuous emission reduction is used.

(2)(A) If a waiver under paragraph (1) is terminated under clause (ii) of paragraph (1)(D), the Administrator shall grant an extension of the requirements of this section for such source for such minimum period as may be necessary to comply with the applicable standard of performance under this section. Such period shall not extend beyond the date three years from the time such waiver is terminated.

(B) An extension granted under this paragraph shall set forth emission limits and a compliance schedule containing increments of progress which require compliance with the applicable standards of performance as expeditiously as practicable and include such measures as are necessary and practicable in the interim to minimize emissions. Such schedule shall be treated as a standard of performance for purposes of subsection (e) of this section and section 7413 of this title.

(July 14, 1955, ch. 360, title I, § 111, as added Pub. L. 91–604, § 4(a), Dec. 31, 1970, 84 Stat. 1683; amended Pub. L. 92–157, title III, § 302(f), Nov. 18, 1971, 85 Stat. 464; Pub. L. 95–95, title I, § 109(a)–(d)(1), (e), (f), title IV, § 401(b), Aug. 7, 1977, 91 Stat. 697–703, 791; Pub. L. 95–190, § 14(a)(7)–(9), Nov. 16, 1977, 91 Stat. 1399; Pub. L. 95–623, § 13(a), Nov. 9, 1978, 92 Stat. 3457; Pub. L. 101–549, title I, § 108(e)–(g), title III, § 302(a), (b), title IV, § 403(a), Nov. 15, 1990, 104 Stat. 2467, 2574, 2631.)

References in Text

Such Act, referred to in subsec. (a)(8), means Pub. L. 93–319, June 22, 1974, 88 Stat. 246, as amended, known as the Energy Supply and Environmental Coordination Act of 1974, which is classified principally to chapter 16C (§ 791 et seq.) of Title 15, Commerce and Trade. For complete classification of this Act to the Code, see Short Title note set out under section 791 of Title 15 and Tables.

Section 7413 of this title, referred to in subsec. (a)(8), was amended generally by Pub. L. 101–549, title VII, § 701, Nov. 15, 1990, 104 Stat. 2672, and, as so amended, subsec. (d) of section 7413 no longer relates to final compliance orders.

Subsection (a)(1) of this section, referred to in subsec. (b)(6), was amended generally by Pub. L. 101–549, title VII, § 403(a), Nov. 15, 1990, 104 Stat. 2631, and, as so amended, no longer contains subpars.

Codification

Section was formerly classified to section 1857c–6 of this title.

Prior Provisions

A prior section 111 of act July 14, 1955, was renumbered section 118 by Pub. L. 91–604 and is classified to section 7418 of this title.

Amendments

1990—Subsec. (a)(1). Pub. L. 101–549, § 403(a), amended par. (1) generally, substituting provisions defining ''standard of performance'' with respect to any air pollutant for provisions defining such term with respect to subsec. (b) fossil fuel fired and other stationary sources and subsec. (d) particular sources.

Subsec. (a)(3). Pub. L. 101–549, § 108(f), inserted at end ''Nothing in subchapter II of this chapter relating to nonroad engines shall be construed to apply to stationary internal combustion engines.''

Subsec. (b)(1)(B). Pub. L. 101–549, § 108(e)(1), substituted ''Within one year'' for ''Within 120 days'', ''within one year'' for ''within 90 days'', and ''every 8 years'' for ''every four years'', inserted before last sentence ''Notwithstanding the requirements of the previous sentence, the Administrator need not review any such standard if the Administrator determines that such review is not appropriate in light of readily available information on the efficacy of such standard.'', and inserted at end ''When implementation and enforcement of any requirement of this chapter indicate that emission limitations and percent reductions beyond those required by the standards promulgated under this section are achieved in practice, the Administrator shall, when revising standards promulgated under this section, consider the emission limitations and percent reductions achieved in practice.''

Subsec. (d)(1)(A)(i). Pub. L. 101–549, § 302(a), which directed the substitution of ''7412(b)'' for ''7412(b)(1)(A)'', could not be executed, because of the prior amendment by Pub. L. 101–549, § 108(g), see below.

Pub. L. 101–549, § 108(g), substituted ''or emitted from a source category which is regulated under section 7412 of this title'' for ''or 7412(b)(1)(A)''.

Subsec. (f)(1). Pub. L. 101–549, § 108(e)(2), amended par. (1) generally, substituting present provisions for provisions requiring the Administrator to promulgate regulations listing the categories of major stationary sources not on the required list by Aug. 7, 1977, and regulations establishing standards of performance for such categories.

Subsec. (g)(5) to (8). Pub. L. 101–549, § 302(b), redesignated par. (7) as (5) and struck out ''or section 7412 of this title'' after ''this section'', redesignated par. (8) as (6), and struck out former pars. (5) and (6) which read as follows:

''(5) Upon application by the Governor of a State showing that the Administrator has failed to list any air pollutant which causes, or contributes to, air pollution which may reasonably be anticipated to result in an increase in mortality or an increase in serious irreversible, or incapacitating reversible, illness as a hazardous air pollutant under section 7412 of this title the Administrator shall revise the list of hazardous air pollutants under such section to include such pollutant.

''(6) Upon application by the Governor of a State showing that any category of stationary sources of a hazardous air pollutant listed under section 7412 of this title is not subject to emission standards under such section, the Administrator shall propose and promulgate such emission standards applicable to such category of sources.''

1978—Subsecs. (d)(1)(A)(ii), (g)(4)(B). Pub. L. 95–623, §13(a)(2), substituted ''under this section'' for ''under subsection (b) of this section''.

Subsec. (h)(5). Pub. L. 95–623, §13(a)(1), added par. (5).

Subsec. (j). Pub. L. 95–623, §13(a)(3), substituted in pars. (1)(A) and (2)(A) ''standards under this section'' and ''under this section'' for ''standards under subsection (b) of this section'' and ''under subsection (b) of this section'', respectively.

1977—Subsec. (a)(1). Pub. L. 95–95, §109(c)(1)(A), added subpars. (A), (B), and (C), substituted ''For the purpose of subparagraphs (A)(i) and (ii) and (B), a standard of performance shall reflect'' for ''a standard for emissions of air pollutants which reflects'', ''and the percentage reduction achievable'' for ''achievable'', and ''technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environment impact and energy requirements)'' for ''system of emission reduction which (taking into account the cost of achieving such reduction)'' in existing provisions, and inserted provision that, for the purpose of subparagraph (1)(A)(ii), any cleaning of the fuel or reduction in the pollution characteristics of the fuel after extraction and prior to combustion may be credited, as determined under regulations promulgated by the Administrator, to a source which burns such fuel.

Subsec. (a)(7). Pub. L. 95–95, §109(c)(1)(B), added par. (7) defining ''technological system of continuous emission reduction''.

Pub. L. 95–95, §109(f), added par. (7) directing that under certain circumstances a conversion to coal not be deemed a modification for purposes of pars. (2) and (4).

Subsec. (a)(7), (8). Pub. L. 95–190, §14(a)(7), redesignated second par. (7) as (8).

Subsec. (b)(1)(A). Pub. L. 95–95, §401(b), substituted ''such list if in his judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger'' for ''such list if he determines it may contribute significantly to air pollution which causes or contributes to the endangerment of''.

Subsec. (b)(1)(B). Pub. L. 95–95, §109(c)(2), substituted ''shall, at least every four years, review and, if appropriate,'' for ''may, from time to time,''.

Subsec. (b)(5), (6). Pub. L. 95–95, §109(c)(3), added pars. (5) and (6).

Subsec. (c)(1). Pub. L. 95–95, §109(d)(1), struck out ''(except with respect to new sources owned or operated by the United States)'' after ''implement and enforce such standards''.

Subsec. (d)(1). Pub. L. 95–95, §109(b)(1), substituted ''standards of performance'' for ''emission standards'' and inserted provisions directing that regulations of the Administrator permit the State, in applying a standard of performance to any particular source under a submitted plan, to take into consideration, among other factors, the remaining useful life of the existing source to which the standard applies.

Subsec. (d)(2). Pub. L. 95–95, §109(b)(2), provided that, in promulgating a standard of performance under a plan, the Administrator take into consideration, among other factors, the remaining useful lives of the sources in the category of sources to which the standard applies.

Subsecs. (f) to (i). Pub. L. 95–95, §109(a), added subsecs. (f) to (i).

Subsecs. (j), (k). Pub. L. 95–190, §14(a)(8), (9), redesignated subsec. (k) as (j) and, as so redesignated, substituted ''(B)'' for ''(8)'' as designation for second subpar. in par. (2). Former subsec. (j), added by Pub. L. 95–95, §109(e), which related to compliance with applicable standards of performance, was struck out.

Pub. L. 95–95, §109(e), added subsec. (k).

1971—Subsec. (b)(1)(B). Pub. L. 92–157 substituted in first sentence ''publish proposed'' for ''propose''.

EFFECTIVE DATE OF 1977 AMENDMENT

Amendment by Pub. L. 95–95 effective Aug. 7, 1977, except as otherwise expressly provided, see section 406(d) of Pub. L. 95–95, set out as a note under section 7401 of this title.

REGULATIONS

Section 403(b), (c) of Pub. L. 101–549 provided that:

''(b) REVISED REGULATIONS.—Not later than three years after the date of enactment of the Clean Air Act Amendments of 1990 [Nov. 15, 1990], the Administrator shall promulgate revised regulations for standards of performance for new fossil fuel fired electric utility units commencing construction after the date on which such regulations are proposed that, at a minimum, require any source subject to such revised standards to emit sulfur dioxide at a rate not greater than would have resulted from compliance by such source with the applicable standards of performance under this section [amending sections 7411 and 7479 of this title] prior to such revision.

''(c) APPLICABILITY.—The provisions of subsections (a) [amending this section] and (b) apply only so long as the provisions of section 403(e) of the Clean Air Act [42 U.S.C. 7651b(e)] remain in effect.''

TRANSFER OF FUNCTIONS

Enforcement functions of Administrator or other official in Environmental Protection Agency related to compliance with new source performance standards under this section with respect to pre-construction, construction, and initial operation of transportation system for Canadian and Alaskan natural gas transferred to Federal Inspector, Office of Federal Inspector for the Alaska Natural Gas Transportation System, until first anniversary of date of initial operation of Alaska Natural Gas Transportation System, see Reorg. Plan No. 1 of 1979, eff. July 1, 1979, §§102(a), 203(a), 44 F.R. 33663, 33666, 93 Stat. 1373, 1376, set out in the Appendix to Title 5, Government Organization and Employees. Office of Federal Inspector for the Alaska Natural Gas Transportation System abolished and functions and authority vested in Inspector transferred to Secretary of Energy by section 3012(b) of Pub. L. 102–486, set out as an Abolition of Office of Federal Inspector note under section 719e of Title 15, Commerce and Trade. Functions and authority vested in Secretary of Energy subsequently transferred to Federal Coordinator for Alaska Natural Gas Transportation Projects by section 720d(f) of Title 15.

PENDING ACTIONS AND PROCEEDINGS

Suits, actions, and other proceedings lawfully commenced by or against the Administrator or any other officer or employee of the United States in his official capacity or in relation to the discharge of his official duties under act July 14, 1955, the Clean Air Act, as in effect immediately prior to the enactment of Pub. L. 95–95 [Aug. 7, 1977], not to abate by reason of the taking effect of Pub. L. 95–95, see section 406(a) of Pub. L. 95–95, set out as an Effective Date of 1977 Amendment note under section 7401 of this title.

MODIFICATION OR RESCISSION OF RULES, REGULATIONS, ORDERS, DETERMINATIONS, CONTRACTS, CERTIFICATIONS, AUTHORIZATIONS, DELEGATIONS, AND OTHER ACTIONS

All rules, regulations, orders, determinations, contracts, certifications, authorizations, delegations, or other actions duly issued, made, or taken by or pursuant to act July 14, 1955, the Clean Air Act, as in effect immediately prior to the date of enactment of Pub. L. 95–95 [Aug. 7, 1977] to continue in full force and effect until modified or rescinded in accordance with act July 14, 1955, as amended by Pub. L. 95–95 [this chapter], see section 406(b) of Pub. L. 95–95, set out as an Effective Date of 1977 Amendment note under section 7401 of this title.

§ 7412. Hazardous air pollutants

(a) Definitions

For purposes of this section, except subsection (r) of this section—

APPENDIX C

EXHIBITS

Exhibit A

Case No. 24-1128

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

ELECTRIC GENERATORS FOR A SENSIBLE TRANSITION,

Petitioner,

v.

U.S. ENVIRONMENTAL PROTECTION AGENCY, MICHAEL S. REGAN

Respondents.

On Petition for Review of Final Agency Action
of the United States Environmental Protection Agency

DECLARATION OF MATTHEW B. BALLEW IN SUPPORT OF PETITIONER ELECTRIC GENERATORS FOR A SENSIBLE TRANSITION MOTION TO STAY

I, Matthew B Ballew, declare and state as follows:

1. I am the Director of Innovation Strategy at Vistra Corp. ("Vistra") and am authorized to make this declaration based on my personal knowledge. I support internal and external teams in technology maturation efforts for emerging decarbonization systems. The maturation of Carbon Capture and Sequestration (CCS) technologies is one of Vistra's strategic priorities for ensuring an energy transition focused on maintaining and improving reliability, affordability, and

sustainability. We work with research institutes, universities, transportation and sequestration vendors, and carbon capture technology providers to advance the analysis and design of potential CCS applications at Vistra. In that capacity, I am intimately familiar with EPA's final rule entitled "EPA New Source Performance Standards For Greenhouse Gas Emissions From New, Modified, And Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines For Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; And Repeal Of The Affordable Clean Energy Rule," ("Final GHG Rule") and its impact on Vistra's existing and future operations.

INTRODUCTION

2. I am providing this declaration on behalf of Oak Grove Management Company, LLC ("the company"), one of Vistra's indirect subsidiaries that owns and operates the Oak Grove Power Plant ("Oak Grove"), in support of Petitioner' motion to stay EPA's Final GHG Rule. EPA's Final GHG Rule, if not stayed, will cause significant irreparable harm to the company because it requires the commitment of near-term costs and resources to implement CCS at Oak Grove that would be lost even if Petitioners are successful on the merits.

3. In light of its fast-approaching compliance deadlines, EPA's Final GHG Rule places the company in the untenable position of having to make commitments and expend substantial costs to implement CCS immediately based

upon an EPA rule that has now been challenged by 27 states and numerous other parties, state plans that have not yet been finalized or approved by EPA, and technologies and infrastructure that have not been developed, are not yet available for commercial deployment, and are unaffordable.

4. Such commitments include but are not limited to the soliciting and securing of bids from contractors to perform work, procuring equipment, mobilizing resources and employees, securing approvals for major capital expenditures, applying for and securing the necessary local, state and federal permits and approvals, and communicating and working with numerous stakeholders. The costs of undertaking such near-term activities would likely exceed $10 million dollars per plant if not more. Should EPA's Final GHG Rule later be invalidated, multi-millions in costs would be lost and would not be recoverable.

5. In addition to impacts on existing coal assets, the final rule could stifle the development and construction of newly permitted efficient combined cycle gas turbine plants to serve as much needed replacement baseload capacity for expected coal retirements across the country. For example, the final rule would require new baseload gas-fueled combustion turbines with a capacity factor greater than 40% (which must use combined cycle technology) to achieve 90% capture of CO_2 beginning Jan. 1, 2032. For the same reasons discussed below that apply to Oak Grove, CCS is also currently not adequately demonstrated at scale and if this

technology does not materialize and remains infeasible, the final rule could impede the development of new gas-fueled baseload plants at a time when significantly increased power demand is expected across the country.

VISTRA OVERVIEW AND OUR OPERATIONS IN THE STATE OF TEXAS

6. Vistra is the largest competitive power generator in the United States with a capacity of approximately 41,000 megawatts, or enough to power 20 million homes, operating in all of the major competitive wholesale markets in the country. Because Vistra only operates in wholesale deregulated competitive power markets, we are incentivized to operate as efficiently as possible and offer electricity at the lowest price that will cover our short run marginal costs, which drives down wholesale electricity prices. Unlike some of our peers in regulated markets, we do not operate as a vertically integrated monopoly and cannot recover our costs from ratepayers for costs such as CCS even if that technology was currently adequately demonstrated. Vistra is a leader in the energy transition and expansion with an unyielding focus on reliability, affordability, and sustainability, powered by a diverse portfolio that includes natural gas, nuclear, coal, solar, and battery energy storage facilities. The company continues to grow its zero-carbon resources, operating the second-largest fleet of competitive nuclear power plants in the country, substantial battery energy storage capacity, and a growing number of solar facilities.

7. Vistra subsidiaries own and/or operate approximately 16,000 megawatts (MW) of installed fossil generation capacity in Texas, which includes 4,650 MW of coal. This capacity is located at a total of 50 electric generating units (EGUs) at seventeen sites in Texas. Thirteen units are subject to additional regulation under the final rule, and thus increased compliance costs. Since 2018, Vistra subsidiaries have retired approximately 4,100 MW of coal-fueled generation capacity in ERCOT, including the Monticello, Big Brown, and Sandow power plants, which resulted in the reduction of approximately 24M metric tons CO_2e of annual GHG emissions in Texas.

8. Vistra's entire generating portfolio in Texas is approximately 19,000 MW, which includes 2,400 MW of nuclear generation and 506 MW of solar and battery energy storage. Vistra is also one of the largest wind purchasers in Texas. Vistra subsidiaries employ approximately 3,715 full-time employees and contracts with independent contractors to work at the company's facilities in Texas. Vistra and its subsidiaries spend approximately $2 billion annually in the form of salaries, taxes, fuel, maintenance, and other operating and capital expenditures, and its impact on gross state product and gross domestic product is substantial.

9. Vistra agrees that climate change is an issue that must be addressed collectively, with all participants doing their part to reduce their environmental footprint, and we have committed to combating climate change through, most

importantly, the reduction of 60% of our Scope 1 and Scope 2 CO_2e emissions by 2030, compared to a 2010 baseline, and achieving net zero carbon emissions by 2050. Vistra is well on its way to meeting that 60% reduction target having already achieved 80% of those targeted reductions (equivalent to annual reduction of more than 85 million metric tons) by the end of 2023. Since 2010, Vistra and its subsidiaries have retired or announced the retirement of more than 19,000 megawatts at 23 coal and natural gas plants. We also believe that the transition to zero carbon emissions should take place in an orderly fashion, accounting for the reliability needs of the states in which we operate and the affordability needs of our customers.

THE COMPANY'S OAK GROVE PLANT

10. In 2010, construction of the Oak Grove Power Plant was completed near Franklin, Texas. The plant includes two 800-MW coal-fired units featuring first-of-a-kind environmental controls. In addition to its state-of-the-art environmental controls that reduce NO_X emissions, SO_2 and PM, Oak Grove is the nation's first pulverized coal plant fueled by lignite to utilize new activated carbon sorbent injection technology to remove mercury. Units 1 and 2 at Oak Grove generate enough electricity to power 850,000 Texas homes on a typical summer day.

11. Because Units 1 and 2 operate nearly all of the time and are not expected to retire before January 1, 2039, they would be subject to the requirements applicable to "long term" existing units under EPA's Final GHG Rule. Such

requirements include an emission rate limit based on application of CCS with 90% capture by January 1, 2032. CCS consists of three primary components: (1) capturing CO_2 produced by power generation; (2) transporting that CO_2 by pipeline or other means; and (3) storing the CO_2 in deep underground injection control wells at a sequestration site. As I understand it, CCS with 90% capture has not been consistently demonstrated at any electric generating unit in the world. The scale of a CCS plant at Oak Grove to achieve 90% capture would be an order of magnitude larger than the two demonstration plants currently using CCS. Moreover, there are no existing CO_2 pipelines to transport any captured CO_2 from Oak Grove and it appears that the nearest existing sequestration site is over 800 miles away in Macon County, IL, of which a pipeline to this location from Oak Grove would be expected to cost $1-2B. That site does not have near enough capacity to store Oak Grove's CO_2, much less CO_2 from other power plants in the United States.

12. Despite these logistical challenges, the company has been exploring the potential costs associated with installing a carbon capture facility at Oak Grove. We project that these costs alone (i.e., not including the costs associated with transport and sequestration) could exceed $5 billion. That cost would be more than twice what it cost to build the Oak Grove Power Plant. And because carbon capture technology has not been demonstrated at this scale, there is no guarantee that the carbon capture plant would work as required by the rules.

IF NOT STAYED, EPA FINAL GHG RULE WILL RESULT IN IRREPARABLE HARM

13. EPA's Final GHG Rule requires compliance with standards that are based on systems of emission reduction that have not been adequately demonstrated and performance standards that are not achievable. If not stayed, compliance with these requirements will require the company to start making major resource, capital and infrastructure decisions very soon—before the many challenges to EPA's Final GHG Rule are resolved in this Court (or ultimately the Supreme Court) and before any state plan is developed, submitted and approved by EPA. This forces the company to expend costs and resources now based upon an EPA rule that is being challenged, state plans that have not been developed, finalized or approved by EPA, and technologies that are not available for commercial deployment.

14. If the Oak Grove units attempted to proceed with CCS with 90% capture, for example, the company would be required to start the process now of seeking approval for the construction and operation of a CCS plant on-site, as well as a CO_2 pipeline to connect Oak Grove to a sequestration site, which would include permitting for a Class VI well. The company would be forced to undertake this effort even though: (1) EPA's Final GHG Rule is subject to numerous challenges in this Court; (2) neither Texas nor any other state has submitted state plans for EPA's approval, as required under EPA's GHG Rule; (3) CCS has not been adequately demonstrated and EPA's performance standards based on CCS are not achievable;

(4) any CO_2 pipeline from Oak Grove would likely have to be sited through numerous local communities in Texas and other states and likely cross major waterways; (5) such a pipeline would likely encounter significant local and national opposition, thereby significantly delaying (if not cancelling) the project; (6) many communities have objected to or adopted moratoriums prohibiting CO_2 pipelines/sequestration sites; and (7) there is no permitted Class VI sequestration site in the country that has the capacity to store Oak Grove's CO_2, even if the units could somehow consistently capture 90%—a level of capture that has yet to be accomplished anywhere for a meaningful length of time.

15. Oak Grove produces 12 to 13 million metric tons of CO_2 per year. The carbon capture systems that EPA relies on in the final rule have only been able to capture between 1 and 1.5 million metric tons per year.

16. Further, installation of CCS would cause reliability concerns because the technologies that the company has researched, none of which are commercially demonstrated, would reduce the output of units 1 and 2 by an estimated 30% to power the CCS process itself and therefore that output would not be available to power the grid. Oak Grove historically operates at a 90% or greater capacity during the hottest months in Texas. There is significant demand expected in Texas for new data center load, electrification of vehicles and increased electric cooling and heating

load, and thus any reduction in generation as a result of the parasitic load[1] for CCS could have significant consequences for the Texas grid, especially given the intermittent nature of any new renewables that are brought online. Simply put, significant reliability issues would be expected if baseload units, like Oak Grove, are required to commit 30% capacity to CCS efforts.

17. These reliability concerns would be exacerbated if units like Oak Grove were required to retire because of an inability to comply with the CCS provisions in the final rule. The Electric Reliability Council of Texas, Inc. recently stated in comments submitted to EPA that "depending on untested and unproven technologies to meet the nation's future electric demand while also forcing the retirement of dispatchable generators presents an unacceptable level of risk to the reliability of the power supply." The process of building a carbon capture plant at Oak Grove would take many years, as there are many phases of developing such a massive project. The technology would need to be studied to understand the design parameters and associated risks to get to the pilot demonstration stage. After that stage, the company would need to build a full-scale first-of-a-kind prototype. Each of these steps is critical to ensure the safety of the facility and would take years to complete. If it were to start this process immediately, the company has estimated that it might be

[1] Parasitic load is amount of electricity that is needed to run the CCS process itself and would not be available to supply electricity to the grid.

able to begin construction on a carbon capture plant in 2032 (the deadline EPA has set for compliance), even with no opposition or permitting delays. With any legal challenges to construction, local opposition or permitting delays, the projected timeline would be much longer. The Final GHG Rule's provision allowing states to provide a compliance date extension of up to one year is a wholly inadequate remedy.

18. Even assuming the company could install an operational plant with 90% capture at Oak Grove by the EPA's deadline, that carbon would need to be transported by CO_2 pipeline to a sequestration site, as discussed above. Such a CO_2 pipeline would give rise to numerous regulatory and permitting challenges, which would result in additional delays or cancellation. Because no workable regulatory framework exists for CO_2 pipelines, such a project would also be subject to a mishmash of complicated federal and state regulatory and permitting requirements—a process that can take many years to complete. Additionally, CO_2 will need to be sequestered in Class VI deep underground injection control (UIC) wells that must ensure the geology in the project area can receive and contain the CO_2 within the zone where it will be injected. The permitting for these wells is very onerous and only 18 permitted wells have been approved in the country.[2] Finally,

[2] Current Class VI Projects under Review at EPA | US EPA

because no adequate sequestration site exists, the company would be proceeding with hope that such a site is one day established before EPA's compliance deadline.

19. Forging ahead and expending such massive resources and tens of millions of dollars in near-term costs in the face of so much uncertainty regarding the validity of the final rule, the provisions of any EPA-approved state plan, and unproven technology and undeveloped infrastructure will inevitably result in significant economic waste, stranded assets and irreparable harm to the company.

20. I declare that the foregoing is true and correct based on current knowledge.

Executed this 23 day of May 2024.

Matthew B Ballew

Matthew B Ballew

Exhibit B

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

ELECTRIC GENERATORS FOR A SENSIBLE TRANSITION, *Petitioner*, v. U.S. ENVIRONMENTAL PROTECTION AGENCY, *Respondent*.	Case No.: 24-1128

DECLARATION OF CHRISTIAN T. BEAM

I, Christian T. Beam, declare as follows:

1. I am executive vice president of Energy Services for American Electric Power. In that role, I oversee AEP's generation, transmission, nuclear, supply chain, procurement, fleet, and safety and health organizations.

2. I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. I have personal knowledge of the facts set forth in this declaration, and if called and sworn as a witness, could and would competently testify to them.

3. Previously, I served as president and chief operating officer of Appalachian Power Company, serving approximately 1 million customers in West Virginia, Virginia, and Tennessee.

4. Prior to that, I was vice president, Projects, Controls and Construction, responsible for all aspects of project management, project controls, commissioning, and construction activities within AEP's Generation organization. I was also managing director, Projects and Construction, from November 2010 to January 2013. In this role I was responsible for project management of AEP's Western fleet, all new generating projects, and the commissioning and construction activities within the Generation organization.

5. My work experiences offer me a unique perspective on the implications of the Greenhouse Gas (GHG) Rule on the entire AEP system.

6. I offer these declarations on behalf of AEP and our operating companies, including Appalachian Power Company, Kentucky Power Company, Public Service Company of Oklahoma, Southwestern Power Company, and Wheeling Power Company, who are all members of Electric Generators for a Reliable Transition. The Clean Power Plan, the precursor to this rule, took several years to litigate. This litigation will surely take as long. Yet, critical decisions about whether to opt into a "retirement" category as a means of compliance with not just the GHG Rule but also EPA's newly revised Effluent Limitations Guidelines (ELG) Rule must be made by the end of next year – 18 months from now, and most likely before the litigation has concluded. As shown herein, without a ruling to stay the GHG Rule pending the outcome of this litigation, AEP will be forced to make commitments that – practically speaking – are irreversible and will impact citizens in all of our states for decades to come, including decisions potentially leading to premature retirement of coal plants and replacement with generation that is neither as reliable nor affordable.

AEP is Proud of its Environmental Progress and Goals

7. AEP is one of the largest investor-owned electric public utility holding companies in the United States. AEP's electric utility operating companies provide generation, transmission and distribution services to approximately 5.6 million retail customers in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. AEP currently employs approximately 17,000 people.

8. AEP's subsidiaries operate an extensive portfolio of assets including approximately 225,000 circuit miles of distribution lines and approximately 40,000 circuit miles of transmission lines, including approximately 2,200 circuit miles of 765 kV lines, the backbone of the electric interconnection grid in the eastern United States.

9. As of December 31, 2023, AEP owns approximately 23,000 MWs of regulated generating capacity – one of the largest complements of generation in the United States.

10. AEP has already made tremendous reductions in all air emissions, including CO_2, and has a goal of net-zero CO_2 emissions by 2045. Even without a GHG rule to mandate reductions, AEP 2023 CO_2 emissions (43M metric tons) were 72% less than in 2005 (152M metric tons). And between 1990 and 2023, AEP reduced SO_2 emissions by 98% and NOx emissions by 96%, while 2023 mercury air emissions have been reduced by 98% from 2001 levels.

11. AEP's climate goals include an 80% reduction of scope 1 GHG emissions by 2030 as compared to 2005 levels and net-zero scope 1 and scope 2 GHG emissions by 2045.[1]

12. AEP – once one of the largest coal-fired generators of electricity in the country – will go from having owned more than 50 coal-fired units located at more than 20 power plant sites,

[1] See AEP's Corporate Sustainability Report, available at https://www.aep.com/investors/ESG .

with over 25,000 MW nameplate generating capacity, in 2005, to just 8 coal-fired units at 5 power plant sites, with just over 6,500 MW nameplate generating capacity, in 2029. Put another way, in 2005, coal was 70% of AEP's nameplate generating capacity. Before the GHG Rule, and without factoring in how it might affect decisions about the retirement of coal plants, AEP was projecting that by 2033, coal would be just 17% of our generating capacity. During this same time, renewable generation has gone from 4% in 2005 to an expected 46% in 2033.

13. Between 2000 and 2021, AEP invested an estimated $9 billion in environmental controls in its coal-fueled generating fleet. These investments resulted in significant reductions in emissions and were made in compliance with environmental regulations. The investments we make in the electric power system are long-term investments, made after review and approval by regulatory commissions that ensure the investments are sound and make sense in light of the anticipated operating life of a unit.

14. More recently, since 2016, AEP has spent over $460 million at the Amos, Flint Creek, Mitchell, Mountaineer, and Turk plants to comply with environmental regulations targeting the electric utility industry, including – to date -- $315 million on the ELG Rule[2] and $110 million on the Coal Combustion Residuals (CCR) Rule,[3] so that these 5 coal-fired power plants can continue to operate and provide reliable power into the future. These expenditures were approved by regulators based on the premise that the plants would be in operation for some time to come.

15. On April 25, 2024, EPA announced not only the new GHG Rule, but three other major rules targeted at the electric utility industry – revisions to the Mercury Air Toxics Standards (MATS) Rule, the Effluent Limitation Guidelines (ELG) Rule, and the Legacy Coal Combustion Residuals (CCR) Rule.

16. While each of these new regulations purports to address a specific air, water or waste issue, the rules taken as a whole demonstrate in no uncertain terms a policy choice by EPA to force electric generation away from fossil fuels and towards renewable resources. EPA is dictating energy policy by purporting to offer compliance options that, upon closer examination, offer only one viable option – the early retirement of coal-fired generation with a shift to natural gas or renewables.

17. At the same time that AEP is facing significant load growth, with over 100,000 MW of new load expected in the near term, AEP still has an obligation to reliably serve all customers located in our service territories. Meeting the substantial load growth needs would be challenging even without the GHG Rule; with the GHG Rule, the challenges of providing reliable and affordable energy are magnified.

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[2] The ELG Rule establishes wastewater discharge standards that apply to coal-fired power plants. See 40 CFR Part 243.

[3] The CCR Rule is establishes requirements for the management and disposal of coal combustion residuals (coal ash) from power plants. See 40 CFR Part 257, subpart D.

18. In light of this, AEP has serious concerns about the impacts of the GHG Rule on grid reliability and our ability to meet growing demand for affordable, reliable electricity. For the reasons set forth below, AEP will be concretely and irreparably harmed if the GHG Rule is not stayed pending this litigation.

AEP has Obligations as both a Public Utility and a Load-Serving Entity in Regional Transmission Organizations

19. The Federal Power Act prioritizes reliability of the supply of electricity. Section 215(b) grants the Federal Energy Regulatory Commission jurisdiction over "all users, owners, and operators of the bulk-power system" for "purposes of approving reliability standards" and enforcing such standards.[4]

20. The Federal Power Act also requires that wholesale energy and transmission rates be "just and reasonable."[5]

21. State regulatory agencies in each of our states oversee the delivery of electricity to ensure that the service is just and reasonable.

22. Regional Transmission Operators (RTOs) and/or Independent System Operators (ISOs) are independent, membership-based, non-profit organizations that coordinate, control, and monitor the electric grid to support reliability. AEP operates within the PJM Interconnection, L.L.C. (PJM), the Midcontinent Independent System Operator (MISO), the Southwest Power Pool (SPP) and the Electric Reliability Council of Texas (ERCOT) RTOs/ISOs.

23. One way RTOs/ISOs ensure adequate supply of resources to meet peak demand is through required reserve margins. A reserve margin is the amount of unused available capability of an electric power system as a percentage of total capability. For example, a reserve margin of 15% means that an electric system has an excess capacity in the amount of 15% of expected peak demand. Different types of generation are allocated differing amounts of "capacity credit" towards meeting the reliability requirements of the RTO/ISO.

24. The retirement of fossil generation requires the addition of significantly more renewable resources just to maintain the status quo, because 1 MW of solar or wind generation does not carry the same reliability "capacity credit" of 1 MW of fossil generation from the RTO/ISO perspective.

25. For example, PJM assigns an Effective Load Carrying Capability (ELCC) to various types of generation. In PJM, coal fired generation can have a typical ELCC rating of 84% – meaning it is available to provide electricity roughly 84% of the time, taking maintenance and other outages into account when the generation is not available. Therefore, a 1000 MW coal plant counts for about 840 MW towards reliability needs of the system (1000 X 84% = 840 MW). Natural gas

[4] See 16 U.S. Code § 824o.
[5] See 16 U.S. Code § 824d.

fired combustion turbines can have a typical ELCC of 62%. On the other hand, on-shore wind has an ELCC of 35% and single-axis tracking solar panels may have an ELCC of only 14% depending on location. This means is that you would need 2400 MW of on-shore wind (ELCC of 35%) to replace that same 840 MW (2400 X 35% = 840 MW). If you assume that 1000 MW coal plant is replaced by tracking solar with a 14% ELCC rating, you get 6000 MW (840/.14 = 6000 MW). Meaning, 6000 MW of tracking solar is needed to replace 1000 MW of coal from a reliability perspective and this does not fully address service during night time and early morning peak demands.

26. In PJM and other RTOs, renewable resources are expected to receive even less capacity credit towards reliability going forward as penetration increases.[6] Consequently, dispatchable generation is always going to be required to support the supply of electricity "at the flip of a switch," day or night, and not just when renewables are available. Multiple MWs of renewable generation are needed to replace each MW of dispatchable, fossil-fired generation to maintain reliability. The system must always be balanced, meaning until there is a solution for storage, we must make what is consumed in real time.

27. While storage, such as batteries, can be part of the solution to providing this dispatchable power, the magnitude of the scale and costs of these resources, which themselves produce no energy, are not a reasonable sole replacement option for the on-call generation benefit that fossil resources provide.

28. The RTOs are already recognizing reliability concerns – even without the impacts of the GHG Rule. SPP, in a statement on the GHG Rule, notes "SPP is not expressing these concerns about a hypothetical resource adequacy scenario in the future. SPP and other grid operators are currently working to develop planning and operations policies and practices to deal with resource adequacy issues that have already manifested."[7] SPP notes its concerns about resource adequacy were identified before the GHG Rule was finalized, and says that it did not consider the additional at-risk generation that may retire and not be adequately replaced as a result of the GHG Rule. "This outcome would further intensify the need for generating capacity and associated transmission upgrades in the SPP region, likely at a pace and cost unprecedented for the industry."[8]

29. PJM has issued a similar statement, which notes, "[t]he Final Rule imposes the most stringent requirements on new gas and existing coal units that operate as baseload units. Although EPA has focused on these units given that they have greater emissions, these baseload units provide a critical reliability role. We are seeing vastly increased demand as a result of new data center load, electrification of vehicles and increased electric heating load. The future demand for electricity cannot be met simply through renewables given their intermittent

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[6] See, for example, PJM preliminary ELCC class ratings through 2034. See https://www.pjm.com/-/media/planning/res-adeq/elcc/preliminary-elcc-class-ratings-for-period-2026-2027-through-2034-2035.ashx

[7] See SPP Statement on the Recent Greenhouse Gas Emission Rule (attached hereto as Exhibit A).

[8] *Id.*

nature. Yet in the very years when we are projecting significant increases in the demand for electricity, the Final Rule may work to drive premature retirement of coal units that provide essential reliability services and dissuade new gas resources from coming online. The EPA has not sufficiently reconciled its compliance dates with the need for generation to meet dramatically increasing load demands on the system."[9]

30. SPP, MISO, PJM and ERCOT all told EPA the same thing in their joint comments on the proposed rule.[10] The reliability concerns are not hypothetical. They are real and they existed before the GHG Rule was finalized. The rule serves to make the situation worse.

31. If LSEs can't provide the capacity that the RTO requires to ensure reliability on peak usage days, there are significant consequences. Using SPP as an example, in the event AEP fails to fulfill its SPP planning reserve margin requirement, AEP and its customers are exposed to significant deficiency charges, potential penalties, and service risks. First, AEP would be subject to a deficiency charge of up to $171,500/MW under the SPP RTO's Open Access Transmission Service Tariff (SPP Tariff). Second, AEP and its customers may be subject to reliability compliance penalties assessed by the North American Electric Reliability Corporation (NERC) to SPP and/or AEP due to the violation of reliability standards. The violation of NERC standards can result in penalties, which can reach up to $1 million per day per violation, a substantial financial burden for any organization. Finally, AEP's customers will be subject to lower levels of reliability including a higher likelihood of being subject to controlled service interruptions to maintain the power balance on the grid and prevent cascading outages across the system.

The Electric Grid is Already Strained

32. Our nation's electric system is under significant strain today. According to NERC, this is especially true for our electric supply.[11]

33. NERC is a not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.

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[9] PJM Statement on the Newly Issued EPA Greenhouse Gas and Related Regulations, available at 20240508-pjm-statement-on-the-newly-issued-epa-greenhouse-gas-and-related-regulations.ashx (attached hereto as Exhibit B)
[10] https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-8207
[11] James B. Robb, "The Reliability and Resiliency of Electric Service in the United States in Light of Recent Reliability Assessments and Alerts," Testimony Before the Senate Energy and Natural Resources Committee, p.2, (June 1, 2023), D47C2B83-A0A7-4E0B-ABF2-9574D9990C11 (senate.gov).

34. In its 2024 Summer Assessment, NERC noted that "[a] large part of North America could be at risk of supply shortfalls during heat waves and extreme summer conditions that can affect generation or wind output or the transmission systems." NERC also noted that Texas, in which AEP provides significant transmission service, is at elevated risk.[12]

35. Reliability constraints are not limited to the summer. In its 2023 Winter Reliability Assessment, NERC found that over the course of the December-February winter period, a large portion of North America was at risk of insufficient electricity supplies during peak periods.[13]

36. In MISO, an area in which AEP operates and which NERC identified as at greater risk of electricity supply shortfalls, in addition to new wind and natural-gas-fired generation, the extension of fossil-fired plants was necessary to increase available resources to help with reliability constraints.[14]

37. NERC is not alone in its assessment. PJM, the RTO governing thirteen states plus the District of Columbia, has also raised concerns about the rapid retirement of dispatchable generation and their fear that the current pace of new generation is not sufficient to keep up with expected retirements. [15] PJM went so far as to say that, "For the first time in recent history, PJM could face decreasing reserve margins should these trends continue."[16]

For Existing Generation in an Already Constrained System, The Rule Requires That Companies Choose Between Unreasonable Compliance Alternatives on an Unrealistic Timeframe, Further Jeopardizing Reliability and Increasing Costs

38. As the President and CEO of NERC testified before Congress last year, "[m]anaging the pace of change is the central challenge for reliability. The rapid evolution of the generation resource mix is altering the operational characteristics of the grid. Through the transition... [u]ntil energy, capacity, and essential reliability services are fully replaced, the retirement of traditional units must be managed."[17]

39. Despite this warning, the GHG Rule does the opposite – it will essentially force early retirements of reliable "traditional units."

40. Under the rule, existing coal-fired power plants must elect to either (a) install CCS and capture 90% of their CO_2 emissions by 2032, (b) reconfigure units to cofire 40% natural gas by 2030 and retire by 2039, (c) convert to 100% gas firing by 2030, or (d) make no modifications

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[12] NERC, "2024 Summer Reliability Assessment," NERC_SRA_Infographic_2024.pdf.
[13] NERC, "2023 Winter Reliability Assessment," p.5, Report (nerc.com).
[14] *Id.*
[15] PJM, Inc., "Energy Transition in PJM: Resource Retirements, Replacements, and Risks (Feb. 24, 2023), p.2, energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx.
[16] *Id.*
[17] Robb testimony, p. 8.

and retire before 2032. Whatever compliance strategy is chosen has its own obstacles to completion within the allotted timeframe.

41. Absent a stay, the rule becomes effective on July 8, 2024, setting in motion the process of state plan development. State submissions are due by 2026 and EPA has indicated that approval of State Plans is expected by 2027. However, EPA's track record of approving SIP revisions shows that a one-year approval of a state plan (let alone 50 state plans!) is quite ambitious and much quicker than typical SIP submission approvals.[18] Until state plans are developed and approved, utilities won't know with certainty what their legal obligations are in each state. Thus, AEP is faced with a difficult choice. AEP can wait until there is certainty surrounding the state plan, in which case we likely cannot make regulatory filings to seek approval for and recovery of costs associated with compliance until 2027 at the earliest. Alternatively, AEP must proceed to incur those costs – significant costs – at risk, without knowing the final requirements of the state plans and whether EPA will approve them, and without assurance that a regulatory commission will authorize recovery of those costs through rates. If AEP incurs millions or billions of dollars in costs in pursuit of requirements to comply with the GHG rule and those requirements are later vacated by the court, a commission could very well conclude we shouldn't have based our spending decisions on state plan requirements that weren't final. Yet to meet the compliance deadlines of the GHG Rule, we will have no choice but to do just that. A stay is needed so that we don't have to make consequential decisions of this magnitude before we have certainty around the requirements that must be met.

42. To further complicate matters, for all of our coal plants, more than one state has a say in the regulatory process. Our Amos and Mountaineer Plants are regulated by both the Virginia and West Virginia Public Service Commissions. Our Mitchell Plant is co-owned by two operating companies – Kentucky Power and Wheeling Power -- and is regulated by the Kentucky Public Service Commission and the West Virginia Public Service Commission. In SWEPCO, three different states – Texas, Louisiana, and Arkansas – have a say in what we can ultimately do and seek recovery for at our Flint Creek and Turk plants. Any compliance decisions we make before the state plans are finalized and without commission approval – decisions that may cost billions of dollars – are done at risk and subject to scrutiny and disallowance by multiple state regulatory commissions. If we wait for regulatory approval, we are likely to have less than 5 years to implement compliance strategies under the rule.

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[18] In fact, according to a 2021 report by the EPA Office of Inspector General, as of January 1, 2021, approximately 39 percent of the 903 active state implementation plan submittals awaiting EPA action were considered backlogged. See https://www.epa.gov/sites/default/files/2021-06/documents/_epaoig_20210614-21-e-0163__0.pdf For purposes of the report, a submittal is considered backlogged when it is not acted upon by the EPA with 12 months from the date of the completeness determination. Thus, there is a very real likelihood that state plans won't be approved until sometime after 2027.

43. AEP can't make decisions about compliance with the GHG Rule in a vacuum. EPA's other recently adopted rules must also be taken into consideration. In particular, the ELG Rule requires companies to decide, by December of 2025, whether to install costly Zero Liquid Discharge (ZLD) technology or retire by 2034. This ELG rule decision-point essentially accelerates the GHG Rule's retirement decision timeline by several years to coincide. In other words, when ELG and GHG rule requirements are both taken into consideration, companies must decide whether to retire coal plants or not by the end of next year – a mere 18 months from now. These decisions must be made before we know how each state will implement the GHG Rule in its state plan, or in all probability, before we can ascertain whether the regulatory commissions will approve recovery of costs associated with such decisions.

44. If, in order to comply with the ELG Rule, a coal plant elects to install ZLD – which is estimated to cost approximately $120 million per site, -- it must do so by December 31, 2029, and even then – because of the requirements of the GHG Rule – it could only operate that plant until 2032, unless it also installs CCS.

AEP Cannot in Good Faith Pursue CCS as a Compliance Option Because 90% CCS is Not a Proven Technology That Can Be Deployed at Utility Scale by 2032

45. AEP, perhaps more than any other utility in the United States, is uniquely qualified to speak about the challenges inherent in deploying CCS to reduce CO_2 emissions. AEP has first-hand experience with development and demonstration of the technology in an integrated configuration at a coal-combustion power plant. CCS is a promising technology, but significant development challenges remain that will require years – perhaps decades - to resolve. A comprehensive review of those challenges, coupled with experiences of private and public entities developing the technologies, reveals that CCS has yet to be demonstrated as the BSER.

46. CCS development challenges include technical, financial, regulatory, legal and practical concerns related to each of the capture, transport, and storage aspects of the process. Even though much investment has gone into advancement of CCS technologies, these technologies have not yet been demonstrated to be viable for reducing CO_2 emissions at fossil fueled power plants. Simply put, there exists not a single coal or gas power plant in operation today in the US with integrated CCS capturing and permanently sequestering 90% of the CO_2 produced by that plant. Not one! At the current pace of development, CCS is not likely to be adequately demonstrated as a viable control option, if at all, for many years.

47. AEP's Appalachian Power Operating Company undertook a carbon sequestration demonstration project at our Mountaineer plant from 2007 – 2011, with geologic evaluations and other preparatory working starting in 2003. While AEP did successfully deploy a CO_2 capture system on a validation scale slip-stream process, that represented only a 20 MW electric equivalent, or 1.5% of the Mountaineer Plant's 1,300 MW capacity. AEP did not construct or operate a full-scale capture CCS system.

48. Over the course of nearly a decade working on the CCS project, we learned that the practical considerations of trying to deploy CCS alone are sufficient to support our claims that CCS is not currently the BSER (i.e., demonstrated and achievable) and cannot be deployed by 2032, as the rule requires. CCS requires the construction of an entirely new chemical plant to capture CO_2, the development of a pipeline to transport CO_2, and the identification and evaluation of areas suitable for sequestration, followed by the acquisition of property rights from hundreds of people and the issuance of controversial injection permits – all within 5 years or less, based on the state plan development timelines outlined above. Preliminary assessments indicate that CCS compliance costs for an individual coal plant alone could easily be several billion dollars.

49. Based on our experiences with the Mountaineer CCS demonstration project, which we have shared extensively with EPA in comments on the proposed GHG Rule and prior rulemakings, we have concluded that it is not feasible to meet the Rule's deadline of 2032 to install CCS – or for that matter a 2033 deadline if AEP gets an extension – at any of our plants. In addition, 90% CO_2 capture has never been sustainably achieved anywhere at this scale, and it is highly unlikely to be achieved by 2032. In short, CCS is not an option, and AEP must either convert its existing coal-fired plants to 100% gas by 2030, co-fire 40% natural gas by 2030 and retire by 2039, or shut the plants down by 2032.

Co-Firing with Natural Gas Is Not a Viable Compliance Option Because of the Associated ELG Rule Compliance Obligations

50. Altering existing coal-fired boilers to allow them to co-fire up to 40% natural gas would require a significant investment in not only the gas co-fired retrofit, but also in the aforementioned ZLD compliance costs under the ELG Rule, which the units would still be subject to because coal would still be a fuel source. Additionally, co-firing with gas would provide less flexibility than other dispatchable energy sources.

51. Financially, this option also doesn't appear to make sense because any unit so converted could only operate through 2039, when the GHG Rule would require it to retire. The cost of ZLD to comply with ELG, coupled with the short remaining life of such a plant under the GHG Rule over which to recover the costs of that technology makes the gas co-firing option unreasonable, uneconomical, and not one that would be likely to receive regulatory commission approval.

52. While it is unlikely that we would pursue co-firing given the economics costs with deploying ZLD, if we were to change our mind, that compliance options would require us to be working now to design, engineer, and build out the conversion, including ordering custom designed parts that would have no real value if the court were to vacate the rule and eliminate this requirement. Absent a stay, AEP will be harmed by the outlay of time and money to pursue such an endeavor.

Without a Stay, AEP's Only Realistic Options are Choosing Between 100% Natural Gas Conversion or Retirement of Coal Plants

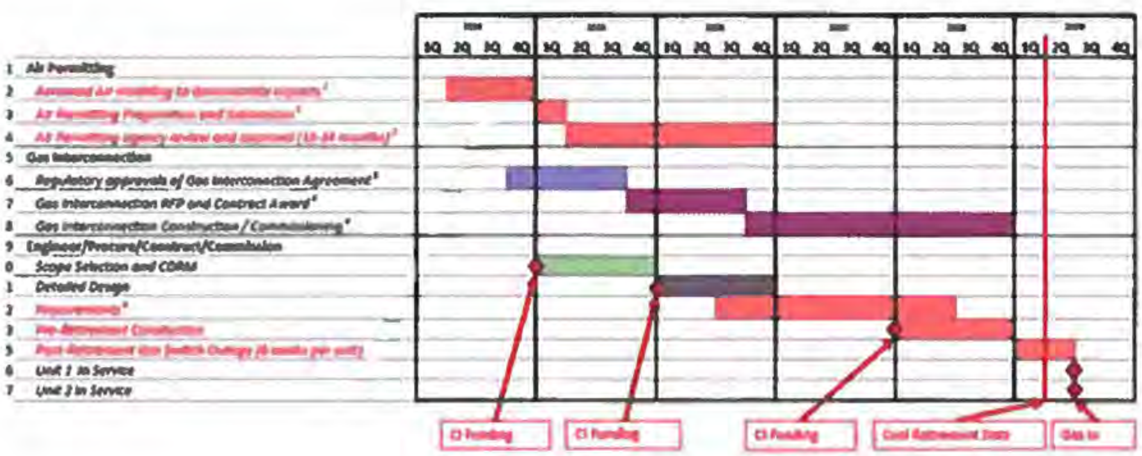
53. If the rule is not stayed, the difficulties inherent in the CCS and co-firing options detailed above leave just two options for compliance at coal plants – conversion to natural gas firing or retirement.

54. Should AEP elect to comply with the rule by retiring coal plants, AEP must start in earnest planning for the construction of a substantial amount of gas-fired generation – be it new construction or conversion of existing coal units to burn gas – because dispatchable coal-fired generation must largely be replaced with dispatchable gas-fired generation in order to maintain reliability and meet fast-growing demand.

55. Converting coal-fired boilers to 100% gas generation will require significant investment in units that would likely have very low capacity factors. Additionally, due to startup and shutdown times, these converted units would decrease grid flexibility to respond to intermittent variable renewable energy supply at a time where more flexibility is needed.

56. Our engineers estimate that converting a coal fired boiler to natural gas will require at least 5 years, under the best-case scenario, where gas is readily available. In order to meet a January 1, 2030, deadline to convert, the physical construction process must begin now, essentially. A timeline from a hypothetical scenario that we previously evaluated – which assumes that work would already be underway by now - shows that air permitting, gas interconnections, engineering, procurement and construction all take significant time and money and – absent a stay, must be happening during the pendency of this litigation if there is any hope of having a converted unit available by the January 1, 2030 deadline.

Timeline for coal to gas conversion



57. Without a stay, AEP must enter into binding contractual agreements with engineers and consultants and purchase custom designed equipment necessary for the conversion, all before the court will have ruled on the legal challenges to the rule. If AEP begins the work to convert a coal plant to gas, and this litigation ultimately results in the rule being vacated, AEP is harmed by having to cancel contracts, which can carry significant penalties, and by having expended significant resources to pursue a technical solution that ultimately is not necessary. AEP cannot later be made whole for these harms.

58. Our engineers' Class IV estimates (-30% to +50% range) of the financial commitment to convert two units to 100% natural gas is approximately $140 Million per unit. That estimate includes engineering and design along with construction and the applicable overheads for all of the "inside the fence" conversion needs. It does not include the cost of constructing a pipeline to supply fuel to the plant or the cost of firm gas transmission. That estimate is roughly $20M per year for 10 years for a total of nearly $200M. This estimate doesn't include costs for any studies for permitting or additional property that may need to be purchased for the installation of a gas yard.

59. A coal plant that converts to natural gas is, in all likelihood, not going to run much. This is because variable dispatch costs tend to go up when switching a given unit from coal to natural gas due to the higher fuel cost, so the dispatch of the unit goes down. This is another example of how the rule forces generation shifting, first from coal to gas, and then again from gas to renewables, by making the costs of providing gas fired generation uneconomical.

60. Moreover, there are opportunity costs associated with pursuing such a conversion. The time and resources that AEP must expend to convert coal fired boilers to gas is time and money that can't be spent pursuing other endeavors – including the development of additional renewable projects. Compliance with the rule during the pendency of the litigation thus hurts AEP in multiple ways.

61. Alternatively, without a stay, by 2026, AEP will need to commit to retire coal plants; that is when state plan development would require AEP to select a compliance category, if not sooner because of the ELG Rule's deadline to make a similar compliance election.

62. A decision to retire a coal plant is a difficult one. In addition to the costs associated with decommissioning the plant at the time of retirement, there are significant up-front costs, including engineering studies to identify and optimize replacement generation and associated transmission needs, and penalties for cancelling coal and other contracts. Here, too, if AEP elects to retire a plant as the means of complying with the GHG Rule, it must incur costs now, during the pendency of the litigation, even though retirement itself would be several years away.

63. Whichever compliance option AEP pursues, AEP will be significantly harmed if the rule is not stayed.

The Rule Significantly Limits our Options for New Dispatchable Generation

64. Under the GHG Rule, new natural gas combustion turbines are categorized as low load (≤20% capacity), intermediate load (between 20% and 40% capacity), and baseload (>40% capacity). Baseload natural gas turbines must install 90% carbon capture and storage (CCS) by January 1, 2032. For reasons detailed elsewhere in this declaration and in our comments in the GHG Rulemaking docket, 90% CCS at a utility scale is not a proven technology that is a viable option by 2032. CCS by 2032 is perhaps even more unrealistic for baseload gas-fired generation than for coal-fired generation, as this technology has not been fully demonstrated at a gas-fired plant to date. Thus, absent a stay, there is no scenario in which AEP would be able to build a new, baseload natural gas turbine and achieve the CO_2 standard in the final rule.

65. In evaluating options since the rule was finalized, AEP has realized that only a very few of the currently available combustion turbine models available from the limited universe of manufacturers can meet the presumptive BSER emission rates for intermediate load turbines – and then, it is only under ideal, steady state operating conditions that do not represent the range of operating conditions that the units will reasonably experience over their lifetime. The vast majority of turbines on the market currently simply can't meet the rule's CO_2 emission limits. Yet, utilities that need to acquire dispatchable generation to ensure reliability and meet load growth must place orders now if they hope to get any new turbines built and delivered in time to meet anticipated demand. Based on our recent experiences, any turbines we order today – assuming we were in a position to be ready to order something today – would most likely not be in service for 5 – 7 years under the best circumstances. And, as demand for those very few models that might meet the CO_2 standard increases, availability decreases and costs increase.

66. A leading turbine manufacturer with whom we have spoken has confirmed that very few of its machines can meet a 1170 lbs. CO_2/MWhr-gross limit – even when assuming ideal steady state conditions at full load, which is when these turbines are most efficient. As you move away from full load, you lose efficiency and emissions will begin to exceed the target. We expect to hear similar statements from the other manufacturers with whom we plan to meet.

67. Therefore, despite EPA's public statements that it backed away from including hydrogen co-firing as a BSER pathway in the final rule, the reality is that, for the vast majority of combustion turbines readily available in the marketplace, the use of hydrogen in addition to natural gas appears to be necessary to ensure the presumptive BSER emission limits can be met when turbines are operated as peaking units that ramp up and down based on need and not as baseload, steady state operation.

68. Despite not "requiring" hydrogen co-firing, EPA notes that sources "may elect to co-fire hydrogen for compliance with the final standards of performance, even absent the technology being a BSER pathway." By setting the emission limits as it has, EPA has essentially mandated hydrogen co-firing without calling it BSER. The problems with this are the same as were noted in our comments on the proposed rule – there is no reliable source for hydrogen production; no

readily available pipeline infrastructure to provide hydrogen to power plant locations across the country, and combustion turbine technology has yet to be developed to support the use of larger blends of hydrogen co-firing so that it can be a significant portion of the fuel mix for our turbine. Developing and permitting hydrogen pipelines is fraught with the same difficulties facing CO_2 pipelines. And onsite storage is impractical given the volumes of hydrogen that would be needed, and the unmanageable number of trucks required for delivery. Further, at the current slow pace of development, it will be many years before these challenges to hydrogen utilization will even begin to be addressed.

69. Because hydrogen isn't available and is unlikely to be available by the time it is needed, AEP cannot commit to purchase new combustion turbines as a means of providing electricity in compliance with the rule based on an assumption that it can combust hydrogen to meet the intermediate load BSER emission limits. Moreover, there is tremendous uncertainty surrounding hydrogen pricing as that market has yet to emerge.

70. Because of the lack of hydrogen supply, transportation and storage infrastructure, and available combustion turbine technology to ensure that the intermediate capacity BSER limits can be met, any new turbines AEP builds will most likely be in the low load category – meaning they would be limited to operating at 20% capacity or less. Units in this low load category are subject to a less stringent limit that can be met. However, as a result of each turbine being limited to 20% capacity or less, AEP would have to commit resources to install multiple new gas generation plants to provide the needed energy – energy that could be provided by a single turbine but for the rule. This is because any new natural gas combustion turbine that operates at more than a 20% capacity factor must co-fire a fuel that is not available - hydrogen - to meet the applicable emission limit and anything operating above a 40% capacity factor must install CCS. As discussed above, neither is a viable compliance option within the timeframe mandated by the rule.

71. Indeed, the rule effectively allows an unlimited number of new gas combustion turbines to be installed without CCS and without hydrogen co-firing if they each operate less than 20% of the time but will not allow one new turbine to operate without CCS for 45% of the time. This approach basically forces gas generation to be uneconomical because of the capacity constraints placed upon individual turbines and the need to install multiple turbines operating at limited capacity. This also demonstrates that the rule is not about the actual emissions at all, but about forcing a policy that favors renewables over fossil fuels, putting grid reliability at significant risk.

72. Electing to build multiple gas-fired turbines, with each limited to operating only a fraction of the time, is an inefficient utilization of gas for generation, is not a cost-effective development strategy, and will be a difficult decision to justify to our state regulatory commissions. This will needlessly increase costs for ratepayers. And, because the demand for new turbines is already expected to grow, this artificial increase in demand resulting from the need to purchase multiple turbines subject to capacity limitations when, but for the rule, one

could deliver the energy needed will only make it harder to get enough turbines in place and operational in a timely manner to ensure uninterrupted power.

73. Additionally, if multiple turbines must be built to provide replacement generation, each additional turbine introduces an increased risk of encountering manufacturing issues, site-specific problems, delays, etc. such that the overall risk of meeting required in-service date increases.

74. Even with all of the uncertainties described, if AEP elects to install new gas turbines to either replace retiring coal generation or meet growing demand, AEP must enter into contracts now to secure a spot in the production queue for the limited models of new turbines that might be able to meet the presumptive BSER limits. AEP must do so before the states have even developed their state plans and without knowing what the approved state plan requirements will be.

75. Any new turbines will face long interconnection wait times if they can't repurpose existing interconnections to the grid. A typical interconnection time in recent experience has been several years. Those interconnection delays are expected to grow as more new generation is added to the grid.

76. Based on our experiences, it would cost approximately $250 million today to purchase a 225 MW turbine that would be limited to 20% capacity factor. It is very likely that these costs will increase as demand for turbines increases as a result of this rule. If we proceed down a path to ordering multiple new combustion turbines and the court ultimately reverses the GHG Rule, we will face significant penalties to cancel the contracts, or we will have committed to purchasing significantly more generation that we need. Any expenses incurred for design and engineering, permitting, or legal support not included in the purchase agreement will simply be lost and rate recovery for such expenses is doubtful.

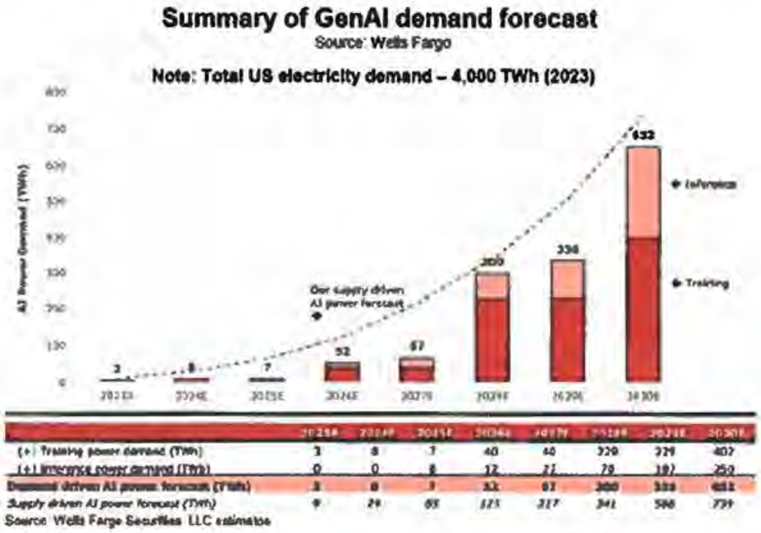
Load Growth Issues and Opportunities

77. At the same time that EPA has finalized the GHG Rule, the United States is experiencing power demand growth not seen in a generation. For the first time in two decades, demand for power is rapidly increasing, and in some areas is outpacing available capacity. Power demand from artificial intelligence (AI), data centers, manufacturing, cryptomining and large industrial customers is expected to double in three years.[19]

78. Not only are the number of data centers increasing, but each data center is also growing bigger. Prior to 2021, the electricity demand from a large data center was approximately 200 MW; today it is 1,000 MW or greater. This is because the rising use of AI in various sectors is increasing the overall power demand of data centers. For example, a typical Google search uses

[19] *See* https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/datacenter-power-demand-to-double-in-three-years-8211-iea-80123428.

0.3 watt-hours of electricity, while OpenAI's ChatGPT requires 2.9 watt-hours for a request—nearly ten times more power. Assuming 9 billion searches daily, this would require almost 10 TWh of additional electricity in a year.[20] As the chart below illustrates, the power demand for AI will grow 80-fold, from 8 TWh in 2024 to 652 TWh by the beginning of the next decade.21 To put that into perspective, 652 TWh is more energy than is used today by 60 million homes in a year.



79. Finally, it should be noted that this growth is not isolated to only one part of the country. The PJM Interconnection in its most recent long-term load forecast predicted summer peak demand to increase by roughly 28GW by 2034 and 42GW by 2039 compared to 2024 levels.[22] ERCOT, the regional transmission organization that serves most of the state of Texas, is also predicting significant demand growth – approximately an additional 70 GW in demand by the end of this decade, nearly doubling the demand in the entire region.[23]

80. In some instances, the demand of new customers seeking to interconnect to our system exceeds the total amount of load currently served by AEP in those areas today. For example, AEP has received a combined 108 gigawatts of requests for interconnection in the near-term. This represents over 10 percent of the peak electricity demand in the entire United States.

81. Currently, the amount of load requesting to interconnect to AEP's transmission system eclipses the current peak demand of AEP's operating companies in our PJM and ERCOT regions. For AEP's Ohio, Indiana and Michigan utilities, the demand is over three times AEP's current peak load in these three states. AEP's West Virginia and Virginia utilities' demand would more

[20] *See* https://www.datacenterknowledge.com/energy/electricity-demand-data-centers-could-double-three-years.

[21] Terawatt hours, abbreviated as TWh, is a unit of energy representing one trillion-watt hours. The average American home uses 10,791 kilowatt-hours (kWh) of power a year. One TWh is equal to one billion kWh.

[22] *See* PJM Publishes 2024 Long-Term Load Forecast | PJM Inside Lines

[23] ERCOT, 2024 RTP – Load Review Update (March 2024), PowerPoint Presentation (ercot.com)

than double the current load of Appalachian Power Company. Finally, AEP Texas is experiencing demand over five times its current load today.

82. As demand is rapidly increasing, our nation's electricity system is simultaneously transforming to accommodate new forms of energy. The pace of this transformation must not overtake the reliability needs of the system. Even without factoring in many of the large-scale customers seeking to interconnect to the grid, NERC's independent technical assessments find that the risk of electric power supply disruptions are steadily increasing, as discussed above. Unless reliability and resilience are appropriately prioritized, current trends indicate the potential for more frequent and more serious long duration reliability disruptions, including the possibility of national consequence events.

83. As new generation is developed, connecting that generation in vertically integrated states - meaning states where utilities are responsible for the entire flow of electricity from generation to transmission to distribution - can sometimes take five to ten years. Transmission development has been slowing as interconnection requests are increasing. In the early 2010s, for example, the U.S. installed an average of 1,700 miles of new high-voltage transmission miles per year. That has dropped by nearly two-thirds to 645 miles on average in the second half of the decade. Regulatory approvals, siting, permitting, legal challenges and supply chain constraints pose risks to the process of connecting new generation that can have reliability implications.

84. If the GHG Rule is not stayed, the reliability concerns that I have outlined herein are likely to lead to the loss of potential large-load customers, like data centers, and to cause AEP reputational harm as well.

85. Today, new data centers and other large consumers of electricity are seeking to build new facilities within our service territories, as evidenced by the more than 100 gigawatts of requests for interconnection in the near-term referenced above. If AEP is unable to meet demand and reliably serve potential new customers, whether because AEP must shut down existing sources of generation or because AEP is unable to deploy new generation to meet the growing demand, those customers that are considering developing sites within our footprint are likely to locate elsewhere.

86. Indeed, at a May 21, 2024, hearing before the Senate Energy and Natural Resources Committee, one tech company executive testified that part of the reason his company – Micron – located its manufacturing where it did was because of the proximity to a nuclear plant and large scale hydropower that it knew it could rely on to provide energy. "[A]ccess to reliable, affordable energy was a key part of Micron's site evaluation process."[24]

[24] Written Statement of Scott Gatzemeier, Micron Corporate Vice President of U.S. Front End Expansion Before The U.S. Senate Committee on Energy And Natural Resources "Hearing To Examine The Opportunities, Risks, And Challenges Associated With Growth In Demand For Electric Power In The United States," (May 21, 2024), available at 83B9D031-A702-4CD1-A5AC-0E1CCD5A2EF2 (senate.gov).

87. Once a Micron or a Google decides to locate somewhere, that decision is made. Every other location that was considered has lost that opportunity permanently. A decision by the court that vacates the GHG Rule and eliminates the reliability concerns associated with it will come too late and cannot undo this type of harm to AEP. This loss of customers would be irreparable. It would also result in harm to our communities, who lose out on jobs, tax revenue and other benefits associated with the growth of such new business. Finally, it would harm AEP's reputation as a reliable provider of electricity that is able to accommodate growth in its service territory.

While Plant Closures May Not Occur for Several Years, Even Prospective Plant Closures Have Impacts on Employees and Communities

88. Coal-fired power plants require highly skilled employees and provide well-paying jobs. The plants also provide sizable tax revenues and stimulate associated employment in other sectors that support both the plant and its employees. Coal-fired power plants and their employees often are significant supporters of the communities where they are located, and when plants are retired and decommissioned, they can leave a significant economic void.

89. The community impacts of compliance with this rule are perhaps most stark for Appalachian Power Company, which operates 3 coal-fired power plants in West Virginia. A recent study found that our Amos Plant, located in Winfield, WV, generates an estimated $320 million in economic activity, $123 million in labor income and supports 1,246 jobs annually in the region. The Mitchell Plant, located in Moundsville, WV, generates $111 million in economic activity, $35 million in labor income and supports nearly 459 jobs annually in the region. Finally, the Mountaineer plant, located in New Haven, WV, generates $98 million in economic activity, $32 million in labor income and supports 414 jobs annually in the region. Combined, these three plants located within just a few hours of each other represent more than half a billion dollars in economic activity for the State of West Virginia, over 2000 jobs, and almost $200 million in labor income. Shutting down the plants prematurely would have a devastating impact on West Virginia and communities in neighboring states, even before other impacts of the rule, such as higher energy costs and reliability concerns, are taken into consideration.

90. If AEP chooses to retire a coal-fired plant, that decision must be made before December 31, 2025 (if considering the ELG Rule and the GHG Rule together) or by 2026, pursuant to state plan requirements under the GHG Rule. Absent a stay – such a decision would most likely need to be made during the pendency of this litigation. A decision to close a plant will impact our employees and communities, who will need to begin making alternative plans. Employees will face uncertain prospects for employment while the fate of the plant is in limbo during the litigation. Hard questions to be answered include whether they should look for employment elsewhere, including potentially relocating, or risk the chance that the plant will close if the court doesn't vacate the rule. Communities similarly must budget for future years and must

consider uncertain scenarios in which they must identify ways to replace the tax revenues generated by the plant if the plant closes.

91. Even if a plant closure doesn't materialize, without a stay, the employees and the community will have been harmed by the uncertainty and the planning efforts associated with this uncertainty.

Compliance with the Rule Has Negative Impacts on Our Ratepayers

92. In addition to providing reliable power to customers, we must also continue to ensure it is affordable. AEP, in particular, serves a lower income customer base than most other utilities. In fact, our customers are below the national average for household income in ten of the eleven states in which we provide electric service, and in many of those states, our customers are also below the state average for household income.

93. AEP currently has 5 coal plants scheduled to operate well into the future. Retiring those plants by 2032, many years ahead of schedule, in order to comply with the GHG rule, would force us to recover undepreciated plant balance from ratepayers in several states, including Kentucky, West Virginia and Arkansas – some of the poorest states in the country. Indeed, $460 million has been spent at these plants since 2016 to comply with MATS, ELG and CCR so that these plants could continue operating. Retiring these plants because of the compliance obligations of the GHG Rule, just a few years after mandating installation of costly new controls, is a bitter pill for our regulatory commissions and ratepayers to swallow.

94. If plants are forced to retire prematurely, ratepayers are hit twice: once to pay for the undepreciated balance on any plants forced to retire prematurely and then again, to pay for replacement generation. And because of the fact that the infeasibility of CCS and the lack of hydrogen infrastructure means new gas turbines will most likely be capped at 20% capacity factor or less, it is entirely likely that multiple new turbines will need to be purchased to provide the output that a single turbine is capable and designed to produce.

95. Whatever compliance alternative is selected, rates for the average customer in our operating companies that own and operate coal plants would be expected to significantly increase.

AEP is Harmed by the GHG Rule's Implications for OVEC

96. AEP is also directly impacted by the effects of this rule on the Ohio Valley Electric Corporation, or OVEC, of which AEP is a partial owner, with a 43.47 % ownership share. If this rule drives OVEC to premature retirement of its generating facilities, AEP will be faced with having to replace approximately 940 MW of additional capacity and energy currently supplied to AEP by OVEC.

97. AEP references the declaration of J. Michael Brown, Environmental Safety and Health Director for OVEC for a full description of the scenario facing OVEC absent a stay.

Conclusion

98. In conclusion, if this rule is not stayed, AEP must decide if it will retire coal plants, convert them to natural gas, or replace them with new turbines or renewables, and it must make these decisions for multiple plants, across several states, each with unique circumstances and unique challenges, while trying to ensure that sufficient capacity exists to meet customer demand. Each of these choices is fraught with significant risks and requires that financial commitments begin to be made immediately, with no way for AEP to be made whole if successful in this litigation. During this period of uncertainty, AEP must also make decisions about how to meet load growth reliably, including deciding whether to purchase turbines that are likely to require a fuel that is not currently available – hydrogen - to meet the rule's intermediate subcategory emission limits or being forced to buy multiple new turbines that are each artificially limited to operate at low capacity to stay within the rule's low load category. The difficult choices AEP must make in the near term if this rule is not stayed will lead to harm to AEP's customers, communities, employees and shareholders. Everybody uses electricity. This rule increases the costs and reduces the reliability of our service – all in pursuit of a slight acceleration of a climate goal that we have been successfully marching towards on our own, even without the rule. For the foregoing reasons, AEP faces imminent and irreparable harms if the court does not stay the final rule.

I, Christian T. Beam, declare under penalty of perjury, that the foregoing is true and correct. Executed on this 23rd day of May, 2024.

Christian T. Beam
Executive Vice President, Energy Delivery
American Electric Power Company, Inc.

EXHIBIT A

to Declaration of Christian T. Beam

STATEMENT

FOR IMMEDIATE RELEASE

PJM Statement on the Newly Issued EPA Greenhouse Gas and Related Regulations

(Valley Forge, PA – May 8, 2024) – PJM provides this statement concerning the EPA rule on New Source Performance Standards for Greenhouse Gas Emissions and the other EPA regulations promulgated on April 25, 2024.

PJM has the responsibility to ensure both short- and longer-term reliability for the 65 million people we serve in a region spanning 13 states plus the District of Columbia. "Reliability" in this context refers both to the day-to-day work of managing the grid to keep the system in balance as well as ensuring that, looking forward, there are adequate resources available and committed to serve the expected demand for electricity in future years.

Because of these unique responsibilities, PJM and other affected RTOs have been extensively involved in EPA rulemakings dating back to the Mercury and Air Toxics Standards rule promulgated on Dec. 16, 2011. Our role in these rulemakings has been to ensure that, in developing proposed environmental rules, EPA has appropriately taken into account the reliability needs of our respective grids.

Consistent with this past level of involvement, PJM worked cooperatively with MISO, SPP and ERCOT (the RTOs most affected by the EPA rule) to craft a set of detailed comments to EPA raising our collective reliability concerns with EPA's initial proposed greenhouse gas (GHG) rule. Our comments and subsequent meetings with EPA were focused on:

- Educating EPA as to the reliability needs of our respective systems and the potential impact that the then-proposed GHG Rule could have on both day-to-day reliability and resource adequacy; and

- Providing to EPA constructive proposals to help mitigate, from a reliability perspective, potential adverse impacts of the then-proposed Rule with a particular focus on ensuring adequate flexibility within the Rule for grid operators to be able to address both short-term reliability issues and resource adequacy within their regions.

– MORE –

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Noting the RTO Comments, in its Final Rule issued on April 24, 2024, EPA made certain adjustments to its initial proposal. Those adjustments altered the resources impacted by the rule and provided additional tools that can help provide flexibility to address reliability issues. PJM is appreciative of EPA's acknowledgment of the importance of the existing resources to reliability, of the need for more flexibility, and its consideration of the Joint RTO Comments. The specific adjustments that were grounded in the Joint RTO Comments and adopted in the Final Rule included:

- **Treatment of Existing Gas Resources** – Removing existing gas from this rulemaking to be addressed holistically in a separate rulemaking

- **State-Specific Compliance Flexibility –** Availability of flexibility for the states to address reliability issues, taking into account the remaining useful life and other factors that affect needed units

- **Averaging –** Allowing unit owners to average their compliance obligations over multiple units to ensure least-cost compliance

- **Emissions Trading –** Authorizing states to utilize allowance trading to minimize compliance costs and burdens

- **Mass-Based Programs –** Authorizing states to potentially utilize an emissions cap rather than controlling the rate of emissions from each affected unit

- **Short-Term Reliability Mechanisms –** Allowing needed units to operate for emergencies without jeopardizing compliance with the rule

- **Timeline Extensions** – Providing extensions for retiring units needed for reliability and units needing more time to install controls, with state discretion for longer periods

PJM's Continuing Reliability Concerns

Although we appreciate EPA's adoption of certain flexibility measures in response to our proposals, areas of concern remain related to ensuring reliability given the impact of the Final EPA Rule:

- The new rules governing both existing coal and new natural gas are premised on EPA's finding that carbon capture and sequestration (CCS) technology represents the "best" system of emissions reduction, which will be commercially available at a reasonable cost. However, the availability of CCS is highly dependent on local topology, such as salt caverns available to sequester carbon and the availability of a pipeline infrastructure to transport carbon emissions from individual generating plants to CCS sites potentially hundreds of miles away. There is very little evidence, other than some limited CSS projects, that this technology and associated transportation infrastructure would be widely available throughout the country in time to meet the compliance deadlines under the Rule.

– MORE –

- The Final Rule imposes the most stringent requirements on new gas and existing coal units that operate as baseload units. Although EPA has focused on these units given that they have greater emissions, these baseload units provide a critical reliability role. We are seeing vastly increased demand as a result of new data center load, electrification of vehicles and increased electric heating load. The future demand for electricity cannot be met simply through renewables given their intermittent nature. Yet in the very years when we are projecting significant increases in the demand for electricity, the Final Rule may work to drive premature retirement of coal units that provide essential reliability services and dissuade new gas resources from coming online. The EPA has not sufficiently reconciled its compliance dates with the need for generation to meet dramatically increasing load demands on the system.

- The Final Rule is premised on the availability of increased access to natural gas infrastructure to support the Rule's "co-firing with gas" compliance option for existing coal units. The present gas pipeline system is largely fully subscribed. Moreover, given local opposition, it has proven extremely difficult to site new pipelines just to meet today's needs, let alone a significantly increased need for natural gas in the future. The Final Rule, which is premised, in part, on the availability of natural gas for co-firing or full conversion, does not sufficiently take into account these limitations on the development of new pipeline infrastructure.

- EPA has left many issues for development in individual state implementation plans. Although this is appropriate and in keeping with the structure of the Clean Air Act, each of the multi-state RTOs like PJM operate a single dispatch. As a result, states will need to coordinate and work closely together to ensure that the individual state plans work well on a regional basis. As a result, the need for regional coordination of individual State Implementation Plans is more important than ever. PJM values its continued collaboration with the other affected RTOs (MISO, SPP and ERCOT) and looks forward to working with the U.S. EPA, individual states and affected stakeholders as this process continues.

PJM Interconnection, founded in 1927, ensures the reliability of the high-voltage electric power system serving 65 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM coordinates and directs the operation of the region's transmission grid, which includes 88,115 miles of transmission lines; administers a competitive wholesale electricity market; and plans regional transmission expansion improvements to maintain grid reliability and relieve congestion. PJM's regional grid and market operations produce annual savings of $3.2 billion to $4 billion. For the latest news about PJM, visit PJM Inside Lines at insidelines.pjm.com.

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EXHIBIT B

to Declaration of Christian T. Beam

SPP Southwest Power Pool

STATEMENT ON THE RECENT EPA GREENHOUSE GAS EMISSIONS RULE

SPP issues this statement on the final rule the EPA issued on April 25, 2024, regulating greenhouse gas (GHG) emissions from electric generating units under Section 111 of the Clean Air Act (Final Rule).

As a FERC-approved regional transmission organization (RTO), SPP is responsible for maintaining reliability of the bulk electric system in its region covering all or part of 14 states. A key component of SPP's reliability-based responsibilities is assuring that sufficient resources are available when needed to meet expected future demand.

The generating fleet in the SPP region has undergone significant changes in recent years, and SPP has worked to keep pace by adapting its market design, operating processes, and transmission planning practices. Through these adaptations, SPP has facilitated an ongoing transition to carbon-free generation and is supportive of moving further toward a resource mix that reliably reduces emissions as necessary new technology evolves. The SPP region has long been at the forefront of integrating renewable energy, particularly wind generation. In the last decade, SPP has transitioned from a resource fleet that was overwhelmingly made up of traditional generation to a fleet in which wind is the number-one supplier of energy in the SPP region.

SPP's success in integrating significant wind generation has depended largely on having sufficient flexible thermal generation that can be called upon when wind is unavailable. However, the thermal fleet is shrinking. Thermal units are being retired without being adequately replaced, resulting in less total, fuel-assured, ramp-able capacity. Thermal units with these requisite reliability attributes also make up a shrinking percentage of SPP's total available generating capacity, as the growth of variable energy resources is outpacing the addition of new thermal units. The remaining fleet is expected to carry a potentially unsustainable burden of supplying the necessary reliability attributes needed to assure continuous supply of electricity.

SPP sees no slowing in the growth of demand for electricity or in the growth of new load types such as data centers, cryptocurrency mines, and electric vehicle. SPP is concerned that the current pace of new generation development will be insufficient to offset current and projected resource retirement trends and demand increases.

The region has also experienced extreme weather conditions that have impacted SPP's ability to assure energy provision during times when consumers depend the most on continuous supply of electricity. Since Winter Storm Uri in February 2021, during which SPP was forced to interrupt service to customers for short periods of time, Storms Elliott (December 2022) and Heather/Gerri (January 2024) presented similar circumstances. SPP has also experienced extreme heat over the last two summers, contributing to a new summer peak in 2023 that was 10% higher than the one set two summers prior. These challenges underscore the increasing volatility and unpredictability of weather patterns, further highlighting the need for enhanced grid resilience and adaptive strategies to ensure reliable energy provision in the face of such extreme conditions.

As with previous EPA rulemakings, SPP submitted comments to the EPA in the docket for this Final Rule. SPP submitted individual as well as joint comments with other impacted RTOs: Midcontinent Independent System Operator, Inc.; PJM Interconnection, L.L.C.; and Electric Reliability Council of Texas, Inc. SPP also engaged in meetings with EPA staff to discuss issues raised in the comments. SPP's primary goal throughout this engagement was to communicate the trending urgency of resource adequacy in the SPP region and SPP's sincere concerns about maintaining resource adequacy in the face of thermal generation retirement, an otherwise changing resource mix, increasing demand, and extreme weather trends.

SPP acknowledges and expresses appreciation for EPA staff's consideration of the comments and concerns that SPP and other RTOs presented in the docket and subsequent meetings. SPP notes that the Final Rule reflects changes EPA made from its proposed rule, including removing existing gas generation from the Final Rule's scope and including measures that may provide flexibility in dealing with reliability-impacting events. These changes represent a welcome step toward reflecting the importance of system reliability and the role that existing flexible generation plays toward maintaining that reliability.

SPP remains concerned, however, about the impact the Final Rule may have on the region's ability to maintain resource adequacy and ensure reliability in the SPP region. SPP is concerned that limited technological and infrastructure availability and the compliance time frame will have deleterious impacts including the retirement of, or the decision not to build, thousands of MWs of baseload thermal generation. If sufficient flexible thermal resources are not available to play their critical roles in SPP's resource mix, SPP's ability to maintain regional reliability will be directly impacted. The Final Rule's emissions limits for existing coal and new gas generation are based on the EPA's finding that carbon capture and sequestration (CCS) technology is a viable best source of emissions reduction (BSER) in terms of commercial availability and reasonable cost. SPP continues to be concerned that CCS has not yet been adequately demonstrated at the required capture rate, has not been commercially produced at scale, and will not be widely available and practicable at the level needed for the Final Rule's 2032 compliance time frame. Moreover, while the Final Rule contemplates a natural gas co-firing option for existing coal units that choose to retire before 2039, SPP is concerned about the availability of gas infrastructure necessary to adequately utilize that compliance option in that time frame.

SPP is not expressing these concerns about a hypothetical resource adequacy scenario in the future. SPP and other grid operators are currently working to develop planning and operations policies and practices to deal with resource adequacy issues that have already manifested. SPP's recent Loss of Load Expectation (LOLE) study indicated that, by 2029, as much as a 50% winter season Planning Reserve Margin (PRM) could be necessary to maintain a one-day-in-ten-years LOLE. A PRM of that magnitude would require a significant amount of new capacity to be added in a short time frame. It is important to note that this study considered SPP's existing and projected future resource mix without considering the potential impacts of the Final Rule's 2032 deadline for certain emissions limits. In other words, the study and its projected increase in PRM did not consider the additional at-risk generation that may retire and not be adequately replaced in a relatively short time frame resulting from the compliance time frames contained in the Final Rule. This outcome would further intensify the need for generating capacity and associated transmission upgrades in the SPP region, likely at a pace and cost unprecedented for the industry.

SPP will continue its work to maintain resource adequacy and system reliability. As part of that work, SPP will continue to engage with stakeholders, other RTOs, and the EPA in efforts to address the challenges presented by current and projected trends in resource availability and demand growth.

Exhibit C

IN THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

WEST VIRGINIA, et al.,	)
	)
Petitioners,	)
	)
v.	)
	)
U.S. ENVIRONMENTAL PROTECTION AGENCY, et al.,	)
	)
Respondents.	)
	)

DECLARATION OF JOHN T. BRIDSON

I, John T. Bridson, declare that the following statements made by me are true and accurate to the best of my knowledge, information, and belief:

1. I am the Vice President of Generation of Evergy, Inc. ("Evergy" or the "Company"). As Vice President of Generation**,** I oversee Evergy's electricity generation operations, engineering, reliability, and power marketing. I have been in this role since June 2018. Prior to this position, I served as Sr. Vice President Generation and Power Marketing for Westar Energy, Inc. ("Westar") from 2015 to 2018, Vice President Generation at Westar from 2011 to 2014, the Executive Director, Westar Generation from 2010 to 2011, and various Westar generation engineering and plant management roles from 1993 to 2010.

2. If Evergy is required to immediately undertake steps as required in the Environmental Protection Agency's ("EPA") "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired

Electric Generating Units; and Repeal of the Affordable Clean Energy Rule," 89 Fed. Reg. 39,798 (May 9, 2024) ("Rule") while the Rule is litigated, the immediate and substantial impacts to Evergy include, but may not be limited to:

- Accelerating, by over 12 years, retirement decisions for coal-fired units to comply with the Rule, immediately impacting Evergy's Integrated Resource Plan ("IRP"), our regularly updated 20-year regulatory resource planning document;
- Prematurely retiring of approximately 3,983 megawatts ("MW") of coal-fired units, constituting more than 67% of Evergy's coal-fired generating capacity by 2032 due to the length of time required to receive regulatory approval, permit, construct, and commission equipment that would be necessary for affected units to meet natural gas co-firing or carbon capture and storage ("CCS") conversions requiring Evergy to immediately start investing resources in planning for expedited replacement of generating sources;
- Prematurely retiring the coal-fired units will also cause the loss of nearly 650 full-time jobs by 2032 at the time of premature shuttering combined with the more immediate impact of inability to attract and maintain qualified plant employees when job elimination is imminent due to premature retirement; and
- Prematurely retiring the coal-fired units will result in insufficient generation resources to comply with the minimum reserve margin due to the risk of timely replacement generation installation requiring Evergy to immediately attempt to negotiate contracts for dispatchable resources in a capacity and energy constrained economic environment.

3. It takes many years to plan and implement changes to our generating and transmission resources, Evergy would have to begin activities immediately regardless of the specifics of

any state plan later adopted to implement the Rule. Many of these impacts cannot be reversed once the changes to the generating and transmission resources have begun.

4. I provide this declaration in support of our Motion to Stay EPA's Rule. This declaration is based on my personal knowledge of facts and analysis conducted by Evergy staff and me.

Evergy

5. Evergy is a public holding company incorporated in 2017 and headquartered in Kansas City, Missouri. Evergy operates primarily through the following wholly-owned subsidiaries listed below.

    - Evergy Kansas Central, Inc. is an integrated, regulated electric utility and provides electricity to customers in the state of Kansas. It has one active wholly-owned subsidiary with significant operations, Evergy Kansas South, Inc.
    - Evergy Metro, Inc. is an integrated, regulated electric utility that provides electricity to customers in the states of Missouri and Kansas.
    - Evergy Missouri West, Inc. is an integrated, regulated electric utility that provides electricity to customers in the state of Missouri.

    The subsidiaries conduct business in their respective service territories using the name Evergy. Evergy serves approximately 1.7 million customers located in Kansas and Missouri. Customers include approximately 1.5 million residences, 0.2 million commercial firms, and 7,800 industrials, municipalities and other electric utilities.

6. The core tenets of Evergy's strategy are as follows:

    - Affordability – operating the business cost-effectively and investing in technology and infrastructure to keep rates affordable and improve regional rate competitiveness, mitigating fuel and purchased power volatility by investing in a diverse generation fleet;

- Reliability – targeting transmission and distribution infrastructure investment to support reliability, flexibility, public safety, and resiliency; deploying new technology to improve preventive maintenance and customer restorations times; and
- Sustainability – investing at sustainable capital expenditure levels to maintain reliability and customer affordability for the long-term and balancing clean energy investment to continue fuel diversification and enable a responsible generation portfolio transition.

7. Evergy's total capacity by fuel type, including both owned generating capacity and power purchase agreements, is as follows:

    - Coal: 5,930 MW (38%)
    - Wind: 4,525 MW (29%)
    - Natural Gas and Oil: 4,065 MW (26%)
    - Uranium: 1,106 MW (7%)
    - Solar and Landfill Gas 22 MW
    - Total 15,648 MW

8. Evergy Kansas Central, Evergy Metro and Evergy Missouri West are members of the Southwest Power Pool ("SPP"). The SPP is a Federal Electric Reliability Commission ("FERC") approved regional transmission organization with the responsibility to ensure reliable power supply, adequate transmission infrastructure and competitive wholesale electricity prices in the region. As SPP members, Evergy Kansas Central, Evergy Metro and Evergy Missouri West are required to maintain a minimum reserve margin of 15%. This net positive supply of capacity is maintained through generation asset ownership, capacity agreements, power purchase agreements and peak demand reduction programs. The reserve margin is designed to support reliability of the region's electric supply.
9. The Evergy Companies are committed to a long-term strategy to reduce carbon dioxide ("CO2") emissions in a cost-effective and reliable manner. In 2023, Evergy achieved a reduction of CO2 emissions, from owned generation, by half from 2005 levels. Evergy has

a goal to achieve net-zero carbon dioxide equivalent emissions, for scope 1 and scope 2 emissions, by 2045 with an interim goal of a 70% reduction of owned generation CO_2 emissions from 2005 levels by 2030 through the responsible transition of the Evergy Companies' generation fleet. The trajectory and timing of achieving these emissions reductions are expected to be dependent on many external factors, including enabling technology developments, the reliability of the power grid, availability of transmission capacity, supportive energy policies and regulations, and other factors.

10. Public attention is currently focused on transitioning to a low carbon future, including reducing greenhouse gas emissions and closing coal-fired generating units. Diversity of fuel supply has historically provided cost and reliability benefits. For example, because renewable generation can be intermittent, diversity of baseload generation fuel, including a mix of coal and natural gas, has helped to maintain a consistent availability of power. In addition, the Evergy Companies must prudently utilize the generation assets that regulators have allowed the Evergy Companies to include in rates. The Evergy Companies use an IRP, a detailed analysis that estimates factors that influence the future supply and demand for electricity, to inform the manner in which they supply electricity. The IRP considers forecasts of future electricity demand, fuel prices, transmission improvements, new generating capacity, cost of environmental compliance, integration of renewables, energy storage, energy efficiency and demand response initiatives. Strategies that the Evergy Companies are pursuing to reduce emissions include:

- retiring fossil fuel generation;
- developing renewable energy facilities;
- grid investment and advancement;
- collaborating with regulators to offer customers the opportunity to procure electricity produced with renewable resources; and
- investing in customer energy efficiency programs.

11. Since 2005, the Evergy Companies have added over 4,600 MWs of renewable generation, while retiring more than 2,400 MWs of fossil generation. The Evergy Companies are also committed to transparency. On its website, http://investors.evergy.com, Evergy provides quantitative and qualitative data regarding various environmental, social and governance matters, including information related to emissions, waste and water.

12. As of December 31, 2023, the Evergy Companies had 4,658 employees, including 2,473 represented by five local unions of the International Brotherhood of Electrical Workers and one local union of the United Government Security Officers of America. The Evergy Companies employ 1,650 generation employees, 1,447 transmission and distribution employees and 1,561 support employees that work primarily in the states of Kansas and Missouri.

Evergy's Integrated Resource Plan

13. Evergy has and applies tools to assess and project the status of our power plants to ensure reliability and availability as part of an annual resource planning process. Every three years, as required by the Missouri Public Service Commission ("MPSC") and the Kansas Corporation Commission ("KCC"), the Company files an IRP. The fundamental objective of the resource planning process is to provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in a manner that serves the public interest and is consistent with state energy and environmental policies. This objective requires that the utility shall:

- Consider demand-side resources, renewable energy, and supply-side resources on an equivalent basis;
- Use minimization of the present worth of long-run utility costs as the primary selection

criterion; and

- Identify and where possible, quantitatively analyze any other considerations which are critical to meeting the fundamental objective of the resource planning process. Developing the IRP is a very time intensive task, and we recently submitted the plan to the MPSC in April 2024 and KCC in May 2024.

14. Evergy is committed to a long-term strategy to reduce CO2 emissions in a cost-effective and reliable manner. Evergy's coal fleet is aging and is increasingly at risk due to tightening environmental regulations. As a result, each Evergy utility's IRP is built with a goal of responsibly transitioning its fleet away from coal over time, while maintaining a diverse fuel mix and sufficient flexibility to adjust plans as policy and technology change. A responsible transition means one that focuses on maintaining reliability and affordability while also reducing environmental impact over time.

15. Evergy current strategy to advance this responsible transition is outlined in the preferred plan identified through the IRP. This plan includes the measured retirement of coal plants over time and the replacement of this capacity and energy with a mix of renewable resources, demand-side management programs, and new dispatchable resources. In addition to replacing capacity, these additions also allow Evergy to meet increasing requirements driven by higher resource adequacy requirements and load growth / economic development. This resource plan is designed to be robust across a variety of uncertainties and to include a diverse mix of resources that reduce the risk to both reliability and customer costs which can come from "putting all of your eggs in one basket". Despite the robustness of the risk analysis performed, however, the future remains inherently uncertain and, as a result, maintaining flexibility and continuing to adjust plans over time is imperative. The goal of

this preferred plan is to outline the Company's current long-term strategy for meeting customer energy needs, but also to particularly focus on the robustness of near-term decisions which must be made to begin executing on that strategy. Given the increasing capacity and energy requirements for Evergy, there is significant urgency to continue executing on both supply- and demand-side additions outlined in the first three to five years of this preferred plan. The analysis performed in this IRP will be used to support separate regulatory filings related to these resource additions. These filings must be supported by the IRP and not only by resource-specific evaluations because the evaluation of resource decisions cannot be performed in a vacuum. The integrated analysis of risks and resource options, along with customer needs for energy and capacity, is required to reflect the trade-offs inherent in any resource decision. Any resource added (or not added) today has an impact on future resource decisions in the same way that past resource decisions impact decisions going-forward. Integrated analysis of these trade-offs is performed in IRP filings and updated annually in order to make necessary adjustments to Evergy's long-term resource plan when conditions change.

16. The preferred plan meets the fundamental planning objectives to provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies. The selected preferred plan is the lowest-cost alternative resource plan on an expected value basis. As the inputs to the preferred plan change, the plan will be reviewed and updated to meet the ongoing planning objective.

17. Evergy's consolidated plan, comprised of the summation of Evergy Metro's, Evergy

Missouri West's, and Evergy Kansas Central's preferred plans, is shown in the figure below. While evaluating consolidated plans can be and has been informative, particularly given many of Evergy's generating resources are jointly-owned by different Evergy utilities, Evergy does not perform full integrated planning or select a preferred plan at the consolidated level. This analysis is completed at the individual utility level and then consolidated to produce the view below. Evergy is needing more accredited capacity due to higher load growth and more stringent reserve margin requirements. While all thermal resources were modeled as natural gas-fired resources throughout the twenty-year IRP analysis, additions beyond 2035 are shown as "non-emitting firm, dispatchable resources" consistent with recent IRPs. For planning purposes, Evergy assumes that new, non-emitting dispatchable technologies will be available and cost-effective in the future which could replace what is currently assumed to be conventional natural gas generation.

Impact of EPA's Rule on Evergy's Fossil Fuel-Fired Units

18. The graphic above displays Evergy's current resource plan. Applying the plan's resources and current plan retirement dates to the subcategories identified in EPA's "Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units", to Evergy's fossil-fuel fired units results in the premature shuttering of approximately 3,983 megawatts of coal-fired units, constituting more than 67% of Evergy's coal-fired generating capacity by 2032 due to inability to meet natural gas or carbon capture and storage ("CCS") conversions requirements as further discussed below.

19. Evergy's current resource plan units can be subcategorized pursuant to the Rule based on the generation source fuel type and the retirement dates as follows:

- **Natural Gas-Fired** (40 CFR 60.5775b(c)(7&8)) – Units demonstrating low or intermediate unit standard before January 1, 2030:
    - 2028 Gas conversion - Lawrence Unit 5 (373 MW)
    - 2030 Retirement date – Lake Road Unit 4/6 (95 MW)

- **Coal-Fired Exempt** (40 CFR 60.5775b(c)(7&8)) - Units demonstrating that they plan to permanently cease operating before January 1, 2032:
    - 2028 Retirement - Lawrence Unit 4 (107 MW)
    - 2030 Retirement date – Jeffrey Units 2 and 3 (1,466 MW)

- **Coal-Fired Medium – Term** (40 CFR 60.5775b(c)(2)) - Units operating on or after January 1, 2032, and demonstrating that they plan to permanently cease operating before January 1, 2039, while co-firing 40% (by heat input) natural gas with emission limitation of a 16% reduction in emission rate (lb CO2/MWh gross basis) by January 1, 2030.
    - 2032 Retirement – La Cygne Unit 1 (750 MW)

- **Coal-Fired Long – Term** (40 CFR 60.5775b(c)(1)) - Units operating on or after January 1, 2039, with CCS with 90 percent capture of CO2 (88.4% reduction in emission rate lb/MWh gross) by January 1, 2032.
    - 2039 Retirement – Jeffrey Unit 1 (733 MW), La Cygne Unit 2 (668 MW), Iatan Unit 1 (618 MW)
    - Retirement outside the 20-year planning horizon – Iatan Unit 2 (652), Hawthorn Unit 5 (562 MW)

20. Evergy is required by state regulation to utilize at least a twenty-year planning horizon, and Evergy looks at a longer horizon in some planning decisions. Most of the activities we undertake require years, and sometimes decades, to plan and execute. The nature of the utility planning process requires us to take actions well in advance of a forecasted event or need in order to ensure that we maintain our ability to provide the most cost-effective and reliable electric service possible to our customers. Evergy, its regulators and customers will be harmed by the immediate need to modify the resource commitment, begin implementing that plan and potentially reverse those efforts if the rule stays in place.

21. <u>Natural Gas Conversion of Coal-Fired Medium – Term Units</u> (40 CFR 60.5775b(c)(2)) It is not reasonably possible for Evergy to plan, permit, contract, construct, commission and procure natural gas service for these primarily rural sites at the scale and with the firm delivery needed and to also modify the boilers for natural gas operations in the next 6 years to be compliant with the Rule. As natural gas is not reasonably available to the units in this subcategory, the units would be required to immediately announce prematurely retirement by 2032. This totals to 750 MW of 5,930 MW or 13% of Evergy's coal-fired fleet.

<u>Anticipated Schedule for this Category:</u>

a. Plan (2-3 years estimate) – update IRP to determine if replacement generation or natural gas modification is the most cost-effective and reliable option for customers and receive regulatory approval.
    i. Updating the IRP is a detailed, time-intensive process that can easily require over one year for the team to complete, file, and respond to MPSC, KCC, or other stakeholders.
    ii. Receiving regulatory approval is the next step after the IRP is updated and is similarly a detailed, time-intensive process that may require a case be filed, heard, and order received that can require over one year.
    iii. Consultant feasibility engineering studies are required to determine the boiler modifications required.

b. Permit (1-3 years estimate) – permitting necessary boiler modifications for natural gas operation and gas line.
    i. Permitting of modifications to support 40% natural gas operations will require substantial resources for the number of units selected. There are limited consultants available to complete this work.
    ii. Permitting of new natural gas lines for gas operations will require substantial resources for the unit impacted and the limited consultants available to complete the work. Further, the unit will require a substantial addition of a trunk line to the unit from the interstate pipeline that may also have to be updated for capacity and pressure requirements.

c. Contract (3-5 years estimate) – contracting for boiler modification and pipeline and associated facilities.
    i. Detailed design and engineering for on-site boiler modifications and supporting infrastructure such as regulating stations.
    ii. Interstate pipeline firm capacity agreements will likely be required in order to meet SPP capacity accreditation requirements. Capacity may be limited by interstate pipeline capacity and pressure.

iii. Where firm capacity does not exist, the interstate pipeline will have to be upgraded, which will be required to be completed before natural gas can be delivered. These upgrades are performed by the pipelines and natural gas providers and are not directly managed by Evergy. If upgrades are not sufficient to supply the capacity, the natural gas providers may have to pursue the installation of new natural gas transmission lines in order to provide the capacity.
   - La Cygne Generation Station is 17 miles from the closest interstate pipeline and did not have any firm capacity when last discussed with interstate pipeline owner.

d. Construct and Commission (3-5 years estimate) – implement boiler modification and construct and commission pipeline and associated facilities.
   i. SPP approval of unit outages for necessary boiler modifications may not be attained for the number of outages sought due to the lack of excess dispatchable resources at SPP. This is compounded by the impacts of multiple unit outages occurring at once at Evergy and other SPP members.
   ii. Construction of trunk pipeline will be required prior to natural gas delivery.
   iii. Construction and commissioning of the boiler natural gas conversion modifications and associated equipment.
      - There may be a resource constraint due to the inability for resources to execute conversion projects across Evergy and units across the country for other utilities.

e. Total anticipated schedule range – 8-12 years (includes recognition of some overlapping activities)

As shown above, it is not reasonably possible for Evergy to modify the boilers for natural gas operations in the next 6 years to be compliant with the Rule. Evergy's only options for this category of units is to proceed with attempting an expedited natural gas conversion, requiring significant decisions and expenditures regarding regulatory approval, equipment advance purchase, right-of-way purchase, and remaining contracting items to be made immediately requiring significant at-risk expenditures irreparably harming Evergy during the potential next few years of litigation or to prematurely retire the unit and replace with dispatchable replacement generation with risks as discussed further below.

22. CCS Conversion of Coal-Fired Long – Term Units (40 CFR 60.5775b(c)(1)) It is not possible for Evergy to plan, permit, contract, construct, and commission the CCS for these sites at the utility scale needed for these units in the next 8 years to be compliant with the Rule. Since CCS will not be available to these units, these units would be required to immediately announce premature retirement by 2032. This totals to 3,233 MW of 5,930 MW or 54% of Evergy's coal-fired fleet.

Anticipated Schedule for this Category:

a. Plan (3-4 years - estimate) – update IRP to determine if replacement generation or CCS modification is the most cost-effective and reliable option for customers and receive regulatory approval.
   i. Updating the IRP is a detailed, time-intensive process that can easily require over one year for the team to complete, file, and respond to MPSC, KCC, or other stakeholders. This detailed planning effort is hindered by the fact that there are no successful CCS implementations at utility scale to support the IRP inputs; therefore, any assumptions used in IRP would be highly suspect and potentially erroneous. Further, implementation of CCS at just two of our existing coal-fired boilers, Iatan Unit 2 and Hawthorn Unit 5, would result in up to a 480 MW loss of net power output resulting in Evergy needing to construct additional dispatchable generation to replace the lost generation due to the CCS project.
   ii. Receiving regulatory approval is the next-step after the IRP is updated and is similarly a detailed, time-intensive process that may require a case be filed, heard, and order received that can require over one year.
   iii. Consultant feasibility engineering studies are required to determine the potential installation options.

b. Permit (7-12 years - estimate) – permitting necessary boiler modifications and CCS.
   i. Permitting of modifications to support CCS will require substantial resources for the number of units selected. There are limited consultants available to complete this work.
   ii. Neither Evergy nor other utilities in Kansas or Missouri have successfully permitted CCS. It is not a given that Evergy will be successful in securing the required permits for CCS in Kansas or Missouri.
   iii. CCS has significant permitting hurdles including but not limited to: land use for storage and pipelines, process water requirements, potential increase of air emissions per net MW generated due to

significant auxiliary power requirements, waste products, and end of life considerations.

iv. Permitting of CCS disposal pipelines and sequestration wells will require substantial resources for the number of units selected and the limited consultants available to complete the work. Further, some units will require substantial additions of disposal pipelines to the sequestration sites.

c. Contract (1-2 years - estimate) – contracting for boiler modifications, CCS and associated facilities.

   i. Contractors that would potentially construct CCS are nearing the limit of their ability to perform large scale utility construction projects by the 2032 timeframe due to the growth of new generation opportunities driven by onshoring of manufacturing coupled with considerable data center construction.
   ii. Contractors may not choose to participate in CCS projects given the considerable technical risk and breadth of less risky opportunities.
   iii. Large equipment (piping, valving, transformers, pumps, etc.) fabrication and assembly shop space may be limited due to the corresponding new generation and natural gas retrofit work that will be occurring at the same time as the proposed CCS construction.

d. Construct (5-10 years - estimate) – implement boiler modifications and commission CCS and associated facilities.

   i. SPP approval of unit outages for necessary boiler modifications may not be attained for the number of outages sought due to the lack of excess dispatchable resources at SPP. This is compounded by the impacts of multiple unit modifications occurring all at once at Evergy and other SPP members.
   ii. When Evergy constructed just one SCR at Jeffrey Energy Center Unit 1 in 2010 to 2014, the construction schedule was 3 and a half years.
   iii. When Evergy constructed SCRs, scrubbers, and baghouses at La Cygne Generating Station in 2010 to 2015, the construction schedule was nearly five years.
   iv. CCS construction is significantly larger from both a dollar value and complexity standpoint using unproven technology at the scale needed than either of these projects.
   v. CCS construction required by this Rule at Evergy's generating stations, , would need to be occur in the same timeframe as new replacement natural gas project or gas conversion projects at Evergy's other coal-fired units.
      - It is highly unlikely that Evergy could identify and incent sufficient construction labor to perform these projects in parallel.
      - Construction quality could potentially be extremely poor given the breadth of potential parallel construction work.
      - It is highly unlikely that Evergy could secure outage time with SPP

to perform these construction projects in parallel.

e. Commission (1-5 years – estimate) – start-up execution including sequestration.
    i. Skilled and experienced instrument and controls engineers and technicians with utility and process specific knowledge are in short supply. CCS projects are especially challenging due to their technical complexity and the relative lack of proven controls schemes.
    ii. Commissioning will be significantly more challenging and time consuming as compared to projects that are using proven technologies and equipment.

f. Total anticipated schedule range – Evergy is unable to provide an estimated total schedule range to add CCS to a coal-fired unit because the technology is not reasonably available at a utility scale. The estimates above are based on CCS being reasonably available which it is not currently. While Evergy cannot determine an overall range, it is clear the schedule to implement will be in excess of 8 years.

As shown above, it is not possible for Evergy to modify the units for CCS in the next 8 years to be compliant with the Rule because CCS is not available at utility scale for these units. Evergy's only option for this category of units is to prematurely retire the units and replace with dispatchable replacement generation with the risks as discussed further below. This would immediately require significant at-risk expenditures irreparably harming Evergy during the potential next few years of litigation.

23. The premature shuttering of approximately 3,983 megawatts of coal-fired units by 2032 due to inability to meet natural gas or carbon capture and storage CCS conversions would result in a corresponding loss of over 650 full-time jobs by 2032. Prior to the premature shuttering, Evergy will be harmed by the more immediate impact of inability to attract and maintain qualified plant employees when job elimination is imminent due to premature retirement.

EPA's Rule Contains Insufficient Flexibility Mechanisms

24. In the Rule EPA indicates that it has included several mechanisms to provide implementation flexibility. To provide implementation flexibility, the mechanisms must be constructed and applicable in a manner that that functions as intended. As demonstrated in the following sections, the mechanisms do not go far enough to adequately provide Evergy the necessary flexibility to comply with the Rule.

25. State Plan Requirements Section 40 CFR 60.5740b(a)(11) – Compliance Date Extension. A compliance date extension of no longer than one year for the installation of add-on controls to meet the applicable standard of performance does not mitigate irreparable harm to Evergy. For the Medium-Term and Long-Term units, even if Evergy were able to demonstrate the detailed necessity requirements for this extension, the extension does not fundamentally provide adequate time for natural gas or CCS conversion – the additional one year is not enough. It is not reasonably possible for Evergy to plan, permit, contract, construct, commission, and procure natural gas service for these primarily rural sites at the scale and with the firm delivery needed and to also modify the boilers for natural gas operations even with the one-year extension. Similarly, it is not possible for Evergy to plan, permit, contract, construct, and commission the CCS for these sites at the utility scale needed even with the one-year extension. Evergy would continue to be irreparably harmed by commencing activities and resources to comply with the natural gas or CCS conversion that are not achievable by the compliance date required by the Rule even considering this additional year of flexibility.

26. State Plan Requirements Section 40 CFR 60.5740b(a)(12) – Short-Term Reliability Mechanism. The short-term reliability mechanism for affected electric generating units

("EGU") that operate during a system emergency does not mitigate irreparable harm to Evergy. As stated above, it is not reasonably possible for Evergy to plan, permit, contract, construct, commission, and procure natural gas service for these primarily rural sites at the scale and with the firm delivery needed and to also modify the boilers for natural gas operations by the compliance date. Further, it is not possible for Evergy to plan, permit, contract, construct, and commission the CCS for these sites at the utility scale needed by the compliance date. Evergy would continue to be irreparably harmed by commencing activities and resources to comply with the natural gas or CCS conversion that are not achievable by the compliance date required by the Rule even considering this additional year of flexibility.

27. State Plan Requirements Section 40 CFR 60.5740b(a)(13) – Reliability Assurance Mechanism. The reliability assurance mechanism that would allow for a not to exceed 12-month extension of the date by which an affected EGU has committed to permanently cease operations, based on a demonstration that operation of the affected EGU is necessary for electric grid reliability, does not mitigate irreparable harm to Evergy. As stated above, it is not reasonably possible for Evergy to plan, permit, contract, construct, commission, and procure natural gas service for these primarily rural sites at the scale and with the firm delivery needed and to also modify the boilers for natural gas operations by the compliance date. Further, it is not possible for Evergy to plan, permit, contract, construct, and commission the CCS for these sites at the scale needed by the compliance date. Evergy would be irreparably harmed by commencing activities and resources to comply with the natural gas or CCS conversion that are not achievable by the compliance date required by the Rule even considering this additional year of flexibility.

28. State Plan Requirements Section 40 CFR 60.5775b(g) – a standard of performance in the form of an annual limit on allowable mass carbon dioxide ("CO2") emissions for an individual affected EGU. A mass-based standard of performance in the form of an annual limit on allowable mass CO2 emissions for an individual affected EGU but with a backstop rate-based standard of performance would provide no additional flexibility for Evergy's coal-fired Medium-Term units. This is due to the inability to comply with a CO2 backstop emission rate on units where CCS is not available or achievable at utility scale. Further, a mass-based standard of performance in the form of an annual limit on allowable mass CO2 emissions for an individual affected Long-Term unit due to the requisite 88.4% reduction would provide no meaningful compliance benefit since it would require an operational capacity factor to be limited to under 12% without even considering the backstop rate for these units.

29. State Plan Requirements Section 40 CFR 60.5775b(j) – A less stringent standard of performance or longer compliance schedule is available to an affected EGU based on consideration of electric grid reliability, including resource adequacy. The Rule requires an analysis of the reliability risk clearly demonstrating that the particularly affected EGU is critical to maintaining electric reliability such that requiring it to comply with the applicable requirements would trigger non-compliance with at least one of the mandatory reliability standards approved by the Federal Energy Regulatory Commission along with an analysis and certification by the relevant planning authority. Evergy would not be able to rely on this mechanism because we make 20-year planning decisions that cannot be contingent on a subsequent approval that may or may not be granted.

Inability to Timely Replace Generation Prematurely Retired

30. Depending on the type of natural gas generation (combustion turbine, natural gas combined cycle, etc.) and given the broad industry-wide build-out of new natural gas generation which this Rule would require, new generation plants would be expected to require nearly 8 to 12 years to obtain regulatory approvals, plan, site, design, permit, construct, and commission. This extended timeline would be driven by reduced available supply of materials and labor created by dramatically and rapidly increased demand. For example, new natural gas generation will take a minimum of approximately 8 years to obtain regulatory approvals, engineer, procure, construct, and place in service considering timing risks associated with permitting, equipment delivery, transmission and natural gas supply infrastructure. Accordingly, if new natural gas generation is needed to be placed into service in 2032 as replacement generation for a prematurely retired coal-fired unit, activities to meet that projected in-service date would have to begin immediately as we are already behind schedule.

31. The impact of EPA's "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units" on Evergy's plan by subcategory is summarized as:

    - Low and Intermediate Load (40 CFR 60.5520a(a)) subcategory natural gas generation will be required to be limited to under 20% and 40%, respectively, capacity factors to be eligible for the compliance standards. This will require these new natural gas generation to be artificially capacity limited to avoid the Rule's requirement for CCS for Base Load units which are not achievable. This artificial limit could result is an economic waste of the resource investment for the Low and Intermediate Load units.

- Base Load (40 CFR 60.5520a(a)) subcategory units require CCS beginning January 1, 2032, which is not achievable and harms Evergy by eliminating the use of new natural gas generation for baseload operation above a 40% capacity factor.

32. New Natural Gas Generation It is not reasonably possible for Evergy to plan, permit, contract, construct, and commission Low and Intermediate load units and certainly not possible for Base Load natural gas generation with CCS at the scale needed for these units to be compliant with the Rule.

Low and Intermediate Load Natural Gas Generation Unit Anticipated Schedule

a. Plan (2-3 years estimate) – update IRP to determine what replacement generation is the most cost-effective and reliable option for customers and receive regulatory approval.
    i. Updating the IRP is a detailed, time-intensive process that can easily require over one year for the team to complete, file, and respond to MPSC, KCC, or other stakeholders.
    ii. Receiving regulatory approval is the next-step after IRP is updated and is similarly a detailed, time-intensive process that may require a case be filed, heard, and order received that can require over one year.

b. Permit (2-4 years estimate) – permitting replacement generation – assuming natural gas generation and pipeline.
    i. Permitting of new natural gas line for natural gas generation will require substantial resources for the number of units needed. There are limited consultants available to complete this work. Further, some natural gas generation will require substantial additions of trunk lines to the generating unit from the interstate pipeline that may also have to be updated for capacity and pressure requirements.

c. Contract (2 years estimate) – contracting for natural gas generation, pipeline and associated facilities.
    i. Interstate pipeline firm capacity agreements will be required. Capacity may be limited by interstate pipeline capacity and pressure.
    ii. When firm capacity does not exist, the interstate pipeline will have to be upgraded which will be required to be done before natural gas can be delivered. These upgrades are performed by the pipelines and natural gas providers and are not directly managed by Evergy. If upgrades are not sufficient to supply the capacity, the natural gas providers may have to pursue the installation of new natural gas transmission lines in order to provide the capacity.

iii. Natural gas turbine manufactures supply may be limited by demand during this broad industry-wide build-out period requiring lengthy procurement.

d. Construct and Commission (2-5 years estimate) – implement natural gas generation and construct pipeline and associated facilities.
   i. Construction of trunk pipeline will be required prior to natural gas delivery.
   ii. Construction of additional transmission lines and substations would be required before commercial operation of the new units.
   iii. There may be a resource constraint due to the inability for resources to execute multiple Evergy natural gas generation units and units across the country for other utilities as a result of this period of gas build-out.

e. Total anticipated schedule range – 8-12 years (includes recognition of some overlapping activities)

<u>Base Load Natural Gas Generation Unit Anticipated Schedule</u>

a. Plan (3-4 years - estimate) – update IRP to determine what replacement generation is the most cost-effective and reliable option for customers and receive regulatory approval.
   i. Updating the IRP is a detailed, time-intensive process that can easily require over one year for the team to complete, file, and respond to MPSC, KCC, or other stakeholders. There is limited to no successful CCS implementations at utility scale to support the IRP inputs; therefore, any assumptions used in IRP would be highly suspect and potentially erroneous. Further, implementation of CCS with the associated loss of net power output resulting in Evergy needing to construct additional dispatchable generation to replace the loss generation due to CCS.
   ii. Receiving regulatory approval is the next-step after IRP is updated and is similarly a detailed, time-intensive process that may require a case be filed, heard, and order received that can require over one year.

b. Permit (2-4 years - estimate) – permitting replacement generation – assuming natural gas generation with CCS and associated natural gas and disposal pipelines.
   i. Permitting of new natural gas lines for natural gas generation will require substantial resources for the number of units needed. There are limited consultants available to complete this work. Further, some natural gas generation will require substantial additions of trunk lines to the generating unit from the interstate pipeline that may also have to be updated for capacity and pressure requirements.
   ii. Neither Evergy nor other utilities in Kansas or Missouri have successfully permitted CCS. It is not a given that Evergy will be

successful in securing the required permits for CCS in Kansas or Missouri.

iii. CCS has significant permitting hurdles including but not limited to: land use for storage and pipelines, process water requirements, significant auxiliary power requirements, waste products, and end of life considerations.

iv. Permitting of CCS disposal pipelines and sequestration wells will require substantial resources for the number of units selected and the limited consultants available to complete the work. Further, some units will require substantial additions of disposal pipelines to the sequestration sites.

c. Contract (1-2 years - estimate) – contracting natural gas generation with CCS, pipeline and associated facilities.

   i. Interstate pipeline firm capacity agreements will be required. Capacity may be limited by interstate pipeline capacity and pressure.

   ii. When firm capacity does not exist, the interstate pipeline will have to be upgraded which will be required to be done before natural gas can be delivered.

   iii. Natural gas turbine manufactures supply may be limited by demand requiring lengthy procurement.

   iv. Contractors that would potentially construct CCS are nearing the limit of their ability to perform large scale utility construction projects for industry due to the growth of new generation opportunities driven by onshoring of manufacturing coupled with considerable data center construction.

   v. Contractors may not choose to participate in CCS projects given the considerable technical risk and breadth of less risky opportunities.

   vi. Large equipment (piping, valving, transformers, pumps, etc.) fabrication and assembly shop space may be limited due to the corresponding new generation and natural gas retrofit work that will be occurring at the same time as the proposed CCS construction.

d. Construct and Commission (2-5 years - estimate) – implement natural gas generation with CCS and construct pipelines and associated facilities.

   i. Construction of trunk pipeline will be required prior to natural gas delivery.

   ii. There may be a resource constraint due to the inability for resources to execute multiple Evergy natural gas generation units and units across the country for other utilities.

   iii. CCS construction required by this Rule for this replacement generation would occur in the same timeframe as natural gas conversion projects and CCS at Evergy's other coal-fired units.

      1. It is highly unlikely that Evergy could identify and incent sufficient construction labor to perform these projects in parallel.
      2. Construction quality could potentially be extremely poor given the

breadth of potential parallel construction work.

3. Highly unlikely that Evergy could secure outage time with SPP to perform these construction projects in parallel.

ii. Skilled and experienced instrument and controls engineers and technicians with utility and process specific knowledge are in short supply. CCS projects are especially challenging due to their technical complexity and the relative lack of proven controls schemes.

iii. Commissioning will be significantly more challenging and time consuming as compared to projects that are using proven technologies and equipment.

e. Total anticipated schedule range – Evergy is unable to provide an estimated total schedule range to add CCS to new natural gas generation because the technology is not available at a utility scale. The estimates above are based on CCS being reasonably available which it is not currently. While we cannot determine an overall range, it is clear the schedule to implement will be in excess of 8 years.

The premature replacement of coal-fired units will require replacement with natural gas generation due to the Rule's compliance requirements. While this replacement takes years to accomplish, there is immediate need for significant decisions, expenditures, regulatory approval, equipment advance purchase, right-of-way purchase, and remaining contracting items that all require substantial at-risk expenditures that, without a stay, will irreparably harm Evergy during the potential next few years of litigation.

Impacts to Reserve Margin

33. The premature retirement of over 3,983 MW of 5,960 MW or 67% prior to 2032 would negatively impact the reserve margin of Evergy. A reserve margin is a measure of the amount of resources available in excess of forecasted demand. Evergy's long-term reserve margin is currently established at 15% and is necessary to maintain reliability on the system, taking into account risks due to non-normal weather, unit outages, and inherent inaccuracies in demand forecasts. The SPP requires compliance with the reserve margins

and Evergy may be subject to fines and penalties for non-compliance. Premature retirement would dangerously reduce Evergy's long-term reserve margin if dispatchable replacement generation cannot be timely constructed or contracted for through a long-term agreement. These drastically reduced reserve margins would have significant reliability impacts during a period of significant load growth. Reserve margins may become so constrained that additional load growth cannot be supported resulting in significant economic growth restrictions in Evergy's service territory. In addition, the winter reserve margin significantly benefited in the past from on-site coal storage for coal-fired units while natural gas units experience curtailed natural gas supply. Furthermore, the Company's response to these reliability implications cannot be unwound, because once an electric generating unit is retired, it is not feasible to return the same unit to service.

34. On May 20, 2024, in a statement released by SPP regarding the Rule (*See* Exhibit A *Statement on the Recent EPA Greenhouse Gas Emission Rule*), the regional transmission organization expresses similar and substantial concerns as Evergy regarding resource adequacy and reliability.

> SPP remains concerned, however, about the impact the Final Rule may have on the region's ability to maintain resource adequacy and ensure reliability in the SPP region. SPP is concerned that limited technological and infrastructure availability and the compliance time frame will have deleterious impacts including the retirement of, or the decision not to build, thousands of MWs of baseload thermal generation. If sufficient flexible thermal resources are not available to play their critical roles in SPP's resource mix, SPP's ability to maintain regional reliability will be directly impacted. The Final Rule's emissions limits for existing coal and new gas generation are based on the EPA's finding that carbon capture and sequestration (CCS) technology is a viable best source of emissions reduction (BSER) in terms of commercial availability and reasonable cost. SPP continues to be concerned that CCS has not yet been adequately demonstrated at the required capture rate, has not been commercially produced at scale, and will not be widely available and practicable at the level needed for the Final Rule's 2032 compliance time frame. Moreover, while the Final Rule contemplates a natural gas co-firing option for existing coal units that choose to retire before 2039, SPP is concerned about the availability of gas infrastructure necessary to adequately

utilize that compliance option in that time frame.

Impacts to Transmission

35. As a result of the premature retirements of existing coal-fired units, a significant amount of replacement natural gas generation generating capacity will be needed to maintain resources adequate to reliably serve the demand for electricity. In order to accommodate the coal-fired unit retirements and replacement generation, additional planning and approval of transmission projects must be undertaken to maintain compliance with NERC Reliability Standards. Multiple additional transmission projects are anticipated as a result of the planning. Furthermore, and most critically, due to lead times required to complete these transmission projects, the transmission projects cannot be placed in service by the coal-fired unit premature retirement dates pursuant to this Rule. The new transmission line and substation projects will require from 8-15 years to complete. Once new transmission line construction projects have begun, because they involve acquisition of long-term property rights, they cannot be easily unwound.

36. The same SPP's statement referenced above, further expresses concern regarding recent load studies for resource adequacy and planning results without even consideration of the additional impacts of the Rule when applied to the future resources and associated transmission necessary. The SPP clearly stating the Rule's outcome could result in a build-out at an unprecedented pace and cost.

> It is important to note that this study considered SPP's existing and projected future resource mix without considering the potential impacts of the Final Rule's 2032 deadline for certain emissions limits. In other words, the study and its projected increase in [Planning Reserve Margin] did not consider the additional at-risk generation that may retire and not be adequately replaced in a relatively short time frame resulting from the compliance time frames contained in the Final Rule. This outcome would further intensify the need for generating capacity and associated transmission upgrades

in the SPP region, likely at a pace and cost unprecedented for the industry.

Conclusion

37. Unless the Rule is stayed, the premature retirements of coal-fired units will cause immediate and irreparable impacts on Evergy. The retirement of over 67% of our coal-fired generating capacity, that would otherwise have served Evergy's electricity needs for many years, significantly impacts our generation resources. The premature retirements would significantly harm Evergy due to the inability to meet natural gas or carbon capture and storage conversions requiring us to immediately start investing resources in planning for expedited at-risk replacement dispatchable generating sources. To even have any possibility to achieve the Rule's compliance date, significant decisions and expenditures regarding regulatory approval, equipment advance purchase, right-of-way purchase, and remaining contracting items would have to be made immediately requiring significantly at-risk expenditures irreparably harming Evergy during the potential next few years of litigation. For planning purposes, Evergy assumed that new, non-emitting dispatchable technologies will be available and cost-effective in the twenty-year planning horizon which could replace what is currently assumed to be conventional natural gas generation. EPA's Rule forces the premature retirement of our coal-fired units without any current availability of these anticipated non-emitting dispatchable technologies to reasonably and prudently replace these coal-fired retirements. Ultimately, the costs associated with the immediate and long-term compliance with the Rule will be requested for recovery through future rate cases. Staying this Rule immediately will minimize the immediate at-risk expenditures and commercial risk irreparably harming Evergy during the next few years of litigation.

Signature ______________________

Name: John T. Bridson

Title: Evergy Vice President of Generation

Dated: May 21, 2024

Exhibit A

Declaration of John T. Bridson

FOR IMMEDIATE RELEASE – May 20, 2024

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SPP Southwest Power Pool

EPA Rule Could Severely Impact Nation's Efforts Toward Energy Production, Reliability

LITTLE ROCK, ARK. — Southwest Power Pool (SPP) sent its member utilities a statement on May 20, detailing the impact a final rule issued by the U.S. Environmental Protection Agency (EPA) could have on future energy availability throughout their region and the country. Given SPP's and its stakeholders' commitment to ensuring electric reliability, the grid operator asserts the EPA rule could negatively impact the nation's ability to provide consumers reliable electric service in the interest of a swift transition from fossil fuels to renewable energy, particularly during a time when additional generating capacity is already needed to ensure the reliable supply of energy.

Rule 2023-0072, finalized by the EPA on April 25, is meant to curb greenhouse gas emissions at power plants through new performance standards. SPP prides itself on being a leader in the reliable integration of renewable energy and is supportive of the long-term goals of the rule. However, though wind is the number one source of energy in its 14-state region, the grid operator underscored in its statement to stakeholders that controllable or "dispatchable" energy sources like coal and natural gas remain necessary to meet the ever-growing demand for electricity.

SPP appreciates efforts by federal officials to address concerns that it communicated to the EPA last year in response to the agency's initial notice of proposed rulemaking. The final rule takes into account the RTOs' concerns regarding natural gas availability, state-specific flexibility and timeline extensions for retiring generators, among other things. Despite these concessions, concerns about future production capacity remain among those in the power-providing sector, including SPP.

SPP's statement questions the feasibility of implementing the carbon capture and sequestration process by the rule's deadline and the reasonableness of optional requirements for volumes of natural gas, which may not be available to individual producers. SPP also noted that the need to ensure the reliable delivery of power is becoming both more critical and complex given the increasing frequency of extreme weather events and increasing demand for electricity, among other factors.

"Our mission, and our charge from the Federal Energy Regulatory Commission, is to strive to continuously keep the lights on today and tomorrow throughout our region," said Lanny Nickell, chief operating officer at SPP. "We take our duty to the 18 million people in our footprint very seriously, and we fear that the EPA rule will induce or impose actions that conflict with that duty. At the minimum, it presents serious complications for SPP and our members that may be insurmountable."

The statement (see attachment) enumerates specific issues with the rule. SPP joins some of its peer grid operators in publishing statements on the potentially harmful impacts of the rule.

About SPP: Southwest Power Pool, Inc. is a regional transmission organization: a not-for-profit corporation mandated by the Federal Energy Regulatory Commission to ensure reliable supplies of power, adequate transmission infrastructure and competitive wholesale electricity prices on behalf of its *members in 14 states. SPP ensures electric reliability across a region spanning parts of the central and western U.S., provides energy services on a contract basis to customers in both the Eastern and Western Interconnections, and is expanding its RTO and developing a day-ahead energy market in the west. The company's headquarters are in Little Rock, Arkansas. Learn more at [SPP.org](SPP.org).*

###

STATEMENT ON THE RECENT EPA GREENHOUSE GAS EMISSIONS RULE

SPP issues this statement on the final rule the EPA issued on April 25, 2024, regulating greenhouse gas (GHG) emissions from electric generating units under Section 111 of the Clean Air Act (Final Rule).

As a FERC-approved regional transmission organization (RTO), SPP is responsible for maintaining reliability of the bulk electric system in its region covering all or part of 14 states. A key component of SPP's reliability-based responsibilities is assuring that sufficient resources are available when needed to meet expected future demand.

The generating fleet in the SPP region has undergone significant changes in recent years, and SPP has worked to keep pace by adapting its market design, operating processes, and transmission planning practices. Through these adaptations, SPP has facilitated an ongoing transition to carbon-free generation and is supportive of moving further toward a resource mix that reliably reduces emissions as necessary new technology evolves. The SPP region has long been at the forefront of integrating renewable energy, particularly wind generation. In the last decade, SPP has transitioned from a resource fleet that was overwhelmingly made up of traditional generation to a fleet in which wind is the number-one supplier of energy in the SPP region.

SPP's success in integrating significant wind generation has depended largely on having sufficient flexible thermal generation that can be called upon when wind is unavailable. However, the thermal fleet is shrinking. Thermal units are being retired without being adequately replaced, resulting in less total, fuel-assured, ramp-able capacity. Thermal units with these requisite reliability attributes also make up a shrinking percentage of SPP's total available generating capacity, as the growth of variable energy resources is outpacing the addition of new thermal units. The remaining fleet is expected to carry a potentially unsustainable burden of supplying the necessary reliability attributes needed to assure continuous supply of electricity.

SPP sees no slowing in the growth of demand for electricity or in the growth of new load types such as data centers, cryptocurrency mines, and electric vehicle. SPP is concerned that the current pace of new generation development will be insufficient to offset current and projected resource retirement trends and demand increases.

The region has also experienced extreme weather conditions that have impacted SPP's ability to assure energy provision during times when consumers depend the most on continuous supply of electricity. Since Winter Storm Uri in February 2021, during which SPP was forced to interrupt service to customers for short periods of time, Storms Elliott (December 2022) and Heather/Gerri (January 2024) presented similar circumstances. SPP has also experienced extreme heat over the last two summers, contributing to a new summer peak in 2023 that was 10% higher than the one set two summers prior. These challenges underscore the increasing volatility and unpredictability of weather patterns, further highlighting the need for enhanced grid resilience and adaptive strategies to ensure reliable energy provision in the face of such extreme conditions.

As with previous EPA rulemakings, SPP submitted comments to the EPA in the docket for this Final Rule. SPP submitted individual as well as joint comments with other impacted RTOs: Midcontinent Independent System Operator, Inc.; PJM Interconnection, L.L.C.; and Electric Reliability Council of Texas, Inc. SPP also engaged in meetings with EPA staff to discuss issues raised in the comments. SPP's primary goal throughout this engagement was to communicate the trending urgency of resource adequacy in the SPP region and SPP's sincere concerns about maintaining resource adequacy in the face of thermal generation retirement, an otherwise changing resource mix, increasing demand, and extreme weather trends.

SPP acknowledges and expresses appreciation for EPA staff's consideration of the comments and concerns that SPP and other RTOs presented in the docket and subsequent meetings. SPP notes that the Final Rule reflects changes EPA made from its proposed rule, including removing existing gas generation from the Final Rule's scope and including measures that may provide flexibility in dealing with reliability-impacting events. These changes represent a welcome step toward reflecting the importance of system reliability and the role that existing flexible generation plays toward maintaining that reliability.

SPP remains concerned, however, about the impact the Final Rule may have on the region's ability to maintain resource adequacy and ensure reliability in the SPP region. SPP is concerned that limited technological and infrastructure availability and the compliance time frame will have deleterious impacts including the retirement of, or the decision not to build, thousands of MWs of baseload thermal generation. If sufficient flexible thermal resources are not available to play their critical roles in SPP's resource mix, SPP's ability to maintain regional reliability will be directly impacted. The Final Rule's emissions limits for existing coal and new gas generation are based on the EPA's finding that carbon capture and sequestration (CCS) technology is a viable best source of emissions reduction (BSER) in terms of commercial availability and reasonable cost. SPP continues to be concerned that CCS has not yet been adequately demonstrated at the required capture rate, has not been commercially produced at scale, and will not be widely available and practicable at the level needed for the Final Rule's 2032 compliance time frame. Moreover, while the Final Rule contemplates a natural gas co-firing option for existing coal units that choose to retire before 2039, SPP is concerned about the availability of gas infrastructure necessary to adequately utilize that compliance option in that time frame.

SPP is not expressing these concerns about a hypothetical resource adequacy scenario in the future. SPP and other grid operators are currently working to develop planning and operations policies and practices to deal with resource adequacy issues that have already manifested. SPP's recent Loss of Load Expectation (LOLE) study indicated that, by 2029, as much as a 50% winter season Planning Reserve Margin (PRM) could be necessary to maintain a one-day-in-ten-years LOLE. A PRM of that magnitude would require a significant amount of new capacity to be added in a short time frame. It is important to note that this study considered SPP's existing and projected future resource mix without considering the potential impacts of the Final Rule's 2032 deadline for certain emissions limits. In other words, the study and its projected increase in PRM did not consider the additional at-risk generation that may retire and not be adequately replaced in a relatively short time frame resulting from the compliance time frames contained in the Final Rule. This outcome would further intensify the need for generating capacity and associated transmission upgrades in the SPP region, likely at a pace and cost unprecedented for the industry.

SPP will continue its work to maintain resource adequacy and system reliability. As part of that work, SPP will continue to engage with stakeholders, other RTOs, and the EPA in efforts to address the challenges presented by current and projected trends in resource availability and demand growth.

Exhibit D

UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

OHIO VALLEY ELECTRIC CORPORATION (OVEC)

Petitioner,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, et al.,

Respondents.

DECLARATION SUPPORTING MOTION TO STAY THE FINAL RULE OF THE U.S. ENVIRONMENTAL PROTECTION AGENCY, "**NEW SOURCE PERFORMANCE STANDARDS FOR GREENHOUSE GAS EMISSIONS FROM NEW, MODIFIED, AND RECONSTRUCTED FOSSIL FUEL-FIRED ELECTRIC GENERATING UNITS; EMISSION GUIDELINES FOR GREENHOUSE GAS EMISSIONS FROM EXISTING FOSSIL FUEL-FIRED ELECTRIC GENERATING UNITS; AND REPEAL OF THE AFFORDABLE CLEAN ENERGY RULE"**

DECLARATION OF J. MICHAEL BROWN

1. I am the Environmental Safety and Health Director for Ohio Valley Electric Corporation (OVEC), including its wholly-owned subsidiary, Indiana-Kentucky Electric Corporation (IKEC)[1]. I am responsible for directing corporate environmental permitting and compliance activities, corporate safety policies and procedures, and certain energy scheduling functions, including the offering of OVEC's generating units into the PJM Market. I also serve as the company's Designated Representative (DR) for managing the air emission allowance accounts for each of OVEC's generating stations via USEPA's Clean Air Market Division (CAMD). I provide this declaration in support of the motion to stay the final rule of the U.S. Environmental Protection Agency, titled "***New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule***" (GHG Rule), filed by Petitioners in Case No. _____, while legal proceedings associated with this rulemaking are ongoing.
2. This declaration is based on my personal knowledge of facts, my consultation with other utilities and OVEC's Sponsoring Company personnel, and analysis conducted by my staff.
3. I have been responsible for overseeing OVEC environmental compliance activities since 2011. During my time at OVEC, I have been responsible for directing the overall corporate environmental safety and health compliance, including environmental compliance, at OVEC's two coal-fired generating stations located in Madison, Indiana, and Cheshire, Ohio.
4. My utility career spans over 33 years, all in the field of environmental compliance.
5. I graduated with a Bachelor of Science degree from Penn State University and earned a Master of Business Administration from Capital University.
6. OVEC and IKEC were organized in October 1952 by 15 sponsoring utilities (referred to as "Sponsoring Companies") to provide the electric power requirements of the Atomic Energy Commission's (as predecessor to the Department of Energy (DOE)) gaseous diffusion uranium enrichment plant in Piketon, Ohio. Since that supply agreement was terminated by the DOE in 2003, the entire generating capacity has been committed to

[1] As used herein, the term "OVEC" refers to the combined OVEC and IKEC business.

the Sponsoring Companies under the terms of an inter-company power agreement (ICPA) in effect through June 30, 2040.

7. OVEC employs approximately 520 direct workers and more than 100 full-time local contractors at the two-plant site and the corporate headquarters located in Piketon, Ohio. OVEC also maintains 705 circuit miles of high voltage 345 kV transmission lines that form part of the bulk electric transmission system that is the backbone of the region's power supply, helping to ensure safe and reliable base-load generation to the eastern half of the United States.
8. With a majority of the Sponsoring Companies located in Ohio and over 90% of all Sponsoring Companies in PJM, OVEC continues to provide strong support to the bulk electric system in the Midwest.
9. The premature retirement of OVEC's two coal-fired generating stations would result in the loss of approximately 500 direct jobs, with a payroll in excess of 50 million dollars, as well as the loss of myriad ancillary jobs in our local communities and from our suppliers (including coal suppliers).
10. OVEC also pays in excess of 6 million in total annual real estate and property taxes in the communities where our facilities are located.
11. I am submitting this declaration because absent a stay, the Environmental Protection Agency's (EPA) GHG Rule creates immediate harm in the form of near-term decisions with respect to future plant operations and the timing of "cessation of operation" that the OVEC's Boards of Directors and the OVEC Senior Management Team will be forced to make (and may not be possible to change) long before the outcome of litigation is known. In the interim, the GHG Rule could result in the premature retirement of OVEC's generation stations prior to the end of the existing term of the ICPA on June 30, 2040, and ultimately the premature dissolution of OVEC itself.
12. One example of a near-term decision involves actions required of utilities to support state-level decision-making to implement the GHG Rule. Specifically, the states must immediately begin work on "State Plans", requiring them to reach out to each existing coal-fired electric generating unit subject to this rulemaking to identify which of the GHG Rule's subcategories the units are to be placed in – namely, either the "retire by 2032" subcategory, the "co-fire with 40% gas" subcategory (which requires gas co-firing by 2030 and retirement of the unit by no later than December 31, 2038), or the "install carbon capture and sequestration" (CCS) subcategory.

13. OVEC submits that CCS is not the best system of emission reduction for the myriad reasons addressed in this litigation. CCS is not adequately demonstrated, is a nascent technology at best, and attempted installation is prohibitively costly for most power plants in the nation. It is an experimental technology that is simply not physically possible to construct CCS at a 90% carbon capture rate and have operational by January 1, 2032, at OVEC's power plants – the myriad reasons why are more eloquently documented in the numerous Declarations outlined in the NRECA emergency stay request filed May 13, 2024.
14. If OVEC requests that our states place the OVEC units into any subcategory other than the "install CCS" subcategory, it may trigger an alleged default under OVEC's long-term debt and/or result in unnecessary and premature termination of the ICPA, as no other subcategory would permit OVEC to continue running its generating units consistent with its contractual terms and conditions through June 30, 2040.
15. OVEC is a privately held company that provides electricity via a contractual relationship to its Sponsoring Companies. Any external regulatory action that results in OVEC being required to plan for a plant closure that is earlier than the end of the term of the ICPA could result in the immediate declaration of an alleged default of OVEC's long-term debt, and result in premature wind-down and dissolution of OVEC. As further explained in this declaration, EPA's GHG Rule (as well as other rules EPA released in 2024 targeting steam electric generating facilities) will harm OVEC and could ultimately result in the premature cessation of facility operations a full decade prior to the end of the June 30, 2040 term of the ICPA.

OVEC OPERATIONS

16. OVEC employs approximately 520 full-time employees in Southern Ohio and Southeast Indiana. OVEC, directly and through its wholly owned subsidiary, IKEC, owns and operates the 5-unit 1,086 MW Kyger Creek Station, in Cheshire, Ohio as well as the 6-unit 1,303 MW Clifty Creek Station in Madison, Indiana. Power from these stations is ultimately provided to our utility Sponsoring Companies under the terms of the ICPA, a long-term power contract that allows them to meet the electricity needs of their residential, commercial, industrial, and wholesale customers. Nearly 25% of OVEC's generation is provided for the benefit of rural electric cooperatives whose service territories are primarily comprised of low-income rural residential customers that depend on reliable and affordable electricity such as the baseload generation OVEC provides.

17. The Clifty Creek Station's six units all have electrostatic precipitators for particulate matter (PM) control, all units have over-fire air for nitrogen oxides ("NOx") control, and five of the six units have selective catalytic reduction (SCR) equipment for NOx control. In addition, Units 1, 2, and 3 and, separately, Units 4, 5, and 6, are scrubbed for sulfur dioxide (SO2) control via two Jet bubbling reactor (JBR) scrubbers that came online in 2013. The scrubber design is robust, and the facility is able to meet its Mercury and Air Toxics Rule (MATS) emission limits as a co-benefit via the management of the scrubber chemistry and overall performance. The cost for the air pollution controls installed at this facility is in excess of $800 million.
18. The Kyger Creek Station's five units all have electrostatic precipitators for PM control and over-fire air and SCRs for NOx control. In addition, Units 1 and 2 and, separately, Units 3, 4, and 5, are scrubbed for SO2 control via two JBR scrubbers that came online in 2011 and 2012. The scrubber design is robust, and the facility is able to meet its MATS emission limits as a co-benefit via the management of the scrubber chemistry and overall performance. The cost for the air pollution controls installed at this facility is in excess of $800 million.
19. In addition to the costs referenced above for myriad compliance obligations under various EPA regulations promulgated under the Clean Air Act, OVEC also made substantial investments in water pollution control systems required under the Clean Water Act. Specifically, in 2023, the bottom ash handling systems at both the Clifty Creek and Kyger Creek Stations were upgraded to include tanks in a closed-loop configuration (with a purge/blowdown of up to 10%). Both stations also installed new low-volume wastewater treatment systems for a combined total capital cost of approximately $160 million. In addition, the Kyger Creek generating station invested an additional $35 million to convert the facility to a dry fly ash handling system that was placed into service in late 2022. OVEC is now upgrading its flue gas desulfurization wastewater treatment plant at each facility by installing bioreactors. OVEC plans to have the additional treatment systems installed and operational by no later than December 31, 2025, at an additional total capital cost of approximately $70 million. All of these wastewater treatment system investments were needed to comply with the EPA's 2020 Steam Electric Effluent Limitation Guidelines (ELG), as well as the EPA's 2015 Coal-combustion residuals (CCR) Regulations.

20. The end users of most of the electricity in OVEC's Sponsoring Companies' service territory live in rural areas with some of the lowest economic demographics in the United States.
21. OVEC's baseload electric generation resources power the PJM region, and that baseload generation sustains the grid with reliable access to energy. A balanced generation mix including adequate baseload generation and capacity is essential to maintain a safe and reliable grid.

ADDITIONAL CONTROL REQUIREMENTS UNDER EPA'S GHG RULE

22. EPA's GHG Rule will require most, if not all, coal-fired power plants – including OVEC's two power plants – to shut down, pure and simple. The current EPA Rule is one of many (including the 2024 updates to the Mercury and Air Toxics Standards (MATS), the 2024 Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (ELGs), 2023 revisions to the "Good Neighbor" Rule, and the 2024 Legacy CCR Surface Impoundment Rule) that impose new substantial additional costs, and in the case of the GHG and ELG rules, require immediate major capital investments in unproven technologies for any coal-fired unit that intends to run beyond 2038 (or even earlier for zero-liquid-discharge (ZLD) technologies applicable to scrubber wastewater under the 2024 ELG rule). The exorbitant costs for the GHG Rule itself are self-evident; however, the cumulative cost to comply with the full suite of new environmental regulations promulgated by the USEPA in 2024 will result in the premature retirement of reliable base-load thermal generation assets. The cumulative impact OVEC specifically faces is a cumulative weight represented by the cost to comply with the full suite of new and costly regulations targeting coal-fired steam electric generating facilities across all media (Air, Water, and solid waste). The collective weight of those rules is designed to accomplish one thing – to force coal plants into retirement.
23. Existing coal-fired generating stations in the States of Ohio and Indiana, including OVEC's units, are covered by the GHG Rule and both states are part of the 27 states, to date, that have already separately challenged this rule via requests for reconsideration, via emergency stay requests, or both.
24. Starting in 2024, EGUs in Indiana and Ohio will be required to begin making decisions as to how to comply with the GHG Rule and to submit those decisions to the state agencies responsible for developing State Plans to implement the GHG Rule. Among

the early decisions utility companies, including OVEC, must make is which subcategory will apply to each of their units. Compliance options and future facility retirement dates will be determined by these decisions. However, the only viable option for the vast majority of base-load coal-fired generating units – including OVEC's units – will be to retire, and that will further exacerbate the tenuous hold the regional transmission organizations (RTOs) have on grid reliability, likely jeopardizing reliability for millions of people, and resulting in de-facto generation shifting from reliable thermal base-load generation to renewable generation that cannot provide the capacity needs of the RTOs.

25. CCS is not viable, not proven, and not cost-effective, and would be rife with uncertainty due to anticipated legal challenges associated with any source's attempt to install this unproven technology. Regardless, OVEC cannot elect this subcategory because it is physically impossible to construct CCS and have it operational at either of its power plants by January 1, 2032.
26. OVEC has completed a preliminary review of converting the OVEC units to co-fire with 40% natural gas. This review is broken down into discussions set forth below with respect to gas pipeline supply/availability, pipeline construction/permitting, conversion costs, and operational challenges.
27. Gas Pipeline Supply and Availability: The nearest gas pipeline to the Clifty Creek Station is 12 miles away, and OVEC has not yet determined if that line is able to provide an adequate supply. However, we do know that PJM has stated that, "…gas availability for co-firing or for fuel switching is very limited because present gas pipelines are largely fully subscribed, and PJM also pointed out significant challenges with building out new pipeline infrastructure, which also often include local opposition." The cost for construction of a lateral, per industry estimates, is typically in the $4-8 million per mile; however, OVEC also has determined via Sponsoring Company discussions that the gas suppliers must invest additional capital in securing supply, installing pumping stations, etc. and that the industry generally requires a firm commitment from the utility to purchase gas transportation services for 20-25 years in order for the pipeline company to amortize their investment costs. Such a long-term agreement is not logical since OVEC would be required to retire those units by no later than 2038 under the final GHG Rule.
28. Pipeline construction/permitting: Even if supply was available locally for co-firing, PJM has determined there are significant challenges to building new natural gas pipelines, including local opposition. OVEC also has determined through discussions with our utility

peers and Sponsoring Companies that permitting new pipeline construction can take 5+ years as well. Thus, if a source has not already begun the process, it is unlikely that permitting and construction of a pipeline could be completed in time to meet the January 1, 2030 compliance date in the Rule.

29. Conversion costs and Operational Challenges: OVEC has 1950's vintage wet-bottom, wall-fired boilers at both the Clifty Creek and Kyger Creek Station. Due to the unit design, co-firing with gas will require substantial modifications to facility operations that may not be required for other boilers. For example, OVEC anticipates needed modifications to co-fire with gas would include resizing and installing new ID fans, installing more expensive and challenging gas burners due to the rectangular burner configurations on the OVEC fleet, and substantial upgrades to various controls to meet current NFPA code requirements. In addition to the equipment upgrades and facility modifications, OVEC would need to conduct an evaluation to determine if adequate heat transfer with gas co-firing can occur to ensure the SCRs installed for NOx controls can achieve the temperatures needed to effectively manage facility NOx emissions. Co-firing with 40% gas may decrease SCR temperatures to the point where NOx removal efficiency would be degraded and/or where SCR operations would result in ammonium bisulfate formation and catalyst fouling materially impacting NOx removal efficiency and unit reliability. Finally, there are many other specific modifications and operating challenges required to co-fire with gas at the OVEC units due to the boiler design. The additional costs for conversion, the uncertainty over gas supply availability and delivery timelines, the limited time for cost recovery (units could co-fire with gas for no longer than December 31, 2038), the age of the units, and the contractual terms for firm gas delivery (if even available in an adequate supply and if the pipeline permitting and installation can be completed in time), combined with the separate capital investments to comply with the new wastewater treatment mandates in the EPA's new ELG rule finalized in 2024, will be factored into OVEC's Board of Directors and management team's decisions, absent a stay. The impacts of other regulations such as the ELG rule, are also part of this equation, as co-firing with gas and running the OVE units until no later than December 31, 2038, also would require an investment and the installation of new ELG Rule wastewater treatment system upgrades "as soon as possible" but by no later than December 31, 2029. The collective weight and these new capital-intensive compliance obligations, combined with back-end constraints on how long the units could

operate co-firing with gas, likely would result in only one viable option absent a stay – premature unit retirements.

30. Because neither CCS nor gas co-firing, are viable options for OVEC, absent a stay, OVEC will be required to make unit and facility retirement decisions by 2026 under the GHG rule (or by no later than December 31, 2025, under the ELG rule). In other words, the GHG rule will require OVEC to commit to removing 2,389 MW of thermal baseload generation nearly a decade prematurely, regardless of what kind of generation and/or transmission reliability issues that may cause for the local RTO, PJM.
31. The OVEC units have been specifically dispatched on numerous occasions in the last few years by PJM to aid in relieving grid reliability issues in both the PJM and the MISO RTO footprints and to provide needed generation capacity during storm events. Implementation of the GHG Rule will eliminate the demonstrated value OVEC's generation provides from a grid reliability standpoint.
32. PJM issued a Phase 3 Energy Transition Report[2] on February 24, 2023, documenting PJM's ongoing study of impacts associated with resource retirements, replacement, and the associated risks from the energy transition activities that are underway. This report outlined the pace of resource retirements and replacements through 2030 based on final rules at that time and highlighted potential reliability risks to meeting growing electricity demand. Specifically, the analysis shows that 40 GW of existing generation are at risk of retirement, and PJM's study projections indicate that the current pace of new entry would be insufficient to keep up with expected retirements and demand growth by 2030. Unfortunately, PJM's dire analysis is even worse. The reason is simple, PJM's analysis and conclusions expressing these concerns were also based on the previous suite of EPA rules, not on the new set of new environmental regulations targeting thermal baseload fossil generation EPA has rolled out in 2024. These new set of rules, which include the GHG and ELG Rules, will drive deeper and faster unit retirements, further exacerbating grid reliability issues PJM raised in their 2023 report, and further validated in their May 8, 2024 statement[3]. OVEC submits that PJM's statement further validates unacceptable reliability and resource adequacy issues that support a stay request.
33. RTOs and power generators have no time to devise a diligent plan in future years to ensure compliance with the GHG rule while securing grid reliability and public safety.

[2] energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx (*Attachment 1)*

[3] 20240508-pjm-statement-on-the-newly-issued-epa-greenhouse-gas-and-related-regulations.ashx (*Attachment 2)*

Despite being urged to do so in public comments, EPA provided no meaningful "safety valve" for reliability in the new Rule. Limited one-year extensions conditioned on approval by EPA are not adequate.

34. Compliance with the GHG Rule will entail considerable costs to OVEC, its Sponsoring Companies, and ultimately their customers. Sponsoring Companies' costs include the immediate cost of any OVEC debt that may be rendered in default in the event of a premature unit or facility retirement decision, the cost each Sponsor Company will incur to replace the 2,389 MW generation from OVEC including notifications to their RTOs, balancing authorities, state commissions, cooperative associations, and the actual cost for procuring or building the replacement power consistent with their respective obligations to serve their customers. The costs for OVEC may include corporate "cessation of operations," the range of human resource and retention issues resulting from such an action, impacts to local communities including tax revenues, and other ancillary costs associated with the dissolution of a business. These costs will impact not only OVEC but its owners and their customers.
35. The GHG Rule also sets an aggressive compliance timeframe. It will be particularly challenging for states to develop and finalize plans to implement the rule. That leaves virtually no time for RTOs and generators to plan for and model the total impacts associated with coal-fired generation retirements. The lack of adequate time to react to the new requirements of the GHG Rule could place the reliability of the bulk power grid in jeopardy.
36. Without having the greenhouse gas Final Rule stayed and fully adjudicated and overturned by the end of 2025 (or the 2024 ELG rule also stayed), OVEC and many other affected EGUs otherwise planning to operate after 2034 will be faced with the prospect of making an uneconomic environmental expenditure (uneconomic because of the shortened life of the OVEC resulting from the Final Rule) to comply with the 2024 ELG Rule, or making a retirement commitment through the issuance of a Notice of Planned Participation (NOPP) by the end of 2025 under the new ELG rule (earlier than the retirement commitment required under the greenhouse gas Final Rule, which is via the state SIP process due in 2026), with no assurance that a NOPP retirement commitment would not remain binding, or that compliance with the 2024 ELG rule by 2029 would even be possible, if the Final GHG Rule were ultimately overturned at the end of the litigation process.

Cost of Further Evaluating Gas Co-Firing

37. If OVEC incurs costs to further evaluate gas co-firing or any other option beyond the premature retirement of the generation assets this rule mandates, those costs would be borne by OVEC's Sponsoring Companies in the first instance and presumably by the Sponsoring Companies' commercial, residential and industrial customers.
38. This process also will require OVEC to enter into contracts that may include cancellation fees and termination penalties if this court later overturns EPA's GHG Rule. For example, from OVEC's initial discussions with Sponsor Companies, and with initial investigations into gas-co firing, permitting and construction of natural gas pipeline laterals take a minimum of 5 years, and generally require a gas procurement commitment of 20+ years to allow the gas companies to recoup their investment in compressors, and other infrastructure beyond the lateral pipeline connection needed for gas delivery. Sources that are looking to co-fire may already be too late to start, and if not, contracts to initiate gas delivery and pipeline construction need to begin now to have any hope of being in place by January 1, 2030. Should OVEC or any other coal-fired facility begin that process, that investment in time and capital would be wasted once the legal challenges of this rule are resolved on the merits – unless this court does the right thing and stays the rule.
39. The GHG Rule does not give utilities adequate time to build replacement generation for retiring coal-fired assets, which is crucial to maintain reliability.

CONCLUSION

40. The GHG Rule (and the suite of additional EPA Rules issued in 2024) will result in the early closure of OVEC facilities and the dissolution of OVEC itself.
41. This irreparably and immediately harms OVEC, its owners, and our owner's end-use retail customers by requiring OVEC's Sponsors listed in the Table below to prematurely end the intercompany power agreement in effect through June 30, 2040, and begin the process of seeking replacement power for the 2,389 MW of generation that OVEC's Sponsoring Companies in Indiana, Kentucky, Ohio, Michigan, and West Virginia will lose.

OVEC-IKEC Shareholders and Sponsoring Companies

Sponsoring Company Information				
Parent Entity	**Equity Owner**	**Equity Ownership %**	**Power Participant**	**Power Participation %**
AEP	American Electric Power Co, Inc.	39.17%	Appalachian Power Company	15.69%
			Indiana Michigan Power Company	7.85%
	Ohio Power Company	4.30%	Ohio Power Company	19.93%
Buckeye Power, Inc.	Buckeye Power Generating	18.00%	Buckeye Power Generating	18.00%
Duke Energy	Duke Energy Ohio	9.00%	Duke Energy Ohio	9.00%
FirstEnergy	Ohio Edison Company	0.85%	Allegheny Energy Supply	3.01%
	Allegheny Energy, Inc.	3.50%	Monogahela Power Company	0.49%
	The Toledo Edison Company	4.00%		
PPL	Louisville Gas and Electric	5.63%	Louisville Gas and Electric	5.63%
	Kentucky Utilities	2.50%	Kentucky Utilities	2.50%
Wolverine Power Supply	Peninsula Generation Cooperative	6.65%	Peninsula Generation Cooperative	6.65%
The AES Corporation	Dayton Power & Light	4.90%	Dayton Power & Light	4.90%
CenterPoint Energy, Inc.	Southern Indiana Gas & Electric	1.50%	Southern Indiana Gas & Electric	1.50%
Vistra	N/A	N/A	Vistra Vision	4.85%

42. OVEC sees the combined effect of the greenhouse gas Final Rule and the 2024 ELG Rule to specifically pressure affected EGUs to make binding commitments to retire, whether by 2025 under the 2024 ELG Rule, and/or by 2026 under the greenhouse gas Final Rule, by forcing OVEC to face the prospect of having to make uneconomic or technically impossible investments required under the rules, that are ultimately unlikely to be upheld. Further, absent a stay, if the utilities ultimately prevail in court, it could be too late to unwind the sponsor's efforts to prematurely end the OVEC contract, announce unit closures, and seek replacement power. Both the GHG and ELG rules require binding commitments for the "cessation of coal combustion" subcategories that are to be made during the limited window of time while the rules are still under appeal and regulatory uncertainty prevails. For this reason, and given the combined effect of the two

rules issued at the same time by EPA and as part of a package of four power plant rules designed to unlawfully force generation shifting, it is imperative that both the 2024 ELG Rule and the greenhouse gas Final Rule be stayed.

43. For the reasons described above, OVEC, its sponsors, and potentially its sponsors' customers are facing substantial and irreparable harm from the implementation of the GHG Rule unless this rule is stayed.

I, J. Michael Brown, declare under penalty of perjury that the foregoing is true and correct. Executed this 22nd day of May 2024.

J. Michael Brown

J. Michael Brown

Attachment I

Energy Transition in PJM:
Resource Retirements, Replacements & Risks

Feb. 24, 2023

For Public Use

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Contents

Executive Summary

Driven by industry trends and their associated challenges, PJM developed the following strategic pillars to ensure an efficient and reliable energy transition: facilitating decarbonization policies reliably and cost-effectively; planning/operating the grid of the future; and fostering innovation.

PJM is committed to these strategic pillars, and has undertaken multiple initiatives in coordination with our stakeholders and state and federal governments to further this strategy, including interconnection queue reform, deployment of the State Agreement Approach to facilitate 7,500 MW offshore wind in New Jersey, and coordination with state and federal governments on maintaining system reliability while developing and implementing their specific energy policies.

In light of these trends and in support of these strategic objectives, PJM is continuing a multiphase effort to study the potential impacts of the energy transition. The first two phases of the study focused on energy and ancillary services and resource adequacy in 2035 and beyond. This third phase focuses on resource adequacy in the near term through 2030.[1]

Maintaining an adequate level of generation resources, with the right operational and physical characteristics[2], is essential for PJM's ability to serve electrical demand through the energy transition.

Our research highlights four trends below that we believe, in combination, present increasing reliability risks during the transition, due to a potential timing mismatch between resource retirements, load growth and the pace of new generation entry under a possible "low new entry" scenario:

- The growth rate of electricity demand is likely to continue to increase from electrification coupled with the proliferation of high-demand data centers in the region.
- Thermal generators are retiring at a rapid pace due to government and private sector policies as well as economics.
- Retirements are at risk of outpacing the construction of new resources, due to a combination of industry forces, including siting and supply chain, whose long-term impacts are not fully known.
- PJM's interconnection queue is composed primarily of intermittent and limited-duration resources. Given the operating characteristics of these resources, we need multiple megawatts of these resources to replace 1 MW of thermal generation.

[1] See Energy Transition in PJM: Frameworks for Analysis | Addendum (2021), and Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid | Addendum (2022).

[2] See previous work on Reliability Products and Services, including PJM's Evolving Resource Mix and System Reliability (2017), Reliability in PJM: Today and Tomorrow (2021), Energy Transition in PJM: Frameworks for Analysis | Addendum (2021), and work completed through the RASTF and PJM Operating Committee (2022).

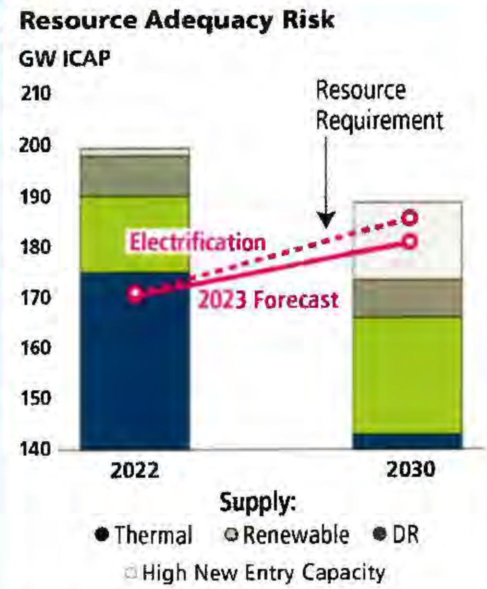
The analysis also considers a "high new entry" scenario, where this timing mismatch is avoided. While this is certainly a potential outcome, given the significant policy support for new renewable resources, our analysis of these long-term trends reinforces the importance of PJM's ongoing stakeholder initiatives, including capacity market modifications, interconnection process reform and clean capacity procurement, and the urgency for continued, combined actions to de-risk the future of resource adequacy while striving to facilitate the energy policies in the PJM footprint.

The first two phases of the energy transition study assumed that PJM had adequate resources to meet load.

In this this third phase of this living study, we explore a range of plausible scenarios up to the year 2030, focusing on the resource mix "balance sheet" as defined by generation retirements, demand growth and entry of new generation.

The analysis shows that 40 GW of existing generation are at risk of retirement by 2030. This figure is composed of: 6 GW of 2022 deactivations, 6 GW of announced retirements, 25 GW of potential policy-driven retirements and 3 GW of potential economic retirements. Combined, this represents 21% of PJM's current installed capacity[3].

In addition to the retirements, PJM's long-term load forecast shows demand growth of 1.4% per year for the PJM footprint over the next 10 years. Due to the expansion of highly concentrated clusters of data centers, combined with overall electrification, certain individual zones exhibit more significant demand growth – as high as 7% annually.[4]



The projections in this study indicate that it is possible that the current pace of new entry would be insufficient to keep up with expected retirements and demand growth by 2030.

On the other side of the balance sheet, PJM's New Services Queue consists primarily of renewables (94%) and gas (6%). Despite the sizable nameplate capacity of renewables in the interconnection queue (290 GW), the historical rate of completion for renewable projects has been approximately 5%. The projections in this study indicate that the current pace of new entry would be insufficient to keep up with expected retirements and demand growth by 2030. The completion rate (from queue to steel in the ground) would have to increase significantly to maintain required reserve margins.

In the study, we also consider generation entry beyond the queue using projections from S&P Global. Those projections indicate that, despite eroding reserve margins, resource adequacy would be maintained if the influx of renewables materializes at a rapid rate and gas remains the transition fuel, adding 9 GW of capacity. The analysis performed at the Clean Attribute Procurement Senior Task Force (CAPSTF) also suggests that further gas expansion is economic and competitive.[5]

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3 Unless otherwise noted, thermal capacity values are expressed in ICAP, without adjustment for EFORd.

4 PJM Load Forecast Report, January 2023.

5 CAPSTF Analysis, Initial Results; Emmanuele Bobbio, Sr. Lead Economist – Advanced Analytics, PJM, Dec. 16, 2022.

Balance Sheet Summary (2022–2030)				
Retirements	**New Entry Wind/Solar**[6]	**New Entry Standalone Storage**	**New Entry Thermal**	**Load Growth**
40 GW **60% Coal** **30% Natural Gas** **10% Other**	**Low =** 48 GW-nameplate / 8 GW-capacity **High =** 94 GW-nameplate / 17 GW-capacity	**Low =** 3 GW **High =** 4 GW	**Low =** 4 GW **High =** 9 GW	**2023 Forecast =** 11 GW **Electrification Forecast =** 13 GW
Unless otherwise noted, thermal capacity values are expressed in ICAP, without adjustment for EFORd.				

For the first time in recent history, PJM could face decreasing reserve margins should these trends continue. The amount of generation retirements appears to be more certain than the timely arrival of replacement generation resources and demand response, given that the quantity of retirements is codified in various policy objectives, while the impacts to the pace of new entry of the Inflation Reduction Act, post-pandemic supply chain issues, and other externalities are still not fully understood.

The findings of this study highlight the importance of PJM's ongoing stakeholder initiatives (Resource Adequacy Senior Task Force, Clean Attribute Procurement Senior Task Force, Interconnection Process Subcommittee), continued efforts between PJM and state and federal agencies to manage reliability impacts of policies and regulations, and the urgency for coordinated actions to shape the future of resource adequacy. The potential for an asymmetrical pace in the energy transition, in which resource retirements and load growth exceed the pace of new entry, underscores the need to enhance the accreditation, qualification and performance requirements of capacity resources.

The composition and performance characteristics of the resource mix will ultimately determine PJM's ability to maintain reliability. It is critical that all PJM markets effectively correct imbalances brought on by retirements or load growth by incentivizing investment in new or expanded resources.

[6] Includes hybrid projects with battery storage

Background

Resource adequacy is the ability of the electric system to supply the aggregate energy requirements of electricity to consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of generation and transmission facilities. To achieve the goal of resource adequacy, PJM maintains an Installed Reserve Margin in excess of the forecast peak load that achieves a loss-of-load expectation (LOLE) of one day in 10 years. This LOLE standard is consistent with that prescribed in the ReliabilityFirst Corporation standard for planning resource adequacy.[7]

Long-term reliability and resource adequacy are addressed through the combined operation of PJM's electricity markets, and in particular the capacity market, called the Reliability Pricing Model (RPM). Each PJM member that provides electricity to consumers must acquire enough power supply to meet demand, not only for today and tomorrow, but for the future. Members secure these capacity resources for future energy needs through a series of base and incremental capacity auctions, as well as Fixed Resource Requirement plans.

The capacity market ensures long-term grid reliability by procuring the appropriate amount of power supply resources needed to meet predicted energy demand up to three years in the future. These capacity resources have an obligation to perform during system emergencies, and are subject to penalties if they underperform. By matching generation with future demand, the capacity market creates long-term price signals to attract needed investments to ensure adequate power supplies. This exchange provides consumers with an assurance of reliable power in the future, while capacity resources receive a dependable flow of income to help maintain their existing capability, attract investment in new resources, and encourage companies to develop new technologies and sources of electric power.

Methodology

The size, composition and performance characteristics of the resource mix will determine PJM's ability to maintain reliability. This study explores a range of scenarios in the context of resource adequacy, focusing on the resource mix "balance sheet" as defined by demand growth, generation retirements and new entry of generation. Using the methodology described in this section, PJM evaluates the future of resource adequacy by estimating the amount of capacity required to cover load expectations versus expected capacity for the years 2023 through 2030.

The study's initial supply levels are 192.3 GW of installed capacity from generation resources and 7.8 GW of installed capacity from demand response capacity resources. The generation mix is approximately 178.9 GW of thermal resources and 13.3 GW of renewables and storage.[8]

[7] RFC Standard BAL-502-RF-03: Planning Resource Adequacy Analysis, Assessment and Documentation

[8] This value includes the capacity value of run-of-river hydro, pumped storage hydro, solar, onshore wind, offshore wind and battery energy storage.

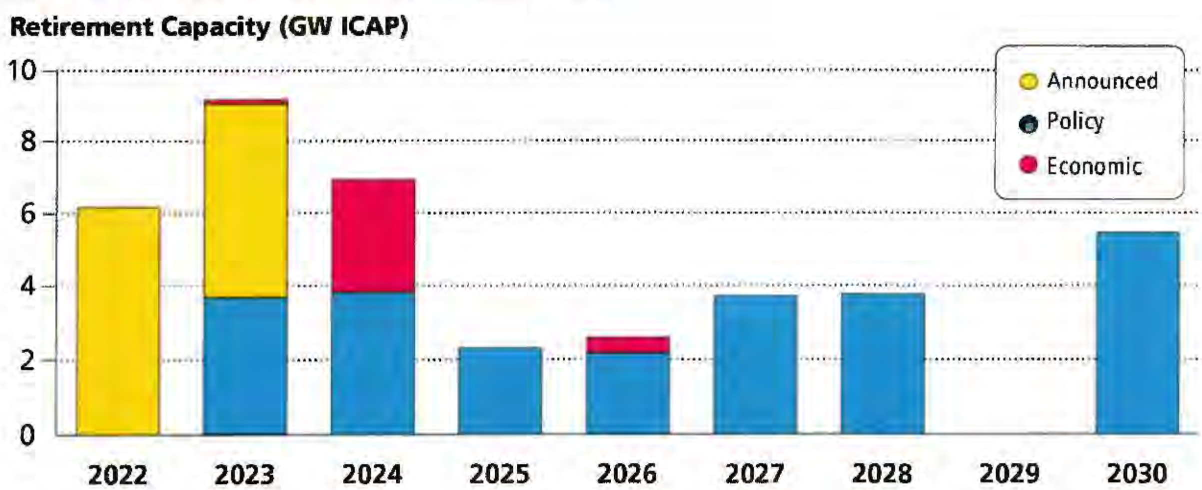
Supply Exits

PJM is undergoing a major transition in the resources needed to maintain bulk power grid reliability.

Historically, thermal resources have provided the majority of the reliability services in PJM. Today, a confluence of conditions, including state and federal policy requirements, industry and corporate goals requiring clean energy, reduced costs and/or subsidies for clean resources, stringent environmental standards, age-related maintenance costs, and diminished energy revenues are hastening the decline in thermal resources.

This study estimates anticipated retirements through 2030 by adding announced retirements with retirements likely as a result of various state and federal policies, and then with those at risk for retirement due to deteriorating unit economics. Potential policy-driven retirements, in this context, reflect resources that are subject to current and proposed federal and state environmental policies, in which it is conservatively assumed that the costs of mitigation and compliance could economically disadvantage these resources to the point of retirement. **Figure 1** highlights the 40 GW of projected generation retirements by 2030, which is composed of: 12 GW of announced retirements[9], 25 GW of potential policy-driven retirements[10] and 3 GW of potential economic retirements. Combined, this represents 21% of PJM's current installed capacity.[11] This section describes each category of potential retirements in more detail.

Figure 1. Total Forecast Retirement by Year (2022–2030)



[9] Includes 6 GW of 2022 retirements.

[10] Note that 7 GW of the 25 GW of supply with policy risk was also identified to have more immediate economic risk. The year that these 7 GW of potential policy retirements shown in **Figure 2** is based on timing identified in the economic analysis. In **Figure 4**, these 7 GW are shown in terms of the regulatory compliance timeline alone. The timeline of these potential quantities of resource retirements does not factor in any reliability "off-ramps" that may be included in established policies.

[11] In this study, PJM assumes that a resource that exits would not return to service in a future delivery year, even if operational conditions improve. Historically, a small percentage of retiring units would instead enter a "mothball" or standby state, in which the unit is put into a state where it may not operate for one or more years; however, in order to obtain an operating permit renewal, the mothballed unit would have to comply with the most recent environmental standards, likely requiring costly upgrades, making investing in newer, cleaner technologies more inviting.

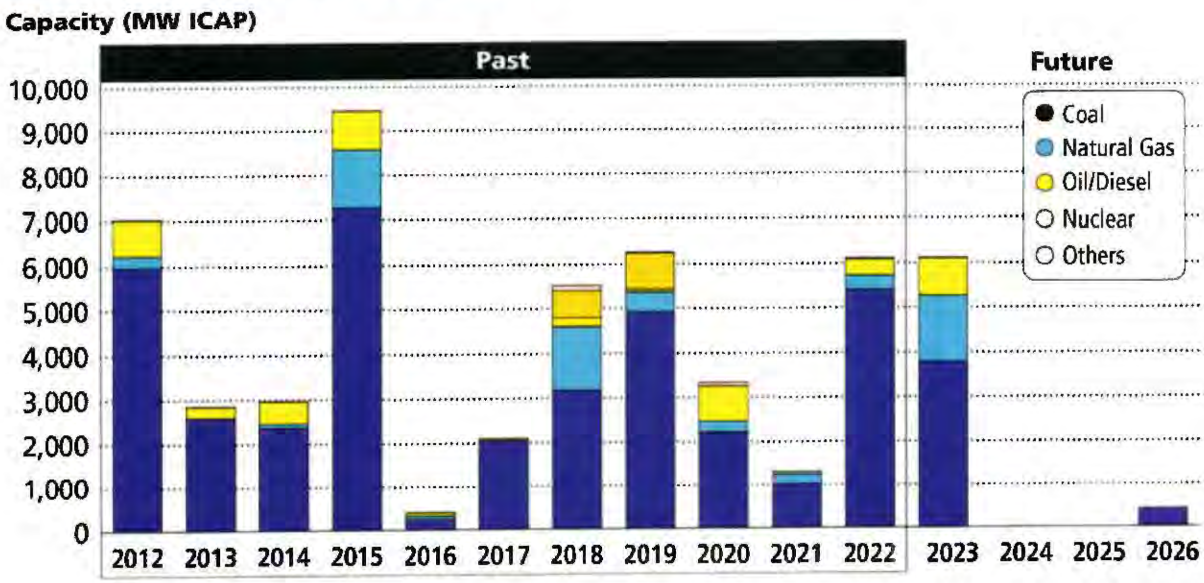
Announced Retirements

One of PJM's responsibilities is to ensure the continued reliability of the high-voltage electric transmission system when a generation owner requests deactivation. Through its Generation Deactivation process,[12] PJM identifies transmission solutions that allow owners to retire generating plants as requested without threatening reliable power supplies to customers. PJM may order transmission upgrades or additions built by transmission owners to accommodate the generation loss. PJM has no authority to order plants to continue operating. However, in some instances, to maintain reliability, PJM may formally request that a plant owner continue operating, subject to rates authorized by the Federal Energy Regulatory Commission (FERC), while transmission upgrades are completed.

Plant owners considering retirement must notify PJM at least two quarters before the proposed deactivation date. PJM and the transmission owners complete a reliability analysis in the subsequent quarter after notification to PJM. Generator retirements and any required system upgrades to keep the grid running smoothly are included in the PJM Regional Transmission Expansion Planning process and are reviewed with PJM members and stakeholders at the PJM Transmission Expansion Advisory Committee.

Between 2012 and 2022, 47.2 GW of generation retired in PJM, as detailed by fuel type in **Figure 2**. In 2022, approximately 6 GW of generation deactivated and an additional 5.8 GW announced ("future") deactivations over the 2023–2026 time frame. The deactivations are slightly above the 10-year average of 4.3 GW, but well under the historical annual peak of 9.5 GW in 2015. Coal-fired resources account for approximately 89% of retired capacity in 2022.

Figure 2. Past and Announced Future Retirements



12 See process details in PJM Manual 14-D, Section 9, and tracking of deactivation requests at https://www.pjm.com/planning/services-requests/gen-deactivations.

Potential Policy Retirements

An analysis of federal and state policies and regulations with direct impacts on generation in the PJM region yielded the largest group of potential future retirements in this study.[13] As highlighted in **Figure 3**, the combined requirements of these regulations and their coincident compliance periods have the potential to result in a significant amount of generation retirements within a condensed time frame. These impacts will be reevaluated as these policies and regulations evolve. PJM will continue to work with both federal and state agencies on the development and implementation of environmental regulations and policies in order to address any reliability concerns.

Below are the policies and regulations included in the study:

EPA Coal Combustion Residuals (CCR): The U.S. Environmental Protection Agency (EPA) promulgated national minimum criteria for existing and new coal combustion residuals (CCR) landfills and existing and new CCR surface impoundments. This led to a number of facilities, approximately 2,700 MW in capacity, indicating their intent to comply with the rule by ceasing coal-firing operations, which is reflected in this study.

EPA Effluent Limitation Guidelines (ELG): The EPA updated these guidelines in 2020, which triggered the announcement by Keystone and Conemaugh facilities (about 3,400 MW) to retire their coal units by the end of 2028.[14] Importantly, but not included in this study, the EPA is planning to propose a rule to strengthen and possibly broaden the guidelines applicable to waste (in particular water) discharges from steam electric generating units. The EPA is expecting this to impact coal units by potentially requiring investments when plants renew their discharge permits, and extending the time that plants can operate if they agree to a retirement date.

EPA Good Neighbor Rule (GNR): This proposal requires units in certain states to meet stringent limits on emissions of nitrogen oxides (NOx), which, for certain units, will require investment in selective catalytic reduction to reduce NOx. For purposes of this study, it is assumed that unit owners will not make that investment and will retire approximately 4,400 MW of units instead. Please note that the EPA plans on finalizing the GNR in March, which may necessitate reevaluation of this assumption.

Illinois Climate & Equitable Jobs Act (CEJA): CEJA mandates the scheduled phase-out of coal and natural gas generation by specified target dates: January 2030, 2035, 2040 and 2045. To understand CEJA criteria impacts and establish the timing of affected generation units' expected deactivation, PJM analyzed each generating unit's publically available emissions data, published heat rate, and proximity to Illinois environmental justice communities and Restore, Reinvest, Renew (R3) zones. For this study, PJM focuses on the approximately 5,800 MW expected to retire in 2030.

[13] Policies impacting forward energy prices, such as the Regional Greenhouse Gas Initiative and Renewable Energy Credits, are implicitly included in economic analysis but are not explicitly included in analysis of policy-related retirements.

[14] See State Impact PA, Nov. 22, 2021. These facilities have not filed formal Deactivation Notices with PJM.

New Jersey Department of Environmental Protection CO_2 Rule: New Jersey's CO_2 rule seeks to reduce carbon dioxide (CO_2) emissions of fossil fuel-fired electric generating units (EGUs) through the application of emissions limits for existing and new facilities greater than 25 MW. Units must meet a CO_2 output-based limit by tiered start dates. The dates and CO_2 limits are:

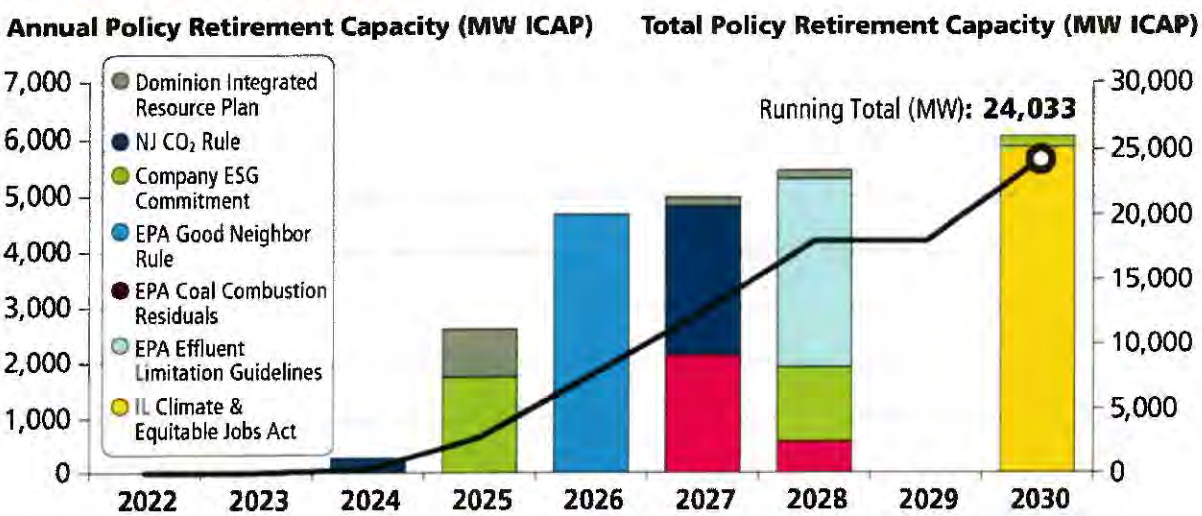
- June 1, 2024 – 1,700 lb/MWh
- June 1, 2027 – 1,300 lb/MWh
- June 1, 2035 – 1,000 lb/MWh

PJM used emissions data found in EPA Clean Air Markets Program Data to evaluate unit compliance. Where a unit's average annual emissions rate was greater than the CO_2 limit on the compliance date, the unit was assumed to be retiring. In this study PJM, estimated retirements at approximately 400 MW in 2024 and approximately 2,700 MW in 2027.

Dominion Integrated Resource Plan (IRP) commits to net zero carbon in its Virginia and North Carolina territory by 2050. PJM studied Dominion's Alternative Plan B retirement schedule, approximately 1,533 MW, for this analysis. Alternative Plan B proposes "significant development of solar, wind and energy storage resource envisioned by the VCEA," (Virginia Clean Economy Act of 2020), while maintaining natural gas generation for reliability, which is reflected in our analysis.

Company ESG (Environmental, Social, Governance) commitments are included where there is a commitment to retire resources per legal consent decree or other public statement. This includes the elimination of coal use and the retirement of the Brandon Shores, 1,273 MW, and Wagner, 305 MW, facilities in Maryland and the retirement of Rockport, 1,318 MW, in Indiana.

Figure 3. Potential Policy Retirements



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Potential Economic Retirements

The third category of retirements in this study, beyond those formally announced and made likely by policy implementation, were identified through an analysis of revenue adequacy, the ability to economically cover going-forward costs from the wholesale markets. A net profit value was calculated for each existing generation resource using an estimate of future revenues and historical costs.

$$\begin{aligned} Net\ Profit = (\ Gross\ Energy\ \&\ Ancillary\ Service\ Revenue - Production\ Costs\ ) \\ + (\ Capacity\ Revenue\ ) - (\ Fixed\ Avoidable\ Costs\ ) \end{aligned}$$

The results reveal that a portion of the thermal fleet is at risk of becoming unprofitable in the coming years.

The capacity market's Variable Resource Requirement (VRR) represents the set of prices for which load is willing to procure additional supply beyond the minimum reliability requirement. There are three points in the sloped demand curve, the first of which is anchored at a price 1.5 times the Net Cost of New Entry (Net CONE). Should the auction clear at this price level, the auction result signals that demand is willing to pay for the construction of new supply, minus the expected energy revenues the resource should expect to earn in the energy markets. As such, it is important to align the revenue expectations for the marginal resources with forward revenues, especially under PJM's continually changing landscape of business rules.

Energy & Ancillary Services Revenue and Production Cost

This study used a scaling approach to estimate forward unit-specific energy and ancillary services (E&AS) revenues from historical energy and ancillary service revenues by applying the following:

$$Fwd\ Unit\ E\&AS\ Revenue = Hist\ Unit\ E\&AS\ Revenue * \frac{Fwd\ Reference\ E\&AS\ Revenue^{15}}{Hist\ Reference\ E\&AS\ Revenue} * \frac{Reference\ Avg\ Heat\ Rate}{Unit\ Avg\ Heat\ Rate}$$

For a given reference resource type, unit dispatch was simulated using both historical and forward energy hub-adjusted energy prices. For the equivalent production cost model, the relative ratio of revenues and heat rates indicate the net effects of both rising fuel costs and energy price revenue. A unit on the margin in the energy markets, typically a natural gas unit, would set a locational price near its short-run marginal costs. Infra-marginal units, potentially coal units, would receive higher revenues as price-taking resources, and thus may see increased profitability. This is reflected in the analysis, in which a reference coal unit's forward revenues increased an average of 139% over previous revenue estimates.

[15] The forward energy and ancillary services revenue calculation used in this study is the method that was developed for use in the Forward Net Energy & Ancillary Services Offset calculation originally developed in 2020, and filed as part of the most recent Quadrennial Review.

Capacity Revenues and Fixed Avoidable Costs

Unit-specific capacity revenues were calculated from prices and cleared quantities in the 2023/2024 Base Residual Auction (BRA). The study used the published 2023/2024 BRA Default Gross Avoidable Cost Rate (ACR) values as representative total fixed costs ($/MW-day) required to keep the generating plant available to produce energy. In other words, these are projected costs that could be avoided by the retirement of the plant. Avoidable costs represent operational factors like operations and maintenance labor, fuel storage costs, taxes and fees, carrying charges, and other costs not directly related to the production of energy. When available, unit-specific ACR values from the 2023/2024 BRA supply offer mitigation process were used, otherwise the class average Gross ACR was used.

Results and Estimated Impact

This study assumes that a simulated economic loss would result in a retirement of the resource at the next available delivery year in which the unit is not committed for capacity. As such, a unit with a revenue loss that did not clear in the 2023/2024 BRA would exit in 2023, while a unit with a revenue loss that cleared in the 2023/2024 BRA would exit in 2024. While units that do not clear a single BRA may remain energy-only resources, this conservative assumption was used to provide awareness.

The economic analysis identified approximately 10 GW of supply in immediate economic risk, of which 7 GW of supply is also affected by policy risk, and 3 GW of supply is economic risk only. In aggregate, 6 GW are steam resources, and 4 GW represent combustion turbines and internal combustion resources. Several of the units identified were older steam boilers that had once converted from coal-fired to natural gas fuel; these resources are less efficient than a modern heat-recovery steam generator in a combined cycle unit. Fifty-three percent of the resources identified for economic risk did not have a PJM capacity obligation in Delivery Year 2023/2024, either through the FRR process or market clearing.

Supply Entry

The composition of the PJM Interconnection Queue has evolved significantly in recent years, primarily increasing in the amount of renewables, storage, and hybrid resources and decreasing in the amount of natural gas-fired resources entering the queue. The PJM New Services Queue stands at approximately 290 ICAP GW of generation interconnection requests, of which almost 94% (271 ICAP GW) is composed of renewable and storage-hybrid resources.

Natural Gas Headwinds

In the last decade, resources in the PJM region have benefitted from the proximity to the Marcellus Shale, an area that extends along the Appalachian Mountains from southern West Virginia to central New York. Beginning around 2010, gas extraction from hydraulic fracturing transformed this region into the largest source of recoverable natural gas in the United States. This local fuel supply decreased the prices for spot market natural gas in much of the PJM region, and prices in the PJM region often trade at negative basis to the Henry Hub spot price.

The entry of natural gas resources in the PJM region peaked in 2018, with 11.1 GW of generation commercializing that single year. From 2019 to 2022, a total of 8.1 GW of natural gas generation began service, or about a third of the 23 GW observed from 2015–2018. Queue proposals have also declined; over the last three years, only 4.1 GW of new natural gas projects entered the queue, while 15.1 GW of existing queue projects withdrew.[16]

Recent movement in the natural gas spot markets across the U.S. and Europe add another degree of uncertainty to future operations. In 2022, European natural gas supply faced many challenges resulting from the war in Ukraine and subsequent sanctions against Russia. Liquefied natural gas (LNG) imports into the EU and the U.K. in the first half of 2022 increased 66% over the 2021 annual average,[17] primarily from U.S. exporters with operational flexibility. This international natural gas demand is a new competitor for domestic spot-market consumers, resulting in significantly higher fuel costs for PJM's natural gas fleet.

This study assumes that, of the approximately 17.6 GW of natural gas generation in the queue, only those that are proposed uprates of existing generation, or currently under construction, will complete.[18] This results in 3.8 GW of entry from under-construction natural gas resources to be completed for the 2023/2024 Delivery Year. While 12 GW of natural gas have reached a signed Interconnection Service Agreement (ISA) stage, it is unclear what percentage of this capacity may move forward. If significantly more natural gas capacity achieved commercial operation, it could help avoid reliability issues.

Renewable Transition

PJM's projected resource mix continues to evolve toward lower-carbon intermittent resources. Entry into the queue from renewable and storage resources has been growing at an annualized rate of 72% per year since 2018, or 199 GW of capacity entry versus 2.8 GW commercializing and 42.1 GW withdrawn. This influx of renewable projects has led to a joint effort between PJM and its stakeholders to enact queue reforms intended to clear the backlog of projects, improve procedures around permitting and site control, simplify analysis by clustering projects, and accelerate projects that don't require network upgrades. FERC approved the proposed package in November 2022, with expected implementation in 2023.

Commercial Probability and Expanding Beyond the Queue

PJM staff developed several forecasts of the rate by which projects successfully exit the queue (the "commercial probability" of reaching an *In-Service* state). Since 1997, the PJM New Services Queue has tracked proposed generation interconnection projects from their submittal and study stages to completion of an ISA and Wholesale Market Participation Agreement (WMPA) and construction. At any point in the process, a resource may withdraw from the queue, effectively ending its commercial viability.

[16] This capacity represents natural gas projects that were submitted prior to 2020 and withdrawn in the 2020–2022 time frame.

[17] Europe imported record amounts of liquefied natural gas in 2022, U.S. Energy Information Administration, June 14, 2022.

[18] Under construction includes the New Service Queue *Partially in Service – Under Construction* and *Under Construction* statuses.

The study utilized a logistical regression classification algorithm to predict the probability of a project reaching an *In-Service* entry (or *Withdrawn* exit) based on several properties of the project. A logistical regression searches for patterns within training datasets, resulting in a model that can forecast a probability of a result. After applying the logistical regression model for 10 years of historical project completion (Y-queue to present) without project stage, approximately 15.3 GW-nameplate/8.7 GW-capacity were deemed commercially probable out of 178 GW of projects examined.

The model results for thermal resources were reasonably in line with expectations. However, the model produced extremely low entry from onshore wind, offshore wind, solar, solar-hybrid and storage resources. The uncertainty of completion rates of newer resource types, like offshore wind, likely plays a role in these model outcomes. After adjusting the new renewable capacity by Effective Load Carrying Capability (ELCC) derations, this commercial probability analysis estimates net 13.2 GW-nameplate / 6.7 GW-capacity to the system by 2030, as shown in **Figure 4**.

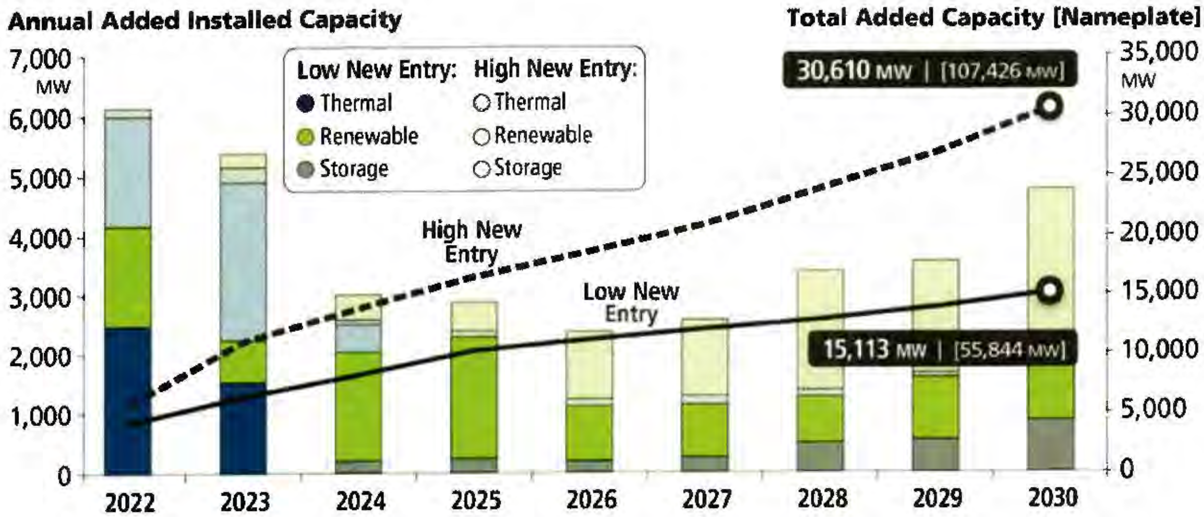
Given that this process may not capture recent policy changes and fiscal incentives toward renewable and storage development, and that the existing queue has fewer resources entered after 2026, PJM staff utilized two S&P Global Power Market Outlook analyses' generation expansion models. As estimates of future entry beyond the queue, these models are used to provide additional insight for the two scenarios: "Low New Entry" utilizes the "Planning Model,"[19] and "High New Entry" utilizes the "Fast Transition" model.[20] Based on these models, PJM added additional capacity to its commercial probability data in each scenario.

These forecasts of generation expansion are economic resource planning solutions, which take state RPS requirements and capacity margins into account to ensure new renewable builds. Over the study period, the Low New Entry scenario adds 42.6 GW-nameplate/8.4 GW-capacity to supply expectations, resulting in total entry of 55.8 GW-nameplate/15.1 GW-capacity. The High New Entry scenario adds 107 GW-nameplate/30.6 GW-capacity after ELCC derations. Net natural gas entry was approximately 5 GW, and renewables was 48.5 GW-nameplate/10.4 GW-capacity, as shown in **Figure 4**.

[19] S&P Global, North American Power Market Outlook, June 2022, planning model. This planning case incorporated effects from the 2021 Infrastructure Investment and Jobs Act, but not the 2022 Inflation Reduction Act.

[20] S&P Global, North American Power Market Outlook, Sept. 2022, Fast Transition model. This planning case assumes carbon net neutrality by 2050 through the IRA and additional policies, such as state clean energy policies, and as such assumes adjustments for increased electrification of heating, tax credits for renewable generation and higher levels of fossil retirements.

Figure 4. Forecast Added Capacity



Impact of Capacity Accreditation on Existing Renewables and Storage

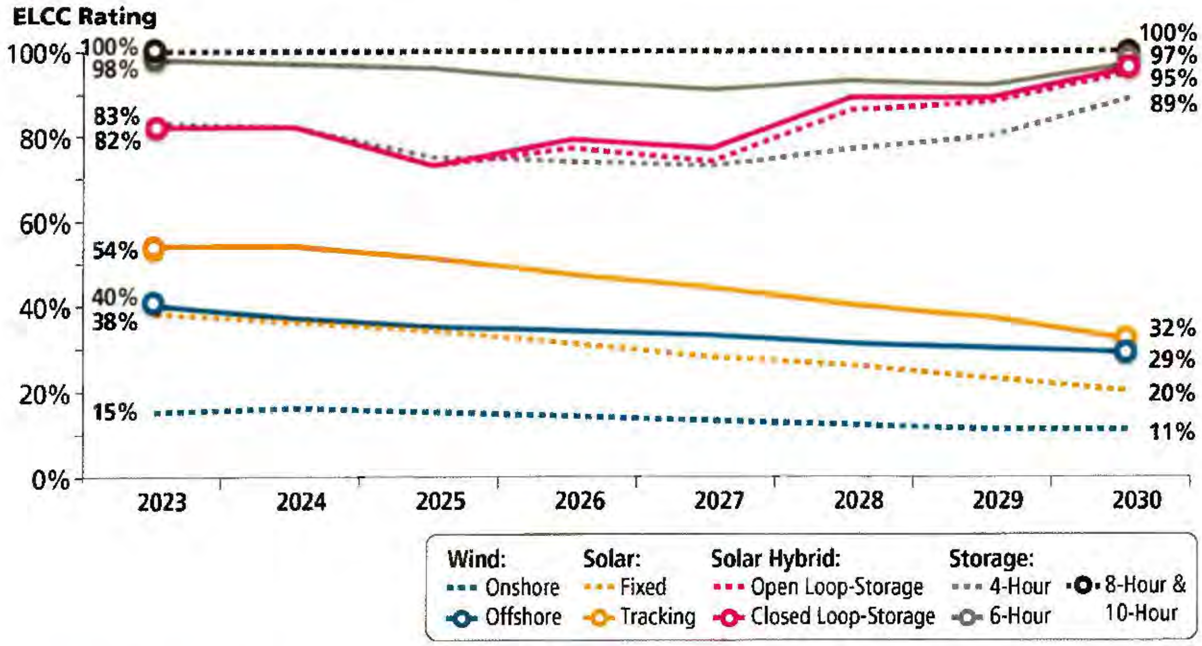
In July 2021, FERC accepted PJM's ELCC methodology for calculating unforced capacity values for intermittent and energy storage capacity resource classes. The ELCC analysis[21] examines load and resource performance uncertainty, and calculates an hourly loss-of-load probability (LOLP) to meet a one-in-10 year loss of load expectation (LOLE) adequacy criteria. The ELCC method examines the alignment of a given resource type's capacity to high risk hours, as well as the change in risk hours proportional to the changes in portfolio size. The adjustments to accredited capacity went into effect in the 2023/2024 BRA executed in June 2022.

This study examined the current renewable generation fleet for the impact of future changes in capacity accreditation. Today, there are approximately 3.5 GW of onshore wind and solar capacity resources participating in the RPM capacity market as intermittent resources. From 2022 to 2030, this accredited capacity is expected to decline by 1.2 GW to 2.3 GW due to portfolio effects resulting in the increase of entry from other intermittent renewable resources.[22] This adjustment is consistent with the renewable expectations presented in the December 2021 Effective Load Carrying Capability (ELCC) Report.

21 Manual 20, Section 5: PJM Effective Load Carrying Capability Analysis

22 Approximate nameplate needed to replace 1 MW of thermal generation: Solar – 5.2 MW; Onshore Wind – 14.0 MW; Offshore Wind – 3.9 MW. These are average values.

Figure 5. Effective Load Carrying Capability (ELCC) Rating by Resource Type



Demand Expectations

Load forecasting is an important part of maintaining the reliability of the bulk electric system. Forecasting helps PJM make decisions about how to plan and operate the bulk electric system in a reliable manner, and how to effectively administer competitive power markets. PJM's Resource Adequacy Planning Department publishes an annual Load Forecast Report, which outlines "long-term load forecasts of peak-loads, net energy, load management, distributed solar generation, plug-in electric vehicles and battery storage."

Along with the energy transition, PJM is witnessing a large growth in data center activity. Importantly, the PJM footprint is home to Data Center Alley in Loudoun County, Virginia, the largest concentration of data centers in the world.[23] PJM uses the Load Analysis Subcommittee (LAS) to perform technical analysis to coordinate information related to the forecast of electrical peak demand. In 2022, the LAS began a review of data center load growth and identified growth rates over 300% in some instances.[24] The 2023 PJM Load Forecast Report incorporates adjustments to specific zones for data center load growth, as shown in **Figure 5**.

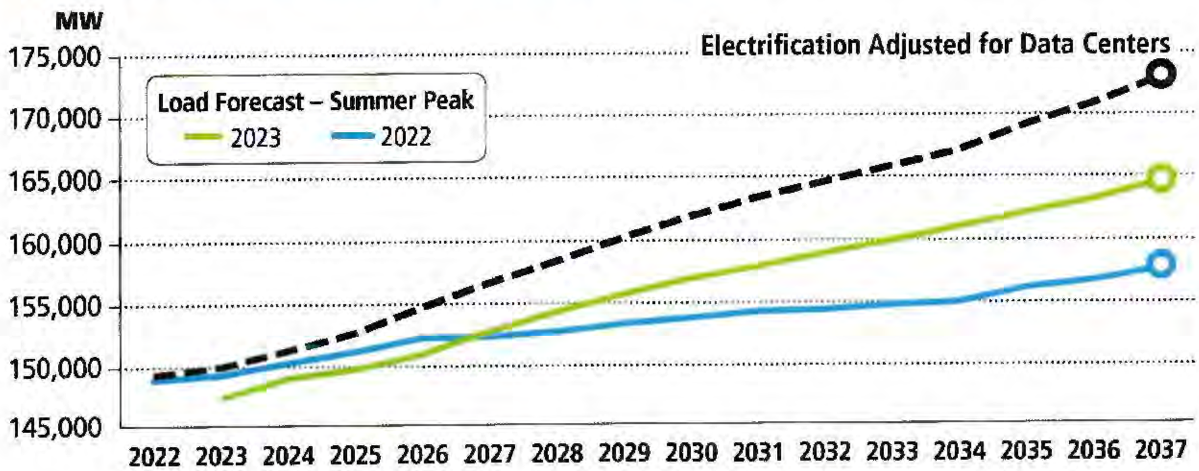
[23] See Loudoun County Department of Economic Development, 2023.

[24] Load Analysis Subcommittee: Load Forecast Adjustment Requests, Andrew Gledhill, Resource Adequacy Planning, Oct. 27, 2022

Additionally, PJM is expecting an increase in electrification resulting from state and federal policies and regulations. The study therefore incorporates an electrification scenario in the load forecast to provide insight on capacity need should accelerated electrification drive demand increases.[25] This accelerated demand increase is consistent with the methodology used in the Emerging Characteristics of a Decarbonizing Grid paper.[26] That paper found electrification to have an asymmetrical impact on demand growth, with demand growth in the winter, mainly due to heating, more than doubling that in the summer. This would move the bulk of the resource adequacy risk from the summer to the winter.

Figure 6 highlights how updated electrification assumptions and accounting for new data center loads have impacted the summer peak between the 2022 and 2023 forecasts.[27]

Figure 6. Impacts of Electrification and Data Center Load on Forecasts



What Does This Mean for Resource Adequacy in PJM?

PJM projects resource adequacy needs through the Reserve Requirement Study (RRS). The purpose of the RRS is to determine the required capacity or Forecast Pool Requirement for future years or delivery years based on load and supply uncertainty. The RRS also satisfies the North America Electric Reliability Corporation/ReliabilityFirst Adequacy Standard BAL-502-RFC-03, Planning Resource Adequacy Analysis, Assessment and Documentation, which requires that the Planning Coordinator performs and documents a resource adequacy analysis that applies a LOLE of one occurrence in 10 years. The RRS establishes the Installed Reserve Margin values for future delivery years. For this study PJM used the most recent 2022 RRS, as well as the 2021 RRS for comparison.

[25] Electrification assumptions are 17 million EVs, 11 million heat pumps, 20 million water heaters, 19 million cooktops in PJM by 2037, built on top of the 2022 Load Forecast.

[26] Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid, May 17, 2022.

[27] 2023 Load Forecast Supplement, PJM Resource Adequacy Planning Department, January 2023.

Combining the resource exit, entry and increases in demand, summarized in **Figure 7**, the study identified some areas of concern. Approximately 40 GW PJM's fossil fuel fleet resources may be pressured to retire as load grows into the 2026/2027 Delivery Year. At current low rates of renewable entry, the projected reserve margin would be 15%, as shown in **Table 1**. The projected total capacity from generating resources would not meet projected peak loads, thus requiring the deployment of demand response. By the 2028/2029 Delivery Year and beyond, at Low New Entry scenario levels, projected reserve margins would be 8%, as projected demand response may be insufficient to cover peak demand expectations, unless new entry progresses at a levels exhibited in the High New Entry scenario. This will require the ability to maintain needed existing resources, as well as quickly incentivize and integrate new entry

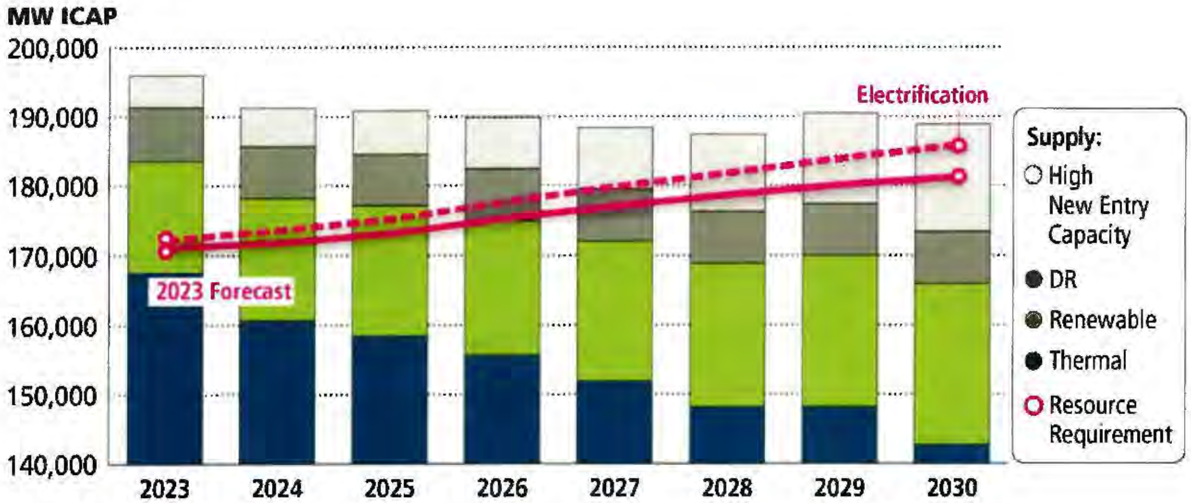
Table 1. Reserve Margin Projections Under Study Scenarios

Reserve Margin	2023	2024	2025	2026	2027	2028	2029	2030
Low New Entry								
2023 Load Forecast	23%	19%	17%	15%	11%	8%	8%	5%
Electrification	22%	18%	16%	13%	10%	7%	6%	3%
High New Entry								
2023 Load Forecast	26%	23%	21%	19%	17%	16%	17%	15%
Electrification	25%	22%	20%	18%	15%	14%	14%	12%

As witnessed during the rapid transition from coal resources to natural gas resources last decade, PJM markets provide incentives for capacity resources. The challenge will be integrating the level of additional resources envisioned to meet this demand, and therefore addressing issues such as resource capacity accreditation is critical in the near term. The low entry rates shown in our Low New Entry scenario are illustrative of recent completion history applied to the current queue. RTO capacity prices in recent auctions have been low for several delivery years, and capacity margins have historically reached around 28% of peak loads. As capacity reserve levels tighten, the markets will clear higher on the VRR curves, sending price signals to build new generation for reliability needs.

The 2024/2025 BRA, which executed in December 2022, highlighted another area of uncertainty. Queue capacity with approved ISAs/WMPAs is currently very high, approximately 35 GW-nameplate, but resources are not progressing into construction. There has only been about 10 GW-nameplate moving to in service in the past three years. There may still be risks to new entry, such as semiconductor supply chain disruptions or pipeline supply restrictions, which are preventing construction despite resources successfully navigating the queue process.

Figure 7. The Balance Sheet



For the first time in recent history, PJM could face decreasing reserve margins, as shown in **Table 1**, should these trends – high load growth, increasing rates of generator retirements, and slower entry of new resources – continue. The amount of generation retirements appears to be more certain than the timely arrival of replacement generation resources, given that the quantity of retirements is codified in various policy objectives, while the impacts to the pace of new entry of the Inflation Reduction Act, post-pandemic supply chain issues, and other externalities are still not fully understood.

The findings of this study highlight the importance of PJM's ongoing stakeholder initiatives (Resource Adequacy Senior Task Force, CAPSTF, Interconnection Process Subcommittee), continued efforts between PJM and state and federal agencies to manage reliability impacts of policies and regulations, and the urgency for coordinated actions to shape the future of resource adequacy.

The potential for an asymmetrical pace within the energy transition, where resource retirements and load growth exceed the pace of new entry, underscores the need for better accreditation, qualification and performance requirements for capacity resources.

The composition and performance characteristics of the resource mix will ultimately determine PJM's ability to maintain the reliability of the bulk electric system. Managing the energy transition through collaborative efforts of PJM stakeholders, state and federal agencies, and consumers will ensure PJM has the tools and resources to maintain reliability.

Attachment II

STATEMENT

FOR IMMEDIATE RELEASE

PJM Statement on the Newly Issued EPA Greenhouse Gas and Related Regulations

(Valley Forge, PA – May 8, 2024) – PJM provides this statement concerning the EPA rule on New Source Performance Standards for Greenhouse Gas Emissions and the other EPA regulations promulgated on April 25, 2024.

PJM has the responsibility to ensure both short- and longer-term reliability for the 65 million people we serve in a region spanning 13 states plus the District of Columbia. "Reliability" in this context refers both to the day-to-day work of managing the grid to keep the system in balance as well as ensuring that, looking forward, there are adequate resources available and committed to serve the expected demand for electricity in future years.

Because of these unique responsibilities, PJM and other affected RTOs have been extensively involved in EPA rulemakings dating back to the Mercury and Air Toxics Standards rule promulgated on Dec. 16, 2011. Our role in these rulemakings has been to ensure that, in developing proposed environmental rules, EPA has appropriately taken into account the reliability needs of our respective grids.

Consistent with this past level of involvement, PJM worked cooperatively with MISO, SPP and ERCOT (the RTOs most affected by the EPA rule) to craft a set of detailed comments to EPA raising our collective reliability concerns with EPA's initial proposed greenhouse gas (GHG) rule. Our comments and subsequent meetings with EPA were focused on:

- Educating EPA as to the reliability needs of our respective systems and the potential impact that the then-proposed GHG Rule could have on both day-to-day reliability and resource adequacy; and
- Providing to EPA constructive proposals to help mitigate, from a reliability perspective, potential adverse impacts of the then-proposed Rule with a particular focus on ensuring adequate flexibility within the Rule for grid operators to be able to address both short-term reliability issues and resource adequacy within their regions.

– MORE –

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Noting the RTO Comments, in its Final Rule issued on April 24, 2024, EPA made certain adjustments to its initial proposal. Those adjustments altered the resources impacted by the rule and provided additional tools that can help provide flexibility to address reliability issues. PJM is appreciative of EPA's acknowledgment of the importance of the existing resources to reliability, of the need for more flexibility, and its consideration of the Joint RTO Comments. The specific adjustments that were grounded in the Joint RTO Comments and adopted in the Final Rule included:

- **Treatment of Existing Gas Resources** – Removing existing gas from this rulemaking to be addressed holistically in a separate rulemaking
- **State-Specific Compliance Flexibility** – Availability of flexibility for the states to address reliability issues, taking into account the remaining useful life and other factors that affect needed units
- **Averaging** – Allowing unit owners to average their compliance obligations over multiple units to ensure least-cost compliance
- **Emissions Trading** – Authorizing states to utilize allowance trading to minimize compliance costs and burdens
- **Mass-Based Programs** – Authorizing states to potentially utilize an emissions cap rather than controlling the rate of emissions from each affected unit
- **Short-Term Reliability Mechanisms** – Allowing needed units to operate for emergencies without jeopardizing compliance with the rule
- **Timeline Extensions** – Providing extensions for retiring units needed for reliability and units needing more time to install controls, with state discretion for longer periods

PJM's Continuing Reliability Concerns

Although we appreciate EPA's adoption of certain flexibility measures in response to our proposals, areas of concern remain related to ensuring reliability given the impact of the Final EPA Rule:

- The new rules governing both existing coal and new natural gas are premised on EPA's finding that carbon capture and sequestration (CCS) technology represents the "best" system of emissions reduction, which will be commercially available at a reasonable cost. However, the availability of CCS is highly dependent on local topology, such as salt caverns available to sequester carbon and the availability of a pipeline infrastructure to transport carbon emissions from individual generating plants to CCS sites potentially hundreds of miles away. There is very little evidence, other than some limited CSS projects, that this technology and associated transportation infrastructure would be widely available throughout the country in time to meet the compliance deadlines under the Rule.

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- The Final Rule imposes the most stringent requirements on new gas and existing coal units that operate as baseload units. Although EPA has focused on these units given that they have greater emissions, these baseload units provide a critical reliability role. We are seeing vastly increased demand as a result of new data center load, electrification of vehicles and increased electric heating load. The future demand for electricity cannot be met simply through renewables given their intermittent nature. Yet in the very years when we are projecting significant increases in the demand for electricity, the Final Rule may work to drive premature retirement of coal units that provide essential reliability services and dissuade new gas resources from coming online. The EPA has not sufficiently reconciled its compliance dates with the need for generation to meet dramatically increasing load demands on the system.

- The Final Rule is premised on the availability of increased access to natural gas infrastructure to support the Rule's "co-firing with gas" compliance option for existing coal units. The present gas pipeline system is largely fully subscribed. Moreover, given local opposition, it has proven extremely difficult to site new pipelines just to meet today's needs, let alone a significantly increased need for natural gas in the future. The Final Rule, which is premised, in part, on the availability of natural gas for co-firing or full conversion, does not sufficiently take into account these limitations on the development of new pipeline infrastructure.

- EPA has left many issues for development in individual state implementation plans. Although this is appropriate and in keeping with the structure of the Clean Air Act, each of the multi-state RTOs like PJM operate a single dispatch. As a result, states will need to coordinate and work closely together to ensure that the individual state plans work well on a regional basis. As a result, the need for regional coordination of individual State Implementation Plans is more important than ever. PJM values its continued collaboration with the other affected RTOs (MISO, SPP and ERCOT) and looks forward to working with the U.S. EPA, individual states and affected stakeholders as this process continues.

PJM Interconnection, founded in 1927, ensures the reliability of the high-voltage electric power system serving 65 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM coordinates and directs the operation of the region's transmission grid, which includes 88,115 miles of transmission lines; administers a competitive wholesale electricity market; and plans regional transmission expansion improvements to maintain grid reliability and relieve congestion. PJM's regional grid and market operations produce annual savings of $3.2 billion to $4 billion. For the latest news about PJM, visit PJM Inside Lines at insidelines.pjm.com.

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Exhibit E

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

ELECTRIC GENERATORS FOR A SENSIBLE TRANSITION, *Petitioner*, v. U.S. ENVIRONMENTAL PROTECTION AGENCY, *Respondent*.	Case No.: 24-1128

DECLARATION OF JOHN R. CROCKETT III

I, John R. Crockett III, declare:

1. Since October 2021, I have served as President of LG&E and KU Energy LLC, the parent company of Louisville Gas and Electric Company (LG&E and KU) (collectively, the "Company") and Chief Development Officer for PPL Corporation. I am responsible for all matters associated with the business of LG&E and KU, including state and federal government affairs, rates and regulatory strategy, local communications, stakeholder engagement, and driving economic development and growth in our communities. From 2018 to 2021, I served as General Counsel and Chief Compliance Officer for the Company. Prior to that, I served as the Company's outside counsel handling claims arising from the gas and electric operations of LG&E and KU. I have a Bachelor's degree from the University of North Carolina and a Juris Doctor degree from

the University of Kentucky. This declaration is based on my personal knowledge of facts and analysis conducted by staff of the Company and me.

2. In this declaration, I identify impacts on the Company, its employees, its customers, local communities, and the Commonwealth of Kentucky generally if the Company is required to undertake measures to comply with the final rule of the U.S. Environmental Protection Agency ("EPA") entitled "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule," 89 Fed. Reg. 39,798 (May 9, 2024) (the "Rule"). Without a stay of the Rule, the Company, its employees, its customers, local communities, and the Commonwealth will suffer immediate and irreparable harm as the Company cannot comply with the new standards of the Rule within the timeframe required.

3. Compliance with the Rule will result in impacts including the following:

a. Premature and accelerated retirement of approximately 4,750 megawatts (MW) nameplate capacity of the Company's coal-fired generation, comprising nearly 55% of its generating fleet, with a current net book value of $5.2 billion;

b. Accelerated construction of replacement generation by the Company on an unduly compressed schedule, which given current supply chain constraints cannot be met, ensuring, capacity shortfalls and reduced system reliability which will harm the Company's customers and the state, generally;

c. Costs of at least $7 billion for replacement generation alone before considering electric or gas transmission infrastructure upgrades, uncertain cost escalation impacts due to the compressed compliance schedule, and other costs; and

d. Significant rate increases which will impede economic development and job growth in the state and result in job losses at the Company and in industries sensitive to electricity costs.

4. LG&E and KU are vertically integrated regulated utilities engaged in the production, transmission, and distribution of electricity and distribution of natural gas to approximately 1.3 million customers in Kentucky and Virginia. The Company has 11 coal-fired generating units at four power plants with a total generating capacity of approximately 5,460 megawatts (MW) nameplate capacity. Additionally, the Company has 19 natural gas-fired generating units with a total generating capacity of approximately 3,234 MW. Coal or natural gas-fired generating units provide approximately 98% of the electricity needs of the Company's customers. Most of the Company's fossil-fired generation is subject to the requirements of the Rule.

COMPLIANCE OPTIONS AVAILABLE

5. Under the provisions of the Rule, the Company has three basic options for its coal-fired generating units: (1) Meet an emission rate based on 40% natural gas co-firing by January 1, 2030, which will allow the unit to operate through 2038; (2) deploy 90% efficient carbon capture and storage ("CCS") by January 1, 2032, which will allow the unit to operate after 2040; or (3) retire the unit by January 1, 2032 and bring online all necessary replacement generation by that date. Based on the Company's initial assessment of the Rule, the only compliance strategy available to the Company consists primarily of premature and accelerated retirement of the Company's coal-fired generating units and accelerated deployment of replacement generation.

6. Meeting an emission rate based on 40% natural gas co-firing by January 1, 2030 is not a certain compliance option that can be applied generally across the entire LG&E and KU coal-fired fleet due to significant impediments to natural gas transportation and infrastructure development and limited availability of transportation on interstate pipelines that serve the Company's sites. Natural gas infrastructure currently exists at only one of the Company's four

coal-fired power plant sites and even the existing infrastructure must be upgraded. Siting and permitting pose significant challenges for new pipelines to be built or upgraded for the affected plant sites. No arrangements have been made to reserve interstate pipeline capacity necessary to accommodate significant incremental gas needed for co-firing. Such arrangements will require extensive negotiations with pipeline operators on long term transportation contracts to support likely infrastructure expansion on their systems. Past experience does not support EPA's assumption that the necessary pipeline transportation and infrastructure arrangements could be fully in place by the 2030 compliance date. Based on our initial analysis, adopting this compliance option on a fleetwide basis would have a high risk of falling short of the aggressive deadlines under the Rule.

7. Deploying CCS on the Company's coal-fired generating units is not an undertaking that can be completed by January 1, 2032 due to the early stage of development of that technology, the unavailability of carbon dioxide (CO2) transport pipelines and of sequestration sites close to our plants, and the sheer amount of investigation, engineering and design, permitting and regulatory approvals, and construction required for CCS. The Company has a history of pilot scale testing on coal-fired electric generation at the Company's E.W. Brown plant and is actively engaged in natural gas combustion turbine CCS research and development (R&D). The U.S. Department of Energy (DOE) recently selected for final award negotiation a CCS R&D project at the Company's Cane Run plant. This R&D project is projected to conclude in 2030, further demonstrating that this technology is not commercially available today. The Company looks forward to working with DOE and other partners to test and demonstrate these technologies so that they can be cost-effectively commercialized at scale in the decades to come. Based on my knowledge of technology deployment in the coal and natural gas electric generation industry, I

assert that CCS has not been adequately demonstrated at utility scale for either coal or natural gas-fired generation and is not ready for full scale commercial deployment at this time. Additionally, Kentucky lacks geology sufficient for long term CO2 storage, so it would be necessary for carbon captured at the Company's plants to be transported by pipeline to states with geology sufficient for long term sequestration. Currently, the pipeline and other infrastructure necessary for transport to potential storage formations outside the state does not exist. Past experience does not support EPA's assumption that technology and infrastructure challenges of this magnitude can be overcome by 2032, as would be necessary to operate coal-fired generating units beyond year-end 2039. For our plants, CCS is impossible to achieve by the 2032 compliance date.

8. Under the provisions of the Rule, the Company is essentially prohibited from operating its coal-fired generation beyond year-end 2031. This will result in premature and accelerated retirement of the Company's entire coal-fired generation fleet which comprises nearly 55% of its current generating capacity with a current net book value of approximately $5.2 billion. The units which must be retired have substantial remaining useful life and are a key part of the Company's generating fleet designed to provide reliable and affordable electricity to its customers.

REPLACEMENT GENERATION

9. Based on the Company's assessment to date, to comply with the Rule, the Company faces the extraordinary challenge of deploying an additional 4,000 MW to 5,400 MW of replacement, dispatchable generation (84% to 114%+ of the Company's current baseload generating fleet). This projection does not include any additional generation needed to accommodate increased demand due to system growth, including a potential data center deal currently being negotiated. Replacement generation will consist primarily of seven to eight

combined-cycle natural gas (NGCC) generating units supplemented by a combination of renewables (solar and wind) and battery storage.

10. Under the provisions of the Rule, it is necessary for a baseload NGCC (defined as one that would operate at a capacity factor of more than 40%) to install and operate 90% CCS by 2032. For the same reason discussed above, that is an impossible task using today's technology. Accordingly, the Company will be forced to construct significant extra capacity that must remain under-utilized in order to operate the NGCC units with an annual capacity factor less than 40%. This capacity factor requirement makes the compliance challenge even greater. It will be necessary to obtain the necessary regulatory approvals, procure the necessary land and equipment, obtain required permits, and complete construction of replacement generation by year end 2031.

11. The one NGCC plant currently in the company's fleet – the 640 MW Cane Run Unit 7, which commenced operation in 2015 – took approximately five years for design, procurement, permitting, and construction. Ongoing preparatory work for the company's newest NGCC unit – Mill Creek 5 – indicates that the development time for new units is now at least five and a half years from initial payment reserving a place in the manufacturing queue for key facility components to commercial operation of the new unit. Substantial additional development time can be expected for new units constructed on greenfield sites or subject to Prevention of Significant Deterioration program permitting. Constructing seven to eight units within a five-year time frame – as required under the rule - would not only exceed the Company's implementation capability, but also overwhelm available supply chains, third-party engineering, procurement, and construction capacity and permitting capacity of the Kentucky Energy and Environment Cabinet.

12. While renewable wind and solar generation may be part of any plan for compliance with the new Rule, real world constraints will prevent them from being the primary compliance

measure. Due to the large amount of coal-fired generating capacity to be retired in both the LG&E and KU systems and by other electricity suppliers, any renewable generation replacing the retired capacity would have to be on a scale significantly larger than all renewable facilities constructed to date. Large-scale wind and solar renewables would also require construction of battery storage on an unprecedented scale and transmission siting and permitting that will result in additional delays for pending renewable generation projects. Development of renewable wind and solar generation requires extensive design, procurement, site acquisition, permitting, and construction efforts, like other generation projects, and renewable energy projects increasingly face public opposition and lawsuits which result in delay. The limited experience of the Company and virtually every other electric utility in the nation indicates that operating renewables at such a scale would pose significant system reliability risks. Currently, and for the foreseeable future, renewable power is not dispatchable, that is, it is not always available on request. The sun does not shine 24 hours a day; the wind does not gust 24 hours a day. And battery storage is simply not at a stage of development to sustain adequately long periods of dispatchable power at scale. Renewables with battery storage also present power quality issues for the grid, with requirements for a level of synchronous generation (i.e., fossil-fired or nuclear generation).

13. Over the past 40 years, the Company has not pursued procurement and construction of even two major baseload generating units simultaneously. However, the rule will require LG&E and KU to complete seven to eight NGCC plants and major renewable generation over the span of less than five years. Other electric utilities are similarly situated, and the large number of existing unit retirements and construction of replacement units across the country will overwhelm procurement systems, supply chains, electric and natural gas infrastructure, and state regulatory approval processes not designed to handle an energy transition of this magnitude on this kind of

timeline. Delays associated with legal challenges to new facilities such as generating plants and pipelines can be expected. EPA's compliance deadlines do not reflect the massive scale of replacement power construction that will take place throughout the electric generation industry.

14. Regardless of whether the Company can meet the compliance deadlines in the rule, implementation of compliance measures including retirement of existing coal-fired plants and replacement with natural gas-fired generation and renewables will result in significant cost to the Company and its customers. Based on the Company's approximately $1 billion cost projection for its 645 MW (net summer rating) Mill Creek 5 NGCC currently under development, deploying seven to eight similar NGCC units to comply with the Rule is expected to cost the Company a minimum of $7 billion for construction of replacement generation alone. This cost estimate does not include electric or natural gas infrastructure upgrades, uncertain cost escalation due to the compressed compliance schedule, pipeline, and other infrastructure necessary for CCS, if implemented, and other compliance costs including the cost of any solar and wind generation added to comply with the Rule. If the Rule is not stayed, LG&E and KU will have to try to meet its requirements as much as feasible as well as their duty to serve by attempting to plan, permit, and construct these new NGCCs by 2032. This means work must commence immediately, and, as discussed in more detail later in this declaration, the Company will have spent hundreds of millions of dollars on these projects by the time the court decides the legality of the Rule, resulting in irreparable harm if the Rule is overturned in whole or part by the Court.

STATE APPROVALS

15. To retire any of its coal-fired generating units, the Company must undertake a rigorous process to comply with extensive state law requirements. KRS 278.264 establishes a rebuttable presumption against retiring fossil-fired generating units which can be overcome by

demonstrating that the replacement power is dispatchable, will maintain grid reliability, meet minimum reserve capacity requirements, and will result in cost savings to customers. The applicant must also demonstrate that retirement will not result in incremental costs that could be avoided by continuing to operate the unit in compliance with applicable law and that the decision to retire the unit is not the result of federal incentives or benefits. In 2024, additional state legislation was enacted that establishes more retirement restrictions and requires retirement requests to be reviewed by the newly created Energy Planning and Inventory Commission.

16. Expedited state approvals for retirement of coal-fired units and construction of replacement units cannot be presumed. In 2023, the Company requested approval to retire four coal-fired units and construct two NGCC units for replacements along with renewables and battery storage. After review, the Kentucky Public Service Commission approved retirement of two coal-fired units and construction of one gas-fired unit along with the renewables and battery storage, deferring other approvals to the future. At a minimum, obtaining state approvals for retirement of coal-fired units and construction of replacement units will add time to an already protracted process. This makes compliance with the deadlines in the rule even more onerous for Kentucky-based generating units.

17. Another state law in Kentucky, KRS 224.20-142 bars the Kentucky Energy and Environmental Cabinet from setting GHG performance standards for existing coal-fired generating units based on co-firing with other fuels, fuel switching, or limiting the utilization of generating units. KRS 224.20-143 imposes other restrictions on setting performance standards for natural gas-fired units. With the states having significant authority over existing units under Section 111 of the Clean Air Act, state law compels the Kentucky agency to undertake additional analysis beyond consulting EPA's guidelines. This too will delay the process for obtaining state approvals

and, in any event, injects additional complexity into the Company's compliance efforts and potentially results in more stringent requirements for electric generating units in Kentucky (further exacerbating economic disparity for Kentucky's low-income consumers). EPA's compliance deadlines under the rule are particularly onerous for a state like Kentucky with heavy reliance on existing coal-fired generation and highly prescriptive requirements for a transition to other generation.

18. The Kentucky Energy and Environment Cabinet must submit an implementation plan encompassing compliance with the rule within 24 months of the Rule's publication in the Federal Register. In order for the Cabinet to have sufficient time to prepare its plan, the Company must make retirement and replacement generation commitments to the agency almost immediately. The schedule necessary for submittal of commitments to the Cabinet is entirely inconsistent with the timeframe to obtain other state approvals required under state law.

IMMEDIATE COMPLIANCE ACTION REQUIRED

19. To comply with the highly aggressive deadlines under the Rule, the Company must commence immediate actions at substantial cost. These actions will result in both near term and long term financial commitments, binding regulatory determinations, and irreversible business decisions, unless a stay is granted.

20. To implement a compliance strategy centered on retiring coal-fired generation on an extremely accelerated schedule and constructing seven to eight NGCC units simultaneously for replacement generation, the Company must initiate immediate actions to address planning, implementation, and regulatory demands. The Company must immediately enter contracts for engineering and other technical services necessary to complete planning, design, and environmental permitting work for the replacement generation. Concurrently, the Company must

issue Requests for Proposals and commence negotiations with original equipment manufacturers (OEMs) for key components such as turbines. Based on the Company's recent development work on the Mill Creek 5 NGCC, the Company expects OEMs to demand non-refundable and non-transferable multi-million-dollar payments upfront to reserve a place in the manufacturing queue. It will be necessary for the Company to make the appropriate regulatory filings by late 2024 to commence proceedings to obtain the requisite approvals of the Kentucky Public Service Commission (KPSC) within the specified timeframe. Obtaining state regulatory approvals will require the Company to immediately retain attorneys and technical consultants required for the extensive administrative proceedings before the KPSC. Finally, the Company must immediately commence actions to obtain sufficient natural gas transportation for replacement generation at multiple sites. The Company must retain engineering and other technical consultants for planning, design, and environmental permitting for new or upgraded pipelines to serve the new NGCCs. The Company must immediately undertake efforts to obtain the necessary rights of way for pipelines, which typically involves exhaustive negotiations with landowners and often eminent domain proceedings. The Company must also immediately commence negotiations with interstate pipeline companies to reserve pipeline capacity necessary to transport the large volumes of natural gas required for NGCC generation. Based on recent negotiations regarding gas transportation service for the Mill Creek 5 NGCC, the Company expects interstate pipeline companies to demand entry into long term contracts in order to reserve the necessary pipeline capacity and cover any capacity upgrades necessary for the interstate pipelines.

21. The above compliance measures must be completed on an accelerated basis in order to allow sufficient time for construction of facilities by the compliance deadlines under the Rule. For replacement generation, the Company would need to file for KPSC approval by late 2024,

obtain the required approvals by late 2025, and enter into contracts with OEMs for equipment and interstate pipelines for natural gas transport in 2025 or early 2026. Planning and design costs are front-loaded in the process, so the vast majority of such costs will be incurred in the near term. In the case of seven or more NGCC units constructed at a total cost of more than $7 billion, planning and design costs and procurement commitments are expected in the range of $300 to $700 million over the next three years. When the Company enters into equipment contracts and gas supply contracts, it will incur significant and irreversible payment obligations regardless of whether the Rule is ultimately invalidated or upheld. When the Company negotiates pipeline rights of way with landowners, it is obligated to pay compensation regardless of whether the pipeline is ultimately constructed. In pursuing the scale of replacement generation on the schedule required by the Rule, the Company expects to incur substantial and irreversible costs within the next one to three years. With the Company current estimating that it will take five and one half years after initial payment reserving a place in the manufacturing queue for key NGCC unit components to achieve commercial operation of a new unit, the Company will face intense pressure from a procurement standpoint to make substantial and irreversible financial commitments before obtaining all necessary regulatory approvals, if the Company is to have any chance of meeting compliance deadlines under the Rule.

22. The Company has contracted with an engineering consultant to determine specific measures required for co-firing 40% natural gas at each of its existing coal-fired units. The Company's initial assessment is that gas transportation constraints eliminate natural gas co-firing as a viable fleet-wide compliance strategy. To the extent that the Company determines that natural gas co-firing is feasible for some of its coal-fired units, the Company will face the same gas transportation challenges as described above for replacement NGCC units. Gas pipelines to the

plants must be upgraded or constructed in their entirety. Pipeline rights of way must be acquired. Interstate pipeline transport capacity must be secured. Additionally, the Company will need to undertake planning and design work for any necessary equipment modifications for co-firing. Because the compliance deadline for co-firing is January 1, 2030 – two years in advance of the deadline discussed above, the Company would incur substantial costs even sooner under the co-firing option. If the Company is compelled to adopt natural gas co-firing as a compliance strategy for some or all of its coal-fired units because of even greater problems with other compliance options, the Company will incur substantial near term costs on a compliance option that has a high risk of falling short of the aggressive deadlines under the Rule.

23. The Company has firmly concluded that CCS is not viable for deployment by the January 1, 2032 compliance date under the Rule. However, if the Company were to pursue that option, it would be necessary to undertake extensive planning and design work, procurement actions for capture and other equipment, and state regulatory approvals on an accelerated basis, incurring substantial and irreversible costs in the next one to three years. The challenges to build out a pipeline network to transport captured carbon dioxide to available storage sites would be even greater due to the total absence of interstate carbon dioxide pipelines and storage facilities. Deployment of new technologies and construction of entirely new facilities and systems would be expected to require substantial near term development costs.

SYSTEM RELIABILITY RISKS

24. Multiple choke points in this complex and lengthy compliance implementation chain pose serious risks to continued grid reliability, especially in the decade of the 2030's, if existing generation must retire before replacement generation can be built. The rule provides for short term extensions to address emergencies and extensions of up to one year to address reliability

problems. However, these provisions are entirely inadequate to mitigate reliability risks resulting from the multi-year delays that can be expected in completing replacement generation. Premature retirements of coal-fired generation which serve as the primary generation resource for the company and all other electric utilities in the state, coupled with foreseeable delays in replacement generation, pose a serious risk of blackouts, brownouts, curtailment of interruptible customers, and other service interruptions that will harm the safety, welfare, and prosperity of Kentucky residents.

GENERAL IMPACTS

25. The Kentucky Cabinet for Economic Development has identified low electricity costs for industrial customers as one of the key advantages that Kentucky enjoys in economic development and job creation, with average costs 17% below the national average. With the state meeting more than two-thirds of its electricity needs from coal-fired generation forced to prematurely retire, the rule will have a disproportionate impact on Kentucky's energy costs and therefore its economy. Kentucky's economic development and job creation efforts will be severely hampered by electricity costs which can be expected to increase substantially. Kentucky will be much less competitive in attracting important new projects like the recent Ford Blue Oval SK battery plant which will result in a $5.8 billion investment creating 5,000 jobs. When industry selects other states for new or expanded facilities, the associated jobs are permanently lost to Kentucky. Significantly higher electricity costs will also affect the ability of Kentucky to retain manufacturing and other jobs already located in the state.

26. Compared to coal-fired generating units, natural gas-fired units and renewables require substantially fewer staff. Replacement natural gas-fired units will result in plant staff reductions of approximately 70%, while renewables will result in even greater staff reductions of 95+%. The job losses resulting from compliance with the rule will impose significant hardship

not only for individual employees, but also the small communities in which many of them reside. Once these experienced employees obtain reassignments, obtain jobs with other employers, or retire, it would be highly impractical to reassemble the necessary workforce to reopen retired plants even if the rule was eventually overturned without a stay in the interim. Significant additional job losses in industries sensitive to electricity prices can be expected.

27. As a byproduct of the generation process, the company's coal-fired power plants produce fly ash and gypsum which may be beneficially used in the manufacture of products such as concrete, wallboard, and fertilizer. For sale of these coal combustion residues (CCRs) to end users, the company projects revenues of \$45 million in 2024, growing to \$60 million in 2028. Revenue from the sale of CCRs is rebated back to the company's electricity customers. Cement plants and wallboard manufacturing facilities have located in close proximity to three of the company's coal-fired plants to facilitate access to a stable feedstock of CCRs for their manufacturing processes. As the company retires its coal-fired plants to comply with the rule and eliminates its CCR byproduct streams, revenue rebates to electricity customers and byproduct sales to end users will be curtailed. This will harm the company's electricity customers and pose a major threat to the continued viability of byproduct end users which have located near the company's plants for access to feedstock.

28. Generating plants located in small communities are key providers of high-paying jobs and support for local charities. Retirement of coal-fired generating plants or major reductions in their operations and workforce will result in significant negative impacts to the economy and welfare of small communities in which they are located.

29. Unless a stay is granted, the company will have to undertake immediate and irreversible actions in order to attempt compliance with the provisions of the rule. To meet the

compressed schedule under the rule, the company is unable to defer action until the court issues a final ruling on the validity of the Rule.

Executed this 23 day of May 2024.

John R. Crockett III

John R. Crockett III

Exhibit F

DECLARATION OF ILLINOIS MUNICIPAL ELECTRIC AGENCY

I, Kevin M. Gaden, on behalf of the Illinois Municipal Electric Agency ("IMEA"), declare as follows:

1. My name is Kevin M. Gaden, and I am the President & CEO of IMEA. I have relied on statements and analyses from executives within IMEA's Engineering and Energy Markets and Electric Operations departments and the operators of the power plants[1] which IMEA co-owns with other entities in preparation of this declaration.

2. IMEA is a body politic and corporate, municipal corporation and unit of local government of the State of Illinois[2] that serves as the municipal joint action agency comprising of thirty-two municipal members,[3] all of which own and operate their own municipal electric systems in the State of Illinois and provide electricity to their respective end use customers. IMEA operates on a not-for-profit basis and through long-term contracts, IMEA provides its member municipalities with their full requirements supply of electric power and energy as a fully bundled and delivered service. IMEA sources its electric power and energy from owned generation and

[1] Trimble County Generating Station, under its primary co-owner, Louisville Gas & Electric/Kentucky Utilities, filed a Declaration of Harm by Philip Imber in response to the instant EPA Final Rule. Additionally, Prairie State Energy Campus, under its management entity, Prairie State Generating Company, filed a Declaration of Harm by Randy Short in response to the instant EPA Final Rule.
[2] 65 ILCS 5/11-119.1-1 *et seq.*
[3] City of Altamont, Village of Bethany, City of Breese, City of Bushnell, City of Cairo, City of Carlyle, City of Carmi, City of Casey, Village of Chatham, City of Fairfield, City of Farmer City, City of Flora, Village of Freeburg, Village of Greenup, City of Highland, Village of Ladd, City of Marshall, City of Mascoutah, City of Metropolis, City of Naperville, City of Oglesby, City of Peru, City of Princeton, Village of Rantoul, City of Red Bud, Village of Riverton, City of Rock Falls, City of Roodhouse, City of St. Charles, City of Sullivan, City of Waterloo, and Village of Winnetka.

through bilaterally contracted capacity and energy and from the regional transmission organizations that control the transmission systems and electric markets in Illinois. Among its generation assets are partial ownership of two coal-fired generating facilities, several oil-fired generators, as well as an increasing share of renewable resources like wind and solar. This diverse mix of resources allows IMEA to keep its members' lights on affordably, reliably, and sustainably.

3. The Environmental Protection Agency's ("EPA's") final rule establishes an unreasonable and arguably catastrophic framework to seek carbon reduction in the electric generation industry. Among mandates, EPA requires fossil plants to comply with a new definition of Best System of Emissions Reduction ("BSER") for several categories of Electric Generating Units ("EGUs"). For existing coal-fired steam EGUs, they must reduce CO_2 emissions by 90% or more, using Carbon Capture and Sequestration/Storage ("CCS") technology. For coal-fired steam EGUs planning to retire by 2039, they must be able to co-fire with natural gas at a 40% annual heat input. While EPA states that its mandate was drafted with considerable attention to viability, cost, and grid reliability, the outcome and effect of its Final Rule will in fact jeopardize grid reliability and substantially increase the costs of electricity, which will ultimately harm IMEA, its member municipalities and their citizens and businesses who are their end-use customers.

4. Restrictions and requirements as finalized by EPA will make IMEA's ability to deliver wholesale power and energy reliably and affordably to its member municipalities

incredibly difficult if not impossible. Among the coal-fired generating facilities in its resource portfolio is a 12.12% ownership of Trimble County Generating Station's ("Trimble County's") two coal-fired units ("TC1" and "TC2"). Both generators have provided IMEA stable, affordable, and reliable baseload power to IMEA's member municipalities since 1991 for TC1 and 2011 for TC2. Further, TC1 & TC2 are already outfitted with ten to hundreds of millions of dollars of the latest emissions control technology. Namely, TC1 is equipped with particulate, sulfur dioxide, and nitrogen oxide (NO_x) removal facilities; low-NO_x burners; selective catalytic reduction equipment; a carbon injection/bag house system; and a dry electrostatic precipitator. TC2 is equipped with state-of-the-art emissions control technology including a wet flue gas desulfurization system, a wet electrostatic precipitator for fine acid mist reduction, a bag house, and low-NO_x burners. What the Final Rule will do is to make these investments meaningless and force IMEA and its other co-owners to either invest hundreds of millions of dollars more in expensive and unproven technology or close down reliable generation that is necessary to support the electric grid well before the end of its useful life. That will ultimately harm IMEA's ability to carry out its purpose as a municipal wholesale electricity supplier. TC1 & TC2 have useful lives that extend well beyond 2039, and if forced to retire before then, will effectively turn them into stranded assets. IMEA, in addition to any outstanding debt still owed, would need to consider the cost of premature retirement, decommissioning, capacity replacement, regulatory compliance, and mass layoffs of Trimble County's plant workers in an unreasonably condensed timeline and without a clear path toward baseload replacement capacity. Ultimately, the citizens and businesses of IMEA's member municipalities will pay higher rates for electric to cover the cost of the stranded investments in TC1 and TC2 and other coal-fired generation that IMEA co-owns with other public power entities and the replacement resources or higher market prices that will be caused by the Final Rule. For IMEA's municipal members, this will be yet another unfunded mandate that will be borne by the backs of their citizens and businesses, like the required replacement of lead-lined pipes from their water utilities. These unfunded mandates will greatly hamper the citizens of these communities.

5. The alternate option is to install expensive and untested CCS or co-firing technology in a highly condensed timeframe. Contrary to the characterization in the Final Rule, CCS is still in the early stage of development and has not been proven in utility-scale commercial operation. This means that any attempt at widescale adoption, especially under the Final Rule, will result in a "damned if you do, damned if you don't" scenario where coal plants will be forced to adopt an unproven technology with all the costs and risks associated thereof. Otherwise, IMEA will have to eat the stranded costs associated with premature retirement and directly pass those costs along to its not-for-profit member municipal utilities who must then collect those costs from their citizens.

6. Recently, one of IMEA's coal-fired generating facilities, Prairie State Energy Campus, explored the feasibility of CCS technology through a Front End Engineering and Design ("FEED") Study. The findings from that study showed that the cost of

installing CCS equipment, which only included the development, permitting, and construction of the capture system, amounted to about $2.04 Billion <u>for a single unit</u>. This cost projection did not include the enormous cost of any pipeline, transport, or permanent storage of the captured CO_2. There is little clarity at both the state and national level on how these projects will be handled. Additionally, the cost projection did not consider the heavy parasitic load required for CCS equipment to run, which will reduce the capacity and energy output from the unit that would otherwise be available to serve the citizens and businesses of IMEA's member municipalities; the cost of operation; ongoing routine maintenance of the CCS project; and the risk of unplanned outages and fines if the CCS equipment unexpectedly malfunctions, among other things.

7. The Final Rule states that CCS projects are cost-reasonable because coal plant owners can take advantage of tax credits and incentives afforded by the Inflation Reduction Act ("IRA") and the Infrastructure Investment and Jobs Act ("IIJA"). EPA mischaracterizes the ability to gain financing under these federal laws. While the former does incentivize carbon capture with subsidies, the latter has only funded demonstration projects that do not reflect the true scale of necessary CCS for utility-scale fossil plants. Affecting all utilities generally, are still-unresolved issues of inflation, supply chain uncertainty, land use rights, permitting, and high interest rates that make planning for and financing CCS operations improbable if not impossible. As a not-for-profit unit of local government, IMEA cannot freely finance large-scale energy projects

like utility-scale CCS, especially in its current, untested state. The decision to finance such a speculative technology will have serious consequences for IMEA member municipalities' wholesale power and electric supply. Thus, IMEA will be financially harmed by the unfunded mandates EPA imposes under the Final Rule.

8. With CCS being unfeasible at this time and in the near future, the only other option IMEA has under the Final Rule IMEA is to take steps to retrofit these units with natural gas co-firing equipment for a short period of time and then retire them. Like with CCS, co-firing may not be feasible based on currently existing infrastructure. Even if co-firing was feasible, installing equipment, including completely new natural gas infrastructure, for these operational objectives require extensive time, capital, and other resources that IMEA does not have and likely cannot obtain without serious financial and operational harm. Retiring IMEA's coal generators by 2039 will not only incur stranded costs on the units themselves upon retirement but will additionally incur construction and operation costs from installing the co-firing equipment. There is also considerable concern about the ability to procure firm natural gas supply and firm transport rights on regional pipelines that are already fully subscribed. The ability to permit and construct such additional pipelines in the required timeline is questionable at best.

9. Because IMEA is a body of 32 Illinois cities and villages, the Final Rule will also harm them and their customers. In all scenarios, the loss or significant modification to coal plants will dramatically and simultaneously increase electric bills and decrease

electric supply for IMEA's member communities, thereby reducing reliability. As a result, people and businesses in IMEA's member communities may have to choose between keeping the lights or forgoing necessities like paying wages, affording food, or seeking medical care. Additionally, an absence of baseload electric power will disproportionately harm low-income and other vulnerable community members as they will be most affected by higher electric bills. Without further state or federal action, they will suffer the greatest risk of the consequences that the EPA Final Rule will cause.

10. In a nationwide context, EPA's Final Rule will force entities like IMEA all throughout the nation to decide between retiring their coal plants well before the end of their useful lives or installing expensive equipment to comply with the Final Rule. As many entities across the United States will choose to retire early rather than to pay for unproven CCS or co-firing capabilities, this will further strain an already strained electric grid. The North American Electric Reliability Corporation ("NERC"), the electric reliability coordinator across the United States, recently reported that the majority of the country is already on its way to an unstable power supply risk, especially at times when it will be needed most. In particular, NERC singled out MISO—the grid operator responsible for electric transmission and reliability in the Midwest where most of IMEA's member municipalities are located — and the SERC-Central region for their imminent capacity shortfall and eroding reserve margins.[4] At the same time, the

[4] NERC, 2023 Long-Term Reliability Assessment, at p.7, available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf (Dec. 2023).

prospect of vastly increasing need for electric power for electric vehicles, large-load data centers for artificial intelligence, and other advancements cry out for more electricity production, not less. The timing of the new renewable generating resources that are supposed to be the ultimate solution of the day are hampered by supply chain issues, the need to study the transmission systems to which these resources will be interconnected in order to ensure safe and reliable integration, and increased costs due to the investments required to interconnect the new generation with the grid, as well as inflation (and soon, the increased costs from the new tariffs recently imposed). New resources are not and cannot be built and interconnected fast enough to meet this need. EPA's Final Rule will only accelerate the pace at which electrical grids across the nation will no longer be able to support their ever-increasing load. Early retirements and extended outages resulting from the Final Rule will bring about a demand-supply mismatch at a greater magnitude than anticipated, almost certainly assuring high electric bills, blackouts, or a combination of the two across the United States.

11. In all, I believe that the Final Rule imposes unattainable mandates on IMEA, putting it and its member municipalities at risk of financial and operational peril. The Final Rule will undoubtedly raise electric bills and leave electric utilities unprepared to keep the lights on for all customers in extreme weather or high demand.

12. I, Kevin M. Gaden, declare under penalty of perjury under the laws of the United States that the foregoing is true and correct.

Kevin M. Gaden
President & CEO
Illinois Municipal Electric Agency

Dated: May 23, 2024

Exhibit G

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

ELECTRIC GENERATORS FOR A SENSIBLE TRANSITION, Petitioner, v. U.S. ENVIRONMENTAL PROTECTION AGENCY, Respondent.	Case No.: 24-1128

DECLARATION OF ALEX GLENN

I, Alex Glenn, declare:

1. I am Executive Vice President and Chief Executive Officer for Duke Energy Florida and Midwest ("Duke Energy FL & MW"), which includes Duke Energy Florida, LLC, Duke Energy Indiana, LLC, Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc., which are affiliates of Duke Energy Corp. ("Duke Energy").

2. Duke Energy, one of the largest energy holding companies in the United States, serves approximately 3.7 million electric customers in Duke Energy FL & MW and approximately 557,000 natural gas customers in Ohio and Kentucky.

3. Duke Energy FL & MW's coal-fired units and potential new natural gas-fired generating units are regulated under the U.S. Environmental Protection Agency's ("EPA") final rule titled "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric

Generating Units; and Repeal of the Affordable Clean Energy Rule," 89 Fed. Reg. 39,798 (May 9, 2024) ("GHG Rule").

4. In this declaration, immediate and irreparable harms to Duke Energy FL & MW and its customers are enumerated below if a stay is not granted of the GHG Rule. Duke Energy Ohio is responsible for the procurement of a standard service offer of electric supply for its Ohio customers who do not switch to competitive retail electric suppliers and is the statutory provider of last resort for all electric customers in its service territory, which obligations are met today through competitive wholesale auctions. The GHG Rule will result in a more rapid retirement of baseload dispatchable generation without a reasonable glide path for replacement, thereby exposing Duke Energy Ohio's customers to volatility in the wholesale electric markets. Duke Energy Florida, Duke Energy Indiana, and Duke Energy Kentucky have Integrated Resource Plans ("IRPs") that, among other things, lay out a balanced and orderly transition to cleaner energy resources. The GHG Rule will negatively impact those plans in varying degrees depending on jurisdiction in the following ways:

a. Requiring significant changes from engineering, construction, and approval process without sufficient compliance timelines;

b. Requiring all coal units to retire by the end of 2031 if they do not install natural gas cofiring by the end of 2029 or carbon capture and sequestration (CCS) by the end of 2031 to be able to meet the GHG Rule's emission limits, rather than in a more orderly manner between 2028 and 2035, as reflected in the most recent IRPs for Indiana, Kentucky and Florida;

c. Significantly limiting the use and increasing the costs of new natural gas combined cycle plants where planned, which could provide a dispatchable, reliable resource replacement for coal fired generating units;

d. Basing the GHG Rule's emission limits on the use of CCS by 2032 on new natural gas and existing coal even though the technology is not proven, and the timeline provided is not sufficient for the adequate analysis, engineering, permitting, construction and implementation of CCS. CCS has never been demonstrated on a natural gas combined cycle, and only one coal-fired facility in the United States has operated with CCS, but only on an intermittent basis; and

e. Not realistically considering the nation's electric reliability concerns.

5. Under the GHG Rule, covered generating units must either implement an emissions-reduction system that has not yet been demonstrated anywhere (90% CCS) or they must shift electricity generation by converting coal units to fire natural gas, retire coal units, or curtail generation at new state-of-the-art natural gas combined cycle units. This plan is not feasible in the timelines provided presenting significant reliability concerns for our customers' dependence upon dispatchable base-load generation resources to serve their energy needs and desire for affordable and reliable energy and a smooth transition to cleaner resources.

Insufficient Compliance Timelines

6. The GHG Rule requires an expeditious national shift in generation away from coal-fired sources, without an executable plan for replacement power within the mandated compliance schedule. New natural gas generating plants require between seven

and eight years to develop, permit, obtain regulatory approval and construct. Even new renewable projects can take five or more years, given delays in transmission interconnection studies and local siting concerns. Substituting either natural gas-fired or renewable generation for reduced coal-fired generation requires intensive planning, permitting and regulatory approval processes. The timelines included in the GHG Rule do not provide sufficient time to plan for and execute on reliable generating resources to replace retiring coal plants.

7. Under the GHG Rule, the states of Florida, Indiana, Ohio, and Kentucky likely will not have approved plans to implement the emission guidelines until 2027. Duke Energy FL & MW must begin complying with the rule as early as January 1, 2030. This means there will be less than three years between the time Duke Energy FL & MW know exactly what their regulatory requirements will be and when they must begin complying with those regulatory requirements.

8. As a result, if Duke Energy FL & MW are to comply with the GHG Rule by the required deadlines, Duke Energy FL & MW must start making decisions about whether to retire, co-fire with gas, or construct CCS at their coal-fired EGUs, what gas-fired generation they will have to construct, and under what conditions such new gas-fired generation will be able to operate. Once Duke Energy FL & MW have made those decisions, Duke Energy FL & MW must initiate (1) engineering, design, and contracting on new gas plants that would be needed to replace the power generated by coal-fired EGUs that would be retired by January 1, 2032; (2) engineering, design, and contracting on modifications of coal-fired EGUs to co-fire gas at 40% and gas pipeline construction for

those EGUs at plants where gas co-firing is possible; (3) studies and investigations, as well as engineering, design, and contracting on CCS; and (4) either modification of currently planned new gas-fired EGUs to include CCS by January 1, 2032 or limit new combined-cycle EGUs to 40% capacity factor. These engineering, design, and contracting activities and studies, investigations, and planning for CCS, amount to hundreds of millions of dollars that would have to be expended in the next 2-3 years, during the pendency of the litigation.

Generation Resource Planning

9. Duke Energy FL & MW have legal obligations to serve customers and their operations are regulated by utility commissions, including the Florida Public Service Commission ("FPSC"), Indiana Utility Regulatory Commission, ("IURC"), Public Utilities Commission of Ohio ("PUCO"), and Kentucky Public Service Commission ("KPSC"), which must approve infrastructure decisions, including construction of new generating units. The utility commissions' approval processes for converting coal plants to partial or full natural gas operations vary, but often take about a year to complete and involve lengthy public proceedings. Prior to filing for these approvals, extensive modeling, planning, designing, engineering and costs estimating must occur to present a solid proposal to the commissions, further challenging meeting the compliance timelines.

10. Additionally, in Kentucky, the legislature passed two pieces of legislation aimed at maintaining the viability of existing fossil generation resources. Senate Bill 4, passed in 2023 created a rebuttable presumption against the retirement of a fossil fuel-fired electric generating unit, requiring a utility to receive state commission approval before any

fossil retirements and requires replacement with dispatchable generation. More recently, Senate Bill 349 enacted in 2024 created the Energy Planning and Inventory Commission ("EPIC") and requires utilities to give notice to EPIC about plans to retire any existing coal, oil, or natural gas-fired electric generating unit prior to officially filing any retirement application with the KPSC. Within 135 days, EPIC will issue a final report with findings and recommendations about reliability, economic impacts, alternatives to retirement, and replacement generation. The findings are submitted to the KPSC as part of the utility's retirement request, and KPSC shall not approve any retirement application without considering all information from EPIC. This additional layer of review and challenge against retirements will add to the timeline of retirement approvals further demonstrating the compliance timelines are not obtainable.

11. If the GHG Rule is not stayed, Duke Energy FL & MW would suffer irreparable harm as they would need to take action to comply with the rule immediately and well before the precise regulatory obligations are known with certainty. There simply is not enough time between when state plans are approved, and the compliance period begins to wait to make decisions regarding compliance. Because the rule envisions utilities will substantially shift the sources of their generation, and because retiring existing generation and building new generation takes many years, Duke Energy FL & MW have started the process to analyze the impact of the rule on each of its impacted generating units and what type of generation it must build or buy to replace retired coal fired generating capacity. This creates an untenable situation where the final rule will have had its intended impact, even if the rule is eventually overturned, or utilities will have to start spending

immediately hundreds of millions of dollars on potentially unnecessary generating resources and unproven technologies, straining the affordability of their service for customers, especially the most vulnerable customers.

Limited Use and Increased Cost of Natural Gas

12. Regarding natural gas, the final GHG rule imposes a strict capacity factor penalty on the ability of new baseload natural gas units to serve our customers' needs or requires an emission limit be met that requires CCS technology, significantly increasing costs and risk.

13. Duke Energy Indiana has already delayed plans to add incremental natural gas combined cycle generation to its system so that it could study the impacts of the proposed GHG Rule and now must perform further analysis to account for the stricter final GHG Rule, yet again delaying a final decision to move forward with new generation that is needed to replace retiring capacity and to meet customer load.

14. In the interim period, Duke Energy MW will be required to take steps for replacement generation sooner than reasonably feasible. This could include commitments to vendors, filing for environmental permits, making deposits to enter the transmission interconnection queue, committing to natural gas pipeline construction and/or transportation contracts, making down payments for major long lead time parts and continued engineering, all of which are at risk if the GHG Rule is set aside by the courts. Indeed, construction activities require state regulatory approval prior to undertaking any project commitments. Such approvals themselves take time.

15. Duke Energy FL & MW will suffer irreparable harm if their only remaining option is to convert to 100% natural gas or to co-fire coal units with natural gas by the end of 2029. The engineering, permitting, and construction implementation for these projects would take *at least* five years, meaning this process would need to start almost immediately. By the time the challenge to the rule is decided by the courts, Duke Energy FL & MW will have spent tens of millions of dollars on these necessary activities, unless the GHG Rule is stayed. In addition, many sites will require construction of lateral gas lines and upgrades of interstate pipelines, which is also a multi-year process for both permitting and construction approval under the Federal Energy Regulatory Commission (FERC) and possibly several states. Before undertaking construction and operation of these projects, the state approved plan and utility commissions' approvals, and other governing bodies must be obtained as discussed earlier. All of this significant permitting activity and tens of millions of dollars of expenditures would need to start almost immediately to meet EPA's end-of-2029 deadline if the rule is not stayed.

Insufficient CCS Timelines

16. Regarding CCS, Duke Energy supports the use of CCS to reduce emissions from the power sector if and when those technologies become cost-effective and available at the scales necessary, including supporting infrastructure, to support widespread application. However, CCS is not feasible in all locations because they do not have suitable subsurface geology, has not been proven at scale yet, and the timing and risks are still being understood.

17. At our Edwardsport Integrated Gasification Combined Cycle Plant, Duke Energy Indiana began working with the Department of Energy ("DOE") in 2023 on a front-end engineering design ("FEED") study for CCS, and Duke Energy Indiana had performed prior CCS studies in the 2009-2010 timeframe. Even with this significant head start at Edwardsport, Duke Energy Indiana would be challenged to have all the permit approvals and be operational by 2032.

18. At our East Bend Station, Duke Energy Kentucky conducted a DOE study that injected 990 tons of CO_2 at a depth of 3,000-4,000 feet below drinking water sources. The CO_2 was supplied by a commercial gas supplier that delivered it to East Bend Station for injection as East Bend did not have the required equipment to capture CO_2. Conducted from 2003-2011, the study's primary objective was to assess CO_2 storage potential in the Mt. Simon Sandstone as part of DOE's national effort to develop strategies for emissions reduction. Even with some injection experience in this space and notwithstanding the concerns noted above, Duke Energy Kentucky would be challenged to install CCS at East Bend Station by 2032. At the remaining Florida and Midwest sites, the CCS deadlines would be out of reach.

19. A U.S. EPA Class VI permit is needed for CCS operations. Class VI well applications can take at least three years for an extensive geologic investigation and prepare the permit application and then an additional three years for EPA to process and approve. So up to six years for the entire permitting process. Of the more than 700,000 well permits issued under the underground injection program, there are only four active EPA issued Class VI permits as of May 2024. Two pre-operation permits were issued to Wabash

Carbon Services, LLC to build CCS for an ammonia fertilizer production facility in Indiana. The permits became effective in March 2024. Wabash Carbon Services submitted the permit application in May 2021; it took approximately three years for EPA to issue the permits after extensive public participation and addressing a plethora of comments. The other two permits are for operations at Archer Daniel Midland's ethanol plant in Macon County, Illinois. Similarly, for both, the time from application submission to issuance was approximately three years.

20. At this time, Duke Energy FL & MW, like many others, have not begun CCS work at gas plants in their territories and it would be nearly impossible to meet compliance deadline of 2032 as CCS on natural gas combined-cycle power plants has not been demonstrated at the scale proposed and capture technology is not yet commercially available for natural gas turbines in the power generation industry. Additionally, the GHG Rule's compliance deadline – including the extremely constrained possibility of obtaining a one-year extension – does not provide enough flexibility for delays such as permitting issues and supply chain constraints.

Reliability Issues

21. Duke Energy FL & MW have obligations to serve their customer load and are required to meet specific system planning reserve margins above and beyond that system demand. Duke Energy FL & MW could do this through a variety of options, including but not limited to self-owned assets, when available. Duke Energy FL &MW can also purchase capacity from wholesale markets and purchased power agreements/bilateral agreements with other generator owners or developers. However, under the GHG Rule,

critical cost considerations relative to construction, new gas generation, operations and maintenance costs, variable fuel costs, onsite fuel blending, pipeline construction, additional labor, training, insurance and bonding have one glaring implication – grossly compromised affordability for American consumers.

22. Indiana, Ohio, Kentucky, Florida, and many other parts of the country are experiencing unprecedented economic development leading to load growth from the proliferation of data centers, onshoring of manufacturing and growing interest in electrification. Duke Energy FL & MW have an obligation not only to replace retiring coal plants with dispatchable generation, but to add dispatchable generation to serve this increased load. The timing and stringency of the requirements of the GHG rule will challenge the reliability and affordability of service to our customers at time when reliance on electricity at an affordable price is critical to the success of our industry and well-being of our customers.

23. The costs associated with compliance with the GHG Rule will be felt throughout the industry and affected utilities' customers will ultimately bear these costs in utility rates. Under the GHG rule, the coal units that are co-fired with natural gas will have high heat rates and long ramp-up times, making the units potentially disadvantaged, where applicable, in the economic market of Regional Transmission Organizations (RTOs) that are already concerned about tightened capacity to address significant load growth.

24. The unintended consequences of the GHG Rule are obscured by flawed assumptions that the U.S. EPA uses in assessing the effects on grid reliability, resource adequacy and cost.

25. Duke Energy FL & MW are monitoring the stability of the measured and safe transition from coal to natural gas power and renewable generation while simultaneously promoting the development of other technologies and energy sources. The GHG Rule places at risk the nation's key infrastructure for electricity that is critical to the health, well-being, and security for all citizens of the United States.

Executed this 23rd day of May, 2024

Alex Glenn

Exhibit H

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

ELECTRIC GENERATORS FOR A SENSIBLE TRANSITION, Petitioner, v. U.S. ENVIRONMENTAL PROTECTION AGENCY, Respondent.	Case No.: 24-1128

DECLARATION OF JULIA S. JANSON

I, Julia S. Janson, declare:

1. I am Executive Vice President and Chief Executive Officer of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, "Duke Carolinas Utilities"), both wholly owned subsidiaries of Duke Energy Corporation ("Duke Energy"). I have responsibility for regulatory and legislative affairs, natural gas business unit, and for the long-term strategic direction, growth, and overall financial performance of DEC and DEP—regulated utilities operating in North Carolina and South Carolina.

2. DEC owns 19,500 megawatts ("MW") of energy capacity, supplying electricity to 2.8 million residential, commercial, and industrial customers across a 24,000-square-mile service area in North Carolina and South Carolina. DEP owns 12,500 MW of energy capacity, supplying electricity to 1.7 million residential, commercial, and industrial customers across a 29,000-square-mile service area in North Carolina and South Carolina.

3. The Duke Carolinas Utilities are vertically integrated, regulated electric utilities that own and operate a diverse fleet of generating facilities for the generation of

electricity as well as transmission and distribution facilities to ensure the safe, reliable delivery of that electricity to our customers. The Duke Carolinas Utilities operate a generation fleet with over 36,300 MW of winter generating capacity to reliably meet customer demand and a power delivery system consisting of approximately 19,300 miles of transmission lines. In addition to retail sales to approximately 4.5 million customers (3.7 million in North Carolina and 800,000 in South Carolina), the Duke Carolinas Utilities sell wholesale electricity to incorporated municipalities and to other public and private utilities.

4. The Duke Carolinas Utilities' operations are subject to the jurisdiction and regulatory oversight of the North Carolina Utilities Commission ("NCUC") as well as of the Public Service Commission of South Carolina ("PSCSC"), which regulate the Duke Carolinas Utilities' rates for service and operations, including overseeing integrated resource planning ("IRP") and need determinations for new generation to serve customers in North Carolina and South Carolina, respectively.

5. The Duke Carolinas Utilities' existing generation fleet includes 11 nuclear units at six sites across North Carolina and South Carolina; 14 coal-fired generating units located in North Carolina; nine natural gas-fired combined-cycle combustion turbines ("CC"), 55 simple-cycle combustion turbines ("CT"), and one cogeneration facility located across North Carolina and South Carolina; significant pumped storage hydro capacity and hydroelectric generation; rapidly expanding portfolios of utility-owned solar and battery

energy storage facilities; and, purchased power agreements for solar and other renewable generation.

6. All of Duke Carolinas Utilities' operating coal-fired generating facilities and any new natural gas-fired generating units are or will be regulated under the U.S. Environmental Protection Agency's final rule titled *New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, 89 Fed. Reg. 39,798 (May 9, 2024) ("GHG Rule").

7. In this declaration, Duke Carolinas Utilities enumerate below immediate and irreparable harms to the utilities and their customers if a stay of the GHG Rule is not granted.

8. The GHG Rule will immediately impact the Duke Carolinas Utilities' current operations and plans for future generating resources and creates irreparable harm to the continued reliability and affordability of the electric service the Duke Carolinas Utilities provide to customers in North Carolina and South Carolina. In 2021, the North Carolina General Assembly enacted into law House Bill 951: *Energy Solutions for North*

Carolina[1] ("HB 951")—the first carbon reduction mandate for a state in the Southeast. HB 951 directs the NCUC to determine the least-cost path for the Duke Carolinas Utilities to reduce carbon emissions from their North Carolina-sited generation fleet, with an interim goal to reduce carbon emissions by 70% from 2005 levels by 2030 and a long-term target of achieving carbon neutrality by 2050. HB 951 also requires the NCUC's approved Carbon Plan to ensure that all planned generation and resource changes maintain or improve upon the adequacy and reliability of the existing grid.[2]

9. The Duke Carolinas Utilities' resource planning is also subject to ongoing PSCSC oversight under South Carolina's *Energy Freedom Act,* enacted in 2019, which established a robust IRP review and approval process to ensure the Duke Carolinas Utilities are analyzing all available resource options and pursuing the most reasonable and prudent plan to serve South Carolina customers.[3] In South Carolina, the Duke Carolinas Utilities are required under state law to plan their system in a way that balances a variety of factors that include diversity of generation supply, commodity price risk, and ensuring sufficient capacity to meet peak load and planning reserve margins. The resource portfolio proffered by the Duke Carolinas Utilities is designed to meet growth while prudently managing

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[1] N.C. Sess. Laws 2021-165.

[2] N.C. Gen. Stat. § 62-110.9.

[3] 2019 S.C. Acts 62.

operating, reliability, and cost risk during an orderly exit from the companies' coal fleet. However, the substantial economic development growth we are experiencing across the Carolinas will require replacement baseload generation as well as incremental generation that can provide power every hour of every day, and this generation cannot be provided by renewables and storage alone given the substantial 24-hour load profile of certain customers. So, while the Duke Carolinas Utilities have plans to develop significant amounts of new renewables and storage resources on-system, as discussed in more detail below, to facilitate the orderly retirement of their coal fleets and meet substantial load growth, the development of new natural gas generation is vital to support the communities and customers who live and work in the Carolinas.

10. The Duke Carolinas Utilities filed their 2023-2024 Carolinas Resource Plan with both the NCUC and PSCSC in August 2023, and subsequently supplemented both in January 2024 to address increased demand. The Carolinas Resource Plan is designed to advance the Duke Carolinas Utilities' energy transition towards carbon neutrality consistent with North Carolina law while prioritizing reliability and affordability as required by both states' laws and planning requirements. The Carolinas Resource Plan projects significant load growth resulting from the Carolinas' growing population, transportation electrification, and the Carolinas' recent nation-leading economic development success. South Carolina, for example, experienced the fastest growing

population in the nation in 2023, according to the U.S. Census Bureau,[4] while the Carolinas region as a whole continues to experience growth in demand for electricity driven by significant new and expanding load from manufacturing, electric transportation, data centers, and advanced cloud computing and blockchain operations that have recently made new announcements and material commitments to take electric service from the Duke Carolinas Utilities.

11. The Carolinas Resource Plan now under review by the NCUC and PSCSC plans for the orderly retirement of the Duke Carolinas Utilities' remaining 8,400 MW of coal-fired generating capacity by 2035— representing approximately 20% of the winter capacity requirement for the combined system. To replace this significant retiring dispatchable generating capacity and meet the Carolinas' significant economic development load growth, the companies' proposed execution plan for new generation requires an unprecedented pace, scope, and scale of generation additions in the near-term and longer-term planning horizon in order to continue to deliver cleaner energy to our customers without compromising grid reliability and affordability.

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[4] U.S. POPULATION TRENDS RETURN TO PRE-PANDEMIC NORMS AS MORE STATES GAIN POPULATION, https://www.census.gov/newsroom/press-releases/2023/population-trends-return-to-pre-pandemic-norms.html#:~:text=South%20Carolina%20and%20Florida%20were,%25%2C%20respectively%2C%20in%202023 (last visited May 13, 2024).

12. In the near term, the Duke Carolinas Utilities are planning to retire four coal-fired generating units totaling 1,850 MW by the beginning of 2029 and have filed for certificates of public convenience and necessity for authorization to construct a 1,360 MW hydrogen-capable CC unit and two 425 MW CT units to replace these retiring coal units. These new replacement generating facilities must be placed into service before the coal units can be retired to ensure adequate dispatchable capacity on the system and to maintain grid reliability. The Duke Carolinas Utilities' overall execution plan presented to the NCUC and PSCSC includes plans for significant dispatchable and carbon-free generation additions, including constructing and placing into service five new advanced class, hydrogen-capable CC units (6,800 MW) by 2033, five new advanced class, hydrogen-capable CT units (2,125 MW) by 2032, 6,000 MW of solar and 2,700 MW of battery energy storage by 2031, 1,200 MW of onshore wind by 2033, 1,700 MW of pumped storage hydro by 2034, and 2,400 MW of offshore wind and 600 MW of advanced nuclear small modular reactors by 2035.

13. Because it takes many years to plan, site and implement changes to our generating and transmission resources, the Duke Carolinas Utilities have begun these activities immediately, and many of these impacts cannot simply be reversed once the changes to the generating and transmission resources have begun. However, the GHG Rule imposes requirements that materially change the operation of generation assets and has the potential to change the Duke Carolinas Utilities' resource additions and generation mix that is needed to ensure safe and reliable operation of the electric grid and as required by

both states' laws. As a result, the plans that are now before the NCUC and PSCSC for approval have the potential to be adversely impacted.

14. A critical aspect of Duke Energy Carolinas Utilities' plans is to achieve an orderly transition and exit from aged and approaching the end-of-life coal-fired generation by ensuring that a set of adequate and diverse replacement resources that are equally or more reliable are developed and enter commercial operation prior to coal unit retirement to maintain or improve system reliability. This is impacted in a two-fold manner in the GHG Rule: (a) by requiring all coal plants to retire by the end of 2031 if they do not install natural gas co-firing by the end of 2029 or carbon capture and storage/sequestration (CCS) by the end of 2031 as opposed to the coal retirement schedule outlined in the Carolinas Resource Plan; and (b) by effectively limiting the operation of new natural gas assets if CCS is not installed by 2032, as CCS cannot be installed on new gas in the Carolinas in that timeframe due to unavailability of CO_2 transport pipelines and/or lack of known suitable geology for sequestration. New natural gas plays a critical role as coal retires in ensuring that the Duke Carolinas Utilities maintain or improve upon the adequacy and reliability of the existing grid as required under state law.

15. The requirements imposed on coal-fired generation in the GHG Rule thus could alter the coal retirement schedule in the Carolinas Resource Plan and ignore the realities around lead times for regulatory actions, siting and permitting, procurement and construction, fuel, and transmission dependencies needed to retire coal capacity and implement the replacement resources and demand-side tools necessary to maintain

reliability. The burdens imposed by the mandated compliance schedule required by the GHG Rule will challenge Duke Energy Carolinas' meaningful progress in executing an orderly energy transition, thereby amplifying reliability and affordability risks related to Duke Energy Carolinas' exit from coal, as well as adversely impacting Duke Energy Carolinas' ability to meet the carbon reduction targets set out in HB 951 at the same time our service territory is experiencing unprecedented load growth.

16. By limiting the use of potential new natural gas-fired units, the GHG rule would require the Duke Carolinas Utilities to plan for and construct additional generation resources beyond what was outlined in the Carolinas Resource Plan. As the Carolinas Resource Plan already outlines a least-cost pathway to meeting customer load and progressing the Duke Carolinas Utilities' North Carolina-sited generating fleets towards carbon neutrality, it is clear that the GHG Rule will require additional generating resources beyond what is outlined in the plan, thus imposing additional, and significant, costs on customers. Planning and associated substantial expenditures for such additional generation would have to commence now, in order to meet the target dates for retiring our coal assets.

17. Because the GHG Rule limits the use of new natural gas generation, generation must be shifted to generating sources that operate less efficiently and have a higher CO_2 emission rate than the generation mix modeled in the Carolinas Resource Plan, resulting in incrementally higher CO_2 emissions from the Duke Carolinas Utilities' generating fleet. As a result, the Duke Energy Carolinas Utilities may be delayed in their ability to meet the 70% carbon emission reduction target under North Carolina law—an

absurd result for a rule the U.S. Environmental Protection Agency states is intended to "significantly reduce greenhouse gas (GHG) emissions."[5]

18. Unless the GHG Rule is stayed, the Duke Carolinas Utilities' orderly plan to reduce carbon emissions and serve substantial load growth while ensuring reliability and affordability for customers in North Carolina and South Carolina, will experience immediate and irreparable impacts by (1) increasing the cost for electricity; (2) creating operational hurdles for serving the tremendous growth in South Carolina and North Carolina; and (3) challenging the Duke Carolinas Utilities' ability to execute a least-cost path to meet the CO_2 emissions reduction targets established under HB 951.

Executed this 23rd day of May, 2024.

Julia S. Janson

Julia S. Janson

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[5] GREENHOUSE GAS STANDARDS AND GUIDELINES FOR FOSSIL FUEL-FIRED POWER PLANTS, Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants | US EPA (last visited May 13, 2024).

Exhibit I

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

ELECTRIC GENERATORS FOR A SENSIBLE TRANSITION, *Petitioner*, v. U.S. ENVIRONMENTAL PROTECTION AGENCY, *Respondent.*	Case No.: 24-1128

DECLARATION OF WILLIAM A. JOHNSON

1. I am the General Manager of the Kansas City Board of Public Utilities (KCBPU or the Utility), serving as the chief executive for the largest electric and water municipal utility in the state of Kansas.

2. I graduated with a Master of Business Administration from Ottawa University in 2008.

3. I began my career at KCBPU more than 44 years ago. I started in an entry-level position and worked my way up through the ranks into an executive level position prior to being appointed General Manager. My previous position included directing KCBPU Electric Operation & Technology division activities; including but not limited to, Electric Transmission and Distribution, Electric Engineering, Information Technology, Telecommunications, and Fleet Maintenance.

4. Over my career, I have sponsored many large utility projects, including modernizing KCBPU's electric infrastructure, and I have played a key role in introducing some of the utility's most advanced enterprise technology systems designed to improve utility operations.

5. I am a past President of Kansas Municipal Utilities, a current board member for the Kansas City Kansas United Way, and past board member of the Boys & Girls Club. I am also a member of the American Public Power Association (APPA) and the Rocky Mountain Electric League (RMEL).

6. I am also past President of the Kansas-Missouri chapter of the American Association of Blacks in Energy. I received the distinguished Black Achievers Award from the Southern Christian Leadership Council and the Black Man of Distinction Award from the Friends of Yates.

7. This declaration is based on my personal knowledge of facts and analysis conducted by my staff.

8. I am submitting this Declaration in support of the motion to stay the U.S. Environmental Protection Agency (EPA) final rule, titled "New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule" (GHG Rules). Implementation of the GHG Rule poses significant and imminent risk of harm for KCBPU, as described in this Declaration.

I. Description of KCBPU

9. KCBPU is a public utility operating water and electric utilities on a not-for-profit basis for the benefit of residential, commercial, and industrial customers in Wyandotte County/Kansas City, Kansas. The KCBPU water department was originally created in 1909, and its electric utility was operational in 1912, with the Utility officially being established in 1929.

10. KCBPU's 520 employees currently service approximately 53,000 water customers and 67,000 electric customers. As a public utility operating on a not-for-profit basis,

KCBPU is dedicated to providing excellent service on a cost-conscious basis, which involves balancing its financial limitations with its commitment to protect the environment. The mission of the Utility and its employees is "to focus on the needs of our customers, to improve the quality of life in our community while promoting safe, reliable and sustainable utilities." KCBPU is a publicly owned administrative agency of the Unified Government of Wyandotte County/Kansas City, Kansas, and is self-governed by an elected six-member board of directors.

11. KCBPU serves the city of Kansas City, KS. Kansas City, KS is an urban area, and, according to the EPA EJScreen tool, Kansas City, KS has a population of 155,728 across an area of 128.3 square miles. 42% of the population is considered low income, 63% of the population are people of color, 20% have less than a high school education, the per capita income is $22,478 and the average life expectancy is 69 years.

II. KCBPU Resources and Facilities

12. KCBPU provides power to its customers via power purchase agreements with the Utility's partners and through the Utility's own generation assets.

KCBPU owns and operates the Nearman Creek Power Station, which is composed of one 235 MW net capacity coal-fired electric generating plant and one 85 MW net capacity simple cycle dual fuel combustion turbine.

13. KCBPU has contracts with the Southwestern Power Administration (SPA) entitling the Utility to annually purchase 38.6 MW of hydroelectric peaking capacity and 5 MW of hydroelectric power from the Western Area Power Administration (WAPA). The Utility also has entered into seven Renewable Energy Purchase Agreements. KCBPU's agreement with TradeWind Energy is to receive 25% of the energy output of Phase 1 of the Smoky Hills Wind Farm. Phase I of the project has a name plate of approximately 100 MW of wind capacity. The wind farm was built approximately 25 miles west of Salina, Kansas in Lincoln and Ellsworth

Counties in Kansas. In March 2017, also through TradeWind Energy, the KCBPU began receiving 200 MW of energy generated by wind turbines from the Cimarron Bend Wind Project. The wind farm is located just south of Minneola, Kansas. KCBPU also has an agreement with Oak Grove Power Producers to provide 3.5 MW of landfill gas from Arcadia, Kansas. The Utility maintains a contract with the Bowersock Mills & Power Company ("Bowersock") to purchase the capacity and energy of an existing 2.15 MW run-of-the-river hydroelectric facility on the Kansas River in Lawrence, Kansas and 4.70 MW of capacity from an expansion of Bowersock's existing hydroelectric facilities. KCBPU also receives 25 MW of energy generated by wind turbines from OwnEnergy, Inc. The wind farm is located south of Alexander, Kansas in Rush County, Kansas. Lastly, in November 2016, KCBPU along with MC Power, a solar developer, agreed to install a 1 MW alternating current solar photovoltaic facility at the Nearman Creek Power facility. The project is intended to be a community solar project where customers can license panels to reduce their monthly electric expenses and support greener initiatives.

14. Over the past 5 years, KCBPU has invested approximately $45 million and, since 2003, approximately $393 million in capital improvements at the Nearman Creek Power Station, which is inclusive of the control technology investment and was intended to ensure long-term functionality and reliability. These investments were made with the assumption that Nearman would operate another 25 years and provide the community affordable and reliable power.

15. KCBPU has invested heavily in renewables and has one of the largest and most diverse renewable pools of any utility our size. Renewables made up 54% of our retail sales in 2022 and 50% in 2023. Our renewable portfolio is made up of wind, hydro, solar, and landfill gas.

16. KCBPU invested $205 million to comply with the Cross State Air Pollution Rule (CSAPR) and Mercury Air Toxics Standards (MATS) requirements, financing these capital projects through debt issuance. Including interest costs, the outstanding amount owed on this debt is approximately $347 million.

III. Planning and Expected Future Operations

17. KCBPU utilizes an Integrated Resource Planning process to help drive investment decisions associated with meeting the needs of the communities it serves. KCBPU must fulfill all obligations required of it as properly established by the North American Electric Reliability Corporation (NERC), the Federal Energy Regulatory Commission (FERC), and the Southwest Power Pool (SPP), including capacity requirements set by these entities.

18. KCBPU currently projects that, on average, load growth will increase by approximately 0.5% annually over the next decade based on current internal forecasts. The modest growth increase is primarily driven by electrification efforts and modest commercial and residential growth.

19. Being in a highly urban area presents certain challenges. Wind turbines, for instance, are not a possibility in or around KCBPU's service territory, and, thus, those resources provide limited assistance from a reliability standpoint. They also carry minimal capacity accreditation under Effective Load Carrying Capability (ELCC) under SPP's established rules. Under the ELCC methodology, wind resources are expected to carry an accreditation value of approximately 15% of nameplate, with the accreditation value diminishing as more are added to the system. As a result, the ELCC rating requires substantial overbuild to reach the required capacity coverage. . Available land area is also extremely limited. It is thus not feasible to install significant new solar generation within the service area. KCBPU's service territory has also struggled with congestion within SPP's transmission area. Removing generation located close to

Kansas City, KS and the Kansas City metropolitan area will, therefore, require extensive transmission upgrades and investments if replacement generation is not present to help alleviate the congestion and voltage concerns. To maintain transmission system stability and account for potential continency scenarios, KCBPU would need to replace the Nearman Creek Power Station with new internal generation resources. In addition to the cost of constructing these new resources, KCBPU would need to modify the existing transmission system to accommodate interconnection of the new generating units. This would result in substantial capital investment required for either modifications to an existing substation or the construction of a brand new substation and associated high voltage transmission lines. If KCBPU is able to interconnect the new generation resources at an existing substation, the estimated cost for the interconnection would be approximately $2 million. If a new substation is required to accommodate the new resources, the cost to the utility would be approximately $15 - $ 20 million.

IV. EPA's GHG Rules

20. EPA has finalized rules that provide "emission guidelines" for existing fossil fuel-fired steam generating units and New Source Performance Standards (NSPS) for fossil fuel-fired stationary combustion turbines. The GHG Rules have significant ramifications for the future of these types of sources. Requirements for new and existing coal and natural gas-fired units reflect what EPA says would be achievable through implementation of the "best system of emission reduction" (BSER) that, taking into account costs, energy requirements, and other statutory factors, is adequately demonstrated for the purpose of improving the emissions performance of the covered electric generating units.

21. EPA established several "subcategories" of units, and the applicable BSER depends on which subcategory applies. For coal-fired units, EPA has divided units into those that will operate through December 31, 2039 and those that will cease operations before that date.

For the latter, the GHG Rule requires existing coal-fired units to either start co-firing natural gas at a minimum of 40% by January 1, 2030, or shut down permanently by January 1, 2032. For natural gas-fired combustion turbines, EPA has created three subcategories based on utilization of the units: baseload, intermediate load, and low load.

22. Of most significance here, EPA selected carbon capture and storage (CCS) as the BSER for existing coal units that will operate past 2039 and for new base load combustion turbines. CCS is not adequately demonstrated or achievable, certainly not by January 1, 2032, as the GHG Rule requires. The one-year extension that EPA provided for installation of controls makes no difference, as it is just as unrealistic to construct CCS by January 1, 2032 as it is to do so by January 1, 2030.

V. Impact of EPA's GHG Rule on KCPBU

23. As noted above, the Nearman Creek Power Station is comprised of two units, one 235 MW net capacity coal-fired electric generating plant and one 85 MW net capacity simple cycle dual fuel combustion turbine. The coal-fired unit is affected by the GHG Rule.

24. As discussed above, CCS is not an option. CCS has not been demonstrated. It is not achievable at Nearman Creek by January 1, 2032, for the existing coal-fired unit or for a new natural gas-fired unit by January 1, 2033. Moreover, even if it were, compliance in this manner would most likely require development of Class VI wells. EPA estimates a minimum of 24 months for permit approval for such wells. This does not include a feasibility study, site characterization studies, delineation, GS plans, well construction, among other things. This process would take at least 2-3 years, for roughly a total timeframe of 5 years. Geological studies would need to be performed to determine if Class VI wells are a viable option within a relatively close proximity of the power plant. Further, due to the location of our Nearman Water Treatment

Plants horizontal collector wells used for drinking water, Class VI well(s) may not be approved by EPA.

25. KCBPU must begin planning for compliance with EPA's GHG Rules now. It is unclear if KCBPU can comply with the GHG Rule by co-firing the unit with natural gas and retiring the unit by January 1, 2039. If this compliance pathway is viable, KCBPU estimates that the cost of a 10-year firm capacity natural gas contract to be approximately $48.4 million at the Nearman Creek Power Station. It is not, however, clear if there is adequate natural gas supply at the Nearman Creek Power Station to co-fire the existing coal-fired unit with 40% of gas. To determine if compliance through natural gas co-firing and early retirement is viable, KCBPU will have to conduct an engineering study. Past cost of related engineering studies for the Nearman Power Station air quality control projects and natural gas assessments has been approximately $500,000, in 2012 dollars.

26. If the study determines that co-firing with gas is a viable path, and KCBPU decides to pursue it, KCBPU will have to start design, engineering, and procurement associated with converting the unit to co-fire natural gas; upgrades for the gas delivery system (if needed); and entering into long-term contracts for firm gas supply for the unit. To convert the unit to co-fire natural gas, KCBPU estimates a capital investment in the $30M - $50M range. To ensure the possibility of co-firing by January 1, 2030, a project of this magnitude will require $1M - $2M of that total to be expended in the next 2-3 years while the litigation is pending. If the GHG Rule is set aside by the courts, KCBPU would have no avenue to recover these funds. In fact, once a project of this type is well under way, it will be difficult if not impossible to reverse it.

27. If the study concludes that natural gas cofiring is not a viable option, KCBPU must comply with the GHG Rule by shutting down existing coal-fired generation at Nearman

Power Station by January 1, 2032. The Utility must begin working with the state to prepare its plan to implement the GHG Rule, which is due in just two years, and undertake the multi-year process of finding adequate replacement power. Once KCBPU begins its efforts to comply with the GHG Rule, the path chosen will be effectively irreversible.

28. KCBPU may elect to replace the existing coal-fired generation at Nearman Creek Power Station with new natural gas-fired unit(s) at the plant. Those units would have to comply with EPA's CCS-based emission rate limits – which is not achievable by 2032 – or limit their capacity factors to 40%. Abiding by a limit on capacity would make any new units uneconomic. But if it is the only option available to KCBPU, the Utility will have to start design, engineering, and procurement associated with constructing new natural gas-fired units; upgrades for the gas delivery system (if needed); and entering into long-term contracts for firm gas supply. To ensure the possibility of installing the new units by January 1, 2032, KCBPU will need to expend funds of approximately $1M - $2M while the litigation is pending. If the GHG Rule is set aside by the courts, KCBPU would have no avenue to recover these funds. In fact, once a project of this type is well under way, it will be difficult if not impossible to reverse it.

29. If KCBPU closes the Nearman Creek Power Station's coal-fired unit, Nearman will likely lose approximately 50 – 75 full time employees (FTE) positions. Depending on the ultimate compliance pathway, the reduction in FTE positions may grow significantly from this estimate. If the compliance pathway is geared toward a wires only pathway and not a direct generation replacement pathway, it is likely that additional staff losses would be felt in other areas of the organization from Compliance to Store Rooms to Purchasing to the Trades to Environmental and potentially more. All of those job losses would directly impact the struggling local economy. There will also be considerable impacts to the tax base and local community

surrounding the Nearman Power Station if closure occurs. KCBPU estimates, for instance, that such closure will likely reduce local wages by $5 - $10 million annually in Kansas City, KS and potentially more depending on the compliance pathway chosen.

30. Compliance with the GHG Rule, including the impacts of the early retirement of coal at Nearman Creek Power Station, will result in higher rates for all rate classes. Depending on the action taken, whether that be a primarily wires-only solution or a new-build replacement, or some combination of those, the organization will be required to incur engineering and development costs well prior to the date of closure because the solutions will have to be in place prior to any retirement date. Further, the development cycle for both generation and transmission assets is incredibly long and cumbersome, which will likely be exacerbated by this rule and the rush to comply.

31. KCBPU's service territory includes large areas of disadvantaged communities. The GHG Rule will increase spending on both generation and transmission if KCBPU is to attempt to maintain the same reliability metrics. These actions, resulting from the GHG Rule, will result in higher rates for those communities.

32. KCBPU has invested substantially in the Nearman Creek Power Station. As of December 2023, the book value of Nearman Creek Power Station was approximately $296.5 million due to the long-term capital improvements that have been placed into service over the last decade. Premature closure of the facility will therefore waste considerable resources.

33. Compliance with the GHG Rule by shutting down existing coal-fired generation at Nearman Creek Power Station will affect electric reliability and will further injure the Utility. I agree with the SPP, which recently stated:

> SPP remains concerned, however, about the impact the Final Rule may have on the region's ability to maintain resource adequacy and ensure reliability in

> the SPP region. SPP is concerned that limited technological and infrastructure availability and the compliance time frame will have deleterious impacts including the retirement of, or the decision not to build, thousands of MWs of baseload thermal generation. If sufficient flexible thermal resources are not available to play their critical roles in SPP's resource mix, SPP's ability to maintain regional reliability will be directly impacted. The Final Rule's emissions limits for existing coal and new gas generation are based on the EPA's finding that carbon capture and sequestration (CCS) technology is a viable best source of emissions reduction (BSER) in terms of commercial availability and reasonable cost. SPP continues to be concerned that CCS has not yet been adequately demonstrated at the required capture rate, has not been commercially produced at scale, and will not be widely available and practicable at the level needed for the Final Rule's 2032 compliance time frame. Moreover, while the Final Rule contemplates a natural gas co-firing option for existing coal units that choose to retire before 2039, SPP is concerned about the availability of gas infrastructure necessary to adequately utilize that compliance option in that time frame.[1]

34. To build replacement power and/or additional transmission, KCBPU may be required to take on additional debt in the relatively near future. This will put downward pressure on credit ratings for the Utility due to the debt still carried for the financing of other projects at the facility.

35. Because CCS is not feasible at this time or by the compliance deadline in the GHG Rule, any new natural gas combined cycle units will need to limit their capacity factor to 40% to avoid becoming subject to emission rate requirements based on deployment of CCS. Limiting the capacity of natural gas-fired units in this manner is a waste of resources. KCBPU operates all of its units on a lowest cost basis, as the market allows. This means that if there is market energy available at a lower cost, the Utility purchases the market energy in lieu of running owned or contracted generation. It would be a waste of resources and a cost to customers to be required to purchase energy due to this capacity factor limit when the unit could produce energy at a lower cost.

[1] SPP, *Statement on the Recent EPA Greenhouse Gas Emission Rule* (May 20, 2024) (Attachment A).

36. The process to construct and develop new generation is long and cumbersome under the current requirements. In many cases the total development time from inception to commercial operations may be 7 – 8 years. Regional Transmission Organizations (RTOs), including SPP, are also in the process of requiring more generating capability from their load serving entities. Thus, while utilities are already moving into a period of requiring additional generating capabilities based on the RTO's criteria, load growth will exacerbate that need, thus putting additional constraints on the ability and timing of generation expansion. If the GHG Rule is implemented, resulting in premature facility closures, the costs and time commitments associated with new generation development will likely be extremely punitive.

> In the event that permitting new natural gas-fired generation is not feasible, KCBPU would be forced to look to the market for replacement power. There are limited shovel-ready renewable projects, and all such projects would require substantial transmission upgrades. All types of new generation resources will be constrained due to regional load increases, tightening capability values, and new EPA regulatory burdens, which will cause pricing pressures and limited availability. Additional solar restrictions and tariffs will add to the limited availability and its pricing. Capacity accreditation values based on the ELCC methodology utilized through the SPP also limits the overall effectiveness of renewables during those periods of heightened demand. Solar, for example, would likely need approximately nine times the nameplate value to equate to that same value on a thermal unit during the winter season. Wind resources likely would require approximately seven times the nameplate value to equate to the same value on a thermal unit.

Executed this 22 day of May 2024.

William A. Johnson

Exhibit J

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

ELECTRIC GENERATORS FOR A SENSIBLE TRANSITION, *Petitioner*, v. U.S. ENVIRONMENTAL PROTECTION AGENCY, *Respondent*.	Case No.: 24-1128

DECLARATION OF TODD KOMAROMY

I, Todd Komaromy, declare as follows:

1. I am Todd Komaromy, Director of Resource Planning at Arizona Public Service Company (APS).

2. I possess a Bachelor of Science in Electrical and Computer Engineering from Ohio State University (2002), a Masters of Business Administration from the University of Phoenix (2005), and Juris Doctor from the Sandra Day O'Conner School of Law at Arizona State University (2008).

3. I have over 20 years of industry experience and began my career at APS in 2002 supporting engineering work for APS electricity generation projects. Since that time, I have held a variety of roles of increasing responsibility at APS and other electric utility companies, serving in functions that support electricity generation engineering, electricity transmission and distribution infrastructure, federal regulatory compliance, and state regulatory affairs. In my role as Director of Resource Planning, I lead the development and implementation of APS's future generation resource plans and the evaluation of generation resource alternatives. I also support APS's resource acquisition

teams, as they work to develop and procure the generation resources APS will rely upon to serve growing Company load into the future. As such, I work with and supervise teams with expertise in a variety of electricity generation resources, including traditional thermal generation, renewable generation and energy storage resources, other forms of zero-emitting resources under development, and customer-side solutions, such as distributed generation, energy efficiency, and demand response solutions.

4. This declaration is based on my personal knowledge of facts and analysis conducted by my staff.

5. I am submitting this declaration in support of a stay of EPA's final rule, titled "New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and, Repeal of the Affordable Clean Energy Rule" (the "Final Rule").

6. APS is primarily concerned with one aspect of the Final Rule: new source performance standards ("NSPS") for new natural gas-fired combustion turbines ("CTs") and combined cycle ("CCGs") units. Under Clean Air Act ("CAA") section 111(b), "new" CTs and CCGs are those that commence construction after the publication of EPA's May 2023 proposed NSPS rules. Specifically, EPA has made the compliance obligations for CT and CCG units that operate as baseload units more stringent by requiring those gas-fired electric generating units (EGUs) with a greater than 40% capacity factor to meet, by January 1, 2032, a 100 lb CO_2/MWh-gross emission limit, based on installation of carbon capture systems ("CCS") with a 90% capture rate — so-

called "Phase 2" standards. Prior to 2032, new baseload CT and CCG units must achieve a CO_2 emission rate of 800 lbs CO_2/MWh — so called "Phase 1" standards.

7. This aspect of the Final Rule causes irreparable harm to APS and Arizona customers. As a result of the Final Rule, APS and Arizona could face serious challenges in ensuring the reliability of our electrical energy system. In addition, because of the Final Rule's Phase 2 emission limits, APS and Arizona utility customers will experience serious financial impacts through significantly increased electricity rates. The impacts of the Final Rule, as described below, are happening now as APS makes resource commitments to serve the tremendous load growth within its service territory.

8. The Final Rule fails to address several critical factors that are unique to APS and other Arizona utilities, such as significant load growth, changing electricity resource portfolios, and the impacts of extreme heat during summer months on peak demand and the ability to reliably serve our customers. Under the Final Rule, APS could be forced to choose between compliance and maintaining reliable, affordable service for its customers.

I. Population and Load Growth in Arizona Make the Final Rule Unworkable in Arizona.

9. APS's Integrated Resource Plan ("IRP") is a fifteen-year, forward-looking plan that assesses the forecasted loads (i.e., customer demand) and resources that will be required to serve our customers' needs. As documented in APS's 2023 IRP, Arizona is experiencing unprecedented population growth. Population in the state is growing at one of the fastest rates within the country. In 2023, Maricopa County, Arizona, home to the Phoenix metropolitan area, remained one the largest-gaining counties in the nation.

Additionally, APS is experiencing growth in all customer classes: residential, commercial, and industrial.

10. APS's 2023 IRP projected an average annual population growth rate for Arizona of 1.3%, largely driven by individuals moving into the state. As a result, APS's customer base is expected to grow by 20,000-23,000 customers per year.

11. APS also projects that average annual peak demand and energy needs will increase at a compounded annual growth rates of 2.4% and 3.7%, respectively. The growth over the next 15 years equates to approximately 3,400 megawatts ("MW") of capacity needs or nearly 230 MW as an annual average increase. The IRP further discusses that, by the end of 2027, APS customers will need about 11,350 MW of electricity generation capacity to meet their needs, an amount equivalent to what it takes to serve about 1.8 million Arizona homes. By 2038, APS customers will need more than 14,820 MW of electricity generation capacity.

12. Since completion of the IRP in 2023, the forecast of load growth in APS's service territory has continued to grow at a substantial pace beyond what was identified at that time. This growth within the current forecast is largely attributable to planned commercial and industrial load growth, especially from data centers and technology manufacturing operations moving to Arizona. Because these new businesses are very high-load factor customers (meaning they use very large volumes of energy during <u>all</u> hours of the day, including overnight), they drive increases in load beyond just at peak hours. In this respect, load forecasts into the future are increasingly showing large increases in demand throughout all hours of the day.

13. Growth is expected to continue throughout our 15-year planning horizon and, adding to this challenge, is the increasing share of intermittent energy generators within the portfolio of resources used to cost-effectively and reliably meet the demand and energy needs of APS customers.

14. The significant load growth occurring in Arizona means incremental additions in natural gas generation in the near future will be a critical part of delivering reliable and affordable energy to customers.

15. The Final Rule, requiring EGUs with new baseload CT/CCG units of greater than 40% capacity factor to install CCS with a 90% capture rate (or, somehow, otherwise meet the 100 lbs CO_2/MHh BSER) by 2032, would severely impact APS's ability to meet burgeoning load growth and customer demand. High sustained load growth beyond just at peak hours and into the overnight periods, given increases in demand from extreme heat and very high-load factor commercial and industrial sales growth, drives APS's future needs for baseload CT/CCG units.

II. APS's Plans for Transitioning to New Source of Generation and its Response to Growing Demand in Arizona.

16. APS plans to exit all coal-fired generation in the next eight years, starting with the retirement of its Cholla Power Plant by April of 2025, and a planned exit from the Four Corners Power Plant in 2031. Both have provided long-term reliable and affordable electricity for APS customers. But today, new renewable and energy storage resources have become increasingly more cost-effective and reliable. Paired with dispatchable natural gas resources, reliance on this cost-effective resource portfolio means it is appropriate at this time to transition away from legacy thermal resources, like coal-fired power plants.

17. In accordance with the Company's 2023 IRP, APS expects to add more than 3,000 MW of new renewable generation and more than 2,500 MW of utility-scale batteries in the next five years alone.

18. To backstop resources that are not predictable or capable of generating across an entire 24-hour period of demand (e.g., intermittent resources like solar and wind), APS must rely on a diverse portfolio of assets that includes thermal generation in addition to renewable generation and energy storage. For example, APS cannot replace the capacity of the Four Corners Power Plant with renewable energy on a one-for-one basis. Solar resources only generate electricity when the sun is shining, while wind energy is weather limited, so intermittent resources of this type are only available during portions of the day. In addition, the on-peak generation capacity contribution of these resources is significantly less than conventional, fully-dispatchable thermal resources.

19. As such, to replace a resource like Four Corners with just clean-energy resources and still meet customer demand for around-the-clock, reliable energy, given the technological maturity of resource options available today, APS would be required to significantly over-build more renewable and storage resources than would otherwise be necessary through the incorporation of conventional thermal generation into a diverse portfolio of resources. The additional resources would be necessary to both: (1) meet the day's demand for energy, and (2) also to charge batteries that can be used later in the day to provide energy when intermittent resources aren't available. Such significant overbuilding would drive up customer costs to an unacceptably high level.

20. Thus, to ensure that APS's customers experience the same level of reliability provided by the 970 MW of electricity from the Four Corners facility while

keeping rates affordable, APS is planning to replace these aging, legacy resources with a blend of solar, wind, and energy storage technologies, in addition to dispatchable energy resources, such as natural gas CT and CCG generating units.

21. As additional renewable and storage resources are integrated into APS's system to replace higher cost legacy thermal resources, such as coal-fired power plants, new and existing natural gas resources must increasingly be deployed to "firm up" the new intermittent renewable and storage resources. Such resource diversity is a necessary means of ensuring 24/7 reliability for all APS customers.

22. Natural gas-fired CT and CCG plants are critical resources in responding to quick changes in renewable energy output, due to their ability to increase or decrease output quickly. These resources are uniquely capable of matching energy production and delivery on a minute-by-minute basis with changing load needs throughout the day, making these units critical resources for maintaining grid reliability and resiliency.

23. The Final Rule, requiring EGUs with new baseload CT/CCG units of greater than 40% capacity factor to install CCS with a 90% capture rate (or, somehow, otherwise meet the 100 lbs CO_2/MHh rate) by 2032, would make APS's investment in new natural gas-fired CTs and CCGs substantially more expensive for customers and would potentially deprive APS of the ability to deploy such vital firm resources when needed to meet customer demands when renewable and energy-storage resources are unable to serve load. Under the Final Rule, APS would, either: (1) have to install CCS on new gas-fired resources — which effectively doubles the cost of these resources and cannot be completed by 2032 (or 2033, for that matter) — or, (2) build redundant CT/CCG units in order to reach sufficient overall capacity factors necessary to serve load

throughout the day, which makes no economic sense and is worse for the environment. This is because CT/CCG units are more efficient when they operate at a higher, more sustained levels of operation (meaning their lb CO_2/MWh is less) because of higher thermal efficiency and reduced start-up and shutdown-down cycles.

III. How Increased Proliferation of Renewables and Extreme Heat in Summer Months Influence Peak Demand and Available Resources to Meet Customer Demands

24. The increase in renewable generation along with extreme heat in Arizona, present significant challenges when paired with significant growth from high-load factor business and the need to replace retiring legacy thermal generation. This set of factors contribute to APS's future needs for longer duration, dispatchable resources into the overnight hours of the day.

25. A challenge specific to Arizona utilities is we experience one, exceptionally high-peak season in the summer, while utilities in other regions have two less extreme peaks in summer and winter.

26. During periods of heavy market constraints over the summer season, extreme heat magnifies the importance of ensuring the reliable delivery of resources for customers. While the Arizona grid is robust, the stakes for failure are high. Conditions that create extended outages, especially during the extreme heat in the southwestern desert, could result in catastrophic public health consequences. In this environment, it is essential to ensure we have a resource portfolio capable of meeting our customers' energy needs with limited assistance from our neighbors.

27. APS's system is, at its most, resource-constrained after the sun sets and solar resources are no longer producing output. Extreme heat during the summer in

Arizona is not a condition that is limited to the daytime hours; instead, it largely persists through the overnight hours of the day after solar resources are no longer available and energy-storage resources have been depleted. As the day wears on, natural gas CT and CCG resources ramp up, increasing production to meet customer demand and replacing diminishing solar output.

28. While energy storage resources can provide renewable balancing support similar to that provided by gas-fired resources, the finite storage duration of these resources limits their ability to meet the full period of increasing customer demand, which extends well into the evening and overnight hours within APS's service territory. And while these technologies are continuing to evolve, given the current state of that evolution, APS and other Arizona utilities must use natural gas resources as a partner technology to ensure reliable service.

29. As mentioned above, traditional generation sources of electricity, including coal-fired power plants, which provide firm, available, and on-demand (e.g., dispatchable) energy, are retiring. At the same time, the penetration of intermittent generation resources, like renewable energy and battery storage, are growing. This evolution in resource generation is shifting the periods in which the grid is most vulnerable to reliability risks, away from periods of peak usage to periods of lower renewable production. This shift is commonly referred to as a shift to the "net peak," or the time period where the load minus wind and solar generation is highest. The identification of this net peak period is intended to account for both energy capacity (traditional peak) and energy sufficiency of energy-limited resources.

30. For instance, in 2021, the relative loss of load risk in the Desert Southwest (a summer-peaking area that includes all of Arizona, most of New Mexico, and parts of Texas and Imperial Irrigation District in California) by hour of the day began to increase around 2 PM, grew rapidly until it peaked around 6 PM, stayed relatively level until 7 PM, and then rapidly fell off as the evening progressed. By 2025, the relative loss of load risk is expected to begin closer to 5 PM, peak around 8 PM, drop off by 10 PM, but remain a risk until approximately midnight. By 2033, the effects will be dramatic. The net peak begins around 6 PM, peaks around 9 PM at night, but persists until 7 AM the next day, when renewable energy generation picks up again.

31. Consequently, as the penetration of energy-limited resources like renewable generation and energy storage grows, the risk of loss of load events will spread across an increasing number of hours. Use of energy storage systems at scale will only further extend the constrained periods (and thus the threat to reliability) into the evening and night-time hours. This is due to the abundance of renewable energy during the daylight hours and the growing lack of dispatchable generation capacity after dark. As the number of hours in which the system is at risk increases, the value of energy-limited resources with finite durations (like batteries) will also diminish, emphasizing the need for resources that are capable of delivering energy to the grid for sustained periods of time from the early evening hours until the morning. Between unprecedented load growth and APS's ongoing transition toward greater reliance on cost-effective and reliable renewable and storage resources, dispatchable natural gas generation remains a critical resource to ensure 24/7 reliable service for APS customers.

32. To ensure continued and reliable service for our customers, APS needs to have a variety of dispatchable, fast-ramping generation resources, including both CT and CCG natural gas resources, that can match energy production and delivery on the minute-by-minute basis that the grid, and our customers, demand. In addition to providing load following, peak demand capacity, these resources will be critical to providing overnight energy needs for APS customers, as increasing renewable resources during the daytime and overnight extreme temperatures drive APS's future energy needs.

33. All of these factors — sustained and substantial load growth, in particular from high-load factor customers that drive load increases during all hours of the day; the need to replace dispatchable capacity and energy production from the retirement of legacy, thermal generation, in particular coal-fired power plants; the increasing deployment of cost-effective intermittent (renewable) and battery energy storage systems, which drives the net peak of demand later in the day; and extreme heat in the desert Southwestern U.S. that persists during the overnight hours throughout Arizona's summer peak season — are contributing to APS's need for a diverse portfolio of resources necessary to meet a variety of system needs. While APS is planning to deploy a large variety of cost-effective zero-emitting resources to meet these challenges, including renewable resources, battery energy storage, demand response, and other customer-sited solutions, new CT and CCG natural gas resources are and will be a critical part of APS's resource mix. With increasing load arising throughout all hours of the day and, in particular, during overnight hours when Arizona's abundant solar resources are no longer available and battery energy storage has been largely depleted, new natural gas resources that can run over a 40% capacity factor will be essential for APS to provide reliable,

affordable service to its customers. The Final Rule, however, essentially takes natural gas CCG resources off the table to meet these needs, thereby threatening grid reliability and the affordability of service for APS customers.

IV. The Final Rule Is Impacting APS Now.

34. The resource decisions necessary to address the unprecedented challenges facing the electric generating industry must be made right now to ensure that resource-adequate generation can be available in time to ensure reliable service to APS customers. The Final Rule, however, forces APS to make investment decisions — on behalf of its customer base who bear the costs of those investments — that require the Company to install extremely expensive, untested, and unavailable CCS controls for critical natural gas generation resources; more realistically, these investments decisions would be to construct more gas-fired generation that it currently expects to install, in order to limit any new CT or CCG to a capacity factor of less than 40%.

35. At this time, APS does not believe it can install CCS on new APS natural gas generation resources by 2032 (or 2033), nor that such systems can achieve a consistent 100 lb CO2/MWh limit, which threatens the resource adequacy of these resources. In addition to the time, expense, and uncertainty associated with CCS controls installed on new baseload natural gas power plants, APS natural gas investments will be dependent upon the existence of extensive infrastructure for the transportation, storage, and potential re-use of captured carbon dioxide. APS does not control the existence, development, or operation of this infrastructure that is necessary to be in place for CCS controls to be effective, which places additional risk on APS natural gas generation.

Should this infrastructure not be developed in time or function properly, the resource adequacy of APS natural gas generation will be unacceptably threatened.

36. Putting aside the technical unknowns and difficulties with CCS at 90% capture for a gas plant, it is not possible for APS to construct CCS at a new gas plant by 2032 or 2033. Between procurement, design, engineering, permitting, and construction, the time necessary to put a new natural gas power plant into service is substantial and ranges from five to seven years (for both peak-focused simple-cycle CT units or for larger, baseload CCG plants). Adding CCS requirements, given the additional complexity of generation-site selection and off-site infrastructure development needed to correspond with carbon sequestration or re-use opportunities, along with added permitting and development complexities, likely adds at least four to five additional years to permitting, development, and construction timeframes for these critical resources. This means that the development timeframes for new natural gas-fired CTs and CCGs would be between nine and twelve (9 to 12) years. With APS seeking to procure resources *now* for the 2029 through 2031 timeframe — corresponding with the time when APS will finally exit from all coal-fired power plants — the additional time necessary to install CCS controls on baseload CT or CCG gas-fired power plants takes these resources off the table to meet expected significant load growth.

37. Should APS need to install CCS on its new natural gas generation so that it can operate above the 40% capacity factor and meet the 100 lb CO_2/MWh limit, that will *more than double* the "all-in" cost of installing such generation. Based on levelized generation capacity costs developed in APS's 2023 IRP, adding CCS to gas-fired CCG generation increases the capital cost per kW from $1,042 up to $2,224.

38. In short, APS has determined that CCS for a new gas plant is not feasible by 2032. The additional one-year extension that the Final Rule purportedly provides for installation of controls makes no difference. CCS technology that would achieve 90% capture for gas plants is not demonstrated and may become achievable only many years into the future, well after 2032 and 2033.

39. Because of the infeasibility, added time, complexity, and cost of CCS-equipped gas-fired generation, EPA's Final Rule effectively removes baseload gas-fired resources as a viable option to serve rapidly growing APS customer load, especially over the next five to seven years. This substantially limits the field of available resources that could be deployed to serve APS customers and would require APS: (1) to construct more gas-fired generation that it currently expects to install, in order to limit any new CT or CCG to a capacity factor of less than 40%; or, (2) to make procurement decisions involving technologies that either have not yet reached maturity or availability at scale, or involve complicated and time-consuming development pathways.

40. For example, long-duration energy storage applications, such as pumped hydro-electric storage projects, involve extremely complicated development pathways that would require longer than nine to twelve years of development (i.e., the same as APS's expected timeframe to develop natural gas-fired resources equipped with CCS as needed to achieve the Phase 2 emission limits in the Final Rule). Other options, such as small-modular nuclear reactors, have similarly not yet been developed at scale. As to both of these applications, they are unlikely to mature until at least the mid-to-late 2030s, which is far beyond the time horizon where APS critically needs large-scale capacity and energy generation resources. Alternatively, substantial additions of wind and energy

storage resources would involve significant new transmission line development, which — because of its development complexity — would require between eight and ten years of additional permitting, development, and construction. In the absence of compliance obligations based on CCS being deployed by 2032, baseload CCG plants would ideally help solve near-term needs, especially while these other technology options are given adequate time to develop. Removing baseload gas-fired resources from the mix of options APS is looking at, in order to serve customers during the early 2030s, means injecting substantial risk that adequate generation won't be available when needed.

41. Finally, once APS makes an investment decision involving resources with multi-year development timelines, they cannot be reversed. Apart from the financial penalties that would be associated with any breach of contractual commitments that are made with resource developers and others, cancelling a project mid-way through development means losing critical time that cannot be wasted in order to bring on sufficient resources necessary to serve ever-growing customer load, especially between now and 2031 when APS is planning to exit from coal-fired generation. Doing so likely would result in APS having insufficient resources to serve customers in the coming years.

42. Based on the Final Rule, the only viable path for APS to meet its obligations to provide reliable power to its customers — both to replace retiring baseload coal generation and meet substantial demand growth in Arizona — is to construct new gas-fired generation but limit capacity factors to 40% or less. Between procurement, design, engineering, permitting, and construction, the time necessary to put a new natural gas power plant into service is substantial and ranges from five to seven years (for both peak-focused simple-cycle CT units or for larger, baseload CCG plants). Accordingly, in

the absence of a stay of the Final Rule, APS must immediately start this process, given that the Company is in the process *now* of seeking to procure resources for expected load growth in the 2029 to 2031 timeframe. These decisions will involve the commitment of substantial resources — in the tens of millions of dollars, if not in the range of $100 million — for design, engineering, and permitting, in order to meet the Final Rule's deadline of 2032.

43. The Final Rule, therefore, requires companies like APS to make near-term investment decisions associated with critical natural gas generation that threatens to impose unacceptable risks to reliability and significantly increase costs for APS customers. The loss of these investments and the cost to APS and its customers will be irreparable, should the courts later set aside the Final Rule.

Executed this 24th day of May 2024.

Todd Komaromy

Todd Komaromy
APS Director of Resource Planning

Exhibit K

Case No. 24-1128

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

ELECTRIC GENERATORS FOR A SENSIBLE TRANSITION,

Petitioner,

v.

U.S. ENVIRONMENTAL PROTECTION AGENCY, MICHAEL S. REGAN

Respondents.

On Petition for Review of Final Agency Action
of the United States Environmental Protection Agency

DECLARATION OF TIM LAFSER

I, Tim Lafser, declare and state as follows:

1. I am Vice President of Operations at Ameren Missouri and am authorized to make this declaration on behalf of the company, based on my personal knowledge.

INTRODUCTION

2. I am responsible for ensuring that Ameren Missouri's non-nuclear generation fleet including coal, natural gas, and renewable energy resources (e.g.,

hydro, solar and wind) operate in a safe and reliable manner so as to meet the energy needs of our retail and wholesale customers. To fulfill my responsibilities, and in addition to plant directors, I rely on various specialized work groups including engineering design, plant engineering, and energy management, the latter of which is responsible for interacting with the Midcontinent Independent System Operator, Inc. ("MISO") and bidding our generation units into MISO's markets. My function works closely with other Ameren Missouri business segments such as corporate planning and the development of Ameren Missouri's generation strategy and transition efforts.

3. As part of my job responsibilities, I have become familiar with EPA's final rule entitled "EPA New Source Performance Standards For Greenhouse Gas Emissions From New, Modified, And Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines For Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; And Repeal Of The Affordable Clean Energy Rule," ("EPA's GHG Rule"), and I have personal knowledge regarding its likely impact on Ameren Missouri's existing and future operations. I am also familiar with the comments previously filed by Ameren Missouri regarding the proposed version of EPA's GHG Rule.

4. As explained in those comments and as further discussed below, EPA's GHG Rule will cause significant and immediate irreparable harm to Ameren

Missouri if not stayed because, in order to comply, the GHG Rule requires the commitment of near-term costs and resources that would be lost even if Petitioner is successful on the merits of its claims. If not stayed, EPA's GHG Rule will force Ameren Missouri to make commitments and incur substantial costs *immediately*, even though the rule is subject to multiple challenges in this Court, state plans implementing the rule have not been submitted or approved by EPA, and the technologies and infrastructure contemplated by the rule are not currently available at scale.

5. These immediately-required commitments include the soliciting and securing bids from contractors, procuring equipment, mobilizing resources and employees, securing approvals for major capital expenditures, applying for and securing the necessary local, state and federal permits and approvals, and communicating and working with numerous stakeholders, including state environmental agencies and local communities. Ameren Missouri estimates that implementing this near-term work alone could cost the company $5-10 million dollars.

6. EPA's GHG Rule, if not stayed, would also interfere with the company's carefully crafted plans to transition to a cleaner portfolio of resources, while at the same time ensuring reliable and affordable electricity, as expressed in Ameren Missouri's integrated resource plans that have already been submitted as

required to the state public utilities commission. EPA's GHG Rule effectively deprives the state public utilities commission of its sovereign authority in ensuring reliable and affordable electricity is available to customers.

BACKGROUND

7. Ameren Corporation is a public utility holding company headquartered in St. Louis, Missouri, whose principal subsidiaries include Union Electric Company, doing business as Ameren Missouri. Ameren Missouri is a vertically integrated utility operating in a traditionally regulated state, where retail electricity rates are set by the state public utilities commission.

8. Ameren Missouri is committed to providing affordable and reliable electricity to its customers and is therefore concerned about the immediate costs and the impacts of EPA's GHG Rule.

9. Ameren Missouri has been and continues to be a responsible environmental steward. Ameren Missouri has invested hundreds of millions of dollars to fund electric and natural gas energy efficiency programs. These and other programs further Ameren Missouri's efforts to reduce carbon emissions and lower customer bills.

10. Ameren Missouri has historically owned and operated four coal-fired power plants in Missouri: the Meramec Energy Center (827 MW) in St. Louis County; the Labadie Energy Center (2,389 MW) in Franklin County; the Rush Island

Energy Center (1,178 MW) in Jefferson County; and the Sioux Energy Center (972 MW) in St. Charles County. These plants have operated for approximately 50 years, generating affordable and reliable electricity for millions of area residents, thousands of businesses, and hundreds of government entities.

11. Consistent with its goal to transition away from coal-fired generation and toward a cleaner fuel portfolio, Ameren Missouri retired its Meramec plant in 2022 and plans to retire its Rush Island plant at the end of 2024, its Sioux plant by the end of 2032, and its Labadie plant by the end of 2042.[1] As explained in Ameren Missouri's 2023 integrated resource plan, this orderly retirement of Ameren Missouri's existing coal fleet will be accompanied by an aggressive build-out of renewable energy capacity complemented by highly efficient natural gas-fired combustion turbines to ensure a continued reliable and cost-effective supply of electricity.

12. This planning effort positions Ameren Missouri to transition its generation portfolio to one that is cleaner and more diverse in a responsible fashion. Such a transition, however, cannot happen overnight and must be accomplished in a

[1] As an alternative, Ameren Missouri could potentially transition to gas co-firing at Labadie with a retirement date of 2039. In that case, planning would have to start immediately even if another year was given under EPA's "reliability mechanisms" in its GHG Rule. Ameren Missouri projects that this massive project, which would include modifications to the boiler and the installation of major pollution controls, would cost hundreds of millions of dollars and require at least a 70-mile pipeline with a major river crossing.

manner that ensures the ongoing safe and reliable supply of electricity, including dispatchable capacity and the ability to make significant investments in transmission facilities to support the reliable delivery of increasing levels of cleaner and renewable energy resources to the regional electric grid. Some of Ameren Missouri's coal plants will continue to operate in the near term at levels consistent with the build-out of renewable generating capacity. Those operations will be conducted in a manner that ensures the ongoing protection of human health and the environment, pursuant to applicable federal and state standards. The operation of these plants while renewable energy resources are built is an essential component of Ameren Missouri's transition plan.

13. As of 2022, roughly 30% of Ameren Missouri's energy production was from carbon-free sources, and an additional 2,800 MW of carbon-free capacity is planned by 2030. Ameren Missouri also projects the addition of 4,700 MW of renewable capacity by 2036, as well as 2,000 MW of gas-fired generation by 2033 to ensure a reliable supply of electricity. As noted above, Ameren Missouri recently invested hundreds of millions of dollars to promote energy-saving measures and is devoting resources to carbon capture and sequestration ("CCS") research and development.

14. Ameren Missouri projects a 60% reduction in carbon emissions by 2030 from 2005 levels, an 85% reduction by 2040, and net zero carbon emissions

by 2045. In the meantime, since 2005, Ameren Missouri has achieved a 55% reduction in NO_X emissions, a 65% reduction in SO_2 emissions, a 91% reduction in mercury emissions, and a 32% reduction in CO_2 emissions.

15. This transition reflects an integrated plan that accounts for community involvement while ensuring resource adequacy. A responsible transition from fossil generation must ensure the continued reliable supply of affordable electricity, account for the time needed to permit and build necessary infrastructure, and be sensitive to impacts on surrounding communities.

16. To help ensure access and promote reliability, Ameren Missouri anticipates making significant investments over the next several years to upgrade infrastructure to bring renewables to market. For Ameren Missouri's coal plants that will continue to operate to meet electric demand in the coming years, Ameren Missouri plans to make capital expenditures of at least $90 to $120 million from 2024 through 2028 to ensure environmental standards continue to be met. All of these measures are part of an integrated resource plan for net zero carbon generation that reflects input from state regulators and surrounding communities.

17. As noted above, while Ameren Missouri is planning to retire most of its coal-fired generation by 2032, it plans to operate the coal-fired units at its Labadie plant until 2042, to ensure a safe, adequate and affordable supply of electricity. In addition, Ameren Missouri expects to add new dispatchable generation over the next

20 years, including 1,200 MW of combined cycle gas-fired turbine generators by 2032. Because these coal- and gas-fired units are expected to run most of the time, Ameren Missouri expects they will be required under EPA's GHG Rule to have an emission rate limit based on application of CCS with 90% capture by 2032. CCS consists of three primary components: (1) capturing CO_2 produced by power generation; (2) transporting that CO_2 by pipeline or other means to a storage site; and (3) storing the CO_2 in deep underground at sequestration sites.

18. To the best of Ameren Missouri's knowledge, CCS with consistent and reliable 90% capture of CO_2 has not been demonstrated at any electric generating unit in the world. There are no existing CO_2 pipelines to transport any captured CO_2 from Ameren Missouri's facilities, and it appears that the nearest location for a potential sequestration site is approximately 100 miles away in Illinois. Even if that site is permitted and approved for sequestration, it would not have nearly enough capacity to store Labadie's CO_2, much less CO_2 from other sources, likely necessitating the development of sequestration sites at even greater distances.

IF NOT STAYED, EPA'S GHG RULE WILL RESULT IN IRREPARABLE HARM

19. EPA's Final GHG Rule requires compliance with standards that are based on systems of emission reduction that have not been demonstrated at scale and performance standards that are not achievable in practice and are not likely to be for many years to come. If not stayed, compliance with these requirements will require

Ameren Missouri to start making major resource, capital and infrastructure decisions immediately—before the many challenges to EPA's Final GHG Rule are resolved and before any state plan is submitted to and approved by EPA. This forces Ameren Missouri to expend and commit human and capital resources now based upon an EPA rule that is being challenged, state plans that have not been finalized or approved by EPA, and technologies that are not currently available for commercial deployment and are not expected to be available for such purposes until at least 2040, eight years after the GHG Rule's compliance deadline.

20. If Ameren Missouri attempted to proceed with CCS with 90% capture at Labadie or any new natural gas plant, for example, Ameren Missouri would be required to start the process now of seeking approval for the construction and operation of a CCS plant on-site, as well as for the acquisition of rights of way and permits for, and construction of, a CO_2 pipeline over 100 miles in length to connect to a sequestration site in another state. Ameren Missouri would be forced to undertake this effort now even though: (1) EPA's Final GHG Rule is subject to numerous challenges in this Court; (2) neither Missouri, Illinois or any other state has submitted state plans for EPA's approval, as required under EPA's GHG Rule; (3) CCS has not been demonstrated for electric generating units ("EGUs") and EPA's performance standards based on 90% capture of CO_2 through CCS are not achievable; (4) any CO_2 pipeline would likely have to be sited through multiple

states, numerous local communities and across numerous waterways, including the Mississippi and Missouri Rivers; (5) such a pipeline would likely encounter significant local and national opposition, thereby significantly delaying (if not entirely impeding) the project; (6) many communities in Illinois have objected to or adopted moratoriums prohibiting CO_2 pipelines/sequestration sites; and (7) there is no known nearby sequestration site that has the capacity to store Ameren Missouri's CO_2 from Labadie or any new natural gas plant, even if they could consistently capture 90% of emitted CO_2 and even if there was pipeline infrastructure available.

21. The process of building a carbon capture plant at Labadie or any new natural gas facility would take many years, as there are numerous phases for developing and implementing such a massive project. The technology would need to be studied to understand the risks to get to the pilot demonstration stage. After that stage, Ameren Missouri would need to build a pilot-scale prototype followed by a full-scale prototype. Each of these steps is critical to ensure the safety of the facility and would take many years to complete, extending well beyond the GHG Rule's 2032 compliance deadline.

22. Even assuming Ameren Missouri could install an operational plant with 90% capture by EPA's 2032 deadline, that carbon would need to be transported by CO_2 pipeline to a sequestration site. Although EPA claims that the U.S. CO_2 "pipeline infrastructure continues to expand," it acknowledges that only 5,385 miles

of CO_2 pipelines exist in the U.S., which marks only a "14 percent increase . . . since 2011." 89 Fed. Reg. at 39,855. At that rate, only a few hundred miles of additional CO_2 pipeline would be constructed by 2032, falling woefully short of the pipeline infrastructure needed to implement EPA's GHG Rule.

23. Immediate action is needed because the process of implementing CCS faces numerous obstacles that are largely beyond Ameren Missouri's control, including significant local and national opposition, community moratoriums prohibiting CO_2 pipelines and sequestration sites, substantial permitting delays, and the lack of a clear regulatory regime for interstate CO_2 pipelines.

24. Proposed CO_2 pipelines will have to comply with numerous federal and state regulatory and permitting regimes, each of which can take years to complete. In many cases, a pipeline will require review under the National Environmental Policy Act ("NEPA"), a process that can involve review by multiple federal agencies, significant stakeholder input, and take years to complete. Proposed pipeline projects that cross waters of the United States (such as the Mississippi and Missouri Rivers) would likely require obtaining permits from the U.S. Army Corps of Engineers under the Clean Water Act, a process that can also take years. If the proposed project might affect a listed endangered or threatened species, further consultation is required with the U.S. Fish & Wildlife Service pursuant to the

Endangered Species Act. Further consultation is required under the National Historic Preservation Act if a project has the potential to impact historic properties.

25. In light of these circumstances, Ameren Missouri must begin incurring costs and expending resources before this litigation concludes to have any hope of meeting the Rule's performance standards by the 2032 deadlines (or, for that matter, 2033 under EPA's "reliability mechanisms" in its GHG Rule). Ameren Missouri must begin the efforts necessary to engage with third parties that will plan and construct these CO_2 pipelines. And that planning must take into account the virtual certainty of national and local opposition and permitting delays. Experience shows that community opposition, permit review, and protracted litigation can leave major interstate pipeline projects delayed for many years or decades, or even result in cancellation of projects altogether. Recent prominent examples of cancellations include the Constitution Pipeline (cancelled in 2020), the Atlantic Coast Pipeline (cancelled in 2020), the Keystone Pipeline (cancelled in 2021), and the Navigator CO_2 Pipeline (cancelled in 2023).

26. In addition to the challenges associated with permitting and constructing such a massive network of CO_2 pipelines, the capacity to sequester that carbon in the U.S. is woefully inadequate. Geologic storage of CO_2 may take place only through compliance with regulations under one of two regulatory classes—Class II or Class VI injection wells—in EPA's Underground Injection Control (UIC)

program. The covering Class II UIC program is for underground injection of fluids in connection with oil and gas production. Class II includes three separate subclasses for disposal, enhanced recovery, and hydrocarbon storage. Class IV—the enhanced recovery subclass—applies to geologic storage.

27. Enhanced recovery is the process of injecting fluids—frequently CO_2—into depleted hydrocarbon formations to stimulate production of additional oil or gas. Incidental to this process, essentially all of the CO_2 injected becomes permanently trapped within the formation. Although this process has been used in the U.S. for over 50 years, opportunities for enhanced recovery have been limited to a subset of oil- and gas-bearing formations, which are not distributed throughout all areas of the country. Moreover, as noted, there is not a CO_2 pipeline network coextensive with fossil-fuel fired EGUs to transport CO_2 to these formations. As a result, they are not broadly available to Ameren Missouri for storage.

28. The Class VI UIC program was adopted by the EPA in 2010 for storage of CO_2 in non-resource-producing formations, such as saline and basalt formations, coal seams that cannot be mined, and depleted oil and gas reservoirs from which no additional production is being undertaken. Although the Class VI program has been in existence for more than a decade, EPA has issued permits for only three facilities during that entire time, one of which was issued during the pendency of the comment period for EPA's proposal.

29. States may administer the Class VI program in lieu of the EPA, in which case a State is said to have "primacy." To attain primacy, a State must submit an application to the EPA demonstrating that it has the necessary law, expertise, and resources to run the program. EPA has approved only three States for primacy—North Dakota, Wyoming and Louisiana. To date, North Dakota has issued only eight Class VI permits, Wyoming has issued three Class VI permits and Louisiana has not issued any. As a result, there is very little experience to date with the Class VI regulatory program, particularly in and around the States within Ameren Missouri's service territory.

30. Commercial storage for the amount of CO_2 resulting from the 90% rate of capture contemplated by EPA's proposal has never been achieved and is not available. For example, according to EIA data, there are 14 power plants in the U.S. that each emitted more than 10 million tons of CO_2 in 2021. At 90% capture, these plants would each produce at least 9 million tons per year of CO_2 for storage, and collectively as much as 126 million tons per year. But no existing carbon storage facility currently stores more than 7 million tons per year.

31. Storage of larger amounts of CO_2 than currently demonstrated is not a simple matter. Geologic storage formations are naturally occurring and include features that may limit the rate of storage that can be achieved and the total amount. This is why EPA's UIC Class VI storage regulations require applicants to include

extensive information on the rate of storage and the total amount to be injected in a storage well over time.

32. In addition to the immediate costs relating to constructing CO_2 pipeline and sequestration infrastructure, Ameren Missouri would need to begin incurring costs and expending resources before this litigation is completed to prepare to capture the CO_2 from its facilities. As discussed above, these types of projects take many years to plan, fund, and construct, particularly when CCS with 90% capture is not available for commercial deployment.

33. Like the requirements applicable to existing coal-fired generation, the Rule's requirements for new combustion turbines will also have immediate and irreparable impacts on Ameren Missouri. As noted, Ameren Missouri plans to construct new natural gas-fired combustion turbines in the coming years, and such turbines with a greater than 40% capacity factor are required to meet performance standards based upon CCS with 90% capture by 2032. As a result, Ameren Missouri will be required to start planning and spending money now to install CCS at these new facilities, even though no State has submitted plans for EPA's approval, no sufficient CO_2 pipeline network exists, and permitted capacity is inadequate to sequester the CO_2 emitted from these facilities. As an alternative, Ameren Missouri could start planning and spending money now to construct and operate two 40% CF combined cycle plants as opposed to one 80% CF combined cycle plant with 90%

CCS, which would mean construction of two (instead of one) large plants each with substantial (60%) unused capacity. Either way, EPA's GHG Rule forces Ameren Missouri to incur significant costs now without knowing what may be required under the Rule or in any state plan that may be approved by EPA at some point in the future. Forging ahead and expending such massive resources and near-term costs in the face of so much uncertainty regarding the validity of the final rule, the provisions of any EPA-approved state plan, and unproven technology and undeveloped infrastructure will inevitably result in significant economic waste, stranded assets, and irreparable harm to Ameren Missouri.

34. Like the costs noted above, these expenditures would include soliciting and securing bids from contractors to perform the work, procuring equipment, mobilizing resources and employees, securing approvals for major capital expenditures, applying for and securing the necessary local, state, and federal permits and approvals, and communicating and working with numerous stakeholders, including state environmental agencies and local communities.

35. In light of recent experience and the current environment for large infrastructure permitting and approvals, Ameren Missouri conservatively estimates that meeting EPA's proposed performance standards based on CCS with 90% would take until 2040 or *longer*, even with no opposition and no permitting delays. With any legal challenges, local opposition or permitting delays, the projected timeline

would be much longer. The "reliability mechanisms" in EPA's GHG Rule are ineffective to mitigate the sheer impossibility of meeting EPA's unrealistic deadlines.

36. Confirming the consequences of a rule based on undemonstrated systems of emission reduction, EPA's own modeling and regulatory impact analysis predict near-negligible adoption of CCS at coal and gas electric generating units. Rather than implement this technology, the modeling and Regulatory Impact Analysis ("RIA") EPA used to support its GHG Rule project that the vast majority of EGUs would elect to retire rather than install CCS.

37. According to EPA, this "reflect[s] EGU operators making least-cost decisions on how to achieve efficient compliance with the rules while maintaining sufficient generating capacity to ensure grid reliability."[2] By imposing unachievable performance standards based on prohibitively expensive and unproven technology, EPA's GHG Rule effectively mandates the retirement of coal plants as the method to achieve "efficient compliance" with the rule.

38. In this regard, EPA's GHG Rule raises serious concerns about Ameren Missouri's ability to serve customers reliably. For example, MISO, which manages the delivery of energy to roughly 45 million people living in the midwestern United States (including Missouri), is already operating close to its maximum resource

[2] RIA at 3-25 to 3-26.

capacity and recognizes the need for new dispatchable generation. In a February 2024 report, MISO stated it is time "to face some hard realities," including "immediate and serious challenges to the reliability of our region's electric grid." [3] According to MISO, "a key risk is that many 'dispatchable' resources that can be turned on and off and adjusted as needed to meet customer demand minute-by-minute are being replaced with weather-dependent resources such as wind and solar," which lack "certain key reliability attributes that are needed to keep the grid reliable every hour of the year."[4] And while MISO indicates that "several emerging technologies may someday change that calculus, they are not proven at scale." [5] Until then, MISO concludes that it "will continue to need dispatchable resources for reliability purposes." Indeed, as shown in the graphic below, at 1:20 pm on May 20, 2024, only about 12.2% of the total MWs of generation in MISO was coming from wind and solar sources, while about 71% was coming from coal and natural gas resources.[6]

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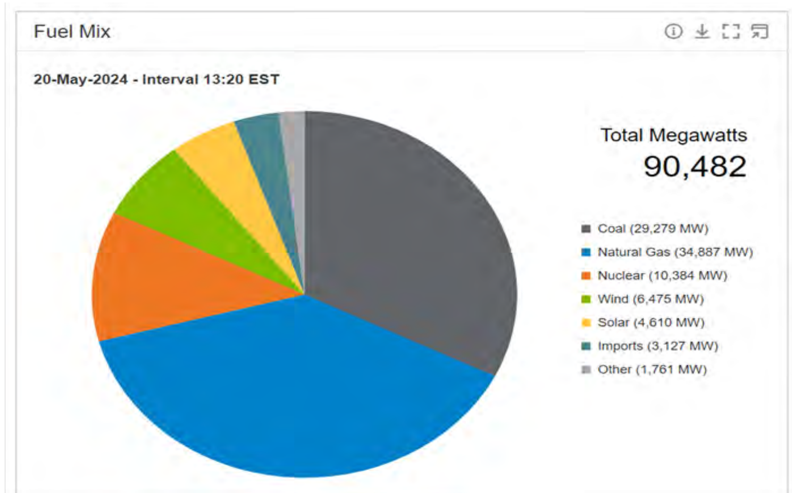
[3] MISO, Response to the Reliability Imperative at 1 (Feb. 2024), https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216. (Attachment A).

[4] *Id.*

[5] *Id.*

[6] https://api.misoenergy.org/MISORTWD/dashboard.html?fuelMix.



39. In its December 2023 Long-Term Reliability Assessment, the North American Electric Reliability Corporation ("NERC") likewise found "clear evidence of growing resource adequacy concerns over the next 10 years," and identified large areas of the country at a "high" risk of failing to meet demand, including the 15-state area covered by MISO.[7] In just four years, "MISO is projected to have a 4.7 GW shortfall if expected generator retirements occur despite the addition of new resources that total over 12 GW."[8] According to NERC, "[c]apacity deficits are projected in areas where future generator retirements are expected before enough replacement resources are in service to meet rising demand forecasts."[9]

[7] NERC, 2023 Long-Term Reliability Assessment at 6-9 (Dec. 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf. (Attachment B).
[8] *Id*. at 7-9.
[9] *Id*. at 6.

40. PJM Interconnection, which is responsible for ensuring reliability for 65 million people across 13 States and the District of Columbia, has expressed similar concerns about reliability as a result of EPA's GHG Rule.[10] According to PJM, the Rule places the most stringent requirements on new gas and existing coal units that provide a critical reliability role.[11] PJM is seeing vastly increased demand as a result of new data center load, electrification of vehicles, and increased electric heating load.[12] And in the same years demand is projected to significantly increase, PJM explains that EPA's GHG Rule appears poised to drive premature retirement of units and dissuade new gas resources from coming online.[13]

41. EPA does not explain how the fossil generation forced to retire as a result of its Rule can or will be replaced at current levels and with similar dispatch characteristics, notwithstanding strong evidence that electricity demand is expected to grow rapidly in the coming years and decades, due in part to data center and AI growth, as well as the widespread electrification of transportation, manufacturing, and housing sectors. As one November 2023 study put it: "the United States … does

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[10] PJM Statement on the Newly Issued EPA Greenhouse Gas and Related Regulations (May 8, 2024), https://www.pjm.com/-/media/about-pjm/newsroom/2024-releases/20240508-pjm-statement-on-the-newly-issued-epa-greenhouse-gas-and-related-regulations.ashx. (Attachment C).
[11] *Id.*
[12] *Id.*
[13] *Id.*

not have a plan to manage the reliable transition of its electricity sector."[14] EPA has finalized "binding power plant emission reduction targets, but fully decarbonizing the electricity sector requires coordinated, regional planning and targeted investments for specific types of resources, many of which are not yet commercially available."[15]

42. In any event, if Ameren Missouri elected to retire a source as a compliance measure under EPA's GHG Rule, it must make preparations *now* in order to do so, including developing plans to account for a significant decrease in dispatchable operations and obtaining the necessary regulatory approvals for both retirements and replacement resources. Retiring a power plant is not a matter of simply shutting down the machines and turning off the lights. The regulatory approval process alone is costly and complex and can take several years. For example, Ameren Missouri submitted a request with MISO to retire Rush Island with an effective date of September 1, 2022. After extensive modeling, MISO designated Rush Island as a system support resource ("SSR") and concluded that certain reliability mitigation measures, including transmission upgrades, must occur before

[14] World Resources Institute, Working Paper, Meeting the Reliability Challenges of the Clean Energy Transition,
(Nov. 2023), https://www.wri.org/research/meeting-reliability-challenges-clean-energy-transition.

[15] *Id.*

the plant retires. FERC approved the SSR designation in 2022, extended it in 2023, and now transmission upgrade projects are being implemented.

43. Given the complexities involved in retiring a source, Ameren Missouri would need to undertake the planning and regulatory processes needed to do so now, long before the many challenges to EPA's GHG Rule are resolved and before any state plan implementing the rule is submitted to or approved by EPA. This again places Ameren Missouri in the position of having to make key decisions and incur significant costs long before this litigation is resolved and long before it obtains any certainty regarding what is ultimately required in EPA's GHG Rule and in any state plan implementing that rule. For this reason as well, Ameren Missouri will suffer irreparable harm if EPA's GHG Rule is not stayed pending judicial review.

44. I declare under penalty of perjury that the foregoing is true and correct.

Executed this 22 day of May, 2024.

Timothy C Lafser

Tim Lafser

Attachment A

MISO'S RESPONSE TO THE RELIABILITY IMPERATIVE

- UPDATED FEBRUARY 2024 -

Living Document

This is a "living" report that is updated periodically as conditions evolve, and as MISO, stakeholders and states continue to assess and respond to the Reliability Imperative.

misoenergy.org

Contents

A Message from John Bear, CEO

We have to face some hard realities.

There are immediate and serious challenges to the reliability of our region's electric grid, and the entire industry — utilities, states and MISO — must work together and move faster to address them.

MISO and its utility and state partners have been deeply engaged on these challenges for years, and we have made important progress. But the region's generating fleet is changing even faster and more profoundly than we anticipated, so we all must act with more urgency and resolve.

Many utilities and states are decarbonizing their resource fleets. Carbon emissions in MISO have declined more than 30% since 2005 due to utilities and states retiring conventional power plants and building renewables such as wind and solar. Far greater emissions reductions — possibly exceeding 90% — could be achieved in coming years under the ambitious plans and goals that utilities and states are pursuing.

Studies conducted by MISO and other entities indicate it is possible to reliably operate an electric system that has far fewer conventional power plants and far more zero-carbon resources than we have today. However, **the *<u>transition</u>* that is underway to *<u>get to</u>* a decarbonized end state is posing material, adverse challenges to electric reliability.**

A key risk is that many existing "dispatchable" resources that can be turned on and off and adjusted as needed are being replaced with weather-dependent resources such as wind and solar that have materially different characteristics and capabilities. While wind and solar produce needed clean energy, they lack certain **key reliability attributes** that are needed to keep the grid reliable every hour of the year. Although several emerging technologies may someday change that calculus, they are not yet proven at grid scale. Meanwhile, efforts to build new dispatchable resources face headwinds from **government regulations and policies**, as well as **prevailing investment criteria for financing new energy projects**. Until new technologies become viable, we will continue to need dispatchable resources for reliability purposes.

But fleet change is not the only challenge we face. **Extreme weather events** have become more frequent and severe. **Supply chain and permitting issues** beyond MISO's control are delaying many new reliability-critical generation projects that are otherwise fully approved. **Large single-site load additions**, such as energy-intensive production facilities or data centers, may not be reliably served with existing or planned resources. **Incremental load growth** due to electric vehicles and other aspects of electrification is exerting new pressure on the grid. And **neighboring grid systems are becoming more interdependent** and reliant on each other, highlighting the need for more interregional planning such as the Joint Targeted Interconnection Queue study that MISO conducted with Southwest Power Pool.

This report documents how MISO is addressing these risks through the **Reliability Imperative** — the critical and shared responsibility that MISO, our members and states have to address the urgent and complex challenges to electric reliability in our region. MISO first published a Reliability Imperative report in 2020, and this is the fourth time we've updated it to reflect the changing landscape.

None of the work we must do is easy, but it is necessary. The region's 45 million people are counting on MISO and its utility and state partners to get it right. Thank you for your interest in these important issues.

Executive Summary

THE CHALLENGE: A "HYPER-COMPLEX RISK ENVIRONMENT"

There are urgent and complex challenges to electric system reliability in the MISO region and elsewhere. This is not just MISO's view; it is a well-documented conclusion throughout the electric industry. The North American Electric Reliability Corporation, a key reliability entity throughout the U.S., Canada and part of Mexico, has described these challenges as a "hyper-complex risk environment." These challenges include:

Fleet change: The new weather-dependent resources that are being built, such as wind and solar, do not provide the same critical reliability attributes as the conventional dispatchable coal and natural gas resources that are being retired. While emerging technologies such as long-duration battery storage, small modular reactors and hydrogen systems may someday offer solutions to this issue, they are not yet viable at grid scale.

Regulations, policies and investment criteria: Many dispatchable resources that provide critical reliability attributes are retiring prematurely due to environmental regulations and clean-energy policies. This regulatory environment, along with prevailing investment criteria for financing new energy projects, increases the challenges to build new dispatchable generation — even if it is critically needed for reliability purposes.

Fuel assurance: Gas resources can face challenging economics to procure fuel because they share the pipeline system with residential and commercial heating and manufacturing uses. Coal plants typically keep large stockpiles of fuel onsite, but coal supplies have tightened due to changing economics, import/export dynamics, supply chain issues and other factors. Aging resources can also be more prone to outages. While renewable resources such as wind turbines do not use "fuel" per se, they are sometimes unavailable due to adverse weather conditions.

Extreme weather events: While extreme weather has always been commonplace in the MISO region, severe weather events that impact electric reliability have been increasing. The Electric Power Research Institute found that hurricanes are increasing in intensity and duration, heat events are increasing in frequency and intensity and cold events are increasing in frequency. Examples include Winter Storm Elliott in 2022, Winter Storm Uri in 2021, Hurricane Ida in 2021, and Hurricanes Laura, Delta and Zeta in 2020.

Load additions: Some parts of the MISO region are enjoying a resurgence in manufacturing and/or other types of economic growth, with companies planning and building new factories, data centers and other energy-intensive facilities. While such development is welcome from an economic perspective, it can also pose significant reliability risks if the load additions it spurs cannot be reliably served with existing or planned resources.

Incremental load growth: While electricity demand has been flat for many years, it is expected to increase due to the electrification of other sectors of the economy. Electric vehicles are growing in popularity, and the residential and commercial sectors are increasingly using electricity for heating and cooling. These trends will accelerate more due to the electrification tax credits in the 2022 Inflation Reduction Act.

Supply chain and permitting issues: Many projects that have been fully approved through MISO's Generator Interconnection Queue process are not going into service on schedule due to supply chain issues and permitting delays that are beyond MISO's control. As of late 2023, about 25 gigawatts (GW) of approved resources are signaling delays that average 650 days to commercial operation.

RELIABILITY IMPERATIVE OVERVIEW

The **Reliability Imperative** is the term MISO uses to describe the shared responsibility that MISO, its members and states have to address the urgent and complex challenges to electric system reliability in the MISO region. MISO's *response* to the Reliability Imperative consists of numerous interconnected and sequenced initiatives that are organized into four primary pillars, as shown here:

RELIABILITY IMPERATIVE PILLAR	KEY INITIATIVES *(partial list)*
MARKET REDEFINITION Enhance and optimize MISO's markets to ensure continued reliability and efficiency while enabling the changing resource mix, responding to more frequent extreme weather events, and preparing for increasing electrification	• Ensure resources are accurately accredited • Identify critical system reliability attributes • Ensure accurate pricing of energy & reserves
OPERATIONS OF THE FUTURE Focus on the skills, processes and technologies needed to ensure MISO can effectively manage the grid of the future under increased complexity	• Manage uncertainty associated with increasing reliance on variable wind and solar generation • Prepare control room operators to rapidly assess and respond to changing system conditions • Use artificial intelligence & machine learning to enhance situational awareness & communications • Evaluate interdependency of neighboring systems
TRANSMISSION EVOLUTION Assess the region's future transmission needs and associated cost allocation holistically, including transmission to support utility and state plans for existing and future generation resources	• Develop "Futures" planning scenarios using ranges of economic, policy, and regulatory inputs • Develop distinct "tranches" (portfolios) of Long Range Transmission Plan (LRTP) projects • Enhance joint transmission planning with seams partners • Improve processes for new generator interconnections and retirements
SYSTEM ENHANCEMENTS Create flexible, upgradeable and secure systems that integrate advanced technologies to process increasingly complex information and evolve with the industry	• Modernize critical tools such as the Day-Ahead and Real-Time Market Clearing Engines • Fortify cybersecurity and proactively address the rapidly evolving cyber threat landscape • Develop cutting-edge data and analytics strategies

RECENT KEY ACCOMPLISHMENTS

MISO and its stakeholders have made great progress under the Reliability Imperative in recent years. Some of our key accomplishments to date include:

Seasonal Resource Adequacy Construct: In August 2022, the Federal Energy Regulatory Commission (FERC) approved MISO's proposal to shift from its summer-focused resource adequacy construct to a new four-season construct that better reflects the risks the region now faces in winter and shoulder seasons due to fleet change, more frequent and severe extreme weather, electrification and other factors. This new construct seeks to ensure that resources will be available when they are needed most by aligning resource accreditation with availability during the highest risk periods in each season.

LRTP Tranche 1: The first of four planned portfolios of Long Range Transmission Planning (LRTP) projects was approved by the MISO Board of Directors in July 2022. This tranche of 18 projects represents a total investment of $10.3 billion — the largest portfolio of transmission projects ever approved by a U.S. Regional Transmission Organization. These projects will integrate new generation resources built in MISO's North and Central subregions, supporting the reliable and affordable transition of the fleet and further hardening the grid against extreme weather events.

Reliability-Based Demand Curve: MISO's Planning Resource Auction (PRA) was not originally designed to set higher capacity clearing prices as the magnitude of a shortfall increases. This lack of a "warning signal" can mask an imminent shortfall — as occurred with the 2022 PRA. Accurate capacity pricing is also crucial to make effective investment and retirement decisions. MISO worked with its stakeholders to design a Reliability-Based Demand Curve that will improve price signals in the PRA. Full implementation is planned for the 2025 PRA, subject to FERC proceedings.

Futures Refresh: The MISO Futures utilize a range of economic, policy and technological inputs to develop three scenarios that "bookend" what the region's resource mix might look like in 20 years. In 2023, MISO updated its Futures to lay the groundwork for LRTP Tranche 2 and to better reflect evolving decarbonization plans of MISO members and states. The refreshed Futures also model how the financial incentives for clean energy in the 2022 Inflation Reduction Act could further accelerate fleet change. The refreshed Futures are indicated with an "A" (e.g., Future 2 was updated and renamed Future 2A).

System Enhancements: The Market System Enhancement (MSE) program made significant progress in 2023. In March, the Energy Management System upgrade was moved into service. This provides a more stable platform with improved visualization while enhancing functionality and user experience. MISO also took delivery of the Reliability Assessment Commitment for the Real-Time Market Clearing Engine, which will improve application security and reduce solution time. MISO also completed Model Manager Phase 2, which connects internal applications to improve model data propagation. MSE will continue to deliver more new products, including Day-Ahead and Real-Time Market Clearing Engine items.

MISO PRIORITIES GOING FORWARD

While far from a complete list, some of MISO's key priorities for 2024 include:

Attributes: In 2023, following an in-depth look at the challenges of reliably operating an electric system in a rapidly transforming landscape, MISO published an *Attributes Roadmap* of recommended solutions to address the potential scarcity of three priority attributes that appear to pose the most acute risks: system adequacy, flexibility and system stability. The recommendations include further modernizing the resource adequacy construct, focusing market signals on emerging flexibility needs, and requirements for new capabilities from inverter-based resources. Next, MISO will prioritize attribute solution integration, including handoffs to MISO business units and stakeholder groups and the scoping of ongoing analysis.

Accreditation: MISO must ensure resource accreditation values reflect what we can expect to receive during high-risk periods. For non-thermal resources, MISO's recommended approach blends a probabilistic methodology with availability during tight conditions, leveraging principles from the thermal accreditation reform implemented in 2022. MISO has proposed a three-year transition to the new methodology that will be applied to all non-emergency resources following the transition period. A FERC filing is planned for 2024.

LRTP Tranche 2: Work to develop the Tranche 2 portfolio of LRTP projects is progressing, with approval by MISO's Board of Directors anticipated in 2024. Planning is complex, but MISO will continue to balance the need to plan quickly with the need to develop a robust, lowest-cost portfolio. Tranche 2 is based on the refreshed Future 2A, which reflects all decarbonization plans of MISO members and states. As with Tranche 1, MISO anticipates Tranche 2 will deliver sufficient benefits to qualify under the Multi-Value Project cost allocation mechanism, with costs allocated only to the subregion where benefits are realized.

CALL TO ACTION: WE MUST WORK TOGETHER AND MOVE FASTER

In light of the urgent and complex risks to electric reliability in the MISO region, utilities, states and MISO must all act with more urgency and more coordination to avoid a looming mismatch between the pace of adding new resources and the retirement of older resources in the MISO region. This means we must:

- Refine generation resource plans across MISO by accelerating the addition of reliability attributes and moderating retirements to avoid undue reliability risk
- Maintain transition resources as reliability "insurance" until promising new technologies become viable at grid scale
- Identify areas of risk in which electricity providers, states and MISO must coordinate

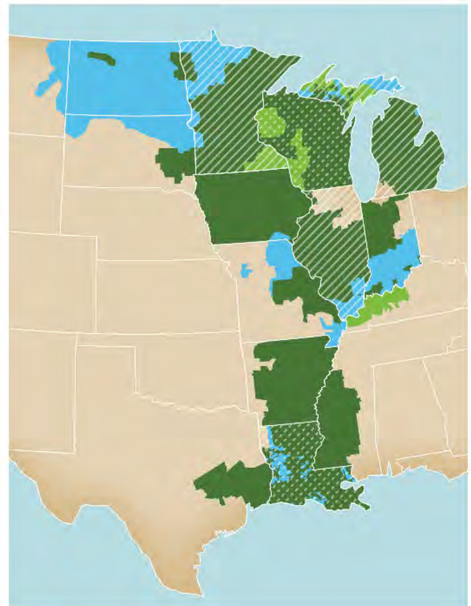
CONTINUED STAKEHOLDER INPUT IS CRUCIAL

Many of the ideas and proposals in this report reflect a great deal of technical input from MISO stakeholders. MISO appreciates stakeholder feedback on the Reliability Imperative, and we look forward to continuing the dialogue. This document is a "living" report that MISO regularly updates.

Challenges Driving the Reliability Imperative

COMPLEX POLICY LANDSCAPE

As the map indicates, many utilities and states in the MISO region have adopted policies and goals to decarbonize their resource fleets. Currently, about 75% of the region's total load is served by utilities that have ambitious decarbonization and/or renewable energy goals.



Without question, utilities and states are making remarkable progress toward their goals. Carbon emissions in MISO have already declined more than 30% since 2005, and far greater reductions are expected going forward.

Currently, wind and solar generation account for about 20% of the region's total energy. Under MISO modeling scenario Future 2A, which reflects all the clean-energy goals that utilities and states have publicly announced, wind and solar are projected to serve 80% of the region's annual load by 2042. Fleet change of that magnitude would foster a 96% reduction in carbon emissions compared to 2005 levels — which would be an extraordinary accomplishment for a region that was predominately reliant on fossil fuels not that long ago.

But at the same time, complex challenges to electric system reliability have been steadily materializing throughout the U.S. in recent years, including in MISO. These challenges are driven by a combination of economic, technological and policy-related factors along with extreme weather events. Here is a look at some of these challenges and the drivers associated with them:

TIGHTENING SUPPLY

Over the last 10-plus years, surplus reserve margins in MISO have been exhausted through load growth and unit retirements. Since 2022, MISO has been operating near the level of minimum reserve margin requirements. While MISO has implemented several reforms to help avert near-term risk, more work is urgently needed to mitigate reliability concerns in the coming years. In fact, the region only averted a capacity shortfall in 2023 because some planned generation retirements were postponed and some additional capacity was made available to MISO.

However, MISO cannot count on such actions being repeated going forward. Indeed, the North American Electric Reliability Corporation (NERC) projects the MISO region will experience a 4.7 GW shortfall beginning in 2028 if currently expected generator retirements actually occur. Notably, NERC says that shortfall will occur *even if* the 12-plus GW of new resources that are expected to come online by then actually materialize. This is because the new resources that are being built have significantly lower accreditation values than the older resources that are retiring, as is discussed in more detail below.

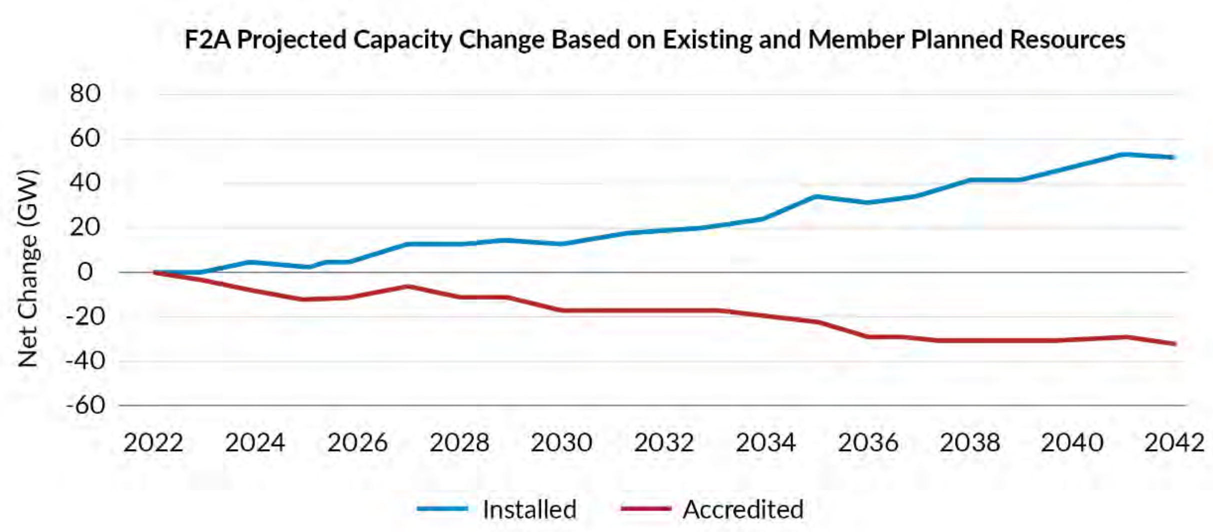
An annual planning tool called the **OMS-MISO Survey** tells a similar story. The survey compiles information about new resources utilities and states plan to build and older assets they intend to retire in the coming years. The 2023 survey shows the region's level of "committed" resources declining going forward, with a potential shortfall of 2.1 GW occurring as soon as 2025 and growing larger over time. MISO administers the survey in partnership with the Organization of MISO States (OMS), which represents the region's state regulatory agencies.

Other drivers of the region's tightening supply picture include:

- U.S. Environmental Protection Agency (EPA) regulations that prompt existing coal and gas resources to retire sooner than they otherwise would.
- Wall Street investment criteria that make it more challenging to build new dispatchable generation, even if it is critically needed for reliability purposes.
- The approximately $370 billion in financial incentives for clean-energy resources in the federal Inflation Reduction Act.

DECLINING ACCREDITED CAPACITY

Fleet change is creating a gap between the region's levels of installed and accredited generation capacity. **Installed capacity** is the maximum amount of energy that resources could theoretically produce if they ran at their highest output levels all the time and never shut down for planned or unplanned reasons. **Accredited capacity**, by contrast, reflects how much energy resources are realistically expected to produce during times when they are needed the most by accounting for their performance, which includes limiting factors such as their forced outage rates during adverse weather conditions.



The chart above is from MISO Future 2A, which reflects the publicly announced decarbonization plans of MISO-member utilities and states. As the chart shows, the region's level of *installed* capacity — the blue line — is forecast to increase by nearly 60 GW from 2022 to 2042 due to the many new resources —

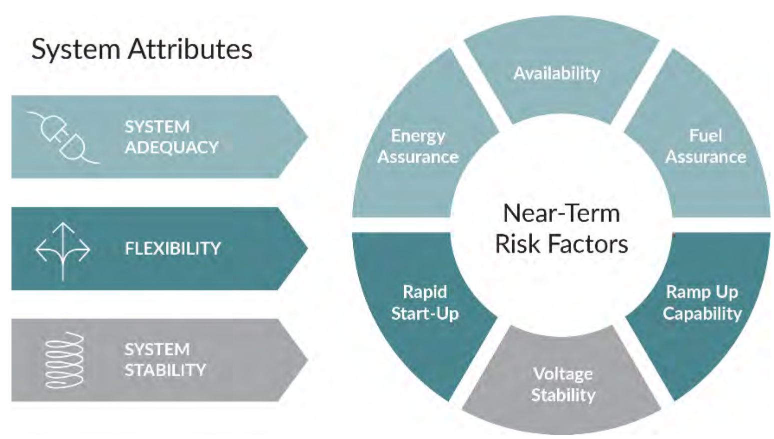
primarily wind and solar — that utilities and states plan to build in that 20-year time period.[1] But because those new wind and solar resources have significantly lower accreditation values[2] than the conventional resources that utilities and states plan to retire in the same 20-year period, the region's level of *accredited* capacity — the red line — is forecast to decline by a net 32 GW by 2042.

MISO modeling indicates that a reduction of that magnitude could result in load interruptions of three to four hours in length for 13-26 days per year when energy output from wind and solar resources is reduced or unavailable. Such interruptions would most likely occur after sunset on hot summer days with low wind output and on cold winter days before sunrise and after sunset.

NEED FOR SYSTEM RELIABILITY ATTRIBUTES

Reliably navigating the energy transition requires more than just having sufficient generating capacity; it also requires urgent action to avoid a looming shortage of broader **system reliability attributes**. In 2023, MISO completed a foundational analysis of attributes, with a focus on three priority attributes where risk for the MISO system is most acute:

- **System adequacy** is the ability to meet electric load requirements during periods of high risk. MISO focused on the near-term risk factors of availability, energy assurance and fuel assurance.
- **Flexibility** is the extent to which a power system can adjust electric production or consumption in response to changing system conditions. MISO focused on the near-term risk factors of rapid start-up and ramp-up capability.
- **System stability** is the ability to remain in a state of operating equilibrium under normal operating conditions and to recover from disturbances. MISO focused on the nearest-term risk factor of voltage stability.



No single type of resource provides every needed system attribute; the needs of the system have always been met by a fleet of diverse resources. However, in many instances, the new weather-dependent resources that are being built today do not have the same characteristics as the dispatchable resources they are replacing. While studies show it is possible to reliably operate the system with substantially lower levels of dispatchable resources, the transformational changes require MISO and its members to study, measure, incentivize and implement changes to ensure that new resources provide adequate levels of the needed system attributes.

[1] It is not a typical industry practice for utilities and states to publicly announce their resource plans a full 20 years in advance, which is the time horizon that MISO used for the MISO Futures. Thus, this forecast should be viewed as a "snapshot in time" that will change going forward as utilities and states solidify their resource plans.
[2] In the Future 2A model, retiring conventional resources are accredited at 95% or more of their nameplate capacity, while wind is accredited at 16.6% and solar declines over time to 20%. Accreditation values will vary depending on the methodologies and assumptions that were used to create them.

In December 2023, MISO published an Attributes Roadmap report that recommends urgent action to advance a portfolio of market reforms and system requirements and to provide ongoing attributes visibility through regular reporting.

EMERGING TECHNOLOGIES SHOW PROMISE BUT ARE NOT YET VIABLE AT GRID SCALE

A number of emerging technologies are being developed that could potentially mitigate the challenges described above. They include long-duration battery storage, carbon capture, small modular nuclear reactors and "green" hydrogen produced from renewables, among others.

However, while these technologies show promise for the future, they are not yet commercially viable to be deployed at scale. MISO is actively engaged in tracking the progress of these technologies and is preparing to incorporate them into the system if/when the opportunity arises.

MISO does expect the commercial viability timelines of these technologies to be accelerated by the $370 billion in financial incentives for clean energy in the 2022 Inflation Reduction Act. In recognition of that, MISO modeled those incentives in the refreshed MISO Futures. More information on emerging technologies is available in MISO's 2022 Regional Resource Assessment.

LOAD ADDITIONS ARE SURGING

Some parts of the MISO region are enjoying a resurgence in manufacturing and/or other economic growth, with companies planning and building new factories, data centers and other energy-intensive facilities. For example, in the MISO South subregion that spans most of Arkansas, Louisiana, Mississippi and a small part of Texas, there are discussions and plans to build a variety of new manufacturing plants for steel, hydrogen, liquified natural gas and other heavy industry that could add more than 1,000 megawatts (MW) of new load. The tax credits for clean-energy manufacturing in the Inflation Reduction Act are helping to drive some of these additions.

While such development is welcome from an economic perspective, it can also pose significant grid reliability risks if the large load additions it spurs cannot be reliably served with existing or planned resources.

LOAD GROWTH DUE TO INCREMENTAL ELECTRIFICATION

While year-over-year demand for electricity in MISO has been fairly flat for many years, it is expected to increase going forward due to the electrification trends in other sectors of the economy. Electric vehicles are growing in popularity, and the residential and commercial building sectors are increasingly using electricity for heating and cooling purposes — with a desire to source this new electric load from renewables. These trends will likely accelerate even more due to the substantial financial incentives in the Inflation Reduction Act for electric vehicles, rooftop solar systems and electric appliances.

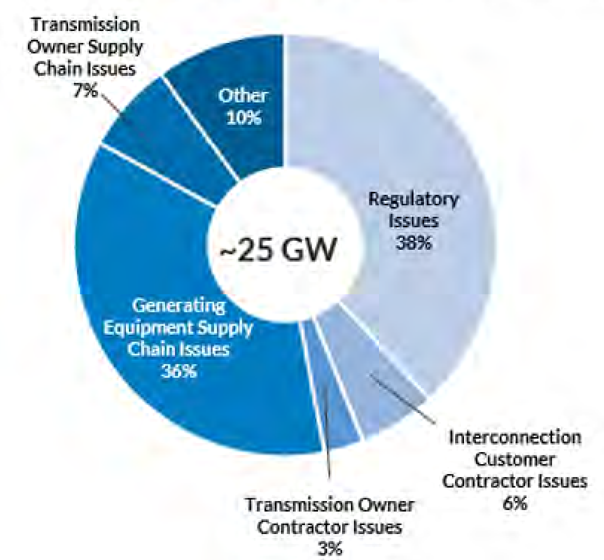
The impacts of these trends could be significant. In MISO's 2021 Electrification Insights report, MISO found that electrification could transform the region's grid from a summer-peaking to a winter-peaking system and that uncontrolled vehicle charging and daily heating and cooling load could result in two daily power peaks in nearly all months of the year.

DELAYS TO APPROVED GENERATION PROJECTS

In addition to reliability being challenged by declining accredited capacity, electrification and load additions, another concern is that a large number of fully approved and much-needed new generation projects are being delayed by supply chain issues, regulatory issues, and other external factors beyond MISO's control.

As of late 2023, about 25 GW of fully approved generation projects in MISO's Generator Interconnection Queue had missed their in-service deadlines by an average of 650 days, with developers citing supply chain and permitting issues as the two biggest reasons for the delays. An additional 25 GW of fully approved queue projects had not yet missed their in-service deadlines as of late 2023, but MISO expects many of them will also be delayed by external factors.

25 GW of fully approved & much-needed generation projects are delayed by supply chain and other issues



As the region's capacity picture continues to tighten, the possibility that upward of 50 GW of fully approved new generation projects could be delayed by external factors beyond MISO's control is deeply concerning.

FUEL ASSURANCE RISKS

The transition to a low- to no-carbon electric grid also poses risks in the realm of fuel assurance. These risks impact conventional coal and gas resources that provide reliability attributes such as system adequacy, flexibility and system stability that may be becoming scarce due to fleet change.

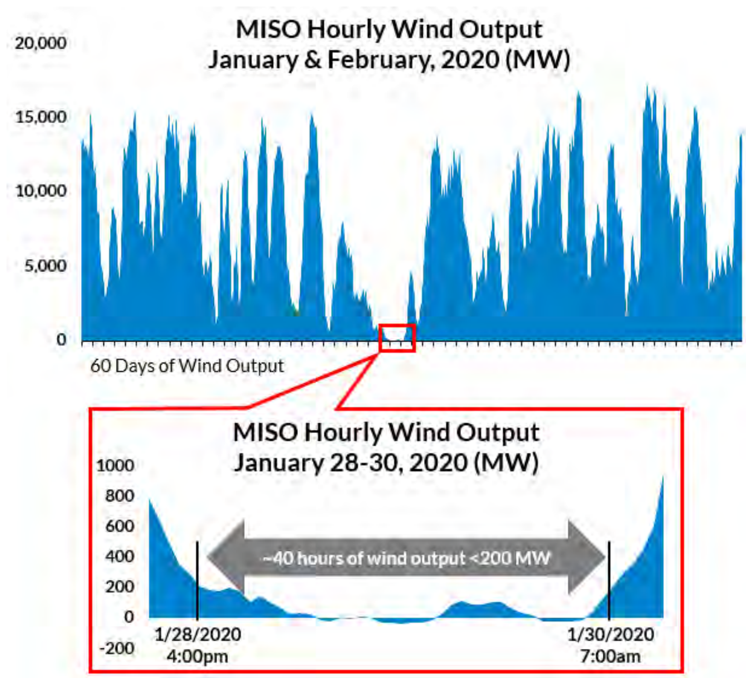
Coal resources have historically been considered fuel-assure because large stockpiles of fuel can be stored on-site. However, coal supplies have tightened in recent years due to a confluence of factors, including contraction of the mining and transportation sectors and supply chain issues. These factors increase the risk that coal plants will be unable to perform due to a lack of fuel availability. Coal resources can also be affected by extreme winter weather freezing onsite coal piles and/or impacting coal-handling equipment.

Gas-fired resources are also subject to fuel-assurance risks because they rely on pipelines to deliver gas to them. However, because the pipeline system was largely built for home-heating and manufacturing purposes, gas power plants sometimes face very challenging economic conditions to procure the fuel they need to operate. In the MISO region, this has historically occurred during extreme winter weather events that drive up home-heating needs for gas. Many gas generators in MISO do not have "firm" fuel-delivery contracts, opting instead for less costly "interruptible" pipeline service or a blend thereof. Only about 27% of the gas generation that responded to MISO's 2023-2024 Generator Winterization Survey indicated it had firm transport contracts in place for all of their supplies during the 2023-2024 winter season. Additionally, gas power plants, gas pipelines and coal generators can be forced out of service by icing and other effects of severe winter weather — as has occurred in the MISO region and elsewhere with increasing frequency.

WIND DROUGHTS

Wind resources can experience "fuel" availability challenges in the form of highly variable wind speeds. Consequently, the energy output of wind can fluctuate significantly on a day-to-day and even an hour-by-hour basis — including multi-day periods when output drops far below average.

For example, over 60 consecutive days in January-February 2020, hourly wind output in MISO averaged more than 8,000 MW. However, as the chart shows, for 40 consecutive hours in the middle of that 60-day block, average hourly wind output dropped to less than 47 MW, and only once exceeded 200 MW in any single hour.



An even longer and broader "wind drought" occurred during Winter Storm Uri in 2021 when the MISO, Southwest Power Pool, Electric Reliability Council of Texas and PJM regions all experienced 12 consecutive days of low wind output.

Wind turbines can also be unavailable in extremely cold weather. While turbines equipped with special "cold weather packages" are designed to operate in temperatures as low as minus 22 F, they generally cut off if temperatures dip below that point. Still, it is important to keep in mind that all types of generators struggle in extreme cold, not just wind turbines.

EPA REGULATIONS COULD ACCELERATE RETIREMENTS OF DISPATCHABLE RESOURCES

While MISO is fuel- and technology-neutral, MISO does have a responsibility to inform state and federal regulations that could jeopardize electric reliability. In the view of MISO, several other grid operators, and numerous utilities and states, the U.S. Environmental Protection Agency (EPA) has issued a number of regulations that could threaten reliability in the MISO region and beyond.

In May 2023, for example, EPA proposed a rule to regulate carbon emissions from all existing coal plants, certain existing gas plants and all new gas plants. As proposed, the rule would require existing coal and gas resources to either retire by certain dates or else retrofit with costly, emerging technologies such as carbon-capture and storage (CCS) or co-firing with low-carbon hydrogen.

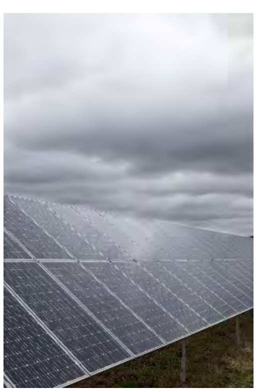
MISO and many other industry entities believe that while CCS and hydrogen co-firing technologies show promise, they are not yet viable at grid scale — and there are no assurances they will become available on EPA's optimistic timeline. If EPA's proposed rule drives coal and gas resources to retire before enough replacement capacity is built with the critical attributes the system needs, grid reliability will be compromised. The proposed rule may also have a chilling effect on attracting the capital investment needed to build new dispatchable resources.

RISKS IN NON-SUMMER SEASONS

In the past, resource adequacy planning in MISO focused on procuring sufficient resources to meet demand in the peak hour of the year, which normally occurs on a hot and humid summer day when air conditioning load is very high. If utilities had enough resources to reliably meet that one peak hour in the summer, the assumption was they could operate reliably for the other 8,759 hours of the year.

That assumption no longer holds true. Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.

This changing risk profile is why MISO shifted from its annual summer-focused resource adequacy construct to a new framework that establishes resource adequacy requirements on a seasonal basis for four distinct seasons: summer (June-August); fall (September-November); winter (December-February); and spring (March-May). This new seasonal construct also seeks to ensure that resources will be available when they are needed most by aligning resource accreditation with availability during the highest risk periods in each season.



Pillar 1: Market Redefinition

MISO established the energy and ancillary service markets w nearly two decades ago when the composition of, and the risks to, the energy industry were very different from today. MISO's [Markets of the Future report]() indicates that the region's foundational market constructs will continue to be effective going forward, but only with significant revisions. Further informed by the attributes analysis completed in 2023, MISO is enhancing and optimizing its market constructs and products to ensure they continue to deliver reliability and value in the face of fleet change, extreme weather events, electrification and load additions. This work occurs under four themes within the Market Redefinition pillar of the Reliability Imperative, as discussed below.

UNCERTAINTY AND VARIABILITY

In the planning horizon, MISO is addressing the changing risk profile and enhancing market signals for new resource investments. MISO's original resource adequacy construct was designed for a conventional fleet of resources where reliability risk was concentrated during the typical summer peak period. This is no longer the case. Factors such as aging conventional resources, more frequent and severe weather events and increased reliance on weather-dependent renewables have altered the region's historic risk profile, creating new risks in non-summer months and at differing times of the day. As the generation mix further diversifies, the accreditation process of evaluating each generator's contribution to the system is a critical reliability and planning mechanism.

In 2022, FERC approved MISO's proposal to shift from the annual, summer-based resource adequacy construct to a new construct with four seasons. The new seasonal construct also aligns the accreditation of thermal resources with availability in the highest-risk periods. These changes, implemented in the 2023-2024 Planning Resource Auction (PRA), are already delivering positive market outcomes, such as more proactive outage coordination among stakeholders and incentivizing improved unit performance.

MISO completed an evaluation of potential paths for non-thermal accreditation reforms 2022. This resulted in a proposed accreditation reform that leverages the principles from the thermal accreditation reform implemented in 2022, aligning the accreditation methodology for all resource types (except for emergency-only resources). MISO has proposed a transition period to begin applying the new accreditation methodology in the 2028-2029 planning year. The design work is expected to be finished with a filing with FERC in 2024.

The PRA was not designed to set higher capacity clearing prices as the magnitude of a shortfall increases. This lack of a "warning signal" can instill a false sense of calm among PRA participants, masking an imminent shortfall — as occurred with the 2022 PRA. MISO is working with its stakeholders to enhance pricing within the capacity construct by designing a Reliability-Based Demand Curve (RBDC) to better reflect MISO's market guiding principles, reliability risk and help avoid uneconomic retirements. Full implementation is planned for the 2025-2026 PRA, subject to FERC proceedings.

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While the RBDC improves price signals in the planning horizon, MISO is also working on pricing reforms in the operating horizon. These focus on **scarcity pricing** when demand and reserve requirements exceed available supply in real time, often happening during extreme events when MISO enters emergency procedures to manage challenging conditions.

MISO's reforms to scarcity pricing will help incentivize appropriate market behavior, manage congestion throughout events and value reserve shortages appropriately, ultimately providing greater transparency and minimizing manual market intervention. MISO's focus areas for 2024 are updating the value of lost load, demand curves and forced-off assets that become physically disconnected from the grid due to weather-related transmission events. MISO has been presenting ideas at the Market Subcommittee stakeholder group. These enhancements will begin in 2024, with complete implementation expected by 2025.

Lastly, informed by the analysis of critical reliability attributes and in light of the changing reliability risk profiles in the region, MISO will work with stakeholders in 2024 to reevaluate the traditional risk metrics used in the industry for resource adequacy assessments and improve the underlying risk models.

RESOURCE MODELS AND CAPABILITIES

To avoid a looming shortage of necessary voltage stability attributes, as detailed in the *Attributes Roadmap*, MISO will advance a multistep technology standard to require capabilities from inverter-based resources to support grid stability at interconnection. In January 2023, MISO embarked on a path to improve inverter-based resource performance requirements using a reliability risk-based approach to evaluate potential gaps in MISO's current tariff. MISO finalized the proposed Tariff language in November to address the highest priority performance requirements and capabilities. This proposal is Phase 1 of the recommended four-phase approach, and this cross-matrix "resource models and capabilities" project will continue in the Interconnection Process Working Group (IPWG).

Another area of focus is MISO's work toward compliance with **FERC Order 2222**, which facilitates the participation of distributed energy resources (DERs) in wholesale electricity markets. DERs are small-scale resources such as rooftop solar panels, electric battery storage systems or electric vehicles and their charging equipment. In isolation, these resources would not have much impact on the grid, but when they are aggregated into a larger block, they can be impactful. MISO is developing a plan to comply with this order through broad collaboration with stakeholders, members, regulators, distributors and DER aggregators.

IDENTIFYING LOCATIONAL NEEDS

Another critical focus associated with increased uncertainty and variability is challenging reserve deliverability due to congestion. Historically, MISO utilized reserve zones to procure and reliably deliver reserves. MISO is working to implement improved locational granularity in its reserve products to ensure deliverability. Updating the reserve zones more frequently should enhance market efficiency and system reliability since there would be better alignment between zonal definitions and system conditions.

In addition to the local deliverability of resources, MISO will explore approaches to better hedge congestion through MISO's Auction Revenue Rights (ARR) mechanism and the Financial Transmission

Rights market. Evaluation has identified gaps and is exploring potential areas of improvement, including updating approaches for allocating ARRs, more granular periods, and ways to incentivize outages that better align with day-ahead energy models.

ENHANCING COORDINATION

As operational uncertainty and complexity increase, MISO continues to improve coordination across stakeholders and external entities, including neighboring grid operators. The collaborative **OMS-MISO Survey** provides a prompt view of resource adequacy over the five-year horizon, characterizing relative levels of resource certainty. MISO's **Regional Resource Assessment** (RRA) provides a collective 20-year view of the evolution of members' resource plans. It aims to provide insights that help members, states and MISO prepare for the energy transition. MISO's *Attributes Roadmap* specifically identifies the need for evolved coordination between MISO's resource adequacy assessments and MISO state and member planning process to ensure attribute sufficiency. MISO is committed to continued analysis, transparency and collaboration in the Resource Adequacy stakeholder forum.

One example is how transmission owners and MISO are working together on **ambient-adjusted ratings (AARs)** and **seasonal ratings** on transmission lines in the region, per the requirements of FERC Order 881. While using more accurate line ratings does not diminish the need to build new transmission, having the most accurate line rating information can help ensure that the region's transmission system is fully utilized and delivers its maximum value. MISO has engaged in extensive discussions with its transmission owners and consulted with other interested stakeholders to develop a compliance approach that meets the requirements of FERC Order 881 and is consistent with MISO's Tariff.

> "Our market products and the signals they send need to evolve and reflect the new realities and trends that we are experiencing. Input and support from our stakeholders will be key in the effective and timely implementation of these changes."
>
> Todd Ramey, MISO Senior Vice President, Markets and Digital Strategy

Pillar 2: Operations of the Future

MISO's control room operations are also challenged by fleet change, extreme weather and other risk drivers. In addition to implementing lessons learned from past events such as Winter Storm Elliott, forward-looking work is underway to ensure MISO has the capabilities, processes and technology to anticipate and respond to operational opportunities and challenges. This work, termed Operations of the Future, focuses on five buckets of work: (1) operations preparedness, (2) operations planning, (3) uncertainty and variability, (4) situational awareness and critical communications and (5) operational continuity.

OPERATIONS PREPAREDNESS

Tomorrow's control room will be very different from today. Operations preparedness is critical to managing the rapidly changing system conditions, increased volumes of data and enhanced technologies and tools that operators face. To ensure that control room personnel are ready to manage reliability effectively and efficiently in this new and continually evolving environment, MISO is developing improved operations simulation tools and enhancing operator training. In the future, operator and member training and drills will leverage a robust simulator that mirrors production and can quickly incorporate and maintain real-time event scenario simulations with broad, controlled access capabilities.

> "In the past, predicting load and generation was relatively straight-forward. In the future, the operating environment will be much more variable, and we need the people, processes and technology to deal with that variability."
>
> Jennifer Curran, MISO Senior Vice President, Planning & Operations
> and Chief Compliance Officer

OPERATIONS PLANNING

Operations planning helps MISO to remain a step ahead of the shifting energy landscape. System operators need to quickly access insights into the future and processes that enable the continued reliable and efficient operation of the bulk electric system. In the future, it will be necessary to leverage information in new ways. The ability to quickly model and analyze realistic planning scenarios will enable operators to develop and modify operating day plans from start to execution. Operators will be better prepared to manage increased uncertainty in resource availability with operational planning processes that are centralized and streamlined and outages that are proactively scheduled leveraging predictive economic impact analysis and power system studies.

UNCERTAINTY AND VARIABILITY

The increase in variable generation such as wind and solar has introduced greater uncertainty. Today, operators leverage a variety of market products and other analytics-based tools to manage uncertainty. To help manage increasing complexity, MISO is using machine-learning to predict net uncertainty for the upcoming operating day, using probabilistic forecasts and advanced analytics. With this more complete view, operators can create daily risk assessments that — when coupled with new dynamic reserve requirements — incentivize efficient unit-commitment decisions.

In the future, operators will need to manage the grid reliably and efficiently through tight margins, high-ramping periods, and increased variability by optimizing a risk management framework that accurately provides a risk profile based on net uncertainty impacts and by leveraging predictive economic impact analysis and power system studies.

SITUATIONAL AWARENESS AND CRITICAL COMMUNICATIONS

Situational awareness and critical communications will become even more important as operating risks become less predictable and more difficult to manage in day-to-day operations. New control room technologies and capabilities, improved real-time data capabilities and more complex operating conditions, driven by new load and generation patterns, will require MISO and its members to communicate even more quickly and efficiently.

Today, MISO operations rely heavily on the expertise of its operators. While operators have access to significant amounts of data related to weather, load and more, they must manually synthesize that data into useable information. Although this has worked well historically, solutions must envision a future with more complex information and operators who may not possess the same historical knowledge.

In the future, operators will need an integrated toolset that leverages artificial intelligence and machine learning, combined with additional data and analytics. Improvements in how MISO sees and navigates will give operators important information automatically. Systems will provide situational awareness insights for operators based on their function in the control room. Operators will analyze information and create new displays in real time to quickly assess the impacts of operational situations. Dynamic views of the state of the system will ensure operators can maintain the appropriate level of situational awareness while also reducing operator burden and automating key communication requirements, especially during critical events.

Additionally, enhancements to communications protocols, such as system declarations, will ensure that control rooms have the information they need when they need it. Automated messaging triggered by specific process and procedure actions will reinforce compliance with NERC standards.

OPERATIONAL CONTINUITY

Operational continuity capabilities need to evolve to align with the changing technologies, resource portfolio and threat landscape. Improved tools and updated processes are vital to ensuring that MISO can reliably operate the grid, mitigate risks, and, if necessary, recover quickly in the event of disruptions to toolsets or control centers.

Pillar 3: Transmission Evolution

The ongoing shift in the resource fleet and the substantial projected increase in load pose significant challenges to the design of the transmission system in the MISO region. MISO's Transmission Evolution work addresses these challenges in concert with other elements of the Reliability Imperative framework.

Under Transmission Evolution, MISO holistically assesses the region's future transmission needs while considering the allocation of transmission costs. This work creates an integrated transmission plan that reliably enables member goals while minimizing the total cost of the fleet transition, inclusive of transmission and generation. It also improves the transfer capability of the transmission system — meaning its ability to effectively and efficiently move energy from where it is generated to where it is needed.

LONG RANGE AND INTERREGIONAL TRANSMISSION PLANNING

Regional Long Range Transmission Planning (LRTP) and interregional planning are important parts of the Transmission Evolution pillar. The LRTP effort is developing four tranches of new backbone transmission to support MISO member plans for the changing fleet. In July 2022, the MISO Board of Directors approved LRTP Tranche 1. The 18-project portfolio of least-regret solutions is focused on MISO's Midwest subregion, representing $10.3 billion in investment. The projects in Tranche 1 will provide a wide range of value, including congestion and fuel savings, avoided capital costs of local resources, avoided transmission investments, resource adequacy savings, avoided risk of load shedding and decarbonization.

> "We see very little risk of over-building the transmission system; the real risk is in a scenario where we have underbuilt the system. Similarly, across markets and operations, our job is to be prepared."
>
> Clair Moeller, MISO President

This transmission investment hinges on appropriate allocation of the associated costs. MISO's Tariff stipulates a roughly commensurate "beneficiaries pay" requirement that must be met while balancing the divergent needs of MISO's three subregions. Because Tranches 1 and 2 primarily benefit the Midwest subregion, costs will only be allocated there. As Tranches 3 and 4 progress, other approaches may be considered based on stakeholder discussion. Work on Tranche 2 is progressing, with an anticipated approval by MISO's Board of Directors in 2024.

Futures refresh

MISO's future scenarios, or Futures, set the foundation for LRTP. The Futures help MISO hedge uncertainty by "bookending" a range of potential economic, policy and technological possibilities based on factors such as load growth, electrification, carbon policy, generator retirements, renewable energy levels, natural gas prices and generation capital cost over a 20-year period.

Member and state plans often do not provide resource information for the full 20-year study period covered by LRTP. Although MISO does not have authority over generation planning or resource procurement, this lack of information creates a gap in the resources needed to serve load and meet member goals. MISO fills the gap through resource expansion analysis, which seeks to find the optimal resource fleet that minimizes overall system cost while meeting reliability and policy requirements. The resulting resource expansion plans are used with their respective Future to identify transmission issues and solutions.

To lay the groundwork for Tranche 2 and to better understand potential future needs based on the most recent plans, legislation, policies and other factors, MISO refreshed its three Futures in 2023. While the defining characteristics of each Future remained the same (e.g., load forecast and retirement assumptions), updates were made to data and information that inform the potential resource mix. Among other factors, this includes state and member plans, capital costs, operating and fuel costs and defined resource additions and retirements. MISO also modeled the impacts of the clean energy tax credits in the federal Inflation Reduction Act because those incentives are expected to accelerate the transition to a decarbonized grid.

Future 2A, the focus of Tranche 2, indicates that fleet change will increase in velocity due to stronger renewable energy mandates, carbon reduction goals and other policies. Future 2A projects a 90% reduction in carbon emissions by 2042 and forecasts that wind and solar will provide 30% of the region's energy a full 10 years earlier than the previous Series 1 Futures that were used for Tranche 1.

Planning for an uncertain future

When planning for larger, regional solutions that address needs 20 years into the future, there is inherent uncertainty, which is why LRTP is designed to identify "least-regrets" transmission solutions. Appropriately managing this uncertainty is a key function of planning. In developing Future 2A, MISO leveraged the consensus on policy goals among MISO members and states about how quickly change would occur. Additionally, MISO's comprehensive processes and robustness testing demonstrate the benefits and needs of transmission solutions that achieve member goals and minimize costs, including several iterations of analyses for Future 2A and other scenarios.

Other visibility tools

As the system becomes more interdependent and interconnected, MISO provides information to members about the outcomes and impacts of their individual plans when studied in the aggregate. Anticipating and communicating changing risks and future systems needs within the planning horizon is critical to ensure continued reliability.

As described earlier in this report, the **OMS-MISO Survey** compiles information about new resources that utilities and states plan to build and older assets they intend to retire in the coming years. While this tool looks several years ahead, certainty is lower in later years when many significant risks will need to be addressed.

Because utility and state plans can be less specific and certain, cover a shorter timeframe and are not always publicly available, MISO conducts the **Regional Resource Assessment (RRA)** to capture more information and details. The RRA aggregates utility and state plans and goals — both public and private —

over a 20-year planning horizon to shed light on regional fleet evolution trends and timing. The information is then used to model potential reliability needs and gaps that may arise and may be leveraged to inform and advance analysis of resource attributes. In the future, new tools will provide stakeholders with ongoing access to RRA information for greater visibility into the impact of these future system changes.

Interregional initiatives

MISO continually works with its neighboring grid operators, Southwest Power Pool (SPP) and PJM, to address issues on the seams. Joint, coordinated, system plan studies are regularly conducted to assess reliability, economic and/or public policy issues. The studies can be more targeted in scope with a shorter study cycle or can be more complex, requiring a longer study period.

The Joint Targeted Interconnection Queue (JTIQ) initiative with SPP is an example of a recent complex study initiative. This unprecedented, coordinated effort identified a portfolio of proposed transmission projects that align with both MISO's and SPP's interconnection processes. These projects will create additional transmission capability to enable generator interconnections in both regions.

In October 2023, the U.S. Department of Energy (DOE) announced it would award $464.5 million in federal funding under the Grid Resilience and Innovation Partnerships (GRIP) program to the JTIQ portfolio. This historic opportunity significantly reduces the estimated investment for new transmission lines that will benefit seven states. A FERC filing to obtain approval of cost allocation for the JTIQ portfolio will be submitted in early 2024, and MISO Board approval will be sought thereafter. The process SPP and MISO followed to coordinate the study proved to be effective and significantly more efficient than typical Affected System Studies. Based on its success, the process will be included in the 2024 filing to enable improved coordination in the future.

PLANNING TRANSFORMATION

MISO's planning tools and processes must also evolve as the transitioning resource mix increases the complexity of transmission planning. In response, Planning Transformation, another component of the Transmission Evolution pillar, will develop aligned, adaptable and flexible processes and tools over the next five to 10 years to recognize and address emerging transmission threats and risks identified in markets and operations.

The new MISO Transmission Expansion Plan (MTEP) Portal is a major step in this transformation. The system launched in October 2023 and helps MISO staff and transmission owners manage project data more efficiently and effectively, and it will save hundreds of work hours each year. It also provides stakeholders better support for submitting, updating, tracking and managing MTEP projects and enables more transparency.

Other measures — such as the Generator Interconnection Portal and technology evaluation of resource siting — are already implemented, underway or planned for the future. These include evolving technology for the resource transition, adapting planning criteria to enhance system resiliency and robustness, and integrating model data.

RESOURCE UTILIZATION

The Resource Utilization initiative focuses on improving resource utilization planning to include a dynamic generator retirement process, more rapid generator interconnections and resource reliability attributes that are addressed throughout the resource lifecycle.

To improve the generator retirement process, asset owners are now required to provide one-year advance notice of resource retirements, an increase from the prior 26 weeks. Quarterly retirement studies have also been instituted to better forecast the engineering workload needed to conduct analyses, and other changes are being implemented that help align retirements with MTEP processes and improve visibility of retirements to stakeholders.

MISO is also working to ensure its processes do not impede generator interconnections. Although MISO's queue processes have been effective in cycles with typical volumes, they are not sufficient for managing recent request volumes that are growing exponentially compared to historical norms. This significantly increases the time it takes MISO to complete studies, which drives more project withdrawals, provides less certainty of early study results, and, ultimately, complicates late-stage studies. These issues are compounded by many speculative projects, despite years of reforms on "first ready, first served" principles.

Improvements to customer-facing and backend operational queue processes over the past several years have enabled more efficient application processing. However, additional changes are needed to manage the dramatic growth in applications, further expedite the interconnection process and maximize transparency and certainty to customers.

As a result, MISO paused accepting interconnection applications for the 2023 cycle, with plans to resume in March 2024 after receiving FERC approval on multiple process improvements to ensure better interconnection requests are submitted. The 2024 cycle is anticipated to begin in the fall of 2024, as it has in previous years.

Tariff changes approved by FERC in January 2024 increase financial commitments and withdrawal penalties and require interconnection customers to provide greater site control for projects. FERC did deny a MISO proposal to cap the size of queue study cycles to ensure they do not exceed a certain percentage of MISO load. However, FERC provided guidance on how MISO could implement a cap in the future, as well as other improvements that will enable the dispatch of existing resources with new interconnection requests. MISO believes these changes will decrease applications and result in higher-quality, more viable projects entering the queue. A reduction in project withdrawals may ultimately reduce network upgrades between studies and provide greater planning certainty for customers and MISO.

In July 2023, FERC issued Order 2023 to ensure that generator interconnection customers can interconnect to the transmission system in a reliable, efficient, transparent, timely and nondiscriminatory manner. The order is mostly consistent with the queue changes MISO has already implemented and intends to implement going forward. MISO is reviewing the order to assess potential changes and compliance needs.

Lastly, as described in the Resource Models And Capabilities section of this report, MISO is advancing a multistep technology standard to require capabilities from inverter-based resources to support grid stability through the Interconnection Process Working Group. This cross-matrix work is further described in MISO's *Attributes Roadmap* report as a solution to mitigate the potential shortage of system stability attributes.

Delays outside of MISO's control

Despite improvements MISO has made to its Generator Interconnection Queue, many fully approved projects are not going into service on schedule due to supply chain issues and permitting delays that are beyond MISO's control. As of late 2023, about 25 gigawatts (GW) of resources that were fully approved through MISO's queue process had missed their in-service deadlines by an average of 650 days, with developers citing supply chain and permitting issues as the two biggest reasons for the delays. An additional 25 GW of fully approved queue projects had not yet missed their in-service deadlines as of late 2023, but MISO expects many of them will also be delayed by external factors.

Pillar 4: System Enhancements

Continual system enhancements and modeling refinements are the bedrock of MISO's response to the Reliability Imperative. The ongoing complexities of the electric industry landscape necessitate paramount upgrades to facilitate reliability-driven market improvements. The Market System Enhancement (MSE) program stands out as a visionary endeavor, focusing on upgrading, building and launching new systems with improved performance, security and architectural modularity. This strategic emphasis enhances MISO's capability to respond swiftly and efficiently and deliver new market products that align with the evolving industry landscape.

MISO places strategic importance on enabling a mature hybrid cloud capability to future-proof the technological infrastructure and foster a resilient and adaptable organizational framework. Simultaneously, the commitment to fostering a flexible work environment amplifies MISO's readiness for ongoing technological changes. This dynamic approach, centered on securely harnessing hybrid cloud technology, optimizes the work environment, positioning MISO for future advancements. The integration of these strategies underlines MISO's forward-looking approach and establishes its leadership in embracing advanced technologies for safeguarding operations.

MARKET SYSTEM ENHANCEMENT (MSE) PROGRAM

The MSE program, initiated in 2017, is a transformative force in reshaping MISO's market platform. Its focus on creating a more flexible, upgradeable and secure system underscores its pivotal role in accommodating the region's evolving portfolio and technology changes. The achievements in 2023 highlight the program's commitment to continuous improvement. The upgrade of the Energy Management System, completion of Phase 2 Core Development, and advancements in the Day-Ahead Market Clearing Engine and Real-Time Market Clearing Engine showcase MSE's impact on improving functionality, user experience, business continuity and security posture. This program is not merely a technological upgrade; it is a strategic initiative that positions MISO to meet the demands of the future electric grid.

> “For MISO to continue to deliver on our mission, we must prioritize our plan to address the right strategic drivers that will enable us to accommodate the region’s evolving portfolio and technology changes. The work we do in System Enhancements supports the transformational efforts across the Reliability Imperative and will increase value to our stakeholders.”
>
> Todd Ramey, Senior Vice President, Markets and Digital Strategy

WORK ANYWHERE

MISO's strategic move toward future-proofing its technological infrastructure involves enabling and maturing hybrid cloud capabilities. This initiative goes beyond technology; it embraces the transformative strategy of realizing a flexible work environment that transcends conventional boundaries. The delicate balance between the freedom to work remotely and stringent adherence to security and compliance requirements signifies a definitive change in how MISO approaches work. This shift sets the stage for a more agile and responsive workforce, enhancing productivity and embracing the evolving nature of work. Simultaneously, adopting a well-managed hybrid cloud platform forms the backbone of MISO's technological evolution, allowing seamless operations between on-premises data centers and the public cloud. This combination fortifies organizational resilience and propels MISO into a future where adaptability is the key to sustainable success.

SECURITY OF THE FUTURE

MISO’s commitment to seamlessly integrating cutting-edge technologies is underpinned by a dedication to security, reliability and efficiency. This includes initiatives designed to fortify MISO's approach to cybersecurity. Refining identity and access management practices, adopting a proactive zero-trust approach and transforming asset management data quality and timeliness demonstrate MISO's proactive stance against the evolving cyber threat landscape. The commitment extends beyond external threats to assessing security best practices for the internal environment. The ongoing thorough review to evaluate and implement the latest security protocols, conduct regular audits and stay abreast of emerging threats exemplifies MISO's dedication to securing tomorrow.

DATA AND ANALYTICS

MISO's data strategy is a comprehensive framework that goes beyond a simple upgrade — it is a visionary approach to enhancing MISO's data capabilities. The three key priorities — fostering an enterprise culture, delivering a holistic process framework and providing a curated environment — fortify MISO's position as a leader in the energy sector. This strategy modernizes tools, platforms, technologies and processes and empowers teams to model, simulate, analyze and visualize data for informed decision-making. Through a focused and well-defined program, MISO is set to realize a data platform that not only meets the needs of today but is agile enough to adapt to the evolving landscape of data requirements.

MISO Roadmap

As illustrated below, the **MISO Roadmap** outlines MISO's priorities to help its members to reliably achieve their plans and goals. The MISO Roadmap resides on MISO's public website.

MISO's Role

This report is written from MISO's perspective. However, the responsibility for ensuring grid reliability and resource adequacy in the MISO region is not MISO's alone. It is shared among Load Serving Entities (LSEs), states and MISO, each of which have designated roles to play.

LSEs are utilities, electric cooperatives and other types of entities that are responsible for providing power to end-use customers. In most (though not all) of the MISO region, LSEs have designated service territories and are regulated by state agencies. LSEs have exclusive authority to plan and build new generation resources and to make decisions about retiring existing resources, with oversight from state agencies as applicable by jurisdiction.

MISO performs certain transmission planning functions but does not plan or build new generation or decide which existing resources should retire. MISO exercises functional control of its members' generation and transmission assets with the consent of its members and per the provisions of its Tariff, which is subject to approval by FERC. By operating these assets as efficiently as possible on a region-wide basis, MISO generates substantial cost savings and other reliability benefits that would not otherwise be realized.

MISO also establishes and administers resource adequacy requirements for LSEs and states, as applicable by jurisdiction. These include:

- A **Planning Reserve Margin (PRM)** that sets the level of contractually obligated resources that MISO can call into service when normally scheduled resources go offline for planned or unplanned reasons or when demand surges due to extreme weather conditions or other factors. The PRM is set through MISO's stakeholder process.
- A **Planning Resource Auction (PRA)** that LSEs can use to procure needed resources or sell surplus resources. LSEs can "opt out" of the PRA by using their own resources or negotiating bilateral contracts with other entities.
- **Resource accreditation metrics** that determine how much "credit" various types of resources receive toward meeting resource adequacy requirements based on factors such as their unplanned outage rates.
- **Locational procedures** that determine how much capacity is needed in certain parts of the MISO region for reliability purposes and how much can be imported from and exported to other locations, among other things.

MISO engages with a broad range of stakeholders to share ideas and discuss potential solutions to the challenges facing the region. The Reliability Imperative work also involves a robust, collaborative dialogue across the many forums within the stakeholder process. The collaboration that takes place in these forums has provided valuable policy and technical-related feedback, and MISO is committed to continuing that engagement.

MISO INITIATIVES ARE INTERCONNECTED AND SEQUENCED

MISO's strategic priorities are connected and build upon each other. Success in one area depends on progress in another, so efforts must be coordinated and sequenced. For example, achieving reliable and economically efficient grid operations requires new tools and processes to be developed under the Operations of the Future workstream and market enhancements to be developed under the Market Redefinition workstream.

Given the urgent and complex challenges that are facing the region, it is crucial for MISO members, states and MISO to work together to execute on the reforms that are needed.

The MISO Value Proposition

MISO creates substantial cost savings and other benefits by managing the grid system on a regional basis that spans all or parts of 15 states and one Canadian province. Before MISO was created, the system was managed by 39 separate Local Balancing Authorities (LBAs), which made the grid much more fragmented and far less economically efficient than it is today.

The benefits that MISO created in calendar year 2022 range from $3.3 billion to $4.5 billion, according to the Value Proposition study that MISO performs every year. That represents a benefit-to-cost ratio of about 12:1 when compared to the fees that utilities pay to be members of MISO. MISO creates benefits in a variety of ways, including through efficient dispatch and reduced need for assets. Since the Value Proposition study was launched in 2007, the cumulative benefits that MISO has created exceed $40 billion. And notably, that figure does not reflect all the benefits MISO creates due to the conservative approach that MISO uses to conduct the study.

While continuing to use this conservative approach, MISO anticipates that it will create even more benefits going forward by helping its members and states to achieve their decarbonization goals in a reliable manner. In June 2022, MISO looked at those anticipated future benefits in a supplemental report called the Forward View of the Value Proposition. That report estimates the value that MISO will create going forward in two ways that are not specifically reflected in the "standard" Value Proposition study: (1) the value of sharing carbon-free energy from areas with higher levels of renewables to regions with lower levels, and (2) the value of sharing flexibility attributes that are required to integrate those new renewables while maintaining reliability.

MISO found that by including these two additional value streams, MISO's total benefit-to-cost ratio would increase from approximately 12:1 today to approximately 26:1 by 2040. This illustrates that while there are indeed many challenges associated with fleet change, there are also tremendous economic benefits that utilities and states can realize by pursuing their decarbonization goals as members of MISO.

Informing the Reliability Imperative

MISO's response to the Reliability Imperative has been informed by years of conversations with stakeholders. MISO has also undertaken numerous studies to assess the region's changing risk profile and to explore how reliability is being affected by various drivers. This work includes:

Attributes Roadmap: This study looks at three key electric system attributes where near-term risk is most acute: (1) System Adequacy, (2) Flexibility and (3) System Stability. The Attributes Roadmap recommends advancing a combination of current and new proposals as well as providing ongoing attributes visibility through regular reporting.

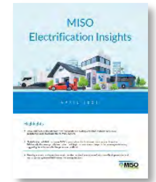
Renewable Integration Impact Assessment (RIIA): This study assesses the impacts of integrating increasingly higher levels of renewables into the MISO system. RIIA indicates that planning and operating the grid will become significantly more complex when greater than 30% of load is served by wind and solar. However, RIIA also indicates that renewable penetrations of greater than 50% could be reliably achieved if utilities, states, and MISO coordinate closely on needed actions.

Regional Resource Assessment (RRA): The RRA is a recurring study based on the plans and goals MISO members have publicly announced for their generation resources. The RRA aggregates these plans and goals to develop an indicative view of how the region's resource mix might evolve to meet utilities' stated objectives. The RRA aims to help utilities and states identify new and shifting risks years before they materialize, creating a window to develop cost-effective solutions.

MISO Futures: The MISO Futures utilize a range of economic, policy and technological inputs to develop three future scenarios that "bookend" what the region's resource mix might look like in 20 years. The Futures inform the development of transmission plans and help MISO prioritize work under the Reliability Imperative. Series 1 was published in 2021. In 2023, MISO updated the report to Series 1A to reflect evolving member/state plans and the clean energy incentives in the Inflation Reduction Act, among other things.

Markets of the Future: This report illustrates how and when MISO's market structures will need to evolve in order to accommodate the transformation of the energy sector. The needs are presented in four broad categories: (1) Uncertainty and Variability, (2) Resource Models and Capabilities, (3) Location and (4) Coordination. This report helped establish the foundation for the work MISO is currently doing to identify critical system attributes.

The February (2021) Arctic Event: This report discusses lessons learned from Winter Storm Uri, which affected the MISO region and other parts of the country in February 2021. MISO and its members took emergency actions during the event to prevent more widespread grid failures. Uri illustrated how extreme weather can exacerbate the challenges of fleet change. Preparing for extreme weather is a major part of MISO's response to the Reliability Imperative.



Electrification Insights: This report explores the challenges and opportunities the grid could face from the growth of electric vehicles and the increasing electrification of other sectors of the economy, such as homes and businesses. The report indicates electrification could transform the MISO grid from a summer-peaking to a winter-peaking system, and that vehicle charging and daily heating and cooling load could result in two daily power peaks nearly all year.

From this groundwork, we know there are many challenges ahead. But we also believe we can respond to the Reliability Imperative in a manner that enables our members to achieve their resource plans and policy objectives. We are determined to do the hard work required to ensure our members benefit from MISO membership.

Acronyms Used in This Report

DER: Distributed Energy Resource

FERC: Federal Energy Regulatory Commission

GW: Gigawatt

JTIQ: Joint Targeted Interconnection Queue

LBA: Load Balancing Authority

LSE: Load Serving Entity

LRTP: Long Range Transmission Planning

MSC: Market Subcommittee

MISO: Midcontinent Independent System Operator

MSE: Market System Enhancement

MTEP: MISO Transmission Expansion Plan

MW: Megawatt

NERC: North American Electric Reliability Corporation

OMS: Organization of MISO States

PAC: Planning Advisory Committee

PRA: Planning Resource Auction

PRM: Planning Reserve Margin

RBDC: Reliability-Based Demand Curve

RIIA: Renewable Integration Impact Assessment

RRA: Regional Resource Assessment

SPP: Southwest Power Pool

Attachment B

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2023 Long-Term Reliability Assessment

December 2023

Infographic | Video

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Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities (LSE) participate in one Regional Entity while associated Transmission Owners/Operators participate in another.

MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

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About this Assessment

NERC is a not-for-profit international regulatory authority with the mission to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC, also known as the Commission) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the North American BPS and serves more than 334 million people. Section 39.11(b) of FERC's regulations provides that "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

Development Process

This assessment was developed based on data and narrative information NERC collected from the six Regional Entities (see **Preface**) on an assessment area basis (see **Regional Assessments Dashboards**) to independently evaluate the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period. The Reliability Assessment Subcommittee (RAS), at the direction of NERC's Reliability and Security Technical Committee (RSTC), supported the development of this assessment through a comprehensive and transparent peer review process that leverages the knowledge and experience of system planners, Reliability Assessment Subcommittee members, NERC staff, and other subject matter experts; this peer review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the RSTC, and the NERC Board of Trustees subsequently accepted this assessment and endorsed the key findings.

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NERC develops the Long-Term Reliability Assessment (LTRA) annually in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations,[3] this is also required by Section 215(g) of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

Considerations

Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2023 about known system changes with updates incorporated prior to publication. This *2023 LTRA* assessment period includes projections for 2024–2033; however, some figures and tables examine data and information for the 2023 year. This assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.[5] NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in the **Demand Assumptions and Resource Categories** section of this report. Reliability impacts related to cyber and physical security risks are not specifically addressed in this assessment; this assessment is primarily focused on resource adequacy and operating reliability. NERC leads a multi-faceted approach through NERC's Electricity-Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information-sharing efforts with the electric industry.

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and system energy needs, demand response (DR), resource capacity, and transmission projects. Data from each Regional Entity is also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and a portion of Baja California, Mexico. NERC's reliability assessments are developed to inform industry, policy makers, and regulators as well as to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

[1] NERC Rules of Procedure - Section 803
[2] Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."
[3] Title 18, § 39.11 of the Code of Federal Regulations
[4] BPS reliability, as defined in the **How NERC Defines BPS Reliability** section of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.
[5] ERO Reliability Assessment Process Document

Assumptions

In this *2023 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:[6]

- Supply and demand projections are based on industry forecasts submitted and validated in July 2023. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame have been included where appropriate.
- Peak demand is based on average peak weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Regional Entity's self-assessment.
- Generation and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in service as planned, planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

Reading this Report

This report is compiled into two major parts:

- A reliability assessment of the North American BPS with the following goals:
  - Evaluate industry preparations that are in place to meet projections and maintain reliability
  - Identify trends in demand, supply, and reserve margins
  - Identify emerging reliability issues
  - Focus the industry, policy makers, and the general public's attention on BPS reliability issues
  - Make recommendations based on an independent NERC reliability assessment process
- A regional reliability assessment that contains the following:
  - 10-year data dashboard
  - Summary assessments for each assessment area
  - Focus on specific issues identified through industry data and emerging issues
  - Identify regional planning processes and methods used to ensure reliability

[6] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

Executive Summary

The North American BPS is on the cusp of large-scale growth, bringing reliability challenges and opportunities to a grid that was already amid unprecedented change.[7] Key measures of transmission development and future electricity peak demand and energy needs, which NERC tracks and reports annually in the LTRA, are rising faster than at any time in the past five or more years. New resource projects continue to enter the interconnection planning process at a faster rate than existing projects are concluded; this increases the backlog of resource additions and prompts some Regional Transmission Organizations (RTO) and Independent System Operators (ISO) to adapt their processes to manage expansion. Industry faces mounting pressures to keep pace with accelerating electricity demand, energy needs, and transmission system adequacy as the resource mix transitions.

This *2023 LTRA* is the ERO's independent assessment and comprehensive report on the adequacy of planned BPS resources to reliably meet the electricity demand across North America over the next ten year; it also identifies reliability trends, emerging issues, and potential risks that could impact the long-term reliability, resilience, and security of the BPS. The findings presented here are vitally important to understanding the reliability risks to the North American BPS as it is currently planned and being influenced by government policies, regulations, consumer preferences, and economic factors.

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Capacity and Energy Risk Assessment

The **Capacity and Energy Risk Assessment** section of this report identifies potential future electricity supply shortfalls under normal as well as extreme conditions; it is a forward-looking snapshot of resource adequacy that is tied to industry forecasts of electricity supplies, demand, and transmission development. NERC's assessment makes use of the latest demand forecasts, resource levels, and area transfer commitments along with collected information on expected generator retirements, resource additions, and demand-side resources.

This assessment provides clear evidence of growing resource adequacy concerns over the next 10 years (**Figure 1**). Capacity deficits are projected in areas where future generator retirements are expected before enough replacement resources are in service to meet rising demand forecasts. Energy risks are projected in areas where the future resource mix could fail to deliver the necessary supply of electricity under energy-constrained conditions. For example, subfreezing temperatures can create energy-limiting conditions by disrupting the natural gas fuel supplies to generators, leading to fuel-related derates or outages and potentially insufficient electricity supply. Furthermore, disruptions in electricity supplies can further exacerbate the availability of natural gas, which is dependent on the delivery of this electrical energy. Periods of low wind are another example of potentially energy-constrained conditions if the resource mix is not sufficiently balanced with dispatchable resources to prevent electricity shortfalls. While the outlook is improving for some assessment areas where resource additions and delayed generator retirements are alleviating previously identified near-term supply shortfalls, a growing number of areas in North American face resource capacity or energy risks over this assessment period. See **Risk Categories** for a general overview of each of the three categories.

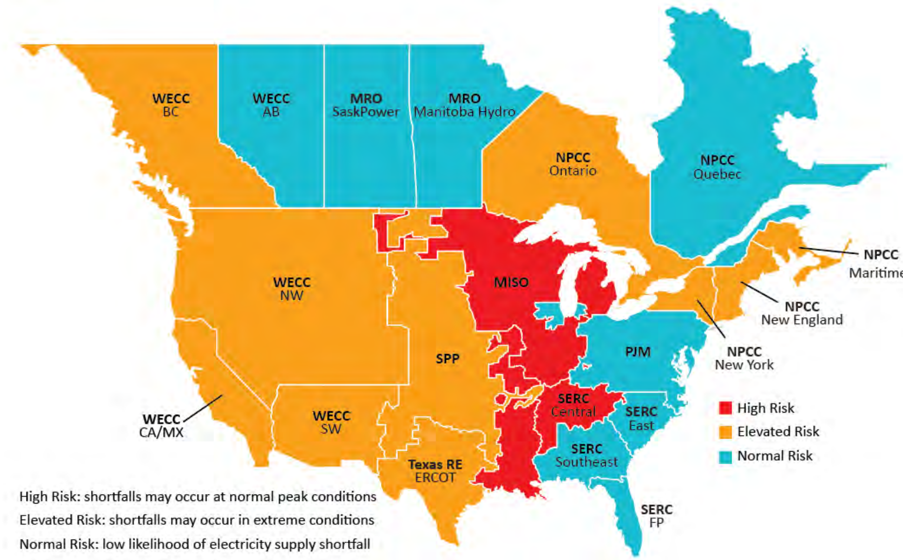

Figure 1: Risk Area Summary 2024–2028[8]

The following pages will provide overviews of each of the risk areas (i.e., high, elevated, and normal).

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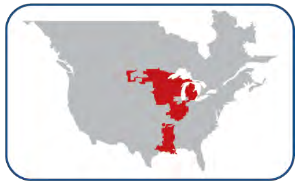
[7] As discussed throughout this report and in other NERC reliability assessments and reports, the North American BPS is undergoing a rapidly changing resource mix and the introduction of new technologies affecting how the system is planned and operated. NERC reliability assessments and the ERO Reliability Risk Priorities Report can be found at these locations: [Reliability Assessments] and [Reliability Issues Steering Committee]

[8] The Capacity and Energy Risk Assessment is focused on the first five years of the assessment period. Capacity, demand, and reserve margin information covering the entire assessment period can be found in the **Regional Assessments Dashboards** pages.

High Risk Areas[9]

Most areas are projected to have adequate electricity supply resources to meet demand forecasts associated with normal weather; however, areas that are red (high risk) in Figure 1 do not meet resource adequacy criteria, such as the 1-day-in-10-year load-loss metric during periods of this assessment period. This indicates that the supply of electricity for these areas is more likely to be insufficient in the forecast period and that more firm resources are needed. See **High Risk Area Details** for additional information. The following are details on the two high risk areas:



- **Midcontinent Independent System Operator (MISO):** Market responses to higher capacity prices in 2022 and new resource additions have overcome the planning reserve deficits that were projected to occur in 2023 and reported in the *2022 LTRA*. In this *2023 LTRA*, MISO's summer anticipated reserve margin (ARM) is projected to be above Reference Margin Levels (RML) established by MISO for reliability through the 2027 summer. However, beginning in 2028, MISO is projected to have a 4.7 GW shortfall if expected generator retirements occur despite the addition of new resources that total over 12 GW. See **MISO** dashboard pages for more information.

- **SERC-Central:** There is a potential shortfall in planned reserves over the 2025–2027 period as demand forecasts increase faster than the transitioning resource mix grows. This assessment area will add over 7 GW of natural gas generation and retire over 5 GW of coal generation over the period. Nearly 4 GW of Bulk Electric System (BES)-connected solar projects are expected in the next 10 years. The period of projected shortfall is occurring in a mid-point of the assessment period from generator retirements that are currently slated to take place before new resources are added. SERC-Central was not identified as a risk area in the *2022 LTRA*. See **SERC-Central** dashboard pages for more information.

Elevated Risk Areas[10]

Extreme temperatures and prolonged severe weather conditions are increasingly impacting the BPS. Extreme heat and subfreezing temperatures can impact the BPS by increasing electricity demand and threatening electricity supplies by forcing vulnerable generation offline and simultaneously disrupting the flow of the natural gas fuel supply to generators. While a given area (see Figure 1) may have sufficient capacity to meet resource adequacy requirements, it may not have sufficient availability and energy from resources during extreme and prolonged weather events and abnormal atmospheric conditions (i.e., smoke, smog, and wind extremes that affect output from solar and wind resources). Therefore, long-duration extreme weather events increase the risk of electricity supply shortfalls. See **Elevated Risk Area Details** for additional information.

As forecasted peak electricity demand rises across the BPS, many areas are also experiencing increasing complexity in load models that adds to operating risk. Extreme heat and cold temperatures and irregular weather patterns can cause demand for electricity to deviate significantly from historical forecasts. Electrification of the heating sector is increasing temperature-sensitive load components while increasing levels of variable-output solar photovoltaic (PV) distributed energy resources (DER) add to the load forecast uncertainty. Underestimating electricity demand prior to the arrival of extreme temperatures can lead to ineffective operations planning and insufficient resources being scheduled. Generator performance and fuel issues are more likely to occur when generators are called upon with short notice; this can expose Balancing Authorities (BA) to potential resource shortfalls. Electrification and DER trends can be expected to further contribute to demand growth and sensitivity to weather patterns.

Electricity supplies can decline in extreme weather for many reasons:

- Generators that are not designed or prepared for severe cold or heat can be forced off-line in increasing amounts.
- Wide area weather events can also impact multiple balancing and transmission operations simultaneously that limit the availability of transfers.

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[9] An assessment area is deemed to be "high risk" when it fails to meet the established resource adequacy target or requirement. The established resource adequacy target is not established by NERC, but instead by the prevailing regulatory authority or market operator. Generally, these targets/requirements are based on a 1-day/event load-loss in a 10-year planning requirement. High risk areas have a probability of load shed greater than the requirement/target. Simply said, high risk areas do not meet resource adequacy requirements.

[10] An assessment area is deemed to be "elevated risk" when it meets the established resource adequacy target or requirement, but the resources fail to meet demand and reserve requirements under the probabilistic or deterministic scenario analysis. The established resource adequacy target is not established by NERC, but instead the prevailing regulatory authority or market operator. Simply put, elevated risk areas meet resource adequacy requirements, but they may face challenges meeting load under extreme conditions.

- Fuel production or transportation disruptions could limit the amount of natural gas or other fuels available for electricity generation.
- Wind, solar, and other variable energy resource (VER) generators are dependent on the weather.

Areas in orange (elevated risk) in **Figure 1** meet resource adequacy criteria and have sufficient energy and capacity for normal forecasted conditions, but they are at risk of shortfall in extreme conditions:

- **NPCC-Maritimes**: Since the *2022 LTRA*, winter peak demand forecasts for this assessment area have risen. As a result, ARMs are currently projected to fall below the RML of 20% beginning in 2026. The small projected shortfall in planning reserves (120 MW or less over the five-year period) can be managed through supply procurements to reach resource adequacy targets. However, supply shortfalls are more likely to occur in the Maritimes province during wide-area heat events and extreme winter storms; this stresses demand and internal resources and puts external transfer assistance at risk of curtailment. NPCC-Maritimes was not identified as a risk area in the *2022 LTRA*. See the **NPCC-Maritimes** dashboard pages for more information.

- **NPCC-New England**: As reported in prior LTRAs and Winter Reliability Assessments (WRA), a persistent concern is whether there will be sufficient fuel available to satisfy electrical energy and operating reserve demands during an extended cold spell, or a series of cold spells, given the existing resource mix and regional fuel delivery infrastructure. ISO-New England's (ISO-NE) latest projections for winter peak demand show the highest growth rates in North America (3.46% compound-annual growth rate (CAGR) over this assessment period), heightening concerns for potential winter supply shortfalls toward the later part of this assessment period. Electrification of the transportation and heating sectors are primary drivers of the increase in demand forecast. New resources in ISO-NE's interconnection request queue do not generally offer the same reliability benefits in winter as the generation resources that are retiring (e.g., dispatchability, stored fuels). See the **NPCC-New England** dashboard pages for more information.

- **NPCC New York:** Reliability studies performed by the New York Independent System Operator (NYISO) have identified potential shortfalls starting in 2025 in New York City, prompting NYISO to solicit for market-based and regulated backstop solutions (i.e., generation, DR, or transmission, or combinations). The need is primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation types in New York City that are affected by a state law to reduce nitrogen oxide emissions. The deficiency could be significantly greater during a summer heatwave. NPCC New York was not identified as a risk area in the *2022 LTRA*. See the **NPCC-New York** dashboard pages for more information.

- **NPCC-Ontario:** Planned and contracted resource additions have improved the resource adequacy outlook since the *2022 LTRA.* At that time, NERC projected that shortfalls could occur beginning in 2025. In this *2023 LTRA*, reserve margins are projected to remain above Ontario's RMLs throughout the first five years. The improved outlook is the result of 1,600 MW of upgrades and expansions to natural-gas-fired generators and new BESS projects as well as a recent memorandum of understanding with Québec for 600 MW of firm summer capacity beginning in 2025. NPCC-Ontario meets resource adequacy criteria but with as little as 300 MW of surplus summer capacity starting in summer 2028. Extreme conditions that cause peak demand to exceed forecasts or above normal outages to occur could expose the area to risks of capacity shortfall. Additional capacity from the Independent Electricity System Operator's (IESO) future annual capacity auctions and ongoing procurements will continue to reduce these risks. See the **NPCC-Ontario** dashboard pages for more information.

- **Southwest Power Pool (SPP):** Since the *2022 LTRA*, projected reserve margins for the assessment period have declined while the RML of reserves needed for maintaining reliability has risen at the same time. Consequently, SPP's surplus capacity over the next five years will fall sharply. Lower reserve margins are driven by generation retirements (1,500 MW since the *2022 LTRA)* and rising peak demand forecasts. SPP raised the RML from 16% to 19% in 2023, LSEs in the RTO area to procure more resource capacity for the same amount of load. Energy shortfalls can occur in SPP when high demand coincides with low wind or above-normal generator outages. See the **SPP** dashboard pages for more information.

- **Texas RE-ERCOT:** Generation resources, primarily solar PV, continue to be added to the grid in large quantities, increasing ARM but also elevating concerns of energy risks. With demand forecast to rise steadily, the future resource mix is likely to have the lowest reserve levels during off-peak periods when solar PV resource output is diminished. These include hot summer evenings as well as fall and spring months when dispatchable thermal generation is performing scheduled maintenance. Extreme winter weather, such as Winter Storm Uri in February 2021, remains a serious concern that warrants continued efforts to ensure that generators and fuel supplies are available and capable of performing in severe conditions. Without provisions for electric grid reliability, new and proposed Environmental Protection Agency (EPA) rules could heighten the risk of thermal unit retirements before solutions to resource adequacy and system planning issues are in place. See the **Texas RE-ERCOT** dashboard pages for more information.

- **British Columbia (WECC-BC):** Forecasted peak demand growth is causing a decline in reserve margins and reduced surplus capacity for managing periods of above-normal demand. Energy shortfall risks in the WECC-BC assessment area are associated with extreme weather conditions that cause periods of above-normal demand to coincide with lower-than-normal resource output. Probabilistic assessment (ProbA) results show little energy risk in 2024; however, load-loss and unserved energy risks increase in 2026 as forecasted demand increases and natural-gas-fired generation retires. WECC-BC was not identified as a risk area in the *2022 LTRA*. See the **WECC-BC** dashboard pages for more information.

- **WECC U.S. Assessment Areas:** Throughout this area, both demand and resource variability are projected to continue increasing as the resource mix transitions and more DERs connect to the distribution system. In normal conditions, the expected demand and resource variability is balanced across the area as excess supply from one part of the system is delivered through the transmission network to places in need. However, more extreme summer temperatures that stress large portions of the Interconnection reduce the availability of excess supply for transfer while also reducing the transmission network's transfer capability:

  - **California/Mexico (WECC-CA/MX):** Resource additions, generator uprating, and service extensions have helped alleviate near-term capacity risks and lower the area's reliance on imports to meet high demand. Since the *2022 LTRA*, WECC's probabilistic analysis indicates that risks of unserved energy and load loss in 2024 have fallen to negligible levels. However, loss-of-load and unserved energy risks emerge in 2026 concentrated in the July–September period and are primarily associated with extreme weather conditions. ARMs continue to rise from levels reported in NERC's previous LTRAs as new resources are added, primarily solar PV, hybrid-solar PV, and BESS resources. See the **WECC-CA/MX** dashboard pages for more information.

  - **Northwest (WECC-NW)** and **Southwest (WECC-SW):** Like WECC-CA/MX, WECC-NW and WECC-SW are projected to be at risk of resource shortfalls during extreme summer weather conditions after 2024. Although the assessment areas are projected to have sufficient capacity to meet forecasted peak demand throughout this assessment period, dispatchable generation declines as generators retire starting in 2026. The resulting resource mix is more variable and has a risk of supply shortfalls during extreme summer conditions emerge in WECC's probabilistic analysis. See the **WECC-NW** and **WECC-SW** dashboard pages for more information.

Normal Risk Areas

Normal risk areas are shown in blue (see **Figure 1**). In these areas, resource adequacy criteria are met, and it is unlikely for electricity supply shortfalls to occur even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance). See **Normal Risk Area Details** for additional information.

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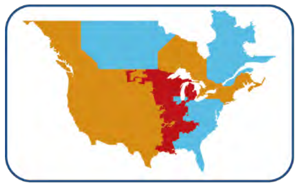
Changing Resource Mix and Reliability Implications

Wind, solar PV, and hybrid generation are projected to be the primary additions to the resource mix over the 10-year assessment period; this leads the continued energy transition as older thermal generators retire. Maintaining a reliable BPS throughout the transition requires unwavering attention to ensure the resource mix satisfies capacity, energy, and essential reliability service (ERS) needs under designed conditions. It will also require significant planning and development of the interconnected transmission system to have a deliverable electricity supply from new resources to changing types of loads and the ability to withstand system contingencies.



In this LTRA, NERC accounted for over 83 GW of fossil-fired and nuclear generator retirements that are currently anticipated through 2033. An additional 30 GW of fossil-fired generators have announced plans to retire over the decade but have yet to enter deactivation processing with the planning authorities. These additional retirements can exacerbate energy, capacity, or ERS issues in high risk (red) and elevate risk (orange) areas and potentially affect the projected sufficiency of resources in normal risk (blue) areas (**Figure 1**). Environmental regulations and energy policies that are overly rigid and lack provisions for electric grid reliability have the potential to influence generators to seek deactivation despite a projected resource adequacy or operating reliability risk; this can potentially jeopardizing the orderly transition of the resource mix.[11] For this reason, regulators and policymakers need to consider effects on the electric grid in their rules and policies and design provisions that safeguard grid reliability.

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Trends and Reliability Implications

Demand and transmission trends affect long-term reliability and the sufficiency of electricity supplies.

Demand Trends

Electricity peak demand and energy growth forecasts over the 10-year assessment period are higher than at any point in the past decade. Electrification and projections for growth in electric vehicles (EV) over this assessment period are a component of the demand and energy estimates provided by each assessment area. Since the *2022 LTRA*, peak season CAGR has risen in nearly all assessment areas, contributing to an overall trend to lower reserve margins. Some of the sharpest peak demand forecast increases and growth rates can be seen in winter seasons as heating system and transportation electrification influence forecasts. Dual-peaking or changing from summer to winter peaking is anticipated in several areas, requiring resource and system planners to shift the focus of adequacy planning. Concentrated growth and the emergence of new types of loads are occurring in many areas. These growth trends bring additional challenges for resource and transmission adequacy. Planners and operators can prepare by considering robust demand and energy scenarios, carefully monitoring and refining demand forecasts, and developing operational tools for peak load management.

Transmission Trends

The amount of BPS transmission projects reported to NERC as under construction or in planning for construction over the next 10 years has increased, indicating an overall increase in transmission development. New transmission projects are being driven to support new generation and enhance reliability. Siting and permitting challenges continue to inflict delays in transmission expansion planning. Regional transmission planning processes are adapting to manage the energy transition, but impediments to transmission development remain.

Conclusions and Recommendations

The energy and capacity risks identified in this *2023 LTRA* underscore the need for reliability to be a top priority for energy policymakers, regulators, and industry. Growing the reliable BPS will involve doing the following four things, numbered only for identification:

1. **Add new resources with needed reliability attributes and make existing resources more dependable.** As BPS resources grow to meet rising demand and the resource mix changes, IBR performance issues as well as generator and fuel vulnerabilities to extreme temperatures must be addressed to have a reliable electricity supply:

    - New wind and solar PV resources use inverters to convert their output power onto the grid, and the vast majority of resource inverters are susceptible to tripping or power disruption during normal grid fault conditions; this makes the future grid less reliable when more resources are inverter-based.

    - Natural-gas-fired generators are essential for meeting demand; they are dispatchable at any hour and provide a consistent rated output under a wide range of conditions. However, sufficient natural gas fuel supplies cannot be assured without better reliability measures and the effective coordination between the operators and planners of both electricity and natural gas infrastructures.

    - Reducing risks to electricity supplies in extreme hot and cold temperatures requires generating resources that are up to the task. However, natural-gas-fired generators, natural gas fuel supplies, and wind resources (which are becoming increasingly common)

[11] The EPA is implementing, has finalized, or has proposed six rules that impact the fossil-fired generators: Coal Combustion Residuals (being implemented), revised Effluent Limitations Guidelines (proposed), revised Mercury and Air Toxics Standards (proposed), Good Neighbor Rule (finalized), Carbon Rule (proposed), and Regional Haze (being implemented).

- have proven vulnerable and unable to meet demand during winter storms over the past decade.
- Additionally, to reliably grow the BPS, generator retirements over the 10-year assessment period of this *2023 LTRA* need to be carefully evaluated. State and provincial resource adequacy stakeholders and policymakers need to ensure that resource plans account for growing electricity demand and load profiles as well as the future resource portfolio's capabilities to provide essential grid reliability services. They must have effective measures that can be implemented to prevent loss of resources that are needed for resource and energy adequacy, grid reliability, and system restoration.

2. **Expand the transmission network to deliver supplies from new resources and locations to serve changing loads.** A strong, flexible transmission system that is capable of coping with a wide variety of system conditions is key for the reliable supply and delivery of electricity. The rapidly changing resource mix requires access and deliverability of new resources—including transmission availability—to maintain reliability:
    - Transmission development is needed to connect resources to load and to adapt to a future system demand profile that will be influenced by EV charging, electrification in heating, large industrial loads and data centers, and the behavior of large flexible loads. The capability for electricity supplies to be transferred between areas may play a significant part in overall energy adequacy when the system may have highly variable electricity supply resources and more weather-sensitive demand.
    - Additionally, introducing new resource types into the system and ensuring that the planned system can be operated within reliability criteria requires engineering analysis that will be increasingly complex. Transmission planning processes are adapting to overcome challenges and the speed of development; however, backlogs remain.
3. **Adapt BPS planning, operations, and resource procurement markets and processes to the realities of a more complex power system.** The addition of variable resources (primarily wind and solar PV) and the retirement of conventional generation are fundamentally changing how the BPS is planned and operated. With electricity supplies coming increasingly from VERs and natural-gas-fired generators, there is a growing risk that supplies can fall short of demand during some periods. To ensure energy shortfall risks are identified and addressed, resource contributions to serving load must be accurately represented in resource planning and operating models as well as in the design of wholesale electricity market designs:
    - Resource and system planners must have robust tools and capabilities for assessing energy needs, extreme weather scenarios, and grid stability. Planning Reserve Margins can fail to identify energy risks that stem from low VER output or generator fuel supply issues, making them unsuitable as a sole basis of resource adequacy. Resource planners and wholesale markets must use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. NERC and the industry should also use wide-area assessments capable of accurately modeling interregional transfers to improve resource adequacy and energy risk assessments.
    - Geographically diverse wind and solar resources and loads can help reduce energy risks but require robust transmission networks, comprehensive energy and transfer capability analysis, and effective operating procedures and market mechanisms.
    - Natural gas supply infrastructure and the BPS form an interconnected energy system that requires a high degree of coordination and integration. The operation of this interconnected energy system can be disrupted when natural gas fuel supplies are not available for electricity generation as well as when electricity is not available to operate electricity-driven compressors and other critical infrastructure components in the natural gas supply chain. The potential for extreme cold temperatures to have wider impact because of the interconnected nature of the electric and natural gas systems makes integrated planning and effective coordination imperative.
    - Explosive growth in rooftop solar PV and other resources on distribution networks add complexity to planning and operating models and market designs that require visibility and coordination across distribution and BPS jurisdictions. Large flexible loads and demand-side management programs offer reliability benefits by providing operators with another resource for managing peak loads; however, operating models and mechanisms for control must be in place.
4. **Strengthen relationships among reliability stakeholders and policymakers.** Making informed policies and decisions in matters that have the potential to affect electric grid reliability requires a high level of awareness as future electricity resource reserves shrink in the face of demand growth and the interconnected nature of the electric and natural gas systems are more pronounced:
    - Initiatives like the North American Energy Standards Board Gas Electric Harmonization Forum—which is comprised of a broad cross section of natural gas and electricity stakeholders and experts; this forum was assembled to address weaknesses identified in 2021's Winter Storm Uri and 2022's Winter Storm Elliott. The NAESB put forward several recommendations that, if implemented today, would enable BPS operators to have a more reliable and fuel-secure generation mix and be in a better position to maintain the integrity of the BPS during extreme weather events, such as Winter Storm Elliott.

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Initiatives like this are essential to come up with structural solutions to risks that arise from critical interdependencies.

- The Memorandum of Understanding between the U.S. Department of Energy (DOE) and the U.S. EPA to foster interagency cooperation and consultation to support electric grid reliability is an encouraging acknowledgement of the need for environmental policies to carefully consider electric grid reliability and provides a path for flexibility provisions to be addressed.[12]
- There is a need for dialogue among a broad group of stakeholders when policies and regulations have the potential to affect future electricity supplies, demand, and the development of electricity and natural gas resources and infrastructure. Regulations that have the potential to accelerate generator retirements or restrict operations must have sufficient flexibility and provisions to support grid reliability. The need for close coordination is further reinforced by the expanding interdependencies with other critical infrastructure sectors (i.e., communications, water and wastewater, transportation, critical manufacturing, and finance).[13]

Specific and actionable recommendations are contained in the **Recommendations: Details** section of this report with the same numbers to identify them. A summary of ERO ongoing activities and resources that address applicable recommendations is included in the **ERO Actions Summary** section.

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[12] DOE-EPA Electric Reliability MOU
[13] 2023 ERO Reliability Risk Priorities Report

Recommendations: Details

The following numbered recommendations are additional details for the Executive Summary **Conclusions and Recommendations** with the same identifying numbers.

1. **Add new resources with needed reliability attributes and make existing resources more dependable:**
   - **Address performance deficiencies with existing and future inverter-based resources:** Reliably integrating IBRs onto the grid is paramount, and evidence indicates that the risk of grid vulnerabilities from interconnection practices and IBR performance issues are growing. IBRs include most solar and wind generation as well as new BESS or hybrid generation and account for over 70% of the new generation in development for connecting to the BPS. IBRs respond to disturbances and dynamic conditions based on programmed logic and inverter controls. The tripping of BPS-connected solar PV generating units and other control system behavior during grid faults has caused sudden loss of generation resources (over wide areas in some cases). Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California and similar events have occurred in new geographic areas as recently as the summer of 2023.[14] A common thread with these events is the lack of IBR ride-through capability that causes a minor system disturbance to become a major disturbance. Based on the findings of a recent NERC alert, more ride-through and ERS capabilities can be enabled within existing solar PV resources to improve performance and support the reliable operation of the BPS.[15] Industry adoption of the recommended practices set forth in NERC reliability guidelines and the NERC alert will reduce risks from IBR performance issues to the grid as NERC also develops mandatory Reliability Standards based on those reliability guidelines. It is also critically important for interconnection processes to include accurate modeling and studies requirements.[16] Guided by NERC's comprehensive Inverter-Based Resources Strategy and in response to FERC Order No. 991, the ERO and industry should take additional steps to ensure that IBRs operate reliably and that the system is planned with due consideration for their characteristics.[17,18]
   - **Improve the performance of the generating fleet in extreme weather:** The ERO and industry need to prioritize the development of Reliability Standard requirements to address reliability related findings from the FERC, NERC, and Regional Entity joint staff inquiry into the February 2021 cold weather grid outages.[19] Findings of the inquiry into Winter Storm Elliott (December 2022) reinforce the urgency of this effort.[20]
   - **Mitigate fuel-related risks to electricity generation (fuel assurance)**: In addition to serving as base and intermediate-load plants, natural-gas-fired generation has become a necessary balancing resource that enables reliable integration of VERs into the dispatch. As a result, the BES has never been more dependent upon the round-the-clock continuity of just-in-time natural gas delivery. The past two winters have seen interruptions of natural gas delivery to generators that resulted in energy deficiencies. NERC strongly endorses actions to establish reliability rules for the natural gas infrastructure necessary to support the grid as recommended in the Winter Storm Elliott report. Additionally, as part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electricity reliability. The NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System,* provides planning guidance.[21]
   - **Carefully manage generator deactivations:** State and provincial regulators and ISOs/RTOs need to have mechanisms they can employ to extend the service of generators seeking to retire when they are needed for reliability, including the management of energy shortfall risks. Regulatory and policy-setting organizations must use their full suite of tools to manage the pace of retirements and ensure that replacement infrastructure can be timely developed and placed in service. If needed, the DOE should use its 202(c) authority in support of electric system operators.

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[14] See the ERO's extensive IBR event reporting here: NERC Major Event Reports

[15] The NERC Level 2 alert to gather data from solar PV resource owners and issue recommendations can be found here: *Industry Recommendation: Inverter-Based Resource Performance Issues*.

[16] NERC's comprehensive initiatives to reduce IBR risks are detailed here: IBR Quick Reference Guide

[17] NERC IBR Activities

[18] FERC Order No. 901 - Final Rule Reliability Standards to Address Inverter-Based Resources

[19] *The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report*

[20] Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott

[21] Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised Guideline also identifies as fuel risks requiring evaluation many of the scenarios industry has encountered during recent periods of extreme cold weather and high demand for natural gas. The revised guideline is under review with the Reliability and Security Technical Committee. The approved and revised draft guideline can be found on the RSTC website: NERC Reliability and Security Guidelines

2. **Expand the transmission network to deliver supplies from new resources and locations to serve changing loads:**

   - **Develop the transmission network:** ISOs/RTOs should continue looking for opportunities to streamline transmission planning processes and reduce the time required for transmission development. However, addressing the siting and permitting challenges that are the most common cause for delayed transmission projects will require regulators and policymakers at the federal, state, and provincial levels to focus attention and provide support.

   - **Assess interregional transfer capabilities and their contribution to BPS reliability.** Studies of interregional transfers and transfer capability under a range of scenarios can provide insight into potential benefits of transmission development on grid reliability. It is important for NERC and the industry to complete the interregional transfer capability study directed in the Fiscal Responsibility Act of 2023 and share the results with legislators, regulators, and policymakers.[22] NERC should also incorporate insights and study approaches from the interregional transfer capability study to better account for interregional transfers in energy and capacity risk assessments.

3. **Adapt BPS planning, operations, and resource procurement markets and processes to the realities of a more complex power system:**

   - **Resource contributions must be accurately represented in resource planning, wholesale electricity markets, and operating models.** Resource planners and wholesale market designers are developing new processes for assigning the contribution of resources to meeting demand in most areas with growing wind and solar PV resources. Earlier this year, MISO implemented seasonal resource adequacy auctions (spring, summer, fall, winter) based on reserve requirements and resource performance that are tailored to each season. Other ISOs and RTOs are exploring similar initiatives. Some assessment areas are implementing effective load-carrying capacity (ELCC) methods that involve probabilistic study to assign the capacity contribution of resources. These ELCC methods must address the risks and shortcomings in the present modeling described in this *2023 LTRA.* Specifically, the statistical representation of capacity that has variable and uncertain fuel can be problematic when combined in a reserve margin evaluation with capacity that has firm fuel and is highly reliable. Planners and operators must continue updating processes, tools, and techniques to keep pace with the changing resource mix. Among the changes needed is the consideration of the energy contributions that each resource type is expected to provide in order to identify periods of potential energy shortfalls. The explosive growth of BESS and hybrid resources seen in most areas requires additional details to be incorporated into operating and planning models, such as state of charge, BESS duration, and BESS operating mode.

   - **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** Planning Reserve Margins are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Industry and research partners should focus on developing tools, models, and methods for including a wide-area view of energy transfers in resource adequacy studies. Additionally, the ERO must develop and implement analytical approaches to incorporate natural-gas fuel supply risks in NERC reliability assessments.

   - **Maintain sufficient amounts of flexible resources**: To maintain load-and-supply balance in real-time with higher penetrations of variable supply and less-predictable demand, dispatchable generators must be available and capable of following changing electricity demand. Retirements of fossil-fired generators are reducing the amounts of dispatchable generation in many areas. As more solar PV and wind generation is added, additional flexible resources are needed to offset these resources' variability, such as supporting solar down ramps when the Sun goes down and complementing wind pattern changes. Natural-gas-fired generators and hydro generators have traditionally provided this ERS. Battery resources can provide flexibility during short durations, while new wind and solar PV have minimal assured flexibility. Maintaining ERSs is critically important. Resource planners and wholesale electricity market operators should ensure resources are procured and made available in the long-range resource portfolio as part of the planning process; markets and other mechanisms need to be in place to deliver weather-ready resources with sufficient energy and ERS capabilities to the operators.[23]

   - **Develop tools for assessing extreme weather risks:** Planners are finding it necessary to have improved tools and methods to study wide-area, long duration extreme weather risks and other low-likelihood, extreme events. Scenario planning is needed to ensure appropriate evaluation of likelihood, consequence, and potential mitigations to enhance reliability and resilience of the BPS. Traditional resource adequacy models and approaches rooted in a loss-of-load expectation (LOLE) of 1 day-in-10-years do not account for the essential role that electricity plays in modern society, and normal demand

[22] Fiscal Responsibility Act of 2023
[23] NERC ERS Measure 6 Forward Tech Brief

distributions appear to be ill-suited for describing the extremes of changing weather patterns. NERC, industry, and research partners should collaborate to develop models and approaches for studying the risks to electricity supplies, including natural gas fuel availability, from wide-area and long-duration extreme weather conditions. Such capabilities for rigorously studying the impact of extreme weather will enable a more accurate assessment of the risks and provide for the development of effective measures for resilience.

- **Include extreme weather scenarios in resource and system planning:** Industry and regulators need to conduct all-hours analyses for evaluating and establishing resource adequacy and include extreme conditions in integrated resource planning and wholesale market designs. While more sophisticated capabilities for assessing extreme event risk are being developed, scenario planning can be more readily incorporated in resource and system planning. Scenarios should consider the potential effects of wide-area, long-duration extreme weather events, including the impact they can have on natural gas fuel supplies and on the interconnected energy system.
- **Accommodate the growth of DERs:** Preparing the grid to operate with increasing levels of distribution resources must also be a priority in many areas. Growth of DERs promise both opportunities and risks for reliability. Increased DER penetrations can improve local resilience at the cost of reduced operator visibility into loads and resource availability. Data sharing, models, and information protocols are needed to support BPS planners and operators. Industry must continue to evaluate potential reliability concerns associated with increasing DER penetration and DER performance and, when necessary, develop reliability standards requirements to address identified gaps. DER aggregators will also play an increasingly important role for BPS reliability in the coming years. ISOs/RTOs must consider how the implementation of DER aggregators in the wholesale market will affect BPS planning and operations.[24]

4. Strengthen relationships among reliability stakeholders and policymakers:

- **The ERO and industry partners need to expand strategic engagements with federal, state, and provincial regulators and policymakers:** These officials have jurisdictional authority to make key decisions that affect reliability, resource adequacy, and infrastructure development.
- **The ERO, regulators, and industry partners need to work together:** Special emphasis needs to be placed on mechanisms to ensure the reliable delivery of natural gas fuel supplies for electricity generation as well as to act on the recommendations in *The FERC-NERC-Regional Entity Staff Report: Inquiry into Bulk Power System Operations December 2022 Winter Storm Elliott*.

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[24] A comprehensive guide to ERO activities on DERs can be found here: [DER Activities]

Capacity and Energy Assessment

Conditions for tighter resource adequacy—characterized by less surplus capacity relative to forecasted demand—have emerged generally across the BPS over the past decade. Figure 2 shows summer peak resource capacity (top) and forecasted peak demand (bottom) aggregated for all NERC assessment areas at the beginning and the end of the 2012–2032 period. While summer forecasted peak demand increased by 3% since 2012, current on-peak BPS resource capacity decreased by 4%. Furthermore, summer peak demand is forecast to increase another 10% by 2032 while resources are expected to grow modestly by 4%. Lower reserves by this broad and retrospective measure are a coarse indicator that signals a need for stakeholders to pay careful attention to more specific and granular resource adequacy measures and input assumptions.

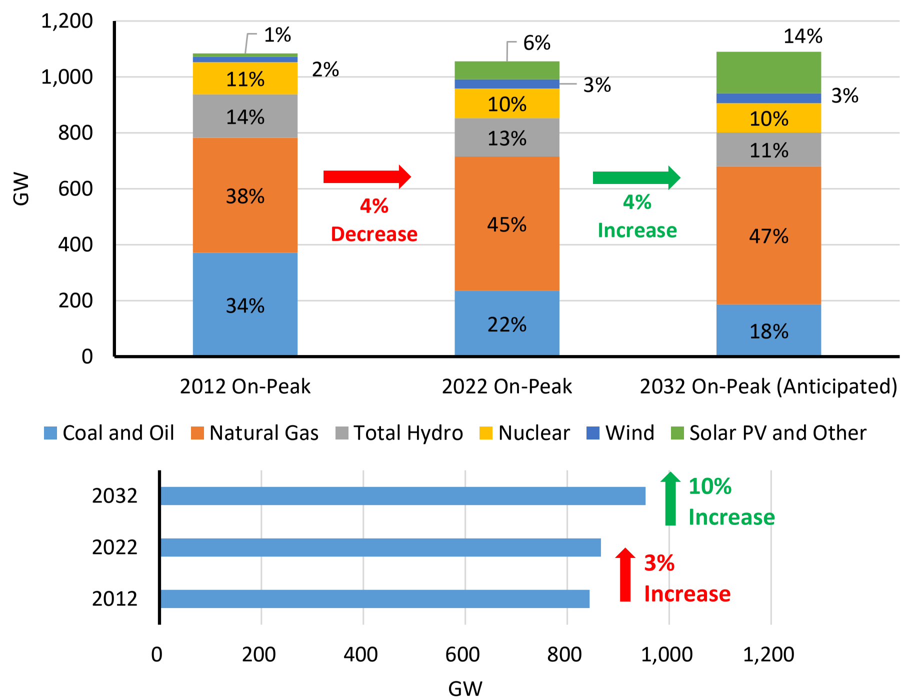

Figure 2: Change in Summer Peak Capacity and Demand Forecast 2012–2032

Assessment Approach

NERC is using two approaches in this *LTRA* to assess future resource capacity and energy risk; both are forward-looking snapshots of resource adequacy that are tied to industry forecasts of electricity supplies, demand, and transmission development:

- Comparing the margin between projected resources and peak net demand, or reserve margin, to an RML that represents the accepted level of risk based on a probability-based loss-of-load analysis.
- Assessing load-loss metrics determined from probability-based simulation of projected demand and resource availability over all hours to identify high risk periods and potential energy constraints resulting in load loss events. Loss-of-load hours (LOLH) and expected unserved energy (EUE) from NERC's biennial ProbA are used to identify risk levels. The ProbA was completed in 2022 and published in the *2022 LTRA*. Subsequently, NERC published the *2022 Probabilistic Assessment Regional Risk Scenarios Report* to analyze more extreme area-specific reliability risks and uncertainties with probabilistic methods.[25] This *LTRA* considers both results and updated projections to determine energy risk trends.

See the **Demand Assumptions and Resource Categories** for further details on these approaches. Assessment area dashboards (see **Regional Assessments Dashboards**) provide resource capacity and energy risk assessment results for all areas.

Finding: This *2023 LTRA* Capacity and Energy Assessment section highlights both progress and growing resource adequacy concerns as the resource mix transition continues. Delayed generator retirements and resource additions are alleviating some previously identified near-term capacity shortfalls. However, a growing number of areas in North American face resource capacity or energy risks over the assessment period. Capacity deficits, where they are projected, are largely the result of generator retirements that have yet to be replaced. While some areas have sufficient capacity resources, energy limitations and unavailable generation during certain conditions (e.g., low wind, extreme and prolonged cold weather) can result in the inability to serve all firm demand.

[25] 2022 ProbA Regional Risk Scenarios Report

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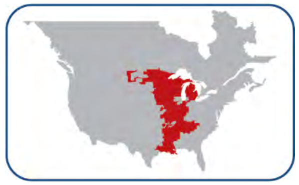
Risk Categories



An assessment area is high risk (see **Figure 1**) when established resource adequacy targets or requirements are not met during this assessment period. NERC does not establish resource adequacy targets; these are set by regulatory authorities or market operator and are typically based on a 1-day/event load-loss in a 10-year planning requirement. High risk areas have a probability of load shed greater than the requirement/target.

An assessment area is considered an elevated risk when it meets the established resource adequacy target or requirement, but the resources fail to meet demand and reserve requirements under probabilistic or deterministic analysis of conditions that are plausible but more extreme than normal seasonal peaks. More extreme conditions can include temperatures that result in above normal demand levels, low resource output or availability, and/or disruption of normal electricity transfers. Simply put, elevated risk areas meet resource adequacy requirements, but they may face challenges meeting load under extreme conditions.

NERC assesses areas as normal risk when resource adequacy criteria are met and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance). Although areas categorized as Normal Risk are expected to have sufficient resources for plausible extreme conditions, they are not immune to the effects of exceedingly rare severe weather events that simultaneously affect demand and generation or other high-impact, low frequency events.

High Risk Area Details

Most areas are projected to have adequate electricity supply resources to meet demand forecasts associated with normal weather. However, the following two areas (listed in order of appearance on the **Regional Assessments Dashboards**) do not meet resource adequacy criteria, such as the 1-day-in-10-year load-loss metric during periods of the assessment period. This indicates that the supply of electricity for these areas is more likely to be insufficient in the forecast period and that more firm resources are needed. See **High Risk Areas** in a previous section for additional information.

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MISO

In 2023, MISO transitioned to its first year of seasonal capacity auctions (summer, fall, winter, spring). Market responses to higher capacity prices in 2022 and new resource additions have overcome planning reserve deficits reported in the *2022 LTRA*, and now MISO's summer ARM is projected to be above the RMLs through the 2031 summer (**Figure 3**). Beginning in 2028, MISO is projected to have a 4.7 GW shortfall if expected generator retirements occur and over 12 GW of new resources are added.

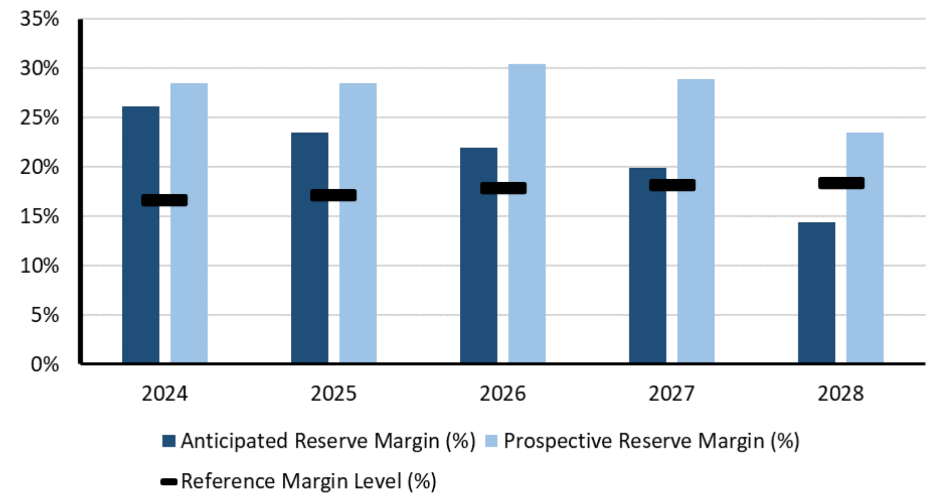

Figure 3: MISO Five-Year Planning Reserve Margin–Summer

MISO's switch to seasonal resource adequacy construct now more effectively identifies risk across the entire year as it makes use of seasonal resource accreditation and seasonal resource adequacy requirements. Resource performance in winter may differ from other seasons (e.g., seasonal wind patterns effect wind generating fleet; thermal generator outage rates vary by season; and solar resources typically have less or no output at times of highest demand in winter). Similarly, demand profiles are different by season. A seasonal RML accounts for these and other factors. Beginning in 2028, MISO's winter ARM is expected to fall below the area's winter RML (1,300 MW shortfall). **Figure 4** shows the steady decline of winter ARMs in MISO and the winter RML. The contrast between the increasing summer ARMs and declining winter ARMs is the result of the changing resource mix. Retiring generators, primarily thermal, are being replaced with solar PV (which has very small capacity contributions in winter) and some wind.

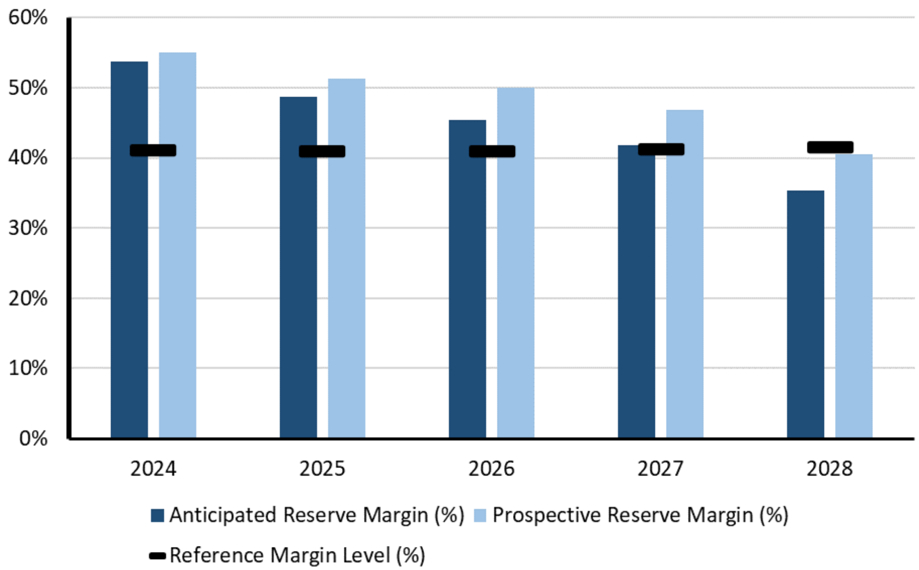

Figure 4: MISO Five-Year Planning Reserve Margin–Winter

Like MISO, other ISO/RTO areas and integrated resource planners are considering or developing seasonal resource adequacy approaches to better respond to anticipated challenges.

SERC-Central

The SERC-Central assessment area faces a potential shortfall in planned reserves over the 2025–2027 period as demand forecasts increase faster than the transitioning resource mix grows (Figure 5). The assessment area will add 7,251 MW of natural gas generation and retire 5,159 MW of coal generation over the period. A total of 3,937 MW of BES-connected Tier 1 solar PV projects are expected in the next 10 years. The period of projected shortfall is occurring in a mid-point of this assessment period from generator retirements that are currently slated to take place before new resources are added. Overall, there will be 2,762 MW of net additions and retirements within the next 10 years.

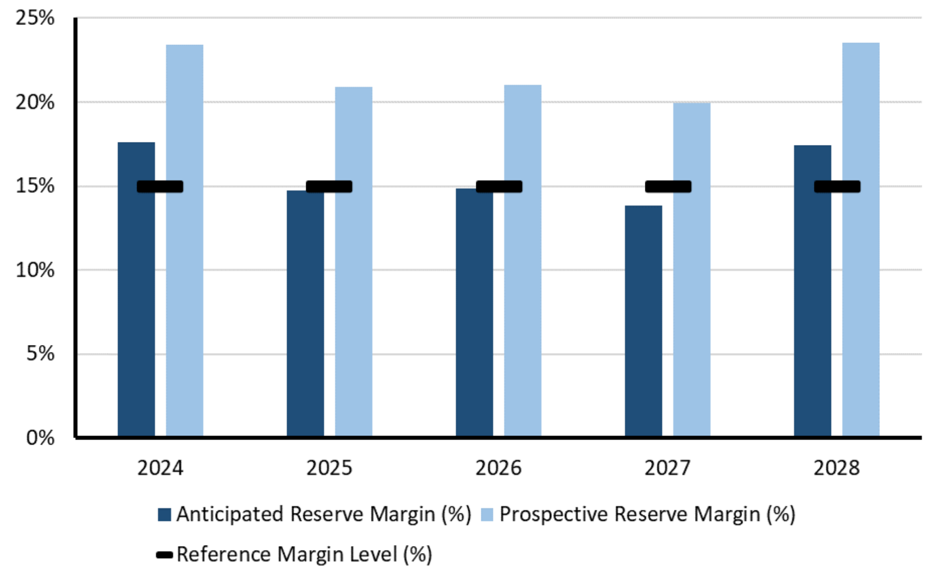

Figure 5: SERC-C Five-Year Planning Reserve Margin

NERC's 2022 ProbA revealed some LOLH (<0.1 hours/year) concentrated in winter. With rising demand projections and relatively unchanged resources, the risk is increasing over this assessment period.

Elevated Risk Area Details

The below areas are projected to meet resource adequacy criteria and have sufficient energy and capacity for normal forecasted conditions but are at risk of supply shortfall in assessed extreme conditions. Areas are listed in order of appearance on the **Regional Assessments Dashboards** section. See **Elevated Risk Areas** in a previous section for additional information.

NPCC-Maritimes

Since the *2022 LTRA*, winter peak demand forecasts for the assessment area have risen. As a result, Anticipated Reserve Margins (ARM) are currently projected to fall below the RML of 20% beginning in 2026 (**Figure 6**). The small projected shortfall in planning reserves (120 MW or less over the five-year period) can be managed through supply procurements to reach resource adequacy targets. However, supply shortfalls are more likely to occur in Maritimes during wide-area heat events and extreme winter storms transfers that stress demand and internal resources and put external transfer assistance at risk of curtailment.

NERC's 2022 ProbA revealed some LOLH (<0.1 hours/year) concentrated in winter. With rising demand projections and relatively unchanged resources, the risk is increasing over this assessment period.

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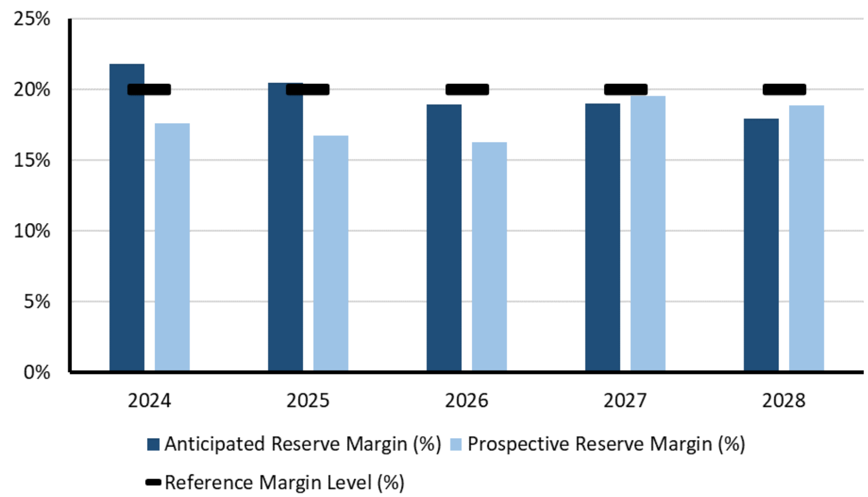
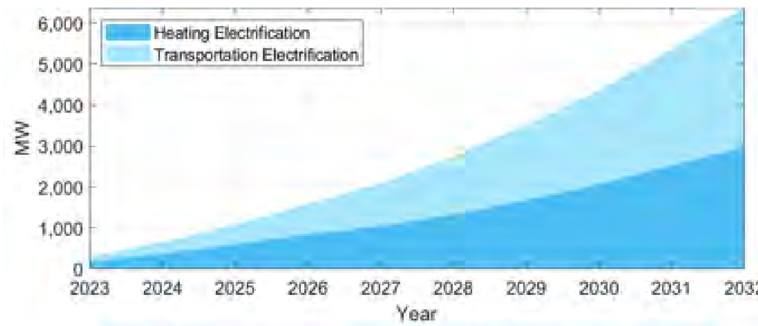


Figure 6: NPCC-Maritimes Five-Year Planning Reserve Margin

NPCC-New England

As reported in prior LTRAs and WRAs, a persistent concern for New England is whether there will be sufficient fuel available to satisfy electrical energy and operating reserve demands during an extended cold spell or a series of cold spells given the existing resource mix and regional fuel delivery infrastructure. ISO-NE's latest projections for winter peak demand show the highest growth rates in North America (3.46% CAGR over this assessment period), heightening concerns for potential winter supply shortfalls toward the later part of this assessment period. Electrification of the transportation and heating sectors are primary drivers of the increase in demand forecast (See **Figure 7**).



	Transportation Electrification				Heating Electrification		
Year	CELT 2022 (MW)	CELT 2023 (MW)	Change (MW)		CELT 2022 (MW)	CELT 2023 (MW)	Change (MW)
2023	50	116	66		75	175	100
2024	133	271	138		179	370	192
2025	244	473	229		311	601	290
2026	382	726	344		473	848	374
2027	549	1,042	493		668	1,040	372
2028	743	1,404	661		895	1,333	438
2029	967	1,822	855		1,158	1,673	515
2030	1,221	2,293	1,072		1,476	2,063	588
2031	1,497	2,820	1,323		1,831	2,521	691
2032		3,420				2,965	

Figure 7: Electrification Component of Winter Peak Demand Projections (Source: ISO-NE CELT Report 2023)

New resources in ISO-NE's interconnection request queue do not offer the same reliability benefits in general during winter as the generation resources that are retiring or at risk of retiring over this assessment period. Thermal generation with stored fuel is at risk of retirement without fuel-assured replacements. The generation interconnection queue includes over 35 GW capacity; however, it is primarily VERs. More dispatchable, fuel-assured, or long-duration stored energy resources will be required to provide for reliable winter operations as electrification continues in the area.

NPCC New York

ARMs exceed a RML of 15% over the near-term; however, reserve surplus is near zero in 2025 (see Figure 8).[26] This leaves little reserve to meet above-normal levels of summer demand or manage high generator outages or loss of imports that can occur during extreme weather events.

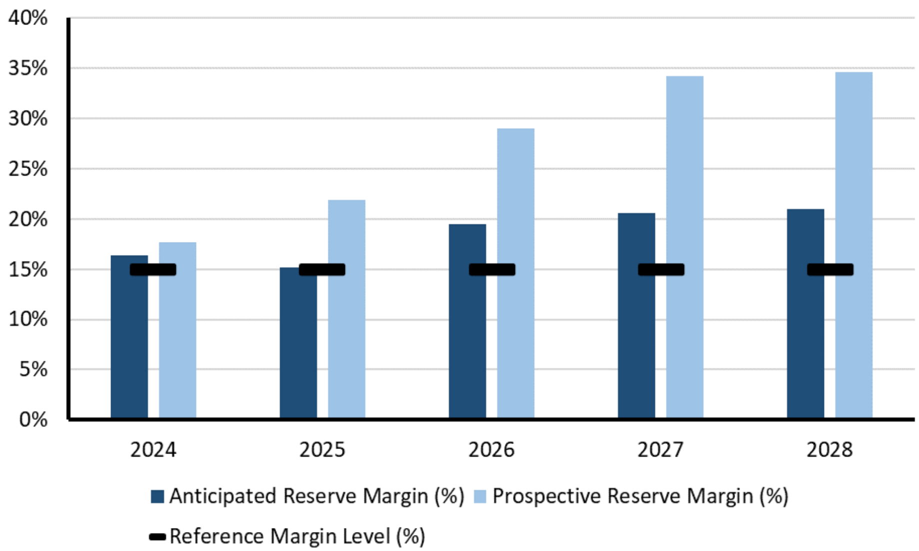


Figure 8: NPCC New York Five-Year Planning Reserve Margin

NYISO reliability studies identified a reliability need that would start in 2025 in New York City, resulting in NYISO evaluating proposed solutions. The need is primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City that is affected by a state law to reduce nitrogen oxide emissions. The deficiency will be significantly greater if a heatwave occurs.

The transition to a cleaner grid in New York is leading to an electric system that is increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation. Reliability margins are shrinking as generators needed for ERSs are planning to retire. Delays in the construction of new supply and transmission, higher than expected demand, and extreme weather could threaten reliability and resilience in the future.

NPCC Ontario

Since the *2022 LTRA,* planned and contracted resource additions have improved the province's resource adequacy outlook. The ARMs in NPCC-Ontario are projected to remain above Ontario's current RMLs throughout the first five years of this assessment period (see Figure 9). The improved outlook is the result of 1,600 MW of upgrades and on-site expansions to natural-gas-fired generators and new BESS projects. In addition, a recent memorandum of understanding with neighboring province Québec adds 600 MW of firm summer capacity beginning in 2025. NPCC-Ontario meets resource adequacy criteria but with as little as 300 MW of surplus summer capacity in 2028 and later. Extreme conditions that cause peak demand to exceed forecasts or that cause above normal outages to occur could expose the area to risks of capacity shortfall. However, the risks can be mitigated with additional capacity from IESO's future annual capacity auctions and ongoing procurements.

[26] NERC uses a RML of 15% in the *2023 LTRA* Capacity and Energy Risk Assessment for NPCC New York in absence of an established Planning Reserve Margin requirement. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. New York requires LSEs to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2023–2024 IRM at 20%. All values in the IRM calculation are based upon full Installed Capacity MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year. Additionally, NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 event-days/year.

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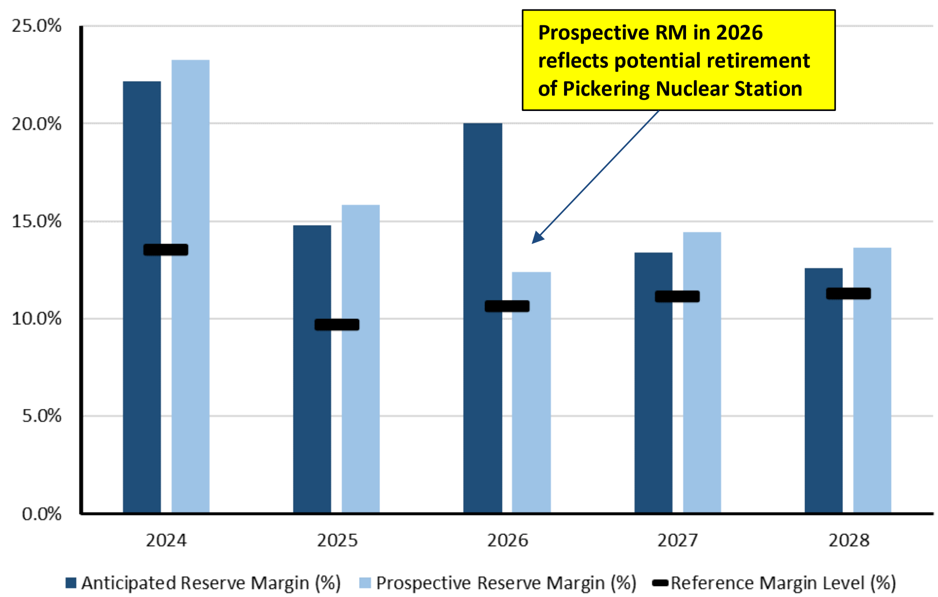

Figure 9: NPCC-Ontario Five-Year Planning Reserve Margin

As reported in the two prior *LTRAs*, the main drivers for Ontario's projected decline in capacity are planned retirements and lengthy outages for nuclear units undergoing refurbishment. In September 2022, Ontario's Ministry of Energy announced that it was supporting a plan by Ontario Power Generation to extend operation of Pickering Nuclear Generating Station beyond its planned retirement in 2025 through September 2026.

Recently, the Canadian federal government released a draft of clean electricity regulations; IESO is undertaking analysis to help inform the final draft.

SPP

Since the *2022 LTRA*, SPP's projected reserve margins for this assessment period have declined while the RMLs needed for maintaining reliability have risen. Consequently, SPP's surplus capacity over the next five years has fallen sharply. See **Figure 10**.

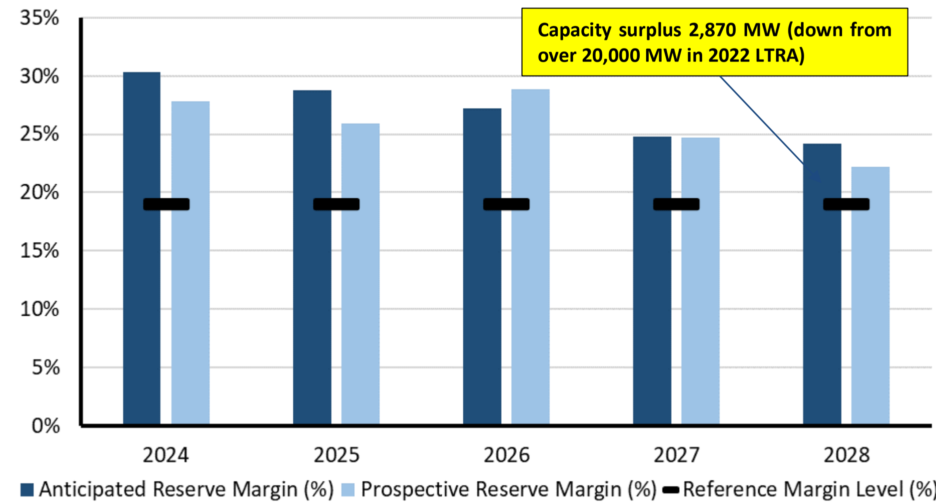

Figure 10: SPP Five-Year Planning Reserve Margin

Lower reserve margins are driven by generation retirements (1,500 MW since the *2022 LTRA*) and rising peak demand forecasts. Winter forecasted peak demand growth is outpacing summer (winter CAGR 1.24% vs. summer CAGR 1.12%). SPP raised the RML from 16% to 19% beginning in 2023 based on its most recent biennial LOLE study. The previous RML was not sufficient to meet 0.1 day/year LOLE. LSEs in SPP must procure resources to cover a higher RML.

SPP's sizeable but diminishing reserve margins do not account for planned, forced, or maintenance generator outages. Instead, they reflect the full availability of accredited capacity. Additionally, anticipated resources do not reflect derates based on real-time operational impacts. Capacity and energy shortfalls can occur in SPP when high demand coincides with low-wind or above-normal generator outages.

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Texas RE-ERCOT

Generation resources, primarily solar PV, continue to be added to the grid in Texas in large quantities, increasing ARMs but also elevating concerns of energy risks that result from the variability of these resources and the potential for delays in implementation. Rising demand forecasts adds to energy risks as the risk of shortfalls increases during warm season evening hours when demand remains high while solar output is diminished. Sufficient levels of dispatchable generation and demand-side resources are needed. New and proposed EPA rules heighten the risk of thermal unit retirements before solutions are in place for reliability (e.g., transmission, resource adequacy).

Extreme winter weather (e.g., Winter Storm Uri in February 2021) remains a serious concern, warranting continued efforts ensure adequate resources are available and capable of performing in severe conditions to meet extreme demand. Market reforms and reliability initiatives that have been instituted are expected to reduce risks in extreme weather. These include the performance credit mechanism (PCM) incentives to generators for commitments to produce during tight grid conditions and to the firm fuel supply service (FFSS), which provides resources that are supported by on-site fuel or have off-site natural gas storage that meets qualification criteria.

U.S. Western Interconnection (WECC-CA/MX, WECC-NW, WECC-SW)

Throughout the U.S. assessment areas in WECC, both demand and resource variability are projected to continue as the resource mix transitions and DERs grow. In normal conditions, the expected demand and resource variability is balanced across the area as excess supply from one part of the system is delivered through the transmission network to places where demand is higher than supply. However, more extreme summer temperatures that stress large portions of the Interconnection reduce the availability of excess supply for transfer while also reducing the transmission network's ability to transfer the excess.

Energy Risks in WECC-CA/MX

Resource additions, generator uprating, and service extensions in WECC-CA/MX have helped alleviate near-term capacity risks and lower the area's reliance on imports to meet high demand. ARMs continue to rise from levels reported in NERC's previous LTRAs as new resources (primarily solar PV), hybrid-solar PV, and BESS are added (see **Figure 11**). Anticipated resources are sufficient to meet forecasted peak demand throughout this assessment period.

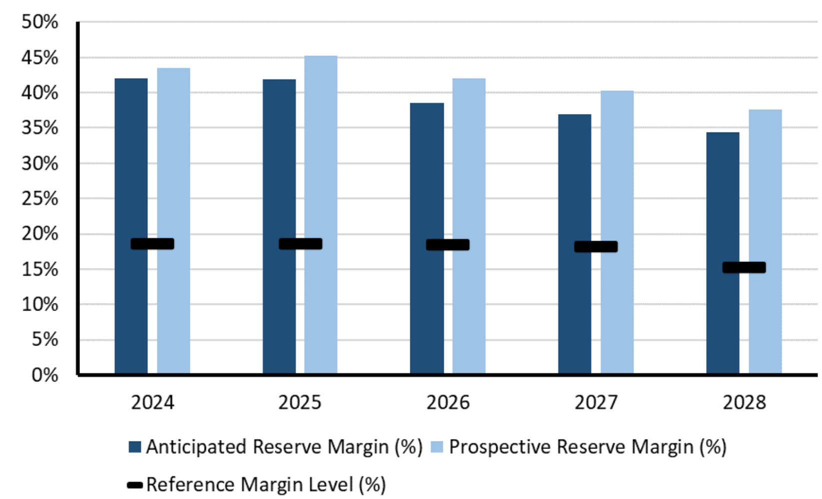

Figure 11: WECC-CA/MX Five-Year Planning Reserve Margin

Despite the on-peak capacity surplus, energy risks persist and are projected to increase after 2024 as additional thermal generators are planned for retirement. **Table 1** provides the results of probabilistic analysis performed by WECC that identify the risks of unserved energy and load-loss. Comparing the results of WECC's probabilistic analysis performed in 2022 with the current results indicates that risks of unserved energy and load loss in 2024 have fallen to negligible levels. However, loss-of-load and unserved energy risks emerge in the July–September period of 2026 and are primarily associated with extreme weather conditions.

Table 1: CA/MX ProbA Base Case Summary of Results

	2024*	2024	2026
EUE (MWh)	37,305	-	11,731
EUE (PPM)	136	-	43
LOLH (hours per Year)	0.721	-	0.227
Operable On-Peak Margin	30.3%	30.7%	27.5%

** Results from the 2022 ProbA are provided for comparison and are trending with the current results.*

WECC-CA/MX remains dependent on electricity imports to manage periods of extreme electricity demand or low resource output. Energy shortfall risks are associated with periods of above-normal demand that coincide with lower-than-normal resource output that is most pronounced during summer late-afternoon and evening periods when solar PV output is lower (see Figure 12). Heat events that span a wide area and reduce the availability of electricity imports into California are likely to continue to raise concerns and increase the risk of energy shortfalls.

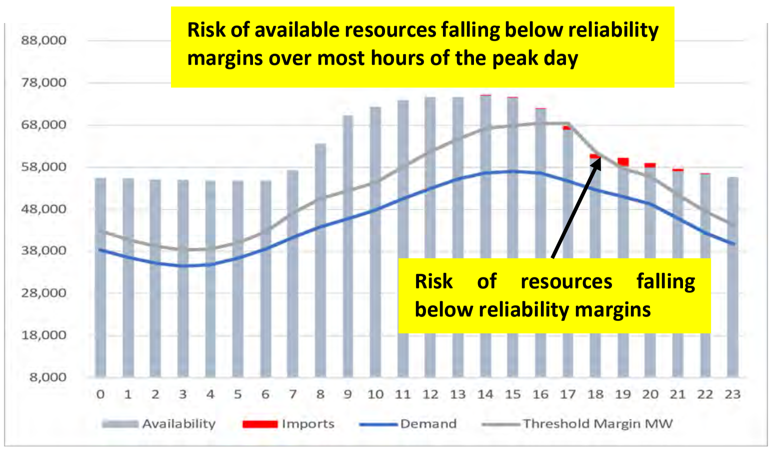

Figure 12: Hourly Resources and Demand Modeled for 2026 Summer Peak Day in WECC-CA/MX (Source: WECC)

Energy Risks in WECC-BC

Forecasted peak demand growth is causing a decline in reserve margins and reduced surplus capacity for managing periods of above-normal demand. British Columbia (WECC-BC) is a winter-peaking area that experiences peak demand typically in the early evening (6:00 p.m.) hours of December. Peak demand is forecasted to grow from 11.6 GW in 2023 to 12.9 GW in 2033. Anticipated resources are sufficient to meet forecasted peak demand throughout this assessment period. See Figure 13.

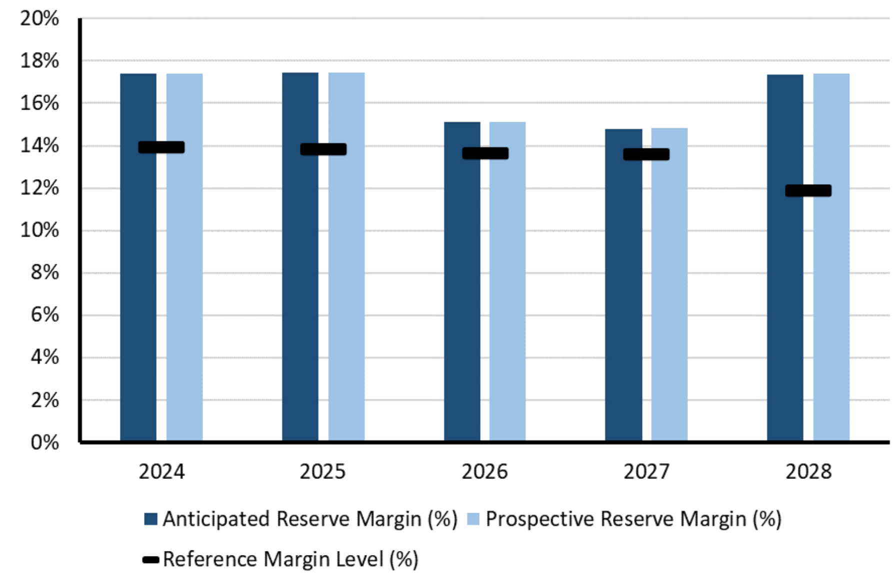

Figure 13: WECC-BC Five-Year Planning Reserve Margin

Energy shortfall risks in the WECC-BC assessment area are associated with extreme weather conditions that cause periods of above-normal demand to coincide with lower-than-normal resource output. Figure 14 shows WECC's modeling of electricity supply and demand for the representative peak day in December 2026. ProbA results show little energy risk in 2024. However, load-loss and unserved energy risks increase in 2026 as forecasted demand increases and natural-gas-fired generation retires.

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Figure 14: WECC-BC Hourly Resources and Demand Modeled 2026 Winter Peak Day (Source: WECC)

Energy Risks in WECC-NW and WECC-SW

Like WECC-CA/MX, the U.S. Northwest (WECC-NW) and U.S. Southwest (WECC-SW) are projected to be at risk of resource shortfalls during extreme summer weather conditions after 2024. Although the assessment areas are projected to have sufficient capacity to meet forecasted peak demand throughout this assessment period, dispatchable generation declines as generators retire in 2026 and later. The resulting resource mix is more variable, causing a risk of supply shortfalls during extreme summer conditions in WECC's probabilistic analysis (see **Table 2** and **Table 3**).

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Table 2: WECC-NW ProbA Base Case Summary of Results

	2024*	2024	2026
EUE (MWh)	1,722	-	8,101
EUE (PPM)	4	-	21
LOLH (hours per Year)	0.036	-	0.132
Operable On-Peak Margin	25.8%	37.6%	32.5%

**Results from the 2022 ProbA are provided for comparison and trending with current results*

Table 3: WECC-SW ProbA Base Case Summary of Results

	2024*	2024	2026
EUE (MWh)	84	-	818
EUE (PPM)	1	-	6
LOLH (hours per Year)	0.003	-	0.031
Operable On-Peak Margin	28.1%	18.3%	18.4%

**Results from the 2022 ProbA are provided for comparison and trending with current results*

WECC-NW and WECC-SW areas' loss-of-load and unserved energy risks are associated with extreme weather events and concentrated in the late afternoon and early evening hours during the July–September period. See the **Regional Assessments Dashboards** pages for WECC's modeling of electricity supply and demand for the peak days in these areas. Modeling shows that imported electricity supplies are needed in all U.S. Western Interconnection assessment areas to meet forecasted demand during summer peak demand days, raising concerns of supplies during a wide-area heat event.

Normal Risk Area Details

All other assessment areas (see **Figure 1**) are assessed as normal risk. In these areas, resource adequacy criteria are met, and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance). See **Normal Risk Areas** for additional information.

Resource and Demand Projections

The **Capacity and Energy Risk Assessment** section in this *LTRA* is a forward-looking snapshot of resource adequacy that is tied to industry forecasts of electricity supplies, demand, and transmission development. Later sections in this report describe important trends in each of these areas. The future electricity supply will come from a resource mix that is more variable, weather dependent, and reliant on natural gas for fuel without a broad coordination and careful attention to the pace of change. Future electricity demand is being shaped by many factors that collectively influence peak demand forecast levels, peak seasons, and hourly profiles. Peak demand and energy forecasts are projected to rise during this *2023 LTRA* assessment period at their highest rates in recent years, providing another sign of acceleration in the broader energy transition. In summary and taken all together, the energy transition has growing potential to threaten resource and energy adequacy without broad coordination and careful attention to the pace of change.

Reducing Resource Capacity and Energy Risk

The risk of electricity supply shortfalls in the assessment period can be lowered through the concerted efforts of resource and system planning stakeholders. The actions taken in electricity markets and regulatory jurisdictions with the improving trends noted previously provide examples of what can work: obtaining additional firm resources to meet resource adequacy targets, delaying generation retirements when reliability needs dictate, and using capacity targets and energy risk metrics based on better resource and demand models. Specific and actionable recommendations are contained in the **Recommendations: Details** section of this report.

Resource Mix Changes

Findings: Wind, solar PV, and hybrid generation are projected to be the primary additions to the resource mix over this 10-year assessment period, leading the continued energy transition as older thermal generators retire. Maintaining a reliable BPS throughout the transition requires unwavering attention to ensure the resource mix satisfies capacity, energy, and ERS needs under designed conditions. It will also require significant planning and development of the interconnected transmission system to have a deliverable electricity supply from new resources to loads and the ability to withstand system contingencies and disturbances.

The addition of VERs (primarily wind and solar PV) and the retirement of conventional generation are fundamentally changing how the BPS is planned and operated. Planning and operating the grid must increasingly account for different characteristics and performance in electricity resources. Maintaining reliability will require industry and regulators to carefully manage the pace of change and take steps to ensure that ERSs continue to be provided as generators retire.

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Generation Resource Mix in 2023 vs. 2033

The total capacity of traditional baseload generation fuel types will continue to decline as older generators retire and are replaced with new generation that has different capacity characteristics. Figure 15 shows how the current (**black)** resource mix (on-peak capacity) compares to the projection of the future on-peak capacity in 2033 (**gray)** if expected retirements occur and all projected Tier 1 resources are added. With these assumptions, the change in resource mix is gradual. Over this 10-year assessment period, Thermal generation, which consists mainly of natural-gas-fired, coal-fired, nuclear plants, and hydroelectric power are projected to continue providing 85% or more of the BPS on-peak generation capacity. As discussed below, the pace of change in the resource mix is likely to be influenced by the addition of more wind, solar PV, battery resources, and the retirement of more fossil-fired generators.

On-peak resource capacity reflects the expected capacity that the resource type will provide at the hour of peak demand. Because the electrical output of wind and solar PV VERs depends on weather and light conditions, on-peak capacity contributions are less than nameplate installed capacity. Wind on-peak capacity contribution contributions range between a low of 10% of installed capacity to over 25% in some assessment areas. Solar PV on-peak contributions are 0% in most areas during winter when the peak occurs in low light. In summer, some areas, such as ERCOT and parts of the U.S. West, can expect the solar PV contribution to reach over 80% of installed capacity at peak demand hour. High expected capacity contributions from VERs help increase Planning Reserve Margins but also increase the exposure of the system to energy risks from weather or environmental conditions that impact VER output. Supplementary tables on NERC's Reliability Assessments[27] web page provide on-peak capacity contributions of existing wind and solar PV resources in each assessment area.

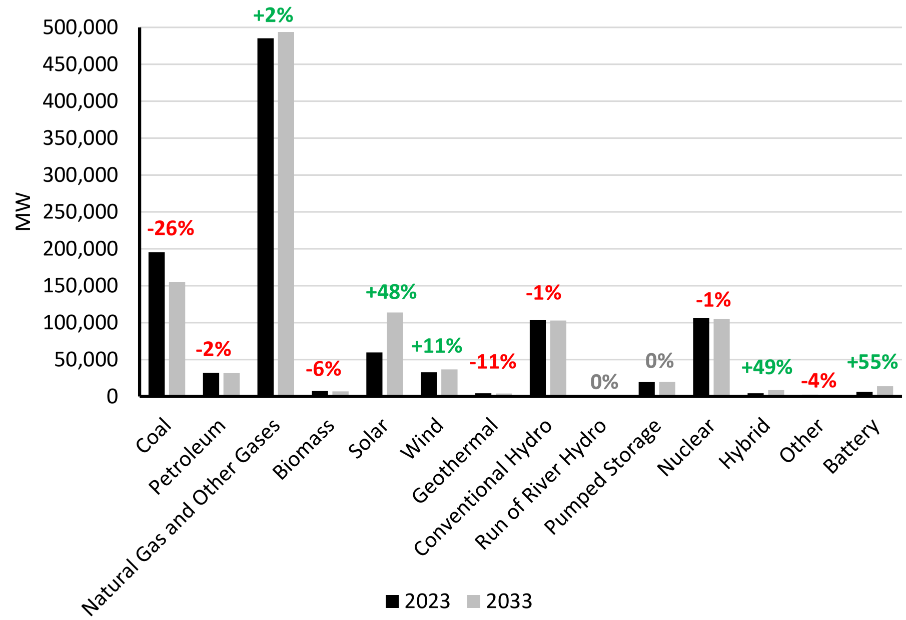

Figure 15: 2023 vs. 2033 BPS On-Peak Capacity by Fuel Type with Tier 1 Resources

[27] Reliability Assessments (nerc.com)

Capacity Additions

New generation is added to the BPS through the area interconnection planning processes. Wind, solar PV, and natural-gas-fired generation are the overwhelmingly predominant generation types planned for addition to the BPS. A summary of generation resources in the interconnection planning queues is shown in Figure 16. Capacity in planning has grown since the *2022 LTRA* by over 9 GW (2%).

In general, Tier 1 resources are in the final stages for connection while Tier 2 resources are further from completion. Supply chain issues, planning and siting challenges, and business or economic factors can cause projects to be delayed or withdrawn.

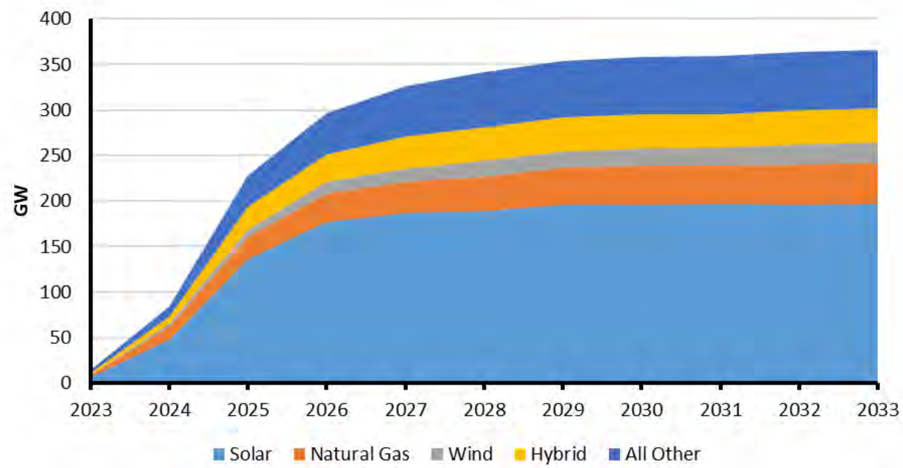

Figure 16: Tier 1 and 2 Planned Resources Projected Through 2033

Solar PV and wind capacity, both existing and planned, vary widely by area. Figure 17 and Figure 18 show current solar PV and wind installed capacities and the capacity in the planning process through 2033 for assessment areas with significant amounts. In addition, hybrid generation resources, which combine energy storage with a generating plant (i.e., a wind or solar farm), are connecting to the grid in parts of North America, and many more projects are in BPS planning processes.

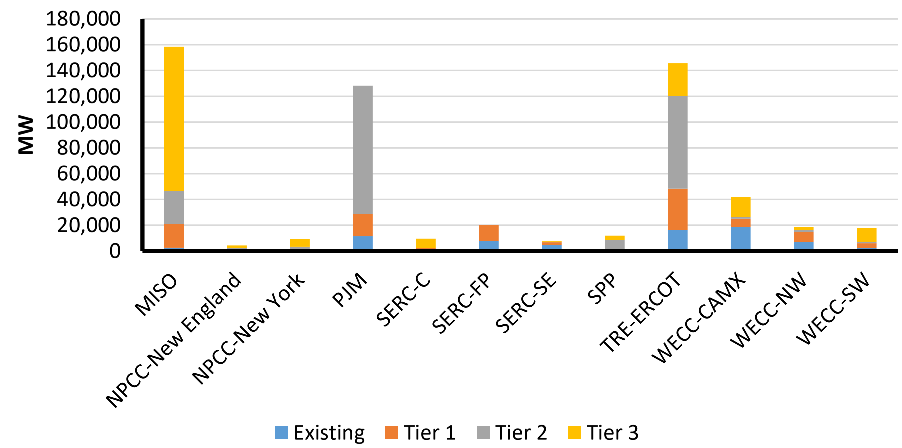

Figure 17: Solar Capacity Existing and Planned through 2033

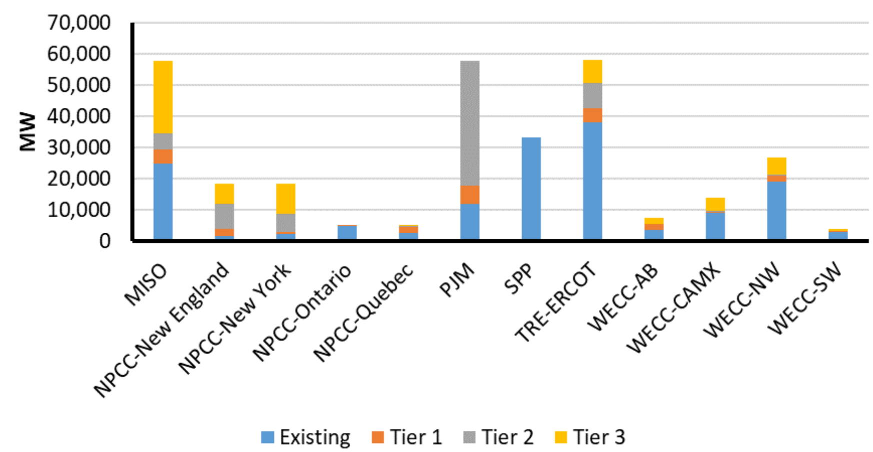

Figure 18: Wind Capacity Existing and Planned through 2033

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Battery Resources

As the BPS increases the share of energy provided by VERs, the ability to provide energy by battery energy storage systems (BESS) or hybrid-solar PV and wind plants is increasingly important. While currently installed capacity totals 7,172 MW, over 260,000 MW of BESS are in planning. Figure 19 shows the nameplate capacity of BESS resources currently in operation and in planning for connection to the BPS through 2033.

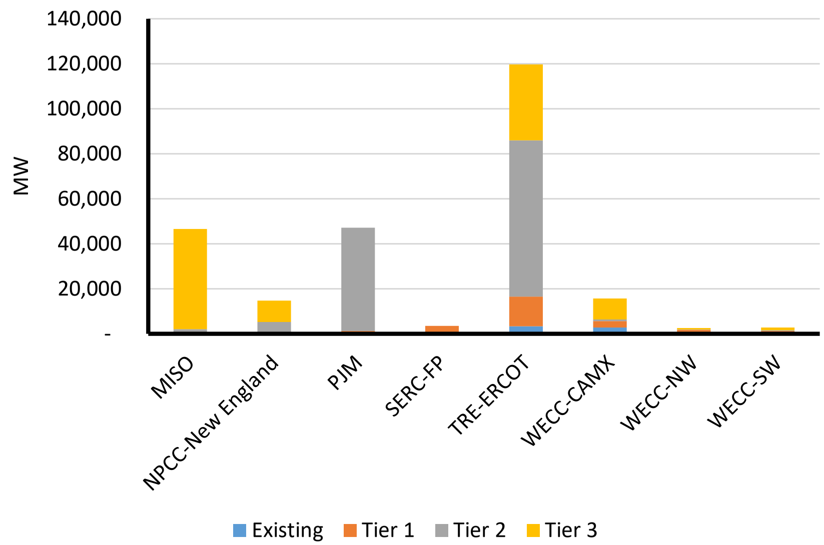

Figure 19: Battery Resource Capacity Existing and Planned through 2033

BESS have the potential to offer reliability benefits for the grid, such as helping to offset the variability and uncertainty of IBRs. BESS are, however, a relatively new type of grid resource with unique operating characteristics. The joint *NERC-WECC Staff Report:* 2022 California Battery Energy Storage System Disturbances[28] report highlights an event when a BESS, like some other IBRs, failed to properly ride through a normal system fault. This indicates that BESS must be included in the currently underway strategies to address IBR performance issues.

Planners and operators are focused on requirements to model, study, and operate the BPS with increased BESS and hybrid resources. In ERCOT and many other areas, BESS are used primarily for ancillary services, such as frequency response. In parts of the Western Interconnection with high solar PV penetration, BESS often reduce ramping requirements on other resources by discharging in late afternoon as solar PV output rapidly declines. The majority of currently installed BESS does not count towards peak hour contribution (i.e., they are not expected to discharge at peak demand). Wholesale markets, programs, and procedures are evolving to effectively integrate these new resources and realize their reliability benefits.

Solar PV Distributed Energy Resource Growth

Behind-the-meter (BTM) solar PV generators are solar PV resources connected on the distribution system, such as residential rooftop solar systems. The rapid growth of BTM solar PV continues with cumulative levels expected to reach almost 89 GW by the end of this 10-year assessment period (up from 80 GW reported in the *2022 LTRA*, an increase of 11.3%), see Figure 20.

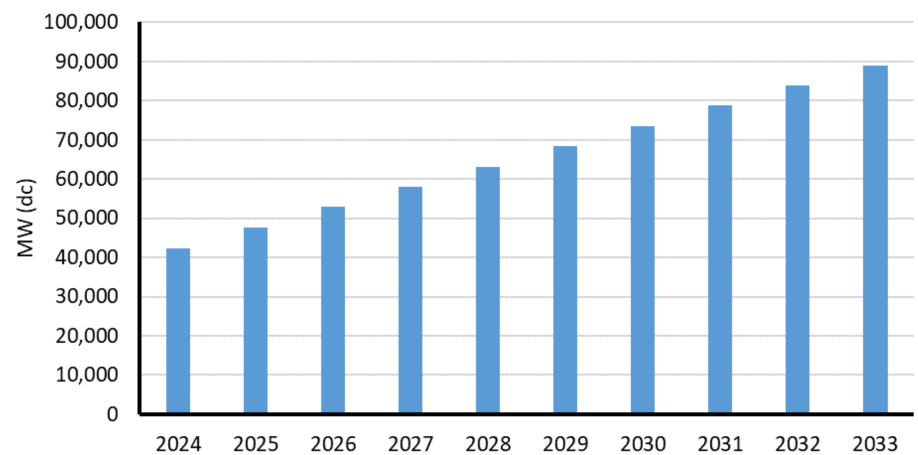

Figure 20: Cumulative Solar PV DER Capacity in All Assessment Areas

[28] NERC–WECC *2022 California Battery Energy Storage System Disturbances*

BTM solar PV generators, like grid-connected solar PV, are also VERs. In large penetrations, their predictable change in output from the time of day contributes to steep ramps in demand. As the Sun sets and output diminishes, grid resources must make up for the decrease in solar generation and increase in demand that was being served. The opposite ramp occurs during morning hours; it may be less impactful to reliability but can be challenging for grid-connected generator scheduling and dispatch. Figure 21 shows the current and projected BTM solar PV by area through 2033.

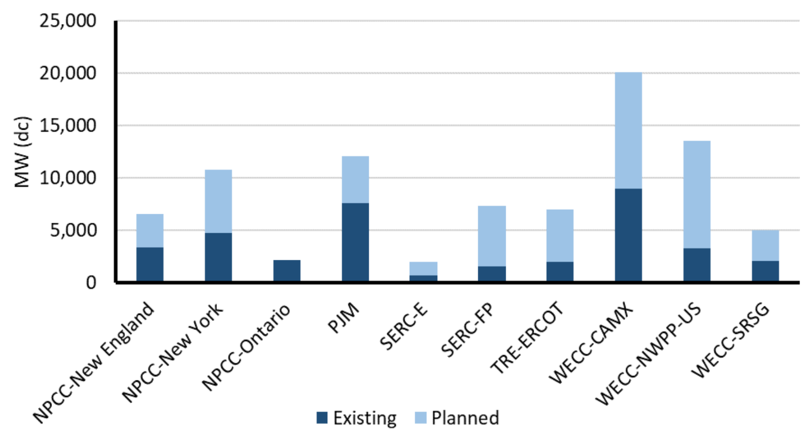

Figure 21: Solar PV DER Capacity Existing and Planned through 2033

Generation Retirements

The total capacity of traditional baseload generation fuel-types will continue to decline as older generators retire. Generators become confirmed for retirement according to various processes in place in the Interconnections, such as regional planning tariffs in the wholesale electricity market areas or the integrated resource planning process in vertically integrated states. Properly designed mechanisms can prevent generators from retiring before planners can study and address reliability issues that could occur.

Currently, over 83 GW of fossil-fired and nuclear generating capacity is retiring over this assessment period (see Figure 22). This capacity includes generators that are confirmed for retirement through retirement planning processes or that have indicated plans to retire to an ISO/RTO or planning coordinator.

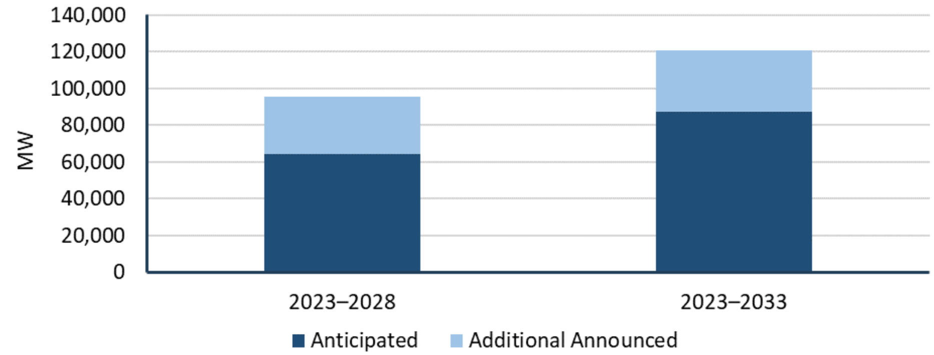

Figure 22: Projected Generation Retirement Capacity Through 2033

Additional fossil-fired generator retirements are expected, leading to a loss of existing capacity more than the reported 83 GW capacity. Generator Owners often announce plans to retire generator units before initiating the interconnection planning process, and the announced plans or timing may be subject to change before the retirement is confirmed. Figure 23 shows the total capacity of reported retirements (i.e., reported to ISOs/RTOs and planning entities) as well as owner-announced, unconfirmed retirements of fossil-fueled and nuclear generators across the BPS over the next 10 years in each assessment area.[29]

[29] Confirmed generator retirements are reported to NERC by each assessment area in this *2023 LTRA* development process. NERC obtained data on announced, unconfirmed generator retirements from Energy Ventures Analysis, Inc. and from each assessment area. Some sources of information on announced generator retirements include EIA 860 data, trade press, and utility integrated resource plans.

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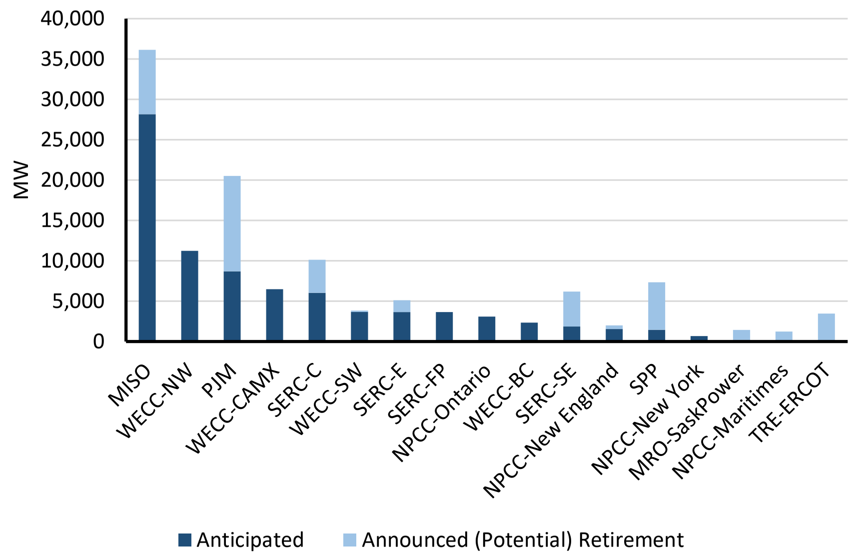
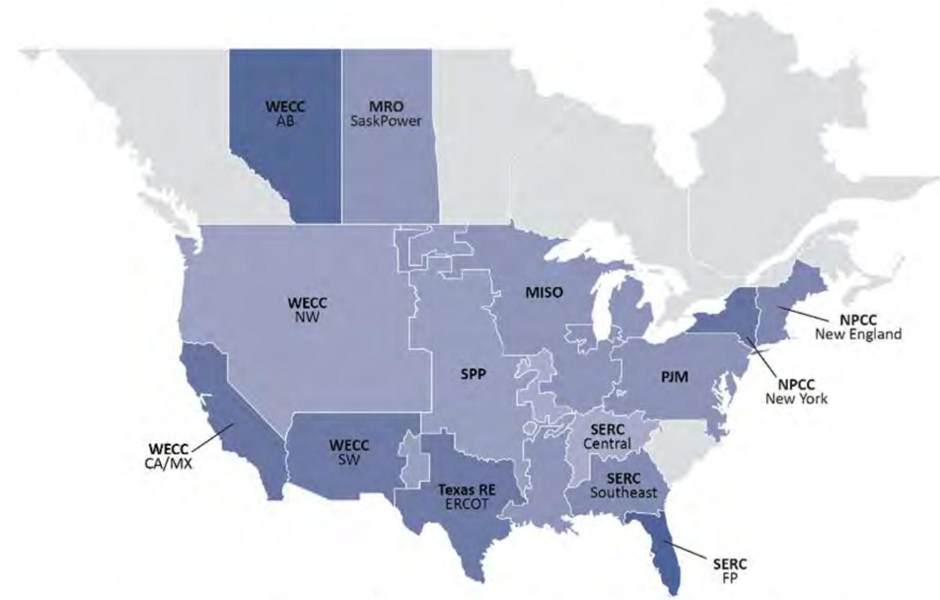


Figure 23: Projected Retiring Nuclear and Fossil Generation Capacity 2023–2033

Throughout this *2023 LTRA*, anticipated generation retirements have been removed from each assessment area's anticipated and prospective resources while unconfirmed, announced generator retirements have been removed from prospective resources only. See Page 32 for information about new policy and regulations that affect future generator retirements.

Natural Gas Fuel Reliance Trends

Natural-gas-fired generators are and will remain a critical resource for BPS reliability in many areas over the 10-year assessment period, especially during winter. **Figure 24** shows the total contribution of natural gas to the winter resource mix; in the figure, areas with more natural gas are darker blue. See **Table 4** for the specific values for each area. These generators provide many necessary reliability attributes that are exiting the system as traditional generators retire and inverter-based renewable resources take their place in the resource mix. Natural-gas-fired generators are dispatchable and provide the ERSs of inertia, frequency response, and ramping flexibility. In winter, when peak demand in most areas occurs during early morning hours, natural-gas-fired generation is at its highest contribution to the resource mix in many areas. Severe winter weather events in 2021 and 2022 provided stark evidence of the critical nature of natural gas as a generator fuel and the importance of secure supplies during times of extreme electricity demand. While more work remains, several important steps to mitigate the risks of natural gas supply interruption have been taken in the aftermath of Winter Storm Uri in February 2021.



All other assessment areas have less than 35% natural gas fired generation contribution to winter resource mix.

Figure 24: Natural-Gas-Fired Generation Contributions to 2023–2024 Winter Generation Mix

For example, ERCOT has developed an FFSS whereby capacity with qualifying on-site fuel or off-site natural and other gas storage can be procured by LSEs through a competitive procurement process with a single clearing price. ERCOT is also working to implement a newly adopted Public Utility Commission of Texas PCM rule that permits generation resources within ERCOT to commit to producing more energy during the tightest grid conditions of the year and sell credits to LSEs. Convened in response to Winter Storm Uri report, the North American Energy Standards Board Gas Electric Harmonization Forum has completed its work and published 20 recommendations that are directed at harmonizing across and improving coordination between natural gas supply/transport and BES operations.

Table 4: Total Natural Gas Peak Winter Capacity

Assessment Area	Total in GW	Contribution to Total Winter Resource Mix
MISO	67.5	46%
MRO-SaskPower	2.1	46%
NPCC-New England	17.3	54%
NPCC-New York	24.5	66%
PJM	84.9	47%
SERC-Central	22.7	44%
SERC-Florida Peninsula	50.6	79%
SERC-Southeast	31.5	51%
SPP	27.4	41%
Texas RE-ERCOT	54.2	62%
WECC-AB	11.4	75%
WECC-CA/MX	39.9	65%
WECC-NW	31.0	39%
WECC-SW	18.2	62%

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Supply Chain Concerns

New resource additions are critical to maintaining resource adequacy criteria and reducing energy shortfall risk under more extreme conditions. Supply chain issues have impacted resource projects over the past year. Lingering pandemic-related issues, competition for scarce resources, and geopolitical matters are likely to continue affecting generation and transmission projects. Supply chain issues are also making the following more difficult: the scheduling of maintenance outages, planning for when new resources will come online when line upgrades can be completed, and the ability to connect new customers. Grid planners and system operators need to continue accounting for uncertainties in resource availability.

Reliability Implications

The addition of variable resources, primarily wind and solar PV, and the retirement of conventional generation are fundamentally changing how the BPS is planned and operated. With electricity supplies coming increasingly from VERs and natural-gas-fired generators, there is a growing risk that supplies can fall short of demand during some periods. Geographically diverse wind and solar resources and loads can help reduce these risks, but they require robust transmission networks, comprehensive energy and transfer capability analysis, and effective operating procedures and market mechanisms. Specific and actionable recommendations are contained in the **Recommendations: Details** section of this report.

New Policy and Regulations Affecting Future Generator Retirements

Coal-fired generating capacity has declined significantly over the past decade, falling from over 280 GW in 2014 to the current level of 195 GW.[30] The U.S. Energy Information Administration models project this trend to steadily continue over the next decade and beyond (**Figure A**).[31] Furthermore, many of these modeled projections exceed the announced generator retirements as shown in **Figure 22**, heightening concerns that generation is at risk of retirement before reliability solutions are in place.

Future fossil-fired generator retirements will be influenced by a range of factors, such as environmental policies, incentives for new renewable generation, operating economics, and technology developments. The Inflation Reduction Act contains climate and energy provisions, including tax credits and expenditures that will influence the BPS resource mix by supporting renewable resources, energy storage, and nuclear generation. The Inflation Reduction Act will accelerate the energy resource transformation, including additional fossil-fired generator retirements. While subject to change in the rulemaking process, proposed EPA regulations under Clean Air Act Section 111 to address carbon emissions from fossil-fired generators would result in an increase in the rate of generator retirements.[32] Recent analysis and models that incorporate the potential effects of these new policies and proposed regulations illustrate projections for coal-fired generator retirements in excess of currently announced retirements (**Figure B**).[33] Natural-gas-fired generator retirements are also expected to increase under proposed new EPA regulations as Generator Owners face added costs of emissions-reducing technologies. Technologies for enabling generators to operate to the new standards are also being developed.

Additional generator retirements beyond currently expected levels have the potential to exacerbate energy, capacity, or ERS issues. See the **Capacity and Energy Assessment** and **Reliability Implications** in the preceding sections of this *2023 LTRA*. Close coordination will be needed among regulators, policymakers, and industry to ensure that sufficient electricity resources will be available to meet rising demand and grid reliability needs. Regulations that have the potential to accelerate generator retirements or restrict operations must have sufficient flexibility and provisions to support grid reliability.

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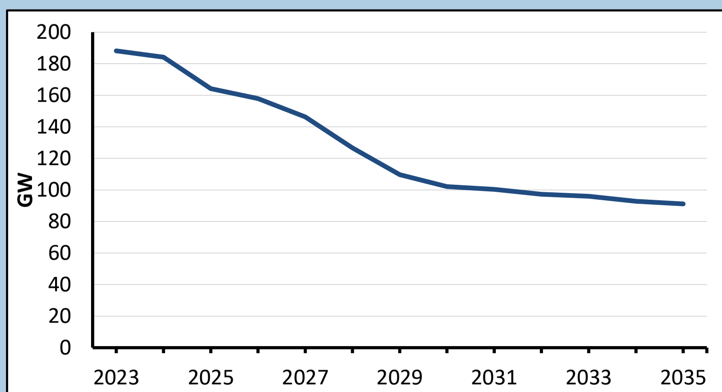

Figure A: BPS Coal-Fired Generation Capacity–United States Only

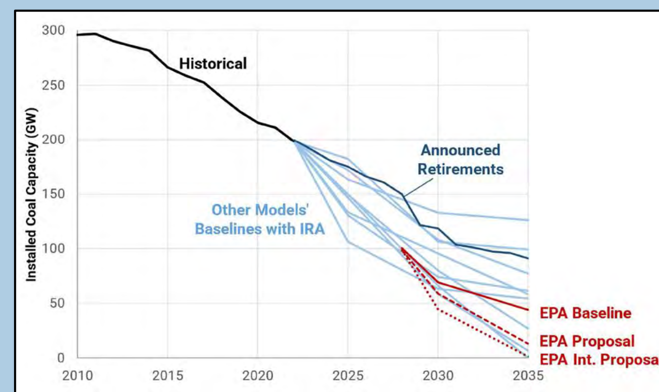

Figure B: BPS Coal-Fired Generation Capacity in Various Scenario Models–United States Only

[30] NERC 2014 LTRA
[31] EIA Annual Energy Outlook 2023
[32] EPA Rulemaking Docket New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of Affordable Clean Energy Rule
[33] *Source: Comment submitted by Electric Power Research Institute (EPRI), Docket EPA-HQ-OAR-2023-072, New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule:* EPRI Comments on U.S. EPA Rule, Docket ID EPA-HQ-OAR-2023-072

Demand Trends and Implications

Finding: Electricity peak demand and net energy growth rates in North America are increasing more rapidly than at any point in the past three decades. Concentrated growth and the emergence of new types of loads are occurring in some areas. These growth trends bring additional challenges for resource and transmission adequacy. Planners and operators can prepare by considering robust demand and energy scenarios, carefully monitoring and refining demand forecasts, and developing operational tools for peak load management.

Demand and Energy Projections

Electricity peak demand and energy growth forecasts over the 10-year assessment period are higher than at any point in the past decade. The aggregated assessment area summer peak demand forecast is expected to rise by over 79 GW, and aggregated winter peak demand forecasts are increasing by nearly 91 GW. Furthermore, the growth rates of forecasted peak demand and energy have risen sharply since the *2022 LTRA*, reversing a decades-long trend of falling or flat growth rates. See **Figure 25** for seasonal peak demand growth over the current and prior assessment periods and **Figure 26** for net energy growth. More information is available in the **Regional Assessments Dashboards** section.

Electrification and Demand Growth

Electrification and projections for EV growth over this assessment period are components of the demand and energy estimates provided by each assessment area. Since the *2022 LTRA*, peak season CAGR has risen in all assessment areas except two: (WECC-AB winter CAGR fell slightly from 0.6% to 0.56% while ERCOT's summer CAGR was unchanged at 1.01%). Rising peak demand forecasts are contributing to the lower reserve margins projected for nearly all assessment areas.

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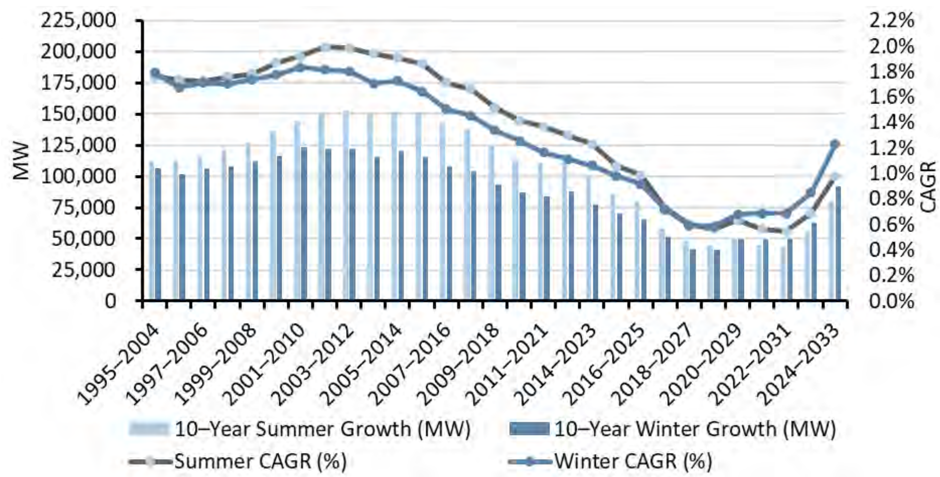

Figure 25: The 10-Year Summer and Winter Peak Demand Growth and Rate Trends

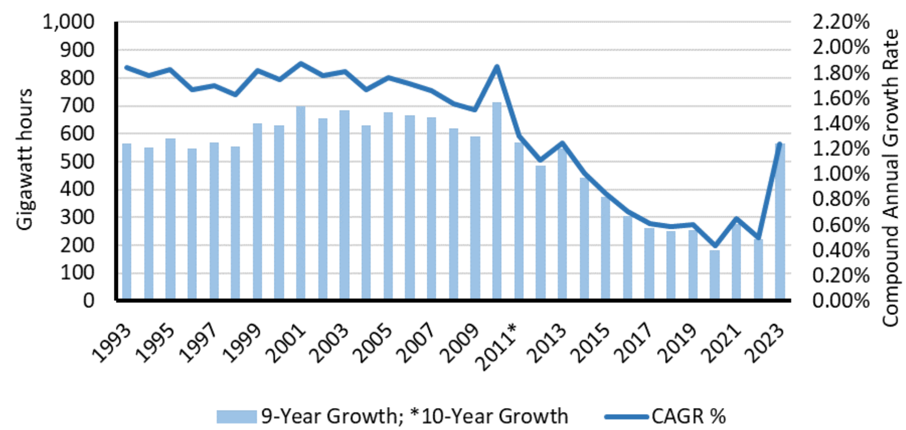

Figure 26: Net Energy for Load Growth and Rate Projection Trends

Peak Season Transition

Some of the sharpest peak demand forecast increases and growth rates can be seen in winter seasons as electrification in heating systems and transportation influence forecasts. Dual-peaking or changing from summer to winter peaking is anticipated in several areas, including the U.S. Southeast and Northeast. Electrification of heating systems and the anticipated growth of EVs (which are expected to charge overnight and coincide with periods of electricity demand for heating) are driving factors. Such changes have wide-ranging implications for how the grid and resources are planned and operated. For example, resource output can be significantly different in winter, requiring the focus of resource adequacy processes to change. The following are the areas that anticipate a change from a summer-peaking system to a winter-peaking (or dual-season peaking) system and the approximate year of the transition:

- NPCC-New England (mid 2030s)
- NPCC-New York (mid 2030s)
- NPCC-Ontario (2036)

In the U.S. Southeast, SERC-Central and SERC-East became dual-peaking systems in recent years. SERC-Southeast recently began experiencing slightly higher peak demand in winter compared to summer.

Reliability Implications

Demand and energy growth projections in this assessment period provide both challenges and opportunities for electric grid reliability. Planning for resource and transmission adequacy requires accurate long-term forecasting, but future demand and energy use will be influenced by many factors, including the economy, energy policies, technology development, weather, and consumer preferences. Changing patterns in electricity use, load behavior, and DER performance affect the accuracy of operational load forecasts that are essential to grid operators. Large flexible loads and demand-side management programs hold promise for peak load management capabilities that can reduce the risk of firm load interruption.

Anticipating electrification, EV adoption, and the impacts of energy transition programs on future demand and energy needs will require even more focus for planners and operators. Peak demand forecast changes in the past year had noticeable effect on resource adequacy for many areas. A confluence of factors (economic, energy policies, technology development, and consumer preferences) has the potential to fuel continued growth.

Transmission Development Trends and Implications

Finding: The amount of BPS transmission projects reported to NERC as under construction or in planning for construction over the next 10 years has increased, indicating an overall increase in transmission development. Siting and permitting challenges continue to inflict delays in transmission expansion planning. Regional transmission planning processes are adapting to manage energy transition, but impediments to transmission development remain.

Transmission Projects

This year's cumulative level of 18,675 miles of transmission (>100 kV) in construction or stages of development for the next 10 years (**Figure 27**) is higher than averages of the past five years of NERC's LTRA reporting on average (16,970 miles of transmission planning projects in each 10-year period published in the last five LTRAs).

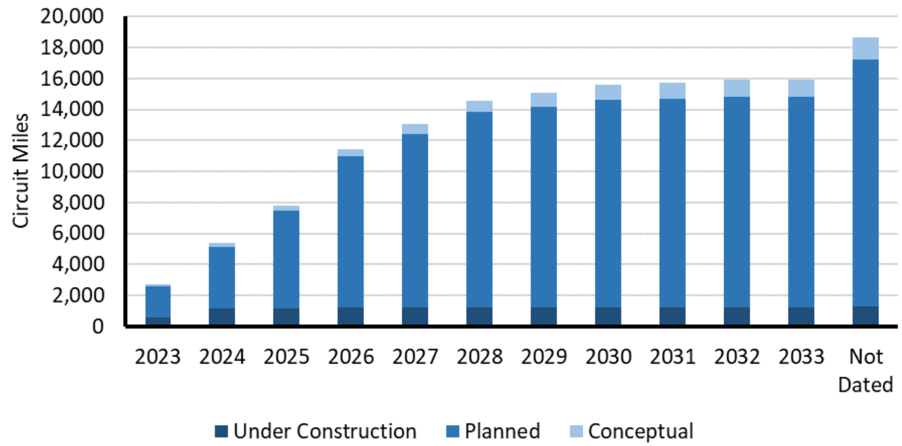

Figure 27: Future Transmission Circuit Miles >100 kV by Project Status

New transmission projects are being driven to support new generation and enhance reliability. **Figure 28** shows the percentage of future transmission circuit miles by primary driver. Most projects reported this year have been initiated for the purpose of grid reliability, which generally includes transmission projects that are needed to ensure that the BPS operates within established limits and design criteria. Some substantial new projects to integrate renewable generation are also in development or are entering planning processes. The NPCC-New York and PJM assessment areas have begun transmission planning to support interconnection of offshore wind resources. See the transmission summaries at the end of each assessment area's pages (see **Regional Assessments Dashboards)** for current transmission development details.

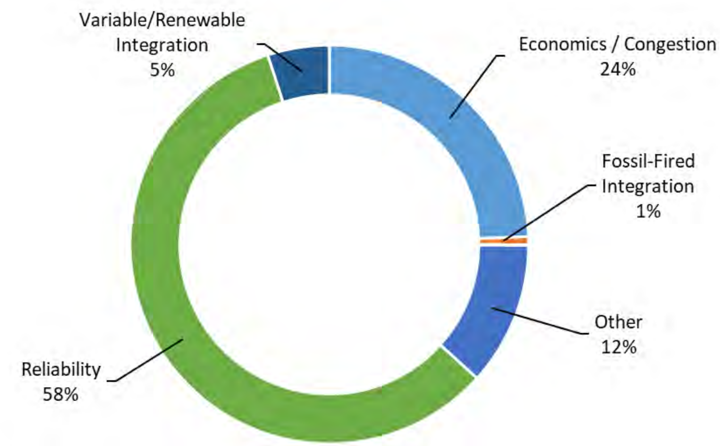

Figure 28: Future Transmission Circuit Miles by Primary Driver

Transmission development in some areas is hampered by siting and permitting challenges. Of the over 900 projects that are under construction or in planning for over the next 10 years, 87 projects are currently delayed from their expected in-service dates. Siting and permitting issues are the most common cause for delays (i.e., 46 projects for a total of 940 miles of new transmission). Other reasons for delays include economic or changing needs.

Adapting Transmission Planning Processes

Regional transmission planning and resource interconnection processes are adapting to manage the development needs of the energy transition. Across ISO/RTO organizations, long-term system planning is increasingly evaluating policy-driven projects that would support investment decisions necessary to reach state and province goals. Many are also instituting processing reforms that are aimed at reducing backlogs in generation interconnection queues. See the **Regional Assessments Dashboards** for details on changes and initiatives.

Reliability Implications

Monitoring and managing transmission planning processes is a necessary part of maintaining reliability as the resource mix evolves. Furthermore, the rapidly changing resource mix requires greater access and deliverability of resources, including transmission availability, to maintain reliability. Regional transmission planning processes are adapting to manage the energy transition, but impediments to transmission development remain.

The transmission system is being tested by an ever-evolving risk landscape. Ensuring an adequate transmission system requires system planners to consider the broad range of future resource, demand, environmental, and security conditions. Planning processes need to include analysis of an expanded set of scenarios for normal and extreme events so that owners and operators can develop proactive plans that will reduce the risk of unacceptable performance.

Emerging Issues

While developing this *LTRA*, NERC and the industry considered trends and developments that have the potential to impact the future reliability of the BPS over the next 10 years and beyond. Discussed below are emerging issues and trends not previously covered in this report that have the potential to impact future long-term projections or resource availability and operations.

Cryptocurrency Impacts on Load and Resources

Due to unique characteristics of the operations associated with cryptocurrency mining, potential growth can have a significant effect on demand and resource projections as well as system operations.

Computer operations for cryptocurrency mining are energy intensive, and mining operators can interrupt or scale operations in response to energy costs. ERCOT continues to see a large volume of interconnect requests from cryptocurrency mining: 9 GW have had planning studies approved of 41 GW that are currently requested.

This new category of large flexible loads is leading some areas to update load forecasting methods to capture the flexibility and price-responsiveness of cryptocurrency mining operations. In anticipation of further growth in large flexible loads, ERCOT and its stakeholders are assessing further operational issues that could emerge, such as the effect on system frequency of sudden changes in large flexible loads.

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Blackstart Resources for Restoration in Extreme Conditions

Blackstart generation resources are a critical element of BPS resilience that enables the orderly restoration of grid sections following a blackout. System restoration plans rely on the ability of designated fossil-fuel generators to provide blackstart service.

Recent extreme winter weather has exposed vulnerabilities to generating units and fuel sources that are not adapted to cold temperatures, raising concerns for blackstart unit readiness. The changing resource mix is cause for additional awareness of blackstart capabilities. Currently, few IBRs on the system are capable of grid forming control, one of the necessary components for blackstart resources.

Industry is working to incorporate IBR grid forming technology to address system stability and performance needs, apart from blackstart capabilities. Wholesale markets and resource planners must anticipate the future needs for system restoration services and procure blackstart resources to ensure reliable operations.

Distribution Transformer Supply Chains

The electric industry reports that distribution transformers are in short supply as manufacturer production is unable to keep pace with demand; lead times often exceed two years. Low inventories of replacement distribution transformers could slow restoration efforts following hurricanes and severe storms.[34] A lack of skilled labor for manufacturing transformers is the primary cause of current backlogs. However, access to the grain-oriented electrical steel used in power transformers is the next constraint as the United States has a single producer of grain-oriented electrical steel. New efficiency standards for distribution transformers proposed by the U.S. DOE could further exacerbate the transformer supply shortages by adding requirements that manufacturers are not currently set up to handle.[35]

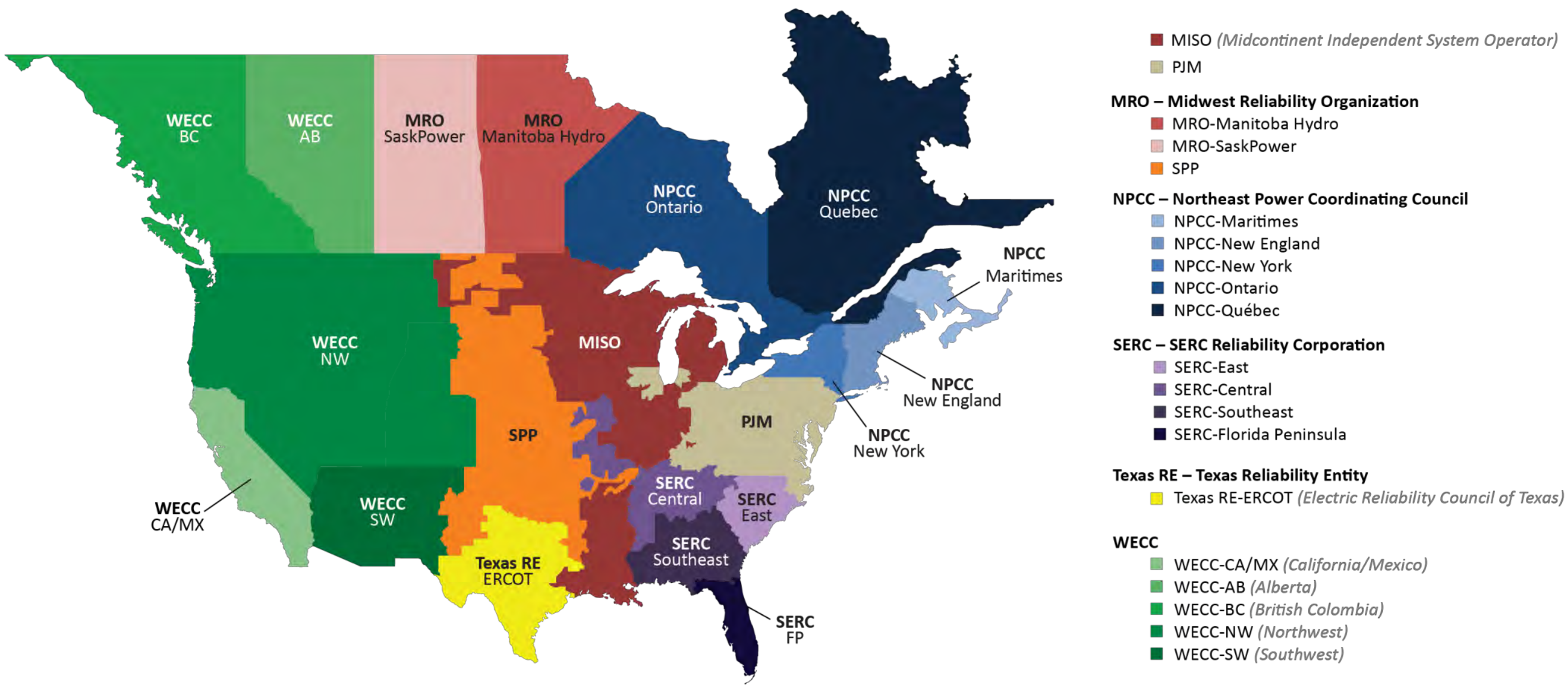
Localized Load Growth

Some areas are experiencing concentrated load growth from industrial and commercial development. Examples of large industrial loads include data centers, smelters, manufacturing centers, hydrogen electrolyzers, and future electrified mass transit or shipping charging stations. Adding large parcels of load on the system can add new uncertainties to peak and hourly load forecasting. For example, data centers have longer operating hours and require more heating and cooling than other commercial buildings. In Texas, crypto mining facilities have connected in recent years that scale their operations (and thus electricity demand) depending on electricity prices. Growth of large, concentrated loads can challenge load forecasting and localized transmission development.

[34] Public Power Article on APPA Survey
[35] Doe Proposes New Efficiency Standards for Distribution Transformers

Regional Assessments Dashboards

The following regional assessments were developed based on data and narrative information collected by NERC from the Regional Entities on an assessment area basis. The Reliability Assessment Subcommittee, at the direction of NERC's RSTC, supported the development of this assessment through a comprehensive and transparent peer review process that leveraged the knowledge and experience of system planners, Reliability Assessment Subcommittee members, NERC staff, and other subject matter experts. This peer review process promotes the accuracy and completeness of all data and information.



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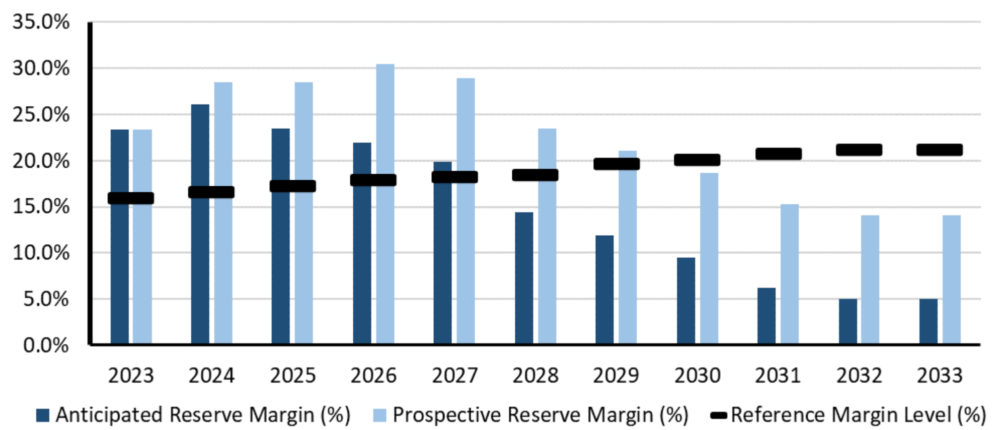
MISO

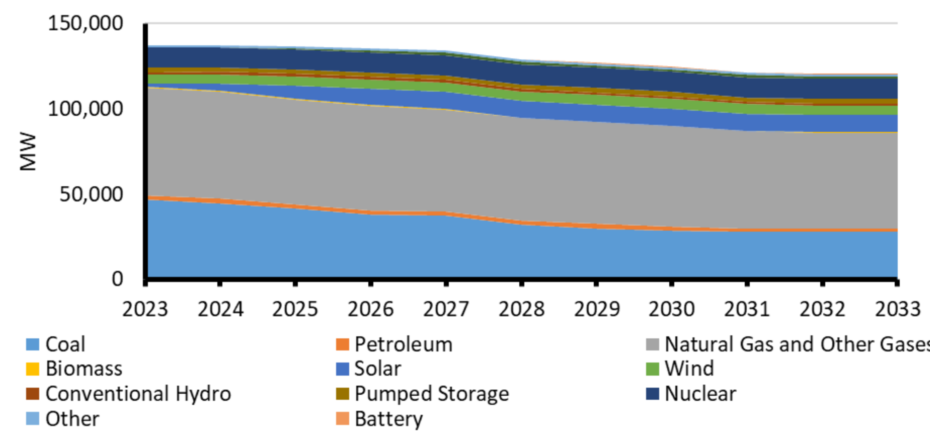
MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy and operating reserve markets that consist of 41 local BAs and over 500 market participants, serving approximately 45 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments. See **High Risk Areas** for more details.

Demand, Resources, and Reserve Margins (Summer)

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	121,933	122,726	123,315	123,888	124,659	125,140	125,591	126,135	126,593	126,593
Demand Response	7,776	7,741	7,798	7,812	7,726	7,728	7,729	7,731	7,728	7,728
Net Internal Demand	114,157	114,985	115,517	116,076	116,933	117,412	117,862	118,404	118,865	118,865
Additions: Tier 1	3,135	6,972	10,936	11,744	11,944	11,945	11,945	11,945	11,945	11,945
Additions: Tier 2	2,694	5,771	9,836	10,495	10,672	10,749	10,749	10,749	10,749	10,749
Additions: Tier 3	163	1,096	3,166	6,615	9,989	12,454	13,332	13,450	13,450	13,450
Net Firm Capacity Transfers	2,125	1,129	1,159	1,057	906	911	806	805	781	781
Existing-Certain and Net Firm Transfers	140,831	134,999	129,924	127,394	121,776	119,493	117,122	113,811	112,865	112,865
Anticipated Reserve Margin (%)	26.1%	23.5%	21.9%	19.9%	14.4%	11.9%	9.5%	6.2%	5.0%	5.0%
Prospective Reserve Margin (%)	28.5%	28.5%	30.5%	28.9%	23.5%	21.1%	18.6%	15.3%	14.0%	14.0%
Reference Margin Level (%)	16.6%	17.2%	17.9%	18.2%	18.4%	19.6%	20.1%	20.7%	21.2%	21.2%



Planning Reserve Margins



Existing and Tier 1 Resources

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Highlights

- MISO transitioned to its first year of seasonal capacity auctions (summer, fall, winter, spring). The switch to a seasonal construct improves understanding of non-summer risk and derives seasonal resource accreditation and seasonal resource adequacy requirements. Market responses to higher capacity prices in 2022 and new resource additions have overcome the planning reserve deficits reported in the *2022 LTRA*, and now MISO's ARMs are projected to meet RMLs for the first three years of this assessment period without significant new Tier 2 and Tier 3 resource additions.
- In the past year, coal-fired and nuclear generation capacity has declined mainly due to retirements by 300 MW and 140 MW, respectively. These reductions are not as large as projected last year due to delayed retirements. New wind and wind accreditation increased 725 MW while solar PV and solar PV accreditation increased by 920 MW. The larger increases in resources since last year's LTRA are the result of new natural-gas-fired generators as well as improvements that increased the accredited output contribution from existing natural-gas-fired generators that account for more than 4 GW of added capacity.

MISO Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	44,742	41,656	38,017	37,297	32,266	30,017	28,771	27,856	27,856	27,856
Petroleum	2,719	2,545	2,545	2,545	2,535	2,535	2,310	2,310	2,239	2,239
Natural Gas	62,909	61,454	61,311	59,919	59,755	59,752	59,059	56,842	56,074	56,074
Biomass	374	374	374	339	230	230	169	169	169	169
Solar	4,367	7,446	9,532	9,964	10,054	10,054	10,054	10,054	10,054	10,054
Wind	5,191	5,534	5,622	5,634	5,566	5,541	5,534	5,520	5,516	5,516
Conventional Hydro	1,443	1,443	1,443	1,443	1,443	1,443	1,443	1,307	1,307	1,307
Pumped Storage	2,696	2,696	2,696	2,696	2,696	2,696	2,696	2,696	2,696	2,696
Nuclear	11,725	11,725	11,725	11,725	11,725	11,725	11,725	11,725	11,725	11,725
Hybrid	31	375	1,006	1,392	1,476	1,492	1,492	1,492	1,492	1,492
Other	1,299	1,243	1,243	1,243	1,243	1,243	1,243	1,238	1,238	1,238
Battery	0	27	183	213	222	222	222	222	222	222
Total MW	137,496	136,518	135,696	134,410	129,211	126,950	124,719	121,432	120,589	120,589

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MISO Assessment

Planning Reserve Margins
In 2023, MISO transitioned to its first year of seasonal capacity auctions (summer, fall, winter, spring). Market responses to higher capacity prices in 2022 and new resource additions have overcome the planning reserve deficits reported in the *2022 LTRA*, and now MISO's summer and winter ARMs are projected to be above the RMLs for the first three years of this assessment period. MISO's summer ARM is projected to be above the RMLs through the 2027 summer. Beginning in 2028, MISO is projected to have a 4.7 GW shortfall if expected generator retirements occur and over 12 GW of new resources are added. It is important to note that there are 50 GW of generation with signed generation interconnection agreements that are not yet on-line and another 200+ GW of new resources within the interconnection queue that are still being evaluated.

With the transition to seasonal auctions, MISO conducted seasonal LOLE studies to identify the RML based on resource installed capacity in each season with the following results: summer 15.9%, fall 25.8%, winter 41.2%, and spring 39.3%.

Energy Assessment and Non-Peak Hour Risk
The introduction of the seasonal planning resource auction and inputs to the process provide more granularity and reliability planning for non-peak hour times during the year; in addition to this change, MISO conducts seasonal resource assessments that evaluate generation availability, outage rates, and forecasted load variation across all four seasons.

Probabilistic Assessments
NERC's most recent probabilistic assessment (2022 ProbA) Base Case results found that most of the LOLHs occur in June–August, corresponding to the typical MISO peak time frame. There are some instances of LOLHs occurring in September–October when seasonal planned outages overlap with high demand. MISO experiences a small amount LOLH in winter when cold temperatures push demand higher than normal.

Base Case Summary of Results (2022 ProbA)			
	2024*	2024	2026
EUE (MWh)	14.3	193.6	68.8
EUE (PPM)	0.02	0.304	0.108
LOLH (hours per Year)	0.085	0.808	0.393
Operable On-Peak Margin	13.7%	8.1%	13.9%

* Provides the 2020 ProbA Results for Comparison

Non-peak risk drivers tend to be unique to the season. In the fall, the risk of unseasonably high demand overlapping with seasonal planned outages increases the loss-of-load risk. Extreme cold weather, particularly in MISO South, increases demand and causes the risk of loss of load to increase.

In 2023, MISO completed a probabilistic analysis of a risk scenario that examined the effects of modeling seasonal forced outage rates as well as correlated cold weather outages rather than annual average outage rates.[36] The sensitivity analysis shows an increase in the total EUE compared to the Base Case results; these values are 201.8 MWh for EUE and 0.824 hours/year for LOLH. LOLH was relatively unchanged in the Sensitivity Case, which indicates that the duration of load-shed events was similar to the Base Case, but the magnitude of load shed was greater.

The results of MISO's 2023 probabilistic risk scenario indicate that summer remains the season with the largest EUE risk; however, resource outages in other seasons contribute to risk throughout the year. MISO's new seasonal resource adequacy construct is better equipped to identify such risks and procure sufficient capacity to avoid shortfalls.

MISO conducted an internal seasonal LOLE study for inputs in the 2023–2024 seasonal planning resource auction.[37]

Demand
The peak demand forecast for each year in this assessment period has decreased from the *2021 LTRA* forecasts by over 4 GW (3.2%) in the near term and narrowing to 1.7 GW (1.3%) by 2032. The forecast is created using inputs from LSEs in the MISO footprint; MISO does not forecast loads for resource adequacy assessments. MISO performs studies to investigate electrification and transportation industry impacts to load forecasts in its transmission expansion planning process.

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[36] See 2022 ProbA Regional Risk Scenarios Report
[37] MISO LOLE Study Report

Demand-Side Management

DR programs continue to play a significant role in MISO's capacity. DR is steady at 7.5–8 GW and is projected to remain constant during this assessment period. MISO's transition to seasonal capacity auctions includes the accreditation of DR and the availability for each season (not strictly the summer peak season).

Distributed Energy Resources

BTM generation contributes about 4.2 GW of capacity in MISO of which about 1.2 GW are distributed solar PV. MISO's transition to seasonal capacity auctions accounts for the availability of DERs in each season. MISO is working with stakeholders to derive adequate methods of aggregating, reporting, and allowing DER participation in MISO markets.

Generation

In the past year, coal-fired and nuclear generation capacity has declined mainly due to retirements by 300 MW and 140 MW, respectively. These reductions are not as large as projected in the *2022 LTRA* as some previously announced retirements have been postponed. New wind and wind accreditation increased 725 MW while solar PV and solar PV accreditation increased 920 MW. The larger increases in resources since last year's LTRA are the result of new natural-gas-fired generators as well as some increases in accredited output contribution from existing natural-gas-fired generators, which account for more than 4GW of added capacity.

There are over 50 GW of generation capacity (predominantly solar PV) with signed generation interconnection agreements in MISO that are projected to come online within the next five years. Some projects have experienced delays in achieving commercial operation due to supply chain issues even as late as the post-agreement phase. MISO tariff changes and interconnection queue processes are reducing interconnection queue timelines.

Recognizing that many projects for new generation terminate the interconnection process before completion, MISO applies a factor to the Tier 2 and Tier 3 resource capacities based on the study phase and likelihood of resources coming on-line. The effect is to reduce the capacity of prospective new resources for more accuracy in long-term planning by accounting for the uncertainty and delays of new resources completing the interconnection process.

Energy Storage

MISO has significant amounts of energy storage (55+GW) currently being studied in the generation interconnection queue that are mostly reflected in Tier 3 of this *2023 LTRA*. MISO does not have information on smaller (distribution level) energy storage in its area.

Capacity Transfers and External Assistance

Net firm transfers have increased since the *2022 LTRA* but are not expected to remain at increased levels. Non-firm transfers across various areas have played a critical role in maintaining reliability during extreme weather events.

Transmission

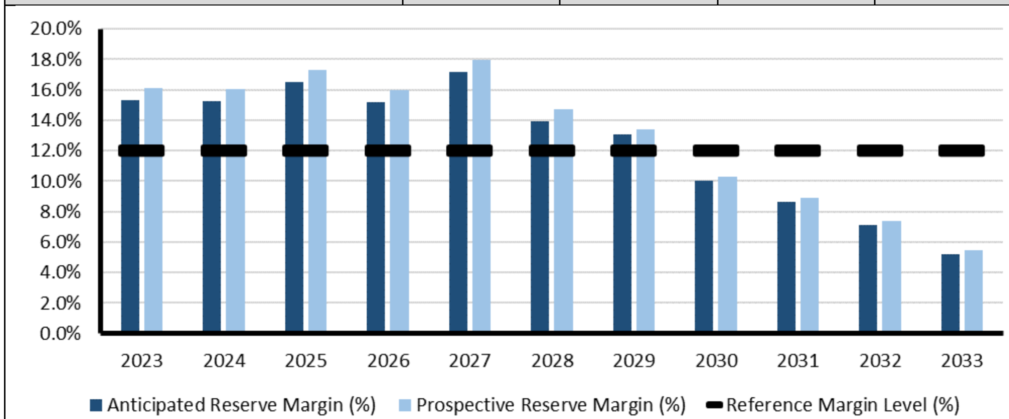
MISO continues to expand its transmission system for reliability and the integration of new resources. In the latest MISO Transmission Expansion Plan, $4.3 billion in transmission projects were approved with $550 million going towards integrating new resources, $550 million going towards baseline reliability projects, and the remainder supporting age- and condition-based needs. The latest approvals in MISO Transmission Expansion Plan (MTEP) 22 build on $10.3 billion in investment contained in MTEP 21 that provides reliability and economic benefits estimated at $23–52 billion across the MISO footprint and facilitates the integration of over 50 GW in new resources. In the *2022 LTRA*, MISO reported approximately 500 miles of new transmission across the footprint. In this *2023 LTRA*, that number has over tripled to near 1,800 miles of new transmission lines across MISO. Next year's MTEP and joint targeted interconnection queue projects with SPP will continue to provide additional transfer capacity across the Midwest and strengthen the transmission grid.

MRO-Manitoba Hydro

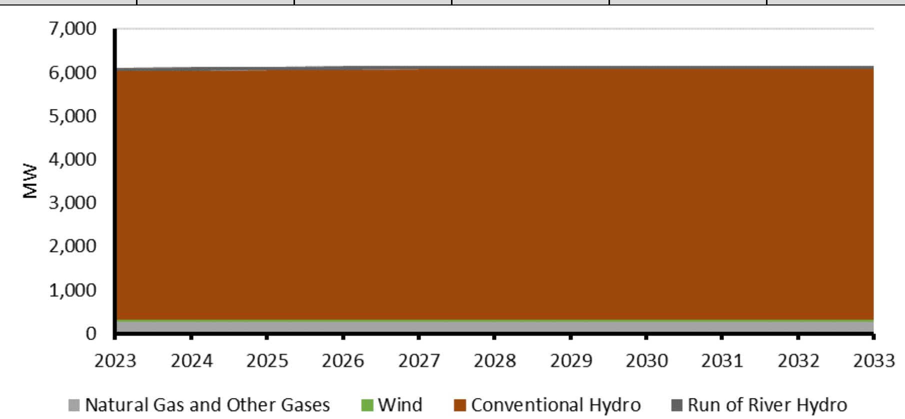
Manitoba Hydro is a provincial crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro provides electricity to approximately 608,500 electricity customers in Manitoba and provides approximately 293,000 natural gas customers in Southern Manitoba. The service area is the province of Manitoba which is 251,000 square miles. Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator and BA. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro. See Normal Risk Areas for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	4,629	4,636	4,656	4,664	4,863	4,895	4,946	5,009	5,081	5,174
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	4,629	4,636	4,656	4,664	4,863	4,895	4,946	5,009	5,081	5,174
Additions: Tier 1	91	111	139	152	152	152	152	152	152	152
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-627	-563	-588	-543	-467	-472	-565	-565	-565	-565
Existing-Certain and Net Firm Transfers	5,244	5,290	5,224	5,313	5,389	5,384	5,291	5,291	5,291	5,291
Anticipated Reserve Margin (%)	15.3%	16.5%	15.2%	17.2%	14.0%	13.1%	10.0%	8.7%	7.1%	5.2%
Prospective Reserve Margin (%)	16.0%	17.3%	15.9%	17.9%	14.7%	13.4%	10.3%	8.9%	7.4%	5.4%
Reference Margin Level (%)	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%



Planning Reserve Margins



Existing and Tier 1 Resources

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Highlights

- Manitoba Hydro ARM is above the RML throughout the first five years of this assessment period. No resource adequacy issues are anticipated.
- The Manitoba Hydro system is not currently experiencing the large additions of wind and solar generation or thermal generation retirements as seen in some other assessment areas. The predominately hydro nature of the system is not expected to change during this assessment period.

MRO-Manitoba Hydro Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Natural Gas	278	278	278	278	278	278	278	278	278	278
Wind	52	52	31	31	31	31	31	31	31	31
Conventional Hydro	5,702	5,722	5,750	5,763	5,763	5,763	5,763	5,763	5,763	5,763
Run of River Hydro	81	81	81	81	81	81	81	81	81	81
Total MW	6,113	6,133	6,140	6,153	6,153	6,153	6,153	6,153	6,153	6,153

MRO-Manitoba Hydro Assessment

Planning Reserve Margins

The ARM for Manitoba does not fall below the RML of 12% during the first five years of this assessment period. No resource adequacy issues are anticipated for the first five years of this assessment period. Manitoba Hydro is nearing the completion of an Integrated Resource Planning process, which will inform resource additions for future assessments.

Energy Assessment and Non-Peak Hour Risk

The primary energy adequacy risk to Manitoba Hydro is severe drought. Manitoba Hydro continually monitors water levels, estimates flows where possible, and uses physically based inflow forecasts to plan its operations. A probabilistic risk evaluation of severe drought is discussed in the following section.

Manitoba Hydro has not identified any ramping issues at the present time and does not anticipate any during the next five years. The inherent flexibility of the hydro resource combined with the limited penetration of variable renewable resources have shielded Manitoba Hydro from ramping issues. In the longer term, Manitoba Hydro will monitor variable renewable penetration and changes in the load shape, including changes from EV charging, to see if ramping demands are increasing.

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Probabilistic Assessments

Every two years, Manitoba Hydro prepares a probabilistic assessment for the Manitoba system, most recently in 2022. The 2022 probabilistic assessment was supportive of a 12% RML for the Manitoba system being sufficient to provide a LOLE of less than 0.1 days per year under the study assumptions.

Base Case Summary of Results (2022 ProbA)			
	2024*	2024	2026
EUE (MWh)	3.383	28.64	7.23
EUE (PPM)	0.133	1.141	0.287
LOLH (hours per Year)	0.004	0.036	0.007
Operable On-Peak Margin	N/A	13.5%	13.5%

* Provides the 2020 ProbA Results for Comparison

In 2023, Manitoba Hydro completed a probabilistic analysis of a risk scenario that examined the impact of the most significant resource adequacy factor over the long-run, variations in water conditions.[38] In this scenario, hydro resources are modeled at one-tenth percentile low-water conditions. Results indicate that LOLH and EUE values increase for both 2024 and 2026 in the low-water scenario to levels. LOLH, for example, will increase by an order of magnitude to nearly 0.6 hours/year in 2024 in comparison with the Base Case, highlighting the significant impact of low-flow conditions on the predominately hydro system. Since Manitoba Hydro is a small winter-peaking system on the northern edge of a summer peaking system, there is generally assistance available to provide energy to supplement hydro generation in low flow conditions in winter, particularly in off-peak hours. Management of energy in reservoir storage in accordance with good utility practice provides risk mitigation under low waterflow conditions.

Demand

Manitoba Hydro is projecting modest electricity load growth over the next five years. Factors considered in load growth projections include economic activity, electric vehicle adoption, and demand-side management programs in Manitoba operated by Efficiency Manitoba. EV adoption in Manitoba is being driven in part by proposed federal regulations that are expected to require that at least 20% of new vehicles sold in Canada to be zero emissions by 2026, at least 60% by 2030, and 100% by 2035.

Demand-Side Management

Manitoba Hydro's Curtailable Rate Program has approximately 160 MW of load enrolled as resources for peak load management as well as some contingency reserves. The program permits up to 16 curtailments of 4.25 hours each.

Distributed Energy Resources

There is a potential for significant solar PV DER resources in the latter half of this assessment period, and plans are being developed to study the impacts on the Manitoba Hydro system. The potential for future solar PV DER may be dependent on solar PV subsidies and/or incentives.

[38] NERC 2022 ProbA Regional Risk Scenarios Report

Generation

All seven generating units at the new Keeyask Generating Station are operating, and their completion improves resource adequacy for the remainder of this assessment period. Keeyask Unit 6 is listed as a Tier 1 capacity resource as it is operating but awaiting official commercial operation/designated network resource status. A Tier 1 project to replace eight older and smaller hydro units is being planned for the Pointe du Bois Generating Station. The Pointe du Bois Renewable Energy Project of about approximately 50 MW replaces the original hydro units that were mothballed or retired based on economics/end-of-life after about 100 years of operation. No Tier 2 or Tier 3 resources have been assumed to come into service during this assessment period.

Manitoba is not currently experiencing the large additions of wind and solar resources being seen in other areas, so the emerging reliability issues arising from such large wind and solar resource additions are not anticipated in the next five years.

Energy Storage

Manitoba Hydro does not currently anticipate additions of energy storage resources in the next 10 years.

Capacity Transfers and External Assistance

The Manitoba Hydro system is winter peaking and is interconnected to MISO, which is summer peaking. Significant capacity transfer limitations from MISO into Manitoba may have the potential to cause reliability impacts, but only if the following conditions occur simultaneously: extreme Manitoba winter loads, unusually high forced generation/transmission outages, and a simultaneous emergency in the northern MISO footprint. Emergency operating procedures may be necessary under such conditions.

The completion of the Manitoba–Minnesota 500 kV transmission line in June 2020 increased import capability from 700 MW to 1,400 MW and firm export capability from 2,100 MW to 2,983 MW. This new 500 kV line also improved the resilience of the network in the event of transmission contingencies.

Transmission

There are several transmission projects expected to come on-line during this assessment period. Most of the projects are dictated by the need to expand the transmission system to reliably serve growing loads, transmit power to the export market, improve safety, improve import capability, increase efficiency, and connect new generation.

Reliability Issues

Manitoba Hydro is monitoring federal and provincial policy/strategies/regulations related to electricity/energy. The Canadian federal government is considering significant carbon emission regulation. Through Environment and Climate Change Canada, the government is taking multiple steps to develop clean electricity regulations that aim for Canadian electricity generation to achieve net zero greenhouse gas emissions by 2035. This includes requiring generating units to meet a stringent emissions intensity standard (measured in tons CO2 equivalent per GWh) and pay a price for any remaining emissions. The proposed regulations are still in development and will not be fully implemented until 2035, so it is too early to determine any potential impacts. The province of Manitoba is developing a provincial energy strategy/policy that may be released in 2023. As details are not yet available, it is too early to determine any potential impacts.

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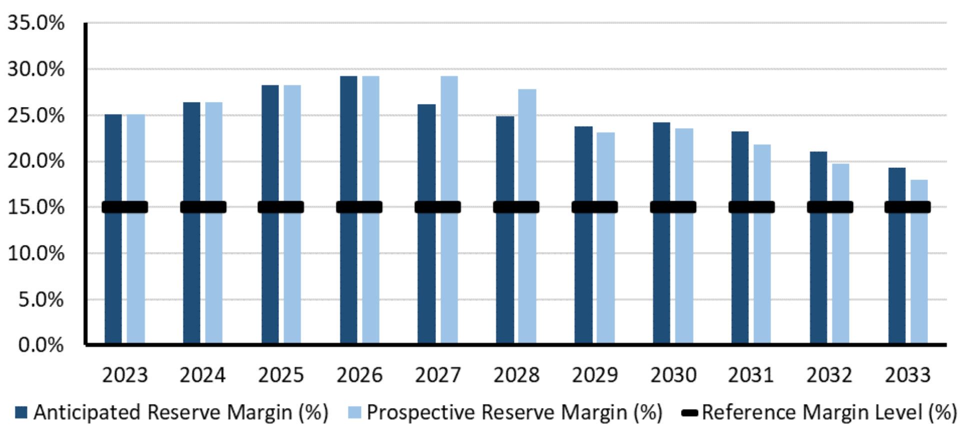
MRO-SaskPower

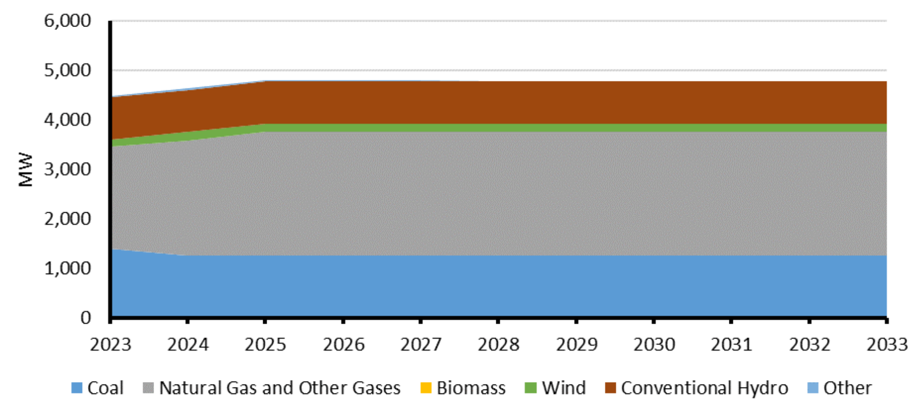
MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles), population of 1.2 million and approximately 550,000 customers. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its interconnections. See Normal Risk Areas for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	3,880	3,941	4,019	4,065	4,096	4,131	4,153	4,189	4,261	4,324
Demand Response	67	67	67	67	67	67	67	67	67	67
Net Internal Demand	3,813	3,874	3,952	3,998	4,029	4,064	4,086	4,122	4,194	4,257
Additions: Tier 1	416	506	506	506	506	506	506	506	506	506
Additions: Tier 2	0	0	0	421	421	1,173	1,173	1,173	1,173	1,173
Additions: Tier 3	0	0	0	80	80	80	80	80	80	80
Net Firm Capacity Transfers	290	315	315	315	315	315	315	315	315	315
Existing-Certain and Net Firm Transfers	4,405	4,461	4,604	4,539	4,524	4,524	4,571	4,572	4,571	4,571
Anticipated Reserve Margin (%)	26.4%	28.2%	29.3%	26.2%	24.9%	23.8%	24.3%	23.2%	21.1%	19.3%
Prospective Reserve Margin (%)	26.4%	28.2%	29.3%	29.2%	27.9%	23.1%	23.6%	21.8%	19.7%	17.9%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

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Highlights

- SaskPower's ARM is above the RML throughout this assessment period. ARMs for winter 2024 are lower than reported in the *2022 LTRA* due to the retirement of generation (one coal-fired and one natural-gas-fired unit with combined capacity of 180 MW), scheduled refurbishment shutdown of an existing generator, and the delay of a new natural-gas-fired generator (45 MW) from December 2024 to April 2025.
- Saskatchewan is adding approximately 734 MW of generation under Tier 1 category within the next five years. This includes a 200 MW wind generation facility, a 10 MW utility-scale solar PV project, two new natural gas facilities totaling 414 MW, and the expansion of two existing natural gas facilities totaling 90 MW. The remaining capacity addition (20 MW) comes from geothermal and other projects.

MRO-Saskpower Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251
Natural Gas	2,334	2,501	2,501	2,501	2,501	2,501	2,501	2,501	2,501	2,501
Biomass	3	3	3	3	3	3	3	3	3	3
Wind	164	164	164	162	162	162	162	162	162	162
Conventional Hydro	860	860	860	860	860	860	860	860	860	860
Other	22	22	17	17	1	1	1	1	1	1
Total MW	4,632	4,800	4,795	4,793	4,777	4,777	4,777	4,777	4,776	4,776

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MRO-Saskpower Assessment

Planning Reserve Margins
Saskatchewan uses a criterion of 15% as the RML and has assessed its Planning Reserve Margin for the upcoming 10 years with summer and winter peak hour loads, available existing and anticipated generating resources, firm capacity transfers, and available DR for each year. Saskatchewan's ARM ranges from approximately 18–33% and does not fall below the RML.

Energy Assessment and Non-Peak Hour Risk
Saskatchewan performs energy assessments using probabilistic methods to inform the area's resource adequacy requirements. Saskatchewan is evaluating non-peak hours risks and diminishing capacity credits associated with higher penetration levels of VERs as part of the long-term planning process. It is exploring a probabilistic evaluation approach to evaluate VER capacity contribution values.

Probabilistic Assessments
NERC's most recent probabilistic assessment (2022 ProbA) Base Case results found some risk of load loss in both study years, but LOLH remained below 1-day-in-10-year criteria. The major contribution to LOLH and EUE is extended planned maintenance at some of Saskatchewan's hydroelectric units through winter peak season for life extension and upgrade. The planned maintenance on the hydro units is staggered to minimize adverse impacts on system reliability.

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Base Case Summary of Results (2022 ProbA)			
	2024*	2024	2026
EUE (MWh)	26.5	169.5	117.0
EUE (PPM)	1.1	6.5	4.4
LOLH (hours per Year)	0.3	1.4	0.9
Operable On-Peak Margin	22.8%	23.1%	24.6%

* Provides the 2020 ProbA Results for Comparison

In 2023, SaskPower completed a probabilistic analysis of a risk scenario that examines the system's reliability when a coal unit approaching its planned end-of-life experiences a critical failure leading to premature unavailability. This scenario was selected to better understand the strategy for managing the coal units in Saskatchewan as they approach end of life in the next few years.[39] The results of this scenario reveal higher loss-of-load values in the first year of the assessment as compared to the Base Case. Saskatchewan is on track to add a large natural gas unit facility (377 MW) in-service by April 2024 that should enhance the system reliability for the remainder of this assessment period. SaskPower is also reviewing lay-up strategies for its existing units to support the system's reliability during peak periods.

Demand
Saskatchewan's system peak load forecast is based on econometric variables, weather normalization, and individual level forecasts for large industrial customers. Average annual summer and winter peak demand growth is expected to be approximately 1.15% throughout this assessment period.

Demand-Side Management
Saskatchewan's EE and energy conservation programs include incentives-based and education programs that focus on installed measures and products that provide verifiable, measurable, and permanent reductions in electrical energy and demand reductions during peak hours. DR consists of contracts with industrial customers for interruptible load based under conditions specified in DR programs. The first of these programs provides a curtailable load, currently up to 67 MW, with a 12-minute event response time. Other programs are in place providing access to additional curtailable load that require up to two hours notification time.

Distributed Energy Resources
Current BTM DER installed capacity in Saskatchewan is approximately 42 MW, which includes approximately 40 MW of solar PV, and approximately 2 MW of distributed wind projects. 25 MW of additional DER solar PV are expected to be added in the next five years. The estimated BTM DER installations are incorporated into the load forecast models that are used in supply and transmission planning study models.

Small power producers contribute an additional 5 MW of installed DER capacity (non-BTM) in Saskatchewan. There is currently an existing 8 MW and a potential for up to 20 MW of DERs being added in the next two years based on the currently approved Power Generation Partner programs. These projects are included as generation additions categories but currently their capacity is not considered in reliability planning.

[39] See 2022 ProbA Regional Risk Scenarios Report

Generation

Saskatchewan is adding approximately 734 MW of generation under Tier 1 category within the next five years. This includes a 200 MW wind generation facility and the expansion of two existing natural gas facilities that total 90 MW, two new natural gas facilities that total 414 MW, and the remaining capacity (30 MW) is projected to be geothermal and other projects.

Under Tier 2, over 1,279 MWs of new generation is projected in this assessment period. This includes three large (377 MW), two small (<50 MW) natural gas facilities, and a 100 MW utility-scale project. Natural gas generation is a proxy holder for any new generation needed beyond the medium-term (>5 years), but a portion of this capacity is anticipated to be covered through deploying renewables as well as carbon neutral and low emission generation projects.

Generating resources being planned as Tier 2 and Tier 3 will replace generators planned for retirement prior to deactivation. Therefore, Saskatchewan is not expecting any long-term reliability impacts due to generation retirements.

Energy Storage

SaskPower currently has its first BESS, a 20 MW/20 MWh unit, under construction. There are plans to expand this site by an additional 60 MW/60 MWh capacity.

The prevalent use for the planned energy storage is to provide regulating reserve, peak capacity and energy reduction, net demand ramping control, reactive power/voltage control, primary frequency control, and blackstart.

Capacity Transfers and External Assistance

SaskPower has three interfaces with its neighboring areas. The interface with Manitoba is currently the largest of the three interfaces and is the only interface with long term firm contracts. Capacity transfers from Manitoba would be limited in the events of prior outage of tie lines between SPC and MH as well as nearby transmission facilities supporting the interface. This could only impact reliability if it coincided with the extreme winter or summer peak demand and prior outage of one or more large generating units in Saskatchewan. Risk mitigation is in place through SaskPower's emergency operating procedure that will allow one or more measures, such as short-term imports from other available interfaces (for example Alberta or SPP), initiating DR and short-term load shedding.

Transmission

Approximately 80 km of 230 kV transmission line has been completed this summer and several other transmission projects (approximately 650 circuit km) are under the planning and conceptual phase in the 5-to-10-year assessment period. These projects are driven by load growth, new generation additions and reliability needs.

SaskPower performs transmission planning studies including the annual TPL assessment and other applicable periodic studies to meet NERC requirements, System Impact Studies for new load/generation interconnections, generation retirements, transmission service request (TSR) studies, area adequacy studies and other special studies as required to identify potential system issues. Mitigations are identified as part of these studies and included in the system development plan to ensure system performance requirements are met.

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NPCC-Maritimes

The Maritimes assessment area is a winter peaking NPCC sub-region with a single Reliability Coordinator and two BA areas (New Brunswick and Nova Scotia). It is comprised of the Canadian provinces of New Brunswick (NB), Nova Scotia (NS), and Prince Edward Island (PEI), and the northern portion of Maine (NM), which is radially connected to NB. The area covers 58,000 square miles with a total population of 2 million people. See Elevated Risk Areas for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	5,911	5,951	5,999	6,052	6,105	6,171	6,240	6,314	6,381	6,451
Demand Response	266	285	290	290	289	288	288	287	287	286
Net Internal Demand	5,644	5,665	5,709	5,763	5,816	5,883	5,953	6,027	6,095	6,165
Additions: Tier 1	34	34	52	52	52	52	52	52	52	52
Additions: Tier 2	10	36	93	276	451	960	1,083	1,103	1,253	1,253
Additions: Tier 3	0	32	105	125	495	515	535	555	575	590
Net Firm Capacity Transfers	55	23	-32	145	145	145	145	145	145	145
Existing-Certain and Net Firm Transfers	6,841	6,792	6,740	6,807	6,807	6,807	6,716	6,716	6,716	6,732
Anticipated Reserve Margin (%)	21.8%	20.5%	19.0%	19.0%	17.9%	16.6%	13.7%	12.3%	11.0%	10.0%
Prospective Reserve Margin (%)	17.6%	16.8%	16.3%	19.5%	18.9%	18.4%	17.5%	16.4%	17.6%	16.5%
Reference Margin Level (%)	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%

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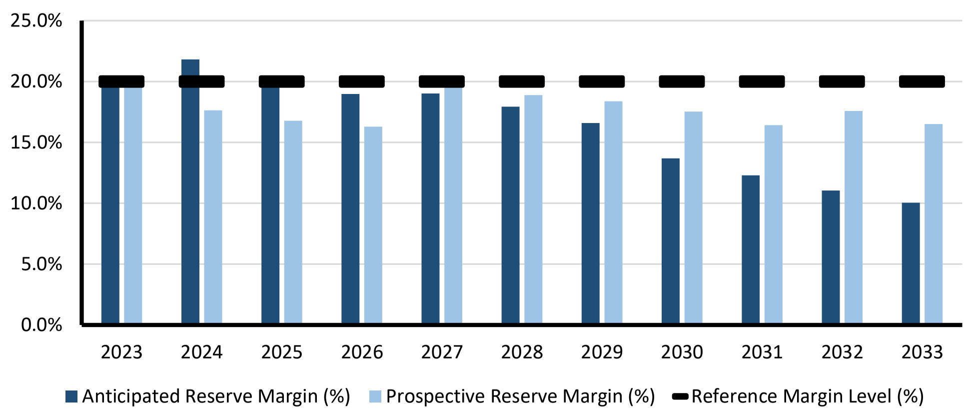
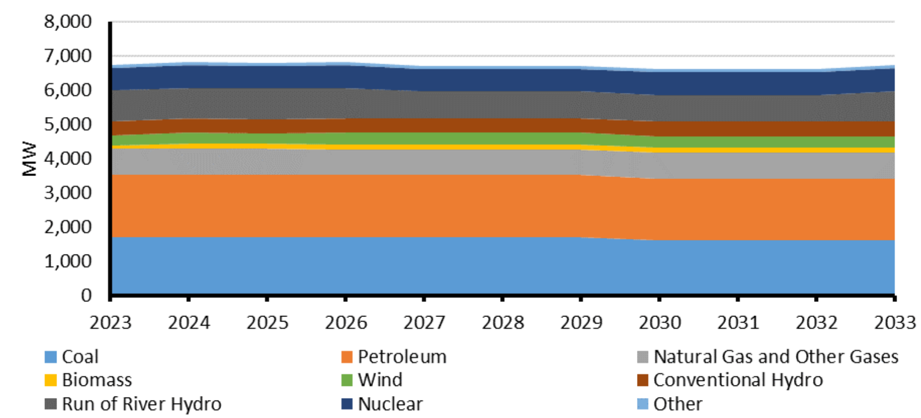


Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Since the *2022 LTRA*, winter peak demand forecasts for this assessment area have risen. As a result, ARMs are currently projected to fall below the RML of 20% beginning in 2026.

NPCC-Maritimes Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	1,695	1,695	1,695	1,695	1,695	1,695	1,604	1,604	1,604	1,604
Petroleum	1,829	1,823	1,818	1,818	1,818	1,818	1,818	1,818	1,818	1,818
Natural Gas	760	760	760	760	760	760	760	760	760	760
Biomass	148	148	148	148	148	148	148	148	148	148
Wind	322	310	328	328	328	328	328	328	328	328
Conventional Hydro	418	418	418	418	418	418	418	418	418	418
Run of River Hydro	902	902	902	792	792	792	792	792	792	902
Nuclear	663	663	671	671	671	671	671	671	671	671
Other	90	90	90	90	90	90	90	90	90	90
Total MW	6,827	6,809	6,830	6,720	6,720	6,720	6,629	6,629	6,629	6,739

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NPCC-Maritimes Assessment

Planning Reserve Margins

The reference reserve margin level that is used for evaluating the New Brunswick (NB), Nova Scotia (NS), Prince Edward Island (PEI), and Northern Maine (NM) sub-areas that make up the Maritimes area is 20% of firm load. The 20% criterion is not a mandated requirement. The ARM in the first five years for Maritimes ranges between 19% to 22% during the winter period and between 73% to 83% during the summer period of this LTRA study.

Energy Assessment and Non-Peak Hour Risk

The ARM level during off-peak season for the Maritimes areas ranges between 73% to 83%. During off peak hours, Maritimes has surplus generation available to meet the area's energy needs and hence there are no constraints with converting the capacity to energy during these times.

Probabilistic Assessments

The two BAs within Maritimes, as members of NPCC, jointly prepare annual interim or comprehensive probabilistic assessment reviews that cover three- to five-year forward-looking periods for both Maritimes' transmission system and resource adequacy evaluations. In addition, the Maritimes area also supports NERC's annual seasonal probabilistic assessments, which provide an evaluation of generation resource and transmission system adequacy that will be necessary to meet projected seasonal peak demands and operating reserves.

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Base Case Summary of Results (2022 ProbA)			
	2024*	2024	2026
EUE (MWh)	1.125	1.838	3.869
EUE (PPM)	0.039	0.06	0.138
LOLH (hours per Year)	0.023	0.023	0.071
Operable On-Peak Margin	16.7%	25%	22.9%

* Provides the 2020 ProbA Results for Comparison

Demand

There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes area. The peak area demand occurs in winter and is highly reliant on the forecasts of the two largest sub-areas of NB and NS, which are historically highly coincidental. Demand for the Maritimes area is determined to be the non-coincident sum of the peak loads forecasted by the individual sub-areas. The aggregated growth of both demand and energy for the combined sub-areas see an upward trend over summer and winter seasonal periods of this LTRA assessment period. The Maritimes area peak loads are expected to increase by 11.3% during summer and by 10% during winter seasons over the 10-year assessment period. This translates to compound average growth rates of 1.1% in summer and 1% in winter. The Maritimes area annual energy forecasts are expected to increase by a total of 6.2% during the 10-year assessment period for an average growth of 0.6% per year.

Demand-Side Management

Plans to develop up to 100 MW by 2030/2031 of controllable direct load control programs with smart grid technology to selectively interrupt space and/or water heater systems in residential and commercial facilities are underway, but no specific annual demand and energy saving targets currently exist. During the 10-year LTRA assessment period in the Maritimes area, annual amounts for summer peak demand reductions associated with EE and conservation programs rise from 17 MW to 162 MW while the annual amounts for winter peak demand reductions rise from 88 MW to 551 MW.[40]

Distributed Energy Resources

The DER installed capacity in NS is approximately 230 MW at present, including distribution-connected wind projects under purchase power agreements, small community wind projects under a feed-in tariff and BTM solar PV.

The LTRA wind capacity for NB, NS and PEI is de-rated between 18% and 33% with probabilistic methods to calculate equivalent perfect capacities for each sub-area excluding Northern Maine which uses seasonal capacity factors. BTM solar PV is assumed to have an ELCC of 0% during winter period. The Maritimes Area has shown embedded BTM solar PV projections of 99 MW in 2023 rising to 669 MW by 2033. These projects include distributed small-scale solar PV (mainly rooftop) that fall under the net metering program and serve as a reduction in load mainly in the residential class. The forecasted increase in solar PV installations in the coming years is a result of initiatives, including municipal and provincial incentive programs. There is no capacity contribution from solar generation due to the timing of area's system peak, which occurs either before sunrise or after sunset in the winter period.

[40] Current and projected EE effects based on actual and forecasted customer adoption of various demand-side management programs with differing levels of impact are incorporated directly into the load forecast for each of the areas but are not separately itemized in the forecasts. Since controllable space and water heaters will be interrupted via smart meters, the savings attributed to these programs will be directly and immediately measurable.

Generation

In NB, a hydro facility of 4 MW nameplate capacity shall reach its end of life and is planned to be retired at the end of 2023. NB assumes that 28 MW of diesel-fired generation will be extended starting in 2025 and that recently upgraded 290 MW of natural-gas-fueled resources will be completed in 2023. In NB, unconfirmed retirements include a 98 MW power purchase agreement contract that will come to an end in 2024–2025. An anticipated replacement power purchase agreement contract, a long-term firm energy contract from neighboring jurisdictions, and opportunities to buy in day-ahead and real-time markets will be utilized to maintain overall resource adequacy.

In Nova Scotia, Tier 1 resources include wind projects with a total nameplate capacity of 502 MW phased-in from 2024–2027 with an ELCC of 10%. Tier 2 resources in NS include a 200 MW of BESS (2026–2032), 520 MW of combustion turbines (2027–2033), a 150 MW conversion of a coal-fired unit to natural gas (2028), and 459 MW conversion of coal-fire units to oil (2030). Tier 3 resources in NS include natural gas additions (combustion turbines) of 350 MW in 2029 and new wind generation with a nameplate capacity of 1,600 MW phased in from 2026–2033. These Tier 3 resource additions are anticipated to facilitate the retirement of additional coal-fired generation by 2030. However, these retirements have not been included in the assessment due to their uncertainty.

Small amounts of new solar PV generation capacity (Tier 2) of up to 31 MW are expected to be installed in PEI in the fall of year 2023. PEI also plans to add a new 10 MW of hybrid energy storage (Tier 2) during the year 2023.

Tier 3 additions include wind projects with a total nameplate capacity of 1,840 MW starting year 2025, solar PV projects of 200 MW nameplate capacity starting year 2025 and 400 MW nameplate capacity of dual fueled combustion turbines starting year 2027.

NB de-rates its wind capacity with a calculated year-round equivalent capacity of 33%. NS and PEI de-rate wind capacity to 18% and 17%, respectively, of nameplate based on year-round calculated equivalent load carrying capabilities for their respective individual sub areas. The peak capacity contribution of grid based solar is estimated at zero since the Maritimes area peak occurs in the winter either before sunrise or after sunset.

Energy Storage

NS Power includes a 200 MW (4-hour duration) nameplate capacity standalone BESS added as a Tier 2 resource phased-in from 2026–2032. This grid-scale project will support the integration of new renewable generation, provide energy arbitrage and resiliency services, and provide firm capacity and fuel savings.

PEI includes a 10 MW nameplate capacity hybrid energy storage as a Tier 2 resource starting fall of 2023. This project will provide storage option to the output from the 10 MW solar PV facility that is planned to be coming on-line during the same time frame. This project will provide fuel savings and may provide additional reliability if a generation outage occurs.

NB Power has not included any BESS in the 2023 LTRA submission; however, the value of energy storage options is expected to increase as the technology improves and NB's smart grid network develops. NB Power issued a request for expressions of interest for new renewable generation sources, including 200 MW of wind, 15 MW of solar PV, 5 MW of tidal, and 50 MW of 4-hour duration BESS in February of 2023. Under this program, NB Power expects uptake in new energy storage projects in the coming years. Internal pilot projects and studies are underway to understand the economics, application, and performance of BESS resources. Ongoing internal analyses are conducted by NB Power to determine the cost and benefit associated with BESS options as well as dispatching these resources to reduce/shift peaks and/or balance intermittent resources, such as wind, to provide additional flexibility to the system.

Capacity Transfers and External Assistance

ProbA studies show that the Maritimes area is not reliant on inter-area capacity transfers to meet NPCC resource adequacy criteria.

Transmission

There are no new transmission projects in the Maritimes area.

Reliability Issues

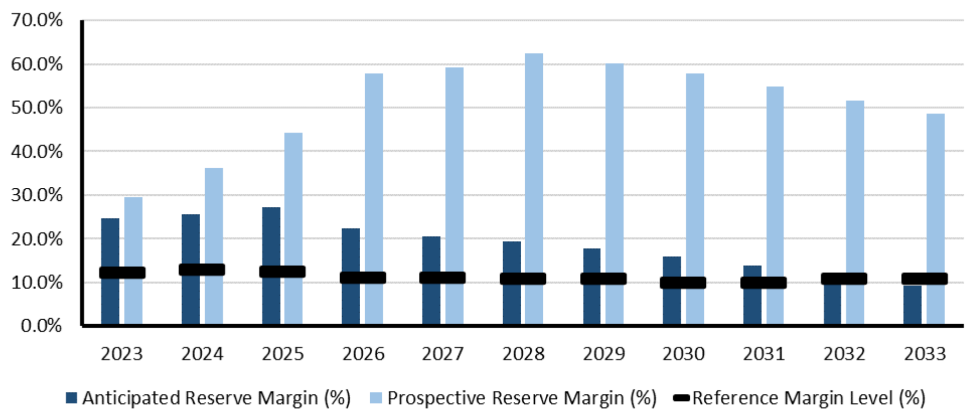
The Maritimes area has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind (de-rated), dual fuel oil/gas, tie benefits, and biomass with no one type feeding more than about 27% of the total capacity in the area. The Maritimes area does not anticipate fuel disruptions that pose significant challenges for resources during this assessment period.

NPCC-New England

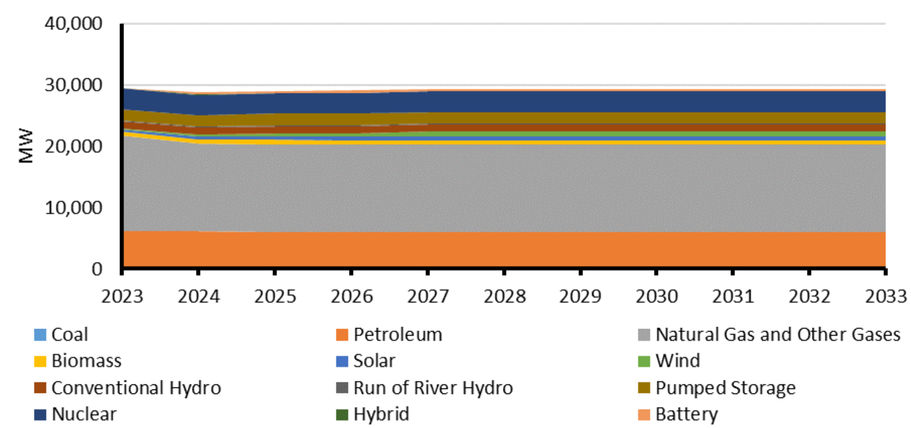
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont served by ISO-NE Inc. ISO-NE is a regional transmission organization responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS. The New England BPS serves approximately 14.5 million customers over 68,000 square miles. See **Elevated Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	24,633	24,708	24,866	25,052	25,307	25,636	26,036	26,505	27,046	27,598
Demand Response	661	669	623	623	623	623	623	623	623	623
Net Internal Demand	23,972	24,039	24,243	24,429	24,684	25,013	25,413	25,882	26,423	26,975
Additions: Tier 1	708	1,084	1,111	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Additions: Tier 2	1,376	1,836	6,338	7,181	8,392	8,392	8,392	8,392	8,392	8,392
Additions: Tier 3	1,130	2,199	3,625	9,514	11,306	11,836	12,525	12,525	12,525	12,525
Net Firm Capacity Transfers	1,297	1,504	567	84	84	84	84	84	84	84
Existing-Certain and Net Firm Transfers	29,408	29,505	28,552	28,068	28,068	28,068	28,068	28,068	28,068	28,068
Anticipated Reserve Margin (%)	25.6%	27.2%	22.4%	20.5%	19.3%	17.7%	15.9%	13.8%	11.4%	9.2%
Prospective Reserve Margin (%)	36.2%	44.2%	57.7%	59.1%	62.4%	60.2%	57.7%	54.9%	51.7%	48.6%
Reference Margin Level (%)	12.9%	12.6%	11.0%	11.0%	11.0%	11.0%	10.0%	10.0%	11.0%	11.0%



Planning Reserve Margins



Existing and Tier 1 Resources

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Highlights

- New England is forecast to have the resources needed to meet consumer demand for electricity through the first nine years of the 10-year LTRA assessment period. In the last year of the assessment, in the summer of 2033, the summer ARM of 9.2% falls below the annual RML of 11.0%. However, at this time, ISO-NE does not expect the need to procure capacity additions to mitigate potential resource adequacy issues forecast for the last summer of the 10-year LTRA.
- Beyond the LTRA assessment period, additional imports of Canadian hydroelectricity, offshore wind, and new technologies, such as longer-duration energy storage, will likely continue the trend toward a cleaner, albeit more complex, power system.
- ISO-NE is addressing the issues brought on by grid transformation through a number of planning, operational, and market measures.

NPCC-New England Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	437	437	437	437	437	437	437	437	437	437
Petroleum	5,635	5,562	5,546	5,546	5,546	5,546	5,546	5,546	5,546	5,546
Natural Gas	14,311	14,328	14,328	14,328	14,328	14,328	14,328	14,328	14,328	14,328
Biomass	749	711	711	711	711	711	711	711	711	711
Solar	424	542	568	568	568	568	568	568	568	568
Wind	341	583	583	852	852	852	852	852	852	852
Conventional Hydro	1,155	1,155	1,155	1,155	1,155	1,155	1,155	1,155	1,155	1,155
Run of River Hydro	133	133	133	133	133	133	133	133	133	133
Pumped Storage	1,861	1,861	1,861	1,861	1,861	1,861	1,861	1,861	1,861	1,861
Nuclear	3,354	3,354	3,354	3,354	3,354	3,354	3,354	3,354	3,354	3,354
Hybrid	34	34	34	34	34	34	34	34	34	34
Battery	386	386	386	386	386	386	386	386	386	386
Total MW	28,820	29,086	29,095	29,364	29,364	29,364	29,364	29,364	29,364	29,364

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NPCC-New England Assessment

New England is forecast to have the resources needed to meet consumer demand for electricity through the first nine years of the 10-year LTRA assessment period. In the last year of the assessment, in the summer of 2033, the summer ARM of 9.2% falls below the annual RML of 11.0%, a 1.8% (-494 MW) shortfall. If only 6% (about 500 MW) of the total Tier 2 resources (8,392 MW) materializes in the future, the summer shortfall in the final year of the assessment would be mitigated. However, at this time, ISO-NE does not expect the need to procure capacity additions to mitigate potential resource adequacy issues forecast for the last summer of the 10-year LTRA.

With the widespread development of renewable and clean energy resources, the BPS will emit lower air emissions. Beyond the LTRA assessment period, additional imports of Canadian hydroelectricity, offshore wind, and new technologies (e.g., longer duration energy storage) will likely continue the trend toward a cleaner, albeit more complex, power system. ISO-NE is addressing these issues brought on by grid transformation through a number of planning, operational, and market measures.

Planning Reserve Margins

ISO-NE's seasonal ARM is based on the capacity needed to meet the ISO-NE and NPCC 1-day-in-10 years LOLE resource planning reliability criterion. The capacity needed, referred to as the installed capacity requirement (ICR), varies from year to year depending on projected system conditions. The ICR is calculated on an annual basis, covering four years into the future. The latest calculations result in an annual RML of 12.3% in 2023, 12.9% in 2024, 12.6% in 2025, and 11.0% in 2026 and 2027. For the years beyond ISO-NE's forward capacity market (FCM) time frame, this assessment uses the annual RML associated with the representative future ICRs calculated for 2028 through 2032. ISO-NE assumes a continuation of the annual RML in 2032 for the annual RML in 2033. These annual RMLs range from a low of 10.0% in 2030 and 2031 to a high of 11.0% in 2028, 2029, 2032 and 2033.

Energy Assessment and Non-Peak Hour Risk

ISO-NE's probabilistic and deterministic study results indicate that there are sufficient capacity resources to meet forecasts of seasonal peak and energy demands for nine years out of the 10-year LTRA assessment period. However, a standing concern is whether there will be sufficient fuel available for resources to turn capacity into electricity to satisfy both demand and required operating reserves during an extended cold spell, a series of cold spells, or a long-term critical infrastructure or supply chain force majeure scenario.

ISO-NE regularly prepares outlooks for both energy demand and production. Forecasts of weather, transmission topology, resource capability, fuel inventories, known and forced outages, regional gas pipeline or liquid fuel constraints, and projected imports/exports all factor into this outlook for New England's energy production capability. If the regional supply/demand balance is negative, projected energy deficiencies can trigger energy alerts or energy emergencies that are then disseminated to market participants and federal and state regulators. This early notification of potential electricity shortages should incentivize market participants to procure the necessary fuel needed to support future ISO dispatch orders.

ISO-NE has undertaken several new projects to develop more enhanced deterministic and probabilistic energy security analyses. For instance, ISO-NE is working with the Electric Power Research Institute to conduct probabilistic energy adequacy studies for New England under extreme weather events. These studies establish a framework for risk analysis that can be updated as climate projections are refined and the resource mix evolves. The energy adequacy risk profile is dynamic and will be a function of the evolution of both supply and demand profiles. Preliminary results for 2027 winter events, 2027 summer events, 2032 summer events, and 2032 winter events reveal a range of energy shortfall risks and associated probabilities.[41] In terms of magnitude and probability, these baseline results indicate that energy shortfall risks in the near-term appear manageable over a 21-day period. Sensitivity analysis of 2032 worst-case scenarios indicates an increasing energy shortfall risk profile between 2027 and 2032.

ISO-NE and stakeholders are working on near- and long-term market improvements to expand the existing suite of energy and ancillary services that will cost-effectively address uncertainties in firm electricity production. All of these activities directly enhance overall BPS energy security.

Probabilistic Assessments

ISO-NE conducts probabilistic resource adequacy assessments annually in conjunction with NPCC to identify regional capacity resource needs and to comply with NPCC/NERC reliability requirements. In the transmission assessment domain, revisions to ISO-NE planning processes now reflect the changing resource characteristics, probabilistic study assumptions, and changes to national and regional criteria. Coordinated transmission planning activities with neighboring systems will continue and help

[41] Results of the preliminary EPRI/ISO-NE studies reveal similar energy adequacy risk both with and without the Everett Marine Terminal LNG facility in-service.

support the New England states' policy objectives of providing access to a greater diversity of clean resources to meet environmental compliance obligations.

Base Case Summary of Results (2022 ProbA)			
	2024*	2024	2026
EUE (MWh)	58.62	0.937	0.551
EUE (PPM)	0.471	0.007	0.004
LOLH (hours per Year)	0.095	0.002	0.002
Operable On-Peak Margin	9.8%	32.6%	27.8%

* Provides the 2020 ProbA Results for Comparison

As expected from the 2022 ProbA risk scenario, the EUE and LOLH remain close to zero with increased capacity, decreasing demand, and no major reported Tier 1 resources after 2024. The New England area is currently summer-peaking, and the EUE risk occurs during the summer months; however, the EUE values are negligible.

Demand

Over the 10-year planning period, the forecast net internal summer peak demand increases by 2,993 MW from 24,605 MW in 2023 to 27,598 MW in 2033. The corresponding net internal winter peak demand forecast increases by 7,183 MW from 20,269 MW in 2023–2024 to 27,452 MW in 2033–2034. Net energy for load is forecast to grow by 33,006 GWh from 120,552 GWh in 2023 to 153,558 GWh in 2033.

The forecast for summer peak load reductions due to EE and conservation is expected to increase by 436 MW from 1,969 MW in 2023 to 2,405 MW in 2033. This demand reduction is represented in the reported total internal demand of the Demand, Resources and Reserve Margins table.

Currently, New England has 981 MW (3,366 MW nameplate) of BTM-PV. BTM-PV is forecast to grow to 1,116 MW (6,553 MW nameplate) by 2033. The BTM-PV peak load reduction values are calculated as a percentage of nameplate. The percentages include the effect of diminishing PV production at time of system peak as increasing PV penetrations shift the timing of summer peaks to later in the day. As such, the BTM-PV summer peak load reduction values decrease from 29.1% of nameplate in 2023 to 17.0% in 2033. Like EE and conservation, BTM-PV is also a demand reduction represented in the reported Total Internal Demand of the Demand, Resources and Reserve Margins table on the **NPCC-New England** dashboard.

Demand-Side Management

New England currently has 564 MW of controllable and dispatchable DR resources, and that amount is projected to grow by 59 MW to 623 MW by 2033. The area also currently has over 3,253 MW of passive demand-side management resources that participate in the regional FCM. This amount is projected to decrease by 936 MW to 2,317 MW by 2032.

Distributed Energy Resources

Approximately 2,550 MW (nameplate) of settlement-only generation does not participate in ISO-NE's FCM. Of this total, approximately 2,400 MW is made up of units or stations smaller than 5 MW each.

Generation

Future capacity required to comply with NPCC's resource planning criterion is procured through ISO-NE's FCM. Studies of projected system conditions show that developing new resources near load centers, particularly in Northeast Massachusetts/Boston and Southeastern Massachusetts and Rhode Island, would provide the greatest reliability benefit. To the extent that new resources are developed to help balance supply with demand, the BPS would require fewer transmission upgrades and ancillary services and would exhibit less congestion and losses.

The continued reliance on natural-gas-fired generation still exposes New England to the reliability impacts from the fleet's lack of firm gas pipeline transportation contracting and its dependence upon uncertain liquified natural gas import deliveries. Natural gas sector infrastructure contingencies can become electric sector reliability risks during any time of the year. ISO-NE and interregional reliability organizations have identified these risks in a number of energy security studies and assessments, and ISO-NE has taken a number of remedial actions to improve the overall gas/electric interface. The development of renewable resources with energy storage, imports from neighboring areas, and fast-start and flexible ramping resources along with the continued investment in EE/conservation measures within both the electric and natural gas sectors are also part of the overall reliability solution.

Future environmental regulations, public policies, and economic considerations will all affect the operation of existing resources and the mix of new resources. As existing oil- and coal-fired generators retire, their replacements would likely be predominantly renewable sources of energy, notably wind and solar PV. Federal and state policies, such as those that promote EE, PV, and wind resources, will continue to affect the planning process. Carbon emission reduction targets will continue to be the key regional constraint on electricity production by fossil-fueled generating units.

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Energy Storage

ISO-NE currently has 1,861 MW of pumped-storage hydroelectric stations, 61 MW of stand-alone BESS, and 27 MW of co-located and integrated hybrid BESS (summer ratings). These amounts are expected to grow over the 10-year LTRA assessment period. ISO-NE reports 386 MW of stand-alone BESS and 34 MW of co-located/integrated hybrid BESS for the summer of 2033.

Capacity Transfers and External Assistance

New England is interconnected with the three Bas of Québec, Maritimes, and New York. ISO-NE considers the tie benefits associated with these Bas to meet the regional resource adequacy criterion and to prevent over-reliance on such assistance. ISO-NE's FCM methodology limits the purchase of import capacity based on the interconnection transfer limits. ISO-NE's capacity imports are assumed to range from 567 MW to 1,504 MW during the 2023–2026 summer periods. There is one long-term firm import contract of 84 MW that extends through the 10-year LTRA assessment period. In addition, there are no firm exports identified over the 10-year LTRA assessment period.

As a result of updates to the permitting status of the New England Clean Energy Connect inter-area transmission line and supporting energy contract, which is scheduled for commercial operation in December of 2024 and starting in the summer of 2025, ISO-NE is reporting an expected import from Québec in the amount of 1,090 MW/hr. This contract is not reported by ISO-NE for the winter periods due to Québec's own load needs for serving its winter-peaking system.

Transmission

Transmission expansion in New England has improved the overall level of reliability and resiliency, reduced air emissions, and lowered wholesale market costs by nearly eliminating congestion. Generator retirements, off-peak system needs, the growth of DERs and VERs by using IBRs, and changes to mandatory planning criteria promulgated by NERC, NPCC, and regional stakeholders have driven the need for longer-term transmission assessments.

Future reliable and economic performance of the BPS is expected to continue to improve as a result of approximately $1.5 billion of planned transmission upgrades over the next 10 years, much of which is still under construction. Generator retirements, the integration of many DERs and VERs, the use of IBR technologies, and issues rising from minimum load assessments and high-voltage conditions are changing the needs for reliability-based transmission upgrades. In addition, transmission improvements will also be needed to support state policies to access remotely located sources of clean energy. Transmission assessments and resultant plans are being developed throughout the area to meet these future system needs.

Reliability Issues

New England's BPS is transitioning to a system with a growing number of renewables, clean energy resources, VERs and DERs. The rapid implementation of revised interconnection standards for VERs and DERs is vital to ensure overall BPS reliability and facilitate the economic development of IBRs.

As of summer 2023, constraints on global, regional, and local supply chains are affecting the procurement of new (or needed) BPS infrastructure due to the lack of raw materials, manufacturing limitations, labor shortages, and high inflation and interest rates. This has led to some previously signed long-term, off-shore wind contracts being renegotiated and/or canceled.

New England has already experienced constraints on electricity production due to a lack of natural gas for the power sector during winter. In response, ISO-NE has been a key player at the national level in promoting BPS reliability through sharing of lessons learned and best practices and now through initiating the performance of more detailed and in-depth BPS energy assessments. Additionally, to address winter energy security challenges, ISO-NE and regional stakeholders developed and put in place a two-year program to compensate certain resources that provide energy security during the winters of 2023–2024 and 2024–2025 (from December to February). ISO-NE's Inventoried Energy Program is a voluntary program designed to provide incremental, winter period compensation for participants that maintain inventoried energy for their assets during extreme cold periods when energy security is most stressed. [42]

The just-in-time delivery of a generators fuel supply, whether natural gas, wind, or solar, is creating the need for the electric sector to quickly develop ways to retain access to flexible, stored energy either through long-term energy storage solutions that can capture and store renewable power or through the use of dispatchable resources, whether these dispatchable resources are carbon emitting or not.

[42] Beginning September 1, 2023, only participants using the fuel types of oil, refuse, batteries, pumped storage and natural gas (with firm supply and transport) may elect to participate in IEP.

NPCC-New York

NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within New York. NYISO supports reliability primarily through three complementary markets: energy, ancillary services, and capacity. The transmission grid of New York State encompasses over 11,000 miles of transmission lines, 760 power generation units, and serves the electricity needs of 19.6 million people. New York experienced its all-time peak demand of 33,956 MW in the summer of 2013. See **Elevated Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	32,280	32,390	32,440	32,410	32,310	32,300	32,490	32,750	33,110	33,520
Demand Response	860	860	860	860	860	860	860	860	860	860
Net Internal Demand	31,420	31,530	31,580	31,550	31,450	31,440	31,630	31,890	32,250	32,660
Additions: Tier 1	410	877	888	888	888	888	888	888	888	888
Additions: Tier 2	415	2,124	3,000	4,305	4,305	4,305	4,305	4,305	4,305	4,305
Additions: Tier 3	3,796	6,124	10,171	12,204	12,204	12,204	12,204	12,204	12,204	12,204
Net Firm Capacity Transfers	1,932	1,815	3,212	3,518	3,518	3,518	3,518	3,518	3,518	3,518
Existing-Certain and Net Firm Transfers	36,152	35,445	36,842	37,148	37,148	37,148	37,148	37,148	37,148	37,148
Anticipated Reserve Margin (%)*	16.4%	15.2%	19.5%	20.6%	20.9%	21.0%	20.3%	19.3%	17.9%	16.5%
Prospective Reserve Margin (%)	17.7%	21.9%	29.0%	34.2%	34.6%	34.7%	33.9%	32.8%	31.3%	29.6%
Reference Margin Level (%)**	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%

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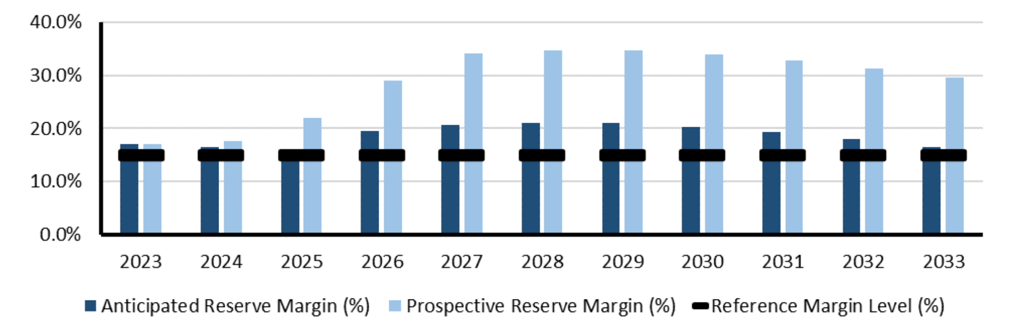
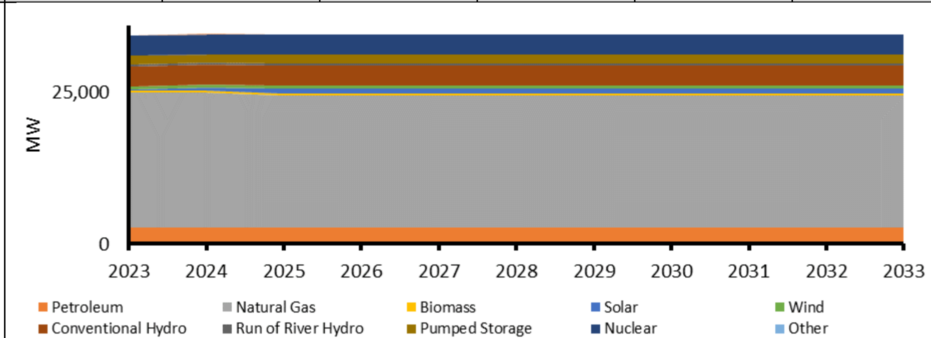


Planning Reserve Margins



Existing and Tier 1 Resources

*Values are with wind derated by 82% wind, solar by 43% and run-of-river by 60% for summer capability period. Additionally, the proposed 1,250 MW Champlain-Hudson Power Express HVDC from Québec to New York City is assumed in the net transfers starting 2026.

**The NERC LTRA RML is 15% and it is used for the sole purpose of the LTRA; however, there is no Planning Reserve Margin criteria in New York. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. Additionally, NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 days/year. However, New York requires LSEs to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2023–2024 IRM at 20%. All values in the IRM calculation are based upon full installed capacity MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year.

Highlights

- Public policies, such as the 2019 Climate Leadership and Community Protection Act (CLCPA), are driving rapid changes in New York's electric system and impacting how electricity is produced, transmitted, and consumed. The transition to a cleaner grid in New York is leading to an electric system that will be increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation.
- Recent assessments reveal that reliability margins are shrinking. Electrification programs are driving demand for electricity higher, and New York is projected to become winter peaking in the future. Largely in response to public policies, fossil fuel generators are retiring at a faster pace than new renewable supply is entering service. The potential for delays in construction of new supply and transmission, higher than forecasted demand, and extreme weather could threaten grid reliability and resilience.
- NYISO's reliability studies identified actionable reliability needs starting 2025 in New York City, resulting in NYISO solicitating for market-based and regulated backstop solutions (the solutions can be generation, DR, or transmission, or combinations). The need is primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City that is affected by state legislation for emissions limits, known as The Peaker Rule.[43]
- Driven by public polices, new supply, load, and transmission projects are seeking to interconnect to the grid at record levels. NYISO's interconnection process balances developer needs with grid reliability. Efforts are underway to make this process more efficient while protecting grid reliability. New transmission is being built, but more investment is necessary to support the delivery of offshore wind energy to connect new resources upstate to downstate load centers where demand is greatest. Planning for new transmission to support offshore wind is underway.
- To achieve the mandates of the CLCPA, new emission-free supply with the necessary reliability services will be needed to replace the capabilities of today's generation. These types of resources must be significant in capacity and have attributes like the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid and steep ramping requirements. Such new emission-free supply is not yet available on a commercial scale.
- New wholesale electricity market rules are supporting the grid in transition. These markets are critical for a reliable transition. Wholesale electricity markets are open to significant investment in wind, solar, and BESS. Peak load management needs to be integrated as a measure to facilitate achievement of CLCPA targets. By lowering peak load and avoiding system buildout to serve the highest demand hour, less dispatchable emission-free resource build-out will be needed and fewer fossil fuel-fired plants will be needed to meet lower peaks during the transition.

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NPCC-New York Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Petroleum	2,632	2,632	2,632	2,632	2,632	2,632	2,632	2,632	2,632	2,632
Natural Gas	22,384	21,794	21,794	21,794	21,794	21,794	21,794	21,794	21,794	21,794
Biomass	330	330	330	330	330	330	330	330	330	330
Solar	379	803	814	814	814	814	814	814	814	814
Wind	490	533	533	533	533	533	533	533	533	533
Conventional Hydro	3,305	3,305	3,305	3,305	3,305	3,305	3,305	3,305	3,305	3,305
Run of River Hydro	379	379	379	379	379	379	379	379	379	379
Pumped Storage	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407
Nuclear	3,305	3,305	3,305	3,305	3,305	3,305	3,305	3,305	3,305	3,305
Battery	20	20	20	20	20	20	20	20	20	20
Total MW	34,631	34,507	34,518	34,518	34,518	34,518	34,518	34,518	34,518	34,518

[43] New York Department of Environmental Conservation Peaker Rule

NPCC-New York Assessment

Planning Reserve Margins

The LTRA Planning Reserve Margins are above 15% throughout the 10-year assessment period; however, the system margins are narrowing. Wind, grid-connected solar, and run-of-river totals were derated for the LTRA calculation. Under its reliability planning processes, NYISO uses probabilistic assessments to evaluate the system's resource adequacy against the LOLE resource adequacy criterion of no greater than 0.1 event-days/year probability of unplanned load loss. NYISO's *2022 Reliability Needs Assessment*, completed on November 2022, identified that the New York Control Area (NYCA) LOLE is below its "one day in 10 years" criterion for the 10-year study period.

NYISO also provides support to the New York State Reliability Council (NYSRC) in conducting an annual IRM[44] study. This study determines the IRM for the upcoming capability year (May 1 through April 30). The IRM is used to quantify the capacity required to meet the NPCC and NYSRC resource adequacy criterion of "one day in 10 years." The current IRM for the 2023–2024 capability year is 20% of the forecasted NYCA peak load. All values in the IRM calculation are based upon full installed capacity values of resources. The IRM has varied historically from 15% to 20.7%. Additionally, NYISO performs an annual study to identify the locational minimum installed capacity requirements[45] for the upcoming capability year.

Energy Assessment, Including Non-Peak Hour Risk

The Climate Leadership and Community Protection Act decarbonization targets span over all major industries and are a main driver for the electric system changes. NYISO staff in system operations, planning, and markets will continue to assess the system changes to prepare for the grid's transformation.

With high penetration of renewable intermittent resources, dispatchable emission-free resources and long-duration resources are needed to balance intermittent supply with demand. These types of resources must be significant in capacity and have attributes, such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. Additionally, although new transmission is being built, more investment is necessary to support the delivery of offshore wind energy and to connect new resources upstate to downstate load centers where demand is greatest.

NYISO performs long-range energy assessments (10-year and beyond) in the is accounted for in the 8,760 hours per year simulations in the resource adequacy studies as part of the RPP and the production cost simulations as part of the system and resource outlook study.

NYISO Grid Operations performs or assists in performing energy assessments, including, but not limited to, a fuel and energy security study and ongoing assessments, a study that assesses potential impacts related to climate change, and weekly analysis based on the results of reporting by generation resources through NYISO's Generator and Fuel Emissions Reporting data portal. NYISO grid operations also performs an internal energy analysis at least weekly based on data and information reported by supply resources through NYISO Generator and Fuel Emissions Reporting system. Resources provide data and information on an annual, weekly, and as needed basis considering system operating conditions. This analysis has the capability to analyze the impact of changes in stored fuel inventory, resource outages, fuel supply disruptions, transmission constraints, and other relevant conditions that may adversely impact fuel and energy security. Additionally, the New York City and Long Island areas have a loss of gas supply dual-fuel requirement and certain combined-cycle natural gas units participate in a Minimum Oil Burn program. While oil accounts for a relatively small percentage of the total energy production in New York, it is often called upon to fuel generation during critical periods, such as when severe cold weather limits access to natural gas.

Probabilistic Assessments (NERC ProbA and other studies)

NYISO performs probabilistic assessments by using General Electric's Multi-Area Reliability Simulation (MARS) as part of its reliability planning processes as well as to determine annual Locational Minimum Installed Capacity Requirements (LCR). NYISO also pursued capacity accreditation market rules to more accurately reflect capacity market suppliers' contributions to resource adequacy. These new market rules align compensation for capacity suppliers with an individual resource's expected reliability benefit to consumers and uses the probabilistic models from the LCR process to define capacity accreditation factors for various capacity accreditation resource classes. The groundbreaking proposal was accepted by FERC in May 2022. The capacity accreditation factors will reflect the marginal reliability contribution of the installed capacity suppliers within each capacity accreditation resource class toward meeting NYSRC resource adequacy requirements for the upcoming capability year, starting with the capability year that begins in May 2024.

[44] NYSRC IRM Study
[45] LCRs

Additionally, every other year, each Regional Entity provides results for NERC's ProbA process; the results from the ProbA performed in 2022 by NPCC appear below.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	6.837	0.091	0.059
EUE (PPM)	0.046	0.001	0.00
LOLH (hours per Year)	0.029	0.00	0.00
Operable On-Peak Margin	11.3%	11.6%	16.7%

* Provides the 2022 ProbA Results for Comparison

NPCC's Directory 1 defines a compliance obligation for NYISO, as Resource Planner and Planning Coordinator, to perform a resource adequacy study evaluating a five-year planning period. NYISO delivers a report every year under this study process to verify the system against the one-day-in-ten-years LOLE criterion, usually based on NYISO's latest available reliability assessment results and assumptions. NYSRC Reliability Rules have recently included a requirement that defines NYISO's obligation to deliver a *Long-Term Resource Adequacy Assessment Report* every *Reliability Needs Assessment Report* year and an annual update in the non-RNA years.

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Demand

NYISO employs a multi-stage process to develop load forecasts for each of the 11 zones within the NYCA. The impacts of net electricity consumption of energy storage resources due to charging and discharging are added to the energy forecasts while the peak-reducing impacts of BTM energy storage resources are deducted from the peak forecasts.

Currently, the NYCA summer peak typically occurs in late afternoon. The NYCA summer peak will likely shift into the evening as additional BTM solar PV is added to the system and as EV charging impacts increase during the evening hours. Because the hour of the summer peak shifts into the evening over the course of the assessment period, BTM solar PV generation becomes less coincident with the NYCA peak hour, and BTM solar PV coincident peak reductions are forecasted to decrease in later years. The forecast of solar PV-related reductions to the winter peak is zero because the system typically peaks after sunset.

Trended weather conditions from the *Climate Impact Study Phase I* report are included in NYISO's end-use models and are reflected in the baseline, policy scenario, and percentile forecasts. NYISO develops 90th and 99th percentile forecasts to account for the impacts of extreme weather on seasonal peak demand and calculates 10th percentile forecasts to represent milder seasonal peak conditions.

The ten-year annual average energy (+1.0%) and summer peak demand (+0.5%) growth rates are higher than last year's forecast. Increases in growth rates relative to the prior forecast are primarily attributed to increased large load projects and EV charging impacts, including greater coincidence with periods of peak electricity demand. Baseline energy and coincident peak demand increase significantly throughout the 30-year forecast period, largely by high load project growth in the early forecast years and electrification of space heating, non-weather sensitive appliances, and electric vehicle charging in the outer forecast years. New York is projected to become winter peaking in future decades due to space heating electrification and electric vehicle penetration.

Demand-Side Management

NYISO will develop market concepts to encourage the participation of flexible load; this will become increasingly important as the levels of weather-dependent intermittent resources on New York's grid increases in response to the state's climate and clean energy policies. Many New York utilities are piloting several load management programs (e.g., smart EV charging, home-thermostat use, and the integration of BTM storage for local peak demand modulation. As part of NYISO's annual long-term forecasting process, the impacts of these programs are discussed and significant impacts on demand are included in the load forecast.

For the *2023 LTRA Report*, the DR participation for the summer capability period has increased slightly from 1,170 MW to 1,234 MW. There are currently 307 MW of DR participating in ancillary services programs to provide either 10-minute spinning reserves or 30-minute non-synchronous reserves.

Distributed Energy Resources

NYISO is currently implementing a plan to integrate DERs, including DR resources, into the markets it administers. The DER Participation Model project aims to enhance DER participation in competitive wholesale markets. These measures closely align the bidding and performance measurements for DERs with the rules for generators. The measures establish a state-of-the-art model that is largely consistent with the market design envisioned by FERC in its Order 2222. This project, which began in 2017, will provide a single participation model for DER DR resources to provide energy, ancillary services, and installed capacity through an aggregation. The market rules for the DER and aggregation participation model were accepted by FERC in January 2020. NYISO filed additional proposed tariff revisions with FERC in June 2023 to clarify and enhance these market rules. NYISO is currently developing software associated with these tariff revisions and anticipates deploying its DER participation model in 2023.

Generation

The pace of renewable project development and existing generation retirement is unprecedented and driving a need to increase the pace of transmission, new clean dispatchable generation, and demand management programs development. In general, resource and transmission expansion take many years from development to deployment. Coordination of project additions and retirements is essential to maintaining reliability and achieving policy. Significant new resource development will be required to achieve CLCPA energy targets. The total installed generation capacity to meet policy objectives within New York is projected to range between 111 GW and 124 GW by 2040. At least 95 GW of this capacity will consist of new generation projects and/or modifications to existing plants. Even with these additions, New York still may not be sufficient to maintain the reliable electricity supply. The sheer scale of resources needed to satisfy system reliability and policy requirements within the next 20 years is unprecedented.

To achieve an emission-free grid, dispatchable emission-free resources (DEFR) must be developed and deployed throughout New York. DEFRs that provide sustained on-demand power and system stability will be essential to meeting policy objectives while maintaining a reliable electric grid. While essential to the grid of the future, such DEFR technologies are not commercially available today.

Essential reliability services usually provided for the system by synchronous fossil generation will continue to be necessary. New technology is being developed to allow for a reliable transition to a clean grid. Grid-forming inverter capabilities as well as DEFRs will likely be part of this transformation. On May 2023, the New York State Public Service Commission has initiated a process to examine the need for resources to ensure the reliability of the 2040 zero-emissions electric grid mandated by the CLCPA. Under this initiative, the Public Service Commission seeks to identify innovative technologies to ensure reliability of a zero emissions electric grid. Numerous other initiatives at both state and federal levels are in progress and will impact the grid of the future.

Additionally, NYISO's interconnection process contains a significant number of proposed projects in various stages of development with only a fraction in more advanced stages included in the reliability planning models.

Energy Storage

Storage resources can help to fill in voids created by reduced output from renewable resources; however, sustained periods of reduced renewable generation can rapidly deplete storage capabilities. NYISO has implemented its Co-located Storage Resources model to allow wind or solar resources that are interconnected with an energy storage resource the ability to participate in the markets while respecting a shared interconnection limitation. NYISO is developing a model for hybrid storage resources to allow multiple technologies at the same point of interconnection participate in the market as a single resource. Additionally, the resource adequacy simulation tools (e.g., GE's MARS) used in system planning and for setting the IRMs were enhanced to include energy limited resources models that allow for charging and discharging and also include temporal constraints (*e.g.,* hours/days or hours/month).

Capacity Transfers

The models used for NYISO reliability planning studies include firm capacity transactions (purchases and sales) with the neighboring systems as a base case assumption. Proposed projects that are in a more advanced stage are included. One such project is the 1,250 MW HVDC line from Québec into New York City, which is reflected in the LTRA summer total transfers starting in 2026. Additionally, the probabilistic model used in the RPP to assess the adequacy of resources employs a number of methods that are aimed at preventing overreliance on the external systems support (e.g., limiting emergency assistance from neighbors by modeling a total limit of 3,500 MW, modeling simultaneous peak days, modeling the long-term purchases and sales with neighboring control areas, not modeling emergency operating procedure steps for the neighbors, etc.). As the energy policies in neighboring areas evolve, New York's energy imports and exports could vary significantly due to the resulting changes in neighboring grids. New York is fortunate to have strong interconnections with neighboring areas and has enjoyed reliability and economic benefits from such connections. The availability of energy for interchange is predicted to shift fundamentally as policy achievement progresses. Balancing the need to serve demand reliably while achieving New York's emission-free target will require continuous monitoring and collaboration with neighboring states.

Transmission

Significant new transmission is being built across New York, but more investment is necessary to support, among other things, the delivery of offshore wind energy to connect new resources upstate to downstate load centers where demand is greatest. Key transmission projects under development and accounted for in the reliability models include the following:

- New York Power Authority/National Grid's Northern New York Priority Transmission Project upgrading the transmission corridors from the renewable generation pocket in the north country to central NY
- The 1,250 MW Champlain-Hudson Power Express HVDC line from Hydro Québec to New York City
- The AC Public Policy Transmission Projects: upgrading transmission corridors on central NY and lower Hudson Valley (These projects target completion of the majority of the components by December 2023.)

Additionally, there are significant transmission projects either recently selected or under study that are not yet in the reliability model, including the following:

- New York Power Authority/New York Transco project selected by NYISO's Board of Directors to meet the Long Island offshore wind export public policy transmission need.
- PSC recently declared a new Public Policy Transmission Planning Need that is intended to support the integration of 4.7 GW of wind resources in New York City.
- Con Edison's proposed Brooklyn Hub project includes a new 345 kV load serving substation that is reported to potentially serve as a point-of-interconnection for up to 1,500 megawatts (MW) of offshore wind power.

Furthermore, NYISO will also be part of the Transmission Owners' Coordinated Grid Planning Process. The NY Utilities proposal was filed with PSC on December 27, 2022. The PSC initiated a proceeding to develop an integrated planning process that identifies and constructs local transmission and distribution infrastructure solutions in coordination with any necessary bulk transmission infrastructure expansion, throughout New York to support the optimal deployment of investments.

Reliability Issues

The *2022 RNA*, completed in November 2022, identified no reliability needs for the study period 2026–2032. However, NYISO found that the system margins are very narrow in certain locations, such as New York City, for parts of the study period. The 2023 Q2 STAR was completed on July 14, 2023.[46] This assessment finds a reliability need beginning in summer 2025 in New York City that is primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City that is affected by the Peaker Rule. The reliability need is a deficiency in the transmission security margin that accounts for expected generator availability, transmission limitations, and updated demand forecasts with data published in the 2023 Gold Book. Specifically, the New York City zone is deficient by as much as 446 MW for a duration of nine hours on the peak day during expected weather conditions (95 degrees Fahrenheit) when accounting for forecasted economic growth and policy-driven increases in demand. Solutions to this need are being evaluated in accordance with the NYISO Short-Term Reliability Process.

The transition to a cleaner grid in New York is leading to an electric system that is increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation. Reliability margins are shrinking. Generators needed for ERSs are planning to retire. Delays in the construction of new supply and transmission, higher than expected demand, and extreme weather could threaten reliability and resilience in the future. A successful transition of the electric system requires replacing the reliability attributes of existing fossil-fueled generation with clean resources with similar capabilities. Such resources must be significant in capacity and have attributes like the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid and steep ramping needs. These attributes are critical to a dynamic and reliable future grid. New transmission is being built but more investment is necessary to support the delivery of offshore wind energy to connect new resources located in upstate to downstate load centers where demand is greatest. Planning for new transmission to support offshore wind is underway.

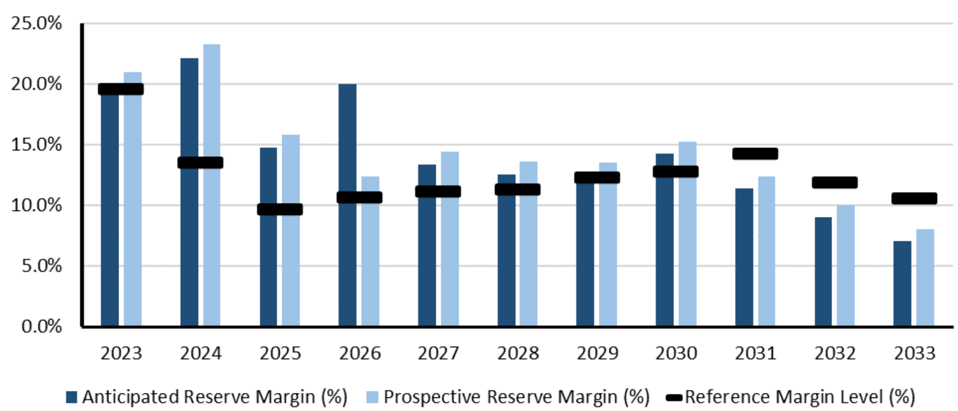
[46] 2023 Q2 STAR Report

NPCC-Ontario

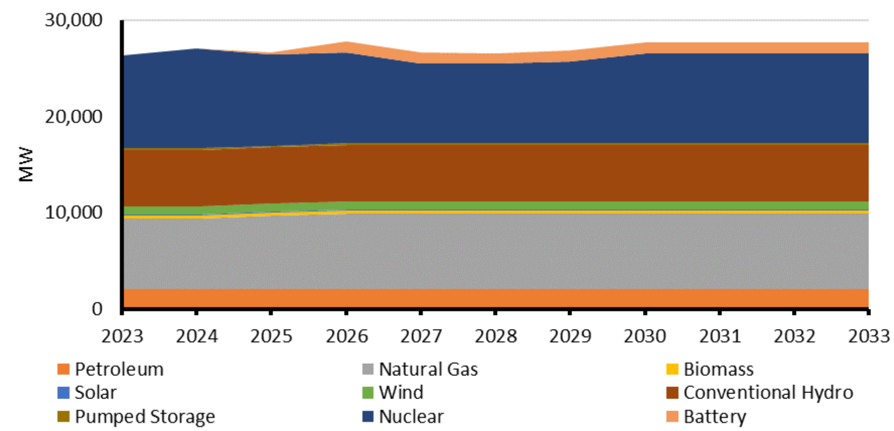
NPCC-Ontario is an assessment area in the Ontario province of Canada. IESO is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 15 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York. See **Elevated Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	23,236	24,321	24,217	24,460	24,695	24,953	25,295	25,928	25,928	26,387
Demand Response	1,022	544	544	544	544	544	544	544	544	544
Net Internal Demand	22,214	23,777	23,673	23,916	24,151	24,409	24,751	25,384	25,384	25,843
Additions: Tier 1	10	513	1,635	1,635	1,635	1,917	1,917	1,917	1,917	1,917
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	0	600	600	500	600	600	600	600	0	0
Existing-Certain and Net Firm Transfers	27,124	26,780	26,780	25,487	25,555	25,555	26,364	26,355	25,755	25,755
Anticipated Reserve Margin (%)	22.1%	14.8%	20.0%	13.4%	12.6%	12.6%	14.3%	11.4%	9.0%	7.1%
Prospective Reserve Margin (%)	23.3%	15.8%	12.4%	14.5%	13.6%	13.6%	15.3%	12.4%	10.0%	8.0%
Reference Margin Level (%)	13.5%	9.7%	10.7%	11.2%	11.3%	12.3%	12.8%	14.2%	11.9%	10.6%



Planning Reserve Margins



Existing and Tier 1 Resources

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Highlights

- The IESO is taking action to secure resources that address reserve margin shortfalls forecast for 2031 that are driven by nuclear retirements, refurbishments, and overall demand growth. The IESO is doing this in part through a mix of long-term contracts for new builds, medium-term contracts for existing resources, and an Annual Capacity Auction. In 2023, the IESO procured new storage resources and upgrades to natural-gas-fired generators and will continue this procurement cycle over the next few years by seeking long-term contracts for both energy and capacity.
- In August 2023, Ontario and Québec signed a memorandum of understanding for the swap of 600 MW of capacity for up to 10 years. Under the proposed electricity trade agreement, the IESO and Hydro-Québec will carry out an annual capacity swap of 600 MW that will help address their respective peak season demands. The agreement is expected to come into effect in winter 2024–2025.
- The IESO is also responsible for implementing new provincial policy as outlined in the Ontario government's *Powering Ontario Growth*, which includes developing new nuclear projects, transmission expansions, and expanded conservation and demand management programs.
- With the recent federal release of draft clean electricity regulations, the IESO is reviewing and will incorporate changes into future planning products, starting with revised supply assumptions in the 2023 Annual Planning Outlook.

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NPCC-Ontario Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Petroleum	2,107	2,107	2,107	2,107	2,107	2,107	2,107	2,107	2,107	2,107
Natural Gas	7,337	7,617	7,856	7,856	7,856	7,856	7,856	7,856	7,856	7,856
Biomass	299	299	299	299	299	299	299	299	299	299
Solar	91	91	91	91	91	91	91	91	91	91
Wind	801	801	801	801	801	801	801	801	801	801
Conventional Hydro	5,930	5,930	5,930	5,930	5,930	5,930	5,930	5,930	5,930	5,930
Pumped Storage	118	118	118	118	118	118	118	118	118	118
Nuclear	10,450	9,506	9,506	8,313	8,280	8,562	9,372	9,363	9,363	9,363
Battery	0	223	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107
Total MW	27,133	26,693	27,815	26,622	26,590	26,872	27,681	27,673	27,673	27,673

NPCC-Ontario Assessment

Planning Reserve Margins

ARMs remain adequate for the first seven years of this assessment period. The IESO continues to actively procure resources to meet longer-term needs by using the mechanisms in the Resource Adequacy Framework.

Ongoing refurbishments at Bruce Nuclear Generating Station and Darlington Nuclear Generating Station will see between one and three reactors concurrently off-line through 2033. Refurbishments remain on or ahead of schedule, and outages continue to be managed to limit impacts to the grid. Currently, a request is before the federal nuclear regulator to construct and operate a 300 MW small modular reactor at Darlington by 2028.

The Ontario government has also announced a plan to deliver new small modular reactors and examine new large-scale nuclear generators. The release of *Powering Ontario's Growth* by the provincial government in July 2023 directed the IESO to conduct an impact assessment on potentially adding 4,800 MW of large-scale nuclear capacity to Bruce and three additional 300 MW SMRs at Darlington. While Pickering Nuclear Generation Station is scheduled for decommissioning in 2025, approval is being sought to extend operation through September 2026. The Ministry of Energy has also requested a feasibility assessment on the potential for refurbishing four units at Pickering NGS. The plant operator is conducting a comprehensive technical examination and aims to submit a final recommendation by the end of 2023.

The IESO's *2022 Annual Acquisition Report* identified a need for 4,000 MW of capacity emerging mid-decade, which the IESO is addressing through its Resource Adequacy Framework. The 2022 annual capacity auction secured 1,431 MW of summer and 1,160 MW of winter capacity. The 2022 Medium-Term Request for Proposal (RFP) secured 757 MW of supply from both existing natural gas and wind resources coming off contract; these resources will be available starting 2024–2026. Through long-term procurements, the IESO has acquired 319 MW through on-site natural gas expansions and 930 MW (3,720 MWh) of storage resources. In addition, the IESO has secured 286 MW in natural gas facility upgrades that have had their contracts extended.

Separately, Ontario has entered into an agreement with Oneida Energy Storage for a 250 MW (1,000 MWh) BESS facility expected to be in operation by summer 2026. The IESO has targeted securing 2,500 MW in capacity (1,600 NW storage and 900 MW non-storage) through its long-term RFP with expected commercial operation in 2028.

The IESO calculates the reserve margin requirement on an annual basis and publishes this in the Annual Planning Outlook.[47] The IESO calculates the reserve margin requirement for each year for net demand at the time of the annual demand peak to provide an LOLE that is at or below 0.1 days per year. The reserve margin requirement in the 2023 LTRA is derived from the capacity requirement in the 2022 *Annual Planning Outlook*[48]

Energy Assessment and Non-Peak Hour Risk

Energy adequacy assessments are conducted annually for the annual planning outlook by using a deterministic approach in the IESO's economic dispatch model. Should Pickering Nuclear Generating Station retire 2024–2025, increased adequacy risks are expected; however, an extension to 2026 would help alleviate these risks until 2027, when unserved energy is forecast to be 1.09 TWh.

The IESO now assesses capacity adequacy accounting for both peak and non-peak load hours to form a more comprehensive assessment. Generally, summer hours represent the highest probability of load loss, but actual hourly profiles change yearly. The IESO's first round of long-term procurements is securing resources that can provide energy at least four hours at a time.

Looking forward, the federal government has proposed Clean Energy Regulations to decarbonize Canada's electric system by 2035. The IESO is assessing the current role of natural gas generation as a flexible resource in the interim as it introduces new sources of non-emitting supply to the system.

Future annual planning outlooks will continue to highlight deficits in capacity and energy as Ontario works toward decarbonization targets and procurements with the regular cadence outlined in the Resource Adequacy Framework.

Probabilistic Assessments

No probabilistic assessment has been performed since 2022 but will occur later this year by both the IESO and NPCC. However, risks will have decreased compared with 2022 due to procurements, nuclear units being extended, and refurbishments coming in on time or ahead of schedule.

[47] Planning and Forecasting Annual Planning Outlook
[48] 2022 Annual Planning Outlook Data Tables

Base Case Summary of Results (2022 ProbA)			
	2024*	2024	2026
EUE (MWh)	0.049	0.00	72.164
EUE (PPM)	0.00	0.00	0.492
LOLH (hours per Year)	0.001	0.00	0.442
Operable On-Peak Margin	4.4%	7.9%	-6.7%

* Provides the 2020 ProbA Results for Comparison

Demand
Forecasted demand over the 10-year study period increased by 5% and 10% in summer and winter, respectively, after the preliminary LTRA data submission. Increased demand for electricity is being driven by population growth, economic expansion, and increased penetration of electric devices. Offsetting this growth are conservation, electricity price responsiveness, and increased output by embedded generation. Overall, demand is ramping up more quickly than in 2022 due to government policy on decarbonization. Notable increases in demand arise from growth in the greenhouse sector, use of industrial electric arc furnaces, EVs, BESS manufacturing operations, and new mines.

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Ontario continues to be summer peaking through the forecast period. The IESO's Industrial Conservation Initiative acts as a critical peak-pricing program and is expected to reduce around 1,300 MW on the system peak hour of the top five system peak days and 650 MW on the second top-five days (days 6-10). It is expected to scale based on increased industrial growth in future years. Over this assessment period, the IESO projects the total internal demand growth to increase at a CAGR of 1.42% for summer and 1.59% for winter.

Demand-Side Management
Capacity auction resources consist mainly of DR followed by generation and imports. Beginning this year, the IESO is introducing a qualification process that will apply resource-specific methodologies to determine the unforced capacity for each resource is able to offer into the auction.

In 2023, the IESO implemented new programs designed to grow Ontario's DR capability, particularly during the peak summer months. The Peak Perks program is targeted at residential customers while a new industrial pilot is designed to identify events in advance that large load customers can respond to effectively to reduce their exposure to capacity charges.

The 2021–2024 Conservation and Demand Management Framework managed by the IESO continues with increased budget and additional savings. Incremental savings are included in the overall demand forecast but remain in line with 2021–2024 levels. An EE auction pilot secured peak demand reductions of 7.4 MW for winter 2022–2023 and 6.6 MW for summer 2023. Typically, EE measures persist for years.

Distributed Energy Resources
The IESO estimates that contracted DERs contributed more than 3,400 MW of capacity and 5.3 TWh of energy in 2022, more than half of which is solar PV, one-third wind and modest contributions from hydroelectric and biomass resources. While IESO has little insight into uncontracted DERs, it has observed energy contributions of approximately 2 TWh in 2022.

Generation
Recent generation procurements are provided in the Planning Reserve Margin section.

IESO has initiated implementation of new technologies, processes, and more dynamic tools to support the operation of the transforming grid with more diverse resource types and a more complex transmission system.

The IESO's 2022 *Pathways to Decarbonization* report included a limited assessment of the ability of Ontario's resource portfolios to manage a variety of conditions in real time. Further areas to explore include the sufficiency of the studies' resource mix to provide inertia and primary frequency response, operating reserve, ramping capability and reactive support, and voltage control. The IESO is also investigating implications of increased penetration of variable resources on the system.

The IESO-controlled grid will have sufficient system inertia and frequency response to ensure stable operation up to 2025. The IESO worked with the provincial regulator to amend the Distribution System Code, which was released in 2022 to include the requirements of the new IEEE 1547-2018 standard. This effort was to ensure all resources contribute, as needed, to maintain grid reliability. The IESO also acts in accordance with NERC Reliability Standards to ensure adequate warning is provided for generators coming off-contract that would adversely impact grid reliability. In such scenarios, Reliability-Must-Run contracts can be established to meet system needs.

Energy Storage
Recent storage procurements are provided in the Planning Reserve Margin section. Currently, storage resources in Ontario amount to only about 50 MW, excluding the Beck generating stations' overall capacity. Some storage provides capacity while the rest offer ancillary services. The Expedited Long-Term RFP procured 930 MW of storage for a commercial operation start date of May 1, 2026. The LT1 RFP process has targeted 1,600 MW of storage with a commercial operation date of May 1, 2028. Both procurements required storage resources to have a minimum four-hour duration.

Prevalent uses for existing storage include regulation services, reactive support and voltage control, energy market participation, and BTM peak shaving. Newly acquired energy storage facilities will be required to participate in Ontario's energy markets during peak hours. Non-committed storage is now able to participate in the annual capacity auctions and provide capacity and operating reserve. Market integration of hybrid storage-generation resources has been identified as a priority under the umbrella of projects within the enabling resources initiative, and stakeholder engagement is underway.

Capacity Transfers and External Assistance

Firm capacity imports and exports with neighboring jurisdictions are included in the IESO's planning studies, but the IESO assumes only a limited amount of imports for the purposes of its reliability assessments. The IESO also includes non-firm imports of 250 MW for summer and 240 MW for winter.

Although Ontario has been a net energy exporter for many years, exports are expected to decrease sharply with the retirement of Pickering Nuclear Generating Station and more units on outage. The area's most recent energy adequacy assessments suggest economic imports will increase, and Ontario could become a net energy importer throughout the refurbishment period.

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As part of the capacity exchange agreement between Ontario and Québec, the IESO may call on a total of 500 MW of firm imports from Hydro-Québec over summer months prior to September 2030. The decision on when to call the capacity will be made in due course depending on the outcomes of the IESO's current procurement and the potential extension to Pickering Nuclear Generating Station operations.

Transmission

March 31, 2022, marked the in-service date for the expansion of the East–West Tie with the addition of a 230 kV double-circuit transmission line to provide the necessary transfer capability to meet capacity needs in the IESO's northwest area.

The IESO is reinforcing its bulk system in the province's Northeast with the development of three new transmission lines to support electrification of the steel industry as well as overall growth in the area.

A new double-circuit 230 kV transmission line from Chatham Transmission Station (TS) to Lakeshore TS will bring additional supply to the Windsor-Essex area and is expected to be completed by Q4 2025. It will also improve the ability for resources and bulk facilities to operate efficiently and maintain the existing interchange capability on the interconnection between Windsor and Detroit, Michigan. The IESO has recommended further reinforcement to support the area's medium-term needs, including an additional double-circuit 230 kV line from Lambton TS to Chatham TS, expected in-service by 2028, and a new 500 kV transmission line from Longwood TS to Lakeshore TS to be in service by 2030.

To reinforce the Peterborough area, the IESO is developing a new double-circuit 230 kV transmission line with a planned in-service date of 2029. In addition to these new lines, additional refurbishment and upgrade projects are planned across the province to maintain reliability.

Reliability Issues

Nuclear refurbishment over the next decade is a major resource risk that requires additional attention. The IESO has regular meetings with nuclear operators to assess probable delays and take appropriate mitigation actions.

For long-term planning purposes, the IESO carries an additional level of reserve to account for these risks. It provides advanced outage approvals solely when Ontario is adequate under extreme weather. Ontario's reserves were below reserve margin requirements during most of summer 2023 due to planned generator outages, including nuclear, but the IESO managed this by either rejecting planned outages during this time if extreme weather materialized or used emergency control actions.

Other factors that may contribute to IESO reliability issues include supply chain issues, conditions in neighboring jurisdictions, extreme weather, decarbonization-driven changes to supply and demand, policy and regulatory uncertainty, asset health, forced outages, and potential market exit.

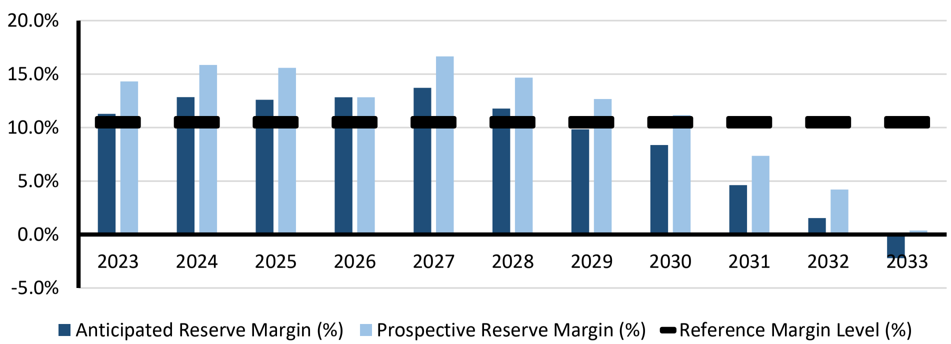
The IESO has not conducted specific assessments on critical infrastructure but does monitor performance of its natural gas facilities. More than 18% of natural-gas-fired generation has dual-fuel capability with on-site oil supply in winter for more than a day of operation. In the *2022 Annual Planning Outlook's* 20-year planning period, the risk for pipeline contingencies is low when calculating reserve margin. While the diverse supply mix helps improve resilience, the IESO will continue to monitor natural gas supply as demand leads to increased dependence on this resource, including for significant energy.

NPCC-Québec

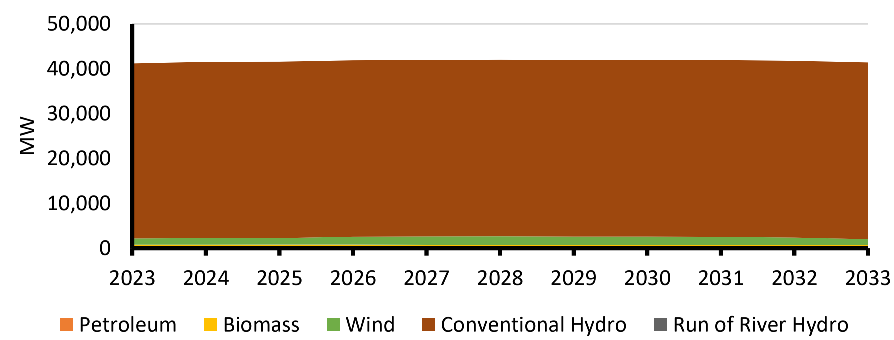
The Québec assessment area (Province of Québec) is a winter-peaking NPCC subregion that covers 595,391 square miles with a population of eight and a half million. Québec is one of the four NERC Interconnections in North America with ties to Ontario, New York, New England, and the Maritimes. These ties consist of either HVDC ties, radial generation, or load to and from neighboring systems. See Normal Risk Areas for more details.

Demand, Resources, and Reserve Margins[49]

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	41,036	41,488	41,946	42,468	43,377	44,062	44,776	45,569	46,627	47,820
Demand Response	4,452	4,732	4,896	5,068	5,258	5,322	5,377	5,389	5,389	5,389
Net Internal Demand	36,584	36,756	37,049	37,400	38,118	38,740	39,399	40,181	41,238	42,432
Additions: Tier 1	73	73	559	687	815	815	815	815	815	815
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-334	-245	-145	455	455	455	600	0	0	0
Existing-Certain and Net Firm Transfers	41,211	41,312	41,246	41,840	41,793	41,734	41,882	41,222	41,060	40,677
Anticipated Reserve Margin (%)	12.8%	12.6%	12.8%	13.7%	11.8%	9.8%	8.4%	4.6%	1.5%	-2.2%
Prospective Reserve Margin (%)	15.9%	15.6%	12.8%	16.7%	14.7%	12.7%	11.2%	7.4%	4.2%	0.4%
Reference Margin Level (%)	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%



Planning Reserve Margins



Existing and Tier 1 Resources

[49] The electric system in NPCC-Quebec

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Highlights

- The ARM remains above the RML until 2029. However, the PRM is above the RML until 2031.
- Approximately 877 MW of capacity additions are expected over this assessment period. A total of 2,548 MW wind generation capacity (815 MW capacity value at peak time) is expected to be in service by 2029.
- The commissioning of the second Micoua-Saguenay 735 kV line is expected by the end of 2023.

NPCC- Québec Fuel Composition

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Petroleum	429	429	429	429	429	429	429	429	429	429
Biomass	378	378	397	397	345	281	277	277	277	269
Solar	10	10	10	10	10	10	10	10	10	10
Wind	1,375	1,449	1,449	1,751	1,843	1,936	1,893	1,893	1,842	1,678
Conventional Hydro	38,975	39,269	39,275	39,280	39,317	39,354	39,354	39,354	39,362	39,362
Total MW	41,166	41,533	41,558	41,866	41,942	42,008	41,962	41,962	41,919	41,748

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NPCC-Québec Assessment

Planning Reserve Margins

The ARM is based on existing and anticipated generating capacity and firm capacity transfers. It is above the area RML over this study period assessment except for the last five winter periods 2030–2034. However, the PRM remains above the RML for almost all years of this assessment. Under the Prospective scenario, a total of 1,100 MW of expected capacity supply is planned by the Québec area; this capacity could either be supplied by resources within the area or by imports. This capacity has not yet been backed by firm long-term contracts. However, based on its annual capacity needs, the Québec area proceeds with short-term capacity contracts to meet its capacity requirements.

Probabilistic Assessments

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	0.00	0.00	0.00
EUE (PPM)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
Operable On-Peak Margin	7.1%	-1.6%	-2.3%

* Provides the 2020 ProbA Results for Comparison

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Demand

The requirements are obtained by adding transmission and distribution losses to the sales forecasts. The monthly peak demand is then calculated by applying load factors to each end-use and/or sector sale. The sum of these monthly end-use sector peak demands is the total monthly peak demand. The Québec area demand forecast average annual growth is 1.2% during this assessment period.

Demand-Side Management

The Québec area has various types of DR resources specifically designed for peak shaving during winter operating periods. The first type of DR resource is the interruptible load program that is mainly designed for large industrial customers; it has an impact of 2,790 MW on winter 2023–2024 peak demand. The area is also expanding its existing interruptible load program for commercial buildings that will grow from 568 MW in 2023–2024 to 889 MW by the end of this assessment period. Another similar program for residential customers is in operation and should gradually rise from 96 MW for winter 2023–2024 to 621 MW for winter 2028–2029 and continue to grow in later years.

New dynamic rate options for residential and small commercial or institutional customers will also contribute to reducing peak load during winter periods by 297 MW for winter 2023–2024and 445 MW for winter 2033–2034.

Moreover, data centers specialized in blockchain applications are required to reduce their demand during peak hours at Hydro-Québec's request. Their contribution as a resource is expected to be around 269 MW over this assessment period.

Finally, another DR resource consists in a voltage reduction scheme allowing for a 250 MW peak demand reduction.

EE and conservation programs are integrated in the assessment area's demand forecasts.

Distributed Energy Resources

Total installed BTM capacity (solar PV) is expected to increase to more than 718 MW in 2034. Solar PV is accounted for in the load forecast. Nevertheless, since Québec is a winter-peaking area, solar PV on-peak contribution ranges from 1 MW for winter 2023–2024 to 5 MW for winter 2033–2034.

Generation

Four wind generation projects are expected to be in service during this assessment period for a total of 2,548 MW of installed capacity (815 MW on-peak value). The first project, Apuiat (204 MW), is expected to be in service in 2024–2025. The second project, Des neiges (1,200 MW), is divided into three phases. The first phase (400 MW) is expected to be in service for the 2026–2027 winter period. The second and third phase with the same capacity (400 MW each) are expected to be in service for the 2027–2028 and 2028–2029 winter periods, respectively. The third and last project is the 2021 call for tenders for a total of 1,144 MW of wind, and it is expected to be in service in December 2026.

The integration of small hydro unit accounts for 41 MW new capacity during this assessment period.

Capacity Transfers and External Assistance

The governments of Québec and Ontario have signed a Memorandum of Understanding (MOU) of an Agreement that allows a seasonal capacity exchange between the two areas for the next seven years except for the year 2027 (no exchange is allowed). The technical details of the Agreement will be completed by the next Fall (2024). The agreement will start from winter 2024–2025 to winter 2030–2031. This agreement will be firm and allow the Québec area to import 600 MW from November to April. In the summer season, Québec will export 600 MW of firm capacity to Ontario from May to October.

Transmission

- **The Micoua-Saguenay 735-kV Line**
  Hydro-Québec has identified the need to build a new 735 kV line that extends 262 km (163 miles) between Micoua substation in the Côte-Nord region and Saguenay substation in Saguenay–Lac–Saint-Jean. The project also includes adding equipment to both substations and expanding Saguenay substation. This project is now under construction and is expected to be in service in 2023.
- **Appalaches-Maine Interconnection**
  This project to increase transfer capability between Québec and Maine by 1,200 MW is in the construction phase. The project will connect to the New England Clean Energy Connect project in Maine. It involves the construction of a ±320-kV DC transmission line about 100 km (62 miles) long from Des Appalaches 735/230-kV substation to the Canada–United States border. From the international border crossing, the dc transmission line will be extended 145 miles to a substation in Lewinston, ME, where the power will be converted from dc to ac. The project in Québec also includes the construction of an ac to dc converter at Des Appalaches substation and triggers the need of thermally upgrading two 735 kV lines in the south of the system. The first thermal upgrade was completed in 2022 and the second one is expected to be completed in 2023. The planned in-service date of the interconnection project is under review.
- **Hertel-New York Interconnection**
  This project to increase transfer capability between Québec and New York by 1,250 MW is currently in the permitting phase. It involves the construction of a ±400 kV DC underground transmission line about 60 km (37 miles) long from Hertel 735/315 kV substation just south of Montréal to the Canada–United States border. The project will connect to the Champlain Hudson Power Express project in New York State. From the international border crossing, the dc transmission line will be extended 339 miles to a substation in Astoria, NY, where the power will be converted from dc to ac. The project in Québec also includes the construction of an ac to dc converter at Hertel substation. The project is expected to be in service in May 2026.

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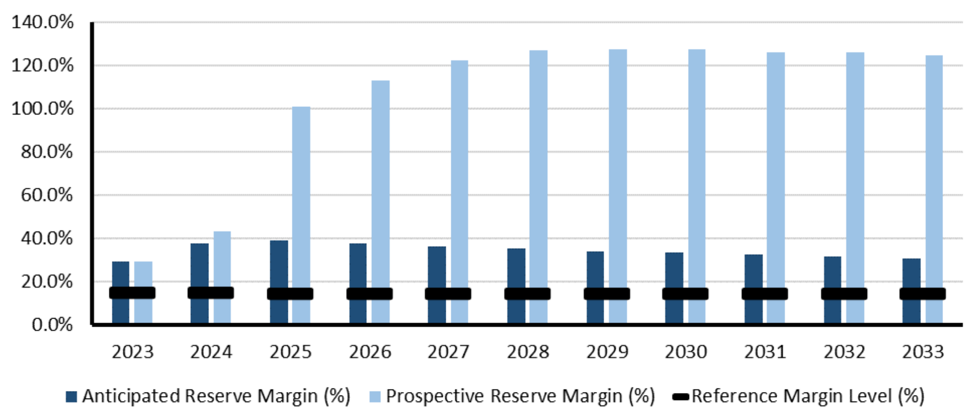
PJM

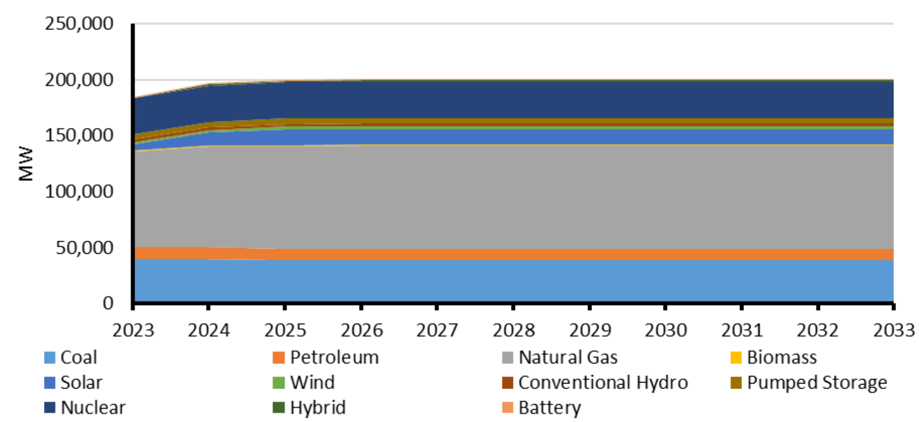
PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator. See **Normal Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	149,737	150,924	152,736	154,275	155,703	156,923	157,899	158,942	159,917	160,971
Demand Response	7,397	7,453	7,515	7,573	7,617	7,646	7,679	7,710	7,731	7,758
Net Internal Demand	142,340	143,471	145,221	146,702	148,086	149,277	150,220	151,232	152,186	153,213
Additions: Tier 1	13,090	18,234	19,715	19,706	19,706	19,706	19,706	19,706	19,706	19,706
Additions: Tier 2	7,982	88,414	109,210	126,252	135,888	139,177	141,681	141,855	144,220	144,220
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-607	-105	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	181,614	180,346	179,338	179,324	179,324	179,324	179,324	179,324	179,324	179,324
Anticipated Reserve Margin (%)	36.8%	38.4%	37.1%	35.7%	34.4%	33.3%	32.5%	31.6%	30.8%	29.9%
Prospective Reserve Margin (%)	42.4%	100.0%	112.2%	121.7%	126.1%	126.5%	126.7%	125.3%	125.5%	124.0%
Reference Margin Level (%)	14.8%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM is above the RML for each year of the assessment period.
- As in other assessment areas, there is potential for resource adequacy risks to emerge in PJM during the later years of the assessment period and beyond. In February 2023, PJM published a report of its analysis of the future energy transition in PJM based on resource retirement, replacement, and electricity demand scenarios.[50] PJM found increasing reliability risks due to the potential for the timing of generator retirements to be misaligned with load growth and the arrival of new generation on the system. Trends toward higher demand, faster generator retirements, and slower resource entry could expose PJM to decreasing Planning Reserve Margins and reliability challenges from imbalanced resource composition and resource performance characteristics. Unlike the demand forecasts and resource projections in this LTRA, the PJM report used scenarios and modeling for its analysis.

PJM Fuel Composition

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	39,921	38,648	38,238	38,238	38,238	38,238	38,238	38,238	38,238	38,238
Petroleum	10,206	10,039	10,039	10,039	10,039	10,039	10,039	10,039	10,039	10,039
Natural Gas	89,804	91,820	93,310	93,310	93,310	93,310	93,310	93,310	93,310	93,310
Biomass	928	931	930	930	930	930	930	930	930	930
Solar	11,802	14,135	13,402	13,386	13,386	13,386	13,386	13,386	13,386	13,386
Wind	1,963	2,527	2,605	2,601	2,601	2,601	2,601	2,601	2,601	2,601
Conventional Hydro	2,523	2,439	2,429	2,426	2,426	2,426	2,426	2,426	2,426	2,426
Pumped Storage	4,798	4,801	4,786	4,786	4,786	4,786	4,786	4,786	4,786	4,786
Nuclear	32,594	32,594	32,594	32,594	32,594	32,594	32,594	32,594	32,594	32,594
Hybrid	1,212	1,035	1,006	1,006	1,006	1,006	1,006	1,006	1,006	1,006
Battery	836	992	990	990	990	990	990	990	990	990
Total MW	196,587	199,960	200,329	200,305	200,305	200,305	200,305	200,305	200,305	200,305

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[50] Energy Transition in PJM: Resource Retirements, Replacements, and Risks

PJM Assessment

Planning Reserve Margins
The ARM for each year in this assessment period does not fall below the RML in PJM. PJM has a normal risk of energy shortages.

Energy Assessment and Non-Peak Hour Risk
PJM is expecting a normal risk of experiencing periods of resources falling below required operating reserves during upcoming peak periods based on the *2022 PJM Reserve Requirement Study*. As indicated in the *2022 PJM Reserve Requirement Study*, PJM is forecasting around 30% installed reserves (including expected committed demand resources), which is well above the target IRM of 14.9% necessary to meet the 1-day-in-10-years LOLE criterion. Due to the relatively low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with most loss-of-load risk remains the hour with highest forecasted demand. Notwithstanding the above, to address potential future reliability concerns due to limitations associated with the performance of limited and variable resources, PJM's ELCC methodology calculates the reliability and energy contribution of limited and variable resources.

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Probabilistic Assessments

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	0.00	0.00	0.00
EUE (PPM)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
Operable On-Peak Margin	29.0%	29.0%	28.0%

* Provides the 2020 ProbA Results for Comparison

Demand
The PJM Interconnection produces an independent peak load forecast of total internal demand by using econometric regression models with daily load as the dependent variable and independent variables including calendar effects, weather, economics, and end-use characteristics. PJM annually reviews load forecast methodology and implements changes when improvements are identified. For the 2021 load forecast, the major changes encompassed refinements to sector models and non-weather-sensitive load, both of which were first introduced with the 2020 load forecast.

Demand-Side Management
DR resources can participate in all PJM Markets–capacity, energy, and ancillary services.

Distributed Energy Resources
PJM expects 4,865 MW of solar PV DER at the time of the peak in 2028 and 7,109 MW in 2033. The effects of solar PV DER are included in the load forecast for PJM. No effect of solar PV DER is incorporated in the winter load forecast since winter expected peak occurs after sundown.

Generation
PJM's existing installed capacity reflects a fuel mix that is comprised of approximately 47% natural gas, 24% coal, and 18% nuclear. Hydro, wind, solar PV, oil, and waste fuels constitute the remaining 11%. A diverse generation portfolio reduces the system risk associated with fuel availability and reduces dispatch price volatility. Totaling over 78,000 MW of Capacity Interconnection Rights (CIRs), renewable fuels are changing the landscape of PJM's interconnection queue. Solar PV energy comprises 66% of the generation in PJM's interconnection queue, a 10% increase over the previous year. An increase in solar PV generation interconnection requests is attributable to state policies encouraging renewable generation.

Prior to 2021, the variable resource capacity value was set at a resource's average output over a defined number of summer peak load hours. This approach has two limitations: it weights the output over all hours equally, regardless of an individual hour's actual contribution to the annual loss-of-load risk; and it fails to recognize the saturation effect as the amount of intermittent resources in PJM increases. To address these two limitations, PJM performed analysis to assess the reliability value of intermittent resources by using an ELCC method. This more robust methodology recognizes the full value of a resource's output over high-load risk hours and also accounts for resources by using an ELCC methodology and also accounts for the saturation effect.

As part of the process to implement the ELCC, a proposal was developed: PJM now requires generation owners of ELCC resources to provide specific information about their resources. This information is used by PJM as input to its resource adequacy model. Pending FERC approval, the ELCC methodology will be applied to intermittent, limited-duration and hybrid resources beginning with the 2023/2024 delivery year.

Energy Storage

Energy storage development continues to grow in PJM. As solar PV generation increases across the PJM footprint, storage growth is expected to follow, particularly as part of co-located projects. Efficient grid operations in an era of rapid renewable energy resource growth will require increased electric system flexibility. Energy storage can help grid operators maintain stable power supply under varying wind and solar power output that is driven by weather conditions and unit outages and improve utilization levels of existing transmission facilities. PJM has worked with various companies and national laboratories to study storage use and to ensure that the PJM wholesale market can permit all forms of energy storage to participate. PJM recognizes that storage paired with renewables and transmission can optimize the delivery of power. To address the limited-duration issue, some developers are pairing storage with variable renewable generation, such as solar PV or wind, to create opportunistic revenue streams. The pairing is either co-located (in which the storage facility and the generator facility are sited on the same parcel of land, but each has its own connection to the grid) or is hybrid (in which the storage facility and generator share a common connection to the grid).

Today, storage resources are made up of pumped storage hydro for a total of nearly 4,000 MW as well as BESS and flywheel energy storage for a total of 300 MW. Pumped storage can participate in the PJM capacity, energy, regulation and reserves markets. Queued storage resources total over 34,000 MW of interconnection requests for CIRs.

Capacity Transfers and External Assistance

PJM does not rely on significant transfers to meet resource adequacy requirements. Maximum transfer (total transmission interchange capability) into PJM would amount to less than 2% of PJM's internal generation capability. At no time within this assessment period does the ARM get anywhere near 2%. PJM reliability would not be negatively affected if transfers were dropped to zero.

Transmission

The $2.4 billion of baseline transmission investment approved during 2022 continues to reflect the shifting dynamics driving transmission expansion. New large-scale transmission projects (345 kV and above) have become more uncommon as RTO load growth has fallen below 1%. Aging infrastructure, grid resilience, a shifting generation mix, and more localized reliability needs are now more frequently driving new system enhancements.

Reliability Issues

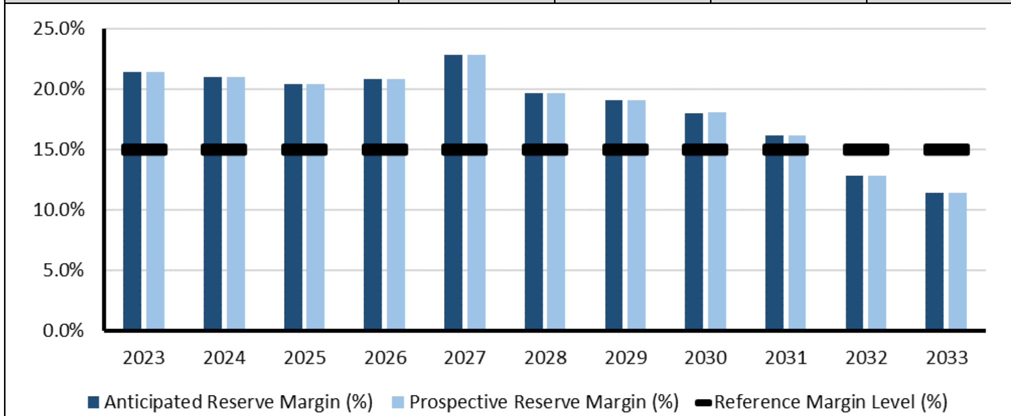
Offshore wind is emerging as a potential major source of power that is seeking grid interconnection along coastal states in the PJM area. Through September 2021, only two operational offshore wind farms in the United States have reached commercial operation: the 30 MW Block Island Wind Farm off the coast of Rhode Island and the 12 MW Coastal Virginia Offshore Wind Pilot Project near Virginia Beach. Although current operational capacity totals are low, offshore wind is expected to be a major contributor to U.S. clean energy and decarbonization initiatives over the coming decades.

SERC-East

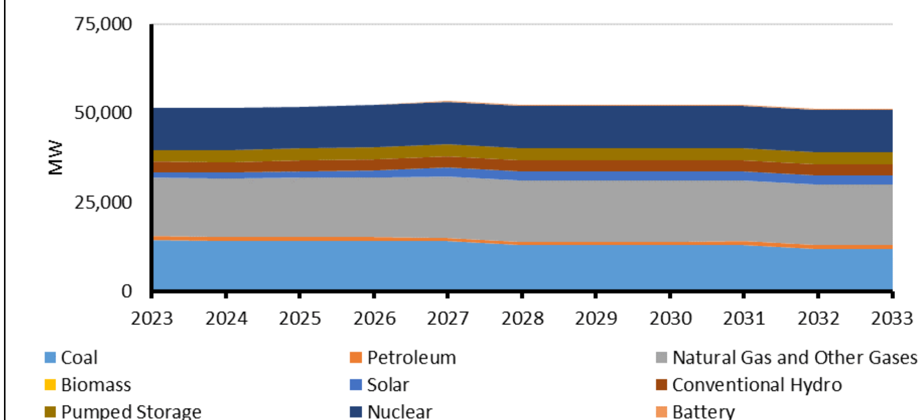
SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 34 Balancing Authorities, 27 PAs, and 7 RCs. See Normal Risk Areas for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	44,014	44,590	44,789	44,993	45,220	45,425	45,831	46,583	46,985	47,580
Demand Response	983	989	996	1,003	1,006	1,007	1,008	1,009	1,010	1,011
Net Internal Demand	43,031	43,601	43,793	43,990	44,214	44,418	44,823	45,574	45,975	46,569
Additions: Tier 1	55	546	961	2,267	2,267	2,267	2,267	2,267	2,267	2,267
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	624	624	624	624	624	624	624	624	624	624
Existing-Certain and Net Firm Transfers	52,290	51,954	51,954	51,778	50,648	50,648	50,648	50,667	49,620	49,620
Anticipated Reserve Margin (%)	21.6%	20.4%	20.8%	22.9%	19.7%	19.1%	18.1%	16.1%	12.9%	11.4%
Prospective Reserve Margin (%)	21.6%	20.4%	20.8%	22.9%	19.7%	19.1%	18.1%	16.2%	12.9%	11.4%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

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Highlights

- ARMs are above the RML through 2031.
- Natural gas (32%), coal (28%), and nuclear (23%) generation are the dominant fuel types within the assessment area. Hydro, renewables, and other fuel types make up the remaining (17%) generation.
- From 2023 to 2033, SERC-East will retire nearly 2.6 GW of coal generation. Tier 1 addition of 0.7 GW natural gas, 1 GW of BES-connected solar PV, and 0.4 GW BESS is expected during this time. At this time, 24 MW of utility-scale transmission BES-connected BESS. 350 MW of Tier 1 nameplate capacity BESS is expected within 10 years.
- Historically a summer peaking area, SERC-East is forecasting higher peak demands during winter months.
- The net non-coincident internal demand, which includes the available, controllable, and dispatchable DR for the assessment area is expected to grow annually at a rate of approximately 0.8% on average in the next 10 years.

SERC-East Generation Capacity by Fuel Type (Summer)										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	14,426	14,005	14,005	14,005	12,875	12,875	12,875	12,875	11,828	11,828
Petroleum	1,174	1,174	1,174	1,122	1,122	1,122	1,122	1,141	1,141	1,141
Natural Gas	16,227	16,718	16,718	16,970	16,970	16,970	16,970	16,970	16,970	16,970
Biomass	173	173	173	173	173	173	173	173	173	173
Solar	1,528	1,528	1,943	2,523	2,523	2,523	2,523	2,523	2,523	2,523
Conventional Hydro	3,030	3,115	3,115	3,115	3,115	3,115	3,115	3,115	3,115	3,115
Pumped Storage	3,364	3,364	3,364	3,364	3,364	3,364	3,364	3,364	3,364	3,364
Nuclear	11,789	11,789	11,789	11,789	11,789	11,789	11,789	11,789	11,789	11,789
Battery	11	11	11	361	361	361	361	361	361	361
Total MW	51,721	51,876	52,291	53,421	52,291	52,291	52,291	52,310	51,263	51,263

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SERC-East Assessment

Planning Reserve Margins

SERC-East ARMs are above the RML during the first nine years of this assessment period.

Energy Assessment and Non-Peak Hour Risk

Entities are developing ways of evaluating energy risk and rely on production cost modeling to evaluate energy adequacy. Entities continue to identify generation resource constraints in operations planning. Some are developing probabilistic techniques to incorporate more variation of inputs, such as load, force outage rate, and renewable energy generation. The assessment area did not identify increased energy risks during the non-peak hours. However, ramping needs are increasing with the additional solar PV generation penetration.

Probabilistic Assessments

Base Case Summary of Results (2022 ProbA)			
	2024*	2024	2026
EUE (MWh)	5.26	64.33	92.49
EUE (PPM)	0.024	0.272	0.389
LOLH (hours per Year)	0.01	0.06	0.081
Operable On-Peak Margin	15.9%	15.0%	16.1%

* Provides the 2022 ProbA Results for Comparison

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SERC-East is peaking during winter months. This is due to the addition of solar PV generation that shaves off summer peak demand and the observed trend toward electrification of heating that drives up winter peak demand. The reliability risk as indicated by the 2022 ProbA is projected to be stable. Higher winter peaks and/or lower supply of capacity during the early winter morning demand contributed to the increase in EUE metric values. The severe cold weather stress-test indicated that there is some risk of customer interruption and loss of energy in the case of combining unusual weather with higher-than-anticipated generator unit outages. The severe cold weather stress-test indicated that there is some risk of customer interruption and loss of energy in the case of combining unusual weather with higher-than-anticipated generator unit outages.

Demand

Historically a summer peaking area, SERC-East is forecasting higher peak demands during winter months. The net non-coincident internal demand, which includes the available, controllable, and dispatchable DR for the assessment area, is expected to grow annually at a rate of approximately 0.8% on average in the next 10 years.

Demand-Side Management

Entities use demand-side management programs to reduce load on the system during times of high peak demand. Seasonal load reduction capabilities for each individual participant are aggregated to determine the estimated program capacities that are available as dispatchable grid reliability resources. Program capacities are continually updated based upon changes in enrollment levels or application of newly acquired peak period data. A continued focus going forward for growth of existing programs and introduction of new programs is on maximizing winter capabilities. Heat strip load control programs can be used for mechanical winter peak reduction for customers. Though they are dependent on the thermostat manufacturer notification and usage rules, they provide the greatest benefit in terms of reduction with minimal customer discomfort. "Bring Your Own kW" programs allow small and medium business participants to compensate for load reduction through any methods they can employ. Electric vehicle managed charging is also being tested in the Carolinas. Other technologies to watch in the short term are Wi-Fi enabled water heaters and BTM storage. Further into the future, smart panels and smart inverters may provide value. Efforts to control voltage are also increasing.

Distributed Energy Resources

The DER resources are mainly solar PV projects. Entities include all future DER resources in their models which have a signed Interconnection Agreement. Any network upgrades associated with those projects are also included in the models. Entities study more light-load scenarios when solar PV resources will be near maximum and a large percentage of system load to reveal any possible transmission issues in that dispatch scenario. The DER forecasts are developed using economic models of payback, which is a function of installed cost, regulatory incentives and statutes, and bill savings. A relationship between payback and customer adoptions is developed through regression modeling, and the resulting regression equations are used to predict future customer adoptions based on projected payback curves. Customer size estimates based on historical adoption data are used to convert the future customer adoptions to capacity and hourly profiles are employed to yield the generation projections. The projected hourly generation from the DER forecasts is incorporated into the load forecasts as a load modifier, thus reducing the expected future load. As the BESS continue to grow, the DER forecasts will be enhanced to include separate projections of BTM solar PV only and BTM solar PV plus storage systems.

Generation

Natural gas (32%), coal (28%), and nuclear (23%) generation are the dominant fuel types within the SERC-East assessment area. Hydro, renewables, and other fuel types make up the remaining (17%) generation. SERC-East assessment area will retire nearly 2.6 GW of coal generation within the next 10 years. Tier 1 addition of 0.7 GW natural gas, 1 GW BES-connected solar PV, and 0.4 GW BESS is expected during this time.

Energy Storage

There is 11 MW of utility-scale transmission BES-connected BESS at this time. 350 MW of Tier 1 BESS is expected within 10 years.

Capacity Transfers and External Assistance

During high demand periods and the simultaneous unavailability of a severe and significant portion of generation, capacity transfer may be limited. Limited coal availability at coal plants located in specific areas of the system could also limit transfer capability. Entities will evaluate transmission projects and coordinate with neighboring TOPs/RCs to manage the interfaces and take needed actions such as generation redispatch, transmission reconfiguration, and TLRs.

Transmission

The assessment area will add another 46.7 miles within the first five years, followed by 0.3 mile in the next five years of new AC transmission lines with the voltage range between 100 to 200 kV. The assessment area will add another 173.6 miles within the first five years, followed by 43.1 miles in the next five years of new AC transmission lines with the voltage range between 200 to 300 kV. These projects are in the planning/construction phase and are projected to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability. Entities do not anticipate any transmission limitations or constraints with significant impacts to reliability.

Reliability Issues

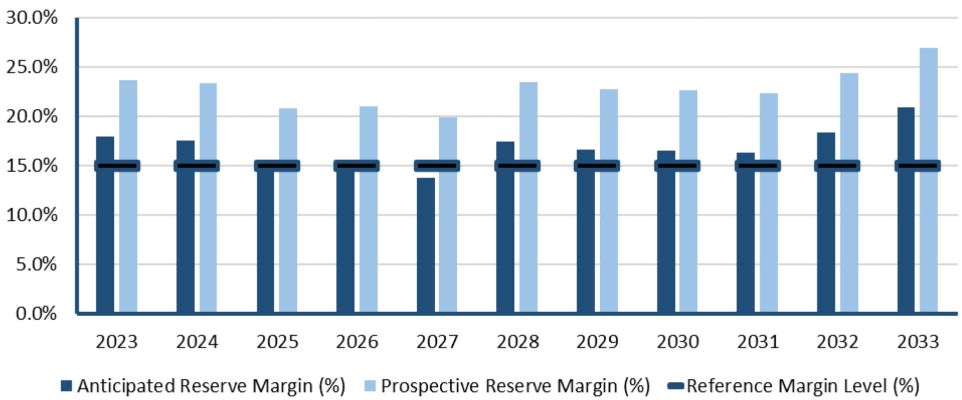
Extreme cold and hot weather preparation with guidance on actions related to forecasted periods of grid stress through risk assessments is an area of focus for this assessment area. One entity reported that it removed natural gas infrastructure from its transmission load shedding plan and coordinates with its natural gas transportation providers in its area to place the appropriate priority on electricity service to any critical natural gas infrastructure. Sensitivity analyses help the entities prepare for changes in generation mix and develop projects to improve future system conditions, and/or operational guidelines to mitigate any observed risks.

SERC-Central

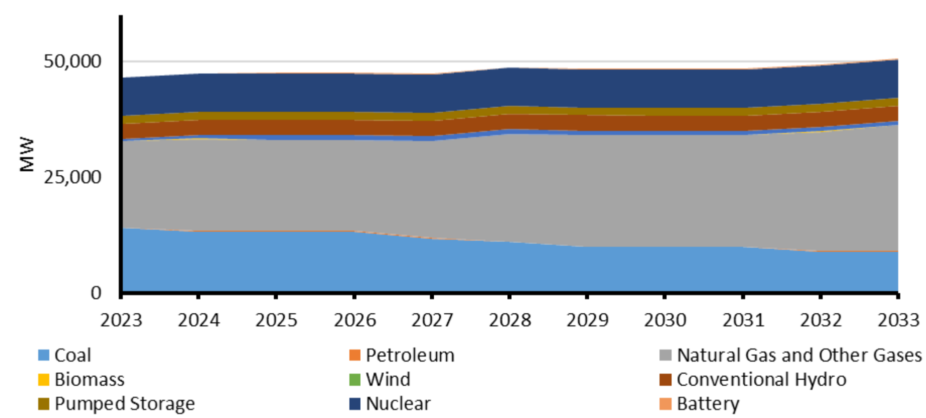
SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission (FERC) approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 34 Balancing Authorities, 27 Planning Authorities (PA), and 7 RCs. See **High Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	42,259	42,595	42,560	42,737	42,739	42,765	42,764	42,858	42,877	43,109
Demand Response	1,851	1,835	1,838	1,842	1,840	1,839	1,837	1,836	1,835	1,834
Net Internal Demand	40,408	40,760	40,722	40,895	40,899	40,926	40,927	41,022	41,042	41,275
Additions: Tier 1	1,600	2,526	2,530	3,876	6,086	6,934	6,934	6,934	8,755	10,081
Additions: Tier 2	20	170	170	170	170	170	170	170	170	170
Additions: Tier 3	28	235	463	1,015	1,568	2,170	2,623	3,075	3,528	3,980
Net Firm Capacity Transfers	198	-677	-677	-677	-677	-677	-677	-677	-677	-677
Existing-Certain and Net Firm Transfers	45,922	44,247	44,247	42,673	41,946	40,816	40,786	40,786	39,818	39,818
Anticipated Reserve Margin (%)	17.6%	14.8%	14.9%	13.8%	17.4%	16.7%	16.6%	16.3%	18.3%	20.9%
Prospective Reserve Margin (%)	23.4%	20.9%	21.0%	19.9%	23.5%	22.8%	22.7%	22.4%	24.4%	26.9%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

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Highlights

- The ARM falls slightly below the RML during the summer months of 2025, 2026, and 2027. The entities plan to secure firm transmission imports to support operating plans when resources are deficient.
- Natural gas (40%), coal (30%), and nuclear (18%) generation are the dominant fuel types within the assessment area. Hydro, renewables, and other fuel types (12%) are minimal.
- From 2023 to 2033, SERC-Central will retire more than 5 GW of coal generation within the next 10 years. Tier 1 additions of nearly 8.6 GW of natural gas, 0.5 GW of BES-connected solar PV, and 0.1 GW of BESS is expected during this time.
- Historically a summer peaking area, SERC-Central has now become a dual-peaking system.
- The net non-coincident internal demand, which includes the available, controllable, and dispatchable DR for the assessment area, is expected to grow annually at a rate of approximately 0.2% on average in the next 10 years.

SERC-Central Generation Capacity by Fuel Type (Summer)										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	13,235	13,235	13,235	11,661	10,934	9,804	9,804	9,804	8,836	8,836
Petroleum	148	148	148	148	148	148	148	148	148	148
Natural Gas	19,888	19,618	19,618	20,964	23,174	24,022	23,992	23,992	25,813	27,139
Biomass	36	36	36	36	36	36	36	36	36	36
Solar	647	983	987	987	987	987	987	987	987	987
Wind	4	4	4	4	4	4	4	4	4	4
Conventional Hydro	3,315	3,315	3,315	3,315	3,315	3,315	3,315	3,315	3,315	3,315
Pumped Storage	1,691	1,691	1,691	1,691	1,691	1,691	1,691	1,691	1,691	1,691
Nuclear	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280
Battery	81	141	141	141	141	141	141	141	141	141
Total MW	47,324	47,450	47,454	47,226	48,709	48,427	48,397	48,397	49,250	50,576

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SERC-Central Assessment

Planning Reserve Margins

The ARM for the SERC-Central assessment area falls slightly below the NERC target reference margin of 15% during the summer months of 2025, 2026, and 2027. Economic development and load growth contribute to an increase in anticipated demand in the near-term future. SERC-Central is also retiring a total of 3,260 MW summery capacity of mostly coal generation by the year 2027, which is reflected through the three-year span. A Tier 1 capacity addition of 3,556 MW in natural gas generation is expected to alleviate the capacity shortage in summer months starting in 2028. SERC-Central entities will use internal processes to review season-ahead and prompt-year positions to ensure reserve margins are adequate in the near term. The entities are constantly monitoring load growth and use additional market capacity as needed. A large entity has recently entered into several short-term power purchase agreements and secured additional firm transmission to help mitigate near-term capacity needs. The entity maintains a diverse portfolio of generating resources with a variety of fuel procurement sources. This variety provides a natural hedge against supply concerns from any one source that could pose a risk to its overall generation.

Energy Assessment and Non-Peak Hour Risk

Entities incorporate energy risks, such as extreme weather, outages (forced and planned), interchange limits, and renewable variability into their loss-of-load probabilistic studies. These results are used to determine the margin targets, generation portfolios, and power contract requirements. They also assist in long term investment and commercial actions to mitigate reserve margin shortfalls. SERC-Central did not identify any increase in energy risk concerns due to the relatively low solar PV and wind penetration. However, ramping needs are expected to increase over time as more solar PV is added to the system. The entities plan to add more storage and flexible dispatchable gas generation to help mitigate the impacts.

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Probabilistic Assessments

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	0.00	0.00	0.00
EUE (PPM)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
Operable On-Peak Margin	18.4%	18.6%	17.1%

* Provides the 2022 ProbA Results for Comparison

SERC-Central has been transitioning from a summer-peaking to a dual-peaking system in the last few years and is projected to continue in that trend. The reliability risk as indicated by the 2022 ProbA is projected to be stable. The 2022 ProbA results indicate no LOLHs or EUE based on data and modeling assumptions. The severe cold weather stress test indicated that there is some risk of customer interruption and loss of energy in the case of combining unusual weather with higher-than-anticipated generator unit outages.

Demand

Historically a summer peaking area, SERC-Central has now become a dual-peaking system. The net non-coincident internal demand, which includes the available, controllable, and dispatchable DR for the assessment area, is expected to grow annually at a rate of approximately 0.2% on average in the next 10 years.

Demand-Side Management

Controllable and dispatchable DR programs are considered available during peak hours from June through September. The amount of MW available is highly dependent on the weather and is estimated based on historical performance. While some program events are dispatched and monitored near real-time, customers receive monthly capacity payments and energy payments based on performance during events. Dispatchable voltage regulation can operate distribution feeder voltages in the lower half of the standard voltage range to lower peak demand. Electric system distribution feeders utilize a voltage feedback loop to bias voltage regulators to maintain the lowest acceptable feeder voltage during an economic event. Interruptible DR program can suspend a portion of participating customers' load with 5- or 30-minutes notice during times of the power system need.

Distributed Energy Resources

The impact of DER resources is forecasted and incorporated into the total energy and peak demand forecasts. Entities do not always include the growth of DERs in resource planning, however. The BTM solar PV is embedded in the load forecast with an hourly shape derived from solar irradiance. The solar PV is often a fixed energy supply resource modeled as an hourly generation profile in a typical week pattern each month derived from simulated data. Consideration is given to aligning the solar PV generation with the peak load for the week, particularly in the summer when the highest load for the week will likely occur during the sunniest day of the week.

Generation

Natural gas (40%), coal (30%), and nuclear (18%) generation are the dominant fuel types within the assessment area. Hydro, renewables, and other fuel types (12%) are minimal. From 2023 to 2033, SERC-Central will retire more than 5 GW of coal generation within the next 10 years. Tier 1 additions of nearly 8.6 GW of natural gas, 0.5 GW of BES-connected solar PV, and 0.1 of GW BESS is expected during this time.

Energy Storage

There is no utility-scale transmission BES-connected BESS at this time. 246 MW of Tier 1 and 770 MW of Tier 2 and Tier 3 nameplate capacity BESS is expected within 10 years.

Capacity Transfers and External Assistance

Severe system events could reduce transfer capacity, possibly affecting a portion of load under summer conditions. The entity would coordinate with neighboring TOP to expedite returning a line to service and shed load if no other options are available. Entities plan to maintain surplus capacity to meet reliability needs during extreme weather scenarios. They will coordinate with its operations personnel, fuel suppliers, pipeline personnel, and neighboring utilities prior to and during weather events.

Transmission

The assessment area will add another 118.4 miles within the first five years followed by 53 miles in the next five years of new ac transmission lines with the voltage range between 100 to 200 kV. These projects are in the planning/construction phase and projected to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability. Entities do not anticipate any transmission limitations or constraints with significant impacts to reliability.

Reliability Issues

SERC and its members have not identified any other emerging reliability issues without existing or planned solutions. However, entities continue to monitor the possible impacts on the long-term reliability of the BES from the supply chain issues, changing resource mix, transmission projects and temporary mitigations, summer and dual peaking scenarios, extreme weather events, and critical infrastructure sector interdependency.

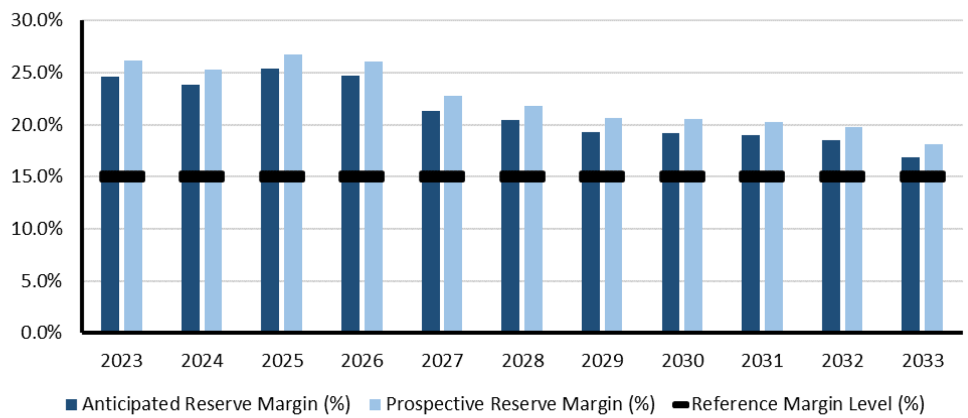
High transfers across the transmission system and their impacts on reliability driven by high regional wind and extreme weather events is an area of risk. To support reliability across the year with changes in generation resources, a dual peaking entity has adopted separate reserve margin targets for winter and summer seasons with plans for effective outage planning in off-peak periods. The entity studied a peak summer demand with low hydro scenario to reflect drought weather conditions and has identified projects to address the more severe reliability concerns. This assessment area can tackle fuel resilience risks with a well-diversified generation portfolio and advantageous location with respect to major gas pipelines, access to multiple coal supply and transport options, and a strong and resilient program to secure nuclear fuel. In addition, entities identified improvement opportunities for both normal operating conditions and to allow for more effective response and restoration activities under severe scenarios.

SERC-Florida Peninsula

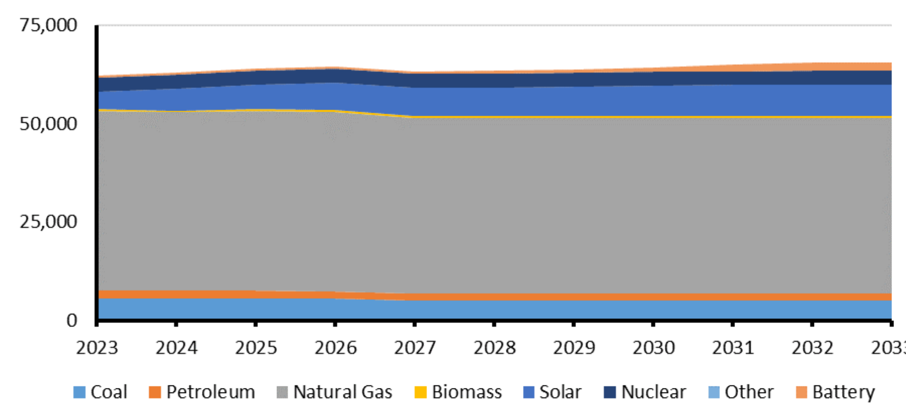
SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 34 Balancing Authorities, 27 PAs, and 7 RCs. See **Normal Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	53,190	53,591	54,107	54,516	54,977	55,719	56,407	57,036	57,847	58,667
Demand Response	2,924	2,957	2,988	3,022	3,064	3,109	3,155	3,202	3,247	3,288
Net Internal Demand	50,266	50,634	51,119	51,494	51,913	52,610	53,252	53,834	54,600	55,379
Additions: Tier 1	1,549	2,394	3,099	3,281	3,464	3,735	4,419	5,004	5,660	5,660
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	594	700	499	499	406	406	406	406	406	406
Existing-Certain and Net Firm Transfers	60,700	61,062	60,624	59,204	59,035	59,035	59,035	59,035	59,035	59,035
Anticipated Reserve Margin (%)	23.8%	25.3%	24.7%	21.3%	20.4%	19.3%	19.2%	19.0%	18.5%	16.8%
Prospective Reserve Margin (%)	25.3%	26.7%	26.1%	22.7%	21.8%	20.7%	20.5%	20.3%	19.8%	18.1%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

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Highlights

- The ARMs are above the RML throughout the assessment period.
- Natural gas (73%), coal (9%), and nuclear (6%) are among the primary fuel types within the assessment areas. Renewables and other fuel types make up the remaining (12%) generation.
- From 2023 to 2033, SERC-Florida Peninsula will retire nearly 0.5 GW of coal generation. Tier 1 addition of nearly 0.9 GW natural gas, 3.5 GW BES-connected solar PV, and 1.6 GW BESS is expected during this time.
- SERC-Florida Peninsula is a summer-peaking assessment area.
- The net non-coincident internal demand, which includes the available, controllable, and dispatchable DR for the assessment area, is expected to grow annually at a rate of approximately 1% on average in the next 10 years.

SERC-Florida Peninsula Generation Capacity by Fuel Type

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	5,172	5,172	5,172	4,713	4,713	4,713	4,713	4,713	4,713	4,713
Petroleum	2,017	2,017	1,846	1,718	1,718	1,718	1,718	1,718	1,718	1,718
Natural Gas	44,424	44,717	44,650	43,832	43,756	43,756	43,793	43,793	43,793	43,793
Biomass	429	429	429	414	414	414	414	414	414	414
Solar	5,565	6,273	6,978	7,161	7,344	7,526	7,709	7,891	8,032	8,032
Nuclear	3,502	3,502	3,502	3,502	3,502	3,502	3,502	3,502	3,502	3,502
Other	12	12	12	12	12	12	12	12	12	12
Battery	534	634	634	634	634	723	1,187	1,589	2,104	2,104
Total MW	61,655	62,756	63,223	61,986	62,092	62,364	63,048	63,632	64,288	64,288

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SERC-Florida Peninsula Assessment

Planning Reserve Margins
SERC -Florida Peninsula ARMs are above the RML throughout the assessment period.

Energy Assessment and Non-Peak Hour Risk
The entities collaborate and run probabilistic assessments that look at every hour of the 5-year study period to determine where a potential energy adequacy risk may arise. Additional scenario cases are also evaluated, such as unavailability of firm imports, DR, and 90/10 load projection. The study results observed in the months surrounding the peak month simulate additional scheduled maintenance outages while the projected demand begins to ramp up to its seasonal peak levels. The current energy assessments do not explicitly evaluate system ramping needs. Over the next few years, The FRCC Planning and Operating Committees plan to further evaluate system ramping needs and determine if system ramping could become a challenge for the overall footprint. The results of the loss-of-load probability study are used in combination with deterministic analyses to determine if the planned resources meet adequacy requirements.

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Probabilistic Assessments

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	2.26	1.09	1.13
EUE (PPM)	0.009	0.004	0.004
LOLH (hours per Year)	0.004	0.002	0.002
Operable On-Peak Margin	11.4%	18.3%	18.6%

* Provides the 2020 ProbA Results for Comparison

SERC-Florida Peninsula is a summer-peaking assessment area. The reliability risk, as indicated by the 2022 ProbA, is projected to be stable. The 2022 ProbA results indicate low to no risk of LOLHs or EUE based on data and modeling assumptions. The severe cold weather stress-test indicated that there is some risk of customer interruption and loss of energy in the case of combining unusual weather with higher-than-anticipated generator unit outages.

Demand
SERC-Florida Peninsula is a summer-peaking assessment area. The net non-coincident internal demand, which includes the available, controllable, and dispatchable DR for the assessment area is expected to grow annually at a rate of approximately 1% on average in the next 10 years.

Demand-Side Management
Controllable DR from interruptible and dispatchable load management programs is treated as a load-modifier and projected to be constant at approximately 6% of the summer and winter total peak demands for all years of this assessment period. Entities develop their own independent forecast of firm controllable and dispatchable DR values to be available at system peak based on their methodology and program policies. These individual reporting entities perform and develop independent analyses of the estimated impacts from their firm DR and load management. The impacts are aggregated for analytical purposes in the assessment area.

Distributed Energy Resources
The FRCC performs an annual collection of Distributed Energy Resources across the membership. Entities utilize the NERC published definitions of DERs when forecasting, monitoring, and reporting. In general, FRCC member DERs are modeled as being netted out with the actual customer demand since they are implicitly accounted for in the load forecasts of entities. Increased penetration levels of BTM PV continues to be observed year over year and is anticipated to continue; however, at relatively low penetration levels when compared to the Total Demand of the assessment area. In addition, members of the resource, transmission, technical and stability analysis subcommittees annually perform reviews of the DER penetration levels to determine if additional study work or sensitivities are needed. At this time, no additional challenges from increased penetration levels of DERs have been identified by the Planning Coordinators and Transmission Planners in the assessment area.

Generation
Natural gas (73%), coal (9%), and nuclear (6%) are among the primary fuel types within the assessment areas. Renewables and other fuel types make up the remaining (12%) generation. From 2023 to 2033, SERC-Florida Peninsula will retire nearly 0.5 GW of coal generation. Tier 1 addition of nearly 0.9 GW natural gas, 3.5 GW BES-connected solar PV, and 1.6 GW BESS is expected during this time.

Energy Storage
There is 519 MW of utility-scale transmission BES-connected BESS at this time. 1,585 MW of Tier 1 nameplate capacity BESS is expected within 10 years.

Capacity Transfers and External Assistance

The assessment area has one interface to the Eastern Interconnection made up of multiple transmission facilities. The owners of these facilities on each side of the subregions study various scenarios to determine transfer capabilities into and out of the assessment area. There are various contingencies that could limit the transfer capability into and out of the subregion that could result in potential reliability impacts. Those potential impacts would be mitigated by the various operating entities affected, including the FRCC Reliability Coordinator and Southeastern Reliability Coordinator.

Transmission

The assessment area will add another 67.6 miles within the first five years followed by 40.2 miles in the next five years of new AC transmission lines with the voltage range between 100 to 200 kV. The assessment area will add another 193.1 miles within the first five years followed by 9.3 miles in the next five years of new AC transmission lines with the voltage range between 200 to 300 kV. These projects are in the planning/construction phase and projected to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability. Entities do not anticipate any transmission limitations or constraints with significant impacts to reliability.

Reliability Issues

The 10-year projected total reserve margin is above 15%, and this assessment area remains under the industry standard metric of 0.1 loss-of-load probability. Although expected resources meet operating reserve requirements under normal peak-demand scenarios, supplemental analysis on significant and sustained temperature deviations from normal winter peak load and outage conditions identified that operating mitigations (i.e., DR and transfers) and energy emergency alerts (EEAs), including potential load shedding that may be needed under extreme peak demand and outage scenarios studied. The entities continue to monitor the possible impacts on the long-term reliability of the BES from the changing resource mix, the higher penetration of IBR generation, the risks of extreme weather, and the assessment area's dependency on natural gas as a fuel resource.

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SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 34 Balancing Authorities, 27 Planning Authorities, and 7 RCs. See **Normal Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	46,354	45,595	45,831	46,267	46,555	46,753	47,050	47,311	47,570	47,937
Demand Response	2,069	2,246	2,341	2,380	2,282	2,286	2,285	2,285	2,285	2,285
Net Internal Demand	44,285	43,349	43,490	43,887	44,273	44,467	44,765	45,026	45,285	45,652
Additions: Tier 1	2,679	2,921	3,186	3,186	3,186	3,186	3,186	3,186	3,186	3,186
Additions: Tier 2	218	218	218	218	218	218	218	218	218	218
Additions: Tier 3	299	426	426	426	426	426	426	426	426	426
Net Firm Capacity Transfers	-971	-471	-471	-471	-471	-471	-256	-256	-256	-256
Existing-Certain and Net Firm Transfers	60,294	60,819	60,878	60,878	60,878	60,878	61,093	61,093	61,093	61,093
Anticipated Reserve Margin (%)	42.2%	47.0%	47.3%	46.0%	44.7%	44.1%	43.6%	42.8%	41.9%	40.8%
Prospective Reserve Margin (%)	44.6%	49.5%	49.8%	48.4%	47.1%	46.5%	46.0%	45.1%	44.3%	43.1%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%

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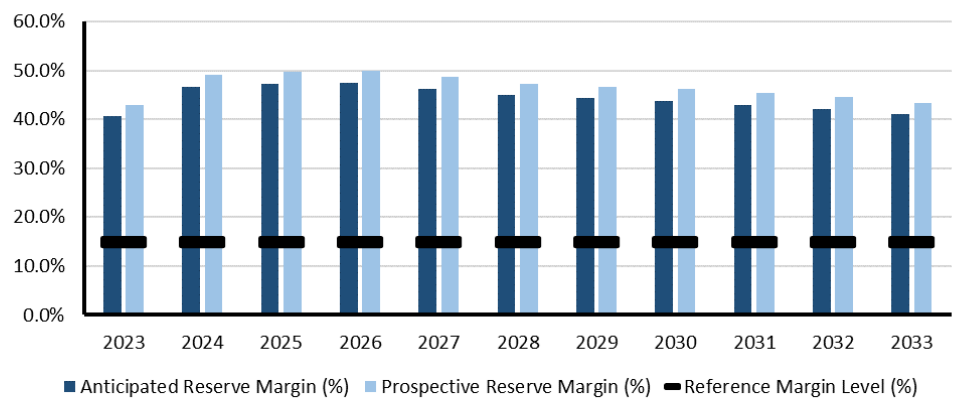
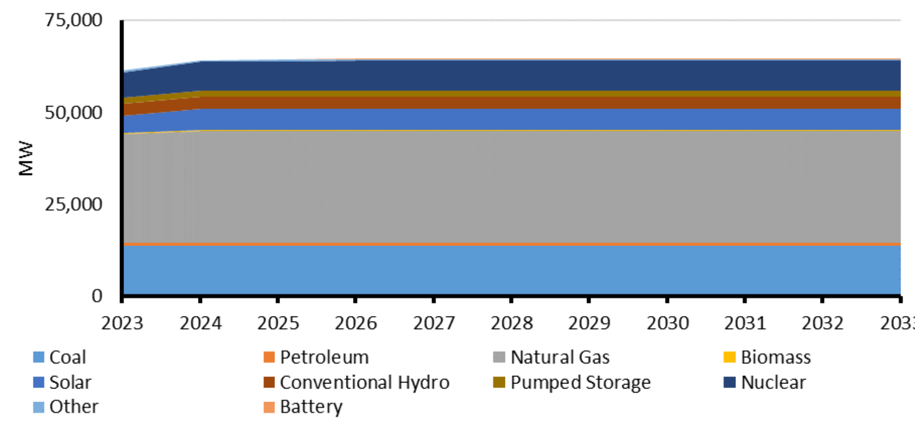


Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- SERC-Southeast show ARMs above the RML during the first five years of this assessment period.
- Natural gas (47%), coal (22%), and nuclear (13%) generation are the dominant fuel types within the assessment areas. Hydro, renewables, and other fuel types make up the remaining (18%) generation.
- The assessment area will add 788 MW of natural gas generation over the period. 3,937 MW of utility-scale transmission BES-connected Tier 1 solar PV projects are expected in the next 10 years. Overall, there will be 1,878 MW of net additions and retirements within the next 10 years.
- There is no utility-scale transmission BES-connected BESS at this time. 330 MW of Tier 1 nameplate capacity BESS is expected within 10 years.

SERC-Southeast Generation Capacity by Fuel Type										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	13,770	13,770	13,770	13,770	13,770	13,770	13,770	13,770	13,770	13,770
Petroleum	915	915	915	915	915	915	915	915	915	915
Natural Gas	30,023	30,048	30,107	30,107	30,107	30,107	30,107	30,107	30,107	30,107
Biomass	424	424	424	424	424	424	424	424	424	424
Solar	5,496	5,738	5,738	5,738	5,738	5,738	5,738	5,738	5,738	5,738
Conventional Hydro	3,288	3,288	3,288	3,288	3,288	3,288	3,288	3,288	3,288	3,288
Pumped Storage	1,632	1,632	1,632	1,632	1,632	1,632	1,632	1,632	1,632	1,632
Nuclear	8,018	8,018	8,018	8,018	8,018	8,018	8,018	8,018	8,018	8,018
Other	313	313	313	313	313	313	313	313	313	313
Battery	65	65	330	330	330	330	330	330	330	330
Total MW	63,944	64,211	64,535	64,535	64,535	64,535	64,535	64,535	64,535	64,535

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SERC-Southeast Assessment

Planning Reserve Margins

SERC-Southeast shows ARMs above RML during this assessment period.

Energy Assessment and Non-Peak Hour Risk

Many entities perform probabilistic assessments to identify energy risk. These assessments cover different scenarios such as hydro generation off-line, low solar PV output scenarios, potential environmental-related generation plant retirements, extreme weather impacting supply to natural-gas-fired generation plants, and unexpected loss of large generation units. The energy adequacy assessment results do not show increased risk outside of expected peak demand hours while considering expected ramping requirements, fuel, and generator availability as well as load forecast uncertainty scenarios. The assessments have demonstrated a need for additional transmission capacity to facilitate the displacement of traditional fossil-fueled generation resources. Lower solar PV output has not yet resulted in system reliability issues due to available alternate resources, but future reserve planning is a concern. DER penetration is currently low and does not significantly contribute to load forecast, particularly for winter periods. The results from the energy assessment are used for support in fuel and capacity appropriation decisions. Additionally, the results are used to determine the amount of seasonal reserve capacity that will be maintained based on the current forecasted peak season demand.

Probabilistic Assessments

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	0.03	0.00	0.00
EUE (PPM)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
Operable On-Peak Margin	30.2%	26.8%	30.8%

* Provides the 2020 ProbA Results for Comparison

SERC-Southeast is slightly winter peaking. The 2023 LTRA data indicates more coal retirements than anticipated in the 2022 LTRA. The reliability risk, as indicated by the 2022 ProbA, is projected to be stable. The 2022 ProbA results indicate no loss-of-load hours or EUE based on data and modeling assumptions. The severe cold weather stress test indicated that there is some risk of customer interruption and loss of energy in the case of combining unusual weather with higher-than-anticipated generator unit outages.

Demand

Each consumer class can have an econometric forecast based on load factor, demand ratio, trend analysis, weather, appliance efficiency, large load adjustment, and load profile models. The weather is a key driver in the forecast process. Regression models relating weather and the economy to energy sales can predict future sales for customers. Load factors and diversity ratios can determine the peaks. Future hourly load shapes are derived from historical hourly load shapes and the forecasted demand and energy. Customer load shapes are added together to form the hourly load shape for its system. Temperature sensitivities are utilized to develop weather case extreme forecast. Discreet adjustments are examined outside of the models for analysis on how DERs impact the forecast. The variable resources do not generally contribute to load forecast uncertainty in long-range forecast. Some entities use the Statistically Adjusted End-Use model, which combines the strengths of econometric and end-use methodologies by incorporating the detail of end-use models while maintaining the ease of use associated with econometric models. The Statistically Adjusted End-Use Model allows the entity to evaluate the function of price, income, population, appliance saturations, market shares, and specifically the importance of weather in determining usage. The model incorporates member cooperative results from their residential end-use surveys, thus capturing any new technology (electric vehicles, residential solar PV) that could affect usage. Each year, historical data will be added to the LF databases for each member, and new regression equations will be developed and evaluated with the SAE model to forecast average residential usage as well as a linear regression equation to forecast non-residential sales. The summer and winter peaks are projected with the most probable weather conditions (50/50 forecast). The historical relationship between total system load levels and weather will continue to be the key component in developing an hourly demand forecast for the total system load.

Demand-Side Management

The demand side management water heater program allows system operators to control appliance usage during peak demand periods. The number of installed water heater control switches are accounted for each month. Historical trends are used to forecast the number of water heater control switches to be installed in future years. Entities monitor and dispatch DR programs per individual contract terms. Annual ELCC simulations are performed to determine the capacity value for each unique and active DR program. An adjustment to that capacity value is then made based on predicted customer response when the program is called or dispatched. The impacts of BTM DERs are accounted for in the development of the annual load forecasts. In front-of-the-meter DERs are considered separate generation resources and do not impact any current demand-side management programs.

Distributed Energy Resources

Some entities record DER contributions by the sum of their capacities for each metering point served via distribution transformers. When DER capacities at a certain metering point meet or exceed a certain level, estimated generation is placed back onto the load bus for load forecasting purposes. Entities model DERs as hourly profiles in all resource planning models, thereby taking into consideration ramping and other operational considerations. The forecast of BTM solar PV is based on a trend model for MWs. This MW forecast is then converted to an energy forecast by using an assumed capacity factor.

The BTM solar PV forecast increases through the assessment period. On a yearly basis, the reliability model is updated based on the latest system Integrated Resource Plan. Capacity values for proposed and newly added DER resources are then calculated based on the current yearly model assumptions. Projections of solar PV are included in the Base Case forecast on the demand side. However, demand-side BESS and other BTM resources are not prevalent and are not included.

Generation

- Natural gas (47%), coal (22%), and nuclear (13%) generation are the dominant fuel types within the assessment area. Hydro, renewables, and other fuel types make up the remaining (18%) generation.
- The assessment area will add 788 MW of natural gas generation over the period.
- Overall, there will be 1,878 MW of net additions and retirements within the next 10 years.
- 2,399 MW of utility-scale transmission BES-connected Tier 1 solar PV projects are expected in the next 10 years.

Energy Storage

- There is no utility-scale transmission BES-connected BESS at this time.
- 330 MW of Tier 1 nameplate capacity BESS is expected within 10 years.

Capacity Transfers and External Assistance

Entity studies confirmed Open Access Same-Time Information System (OASIS) reservations in its long-term assessments and plans for the delivery of those commitments under a variety of scenarios including different load levels and system flow patterns. For imports into the system, OASIS reservations for the capacity benefit margin and Transmission Reliability Margin are included and planned for. Any concerns that are identified in these assessments are reviewed with neighboring utilities, and evaluations are coordinated when necessary to determine optimal solutions.

Transmission

- The assessment area will add another 369.3 miles within the first five years followed by 109.1 miles in the next five years of new AC transmission lines with the voltage range between 100 to 200 kV.
- The assessment area will add another 229.9 miles within the first five years followed by 4.8 miles in the next five years of new AC transmission lines with the voltage range between 200 to 300 kV.
- The assessment area will add another 101.6 miles within the first five years followed by 65.0 miles in the next five years of new AC transmission lines with the voltage range higher than 400 kV.
- These projects are in the planning/construction phase and projected to enhance system reliability by supporting voltage and relieving challenging flows.
- Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability.
- Entities do not anticipate any transmission limitations or constraints with significant impacts on reliability.

Reliability Issues

Electromagnetic transient studies of in-service IBRs in relatively weak areas of the system have been deemed necessary for some entities. This is important to determine appropriate ramp rates, controller settings, and ride-through capabilities for available generation. The potential impacts of driving this need are unexpected responses (voltage oscillations, power quality impacts, etc.) observed during disturbances or abnormal configurations. Extreme weather study processes are evolving, and more emphasis is being placed on extreme cold due to recent events in other areas. Extreme weather events are included as part of the load and weather patterns considered in its probabilistic determination of reserve margins. Additionally, fuel price volatility and fuel availability continue to present challenges that have resulted in various scenarios being studied and evaluated on a continuous basis by some entities. Entities identify potential common mode failures within the natural gas subsector through various processes and studies and coordinate with their critical natural gas facilities, local electric sector participants, and fuel suppliers in performing assessments to ensure any facilities critical to maintaining fuel availability are not included in its load shedding procedures

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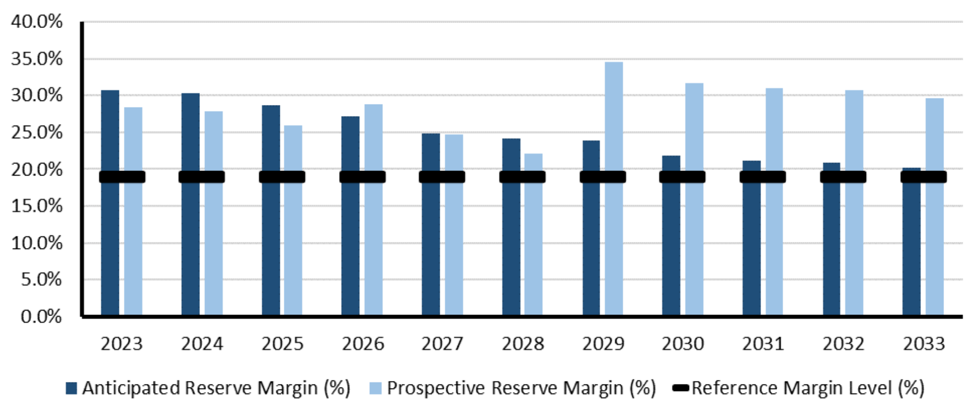
SPP

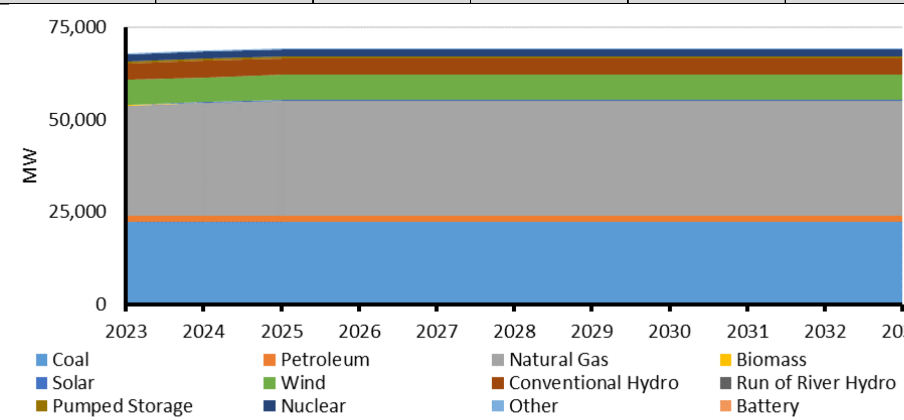
The SPP Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the Planning Coordinator footprint, which touches parts of the Midwest Reliability Organization Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million. See Elevated Risk Areas for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	53,603	54,846	55,784	56,754	57,048	57,249	58,253	58,557	58,908	59,242
Demand Response	1,353	1,489	1,772	1,798	1,807	1,843	1,851	1,857	2,062	2,046
Net Internal Demand	52,250	53,356	54,012	54,957	55,240	55,405	56,402	56,700	56,846	57,196
Additions: Tier 1	718	1,302	1,302	1,302	1,302	1,302	1,302	1,302	1,302	1,302
Additions: Tier 2	0	0	2,739	2,739	2,739	9,795	9,795	9,795	9,795	9,795
Additions: Tier 3	0	0	4,205	4,205	4,205	4,205	4,205	4,205	4,205	4,205
Net Firm Capacity Transfers	-404	-384	-364	-474	-469	-469	-400	-400	-402	-402
Existing-Certain and Net Firm Transfers	67,371	67,391	67,411	67,301	67,306	67,306	67,418	67,418	67,416	67,416
Anticipated Reserve Margin (%)	30.3%	28.7%	27.2%	24.8%	24.2%	23.8%	21.8%	21.2%	20.9%	20.1%
Prospective Reserve Margin (%)	27.8%	25.9%	28.8%	24.7%	22.2%	34.5%	31.7%	31.0%	30.7%	29.7%
Reference Margin Level (%)	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%



Planning Reserve Margins



Existing and Tier 1 Resources

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Highlights

- ARMs do not fall below the RML for this assessment period.

SPP Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	22,283	22,283	22,283	22,283	22,283	22,283	22,283	22,283	22,283	22,283
Petroleum	1,728	1,728	1,728	1,728	1,728	1,728	1,728	1,728	1,728	1,728
Natural Gas	30,544	31,128	31,128	31,128	31,128	31,128	31,128	31,128	31,128	31,128
Biomass	35	35	35	35	35	35	35	35	35	35
Solar	201	201	201	201	201	201	201	201	201	201
Wind	6,713	6,713	6,713	6,713	6,713	6,713	6,713	6,713	6,713	6,713
Conventional Hydro	4,418	4,418	4,418	4,418	4,418	4,418	4,418	4,418	4,418	4,418
Run of River Hydro	75	75	75	75	75	75	75	75	75	75
Pumped Storage	440	440	440	440	440	440	440	440	440	440
Nuclear	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944
Other	281	281	281	281	281	281	281	281	281	281
Battery	1	1	1	1	1	1	1	1	1	1
Total MW	68,664	69,248	69,248	69,248	69,248	69,248	69,248	69,248	69,248	69,248

SPP Assessment

Planning Reserve Margins

ARMS do not fall below the RML of 19% (based on SPP coincident peak demand) for the entire ten-year assessment period. While the SPP ARM shows a robust amount of excess capacity, these margins reflect the full availability of accredited capacity and do not account for planned, forced or maintenance outages. The SPP ARM also does not reflect de-rates based on real time operational impacts. Similar to the Generation Unavailability scenario in the *2023 NERC Summer Reliability Assessment*, SPP shows the potential to use all of the LTRA ARM capacity, which means there could be times of capacity shortfall based on performance impacts during high load periods. While the potential to use all of the LTRA ARM capacity has a low probability, the assumptions and projections are based around historic unavailability during on-peak periods.

The RML of 19% was established by SPP and its stakeholders and is based on results of the most recent biennial LOLE study.[51] The study analyzes the ability to reliably serve the SPP BA area's 50/50 forecasted peak demand with a security constrained economic dispatch. SPP, with stakeholder input, develops the inputs and assumptions used for the LOLE Study. SPP will study the Planning Reserve Margins such that the LOLE for the applicable planning year (2- and 5-year study) does not exceed 1-day-in-10 years, or 0.1 day per year. At a minimum, the RML will be determined with probabilistic methods by altering capacity through the application of generator forced outages and forecasted demand through the application of load uncertainty to ensure the LOLE does not exceed 0.1 day per year. The 2023 LOLE study is underway in SPP but will not be completed prior to publication of the *2023 LTRA*.

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Energy Assessment and Non-Peak Hour Risk

As the resource mix continues to change from a baseload thermal and hydro resources to VERs and short duration energy storage resources, SPP recognizes that its LOLE study must also continue to evolve. A potential change and improvement identified for the 2023 LOLE study includes considering energy adequacy and additional metrics (e.g., EUE).

Probabilistic Assessments

SPP's most recent study performed for NERC's Probabilistic Assessment (2022 ProbA) found negligible risk of load loss in the Base Case for both study years. All unserved energy was concentrated in peak summer months.

Base Case Summary of Results (2022 ProbA)			
	2024*	2024	2026
EUE (MWh)	0.00	0.27	0.84
EUE (PPM)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
Operable On-Peak Margin	13.3%	19.7%	19.6%

* Provides the 2020 ProbA Results for Comparison

In 2023, SPP completed a probabilistic analysis of a winter risk scenario that paired increases in both conventional forced generation outages and peak demand. The scenario was carried out for the 2026 study year by using the 90/10 winter load forecast and increasing the forced outage rate of the conventional fleet by a factor of two.[52] In this scenario, some energy goes unserved in winter months and overall EUE rises to 1.36 MWh.

Demand

SPP peak load occurs during the summer season. The 2024 load forecast is projected to peak at 53,603 MW, which is a 1% increase compared to the previous year's LTRA forecast for the 2024 summer season. SPP forecasts the coincident annual peak growth based on member submitted data over the 10-year assessment time frame. The diversity factor used to convert members' non-coincident peak demand forecasts to an SPP coincident peak demand forecast is consistent with the percentage used for the 2022 LTRA. The current annual growth rate is approximately 1%.

Demand-Side Management

SPP's EE and conservation programs are incorporated into the reporting entities' demand forecasts. The SPP assessment area is projecting a significant amount of DR to come online over the assessment time frame and is currently working on accreditation methodologies to better access reliability contributions from these programs. DR resources are projected to rise sharply over the assessment period from the current contribution of 829 MW to over 2,000 MW by 2033. As an additional sensitivity to the 2023 LOLE study, SPP modeled high level constraints applied to the current DR programs to understand the possible reliability impacts when constraining the programs to a certain limited number of calls per year and limited number of hours per day. Additionally, SPP is working with stakeholders to gather program specific details that can be modeled. With the footprint's projected DR growth, it will be important to model these programs accurately to better depict the

[51] SPP LOLE Study Report

[52] See 2022 ProbA Regional Risk Scenarios Report. The scenario was created in early 2022. Since then, significantly higher forced outage rates have been observed in severe winter events, such as winter storm Elliott.

reliability implications to the SPP system. DR growth and electrification have the potential to introduce new demand forecast uncertainty and reliability risk.

Distributed Energy Resources
SPP currently has approximately 300 MW of installed solar PV generating facilities. The SPP Model Development, Economic Studies, and Supply Adequacy working groups are currently developing policies and procedures around DERs. SPP implemented resource adequacy policies for DERs that require certain testing, reporting and documentation requirements for resources and programs not registered with approval planned for late 2023.

Generation
Since the 2022 LTRA, SPP members have reported approximately 1,500 MWs of conventional resources being retired. There are no known unaddressed reliability impacts at this time. Retirements continue to be assessed throughout the time frame through planning and operational processes. The reliability impacts that retired generation have on the transmission system are also analyzed in the annual Integrated Transmission Plan. Some projected retirements in the assessment time frame are currently expected to be replaced with renewable resources. The confirmed retirement impact to resource adequacy in the assessment area is being studied in the 2023 LOLE study.

In 2023, FERC rejected SPP's proposed ELCC methodology for wind and solar PV resource capacity accreditation. SPP is currently working on revising ELCC policy for wind, solar PV, and storage with the goal of obtaining internal approvals and refiling with FERC in late 2023. More properly accrediting wind, solar PV, and storage resources becomes critical as more conventional generators nearing retirement cause SPP historical Planning Reserve Margin levels to decline.

Energy Storage
There are approximately 17,000 MWs of energy storage and hybrid resources in SPP's generator interconnection queue that are being studied. A small amount (about 50 MWs) of these resources are currently under contract by members across the SPP assessment area. These resources are modeled as generation in both near and long-term planning assumptions.

Capacity Transfers and External Assistance
The SPP assessment area coordinates with neighboring areas to ensure that adequate transfer capabilities will be available for capacity transfers. On an annual basis during the model build season, SPP staff coordinates the modeling of transfers between Planning Coordinator footprints. The modeled transactions are fed into the models created for the SPP planning process.

SPP and ERCOT have executed a coordination plan that addresses operational issues for coordination of the dc ties between the Texas Interconnection and Eastern Interconnection, block load transfers, and switchable generation resources. Under the terms of the coordination plan, SPP has priority to recall the capacity of any switchable generation resources that have been committed to satisfy the resource adequacy requirements contained in Attachment AA of the SPP Open Access Transmission Tariff. SPP's and ERCOT's last annual update the coordination plan occurred in June 2023.

Transmission
After evaluating more than 1,080 solutions, SPP worked together with its member organizations to create a robust portfolio of 44 transmission projects, including 51 miles of new extra-high-voltage transmission that can holistically address the reliability, economic, policy, and operational needs of the system. The recommended portfolio contains reliability and economic projects that will mitigate 137 system issues.[53] The *SPP 2024 Integrated Transmission Plan Assessment* and the *2022 SPP Transmission Expansion Plan* reports provide details for proposed transmission projects needed to either maintain reliability and/or provide economic benefit to end users.

Reliability Issues
There are concerns of drought conditions impacting the Missouri River and other water sources for generation resources that rely on once-through cooling processes. Low water can impact the generation's capacity output and reduce its ability to support congestion management and serve load. An additional concern could be the low water's impact on coal availability, which could cause units to run at a derated level to conserve coal inventory. In order to identify mitigations prior to peak conditions, these extreme conditions are studied in SPP's seasonal assessment process. Closer to real time, additional analysis are performed with more accurate forecast data.

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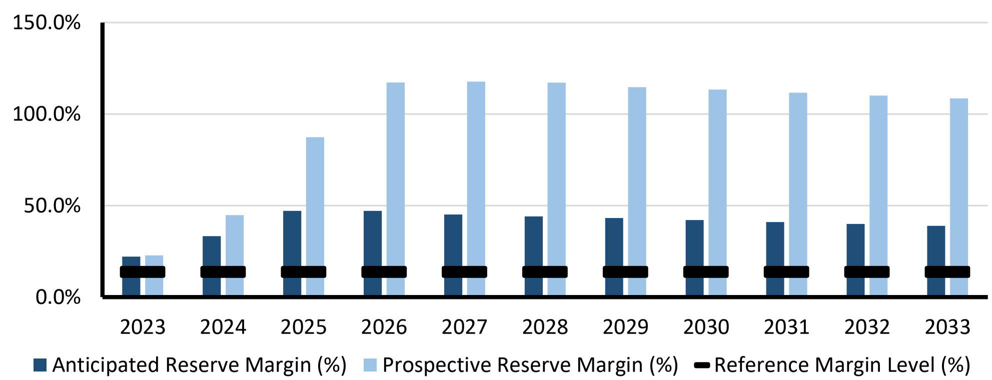
[53] 2022 ITP Report

Texas RE-ERCOT

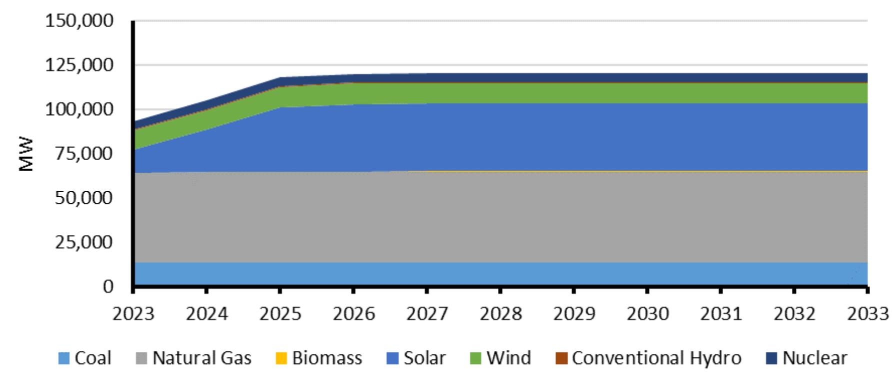
The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single Balancing Authority. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer peaking. It covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,030 generation units, and serves more than 26 million people. Lubbock Power & Light joined the ERCOT grid on June 1, 2021. Texas Regional Entity is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. See Elevated Risk Areas for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	84,325	85,740	87,131	88,518	89,090	89,624	90,298	90,986	91,646	92,296
Demand Response	3,464	3,464	3,464	3,464	3,464	3,464	3,464	3,464	3,464	3,464
Net Internal Demand	80,861	82,276	83,667	85,054	85,626	86,160	86,834	87,522	88,182	88,832
Additions: Tier 1	12,520	25,802	27,852	28,010	28,010	28,010	28,010	28,010	28,010	28,010
Additions: Tier 2	8,618	33,248	58,809	63,012	64,574	64,574	64,874	64,874	64,874	64,874
Additions: Tier 3	7,589	11,955	23,097	26,029	27,828	28,226	28,226	28,226	28,226	28,226
Net Firm Capacity Transfers	20	20	20	20	20	20	20	20	20	20
Existing-Certain and Net Firm Transfers	95,260	95,260	95,260	95,405	95,405	95,405	95,405	95,405	95,405	95,405
Anticipated Reserve Margin (%)	33.3%	47.1%	47.1%	45.1%	44.1%	43.2%	42.1%	41.0%	40.0%	38.9%
Prospective Reserve Margin (%)	44.8%	87.4%	117.2%	117.7%	117.2%	114.7%	113.4%	111.7%	110.1%	108.6%
Reference Margin Level (%)	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%



Planning Reserve Margins



Existing and Tier 1 Resources

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Highlights

- Generation resources, primarily solar PV, continue to be added to the grid in Texas in large quantities, increasing ARMs but also elevating concerns of energy risks that result from the variability of these resources and the potential for delays in implementation. The summer ARM is above the RML (13.75%) for all 10 years of this assessment period (2024–2033). The ARM peaks at 47% by summer 2025, reflecting the expected addition of 25,802 MW of Tier 1 capacity, most of which is solar PV.
- ERCOT's summer peak demand is forecasted to increase by 1.1% per year through 2033 while annual energy is forecasted to increase by 2.1% per year for the same period. While these growth rates are close to the values for the load forecast used in the *2022 LTRA*, ERCOT has adopted more extreme weather assumptions to reflect the increasing frequency of extreme weather events experienced over the last several years and the expectation that this trend will continue.
- ERCOT completed its *2022 Regional Transmission Plan* in December 2022. The plan lists 15 major reliability improvement projects out of a total of 89 proposed projects. Currently, there are $10.26 billion of transmission improvement projects that are expected to be put in service between 2023 and the end of 2028.

Texas RE-ERCOT Fuel Composition

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568
Natural Gas	51,088	51,321	51,321	51,471	51,471	51,471	51,471	51,471	51,471	51,471
Biomass	163	163	163	163	163	163	163	163	163	163
Solar	23,587	36,056	38,033	38,191	38,191	38,191	38,191	38,191	38,191	38,191
Wind	11,032	11,612	11,686	11,686	11,686	11,686	11,686	11,686	11,686	11,686
Conventional Hydro	480	480	480	480	480	480	480	480	480	480
Nuclear	4,973	4,973	4,973	4,973	4,973	4,973	4,973	4,973	4,973	4,973
Total MW	104,891	118,173	120,223	120,531	120,531	120,531	120,531	120,531	120,531	120,531

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Texas RE-ERCOT Assessment

Planning Reserve Margins

The summer ARM is above the RML (13.75%) for all 10 years of this assessment period (2024–2033). The ARM peaks at 47% by summer 2025, reflecting the expected addition of 25,802 MW of Tier 1 capacity, most of which is solar PV. However, the high reserve margin belies concerns about the resource mix in Texas RE-ERCOT—the continuing trend towards less fully dispatchable resources and more IBRs like solar PV and wind—as well as the availability of thermal resources (and associated fuel supplies) for addressing increasing weather volatility and changes to load patterns.

While investigating for the Public Utilities Commission of Texas a reliability standard that encompasses multiple probabilistic reliability measures, ERCOT has proposed a reliability standard framework composed of three measures: frequency, event duration and event magnitude. Pending direction from the Public Utilities Commission of Texas, continued analysis of the reliability standard framework is planned for this summer.

Energy Assessment and Non-Peak Hour Risk

The penetration of solar PV in Texas RE-ERCOT continues to increase the risk of tight operating reserves during hours other than the daily peak load hour. This issue is most acute for the summer season when solar PV generation ramps down during the early evening hours while load is still relatively high. ERCOT's Probabilistic Reserve Risk Model is designed for analysis of the hours with the highest risk of reserve shortages for a seasonal peak demand day. As shown ProbA Base Case chart, the summer 2023 model indicates a progression of increasing hourly EEA risk probabilities from the early afternoon through the early evening hours with the peak EEA probability now occurring for hour-ending 9:00 p.m.

To address energy adequacy concerns, the Public Utility Commission of Texas adopted a performance credit mechanism (PCM) in January 202) as part of a Reliability Standard that the 87th Texas Legislature (by way of Senate Bill 3) directed FERC to implement. The PCM is a new market product that is intended to incentivize development and preservation of dispatchable generation. Under the PCM, generation resources commit to producing more energy during the tightest grid conditions of the year and sell credits to load-serving entities. Since PCM implementation may take up to four years, FERC directed ERCOT to investigate alternative bridging strategies that can be implemented relative quickly. ERCOT proposed modifying the operating reserve demand curve as the preferred approach. The 88th Texas legislative session has passed several bills that address grid reliability and further promote dispatchable resources by including performance penalties for generators with a signed interconnection agreement after January 1, 2026, and a November 2023 ballot measure to provide $7.2 billion in low interest loans and a completion bonus grants for new dispatchable resources of at least 100 MW. This requires ERCOT to consider implementing a new ancillary services program to procure dispatchable reliability reserve services on a day-ahead and real-time basis and placing a cost limit for the PCM of $1 billion (less the cost of the bridging solution), so ERCOT will need to develop reliability plans for areas with high load growth including the Permian Basin.

Probabilistic Assessments

ERCOT's recent study performed for NERC's 2022 ProbA identified LOLH and EUE risk predominantly in the winter, largely driven by the incorporation of additional forced outage risk.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	12.86	492.03	1,235.40
EUE (PPM)	0.03	1.09	2.63
LOLH (hours per Year)	0.01	0.15	0.30
Operable On-Peak Margin	10.2%	36.7%	35.9%

* Provides the 2020 ProbA Results for Comparison

In 2023, ERCOT performed a probabilistic risk scenario that studied the impact of transmission limits on reliability indices as heavy IBRs in one area use transmission to get to its load in the central and eastern parts of Texas for the 2026 study year.[54] Results of this scenario, when compared to the 2022 ProbA Base Case, show that the addition of internal transmission constraints had implications for the reliability of the ERCOT system, resulting in modest EUE increases and a more drastic rise in LOLH.

[54] See 2022 ProbA Regional Risk Scenarios. The scenario was created in early 2022. Since then, significantly higher forced outage rates have been observed in severe winter events, such as winter storm Elliott.

Demand

ERCOT's summer peak demand is forecast to increase by 1.1% per year through 2033 while annual energy is forecasted to increase by 2.1% per year for the same period. While these growth rates are close to the values for the load forecast used in the *2022 LTRA*, ERCOT has adopted more extreme weather assumptions to reflect the increasing frequency of extreme weather events experienced over the last several years and the expectation that this trend will continue. As a result, peak loads are significantly higher than those reported in the *2022 LTRA*. These more extreme weather assumptions are also reflected in the extreme peak loads used for scenario and probabilistic risk analysis.

Since the previous summer, ERCOT has experienced continued rapid load growth in large flexible loads (LFL), i.e., interruptible computer operations such as bitcoin mining. The 2023 load forecast increases the demand due to LFLs by 700 MW per year from 2023 through 2027, resulting in approximately 5,000 MW total LFL load in 2027. LFLs are forecasted to increase ERCOT's 2027 summer peak by 500 MW (10% of this demand responsive load).[55]

Currently there are no adjustments for EVs or BESS in the ERCOT long-term forecast used for the LTRA. ERCOT recently collaborated with a vendor to create an EV forecast that will be integrated into the long-term load forecast in 2023.

Demand-Side Management

Most of the demand-side resources available to ERCOT are dispatchable in the form of non-controllable load resources providing responsive reserve service and ERCOT's Emergency Response Service. The ERCOT Emergency Response Service consists of 10-minute and 30-minute ramping DRs and distributed generation that can first be deployed when physical responsive reserves drop to 3,000 MW and are not projected to be recovered above 3,000 MW within 30 minutes following the deployment of non-spin reserves. Responsive reserve is an ancillary service for controlling system frequency. It is provided by industrial loads and is procured on an hourly basis in the day-ahead market. Post Winter Storm Uri programmatic reforms include increasing the $50 million ERS program budget by 50% and providing ERCOT the flexibility to contract ERSs for up to 24 hours.

The remaining dispatchable DR available to ERCOT is from the transmission and distribution service providers' (TDSP) load management programs. These programs provide price incentives for voluntary load reductions from commercial, industrial, and (most recently) residential loads during EEA events. These programs are available for the months of June through September from 1:00–7:00 pm weekdays (except holidays) and are deployed concurrently with ERSs via ERCOT instruction pursuant to agreements between ERCOT and the TDSPs. TDSP Load Management Programs were also provided for the 2022–2023 winter season.

Distributed Energy Resources

ERCOT is currently working with TDSPs on a more consistent process for how DERs are modelled and dispatched in operations and transmission planning cases. One of the remaining issues to make DERs fully visible for operations and planning assessments is to comprehensively capture "unregistered distributed generation (DG)." Although ERCOT currently has requirements for TDSPs to provide limited unregistered DG data (e.g., rooftop solar PV systems), the data is not suitable for modeling. Approved in the 88th Texas Legislature, HB 3390 authorizes ERCOT to annually require TDSPs to provide unregistered DG information deemed necessary for grid reliability assessment.

Generation

Solar PV capacity continues to be rapidly added to Texas RE-ERCOT, so ERCOT is seeing more severe solar ramps. In June 2023, ERCOT implemented a new ancillary service called "ERCOT Contingency Reserve Service." As the wind and solar PV generation fleet continues to grow, the ERCOT Contingency Reserve Service will give the ERCOT control room the capability to deploy resources that can respond within 10 minutes in anticipation of net demand ramps.

ERCOT conducted a study to assess the impact of integrating potential synchronous condensers in the West Texas system. Following the 2021 Odessa event and subsequent events that resulted in generation loss, ERCOT has intensified its efforts to identify potential corrective measures that can enhance the ride-through performance of IBRs. ERCOT has also proposed new grid code requirements for IBRs to improve voltage ride-through performance to align with IEEE Standard 2800. ERCOT recently proposed that all IBRs must meet the voltage ride-through requirements by the end of 2025.

ERCOT also monitors system inertia on a real-time and forward-looking basis. The need for reliability unit commitment is determined for hours when inertia is not sufficient. ERCOT also uses historical system inertia conditions as an input to determine Responsive Reserve Service requirements and amounts needed for different inertia conditions.

Several mitigation strategies to address fuel acquisition risks have been implemented. For example, ERCOT developed a firm fuel supply service that is intended to help maintain system reliability in the event of a natural gas curtailment or other fuel supply disruption. Firm fuel supply service resources are contracted through a competitive procurement process with a single clearing price with bidders offering capacity with on-site fuel or off-site natural gas storage that meets certain qualification criteria. Based on the procurement experience for the 2022–2023 winter season, ERCOT has proposed improvement to the FFSS procurement process. ERCOT considers limitations for natural-gas-fired generators in its Regional Transmission Plan through the inclusion of extreme events that represent

[55] For the *2023 LTRA*, all LFLs are assumed fully curtailable during an energy emergency condition.

the loss of multiple gas generators following the loss of any single gas pipeline. These events are identified by evaluating the gas-pipeline network topology and survey responses from gas generators.

Improved fuel supply data supports overall reliability operations. During recent cold weather events, not all Resource Entities or their affiliates had purchased enough natural gas to satisfy the level of generation their qualified scheduling entity (QSE) indicated was available in their seven-day Current Operating Plan (COP). To help address this issue, ERCOT has proposed rules requiring a QSE to provide gas purchase constraints data that enables ERCOT to assess the generation resource's ability to run at levels indicated in their Current Operating Plan. ERCOT also recently proposed rules that require a QSE that represents a Generation Resource that uses coal or lignite as its primary fuel to submit to ERCOT a declaration of coal and lignite inventory levels. The proposed seasonal declaration process includes requirements for QSEs to notify ERCOT when inventory levels fall below certain thresholds.

Energy Storage

Currently, there is 3,940 MW of on-line utility-scale BESS capacity in Texas RE-ERCOT that is consuming/discharging energy; these mainly provide ancillary services. For example, BESS provides nearly 68% of ERCOT's regulation up and RRS for PFR. Based on the latest project information in the interconnection queue, ERCOT has 11,800 MW of Tier 1 BESS capacity expected to be operational by the end of 2025.

While BESS can help maintain grid reliability, integration of BESS sources has presented some operational challenges. One challenge is that some BESS systems have failed to deliver the required RRS-PFR response when needed. Another concern is that the growth in non-thermal resources will reduce the diversity of resources providing RRS-PFR, which could lead to NERC Reliability Standard violations. To address this issue, a recently completed study investigates whether there are reliability reasons to establish one or more types of limits on Resources providing RRS-PFR.

Since late 2022, ERCOT has been working on identifying modeling changes to better monitor state-of-charge. ERCOT is researching an initiative to build an state-of-change forecasting system using machine learning models. The forecasts would have a five-minute granularity for the next two hours, and hourly granularity for the next 168 hours.

Capacity Transfers and External Assistance

ERCOT has coordination plans in place with neighboring grids. These plans cover dc tie emergency operations, procedures for generators that can switch between grids, and temporary block load transfers.

Transmission

ERCOT completed its 2022 Regional Transmission Plan in December 2022. The plan lists 15 major reliability improvement projects out of a total of 89 proposed projects. Currently, there are $10.26 billion of transmission improvement projects that are expected to be put in service between 2023 and the end of 2028.

In November 2022, the PUCT amended rules to establish a congestion cost savings test for evaluating economic transmission projects; to require FERC to consider historical load, forecasted load growth, and additional load seeking interconnection when evaluating the need for additional ERCOT reliability transmission projects; to provide exemptions to the certificate of convenience and necessity requirements for certain transmission projects; and to require ERCOT to conduct a biennial assessment of the ERCOT grid's reliability and resiliency in extreme weather conditions. The rule will also allow the PUCT to consider the resiliency benefits of proposed transmission projects as determined by ERCOT's new biennial assessment when determining whether to approve a project. ERCOT has begun implementing the amended rules, including the evaluation of economic projects based on the new criteria using the 2022 RTP economic cases.

Other Reliability Issues

Several proposed rules and rule changes by the U.S. EPA heighten the risk of thermal unit retirements occurring after 2023. ERCOT is working with Generation Owners and state regulators to assess how these rules could impact grid reliability. Unless appropriate reliability safeguards are put in place, there is a risk of regional reliability issues developing, such as overloads on multiple transmission elements as well as the risk of a broader system-wide resource adequacy problem.

WECC-AB

WECC-AB (Alberta) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 90 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between. See Normal Risk Areas for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	12,065	12,065	12,154	12,257	12,373	12,362	12,413	12,548	12,622	12,689
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	12,065	12,065	12,154	12,257	12,373	12,362	12,413	12,548	12,622	12,689
Additions: Tier 1	2,579	2,579	2,579	2,579	2,437	2,578	2,578	2,578	2,578	2,578
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	1,350	1,771	2,088	2,216	2,187	2,433	2,525	2,579	2,647	2,700
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	13,694	13,694	13,694	13,694	13,435	13,687	13,687	13,687	13,687	13,687
Anticipated Reserve Margin (%)	34.9%	34.9%	33.9%	32.8%	28.3%	31.6%	31.0%	29.6%	28.9%	28.2%
Prospective Reserve Margin (%)	34.9%	34.9%	33.9%	32.8%	28.3%	31.6%	31.0%	29.6%	28.9%	28.2%
Reference Margin Level (%)	13.9%	13.8%	13.7%	13.6%	11.9%	13.4%	13.4%	13.2%	13.1%	13.1%

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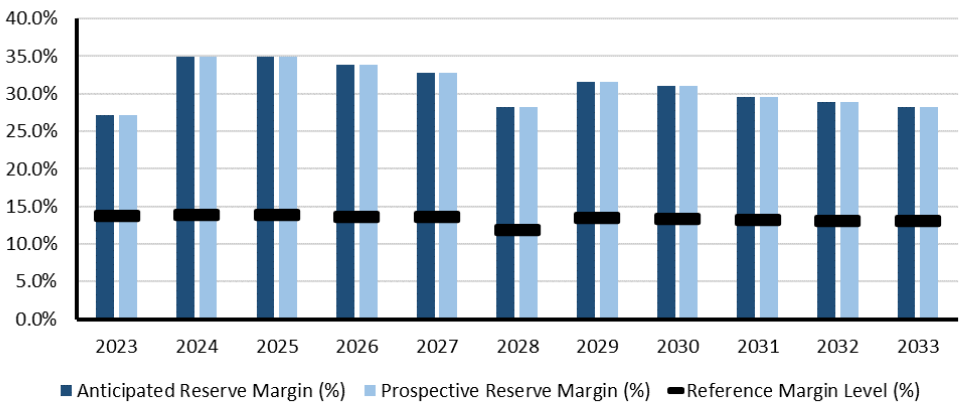
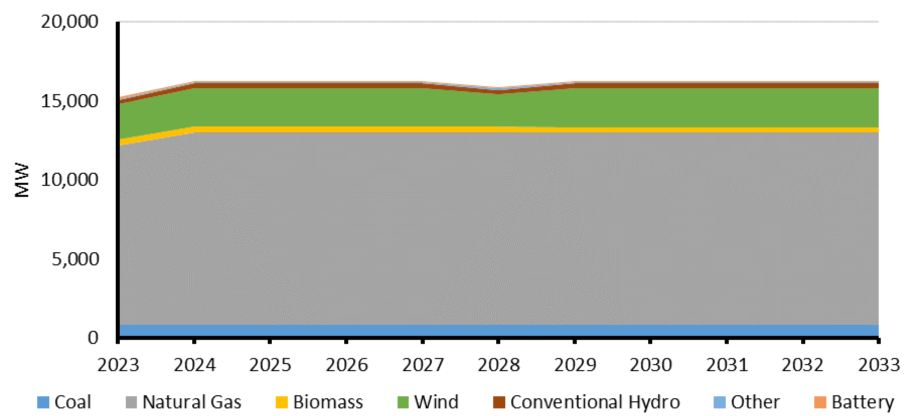


Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML.
- Alberta shows the lowest growth rate in the West. The peak hour demand for the Alberta subregion occurs in the winter. The subregion is expected to grow from about 11.9 GW in 2023 to 12.6 GW in 2033, a 6.1% cumulative load growth over the assessment period, or a 0.78% annualized average rate. There was almost no change to the load forecast for this year's plan from last year.
- Several near-term 2023 transmission projects are planned for reliability and economics/congestion. The Provost to Edgerton and Nilrem to Vermilion project is delayed.

Note: the table below reflects the expected 50th percentile, or a 50% probability of energy availability by resource type on the peak hour.

WECC-AB Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	800	800	800	800	800	800	800	800	800	800
Natural Gas	12,211	12,211	12,211	12,211	12,211	12,204	12,204	12,204	12,204	12,204
Biomass	336	336	336	336	336	336	336	336	336	336
Wind	2,472	2,472	2,472	2,472	2,054	2,472	2,472	2,472	2,472	2,472
Conventional Hydro	285	285	285	285	301	285	285	285	285	285
Other	81	81	81	81	81	81	81	81	81	81
Battery	88	88	88	88	88	88	88	88	88	88
Total MW	16,273	16,273	16,273	16,273	15,872	16,265	16,265	16,265	16,265	16,265

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WECC-AB Assessment

Planning Reserve Margins

The ARM does not fall below the reference margin. The 2024 operable on-peak margin has grown slightly to 26.1% from 22.4% in the last assessment.

Energy Assessment and Non-Peak Hour Risk

WECC uses the Multi-Area Variable Resource Integration Convolution model. The model is a convolution-based probabilistic model and is WECC's chosen method for developing the probability metrics used for assessing demand and variable resource availability in every hour.

WECC performs energy-based probabilistic assessments based on distributions of resource availability and distributions of demand. For resources, WECC uses the 3rd to 97th percentiles of hourly availability. For this reason, WECC does not perform calculations for capacity contributions for VERs or other types of resources, seasonally or otherwise. Similarly, duration is not assumed for storage resources. WECC is still looking at ways of improving BESS modeling.

For variable resources, WECC uses historical hourly generation data to develop expected capacity contributions and the associated probability distributions around the expected capacity contribution on an hourly basis. This is consistent with how the same information was calculated in previous assessments. For the purposes of the LTRA, the expected 50th percentile of the probability density functions is used as the most likely energy contribution from each resource type. For the ProbA, the entire probability density functions are used with the associated probabilities of occurrence. The contributions for all resource types are calculated on a localized, BA footprint. Therefore, solar behavior in one balancing area may not reflect the expected contribution of solar in another balancing area.

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Probabilistic Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the one-day-in-ten-year level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than 0.02% of the total area of the demand curve for any given hour).

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	-	-	-
EUE (PPM)	-	-	-
LOLH (hours per Year)	-	-	-
Operable On-Peak Margin	22.4%	26.1%	33.9%

*Provides the 2022 ProbA Results for Comparison

Demand

The peak hour of demand for Alberta occurs in winter in late December around 6:00 p.m. The subregion is expected to grow from about 11.9 GW in 2023 to 12.6 GW in 2033, a 6.1% cumulative load growth over the assessment period, or 0.78% annualized average rate. There was almost no change to the load forecast for this year's plan. Alberta continues to show the lowest growth rate in WECC.

Alberta produces hourly load projections for 20 years with historical load and real GDP, population, employment, oil sands production, gas production, meteorological inputs, and key load impacting events (e.g., past wildfires) in its demand forecasting. The forecast considers transportation electrification and DERs. The next assessment is expected to reflect more explicit modelling of EE, building and industry electrification, and EV charging profiles in the forecast. They incorporate the impact of temperatures on the efficiency of engines and BESS and the unique driving range needs depending on the day of the week.

Demand-Side Management

WECC-AB reported no controllable and dispatchable DR; however, programs are market driven and can be called upon for economic consideration in the AESO area.

Distributed Energy Resources

Alberta has 3,619 MW of existing nameplate wind and 1,165 MW of solar PV. 4,041 MW of wind and 3,310 MW of solar PV are planned. Solar PV is expected to grow at a CAGR of 7.3% while wind capacity is planned to grow at 3.11% and BESS at 2.77%. These rates will lead to a doubling of solar PV, a 40% increase in wind, and a 35% increase in BESS by 2033. BTM resources are netted with load. The renewable resources will be supported by 205 MW of BESS.

WECC-AB

Generation

Highlights of Alberta’s resource portfolio include almost 800 MW of coal, 11 GW of natural gas (increasing to 16 GW by the end of 2039), and almost 900 MW of conventional hydrogeneration. Almost 800 MW of hydro was built before 1972. No hydro units have retirement dates planned. Alberta has a 30% by 2030 clean energy target.

Energy Storage

Alberta has 90 MW of energy storage and plans to add 105 MW more by 2039, 45 MW of which will be in the next 10 years.

Capacity Transfers and External Assistance

No firm imports are shown to be needed in the model.

Transmission

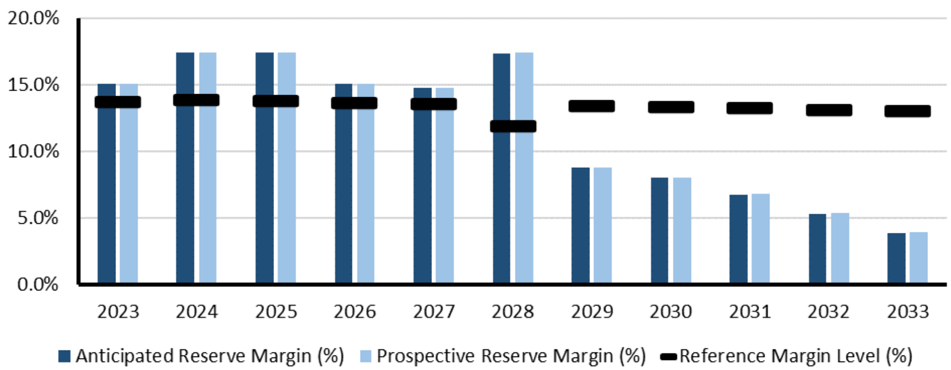
Several near-term 2023 transmission projects are planned for reliability and economics/congestion, covering over 330 miles, and two of which are 400+ kV lines. The Provost to Edgerton and Nilrem to Vermilion project is delayed.

WECC-BC

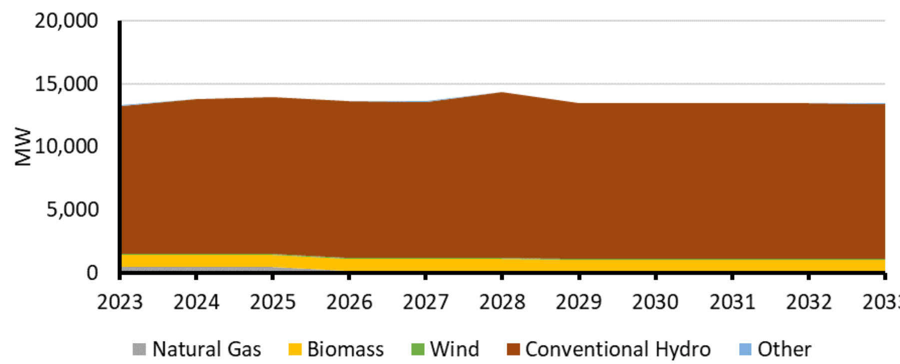
WECC-BC (British Columbia) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 90 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between. See Elevated Risk Areas for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	11,786	11,897	12,031	12,159	12,270	12,389	12,511	12,657	12,799	12,943
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,786	11,897	12,031	12,159	12,270	12,389	12,511	12,657	12,799	12,943
Additions: Tier 1	672	806	806	1,158	1,627	1,561	1,599	1,599	1,913	2,226
Additions: Tier 2	0	0	0	4	4	4	4	4	4	4
Additions: Tier 3	0	0	2	44	46	44	44	95	95	95
Net Firm Capacity Transfers	0	0	198	334	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	13,166	13,166	13,043	12,799	12,774	11,915	11,915	11,915	11,568	11,220
Anticipated Reserve Margin (%)	17.4%	17.4%	15.1%	14.8%	17.4%	8.8%	8.0%	6.8%	5.3%	3.9%
Prospective Reserve Margin (%)	17.4%	17.4%	15.1%	14.8%	17.4%	8.8%	8.1%	6.8%	5.4%	3.9%
Reference Margin Level (%)	13.9%	13.8%	13.7%	13.6%	11.9%	13.4%	13.4%	13.2%	13.1%	13.1%



Planning Reserve Margins



Existing and Tier 1 Resources

App.369

Highlights

- The ARM falls below the RML for the peak hour starting in winter 2029–2030.
- BC Planning Reserve Margins are below the RML from December 2029 through the remainder of this assessment period. BC shows a shortfall of existing-certain and net firm transfers, meaning imports may be necessary if new solar PV or conventional hydrogeneration resources were to be delayed. BC is retiring 400 MW of natural gas and refurbishing significant amounts of hydrogeneration that come off-line for about a year.
- The peak hour demand for the BC subregion occurs in the winter. The subregion is expected to grow from about 11.6 GW in 2023 to 12.9 GW in 2033, a slight (average CAGR of 0.25%) increase from the last forecast and an 11.4% load growth over the assessment period, or 1.07% annualized average rate.
- BC is showing hours of demand at risk that are not fully mitigated by the addition of Tier 3 resources.

Note: the table below reflects the expected 50th percentile, or a 50% probability of energy availability by resource type on the peak hour.

WECC-BC Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Natural Gas	457	457	170	170	170	61	61	61	61	61
Biomass	944	944	944	944	944	938	938	938	938	938
Wind	111	111	111	111	81	111	111	111	111	111
Conventional Hydro	12,303	12,437	12,404	12,375	13,184	12,343	12,382	12,382	12,347	12,313
Other	22	22	22	22	22	22	22	22	22	22
Total MW	13,837	13,972	13,651	13,623	14,401	13,476	13,514	13,514	13,480	13,446

App.370

WECC-BC Assessment

Planning Reserve Margins

For the peak hour, the ARM and PRM fall below the RML starting in winter 2029–2030. BC shows a shortfall of existing-certain and net firm transfers, meaning imports may be necessary if new solar PV or conventional hydrogeneration resources were to be delayed. BC is retiring 400 MW of natural gas and refurbishing significant amounts of hydrogeneration that come offline for about a year.

Energy Assessment and Non-Peak Hour Risk

WECC uses the Multi-Area Variable Resource Integration Convolution model. The model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour.

WECC performs energy-based probabilistic assessments that are based on distributions of resource availability and distributions of demand. For resources, WECC uses the 3rd to 97th percentiles of hourly availability. Looking at all hours of the year and counting existing, Tier 1 and Tier 2 resources, BC shows three potential loss-of-load hours in 2024 and 2025 and 31 om 2026:

App.371

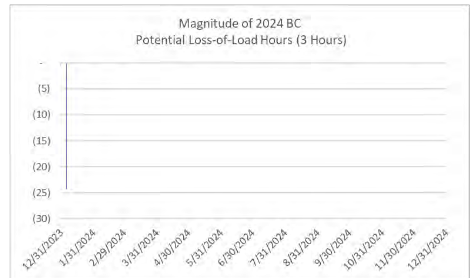
Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	24	47	15,991
EUE (PPM)	0.370	0.71	238
LOLH (hours per Year)	0.002	0.002	0.749
Operable On-Peak Margin	18.5%	12.7%	10.7%

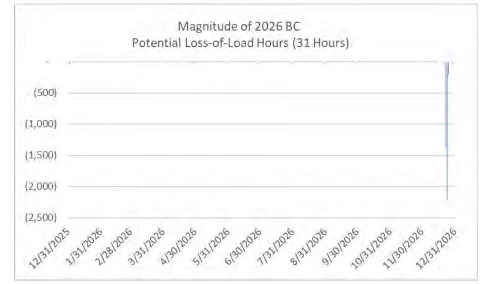
*Provides the 2022 ProbA Results for Comparison

Probabilistic Assessments

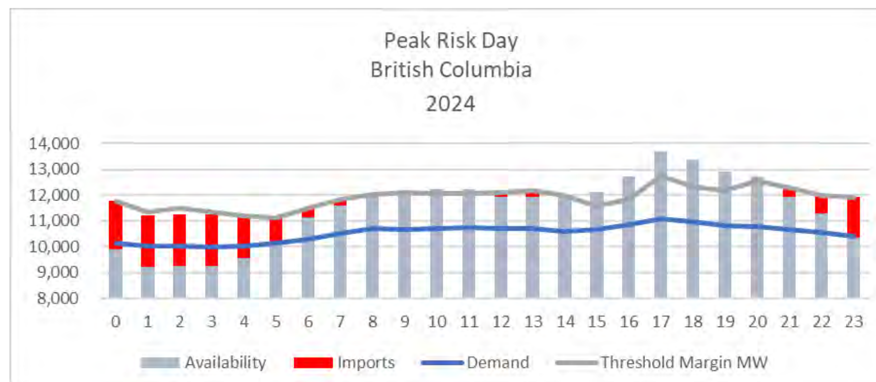
WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the 1-day-in-10-year level, meaning that 99.98% of the demand for each hour is covered by available resources, i.e., the area of overlap is equal to no more than 0.02% of the total area of the demand curve for any given hour.

The following plots are outputs from WECC's probabilistic assessment and show the distribution of load loss events in MW across the study years 2024 and 2026.

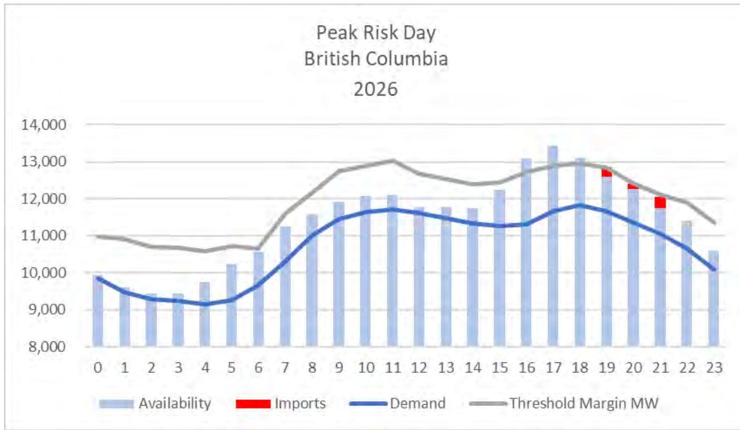




The following plots are outputs from WECC's probabilistic assessment and show the modeled demand and resources on the peak demand day for 2024 and 2026.



WECC-BC



Demand

The peak hour of demand for BC occurs in the winter in late December around 6:00 p.m. The subregion is expected to grow from about 11.6 GW in 2023 to 12.9 GW in 2033, a slight (average CAGR of 0.25%) increase from the last forecast and an 11.4% load growth over this assessment period, or 1.07% annualized average rate.

Demand-Side Management

No controllable or DR program capacities were reported.

Distributed Energy Resources

BTM resources are netted with load. BC has 2 MW of existing solar PV and 30 MW planned, half in 2023 and half in 2027. BC has 15 MW of new wind planned in 2026 to add to its existing portfolio of 747 MW of wind capacity.

Generation

British Columbia is 95% carbon-free today. Its *CleanBC Roadmap to 2030* states, "By 2030, BC will phase out BC Hydro's last gas-powered facility so the electricity we make is 100% clean." In 2023, BC has 462 MW of natural gas, 17 MW of landfill gas, and 143 MW of black liquor fuel. Confirmed retirements increased through 2033 by 1 GW from the last assessment.

Energy Storage

No BESS projects are planned. BC has plentiful hydrogeneration energy storage resources.

Capacity Transfers and External Assistance

BC shows a small amount of import growth in winter 2023–2024 (110 MW), 2026–2027 (198 MW), and 2027–2028 (334) compared to none in last year's result.

Transmission

Out of 12 projects, 6 are planned with voltage design of 500 kV and higher in BC. The primary drivers are economics / congestion and reliability. There are also three conceptual projects for 200–299 kV lines for downtown Vancouver.

App.372

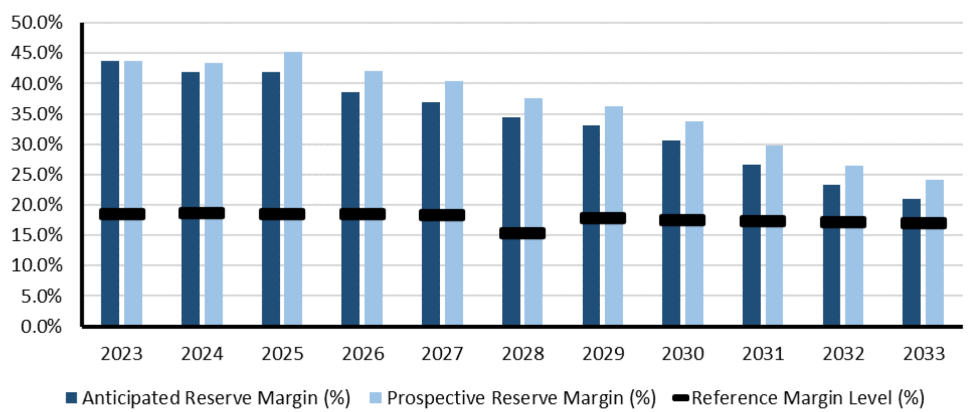
WECC-CA/MX

WECC-CA/MX (California/Mexico) is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorizes, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 90 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between. See Elevated Risk Areas for more details.

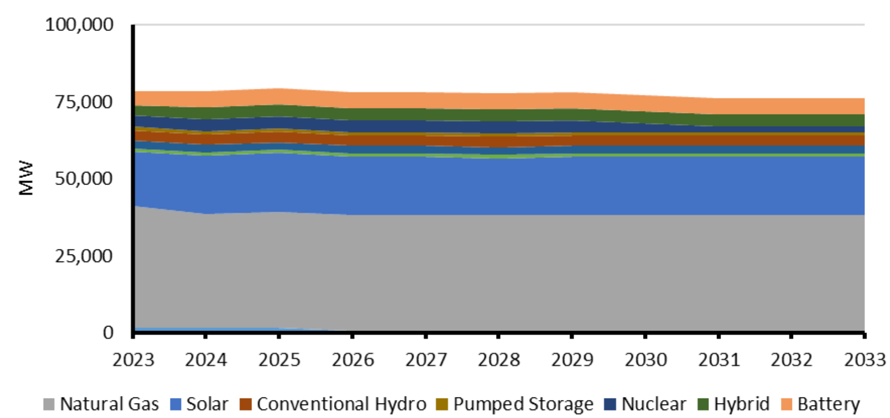
Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	57,178	57,884	58,554	59,380	60,294	61,180	62,213	63,418	64,470	65,449
Demand Response	829	836	841	852	855	866	872	878	883	883
Net Internal Demand	56,349	57,048	57,712	58,529	59,439	60,313	61,341	62,540	63,587	64,566
Additions: Tier 1	10,859	11,771	11,790	11,810	11,610	11,822	11,830	11,830	11,830	11,830
Additions: Tier 2	828	1,964	1,964	1,964	1,932	1,964	1,964	1,964	1,964	1,964
Additions: Tier 3	232	1,957	2,198	3,212	3,316	3,419	3,723	23,547	23,547	23,547
Net Firm Capacity Transfers	0	0	161	338	521	408	1,339	1,572	808	530
Existing-Certain and Net Firm Transfers	69,136	69,136	68,189	68,366	68,281	68,418	68,245	67,374	66,610	66,332
Anticipated Reserve Margin (%)	41.96%	41.82%	38.58%	36.99%	34.41%	33.04%	30.54%	26.65%	23.36%	21.06%
Prospective Reserve Margin (%)	43.43%	45.27%	41.99%	40.34%	37.66%	36.30%	33.74%	29.79%	26.45%	24.10%
Reference Margin Level (%)	18.64%	18.54%	18.42%	18.26%	15.28%	17.81%	17.58%	17.34%	17.17%	17.01%

App.373



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the reference margin on the peak hour; however, CA/MX shows increasing EUE and LOLH over this assessment period, including 19 hours at risk in 2026 that are not fully mitigated by the addition of Tier 3 resources.
- The ARM falls below the RML in summer of 2027 but is covered by additional resources under the PRM if all 3,212 MW come on-line on time. Starting in summer 2024 onwards, CA/MX shows a shortfall of existing-certain and net firm transfers, meaning imports may be necessary if new resources were to be significantly delayed.
- The peak hour demand for the CA/MX subregion occurs in the summer. The subregion is expected to grow from about 55.5 GW in 2023 to 64.6 GW in 2033, a slight (average CAGR of 0.25%) increase from the last forecast in the long-term but a lower forecast through 2028. This represents a 16.3% load growth over this assessment period, or a 1.52% annualized average rate.
- 16 GW of energy storage is planned, and CA/MX has 2.8 GW of natural gas planned for retirement by the end of 2023, 1.2 GW of coal in 2025, and 2.3 GW of nuclear by the end of 2030.

Note: the table below reflects the expected 50th percentile, or 1 in 2 probability of energy availability by resource type on the peak hour.

WECC-CA/MX Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	1,595	1,595	487	487	487	487	487	487	487	487
Petroleum	761	761	761	761	761	757	757	757	757	757
Natural Gas	36,884	37,644	37,644	37,644	37,644	37,639	37,639	37,639	37,639	37,639
Biomass	777	777	777	777	777	775	775	775	775	775
Solar	19,095	19,112	19,130	19,150	18,317	19,166	19,174	19,174	19,174	19,174
Wind	994	994	994	994	1,354	994	994	994	994	994
Geothermal	2,434	2,434	2,434	2,434	2,434	2,428	2,428	2,428	2,428	2,428
Conventional Hydro	3,453	3,453	3,453	3,453	3,495	3,453	3,453	3,453	3,453	3,453
Pumped Storage	1,034	1,034	1,034	1,034	1,057	1,034	1,034	1,034	1,034	1,034
Nuclear	3,880	3,880	3,880	3,880	3,880	3,874	2,770	1,667	1,667	1,667
Hybrid	3,942	3,942	3,942	3,942	3,882	3,940	3,940	3,940	3,940	3,940
Other	29	29	29	29	29	29	29	29	29	29
Battery	5,117	5,252	5,252	5,252	5,252	5,256	5,256	5,256	5,256	5,256
Total MW	79,995	80,908	79,818	79,839	79,370	79,832	78,736	77,632	77,632	77,632

App.374

WECC-CA/MX Assessment

Planning Reserve Margins

The reserve margins would fall below the RML in summer of 2027 without Tier 1 resources (3,212 MW) coming on-line. Starting in summer 2024 onwards, CA/MX shows a shortfall of existing-certain and net firm transfers, meaning imports may be necessary if new resources were to be significantly delayed.

Energy Assessment and Non-Peak Hour Risk

WECC uses the Multi-Area Variable Resource Integration Convolution model. The model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour.

WECC performs energy-based probabilistic assessments that are based on distributions of resource availability and distributions of demand. For resources, WECC uses the 3rd to 97th percentiles of hourly availability. Looking at all hours of the year and counting existing, Tier 1 and Tier 2 resources, CA/MX shows 19 potential loss-of-load hours in 2026:

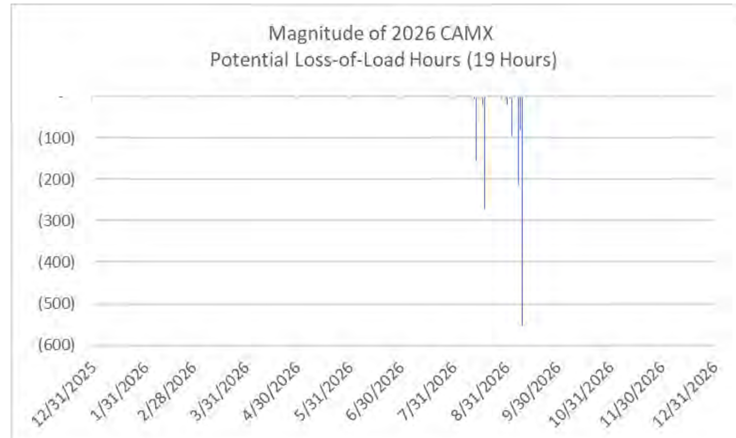
Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	37,305	-	11,731
EUE (PPM)	136	-	43
LOLH (hours per Year)	0.721	-	0.227
Operable On-Peak Margin	30.3%	30.7%	27.5%

* Provides the 2022 ProbA Results for Comparison

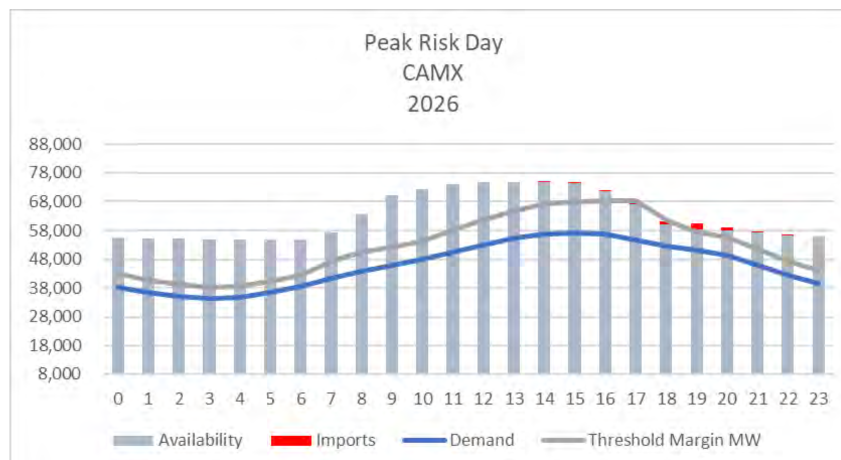
Probabilistic Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the 1-day-in-10-year level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than 0.02% of the total area of the demand curve for any given hour).

The following plot is output from WECC's probabilistic assessment and shows the distribution of load loss events in MW across the 2026 study year.



The following plot is output from WECC's probabilistic assessment and shows the modeled demand and resources on the peak demand day for 2026.



App.375

Demand

The peak hour demand for the CA/MX subregion occurs in the summer around the second week of September at 3:00 p.m. The subregion is expected to grow from about 55.5 GW in 2023 to 64.6 GW in 2033, a slight (average CAGR of 0.25%) increase from the last forecast in the long-term but a lower forecast through 2028. This represents a 16.3% load growth over this assessment period, or 1.52% annualized average rate.

Load forecasts are developed by correlation with econometric and demographic factors. In CA/MX, these include population, households, personal income, energy rates, commercial floorspace, employment, and precipitation. For transportation, vehicle attributes, fuel prices, incentives, vehicle miles traveled, duty cycle, and consumer preference surveys contribute to analyses.

Existing electrification is captured through building surveys and DMV vehicle registration data. Multiple scenarios are designed for both vehicle and building electrification to reflect a variety of state and local ordinances.

There are local policies that have taken effect since the last assessment, driving building electrification. Examples include the following:

- Sacramento's All-Electric Only ordinance that went into effect January 1, 2023, for all new construction under three stories and all new construction regardless of height in 2026.
- San Luis Obispo passed an All-Electric Only ordinance for all new construction with an exception for certain natural gas end uses through 2025 if no all-electric alternative is commercially available or viable (for commercial kitchens, ADU water or space heating and for public swimming pools)
- Pasadena passed an All-Electric Only ordinance for new construction (or 50%+ renovations) multifamily, nonresidential and mixed-use buildings with exceptions for ADUs, commercial kitchens, and essential buildings (defined as medical healthcare facilities and research and development labs).

For a full list of electrification measures reflected in zero emission building ordinances, visit the Building Decarbonization Website.[56]

Additionally, there are transportation electrification goals in place to increase the number of EVs. The California Air Resources Board is regulating all new consumer vehicles sold to produce zero emissions by 2035. Seventeen other states adopted similar rules. The California Energy Commission (CEC) provided a calculator to estimate high, low, and expected impact levels by assuming various levels of meeting the targets of Executive Order B-48-18.

Demand-Side Management

CA/MX DSM is expected to grow from 829 MW in summer 2024 to 883 MW in summer 2033. In addition to the controllable and dispatchable programs, voluntary conservation has played a significant role during extreme events. During the widespread heatwave in 2020, demand reductions of approximately five GW were realized, exceeding the amounts available from dispatchable and controllable programs. For comparison, during the 2022 heat event, demand reductions were approximately 1,900 MW, reflecting the reduced geographic area of that event.

The CEC is utilizing the federal Inflation Reduction Act to provide funding for whole house EE. For low to moderate income households, it will also fund point of sale rebates for panel upgrades and qualified high-efficiency electric appliances, such as heat pumps for space heating and cooling. The programs will launch in 2024.

Some areas reported unavailable capacity when connecting new customer or upgrading service along with delays receiving the equipment, such as switchboards and switchgears, needed to connect new electrical services.

Distributed Energy Resources

BTM resources are netted with load. Utility distribution companies are required under Title 20 to report location, capacity, and technology type to the CEC for all interconnected systems, including BTM. Owners of systems larger than one MW must also report generation. Generation for smaller, less than one MW systems is either modeled according to capacity or purchased from third-party vendors.

One area adopted a bass diffusion model to estimate the rooftop PV impact to system load in terms of annual capacity and energy, capturing all BTM installations.

California changed its net metering tariff to a net billing tariff in 2023. This is expected to create a drag on BTM solar PV installations in the near term due in large part to the increased payback period for the investment. California has accounted for the largest share of BTM solar PV in WECC.

[56] **Building Decarbonization**

Generation

CA/MX has almost three GW of natural gas planned for retirement by the end of 2023, over one GW of coal in 2025, and 2.3 GW of nuclear by the end of 2030. In total, almost six and a half GW of coal, nuclear, and natural gas are planned to be retired by 2030. This is offset by 2.8 GW of planned new natural gas, 665 MW of geothermal, 644 MW of petroleum, 627 MW of pumped storage, 35 MW of new conventional hydro, and 55 MW of biomass capacity.

There are several renewable portfolio or carbon-free electricity targets in CA/MX that contribute to a changing resource mix. For example, the electric system operator in Mexico, CENACE, is aiming for 35% by 2025–2029 and California for 60% by 2030.

Coal deliveries were reduced for one area for the past two years, resulting in a reduction of available generation capacity for the foreseeable future. The area has implemented a fuel rationing procedure to maximize coal inventories.

Supply chain issues continue to be a major factor affecting the delivery of new resources, such as utility-scale solar PV and transmission line upgrades. These supply chain issues along with the increased costs of component suppliers have resulted in the need for renegotiations. Balancing areas report developers are seeing a 75-to-80-week delivery time for transformers and circuit breaker equipment compared to the typical 24 weeks prior to Covid-19. PV module deliveries have been significantly delayed for utility-scale solar PV projects. For example, the deliveries of solar modules delayed one very large multi-hundred MW project by 12 months.

Energy Storage

CA/MX is planning on adding 16 GW of energy storage to its almost three GW of existing energy storage, 6.6 GW of which are planned by the end of 2025.

Capacity Transfers and External Assistance

The summer imports through 2029 and compared to last year are decreasing, then increasing 2030 onwards. Winter firm imports are slightly above last year's results (ranging from 240–632 MW).

Transmission

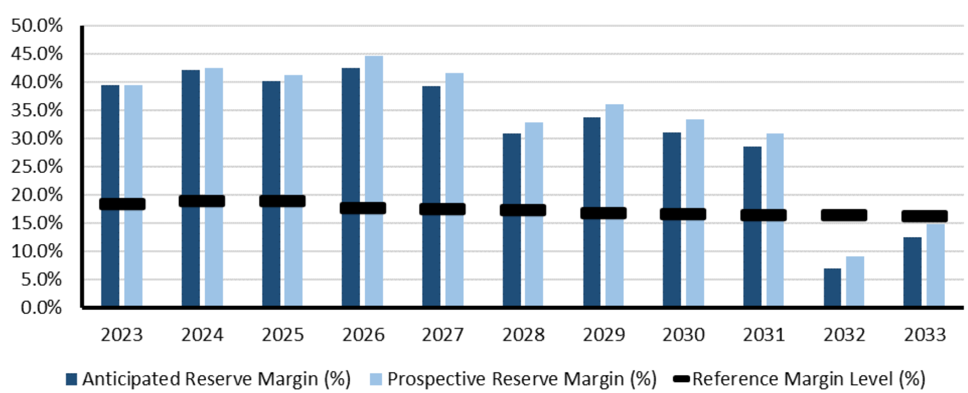
There are 10 planned and 2 conceptual projects with voltage designs of 500 kV and higher in CA/MX, representing a total addition of more than 1,000 miles. A diverse set of 3 conceptual projects spanning 160 miles, driven primarily by economics, congestion, and reliability needs are also in the works. There are 75 projects outside of the conceptual phase and in planning for almost 1,600 miles, plus 6 projects under construction for 35 miles.

WECC-NW

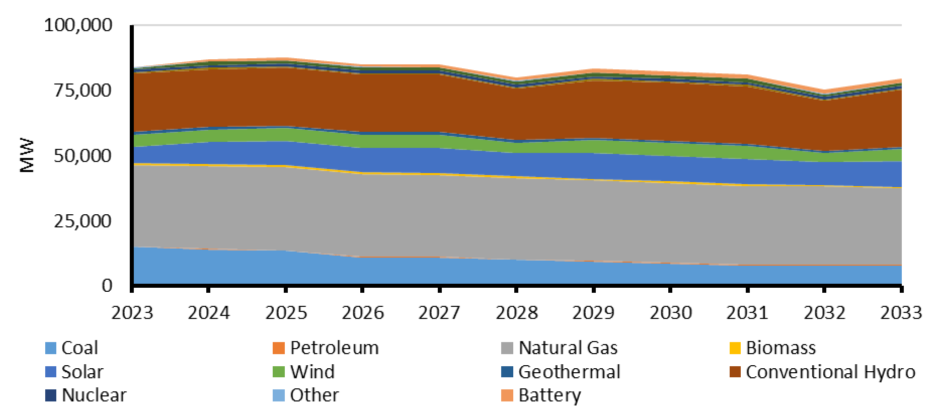
WECC-NW (Northwest) is a summer-peaking assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming and parts of California, Nebraska, Nevada, and South Dakota. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 90 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between. See Elevated Risk Areas for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	62,899	64,432	65,427	67,732	69,449	70,241	70,881	71,453	73,043	73,661
Demand Response	902	912	917	929	947	955	965	976	872	881
Net Internal Demand	61,997	63,520	64,510	66,803	68,502	69,286	69,916	70,477	72,171	72,780
Additions: Tier 1	7,190	8,450	8,846	9,020	8,938	9,691	9,746	9,801	9,303	9,895
Additions: Tier 2	229	671	1,351	1,463	1,365	1,611	1,628	1,628	1,502	1,645
Additions: Tier 3	676	2,131	3,798	3,865	5,820	7,403	8,994	9,889	10,468	11,898
Net Firm Capacity Transfers	1,157	1,290	6,785	8,002	9,826	9,255	9,293	9,383	1,957	2,103
Existing-Certain and Net Firm Transfers	80,900	80,584	83,100	84,066	80,760	83,028	81,942	80,831	67,904	71,957
Anticipated Reserve Margin (%)	42.1%	40.2%	42.5%	39.3%	30.9%	33.8%	31.1%	28.6%	7.0%	12.5%
Prospective Reserve Margin (%)	42.5%	41.2%	44.6%	41.5%	32.9%	36.1%	33.5%	30.9%	9.1%	14.7%
Reference Margin Level (%)	18.9%	18.9%	17.6%	17.6%	17.4%	16.8%	16.5%	16.4%	16.5%	16.3%



Planning Reserve Margins



Existing and Tier 1 Resources

App.378

Highlights

- The ARM falls below the RML for the peak hour starting in summer 2032.
- WECC-NW's demand-side management programs are expected to decline from 902 MW in summer 2024 to 881 in summer 2033 and grow from 584 in winter 2024, peaking in 2031 around 686 MW and then declining to 596 MW in winter 2033.
- Significant demand growth coupled with 19 GW of resources planned to retire from 2023 through 2034 are contributing to increasing loss-of-load hours over the planning period. There are several states in the WECC-NW renewable portfolio and carbon-free electricity targets driving the changes in resource portfolios in addition to a plethora of local building, transportation, and industrial electrification measures.

Note: the table below reflects the expected 50th percentile, or 1 in 2 probability of energy availability by resource type on the peak hour.

WECC-NW Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	13,883	13,450	10,834	10,834	9,961	9,272	8,631	7,675	7,678	7,675
Petroleum	285	285	285	285	285	279	279	279	280	279
Natural Gas	31,882	31,882	31,634	31,457	31,053	30,862	30,519	30,388	30,144	29,414
Biomass	775	773	767	737	731	671	671	671	669	656
Solar	8,373	9,130	9,492	9,660	8,877	9,883	9,883	9,815	8,622	9,767
Wind	4,864	5,077	5,065	5,065	4,119	5,058	5,037	4,998	3,779	4,928
Geothermal	910	892	926	890	905	858	740	740	670	467
Conventional Hydro	22,220	22,216	22,119	22,111	19,768	22,090	22,090	22,083	19,116	22,081
Pumped Storage	448	448	448	448	434	448	448	448	402	448
Nuclear	1,097	1,097	1,097	1,097	1,081	1,095	1,095	1,095	1,091	1,095
Hybrid	1,293	1,293	1,293	1,293	1,394	1,430	1,430	1,430	1,117	1,157
Other	78	78	78	78	78	77	77	77	78	77
Battery	824	1,124	1,124	1,129	1,186	1,440	1,495	1,550	1,605	1,705
Total MW	86,933	87,745	85,161	85,084	79,872	83,464	82,395	81,249	75,250	79,749

App.379

WECC-NW Assessment

Planning Reserve Margins
The ARM falls below the RML for the peak hour starting in summer 2032 and remains insufficient with the additional Tier 2 resources under the PRM following five GW planned for retirement between 2029 and 2032.

Energy Assessment and Non-Peak Hour Risk
WECC uses the Multi-Area Variable Resource Integration Convolution model. The model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour.

WECC performs energy-based probabilistic assessments that are based on distributions of resource availability and distributions of demand. For resources, WECC uses the 3rd to 97th percentiles of hourly availability. Looking at all hours of the year and counting existing Tier 1 and Tier 2 resources, WECC-NW shows 28 potential loss-of-load hours in 2026, which falls to 15 hours at risk when Tier 3 resources are considered.

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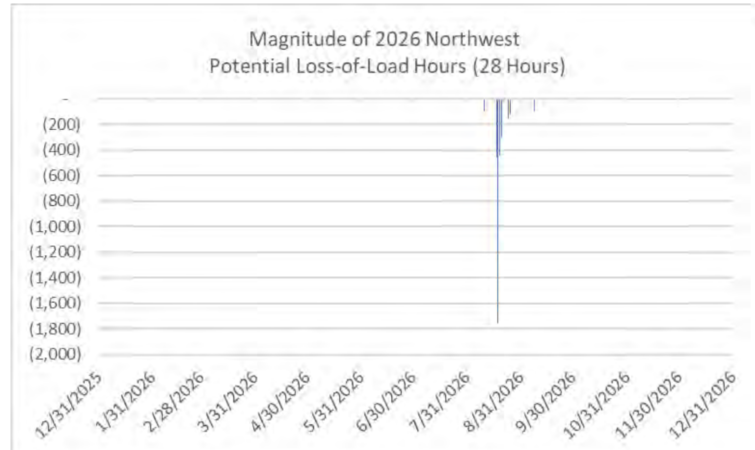
Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	1,722	-	8,101
EUE (PPM)	4	-	21
LOLH (hours per Year)	0.036	-	0.132
Operable On-Peak Margin	25.8%	37.6%	32.5%

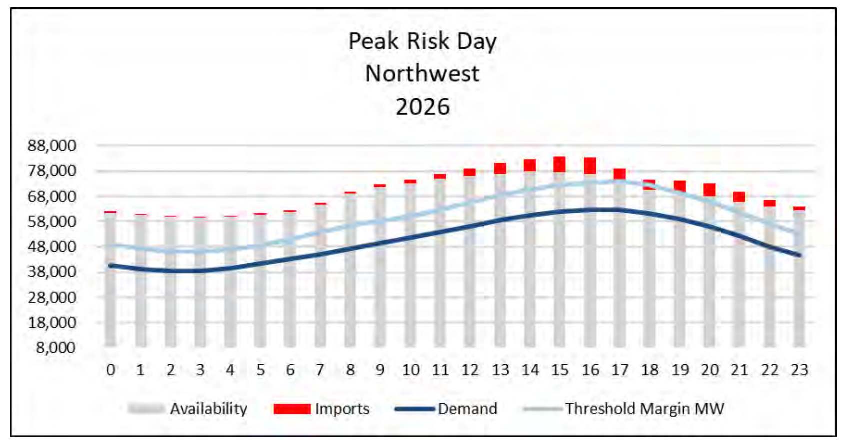
* Provides the 2022 ProbA Results for Comparison

Probabilistic Assessments
WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the one-day-in-ten-year level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than 0.02% of the total area of the demand curve for any given hour).

The following plot is output from WECC's probabilistic assessment and shows the distribution of load loss events in MW across the 2026 study year.



The following plot is output from WECC's probabilistic assessment and shows the modeled demand and resources on the peak demand day for 2026.



WECC-NW

Demand

The peak hour demand for WECC-NW occurs in the summer anywhere from mid-July to late-August around 4:00 p.m.. The subregion is expected to grow from about a 72 GW peak in 2023 to 84 GW in 2033; however, there are significant differences between balancing areas with some showing almost 50% growth compared to last year while others show slight shrinking load. This has been reported to be due to new data centers. This is contributing to some BAs showing a need for increased imports in the model compared to last year. This represents a nearly 17% load growth over this assessment period.

Additionally, there are transportation electrification goals in place to increase the number EVs. WECC-NW serves a portion of Northern California, where the California Air Resources Board is regulating all new consumer vehicles sold to produce zero emissions by 2035. Seventeen other states adopted similar rules. Oregon and Washington will ban the sale of new gas cars by 2035. ACEEE's top three states in the 2023 Transportation Electrification Scorecard are California, Oregon, and Washington for planning and goal setting. The West dominates the top states supporting transportation transitions to electric vehicles with Colorado in 6th and Nevada tied for 12th.

Electrification assumptions are incorporated into the load projects for most areas in WECC-NW, including transportation, building, and some industrial. Several cities across the Northwest have implemented building electrification policies, including Salt Lake City, which has an all-electric requirement, and Park City, Utah, where there are programs that encourage the elimination of natural gas and propane with similar programs in Boulder and Superior, Colorado, respectively. Washington has both statewide and local electrification requirements.

Note that many balancing areas reported supply chain risks in WECC-NW. These include material delays, wires, and meters, causing a variety of projects to be postponed, including connecting new customers. A few said human resources (i.e., staffing) is an equally large problem.

Demand-Side Management

WECC-NW's demand-side management programs are expected to decline from 902 MW in summer 2024 to 881 in summer 2033 and grow from 584 in winter 2024, peaking in 2031 around 686 MW and then declining to 596 MW in winter 2033.

Distributed Energy Resources

BTM resources are netted with load. Wind is expected to grow at CAGR of 2.65%, solar PV at 6.38%, BESS at 19.69% and hybrid resources at almost 28%. Existing solar PV accounts for eight GW of installed capacity and more than 10 GW of capacity are planned through 2033. Over 7.5 GW of wind is planned to be added through 2033 to the existing capacity of over 20 GW.

Generation

There are 19 GW of resources planned to retire from 2023 through 2034. This includes 128 MW of biomass, 8 GW of coal, over 6 GW of natural gas, and 6 MW of petroleum. There are several states in the WECC-NW with renewable portfolio and carbon-free electricity targets that are driving the changes in resource portfolios. These include Montana (15% 2015-19), Nevada (50% by 2030), Oregon (35% by 2030), and Washington state (greenhouse gases neutral with limited offsets by 2030).

Many balancing areas reported supply chain risks in WECC-NW. Supply chain issues are resulting in longer lead times for parts and equipment, delaying resource restoration after forced outages. The impact has been project schedules being extended to account for the procurement issues. Power circuit breaker lead times were being continually delayed. These issues are affecting all resources, both new facilities and updates to existing facilities. It is challenging to prioritize and schedule outages and decisions between stacking versus shifting.

The supply chain issues are expected to contribute to deviations from resource plans in the near term. For instance, solar PV panel supply chain issues have indefinitely postponed the incorporation of a new power supply resource that had been planned for January 2024.

Additionally, coal availability declined, and prices rose due to increased demand spurred by high natural gas prices and weather events. Those issues, combined with transportation constraints, resulted in lower availability. Supply chain issues limited coal inventory during peak hours of the day. This resulted in a new strategy for how units are scheduled on a day-ahead basis and how power is purchased in the real time markets.

Energy Storage

The NW is planning significant increases in BESS, including 425 MW in 2023, 680 MW in 2024, and another 1,130 MW through 2030. Existing BESS capacity is 172 MW.

Capacity Transfers and External Assistance

Significant increases from 1.6 GW to over 9 GW in the latter half of the forecast years compared to no year over 1 GW in the 2022 LTRA results.

Transmission

Four 500 kV and higher planned projects are in WECC-NW. Idaho Power's new 300-mile Boardman-to-Hemingway 500 kV line, originally proposed in 2007 and projected to be in-service in 2013, has cleared its major regulatory requirements and should break ground this year or in 2024 and be energized as early as 2026.

WECC-NW

The balancing areas in WECC-NW report supply chain delays to replace, upgrade, and expand transmission equipment, which has delayed project schedules. Transformer lead times reached three years. Breaker lead times were 85 weeks, or over a year and a half. Instrument transformers and other items were also experiencing much longer lead times, causing significant delays to project schedules.

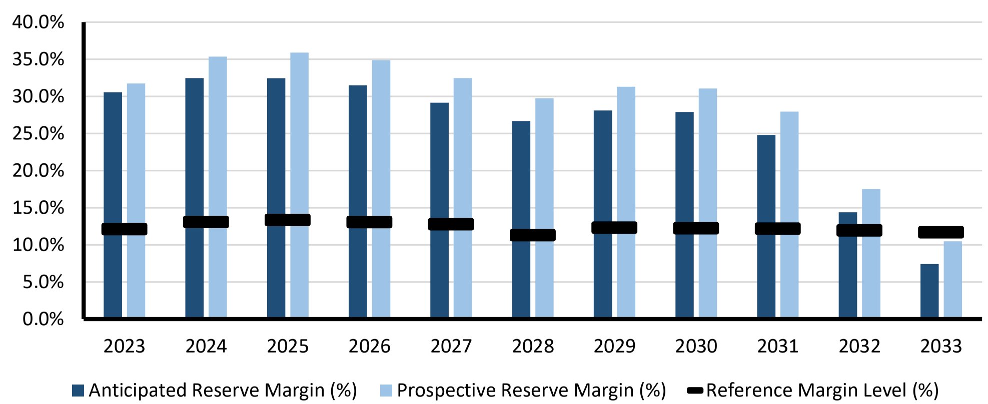
One key transmission risk is unusual outages scheduled during peak summer seasons that limit generation on baseloads, which can ultimately impact reliability.

WECC-SW

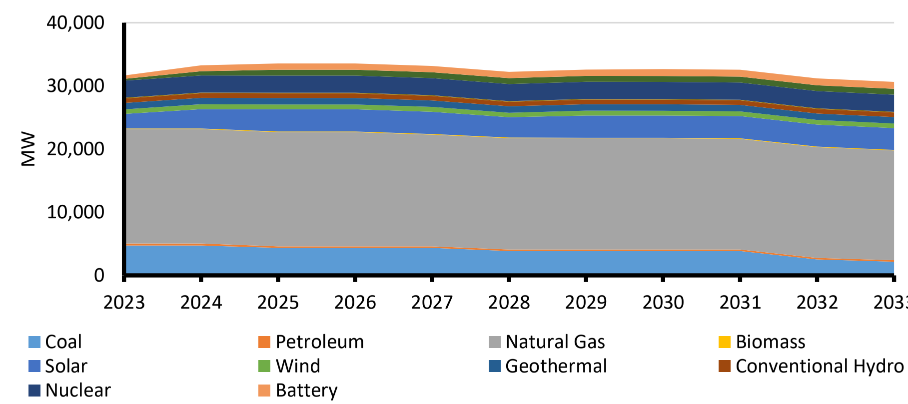
WECC-SW (Southwest) is a summer-peaking assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and part of California and Texas. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 90 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada as well as the northern portion of Baja California in Mexico and all or portions of the 14 Western United States in between. See **Elevated Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	26,749	27,499	28,294	29,029	29,554	29,973	30,400	30,529	30,672	31,234
Demand Response	383	419	384	394	385	388	391	384	394	385
Net Internal Demand	26,366	27,080	27,910	28,635	29,169	29,585	30,009	30,145	30,278	30,848
Additions: Tier 1	3,441	4,217	4,217	4,217	4,046	4,219	4,308	4,308	4,308	4,308
Additions: Tier 2	764	937	948	948	894	948	948	948	948	948
Additions: Tier 3	947	2,074	4,593	4,938	5,081	5,861	6,511	7,277	8,489	8,697
Net Firm Capacity Transfers	1,676	2,316	3,148	3,824	4,731	5,324	5,736	5,072	3,448	2,512
Existing-Certain and Net Firm Transfers	31,484	31,648	32,480	32,765	32,905	33,678	34,075	33,313	30,327	28,828
Anticipated Reserve Margin (%)	32.5%	32.4%	31.5%	29.1%	26.7%	28.1%	27.9%	24.8%	14.4%	7.4%
Prospective Reserve Margin (%)	35.4%	35.9%	34.9%	32.5%	29.7%	31.3%	31.1%	27.9%	17.5%	10.5%
Reference Margin Level (%)	13.1%	13.4%	13.1%	12.8%	11.3%	12.3%	12.2%	12.2%	12.0%	11.7%



Planning Reserve Margins



Existing and Tier 1 Resources

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Highlights

- The ARM does not fall below the RML for the peak hour until Summer 2033 when it shows a shortfall of existing-certain and net firm transfers, meaning imports may be necessary if new capacity were to be delayed.
- Looking at all hours, WECC-SW shows demand at risk starting in 2025 and increasing over this assessment period, which is slightly mitigated and delayed until 2027 with the consideration of on-time Tier 3 resource commissioning.

Note: the table below reflects the expected 50th percentile, or 1 in 2 probability of energy availability by resource type on the peak hour.

WECC-SW Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	4,724	4,354	4,354	4,354	3,859	3,852	3,852	3,852	2,527	2,159
Petroleum	318	241	241	241	241	241	241	241	241	241
Natural Gas	18,113	18,084	18,084	17,692	17,622	17,604	17,604	17,522	17,522	17,377
Biomass	94	94	94	94	94	94	94	94	94	94
Solar	3,063	3,517	3,517	3,517	3,222	3,517	3,517	3,516	3,493	3,442
Wind	770	770	770	770	708	770	756	741	727	727
Geothermal	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022
Conventional Hydro	719	719	719	719	701	719	719	719	719	719
Pumped Storage	110	110	110	110	113	110	110	110	110	110
Nuclear	2,714	2,714	2,714	2,714	2,714	2,717	2,717	2,717	2,717	2,717
Hybrid	668	929	929	929	929	930	930	930	930	930
Battery	933	995	995	995	995	996	1,085	1,085	1,085	1,085
Total MW	33,249	33,549	33,549	33,157	32,220	32,573	32,647	32,548	31,186	30,623

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WECC-SW Assessment

Planning Reserve Margins
ARM and PRM fall below the RML on the peak hour in Summer 2033. Starting in summer 2033, WECC-SW shows a shortfall of existing-certain and net firm transfers, meaning imports may be necessary if new capacity were to be delayed.

Energy Assessment and Non-Peak Hour Risk
WECC uses the Multi-Area Variable Resource Integration Convolution model. The model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour.

WECC performs energy-based probabilistic assessments that are based on distributions of resource availability and distributions of demand. For resources, WECC uses the 3rd to 97th percentiles of hourly availability. Looking at all hours of the year and counting existing, Tier 1 and Tier 2 resources, WECC-SW shows three potential loss-of-load hours in 2026, which falls to zero hours at risk when Tier 3 resources are considered.

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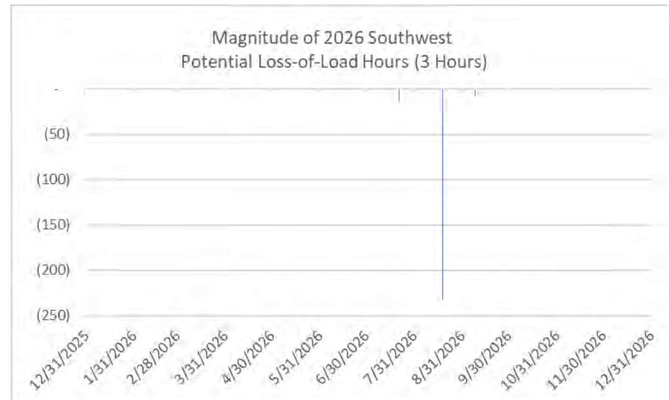
Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	84	-	818
EUE (PPM)	1	-	6
LOLH (hours per Year)	0.003	-	0.031
Operable On-Peak Margin	28.1%	18.3%	18.4%

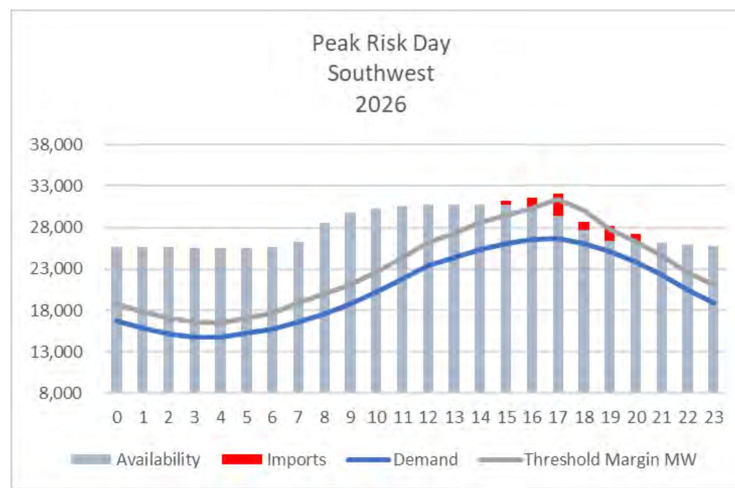
* Provides the 2022 ProbA Results for Comparison

Probabilistic Assessments
WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the 1-day-in-10-year level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than 0.02% of the total area of the demand curve for any given hour).

The following plot is output from WECC's probabilistic assessment and shows the distribution of load loss events in MW across the 2026 study year.



The following plot is output from WECC's probabilistic assessment and shows the modeled demand and resources on the peak demand day for 2026.



Demand

The Southwest's peak demand (summer) CAGR is 1.68%, WECC-SW load forecast is nearly the same as last year's, a slight drop from last year's 1.72%. Over the planning period, WECC-SW goes from a summer peak of almost 27 GW in 2023 to 33 GW by 2033 or 20% over this assessment year. WECC-SW peaks in mid-July around 5:00 p.m.

The load forecasts reflect different degrees of electrification. Most include transportation electrification assumptions, but few are incorporating building and industry electrification impacts. Data centers are another load compounding impact being studied.

Some areas have reported delays energizing customers due to supply chain issues. At times, material has not been available to complete some overhead services on schedule. Alternative design solutions have had to be explored. Due to the supply chain shortages, subdivision projects have been delayed. Chip shortages have impacted meter orders.

Demand-Side Management

WECC-SW summer demand-side management programs are expected to grow from 383 MW in 2024 to 385 MW in 2033 and from 288 MW in winter 2024 to 318 MW by winter 2033.

Distributed Energy Resources

BTM resources are netted with load.

Generation

WECC-SW is retiring 4.1 GW of capacity over this assessment period, which includes almost three GW of coal and 780 MW of natural gas. There are several states in WECC-SW with a renewable portfolio and carbon-free electricity targets driving the changes in resource portfolios. These include Arizona (15% 2025–2029), New Mexico (50% by 2030), and individual utility independent goals.

Almost 350 MW of new geothermal capacity is planned along with 1,230 MW of new natural gas by 2026. Additionally, over 15 GW of new solar PV is in the resource plans, almost 1,200 MW of wind.

Due to fuel shortfalls in 2022, some areas have revamped their communications to manage potential fuel shortages better proactively. Additionally, pipeline outages have been resolved and are now fully available.

Supply chain constraints are impacting WECC-SW. In response, procurement timelines have been accelerated to earlier in projects' processes. Generator step-up transformers have a longer lead time than in prior years, impacting the commercial operation date of new resources in plans through 2026. New utility-scale renewable resource timing has been unstable due to raw material and earth metal accessibility.

Energy Storage

The SW has 3.7 GW of energy storage planned in addition to the existing capacity of 140 MW.

Capacity Transfers and External Assistance

The SW shows increasing firm imports in summer from 1.7 to 5.7 GW over the assessment period and none in winter. Some areas have reported system constraints that could be a future reliability risk for import transfer availability.

Transmission

There are five transmission projects with voltage design of 500 kV and higher planned in the Southwest. In addition, there are 37 conceptual projects to cover almost 250 miles, 43 planned projects for almost 350 miles, and six projects under construction covering 68 miles. The primary driver for a significant majority of projects (137) is reliability followed by VER integration for seven projects and then four projects aimed at economics and congestion.

Areas have reported distribution transformer shortages and control shelter assemblies significantly impacting operations and continue to persist. Furthermore, shortages of 600 v cable have resulted in the need to find secondary suppliers during the summer seasons. Impacts span deferred construction work as crews wait for delated materials to be delivered.

Demand Assumptions and Resource Categories

Demand (Load Forecast)	
Total Internal Demand	This is the peak hourly load[57] for the summer and winter of each year.[58] Projected total internal demand is based on normal weather (50/50 distribution)[59] and includes the impacts of distributed resources, EE, and conservation programs.
Net Internal Demand	This is the total internal demand reduced by the amount of controllable and dispatchable DR projected to be available during the peak hour. Net internal demand is used in all reserve margin calculations.

Load Forecasting Assumptions by Assessment Area

Assessment Area	Peak Season	Coincident / Noncoincident[60]	Load Forecasting Entity
MISO	Summer	Coincident	MISO LSEs
MRO-Manitoba Hydro	Winter	Coincident	Manitoba Hydro
MRO-SaskPower	Winter	Coincident	SaskPower
NPCC-Maritimes	Winter	Noncoincident	Maritimes sub-areas
NPCC-New England	Summer	Coincident	ISO-NE
NPCC-New York	Summer	Coincident	NYISO
NPCC-Ontario	Summer	Coincident	IESO
NPCC-Québec	Winter	Coincident	Hydro Québec
PJM	Summer	Coincident	PJM
SERC-East	Summer	Noncoincident	SERC LSEs
SERC-Florida Peninsula	Summer	Noncoincident	
SERC-Central	Summer	Noncoincident	
SERC-Southeast	Summer	Noncoincident	
SPP	Summer	Noncoincident	SPP LSEs
Texas RE-ERCOT	Summer	Coincident	ERCOT
WECC-AB	Winter	Noncoincident	WECC BAs, aggregated by WECC
WECC-BC	Winter	Noncoincident	
WECC-CA/MX	Summer	Noncoincident	
WECC-NW	Summer	Noncoincident	
WECC-SW	Summer	Noncoincident	

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[57] Glossary of Terms Used in NERC Reliability Standards.
[58] The summer season represents June–September and the winter season represents December–February.
[59] Essentially, this means that there is a 50% probability that actual peak demand will be higher and a 50% probability that actual peak demand will be lower than the value provided for a given season/year.
[60] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval. This is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year.

Resource Categories
NERC collects projections for the amount of existing and planned capacity and net capacity transfers (between assessment areas) that will be available during the forecast hour of peak demand for the summer and winter seasons of each year. Resource planning methods vary throughout the North American BPS. NERC uses the following categories to provide a consistent approach for collecting and presenting resource adequacy.
Anticipated Resources • Existing-certain generating capacity: includes capacity to serve load during period of peak demand from commercially operable generating units with firm transmission or other qualifying provisions specified in the market construct. • Tier 1 capacity additions: includes capacity that is either under construction or has received approved planning requirements • Firm capacity transfers (Imports minus Exports): transfers with firm contracts • Less confirmed retirements[61]
Prospective Resources: Includes all "anticipated resources" plus the following: • Existing-other capacity: includes capacity to serve load during period of peak demand from commercially operable generating units without firm transmission or other qualifying provision specified in the market construct. Existing-other capacity could be unavailable during the peak for a number of reasons. • Tier 2 capacity additions: includes capacity that has been requested but not received approval for planning requirements • Expected (nonfirm) capacity transfers (imports minus exports): transfers without firm contracts but a high probability of future implementation. • Less unconfirmed retirements.[62]

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[61] Generators that have formally announced retirement plans. These units must have an approved generator deactivation request where applicable.
[62] Capacity that is expected to retire based on the result of an assessment area generator survey or analysis. This capacity is aggregated by fuel type.

Demand Assumptions and Resource Categories

Resource Categories
Generating Unit Status: Status at time of reporting:

- Existing: It is in commercial operation.
- Retired: It is permanently removed from commercial operation.
- Mothballed: It is currently inactive or on standby but capable for return to commercial operation. Units that meet this status must have a definite plan to return to service before changing the status to "Existing" with capacity contributions entered in "Expected-Other." Once a "mothballed" unit is confirmed to be capable for commercial operation, capacity contributions should be entered in "Expected-Certain."
- Cancelled: planned unit (previously reported as Tier 1, 2, or 3) that has been cancelled/removed from an interconnection queue.
- Tier 1: A unit that meets <u>at least one</u> of the following guidelines (with consideration for an area's planning processes):[63]
  - Construction complete (not in commercial operation)
  - Under construction
  - Signed/approved Interconnection Service Agreement (ISA)
  - Signed/approved Power Purchase Agreement (PPA) has been approved
  - Signed/approved Interconnection Construction Service Agreement (CSA)
  - Signed/approved Wholesale Market Participant Agreement (WMPA)
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to Vertically Integrated Entities)
- Tier 2: A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):[64]
  - 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)
- Tier 3: A units in an interconnection queue that do not meet the Tier 2 requirement.

[63] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)
[64] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)

Reserve Margin Descriptions
Planning Reserve Margins: The primary metric used to measure resource adequacy defined as the difference in resources (anticipated or prospective) and net internal demand divided by net internal demand, shown as a percentile
Anticipated Reserve Margin (ARM): The amount of anticipated resources less net internal demand calculated as a percentage of net internal demand
Prospective Reserve Margin (PRM): The amount of prospective resources less net internal demand calculated as a percentage of net internal demand
Reference Margin Level (RML): The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, system planners use this metric is to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increased demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the RML is a requirement. RMLs can fluctuate over the duration of this assessment period or may be different for the summer and winter seasons. If an RML is not provided by a given assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Methods and Assumptions

How NERC Defines BPS Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:

- **Adequacy:** The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components
- **Operating Reliability:** The ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components

When extreme or otherwise unanticipated conditions result in a resource shortfall, system operators take controlling actions or implement procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area); these actions include the following:

- Public appeals
- Interruptible demand that the end-use customer makes available to its LSEs via contract or agreement for curtailment[65]
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as 5%)
- Rotating blackouts (The term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, rotating the outages among individual feeders.)

System disturbances affect operating reliability when they cause the unplanned and/or uncontrolled interruption of customer demand. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When interruptions spread over a wide area of the grid, they are referred to as "cascading blackouts," the uncontrolled successive loss of system elements triggered by an incident at any location.

The BES is a defined subset of the BPS that includes all facilities necessary for the reliable operation and planning of the BPS.[66] NERC Reliability Standards are intended to establish requirements for BPS owners and operators so that the BES delivers an adequate level of reliability (ALR),[67] which is defined by the following characteristics.

- **Adequate Level of Reliability:** It is the state that the design, planning, and operation of the BES will achieve when the following reliability performance objectives are met:
  - The BES does not experience instability, uncontrolled separation, cascading,[68] and/or voltage collapse under normal operating conditions or when subject to predefined disturbances.[69]
  - BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
  - BES voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
  - Adverse reliability impacts on the BES following low-probability disturbances (e.g., multiple BES contingences, unplanned/uncontrolled equipment outages, cyber security events, malicious acts) are managed.
  - Restoration of the BES after major system disturbances that result in blackouts and widespread outages of BES elements is performed in a coordinated and controlled manner.

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[65] Interruptible demand (or interruptible load) is a term used in NERC Reliability Standards. See Glossary of Terms used in Reliability Standards: NERC Glossary of Terms

[66] BES Definition

[67] NERC Informational Filing (to FERC) on the Definition of Adequate Level of Reliability

[68] NERC's Glossary of Terms defines Cascading: "Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."

[69] NERC's Glossary of Terms defines Disturbance: "1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load."

How NERC Evaluates Reserve Margins in Assessing Resource Adequacy

Planning Reserve Margins are calculated by finding the difference between the amount of projected on-peak capacity and the forecasted peak demand and then dividing this difference by the forecasted peak demand. Each assessment area has a peak season, summer or winter, for which its peak demand is higher. Planning Reserve Margins used throughout this *LTRA* are for each assessment area's peak season listed in the load forecasting table of the **Demand Assumptions and Resource Categories**.

NERC assesses resource adequacy by evaluating each assessment area's Planning Reserve Margins relative to its RML—a "target" or requirement based on traditional capacity planning criteria. The projected resource capacity used in the evaluations is reduced by known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations) and compared to the RML, which represents the desired level of risk based on a probability-based loss-of-load analysis. On-peak resource capacity reflects expected output at the hour of peak demand. Because the electrical output of VERs (e.g., wind and solar) depend on weather conditions, on-peak capacity contributions are less than nameplate capacity. Based on the five-year projected reserves compared to the established RMLs, NERC determines the risk associated with the projected level of reserve and concludes in terms of the following:

Adequate: The ARM is greater than RML.

Marginal: The ARM is lower than the RML and the PRM is higher than RML.

Inadequate: The ARM and PRMs are less than the RML and Tier 3 resources are unlikely to advance.

Metrics for Probabilistic Evaluation Used in this Assessment

Probabilistic Assessment: Biennially, NERC conducts a probabilistic evaluation as part of its resource adequacy assessment and publishes results in the LTRA.

Loss-of-Load Hours: LOLH is generally defined as the expected number of hours per time period (often one year) when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated by using each hourly load in the given period (or the load duration curve).

LOLH is evaluated using all hours rather than just peak periods. It can be evaluated over seasonal, monthly, or weekly study periods. LOLH does not inform of the magnitude or the frequency of loss-of-load events, but it is used as a measure of their combined duration. LOLH is applicable to both small and large systems and is relevant for assessments covering all hours (compared to only the peak demand hour of each season). LOLH provides insight to the impact of energy limited resources on a system's reliability, particularly in systems with growing penetration of such resources. Examples of such energy limited resources include the following:

- DR programs that can be modeled as resources with specific contract limits, including hours per year, days per week, and hours per day constraints
- EE programs that can be modeled as reductions to load with an hourly load shape impact
- Distributed resources (e.g., BTM solar PV) that can be modeled as reductions to load with an hourly load shape impact
- VERs can be modeled probabilistically with multiple hourly profiles

Expected Unserved Energy: EUE is the summation of the expected number of megawatt hours of demand that will not be served in a given time period as a result of demand exceeding the available capacity across all hours. EUE is an energy-centric metric that considers the magnitude and duration for all hours of the time period and is calculated in MWhs. This measure can be normalized based on various components of an assessment area (e.g., total of peak demand, net energy for load). Normalizing the EUE provides a measure relative to the size of a given assessment area (generally in terms of parts per million or ppm).

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EUE is the only metric that considers magnitude of loss-of-load events. With the changing generation mix, to make EUE a more effective metric, hourly EUE for each month provides insights on potential adequacy risk during shoulder and nonpeak hours. EUE is useful for estimating the size of loss-of-load events so the planners can estimate the cost and impact. EUE can be used as a basis for reference reserve margin to determine capacity credits for VERs. In addition, EUE can be used to quantify the impacts of extreme weather, common mode failure, etc.

NERC is not aware of any planning criteria in North America based on EUE; however, in Australia, the Australian Energy Market Operator is responsible for planning using 0.002% (20 ppm) EUE as their energy adequacy requirement.[70] This requirement incorporates economic factors based on the risk of load shedding and the value of load loss along with the load-loss reliability component.

On the basis of the two years of the ProbA results, NERC determines the risk in terms of the following:

Normal Risk: Negligible amounts of LOLH and EUE.

Periods of Risk: LOLH < 2 Hours and EUE < 0.002% of total annual net energy.

Significant Risk: LOLH > 2 Hours and EUE > 0.002% of total annual net energy.

Understanding Demand Forecasts

Future electricity requirements cannot be predicted precisely. Peak demand and annual energy use are reflections of the ways in which customers use electricity in their domestic, commercial, and industrial activities. Therefore, the electric industry continues to monitor electricity use and generally revise its forecasts on an annual basis or as its resource planning requires. In recent years, the difference between forecast and actual peak demands have decreased, reflecting a trend toward improving forecasting accuracy.

The peak demand and annual net energy for load projections are aggregates of the forecasts of the individual planning entities and LSEs. These resulting forecasts reported in this LTRA are typically "equal probability" forecasts. That is, there is a 50% chance that the forecast will be exceeded and a 50% chance that the forecast will not be reached.

Forecast peak demands, or total internal demand, are electricity demands that have already been reduced to reflect the effects of DSM programs, such as conservation, EE, and time-of-use rates; it is equal to the sum of metered (net) power outputs of all generators within a system and the metered line flows into the system less the metered line flows out of the system. Thus, total internal demand is the maximum (hourly integrated) demand of all customer demands plus losses. The effects of DR resources that are dispatchable and controllable by the system operator, such as utility-controlled water heaters and contractually interruptible customers, are not included in total internal demand. Rather, the effects of dispatchable and controllable DR are included in net internal demand.

Future Transmission Project Categories

- **Under Construction:** Construction of the line has begun.
- **Planned** (any of the following):
  - Permits have been approved to proceed
  - Design is complete
  - Needed in order to meet a regulatory requirement

- **Conceptual** (any of the following):
  - A line projected in the transmission plan
  - A line that is required to meet a NERC TPL standard or power-flow model and cannot be categorized as "Under Construction" or "Planned"

Other projected lines that do not meet requirements of "Under Construction" or "Planned"

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[70] https://wa.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf

ERO Actions Summary

The ERO has a range of activities underway to monitor, assess, and reduce long-term BPS reliability risks. The selected ERO activities summarized below will result in new or enhanced Reliability Standards requirements, reliability guidelines, resources, or significant findings and actionable steps for stakeholders to address reliability risks.

Ongoing ERO Actions Addressing the *2023 LTRA* Recommendations

1: Add new resources with needed reliability attributes and make existing resources more dependable.

Initiative	Description	Product/Reliability Solution
Cold Weather Reliability Standards and Activities	New cold weather Reliability Standards adopted by the NERC Board of Trustees in June 2021 went into effect in the United States in 2023. Generator Owners and Generator Operators are required to implement plans for cold weather preparedness and provide cold weather operating parameters to their RCs, Transmission Operators, and BAs for use in operating plans. Additional Reliability Standard requirements have been developed by NERC and industry to address further recommendations of the *FERC-NERC-Regional Entity staff report—The February 2021 Cold Weather Outages in Texas and Southcentral United States.* The NERC Board adopted these requirements in October 2023 and directed NERC to file them with regulatory authorities for approval and industry implementation. NERC and the industry are currently developing the remaining Reliability Standard enhancements to address the staff report. Refer to *Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination* on NERC's standards development page.[71]	Reliability Standards NERC Alerts Event Analysis Reports Lessons Learned
Inverter Based Resources Strategy	NERC's IBR strategy includes four key focus areas: Risk Analysis, Interconnection Process Improvements, Sharing Best Practices and Industry Education, and Regulatory Enhancements. The status of NERC's extensive activities in each area are described in detail in the *IBR Activities Reference Guide*.[72] NERC has investigated and analyzed IBR performance issues during grid disturbances dating back to 2016. Since that time, NERC and its technical groups have published a range of reliability guidelines for studying, modeling, controlling, and interconnecting IBRs. In partnership with many experts from across the industry, NERC maintains an active campaign of education, awareness, and outreach to support its strategy and reduce IBR performance risks. NERC and the RSTC recognized that Reliability Standard requirements would be needed as part of a comprehensive approach to reliability and undertook a full review of existing standards to identify gaps. Several reliability standards projects were initiated following this review. In October 2023, FERC issued order No. 991, which provided clear direction for the industry to develop requirements that address reliability gaps related to IBR in data sharing, model validation, planning and operational studies, and performance requirements.	Reliability Standards NERC Alerts Reliability Guidelines Event Analysis Reports Lessons Learned Educational Webinars
Natural Gas-Electric Interdependence Initiatives	Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised guideline also identifies the fuel risks encountered by industry during recent periods of extreme cold weather and high demand for natural gas. These natural gas supply risks can inform industry's development of planning scenarios. The revised guideline is under review with the Reliability and Security Technical Committee. Refer to the RSTC-Approved Documents page.[73]	Reliability Guideline

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[71] Project 2021-07
[72] IBR Activities
[73] RSTC Approved Documents

Ongoing ERO Actions Addressing the *2023 LTRA* Recommendations

2: Expand the transmission network to deliver supplies from new resources and locations to serve changing loads.

Initiative	Description	Product/Reliability Solution
Interregional Transfer Capability Study	NERC's study will analyze the amount of power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems. The study will be conducted in consultation with the six Regional Entities and each transmitting utility in neighboring transmission planning areas. Transfer capability is a critical measure of the ability to address energy deficiencies by relying on distant resources and is a key component of a reliable and resilient BPS. The study, which was directed in the Fiscal Responsibility Act of 2023, must be filed with FERC by December 2, 2024. A public comment period will take place when FERC publishes the study in the Federal Register. After submittal, FERC must provide a report to Congress within 12 months of closure of the public comment period with recommendations (if any) for statutory changes. Refer to the ITCS Initiatives page.[74]	ERO Study and Recommendations

3: Adapt BPS planning, operations, and resource procurement markets and processes to the realities of a more complex power system.

Initiative	Description	Product/Reliability Solution
Energy Assessments Initiatives	NERC conducts seasonal long-term and probabilistic reliability assessments and issues reports like this *2023 LTRA* to advise industry and stakeholder of findings on BPS adequacy, including energy adequacy. In recent years, NERC has enhanced the energy risk analysis in seasonal assessments by incorporating deterministic energy risk scenarios and introducing probability-based assessments. NERC's ProbA uses hourly simulations to examine the ability of resources to meet demand over the entire study year, helping to identify energy risks that could otherwise go unaddressed by peak hour reserve margin resource adequacy analysis. NERC reliability assessments continue to evolve as more sophisticated energy assessment tools, models, and capabilities are developed. The RSTC created the Energy Reliability Assessment Working Group (ERAWG) to support wide adoption of technically-sound approaches to energy assessments by BPS planners and operators. Working group projects and activities are described on the ERAWG page.[75] New and revised Reliability Standards requirements for BPS planners and operators to address energy risks are in development in Project 2022-03 *Energy Assurance with Energy Constrained Resources.*[76] In other Reliability Standard development work, Project 2023-07 *Transmission System Planning Performance Requirements for Extreme Weather*, requirements are being developed that will ensure entities consider extreme heat and cold weather scenarios in BPS planning, including the expected availability of the future resource mix.[77]	Reliability Assessments Reliability Standards
Distributed Energy Resources Strategy	NERC has proactively worked with industry stakeholders to identify BPS reliability risks associated with the increasing DER levels and has initiated actions to support broad awareness and education as well as to provide guidance for industry and enhance Reliability Standards where gaps exist. The status of NERC's extensive activities in each area are described in detail in the *DER Activities Reference Guide*.[78]	Reliability Standards Reliability Guidelines Educational Webinars

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[74] ITCS Project
[75] ERAWG
[76] Project 2022-03
[77] Project 2023-07
[78] DER Activities

Ongoing ERO Actions Addressing the *2023 LTRA* Recommendations

4: Strengthen relationships among reliability stakeholders.

Initiative	Description	Product/Reliability Solution
Ongoing Strategic Engagements	NERC and regional entities engage in frequent dialogue and conduct outreach with regulators and policymakers at the state/provincial, regional, and federal/national levels.	Constructive Partnerships

Attachment C

STATEMENT

FOR IMMEDIATE RELEASE

PJM Statement on the Newly Issued EPA Greenhouse Gas and Related Regulations

(Valley Forge, PA – May 8, 2024) – PJM provides this statement concerning the EPA rule on New Source Performance Standards for Greenhouse Gas Emissions and the other EPA regulations promulgated on April 25, 2024.

PJM has the responsibility to ensure both short- and longer-term reliability for the 65 million people we serve in a region spanning 13 states plus the District of Columbia. "Reliability" in this context refers both to the day-to-day work of managing the grid to keep the system in balance as well as ensuring that, looking forward, there are adequate resources available and committed to serve the expected demand for electricity in future years.

Because of these unique responsibilities, PJM and other affected RTOs have been extensively involved in EPA rulemakings dating back to the Mercury and Air Toxics Standards rule promulgated on Dec. 16, 2011. Our role in these rulemakings has been to ensure that, in developing proposed environmental rules, EPA has appropriately taken into account the reliability needs of our respective grids.

Consistent with this past level of involvement, PJM worked cooperatively with MISO, SPP and ERCOT (the RTOs most affected by the EPA rule) to craft a set of detailed comments to EPA raising our collective reliability concerns with EPA's initial proposed greenhouse gas (GHG) rule. Our comments and subsequent meetings with EPA were focused on:

- Educating EPA as to the reliability needs of our respective systems and the potential impact that the then-proposed GHG Rule could have on both day-to-day reliability and resource adequacy; and
- Providing to EPA constructive proposals to help mitigate, from a reliability perspective, potential adverse impacts of the then-proposed Rule with a particular focus on ensuring adequate flexibility within the Rule for grid operators to be able to address both short-term reliability issues and resource adequacy within their regions.

– MORE –

Noting the RTO Comments, in its Final Rule issued on April 24, 2024, EPA made certain adjustments to its initial proposal. Those adjustments altered the resources impacted by the rule and provided additional tools that can help provide flexibility to address reliability issues. PJM is appreciative of EPA's acknowledgment of the importance of the existing resources to reliability, of the need for more flexibility, and its consideration of the Joint RTO Comments. The specific adjustments that were grounded in the Joint RTO Comments and adopted in the Final Rule included:

- **Treatment of Existing Gas Resources** – Removing existing gas from this rulemaking to be addressed holistically in a separate rulemaking

- **State-Specific Compliance Flexibility –** Availability of flexibility for the states to address reliability issues, taking into account the remaining useful life and other factors that affect needed units

- **Averaging –** Allowing unit owners to average their compliance obligations over multiple units to ensure least-cost compliance

- **Emissions Trading –** Authorizing states to utilize allowance trading to minimize compliance costs and burdens

- **Mass-Based Programs –** Authorizing states to potentially utilize an emissions cap rather than controlling the rate of emissions from each affected unit

- **Short-Term Reliability Mechanisms –** Allowing needed units to operate for emergencies without jeopardizing compliance with the rule

- **Timeline Extensions** – Providing extensions for retiring units needed for reliability and units needing more time to install controls, with state discretion for longer periods

PJM's Continuing Reliability Concerns

Although we appreciate EPA's adoption of certain flexibility measures in response to our proposals, areas of concern remain related to ensuring reliability given the impact of the Final EPA Rule:

- The new rules governing both existing coal and new natural gas are premised on EPA's finding that carbon capture and sequestration (CCS) technology represents the "best" system of emissions reduction, which will be commercially available at a reasonable cost. However, the availability of CCS is highly dependent on local topology, such as salt caverns available to sequester carbon and the availability of a pipeline infrastructure to transport carbon emissions from individual generating plants to CCS sites potentially hundreds of miles away. There is very little evidence, other than some limited CSS projects, that this technology and associated transportation infrastructure would be widely available throughout the country in time to meet the compliance deadlines under the Rule.

– MORE –

- The Final Rule imposes the most stringent requirements on new gas and existing coal units that operate as baseload units. Although EPA has focused on these units given that they have greater emissions, these baseload units provide a critical reliability role. We are seeing vastly increased demand as a result of new data center load, electrification of vehicles and increased electric heating load. The future demand for electricity cannot be met simply through renewables given their intermittent nature. Yet in the very years when we are projecting significant increases in the demand for electricity, the Final Rule may work to drive premature retirement of coal units that provide essential reliability services and dissuade new gas resources from coming online. The EPA has not sufficiently reconciled its compliance dates with the need for generation to meet dramatically increasing load demands on the system.

- The Final Rule is premised on the availability of increased access to natural gas infrastructure to support the Rule's "co-firing with gas" compliance option for existing coal units. The present gas pipeline system is largely fully subscribed. Moreover, given local opposition, it has proven extremely difficult to site new pipelines just to meet today's needs, let alone a significantly increased need for natural gas in the future. The Final Rule, which is premised, in part, on the availability of natural gas for co-firing or full conversion, does not sufficiently take into account these limitations on the development of new pipeline infrastructure.

- EPA has left many issues for development in individual state implementation plans. Although this is appropriate and in keeping with the structure of the Clean Air Act, each of the multi-state RTOs like PJM operate a single dispatch. As a result, states will need to coordinate and work closely together to ensure that the individual state plans work well on a regional basis. As a result, the need for regional coordination of individual State Implementation Plans is more important than ever. PJM values its continued collaboration with the other affected RTOs (MISO, SPP and ERCOT) and looks forward to working with the U.S. EPA, individual states and affected stakeholders as this process continues.

PJM Interconnection, founded in 1927, ensures the reliability of the high-voltage electric power system serving 65 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM coordinates and directs the operation of the region's transmission grid, which includes 88,115 miles of transmission lines; administers a competitive wholesale electricity market; and plans regional transmission expansion improvements to maintain grid reliability and relieve congestion. PJM's regional grid and market operations produce annual savings of $3.2 billion to $4 billion. For the latest news about PJM, visit PJM Inside Lines at insidelines.pjm.com.

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Exhibit L

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

ELECTRIC GENERATORS FOR A SENSIBLE TRANSITION, *Petitioner*, v. U.S. ENVIRONMENTAL PROTECTION AGENCY, *Respondent*.	Case No.: 24-1128

DECLARATION OF DALE E. LEBSACK, JR.

I, Dale E. Lebsack, Jr., declare as follows:

1. I currently work as Chief Fossil Officer for Talen Energy Corporation ("Talen"). I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. I have personal knowledge of the facts set forth in this declaration, and if called and sworn as a witness, could and would competently testify to them.

2. Petitioners Talen Generation, LLC and Talen Montana Holdings, LLC (the "Talen Entities") are wholly owned subsidiaries of Talen. Talen is an independent power producer that owns and operates approximately 10.7 gigawatts of power infrastructure in the United States. Talen produces and sells electricity, capacity, and ancillary services

into wholesale U.S. power markets, including PJM Interconnection, LLC ("PJM") and the Western Electricity Coordinating Council ("WECC"), with Talen's generation fleet principally located in the Mid-Atlantic and Montana. Talen's generation fleet includes wholly owned and partially owned assets that use nuclear, coal, oil, and natural gas as fuels.

3. In my current position as Chief Fossil Officer at Talen, I am responsible for asset management and operations for Talen's fossil generating assets in PJM, WECC, and ISO New England. In that capacity, I also serve as President of Talen Generation, LLC, which indirectly owns the fossil generating assets in PJM and is an affiliate of Talen. I have worked for Talen and its predecessor companies for over 19 years. Over that time, I have held roles of increasing responsibility in multiple aspects of fossil power generation, including asset management, plant operations, engineering, environmental, health and safety, and project development. I have directly managed merchant generating assets in ERCOT, PJM, ISO-NE, NYISO, WECC, and SERC. The plants that I managed have utilized a wide range of technologies, including coal, gas, oil, and biomass-fired boilers; combined cycle units of varying configurations; and simple cycle gas turbines of differing designs.

4. This declaration is submitted in support of the Petitioner's motion for stay of the U.S. Environmental Protection Agency's final rule entitled *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units;*

and Repeal of the Affordable Clean Energy Rule, 89 Fed. Reg. 39798 (May 9, 2024) (the "Final Rule" or "Rule"). I am familiar with the Talen Entities' operations, including generation, regulatory compliance, workforce management, and electric markets in general. I also am familiar with the Final Rule, and I am familiar with how the Final Rule will affect the Talen Entities.

5. Talen has ownership interests in coal-fired units that are projected to operate at relatively high capacity factors and will be subject to the Final Rule.

6. Talen is the operator of Units 3 and 4 at the Colstrip Steam Electric Station ("Colstrip") in Rosebud County, Montana. Talen also has a 15 percent ownership stake in these units, which currently consist of two active coal-fired generating units capable of producing up to 1,480 MW of electricity that have been operating for approximately 38 years. Each of the units has approximately 740 MW of generating capacity, and the adjacent Rosebud coal mine supplies Colstrip's low-sulfur subbituminous coal. Units 3 and 4 are the only remaining active units at Colstrip, as Units 1 and 2 recently retired in 2020. Units 3 and 4 have a useful life of at least another two decades.

7. Colstrip is one of the largest coal-fired electric generating facilities west of the Mississippi River, supplying electricity throughout Montana and the Pacific Northwest. Colstrip plays an integral role in maintaining operation of the NorthWestern Balancing Authority in Montana, especially during peak electricity demand events.

THE FINAL RULE

8. The Final Rule establishes, under Section 111(d) of the Clean Air Act, best systems of emission reduction ("BSERs") for existing coal-fired steam generating units

that States must use when setting CO_2 emissions limits for such units. 89 Fed. Reg. at 39,840. Under the provisions of the Rule, Colstrip Units 3 and 4 have three options: (1) retire by January 1, 2032; (2) meet an emission rate based on 40% natural gas co-firing by January 1, 2030, and retire by January 1, 2039; and (3) install and operate 90% efficient carbon capture and storage ("CCS") by January 1, 2032, which would allow the unit to operate after 2038. Based on Talen's assessment, the only compliance strategy available for Colstrip consists of shutting down the plant by January 1, 2032.

9. The CCS BSER established by the Final Rule for existing coal-fired steam units is not yet adequately demonstrated, is not achievable, and is not cost-effective. Further, EPA has established deadlines for incorporating this technology, or in the alternative gas co-firing, that are so unreasonable that they likely cannot be met—even if the technologies were adequately demonstrated and achievable. The end result is that owners and operators will have little choice but to retire such units prematurely.

IMPACT OF THE FINAL RULE ON COLSTRIP

10. The Rule requires major modifications to Colstrip Units 3 and 4 or premature retirement of the Units. Specifically, a decision must be made immediately between the three possible compliance choices (retire by 2032, co-fire gas by 2030, or install full CCS by 2032) in order to complete any retrofits in time for the Rule's compliance deadlines. Prematurely shutting down Colstrip would have significant economic impacts on Montana and beyond and raises serious concerns about grid reliability and transmission.

11. Feasibility and cost evaluations of each compliance option, not to mention financing, engineering, design and construction of the gas-cofiring and CCS options, require years of planning. Additionally, Colstrip is co-owned by six companies, including many utilities subject to PUC regulation in multiple states. The selection of a future compliance option must be agreed upon by a majority of ownership. After the evaluation of compliance options is complete, approval of an option will be difficult and take more time due to the plant's ownership structure.

12. If the CCS and gas co-firing compliance options are impossible or near impossible to meet the Rule's deadlines, or prove prohibitively expensive to undertake, especially in light of future uncertainty, the Rule requires retiring Colstrip Units 3 and 4 by January 1, 2032.

Feasibility and Cost Issues are Compounded by EPA's New MATS Rule

13. Furthermore, the compliance decision for the Rule is intertwined with the EPA's also recently-issued final rule entitled *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 89 Fed. Reg. 38,503 (May 7, 2024) ("MATS Rule").

14. For Colstrip to operate beyond 2027, under the MATS rule, additional costly filterable particulate matter ("fPM") controls must be installed, commissioned, and operable on Units 3 and 4 by July 8, 2027.

15. Colstrip would need to undertake a massive and complex construction project to install, test, and implement these new controls – the costs of which are estimated to exceed $350 million.

16. If the only feasible compliance option for the Final Rule is found to be retirement, then the investment in fPM controls for just over four years (late 2027 to the end of 2032) would be even less justifiable than otherwise. Indeed, a return period of four years on a greater than $350 million investment in fPM controls would be extremely difficult to justify, thus likely requiring Colstrip to shut down by the MATS Rule's compliance deadline of July 2027.

CCS is Not Achievable at Colstrip

17. CCS is impracticable and infeasible at Colstrip. The Final Rule allows affected EGUs to remain in operation beyond 2038 only if they can achieve 90% capture of carbon using CCS by 2032. However, this is not possible at Colstrip for the following reasons.

18. The technology to reliably achieve 90% capture of CO_2 using CCS is not adequately demonstrated or readily available. As described above, CCS is an emerging technology that remains unreliable, as well as prohibitively expensive. And there is not enough time to undertake all of the evaluations and studies, design, engineering, and construction of a CCS system at Colstrip. Talen would not invest hundreds of millions of dollars in a technology that is at best uncertain to work and that, in fact, Talen believes will not work as EPA claims it would by the Rule's deadline.

19. Technological issues related to carbon capture are not the only reason Colstrip would be unable to rely on the CCS pathway to comply with the Final Rule. Even if 90% of CO_2 could be captured by 2032, it would need to be transported for storage and stored. Sequestration sites have not been adequately demonstrated in the vicinity of Colstrip and would require additional time, exploration, and significant cost to complete, in addition to the costs associated with transportation of the CO_2. Colstrip, located in eastern Montana, is not near to any developed CO_2 sequestration sites. It is not known whether the geological formations necessary for CO_2 sequestration exist in the vicinity of Colstrip, and additional drilling and exploration would be required to determine this. Further, no pipeline currently exists to carry captured CO_2 from Colstrip to a storage location.

20. In fact, a study referenced in the proposed Rule reports that the costs of transportation and storage for the purposes of CCS are much higher in Montana's Powder River Basin than in other states. CO_2 pipeline transportation and storage cost in 2018 was $22/tonne for the Powder River Basin. The other basins in the study were Illinois ($10/tonne), East Texas ($11/tonne) and Williston ($15/tonne).

21. On top of these prohibitive costs, there are a number of other challenges associated with evaluating, permitting, siting, designing, and constructing such a CO_2 pipeline. Permits and easements would need to be acquired. It is unlikely such a pipeline could be constructed and operational prior to the compliance date required by the Final Rule.

22. The provision allowing for a one-year extension in the compliance deadline where the delay is needed to complete installation of controls and where the company has taken all steps necessary to otherwise meet the deadline does not make a difference. It is equally unrealistic to expect CCS to be constructed and operational at Colstrip by January 1, 2032, as it is unrealistic to expect it by January 1, 2033.

23. For the reasons outlined above, CCS is not an option for Colstrip.

Gas Co-Firing is Not Achievable at Colstrip

24. As an alternative to CCS, the Final Rule allows affected coal-fired EGUs to remain in operation until January 1, 2039, if they begin co-firing with 40% gas by 2030.

25. A project to retrofit Colstrip to co-fire gas would be exceedingly complicated and expensive. According to preliminary evaluations, conversion of Units 3 and 4 to allow for co-firing of gas would cost in excess of $150 million.

26. In addition to the retrofitting, co-firing gas at Colstrip would require new infrastructure that does not exist. The closest gas transmission pipeline is over 100 miles away. Building such a pipeline would cost on the order of $200 million or more and is economically infeasible. In addition, there are a multitude of challenges and high-cost items, especially involving the need for easement acquisition and permitting for a pipeline estimated to be over 100 miles long.

27. Putting aside that gas co-firing at Colstrip is so costly that it is economically infeasible (*i.e.*, such a costly project would make the Colstrip plant financially unviable), it is also technically near impossible to execute by 2030. A 100-mile gas pipeline is a massive construction project that requires a long lead time for design,

permitting, siting, procurement, and construction. It is also the type of project that will engender protracted challenges. It is highly improbable such a project can be accomplished by the Final Rule's deadline.

28. The provision allowing for a one-year extension in the compliance deadline where the delay is needed to compete installation of controls and where the company has taken all steps necessary to otherwise meet the deadline does not make a difference. It is equally unrealistic to expect a 100-mile gas pipeline to be constructed for Colstrip by January 1, 2030, as it is unrealistic to expect it by January 1, 2031.

29. For the reasons outlined above, gas-co-firing is not an option for Colstrip.

Without a Stay, Talen will Suffer Immediate, Irreparable Harm

30. During the pendency of this litigation, the Talen Entities would sustain the following concrete, irreparable harms if a stay of the Final Rule is not granted:

a. The costs to immediately begin designing, constructing, and permitting a gas pipeline for the ability to co-fire gas at Colstrip and to retrofit the units to provide for co-firing with gas; or

b. The costs to retrofit Colstrip with CCS, to begin construction of a pipeline to transport CO_2 for sequestration, and to evaluate and develop an acceptable site for sequestration.

31. Talen personnel would immediately begin to dedicate substantial time, attention, and resources to tasks associated with evaluating, designing, and financing such projects, which would divert attention from other important duties.

32. Dollars spent on design, permitting, engineering, and other studies cannot be refunded once they are spent. The costs associated with implementing 40 percent natural gas co-firing or installing CCS to achieve 90 percent capture of CO_2 so that Colstrip can operate beyond 2032 are massive. Colstrip would need to spend significant time, resources, and investments to not only implement the technologies, but also to construct supporting infrastructure. When added to the costs associated with complying with the proposed requirements in other rulemakings that impact Colstrip, such as the 2024 MATS Rule, the investments required for Colstrip to operate beyond 2032 would cost many hundreds of millions of dollars. Such costs would likely render Colstrip financially unviable, given Colstrip's uncertain but limited future.

Premature Retirement is the Only Option for Colstrip

33. Given that the CCS and co-firing compliance options are nearly impossible to execute successfully by the Rule's deadlines, and given that the costs of these compliance options would be prohibitively expensive to undertake, especially in light of future uncertainty, the Rule requires retiring Colstrip Units 3 and 4 by January 1, 2032. As discussed above, moreover, the interplay between the Rule and the MATS Rule means that Colstrip would likely retire by July 2027.

34. This litigation is likely to take a minimum of 2 to 3 years. If the Rule is not stayed, Talen will have suffered irreparable harm by the time the legality of the rule is determined. Before we know whether the rule will be struck down, Talen would have to elect – within a year at the most – to shut down Colstrip, and it would have to actually shut down the plant by mid-2027.

35. A decision to retire Colstrip, especially if forced to be made quickly, will have irreversible impacts to the small community around the plant and the neighboring Rosebud Mine. The mine and the power plant are the only employers of any size within 50 miles and contribute immensely to the local economy and tax revenues.

36. In addition, the Talen Entities would face increased costs related to environmental remediation that is ongoing at Colstrip, pursuant to an Administrative Order on Consent between Talen and the Montana Department of Environmental Quality. The current groundwater remediation system reuses captured water at Units 3 and 4. If the Units are prematurely shut down, additional wastewater treatment systems would be needed, which would increase overall remediation costs by approximately $2.5 million per year during the period of the premature shutdown.

The Public will Suffer Irreparable Harm if Colstrip is Retired Prematurely

37. Further, Colstrip is vital to ensuring that Montanans have affordable and reliable electricity, especially during peak winter and summer months. Colstrip is one of Montana's most important energy assets, especially as demand for reliable baseload power in the western U.S. continues to grow.

38. The likely end result of the Final Rule on Colstrip is that its owners and operators, including the Talen Entities, will have little choice but to retire the units prematurely. Such decisions will change the makeup of the nation's electricity system and increase risks to electric and transmission system reliability.

39. Risks to electricity system reliability, driven in part by the early retirement of dispatchable, high-capacity factor thermal EGUs such as Colstrip, is a matter of

significant concern. WECC reports that current utility resource plans in the western interconnect "are not sufficient to meet future demand over each of the next 10 years," and that "starting in 2026, the number and magnitude of demand-at-risk hours increase by orders of magnitude."[1]

a. In statements made in comments on both the proposed MATS rule and the proposed version of this Rule in 2023, Northwestern Energy indicated that there will not be sufficient replacement power on the grid by 2027 if Colstrip must retire.

40. Colstrip Units 3 and 4 generated approximately 41 percent of the electricity generated in Montana in 2022 and represented 23 percent of total installed generating capacity. A decision to prematurely retire Colstrip, an important baseload generator serving at least five states, would cause significant reliability concerns. These concerns would apply well into the rest of the decade, even if the Rule is not stayed and is struck down by the courts at around the same time the plant would shut down.

Dale E. Lebsack, Jr.

Dated: May 24, 2024

[1] Western Electricity Coordinating Council, 2023 Western Assessment of Resource Adequacy (Nov. 2023), *available at* https://www.wecc.org/Administrative/2023%20Western%20Assessment%20of%20Resource%20Adequacy.pdf (Attachment A).

Exhibit M

IN THE UNITED STATES COURT OF APPEALS

FOR THE DISTRICT OF COLUMBIA CIRCUIT

ELECTRIC GENERATORS FOR A SENSIBLE TRANSITION, *Petitioner*, v. U.S. ENVIRONMENTAL PROTECTION AGENCY, *Respondent*.	Case No.: 24-1128

DECLARATION OF JACOB WILLIAMS

I, Jacob Williams, declare:

1. I am the General Manager and CEO of Florida Municipal Power Agency (FMPA). I am responsible for all business matters associated with the mission and operations of FMPA, providing low-cost, reliable, and clean wholesale power, plus value-added services for FMPA's owner-members that benefit their communities and customers, including the development and operation of generation, transmission, and other facilities or projects to deliver economies of scale in power supply and related services, power supply planning, rates and financing strategies, strategic planning for the intermediate and long-term future of FMPA and its projects, local communications, stakeholder engagement, and empowering FMPA in providing wholesale power and value-added services to FMPA's member that are beneficial to local economic development and growth in FMPA member communities.

2. I graduated with a Bachelor of Science degree in Electrical Engineering from the University of Illinois and earned a Master of Business Administration from the University of Wisconsin – Madison.

3. My career in the electric utility and energy sector spans 39 years and includes experience in power markets, integrated resource planning, strategic planning, project development, energy analytics, generation and emissions technologies and executive leadership. I began my career with Alliant Utilities (formerly Wisconsin Power and Light), where I spent 14 years, followed by 17 years with Peabody Energy, followed by the most recent 8 years, in which I have served as General Manager and CEO of FMPA.

4. This declaration is based on my personal knowledge of facts and analysis conducted by my staff.

5. I am submitting this declaration in support of petitioners' motion to stay the U.S. Environmental Protection Agency's (EPA) final rule, titled "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule" (GHG Rule). The GHG Rule harms FMPA, as described in this declaration, by forcing near-term public decisions on the future of FMPA's plant operations and constraining FMPA's near-term opportunities to less economically beneficial and higher emitting alternatives for future power supply affordability and reliability. Those near-term decisions will likely be irreversible by the time this litigation is completed.

I. FMPA

6. FMPA is a wholesale power agency owned by 33 municipal electric utilities in Florida. FMPA's member utilities collectively serve approximately 3 million, or 14%, of the

Floridians in the state. FMPA's mission is to provide low-cost, reliable, and clean wholesale power, plus value-added services for FMPA's owner-customers that benefit their communities and customers.

7. FMPA's Member cities are uniquely skewed to communities of low income, with the Member cities' average incomes 13% below the Florida average and 16% below the U.S. average. 15 of our Member cities are disadvantaged communities having average incomes of 50% or less of the U.S average income, and 27 of our 33 communities have average incomes below the Florida average. Given that Florida has the highest percent of fixed income/retiree residents in the country, FMPA's member city customers are especially sensitive to price increases for basic needs and services, like food, energy, electricity, and medicine, among other things. Florida residents, especially those on fixed and low income, are significantly impacted by electric price increases because, on average, Florida families use twice as much electricity as families in California or New York, because it is hot and humid for much of the year.

8. For Florida, FMPA estimated that the GHG Rule as originally promulgated to have included existing large natural gas generating resources would cause electricity prices to increase by approximately 200%, which is especially alarming given Florida's high percentage of fixed- and low-income rate payers. Because of the final GHG Rule, these communities will still be harmed by significant increases in power costs.

9. FMPA's primary generation resource is natural gas, comprising over 80% of FMPA's resources, which is slightly above the Florida average of 75%. The Florida region has by far the highest percentage of natural gas generation of any region of the country and is therefore uniquely impacted by the EPA GHG rule for new natural gas units.

10. Eleven percent of FMPA's resources is power derived from coal. That percentage is declining as our coal resources are retiring and/or converting to natural gas in the next 4 years. That lost generation is being replaced by growing solar, which is increasing from 1% to 7% of our generation by 2028, and additional natural gas generation. FMPA's natural gas generation fleet is made up of units that are 13 – 30 years old and are facing life extension and replacement decisions over the next 5 – 10 years.

11. FMPA has been on a path to reduce greenhouse gas emission over the last 20 years, reducing the overall carbon dioxide (CO2) emission rate per megawatt-hour (MWh) by 35% from 2005 levels. FMPA is on a path to reduce CO2 emission rates by 50% from 2005 by 2028 with the closure of FMPA's partially owned coal units and the addition of solar generation and increased natural gas generation to replace a portion of the coal-based generation.

12. FMPA faces the additional challenge of compliance with the GHG Rule in the face of significant load growth in the state. FMPA expects to experience approximately 1% annual increase in load as Florida's population grows from in-migration. That growth rate could be even higher if there is continued expansion, as is expected, in vehicle electrification, data centers and artificial intelligence-related facilities, all of which will drive load in Florida over the coming years.

13. This growth and the replacement of traditional, central-station, base load generation with intermittent renewable generation increases FMPA's need for readily dispatchable energy resources. As significant amounts of new intermittent solar are added, more natural gas generation will be required to operate in spinning reserves to rapidly make up rapid solar declines. Even though Florida is marketed as the "Sunshine" state, it is 25% less sunny than Arizona or much of Southern California. Florida also has a unique meteorological pattern in the summer, with daily

cloud cover and rain occurring almost every afternoon throughout the summer months (May through September), leading to disruptions in solar electricity production throughout summer afternoons and evenings, just as load is peaking. More natural gas spinning reserves will be needed, which means having units that are operating at below maximum levels, to be available to make-up shortfalls at a moment's notice.

II. EPA's GHG Rule

14. The GHG Rule will make new baseload Natural Gas Combined Cycle (NGCC) units uneconomic, jeopardizing reliable energy for FMPA's customers. The rule offers limited pathways for compliance. EPA bases the emission rate for new NGCCs on the use of carbon capture and storage/sequestration (CCS) technology to control CO_2 emissions. The rule requires emission rates consistent with deployment of CCS by January 1, 2032. CCS is not demonstrated or achievable, nor is it currently an economic control technology, as explained in the motion that this declaration supports. It certainly will not be available by the GHG Rule's 2032 compliance deadline: putting aside the current technical and economic infeasibility of CCS, it is not possible for CCS to be constructed on a power plant in Florida by 2032 (and for many years thereafter).

15. Because deployment of CCS is not a realistic compliance option, the only available pathway for FMPA is to limit the capacity of any new NGCC units to 40%. Given the highly capital-intensive nature of any newly constructed energy asset, this arbitrary capacity factor restriction effectively guarantees that a new, more efficient, lower emitting NGCC is not economically competitive with life extensions of our existing, older NGCCs.

16. As a result, this GHG Rule will result in the unintended outcome of running less efficient and higher emitting peaking resources more frequently as load-serving entities to attempt to mitigate the risk of energy supply shortages caused by the rule's restrictions on capacity for new NGCCs. This means that FMPA may likely be economically limited to complying with the rule

by extending the life of its most inefficient and highest emitting units. Additionally, using more inefficient peaking units that require more natural gas for the same output as new NGCC generation, especially in the winter, will lead to a higher probability of natural gas supply cuts into the state. This will cause many natural gas units to switch over to diesel, which is significantly higher in cost and higher emitting than the units running on natural gas. This is counter to EPA's intent of the GHG rule for new natural gas units.

17. The effect of the GHG Rule on reliability remains unclear in a state like Florida, which is highly dependent upon natural gas plants as the sole source of firm, dispatchable capacity. Winter reserve margins within the Florida Reliability Coordinating Council (FRCC) service territory are already projected to shrink materially, such that by the end of the decade, the reserve margin in effect that is net of weather-dependent and duration dependent (e.g., storage) resources is effectively negative. An inability to plan for and construct new NGCCs statewide will severely hamper the ability of the state to match supply with demand and maintain adequate planning and operating reserves in scenarios where actual real-time solar performance does not match typical meteorological year-based assumptions or during extreme winter events where solar has a capacity value of zero.

18. As noted in FMPA's comments on the proposed GHG Rule, the level of transmission expansion and vast solar/storage overbuild required to meet the state's energy requirements at the pace assumed by EPA is highly infeasible and at odds with most all existing planning, including the Ten-Year Site Plan and the processes of the Florida Public Service Commission.

III. Impact of Rule on FMPA During the Pendency of the Litigation

19. FMPA must begin planning now for compliance with the GHG Rule. FMPA will have to make \$10-15 million in financial commitments to life extension projects in the next 2-3

years for smaller, older, less efficient, and higher-emitting NGCC and peaking plants that it would not otherwise have to make if FMPA were able to plan for the deployment of next-generation, highly efficient, and low-emitting NGCC units. The result will be increased utilization for the existing natural gas peaking and NGCC units of approximately 10-25%. This will constitute a serious misuse of resources with otherwise unnecessary costs for FMPA's customers.

20. Once FMPA has made substantial financial commitments to these life extensions and other projects at existing NGCC and peaking plants, FMPA cannot undo these decisions if the GHG rule is not stayed and later set aside. In other words, these are irreversible decisions about the long-term mix of generation that FMPA will have to make as a result of the GHG rule.

21. The life extension of higher-emitting natural peaker and combined cycle units will have the unintended consequence of increasing natural gas-related emissions by forcing FMPA to invest in life extension of higher-emitting plants rather than planning the new high-efficiency, low-emitting plants that FMPA would likely otherwise have built. The GHG Rule will also cause these units to more frequently run on their back-up diesel fuel when natural gas supplies and transportation are limited for Florida due to the higher volume of natural gas needed to serve the same load with these less efficient units.

22. In addition to near-term planning and expenditures to comply with the rule and the additional GHG emissions the rule will cause, implementation of the GHG Rule will impact reliability for FMPA's customers.

23. The GHG Rule will impact reliability by forcing the abandonment of customary resource planning practices, which reflect a continuous set of analyses to understand future load requirements, future load shapes (or the amount of energy customers consume by hour each day, which can vary over the long term based on factors such as distributed generation, transportation electrification, and energy efficiency investments), sufficiency of planning and operational reserve requirements, and the interaction of such needs with transmission system solvency. Load growth, in particular over the next 3-5 years—as driven by electrification of transportation, the potential for high load factor commercial and industrial loads, above-average summer and winter degree days and peak demand requirements, and the continued pace of immigration to Florida—presents uncertainty that will likely require nimble action to ensure adequate reserves. Putting the state utilities' integrated resource planning processes in "stasis" mode while this litigation is pending will result in significant customer harm as decisions that need to be made over that timeframe for future solvency are deferred.

24. The FRCC analyzed reliability impacts of the proposed GHG Rule. It concluded that the GHG Rule as originally proposed would require the replacement of 23 million MWh of annual energy supply needed to serve load. This shortfall represents about 8% of FRCC's total projected demand and is equivalent to blacking out about 1.8 million residential customers for the entire year, or all residential customers for about two months. This indicates a significant risk. Indeed, even half that risk would be considered alarming, as FMPA pointed out in its comments on the proposed GHG Rule.

25. It takes as long as 7-8 years to energize a large-scale utility resource, so a 2-3 year hiatus on decision-making is an untenable position in an era where the North American Electric Reliability Corporation's seasonal assessments are already placing resource adequacy risk at high levels across vast swathes of the nation.

IV. Conclusion

26. The GHG Rule will disrupt FMPA's normal orderly planning processes by effectively foreclosing FMPA's ability to construct new efficient and low-emitting NGCC units, as would likely otherwise occur. Instead, the GHG Rule will require FMPA to make decisions and

to invest significant sums in the near-term to extend the life of existing units to which the GHG Rule does not apply. Once FMPA commits to these projects, they are irreversible.

27. This outcome irreparably and immediately harms FMPA by significantly interfering in FMPA's planning process and the mix of generation assets needed for reliable, low-cot service to its customers. And FMPA's customers will also be harmed by greater costs, less reliable electric service, and greater emissions.

Executed this 22 day of May 2024.

Jacob A. Williams

Jacob Williams