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by Sidney Davy Miller

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February 27, 2025

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Hwy.
Lansing, MI 48917

Re: Upper Michigan Energy Resources Corporation
Amended Renewable Energy Plan
Case No. U-21813

Dear Ms. Felice:

Attached for electronic filing on behalf of Upper Michigan Energy Resources Corporation please find: (i) Application; (ii) redacted-public version of the Direct Testimony and Exhibits of Richard F. Stasik, Jaime Cano Lopez, Chelsey A. Biersach, and James M. Beyer; (iii) Protective Order; and (iv) Appearances of Attorneys Sherri A. Wellman and Paul M. Collins.

Should you have any questions or concerns, please advise.

Very truly yours,

Miller, Canfield, Paddock and Stone, P.L.C.

Sherri A. Wellman
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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * *

In the matter of the application of **UPPER MICHIGAN ENERGY RESOURCES CORPORATION** requesting approval of an amended renewable energy plan to comply with Public Act 235 of 2023.	)))))))	Case No. U-21813

APPLICATION

Pursuant to 2008 Public Act 295, as most recently amended by 2023 PA 235 ("Act 235"), MCL 460.1001 *et seq.*, Upper Michigan Energy Resources Corporation ("UMERC" or the "Company") files this Application and requests that the Michigan Public Service Commission ("MPSC" or the "Commission") approve its Amended Renewable Energy Plan ("AREP"). In support thereof, the Company respectfully represents as follows:

1. UMERC is a public service corporation organized under the laws of the State of Michigan with its principal offices located in Milwaukee, Wisconsin, and a service center located at 800 Industrial Park Drive, Iron Mountain, Michigan. By Order Approving Settlement Agreement dated December 9, 2016, in Case No. U-18061, UMERC was granted authority to provide retail electric service to the former Michigan electric customers of Wisconsin Electric Power Company ("WEPCO")[1] and to the former Michigan electric (and natural gas) customers

[1] Initially, Tilden Mining Company LC ("Tilden") and the Empire Iron Mining Partnership ("Empire") were retained by WEPCO as customers. However, after UMERC's reciprocating internal combustion engine ("RICE") Units became operational in 2019, Tilden became an electric customer of UMERC pursuant to the terms of a special contract approved by the Commission. Prior to 2019, Empire ceased operations, no longer received electric services from WEPCO and was, therefore, not transferred to UMERC.

of Wisconsin Public Service Corporation. As a result, UMERC, in addition to providing natural gas service in Menominee County, Michigan, provides retail electric service in cities, villages, and townships in the Michigan counties of Alger, Baraga, Delta, Dickinson, Gogebic, Houghton, Iron, Marquette, Menominee, and Ontonagon. Currently, UMERC provides retail electric service to approximately 37,500 customers.

2. UMERC's retail electric service business is subject to the jurisdiction of the Commission pursuant to 1909 PA 106, as amended, MCL 460.551 *et seq*.; 1919 PA 419, as amended, MCL 460.54 *et seq*.; 1939 PA 3, as amended, MCL 460.1 *et seq*.; and 2008 PA 295, as amended, MCL 460.1001 *et seq*. Pursuant to these statutory provisions, the Commission has power and jurisdiction to regulate UMERC's retail electric rates for service rendered in the State of Michigan.

3. On October 6, 2008, the Clean, Renewable, and Efficient Energy Act, 2008 PA 295, MCL 460.1001 et seq., was signed into law, and then in 2016 it was amended by 2016 PA 342 ("Act 342"), effective April 20, 2017. Thereafter, on November 28, 2023, Governor Gretchen Whitmer signed into law Act 235 which took effect on February 27, 2024.

4. Act 235 requires electric providers to file with the Commission an amended renewable energy plan within one year of the effective date of the Act, MCL 460.1022(3). In its February 8, 2024 Order in Case No. U-21568 the Commission directed UMERC to file its AREP no later than January 17, 2025. Additionally, by its May 23, 2024 Order in Case No. U-21568, the Commission approved Filing Requirements and Instructions for Renewable Energy Plans for Michigan Investor-Owned Retail Rate-Regulated Electric Utilities (Exhibit A to the Order in Case No. U-21568).

5. On November 26, 2024, UMERC filed in this docket its motion to extend the January 17, 2025 deadline for filing its AREP to February 27, 2025. UMERC represented in the motion that granting the extension would not be inconsistent with MCL 460.1022(3) and was necessary to allow the Company adequate time to address the Commission's 2024 Upper Peninsula Energy Report to be made to the Michigan Legislature.[2] On December 19, 2024, the Commission granted UMERC's motion to extend and authorized the Company to file its AREP on or before February 27, 2025.

6. Prior to the start-up of the RICE Units and the transfer of Tilden to UMERC, WEPCO's last renewable energy plan was approved by the Commission in its January 23, 2018 Order Approving Settlement Agreement in Case No. U-18237.[3] UMERC's last renewable energy plan was approved by the Commission in its January 23, 2018 Order Approving Settlement Agreement in Case No. U-18236. At the time, the Company demonstrated compliance with Act 342 by maintaining a Renewable Energy Credit ("REC") Portfolio sourced from power purchase agreements ("PPAs").

7. Act 235, Section 28, modifies the Renewable Portfolio Standards ("RPS") for electric providers by requiring (non-multistate) providers to achieve REC portfolio of at least:

a. 15% through 2029,

b. 50% in years 2030 through 2034, and

c. 60% in 2035 and beyond.

8. As explained in the testimony and exhibits filed in support of this Application, UMERC's AREP addresses compliance with Section 28 of Act 235 as follows: (a) securing

[2] Filed in Case No. U-21572 on December 4, 2024.

[3] In the approved settlement agreement in Case No. U-18237, it was acknowledged that REC requirements associated with Tilden would transfer to UMERC in 2019.

Michigan-sourced Renewable Energy Credits ("RECs") for compliance through 2029, (b) starting January 1, 2027, UMERC will rely in part on its100 MW Renegade Solar Project approved by the Commission in Case No. U-21081, (c) constructing or acquiring additional renewable energy generation and Battery Energy Storage System ("BESS") resources during the period 2030 and 2040 as shown in the table below:

	Wind Generation	**Solar Generation**	**BESS**	**Total Resources**
2030	250 MW	50 MW	125 MW	425 MW
2034	125 MW	-	-	125 MW
2035	50 MW	75 MW	75 MW	200 MW
2039	-	-	50 MW	50 MW
2040	75 MW	50 MW	25 MW	150 MW
Total	***500 MW***	***175 MW***	***275 MW***	***950MW***

The AREP includes the Company's current electric sales forecast for the period 2025-2045, as well as customer count projections for the period 2025-2045, as required by the U-21568 filing requirements

9. UMERC's AREP is also consistent with its proposed course of action and assumptions in its integrated resource plan ("IRP") approved in Case No. U-21081, as required by the Commission in its April 25, 2024 Order in Case No. U-21568.[4] In U-21081, the Commission approved the Company's plan to build or procure new renewable energy generation capacity in its service territory. On April 11, 2024, in Case No. U-21081, the Commission approved the Company's proposed purchase agreement with Renegade Solar Energy, LLC,

[4] The Commission stated that "future amended REPs should reflect the assumptions included in the providers' most recently approved IRP." Case No. U-21568, 4/25/2024 Order, pp 19-20.

("Renegade") for the addition of 100 MW of solar generation located in Delta County, Michigan, to UMERC's renewable energy portfolio ("Renegade Solar Project"). The Renegade Solar Project plays a critical role in meeting UMERC's RPS requirements.

10. The testimony and exhibits filed in support of this Application also address (i) the unique role of UMERC's natural-gas RICE units placed in service to facilitate the retirement of coal-fired generation, (ii) the fact that the Upper Peninsula is ahead of the Lower Peninsula in terms of decarbonization and overall renewable resource portfolio, and (iii) the role of the RICE units in the currently evolving Mid-Continent Independent System Operator ("MISO") resource adequacy requirements.

11. As required by Section 45(3) of Act 235, the AREP also addresses the expected incremental cost of compliance with the RPS for a 20-year period, and that UMERC expects to incur incremental costs of compliance as defined in Section 47 of Act 235. Further, pursuant to Section 45(2) of Act 235, the AREP reflects UMERC's intention to recover the incremental cost of compliance by implementing a renewable energy surcharge. Moreover, UMERC addresses Act 235 cost compliance with clean energy requirements.

12. UMERC is filing this Application with supporting direct testimony and exhibits of Richard F. Stasik, Jamie Cano Lopez, Chelsey A. Biersach, and James M. Beyer.

WHEREFORE, Upper Michigan Energy Resources Corporation respectfully requests that this Honorable Commission:

A. Approve UMERC's AREP as reasonable, prudent, and compliant with Act 235 and the Commission's orders in Case No. U-21568;

B. Approve the cost recovery methodology in the form of the proposed renewable energy surcharge and related tariff sheets; and

C. Grant such other relief and authorizations as may be lawful and proper.

Respectfully Submitted,

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

Sherri A. Wellman Digitally signed by: Sherri A. Wellman DN: CN = Sherri A. Wellman email = wellmans@millercanfield.com C = US O = Miller Canfield Date: 2025.02.27 14:20:38 -05'00'

Dated: February 27, 2025 By:____

One of its Attorneys
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Attorneys for Upper Michigan Energy Resources Corporation

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **UPPER MICHIGAN ENERGY RESOURCES CORPORATION** requesting approval of an amended renewable energy plan to comply with Public Act 235 of 2023.	)))))))	Case No. U-21813

DIRECT TESTIMONY AND EXHIBITS OF RICHARD F. STASIK

FOR

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

February 27, 2025

DIRECT TESTIMONY AND EXHIBITS OF
RICHARD F. STASIK

QUALIFICATIONS
OF
RICHARD F. STASIK
PART I

Q. Please state your name and business address.

A. My name is Richard F. Stasik. My business address is WEC Energy Group, 231 West Michigan Street, Milwaukee, Wisconsin 53203.

Q. In what capacity are you employed?

A. I am Director – State Regulatory Affairs at WEC Energy Group ("WEC"). WEC is the parent company of Upper Michigan Energy Resources Corporation ("UMERC" or the "Company").

Q. Please address your responsibilities as director – state regulatory affairs at WEC.

A. I oversee regulatory rate reviews, policy, and advocacy efforts across the WEC holding company, including proceedings before Michigan Public Service Commission ("MPSC" or the "Commission") and regulatory bodies in other states, including Wisconsin and Minnesota. I also act as one of the lead witnesses for WEC's operating utility subsidiaries in those proceedings.

Q. What is your educational and business experience?

A. I hold a bachelor's degree, summa cum laude, in accounting and management information systems from the University of Wisconsin – Milwaukee and am a licensed Certified Public Accountant in the State of

Wisconsin. Before joining WEC's regulatory team, my current role, in 2016 I was the IT Audit Manager at the Company starting in 2013. Prior to that I held internal and external audit positions in public accounting and companies in the financial services, manufacturing and health care industries for more than ten years.

Q. On whose behalf are you offering this direct testimony?

A. I am offering this direct testimony on behalf of UMERC.

Q. Have you ever testified before a regulatory agency?

A. Yes. I have provided direct testimony to the Michigan Public Service Commission in UMERC's Test Year 2025 general rate case in Case No. U-21541, in the annual reviews of the State Reliability Mechanism charge for UMERC in Case Nos. U-20751, U-21103, U-21222, and U-21852. I have also provided direct and rebuttal testimony on behalf of UMERC in its Integrated Resource Plan filing in Case No. U-21081, and I have provided direct testimony on behalf of UMERC and its preferred criteria for Legally Enforceable Obligations in Case No. U-21130. I have provided direct testimony to the MPSC in Michigan Gas Utilities Corporation's, a sibling utility to UMERC, Test Year 2025 general rate case in Case No. U-21540.

Outside of Michigan, I have provided testimony to the Federal Energy Regulatory Commission on rate and accounting issues associated with WEC's retired power plant cases (Docket Nos. ER19-226-000, AC19-49-000, AC18-231-000, and ER19-103-000) and to the Public Service Commission of

Wisconsin on rate-making issues in rate case cases (Docket Nos. 5-UR-109, 5-UR-110, 5-UR-111, 6690-UR-126, 6690-UR-127, and 6690-UR-128) as well as in multiple renewable and natural-gas fueled generation acquisition and construction dockets.

PART II

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to (i) introduce the witnesses that will file direct testimony in support of UMERC's Amended Renewable Energy Plan ("AREP") required to be file pursuant to PA 235, (ii) provide a summary of the results of UMERC's AREP and the projected cost to UMERC electric customers, (iii) offer an overview and history of UMERC, its generation fleet, and the significant changes and the resulting reduction in emissions, and (iv) address the currently-evolving resource adequacy requirements being established by the Mid-Continent Independent System Operator ("MISO").

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits, which were reviewed/studied by me as an integral part of my job responsibilities and expertise:

- Exhibit A-1 (RFS-1) 2024 Upper Peninsula Energy Report
- Exhibit A-2 (RFS-2) NERC 2024 Long-Term Reliability Assessment ("LTRA")
- Exhibit A-3 (RFS-3): September 2024 Midcontinent Independent System Operator ("MISO") Strategy Update for the MISO Board of Directors on its Reliability Imperative, MISO Board of Directors

Introduction of Company Witness

Q. Please introduce the witnesses that UMERC is providing to support its AREP.

A. In addition to me, UMERC's witnesses who support the AREP include:

1. Jaime Cano Lopez, who will address renewable energy resource identification and associated modeling; and
2. Chelsey A. Biersach, who will provide the sales forecast; and
3. James M. Beyer, who will address recovery of incremental renewable energy costs and propose a recovery mechanism.

Summary of UMERC's AREP and Related Customer Costs

Q. What assumptions did UMERC use when developing its AREP?

A. UMERC assumed all of the key parameters of the relevant law as amended by 2023 PA 235, which in pertinent part requires electric utilities to achieve a Renewable Energy Credit Portfolio Standard ("RECPS") from 15% through 2029 to 50% in years 2030 through 2034, and 60% in 2035 and thereafter (MCL 460.1028), and achieve a clean energy system portfolio requirement of 80% by 2035 and 100% by 2040. UMERC also included reasonable assumptions related to its customers' peak load and energy requirements, which are further discussed in the direct testimony of Company Witness Chelsey Birsach. UMERC also structure its AREP to address the requirements of Exhibit A to the Commission's May 23, 2024 Order issued in Case No. U-21568.

Q. How did UMERC identify the renewable energy resources needed to comply with the requirements of PA 235?

A. As described in greater detail in the direct testimony of Witness Lopez, UMERC performed modeling within the PLEXOS capacity expansion planning tool to identify the most economic energy resource mix to meet the requirements of PA 235.

Q. Does UMERC include battery energy storage systems as part of the AREP?

A. Yes. As technology evolves in the electric energy generation and storage space, not all resources are truly a generation resource. Specifically, utility-scale Battery Energy Storage Systems ("BESS") may have a role to play in the deployment of clean or renewable energy; however, BESS does not generate any electrical energy. BESS is actually both load (when it is charging) and an energy source (when it is discharging) on the transmission or a utility's distribution system. To account for this, UMERC will refer to resources that can supply energy to the grid – even if only for finite and discrete periods of time – as renewable energy resources to broadly include resources that can generate and / or store electric energy.

Q. Has UMERC placed in service any renewable energy resources that will help UMERC meet the requirements of PA 235?

A. No. However, while UMERC has not yet placed any renewable energy resources in service, it received MPSC approval in Case U-21081 to construct the 100 MW Renegade Solar Project ("Renegade Solar"). That project is currently being constructed and is projected to be placed in service at the end of December 2026.

Q. How does UMERC propose to incorporate Renegade Solar into its AREP?

A. UMERC has included Renegade Solar project as a renewable energy resource that will begin serving customers starting January 2027 in the PLEXOS modeling performed. This is the first step in UMERC's AREP.

Additionally, because Renegade Solar will provide renewable energy to UMERC electric customers, and be owned and operated by UMERC for the benefit of its customers, UMERC's AREP includes recovering the revenue requirement of Renegade Solar through its proposed Renewable Energy Surcharge, starting on January 1, 2027, as discussed in more detail in the direct testimony of Witness Beyer.

Q. What additional renewable energy resources were identified by PLEXOS as being the most cost-effective resources for UMERC to comply with the requirements of PA 235?

A. The renewable energy resources that PLEXOS identified are summarized in the table below, which identifies, the technology (solar, wind, BESS, etc.), the capacity of that resource, the projected cost of each resource (in year-of-occurrence dollars), and the in-service date identified by PLEXOS.

Technology	Capacity	Capital Cost	In-Service Date
Wind	500 MW	$856.5 M	2030
Solar	50 MW	$114.0 M	2030
BESS	125 MW	$355.7 M	2030
Wind	250 MW	$468.1 M	2034
Wind	50 MW	$191.5 M	2035
Solar	75 MW	$191.2 M	2035
BESS	75 MW	$238.5 M	2035
BESS	50 MW	$173.8 M	2035
Wind	75 MW	$321.0 M	2040
Solar	50 MW	$142.5 M	2040
BESS	25 MW	$88.9 M	2040

Q. Has UMERC identified any risks to being able to implement the clean energy resources in the years identified above?

A. No. UMERC has not identified any specific risks associated with acquiring the clean energy resources within the timeframes identified above. That said, other than Renegade Solar, as noted by Company Witness Jaime Cano Lopez, the other clean energy resources identified to meet UMERC's obligations are "generic resources" – meaning that specific projects have not been identified. Because of the amount of time between assembling its AREP and when specific resources would need to come on line, UMERC will have ample time to evaluate available projects, perform due diligence, and select the appropriate projects to achieve its clean energy requirements.

Additionally, Renegade Solar remains forecasted to achieve its expected in-service date of December 2026 and within the previously identified project budget. In the unlikely event that Renegade Solar were to experience an unforeseen delay, UMERC would be able to secure Michigan-based RECs to supplement any lost generation if a delay were to be experienced.

Q. What is the estimated revenue requirement that UMERC will need to collect from its electric customers for the renewable energy resources identified by PLEXOS in order to comply with the RE requirements of PA 235?

A. The estimated revenue requirement, by year, is summarized in the table below:

		Estimated Annual Revenue Requirement ($ millions)		
Year	**Capital**	**O&M**	**MI-RECs**	**Total***
2026	-	-	$1.1	$1.1
2027	$20.8	$2.4	$0.3	$23.6
2028	$19.0	$2.5	$0.3	$21.8
2029	$16.8	$2.5	-	$ 19.7
2030	$138.2	$11.7	-	$149.9
2031	$128.2	$11.9	-	$140.2 M
2032	$115.3	$12.2	-	$127.5 M

		Estimated Annual Revenue Requirement ($ millions)		
Year	**Capital**	**O&M**	**MI-RECs**	**Total***
2033	$105.7	$12.5	-	$118.2 M
2034	$138.6	$17.7	-	$ 156.4 M
2035	$185.3	$20.2	-	$ 205.4 M
2036	$171.3	$20.6	-	$ 191.9 M
2037	$167.3	$21.0	-	$188.4 M
2038	$157.1	$21.5	-	$178.7 M
2039	$169.0	$22.0	-	$ 191.1 M
2040	$251.4	$25.9	-	$277.3 M$
2041	$246.0	$26.5	-	$ 268.9 M
2042	$225.9	$27.1	-	$ 253.0 M
2043	$221.2	$27.7	-	$ 238.9 M
2044	$220.2	$28.3	-	$ 248.5 M
2045	$225.4	$28.9	-	$ 254.3 M

* Total may not foot due to rounding

Q. What is the estimated bill impact to UMERC electric customers for the renewable energy resources identified by PLEXOS in order to comply with the RE requirements of PA 235?

A. As discussed in more detail of the direct testimony of Witness Beyer, UMERC is proposing to implement a per-meter renewable energy surcharge for each electric customer class. Those proposed surcharges are summarized in the table below:

	Estimated Monthly Bill Surcharge			
Year	**Residential**	**Commercial**	**Large Industrial**	**Tilden**
2026	$0.35	$15.25	$2,059.70	$64,288.24
2027	$7.28	$316.79	$42,776.59	$1,310,221.82
2028	$6.79	$296.07	$39,978.76	$1,202,456.04
2029	$6.17	$269.79	$36,430.95	$1,077,604.77
2030	$46.99	$2,053.63	$277,308.32	$8,202,601.25
2031	$43.93	$1,920.17	$259,286.98	$7,669,541.37
2032	$39.96	$1,746.48	$235,832.84	$6,975,783.10
2033	$37.04	$1,619.06	$218,626.68	$6,466,836.04
2034	$49.01	$2,141.97	$289,236.47	$8,555,428.17
2035	$64.39	$2,814.24	$380,014.92	$11,240,596.01
2036	$60.16	$2,629.17	$355,025.45	$10,501,423.74
2037	$59.05	$2,580.97	$348,516.98	$10,308,907.40
2038	$56.00	$2,447.67	$330,517.03	$9,776,480.42
2039	$59.89	$2,617.53	$353,453.60	$10,454,929.23
2040	$86.91	$3,798.59	$512,935.00	$15,172,286.27
2041	$84.28	$3,683.39	$497,379.31	$14,712,158.84
2042	$79.29	$3,465.51	$467,959.10	$13,841,928.13
2043	$74.89	$3,273.09	$441,975.05	$13,073,336.72
2044	$77.90	$3,404.61	$459,735.79	$13,598,687.09
2045	$79.72	$3,484.31	$470,496.90	$13,916,994.64

Q. Absent the requirements of PA 235 as relating to RECPS and clean energy requirements, did UMERC envision the need to add renewable energy resources beyond Renegade Solar?

A. No. Based on UMERC's current long-term forecasts of its electric customer capacity and energy needs, the Company does not see a need to add any additional generating capacity – renewable or otherwise – to serve its electric customers reliably and affordably, while substantially reducing the carbon (and all other) emissions from the generation fleet previously used to serve UMERC's customers.

As I describe in further detail in the next section of my testimony, just under six years ago, in May of 2019, UMERC placed in service approximately 180 MW of state-of-the-art, highly-flexible reciprocating internal combustion engine ("RICE") units ("UMERC RICE Units") to meet the electrical energy needs of not just the Company's customers, including the Tilden Mine, but the entirety of Michigan's Upper Peninsula ("UP"). The UMERC RICE Units were selected due to their substantial capabilities to quickly ramp up and down to meet the energy needs of the UP and provide grid stability. Because of their small, modular design the UMERC RICE Units were installed at two strategic locations in the UP to enhance overall reliability. Further, the installation of the RICE Units resulted in the avoidance of hundreds of millions of dollars in transmission system upgrades. Also, as recognized in the 2024 Upper Peninsula Energy Report sponsored here as Exhibit A-1 (SFK-1), a reduction of nearly 2.6 million tons, or 86%, of carbon emissions when compared to the coal-fired electric generation plant they replace – the Presque Isle Power

Plant ("PIPP"). However, recognition of these significant economic and environmental benefits is wholly absent from the legislative mandates and requirements of PA 235.

Q. How does UMERC plan to obtain the RECs it has identified to meet compliance requirements of PA235 in 2026 - 2029?

A. In addition to the RECs that will be associated with Renegade Solar, UMERC will solicit competitive bids through brokers to obtain RECs from renewable resources located within Michigan that produce certified Michigan-based RECs. UMERC does not currently plan to solicit RECs from its distributed generation customers or its current Voluntary Green Program ("VGP") customers. The reason for this is there are very few such customers in UMERC's service territory and the incremental costs to facilitate those transactions would materially increase the cost of RECs procured from them.

Q. What other comments about UMERC's AREP and the associated costs to customers do you have?

A. The implementation of the AREP included in this filing will over time significantly increase customers' costs without a commensurate increase in benefits to customers. UMERC has a very limited number of retail electric customers – approximately 37,500 and the estimated revenue requirement over the next 20 years to support the identified renewable energy resources is approximate $3.3 billion. Further, the mandates of PA 235, if not amended, will require UMERC to prematurely retire the RICE Units. UMERC is mindful of the impact that such a premature retirement as well as the identified substantial additional investments to comply with PA 235 will have on its electric customers monthly bills.

UMERC Overview

Q. Please describe the formation of UMERC as relevant to the UP energy solution.

A. On August 6, 2014, in Case No. U-17682, MPSC approval was sought pursuant to MCL 460.6q., for the transfer of control of Integrys Energy Group, including subsidiary Wisconsin Public Service Corporation ("WPS Corp"), to WEC. On April 23, 2015, the Commission issued its Order Approving Amended and Restated Settlement Agreement ("ARSA") which among other things, approved the transfer and acknowledged WEC's intention to petition the Commission for the creation of a Michigan-only jurisdictional utility and the commitment to pursue a generation solution for the UP. Subsequently, consistent with the ARSA, and pursuant to the Commission's December 9, 2016 Order Approving Settlement Agreement in Case No. U-18061, UMERC was formed as a Michigan only jurisdictional electric and gas utility effective January 1, 2017, by transferring the Michigan operations and select assets of Wisconsin Electric Power Company ("Wisconsin Electric") and WPS Corp to UMERC. The orders issued in Case No. U-17682 and U-18061 are incorporated herein by reference and speak for themselves.

UMERC's Generation History

Q. What were the historic circumstances that caused generation assets to be placed in service in the UP?

A. Unlike other parts of Michigan, large customers in the UP, including the Tilden and Empire Mines (jointly "Cliffs"), planned for their own needs at a time when the transmission system was very limited. As a result, most of the generation in the UP came from customer-owned resources, including PIPP.

Q. When was PIPP placed in service and who owned that plant when it was placed in service?

A. PIPP was constructed in the 1950s when Cliffs owned 90% of the Upper Peninsula Generation Company. Six hundred megawatts ("MW") of needed baseload generation was added in the UP from 1955-1979 to match Cliffs' energy needs.

Q. Did Cliffs own PIPP throughout its operating life?

A. No. First Upper Peninsula Power Company ("UPPCO") acquired PIPP from Cliffs in the 1980s at a time of tremendous economic challenges in the UP and the future of iron ore mining was at risk. Subsequently, Wisconsin Electric acquired PIPP from UPPCO. From that transfer, Cliffs received cash for its operations and an immediate reduction in their power costs by receiving the lowest electricity rates across Wisconsin Electric's combined Wisconsin-Michigan system with very limited impacts on reliability, including curtailments of generation.

Wisconsin Electric continued to own and operate PIPP until its ultimate retirement in 2019, once UMERC's RICE units, the then "UP energy solution", were placed in service.

Q. When was PIPP identified for retirement?

A. Wisconsin Electric[1] originally announced its intention to retire PIPP in 2013, which at the time was the only large baseload resource in the UP.

Q. Was there any particular event that led to PIPP being identified for retirement?

A. Yes. Cliffs switched to an Alternative Energy Supplier ("AES") in 2013 under the Michigan Choice law. After Cliffs announced its intention to procure its energy from an AES, Wisconsin Electric no longer had sufficient load to justify the continued operating costs of the PIPP, causing Wisconsin Electric to announce the retirement of PIPP.

Q. What, if any, implications came about from Wisconsin Electric's announcement to retire PIPP?

A. Upon Wisconsin Electric announcing its intention to retire PIPP, the Midcontinent Independent System Operator ("MISO") determined that PIPP was needed to maintain reliability and designated the plant as a System Support Resource ("SSR"). Once MISO declared PIPP to be an SSR and included the commensurate costs on the load serving entities in the UP and

[1] Wisconsin Electric is currently an affiliate of and was a predecessor to the Michigan-jurisdictional utility UMERC.

Wisconsin (MISO Zone 2), it resulted in a dispute pertaining to how those SSR costs would be allocated between Wisconsin Electric's Michigan and Wisconsin customers.

Q. Was the dispute related to cost allocation of SSR costs resolved? If so, when?

A. Yes, it was. Cliffs agreed to return as a full-requirements customer of Wisconsin Electric as part of the multi-party agreement that resulted in the "UP energy solution" in 2015, which I have previously identified as the ARSA, and which was approved by the MPSC in Case U-17682. As part of the ARSA, it was agreed that the soon-to-be-formed UMERC would develop "new, clean generation" that would provide a "long term solution" to the UP's energy needs.

Q. How was the ARSA requirement to develop "new, clean generation" that would provide a "long term solution" to the UP's energy needs met?

A. On January 31, 2017, UMERC filed an application in Case U-18224 seeking approval of Certificates of Need (CONs) to construct two RICE Units. On October 25, 2017, the Commission issued an order approving the CONs, which is incorporated herein by reference. The RICE units were constructed and placed in service in May 2019.

Q. Describe the benefits of the UMERC RICE Units?

A. Because the physical footprint of a RICE generation plant is smaller than other types of electric generation facilities, they can be – and in the case of the UP RICE Units were – placed in strategic locations to minimize or eliminate investments in transmission infrastructure to interconnect the new plant to the grid and enhance transmission system reliability, which benefitted all customers in the UP – not just UMERC's customers.

UMERC's RICE Units offer the added benefit of having minimal environmental impacts. These benefits include requiring very limited amounts of water and a substantial reduction in emissions – particularly relative to older less efficient coal-fired generators like PIPP.

The RICE units' capabilities include providing energy, capacity, transmission support as well as multifunctional capabilities (e.g., serve as spinning reserves, provide inertia to the bulk electric system, etc.). RICE is an ideal technology to "backstop" renewable generation to ensure energy assurance and reliability due to its capability to adjust generation output extremely quickly.

Q. How do the UMERC RICE Units provide benefit to UMERC's customers and the UP more broadly in a deeply decarbonized future?

A. Even if the UMERC RICE Units run on a limited basis (also known as "constrained dispatch"), they will continue to serve UMERC's customers and the UP as a whole- by providing much needed capacity and reliability. MISO's capacity rules, which are designed to ensure the right type of generation resources are in operation to maintain reliability during all hours of the day and seasons of the year, continue to evolve to meet reliability in a deeply decarbonized future. These changes have already and are expected to continue to reduce the capacity accreditation for wind and solar generation. UMERC's RICE units, which as dispatchable resources that are not dependent on the sun shining or the wind blowing, have proven to be extraordinarily valuable to the UP. The benefit of the UMERC RICE Units is that they will continue to supply energy, local capacity, and grid stability benefits during a very uncertain time as we transition to a cleaner energy future in Michigan generally and the UP in particular.

Q. Have organizations tasked with ensuring reliability of the electric grid expressed concerns about the transition to clean energy?

A. Multiple entities, such as North American Electric Reliability Corporation ("NERC"), have recently expressed concerns regarding the effects of replacement technologies on the reliability of the grid. In its 2024 Long-Term Reliability Assessment ("LTRA"), NERC, sponsored as Exhibit A-2 (RFS-2), noted that "[w]hile a given area may have sufficient capacity to meet resource adequacy requirements, it may not have sufficient availability of resources during extreme and prolonged weather events. Therefore, long-duration weather events increase the risk of electricity supply shortfalls."[2] NERC also noted in its Essential Reliability Services Abstract that "[g]enerating resources

[2] Exhibit A-2 (RFS-2)

need to be able to provide voltage control, frequency support, and ramping capability as Essential Reliability Services (ERSs) to balance and maintain the electric grid. Without these minimal characteristics, the grid could not be operated reliably."[3] This is because voltage control (the ability of a generating resource to aid maintenance of voltage levels within acceptable limits), frequency support (the ability of a generating resource to avoid imbalance between generation and load), and ramping capability (the ability of a generating resource to increase generation to meet additional load) are all needed to maintain grid stability.

Additionally, MISO has identified several approaches that it recommends be implemented to support reliability in the current environment. In its September 2024 Reliability Imperative Strategy Update, sponsored as Exhibit A-3 (RFS-3), two such strategies included (1) delaying retirements and maintaining existing fleets and (2) considering relaxed renewable / clean energy goals.

Q. Please describe the recent and anticipated changes to the MISO resource adequacy construct.

A. MISO has introduced an initiative to review system attributes and revise its capacity construct to ensure the grid includes the generation resources required to continue to perform adequately and reliability as the electric energy landscape continues to evolve. This initiative incorporates concepts

[3] Exhibit A-2 (RFS-2)

such as energy assurance, availability, fuel assurance, ramp capability, voltage stability, and rapid startup; changes to resource accreditation and reserve margin requirements; as well as energy and ancillary market products and requirements.

One specific change to MISO's resource adequacy construct is shifting from a yearly reserve margin requirement to a seasonal accreditation and reserve requirement, which increases the value to customers of dispatchable, natural gas-fueled generation resources like the UMERC RICE Units. Conversely, UMERC expects that future changes to MISO's procedures will diminish the accredited capacity or market value of intermittent resources such as wind and solar generating units as well as batteries and place a premium on units that have demonstrated fuel assurance, longer duration and reliability. These impacts, and the associated cost impacts will likely be magnified for the customers of a utility the size of UMERC.

Q. What would the Impact of prematurely retiring the UMERC RICE Units be to UMERC's customers and more generally the UP?

A. The first practical implication of the forced retirement of the RICE Units by 2040 would be to eliminate a significant portion of the value our largest customer, Tilden, receives from the RICE Units under Special Contract between UMERC and Tilden. The remaining provisions of the contract would remain intact, including Tilden's ability to terminate the contract with 60 days' written notice and the payment of the liquidated damages outlined in the contract for such termination. If Tilden were to execute that provision of the contract in such a scenario, the result would be that the remaining operating costs Tilden would be scheduled to pay under the Special Contract would no longer apply and the costs would need to be recovered from UMERC's non-mine customers.

Furthermore, UMERC is concerned that if the UMERC RICE Units were required to be retired by 2040 as a de facto requirement of the current clean energy system targets mandated by PA 235, which is approximately 10 years prior to these Units' estimated economic lives, the unfortunate result would be a return of the uncertain conditions that existed prior to the comprehensive UP energy solution reached a mere nine years ago as part of the ARSA in Case U-17682. Also, there is the significant financial cost to customers for replacing a source of electricity before the end of its useful life, which as I stated above would total over $X billion

The policy UP energy solution—which the MPSC endorsed in Case Nos. U-17682, U-18061 and U-18224—has worked well for everyone, from UMERC to Cliffs, UMERC's non-mine customers and the UP collectively. UMERC would prefer to avoid the conditions that existed prior to the UMERC RICE Units going into service—which caused many policymakers to express concerns over reliability throughout the UP. Such a situation would result in two concerning circumstances. First, it provides significant uncertainty not only to UMERC's customers but to all UP electric users regarding how reliable electric generating capacity, energy, and grid stability services will be supplied to the UP. Second, as shown by the modeling done in support of this

AREP and summarized earlier in my direct testimony, there would be significant cost increases to UMERC's 37,500 customers.

Q. Have there been any changes in Michigan law that would impact PA 235?

A. No, however HB 4007 was recently introduced in the Michigan Legislature. My understanding of the current draft of HB 4007, if signed into law, it would classify the UMERC RICE Units as a "clean energy system" thereby enabling UMERC to count the Rice Units as part of its clean energy portfolio.

Q. Would UMERC's AREP proposal be different if HB 4007 was signed into law?

A. If HB 4007 was signed into law in its current form, yes, UMERC's AREP proposal would need to be amended. Currently, the AREP reflects a 100% renewable energy portfolio by 2040. If HB 4007 becomes law, UMERC will not need 100% renewables to meet the clean energy portfolio, as it will be able to rely on the RICE Units as a clean energy system, which would save UMERC customers from having to bear substantial bill increases for the foreseeable future.

Q. Does this conclude your pre-filed direct testimony at this time?

A. Yes, it does.

Exhibit A-1 (RFS-1)

2024 Upper Peninsula Energy Report

Prepared pursuant to MCL 460.1051

December 2, 2024

Dan Scripps, Chair
Alessandra Carreon, Commissioner
Katherine Peretick, Commissioner

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Appendix I: UP Generation Integration Screening Study

Appendix J: Biomass with Tire Derived Fuel Emissions Study

Appendix K: UP Carbon Sequestration Feasibility Study

Executive Summary

Governor Gretchen Whitmer signed Public Act 235 (PA 235) into law on November 28, 2023. PA 235 establishes that an electric provider shall achieve a renewable energy credit portfolio of at least 50% in 2030 through 2034 and 60% in 2035 and thereafter. PA 235 also established a clean energy standard whereby electric providers in the state shall achieve a clean energy portfolio of at least 80% by 2035 through 2039 and 100% in 2040 and thereafter. The Legislature recognized the uniqueness of Michigan's Upper Peninsula (UP) and, as part of PA 235, tasked the Michigan Public Service Commission (MPSC) with evaluating the current energy landscape of the UP and potential paths forward for compliance with the law. As part of this evaluation, the Legislature directed the MPSC to consider the unique circumstances involving the natural gas-fired Reciprocating Internal Combustion Engine (RICE) units operated by Upper Michigan Energy Resources Corporation (UMERC).

The UMERC RICE units were built to enable the full retirement of the Presque Isle Power Plant and alleviate expensive system support resource (SSR) charges that were impacting UP customers. At about the same time, the Marquette Board of Light and Power (MBLP) also constructed three RICE units to enable the retirement of Shiras Power Plant. With both coal electric generation facilities retired and the continued operation of several hydroelectric facilities, the UP achieved significant emissions reductions far outpacing reductions in the Lower Peninsula. The UP electric sector has reduced its carbon dioxide (CO_2) emissions by approximately 71% between 2013 and 2022.

This report provides an overview of the energy landscape of the UP as it relates to electric generation, transmission, and load. It reviews the history of the UP's energy system and the unique conditions and challenges facing UP utilities and communities as we move toward a clean energy future. It also examines several clean energy options and how they specifically relate to the UP. Having compiled and reviewed the information necessary to develop this report, the Commission provides the following observations and recommendations:

- The Commission believes it would be helpful to understand whether the UP can accommodate more Energy Waste Reduction (EWR) than what Public Act 229 of 2023 requires. To that end, as part of the implementation of the 2023 energy legislation, a potential study that quantifies the economic/technical/achievable potential of EWR in the UP is underway. Results are expected Q3 of 2025.

- Additional clarity concerning the breadth of technologies that can be considered clean energy systems could help electric providers as they seek to determine the most reasonable and prudent path forward. A clear understanding of the types of technologies that can be considered clean energy systems is necessary to develop a clean energy plan, reducing risk and uncertainty for electric providers. Two possible paths to further define clean energy systems are: 1) for the

Legislature to further define clean energy systems, and 2) for the Commission to embark on a rulemaking process. Tire-derived fuels, renewable natural gas, and direct air capture technologies are not expressly identified as clean energy technologies in the law. If either the Legislature or Commission rules resulted in the inclusion of biomass with TDF as part of the fuel source, such a change should include a demonstration that the amount of carbon removed through the biomass lifecycle exceeds the amount of carbon emitted through electric generation.

- Under PA 235, the limitation on distributed generation resources increased from 1% of a utility's average peak load to 10%. This change is likely to increase interest in opportunities to aggregate distributed generation and other distributed energy resources. At the same time, the issuance of Order 2222 by FERC in September 2020 provides a pathway for aggregated distributed energy resources to participate in wholesale energy markets, potentially providing a cost-effective, distributed approach for customer-owned resources to contribute to maintaining reliability and participating in the energy transition in the UP. In its December 21, 2022 order in Case No. U-21099, the Commission partially lifted the prohibition on the ability of aggregated demand response resources from participating in regional power markets as part of the Commission's ongoing efforts to bolster Michigan's energy capacity. However, the actions taken to date only apply to retail commercial and industrial customers with a minimum enrolled load of 1 megawatt, with the Commission noting that "additional work surrounding customer protections is warranted" before allowing participation by residential and smaller commercial customers. The Legislature should work to enact a statutory framework that provides meaningful consumer protections while providing a pathway for aggregated DERs to participate in the regional wholesale electricity markets, consistent with FERC Order 2222.

- The Legislature should consider expanding the concept of "functional equivalence" to include accelerated economy-wide carbon reduction as a carbon reduction option for power generation by including consideration of carbon reduction in another sector. Considerations of "functional equivalence" should apply to more than just power generation, taking a more holistic view accounting for all sources of carbon emissions. The aim of the MI Healthy Climate Plan is economy-wide emissions reduction, and these efforts could help to offset hard-to-abate emissions in the power sector. In the alternative, the Commission could consider whether the rulemaking authority provided for in PA 235 includes an opportunity to build on the concept of "functional equivalence."

- The Legislature should consider expanding the idea of joint clean energy planning that is described for municipalities in MCL 460.1051(3) to include all electric providers serving under 1,000,000 customers. Joint planning for smaller electric providers would allow for joint solutions and combined capital investment to facilitate the ability to achieve Michigan's clean energy goals and storage targets in a more economical way. More specifically, this would allow for UP-wide solutions to be considered.

The Commission has worked closely with the Midcontinent Independent System Operator (MISO) and the American Transmission Company (ATC) to perform certain modeling of the UP-transmission system under various conditions to better understand how the clean energy standard may impact the reliability. Due to the extensive modeling necessary, the MISO results will be provided in early 2025.

Acknowledgements

The Commission and Commission Staff would like to thank all those who participated and provided information necessary to complete this report. While conducting this study, the Commission engaged in substantial outreach with organizations and interested persons to gather information and UP perspectives. The Commission Staff engaged in many discussions with a range of UP organizations. Special thanks to those who answered Staff-issued questions and/or provided information to Staff either directly or in the U-21572 docket. UP organizations and representatives who provided insight into our work include: UP investor-owned utilities, municipal utilities, electric cooperatives, and member organizations; elected officials; leaders and staff members from several of the federally recognized Tribes in the UP; the Michigan Department of Environment, Great Lakes, and Energy's Oil, Gas, and Mineral Division; the Michigan Department of Environment, Great Lakes, and Energy's Scrap Tire Program; the Midcontinent Independent System Operator; American Transmission Co.; Invest UP; Superior Watershed Partnership; Cleveland-Cliffs' Tilden Mine; Billerud; L'Anse Warden Power Plant; and Wärtsilä.

Introduction

Governor Gretchen Whitmer signed Public Act 235 of 2023 (PA 235) into law on November 28, 2023. PA 235 establishes that an electric provider shall achieve a renewable energy credit portfolio of at least 50% in 2030 through 2034 and 60% in 2035 and thereafter. PA 235 also established a clean energy standard whereby electric providers in the state shall achieve a clean energy portfolio of at least 80% by 2035 through 2039 and 100% in 2040 and thereafter. In establishing these requirements, the Legislature also recognized the unique history and features of the electricity system in Michigan's Upper Peninsula (UP) and, as part of PA 235, tasked the Michigan Public Service Commission (MPSC) with evaluating the current energy landscape of the UP, including the unique role of the Reciprocating Internal Combustion Engine (RICE) units separately owned and operated by Upper Michigan Energy Resources Corporation (UMERC) and Marquette Board of Light and Power (MBLP), and potential paths forward for compliance with the law. This report provides an overview of the energy landscape of the UP as it relates to electric generation, transmission, and load. It also reviews the history of the UP's energy system and the unique conditions and challenges facing UP utilities and communities as Michigan moves toward a clean energy future.

Background of the UP Electricity System

As large industry developed across the UP, including mining and paper milling, electric generation developed to support their operations. In some cases, this generation also supported the surrounding population. Over time, these industry-owned facilities were sold to utilities resulting in an intertwined electrical system that connects dispersed load pockets that are geographically and electrically distinct. In some instances, the symbiotic nature of the generation facilities and industries that originally built them continued despite changes in the ownership of the facilities and integration into the broader system. The development of distinct and dispersed load centers resulted in many different electric providers. It also resulted in a patchwork electric system with limited linkage between load centers and resources creating an almost islanded system at these specific load centers. Today, the UP remains dominated by industrial load with 60% of the UP's load originating from industrial customers. By comparison, approximately 30% of the Lower Peninsula's load is attributable to industrial customers.

The Presque Isle Power Plant (PIPP) provides an example of a symbiotic relationship described above. PIPP was originally constructed by the Cleveland-Cliffs Iron Company in 1955 to power its mining and processing operations outside of Marquette. PIPP was sold to the Upper Peninsula Power Company (UPPCo) in the early 1980s and later sold to Wisconsin Energy. The facility, however, was critical to supporting the UP's transmission system until it was eventually replaced by the

UMERC RICE units and retired in 2019. Despite ownership of PIPP, and later the UMERC RICE units, no longer resting with Cleveland-Cliffs, the relationship between the company and the utility serving it was critical to the operation and retirement of PIPP and the building of the UMERC RICE units that replaced PIPP.

Michigan's geography also plays a role in the historic development of the UP electric system as the Lower Peninsula and Upper Peninsula developed separately and distinctly from one another. As discussed later in detail, American Transmission Company (ATC) provided a link between the two peninsulas through a high voltage direct current device in 2014. Although this device strengthens the link between the peninsulas, it did not strengthen the broader underlying transmission system of either the Upper or Lower Peninsula specifically. Therefore, the transfer capability, which is the amount of electricity that can move between the peninsulas, is limited on a day-to-day basis. This results in the Upper Peninsula being more closely tied electrically to Wisconsin than the Lower Peninsula. The linkage to Wisconsin has allowed for the flow of energy from resources located there but also has resulted in limited resource development in the Upper Peninsula.

The UP currently houses 9.2 MW of solar power, 68.4 MW of diesel fuel generation, 239.3 MW of natural gas generation, 183.9 MW of hydroelectric generation, 22 MW of biomass fuel generation, 100.8 MW of wind generation, and approximately 180 MW of combined heat and power generation resources that are primarily owned by utility customers and operate behind the meter. All values are nameplate capacity values and therefore do not account for any variation in availability or differences in accredited capacity.

2023 Energy Law and Development of UP Report

On November 28, 2023, Public Acts 229, 231, 233, and 235 were signed into law by Governor Gretchan Whitmer. Among other things, these laws:

- Increase the Energy Waste Reduction (EWR) standard for both electric and natural gas providers. For electric providers, the standard is increased from 1% annual energy waste reduction to 1.5% annual energy waste reduction, with a goal of 2% annual energy savings. For natural gas providers, the standard is increased from .75% annually to .85% annually.
- Allow for "fuel switching" in energy waste reduction programs (i.e., changing a customer's home heating source or appliances from a higher emitting fuel to a lesser emitting fuel), allowing for the electrification of home heating and other appliances.

- Expand the issues for consideration in utility Integrated Resource Plan applications to include affordability, cost effectiveness, labor standards, and promotion of environmental quality and public health.
- Establish a siting process at the Commission for utility scale renewable energy and energy storage facilities under certain conditions.
- Establish a renewable energy standard of 50% by 2030 and 60% by 2035 applicable to all investor-owned utilities, co-operative utilities, and municipally owned utilities. Pursuant to PA 235, “renewable energy” includes wind, solar, existing hydro, existing biomass (but only that which does not use tire derived fuel), and methane digesters with specific feedstocks. With some limited exceptions, renewable energy resources must be physically located in Michigan or within the Regional Transmission Organization (RTO) zone in which the utility is operating.
- Establish a clean energy standard of 80% by 2035 and 100% by 2040. Clean energy is defined in the law to include electricity generating systems that generate electricity or steam without emitting greenhouse gases, including nuclear generation; natural gas generation with 90% effective carbon capture and sequestration for existing natural gas facilities; for new natural gas facilities, only those with carbon capture technology that meets either EPA Best Available Control Technology (BACT) criteria or is 90% effective, whichever is greater; and any other clean energy resources as defined by the Commission. The act also includes within the definition of a clean energy system a carve out for the Midland Cogeneration Venture (MCV) natural gas facility subject to approval by the Commission of a plan that achieves “functional equivalence” with the clean energy standard through reduction of greenhouse gas emissions through carbon capture and sequestration and other available applications, including carbon removal technologies.
- Allow the Commission to grant extensions to the compliance deadlines for both the renewable energy standard and the clean energy standard if the utility can make certain showings related to compliance challenges.
- Expand the minimum size of utility distributed generation programs from 1% to 10% of a utility’s average in-state peak load and make other programmatic adjustments.
- Establish a statewide 2,500 MW storage target.

Recognizing the unique characteristics of the UP and the energy system that serves its residents, PA 235 also directs the Commission to conduct a study into the unique energy needs of the UP specifically related to the RICE units owned by UMERC and the impact of mining activities on the UP’s energy system. Specifically, PA 235 directs the Commission to provide a written report detailing:

(a) The unique conditions influencing electric generation, transmission, and demand in the Upper Peninsula.

(b) The unique role of the reciprocating internal combustion units placed in service to facilitate the retirement of coal-fired generation located in the Upper Peninsula after the regional transmission organization-imposed system support resource charges.

(c) Changes in electric demand, including changes from mining-related economic development projects, that may influence the utilization of the reciprocating internal combustion units described in subdivision (b).

(d) Options to reduce the carbon intensity of the existing reciprocating internal combustion units described in subdivision (c), with particular focus on how the unique geological conditions within the Upper Peninsula influence the feasibility of deploying clean energy systems.

(e) Any other information the Commission determines may be relevant to the development of strategies to satisfy the clean energy standard for an electric provider whose rates are regulated by the Commission and that owns and operates reciprocating internal combustion engine units in the Upper Peninsula.

On February 8, 2024, the Commission issued an Order in MPSC Case No. U-21572 initiating the required study and directing the Commission's Staff to prepare a report examining the role of the RICE units and transmission reliability with aid from UMERC, ATC, Cleveland-Cliffs, and MISO and to investigate the roles Energy Waste Reduction, Demand Response, generation, and transmission infrastructure play in grid stability and resource adequacy should the RICE units be retired or otherwise operationally constrained in order for UMERC to comply with the clean energy standard. The Commission and Commission Staff have undertaken this work through MISO and ATC engagement in an updated transmission study, public engagement in the UP, one-on-one meetings, and questionnaire responses from UP utilities and industrial customers.

Public Comment: Voices of the UP

The experiences of UP customers in the energy space are unique and the concerns around energy supply and costs arising from those experiences are important when considering implementation of the 2023 energy laws. To ensure these experiences are considered and concerns are addressed, the Commission has worked to include the voices of UP utility customers in preparing this report. As part of this process, the Commission solicited written comments from interested persons in MPSC Case No.

U-21572. Additionally, Commissioners and Staff engaged in discussions with utilities, customers, Tribes, elected officials, and industry representatives from across the UP to understand their perspectives relative to implementing the 2023 energy laws. This outreach and engagement included multiple visits to the UP where Commissioners and Staff met with individuals from each of these constituencies and held a public hearing in Marquette, MI, to take public comment on the study.

Twenty-four members of the public and interested parties submitted written comments in Case No. U-21572[1] and several dozen individuals spoke at the public hearing. Many of these comments shared similar themes including the importance of energy affordability and a desire to protect the unique natural beauty of the UP from excessive development. Commenters shared that the beauty of the UP is something worth preserving and that great care should be taken for the protection of our collective natural treasures.

Commenters also shared several thoughts concerning affordability which are briefly summarized here. They shared that energy affordability is a primary concern for most utility customers, especially those in the UP, and any energy solution for the UP must be affordable for the people who will ultimately pay for it. The UP's grid is currently reliable and operational, but commenters pointed out that many of the investments are still being paid for by UP customers. The shift to new investments while still paying for the ones already made creates concerns about affordability. Commenters shared concerns that the RICE units operated by UMERC and MBLP were only brought into service within the last few years and are being paid off over their expected useful life of 30 years. They noted that these units are relatively easy to maintain and rebuild, and therefore could continue to operate well beyond their installed useful life. Commenters expressed great concern about affordability and local choice for solution development. In the move toward a clean energy future, affordability is vital. Energy waste reduction (EWR) and energy efficiency (EE) are crucial in addition to building a local workforce for clean energy jobs. Commenters believe that the Commission and utilities must build trust and meet people's real needs for EWR to be successful. The public also must be informed of existing assistance programs. Finally, commenters reminded the Commission that any decision made regarding the UP's electric energy system will have an impact on everyday people and that must not be forgotten.

The comments are provided in their entirety in Appendix B.

The UP is also home to five federally recognized Tribes: Bay Mills Indian Community, Hannahville Indian Community, Keweenaw Bay Indian Community, Lac Vieux Desert Band of Lake Superior Chippewa, and Sault Ste. Marie Tribe of Chippewa Indians. Some Tribes and Tribal members shared their desire to develop their own clean

[1] Michigan Public Service Commission, Case No. U-21572, https://mi-psc.my.site.com/s/global-search/21572, retrieved 11/25/2024.

energy resources as well as concerns that included preservation of their land, culture, and resources.

Staff Interviews and Solicitations

In addition to working with MISO and ATC on an updated transmission study and soliciting public comment, Commission Staff engaged with multiple UP utilities in the course of preparing this report, including UMERC, UPPCo, Northern States Power Company – Wisconsin (NSP-W), Cloverland Electric Cooperative (Cloverland), the Marquette Board of Light and Power (MBLP), the Michigan Public Power Association (MPPA), WPPI, the City of Escanaba, the Michigan Municipal Electric Association (MMEA), and Wisconsin Public Service Corporation. This engagement included discussions, meetings, case docket comments, and soliciting information via questionnaires regarding several topics of this report. All nonconfidential written information that was provided directly to Staff from businesses and load-serving entities is included in the appendices of this report.

UP Energy Considerations Required by PA 235

As acknowledged by the Legislature, the energy landscape of the UP is different from that of the Lower Peninsula. This is due, in part, to the UP's population density and the number of utilities serving its population.

The Unique Conditions Influencing Demand, Electric Generation, and Transmission in the Upper Peninsula

Population

Today, the UP is home to 21 load-serving entities (electric utilities): 3 investor-owned utilities, 4 electric cooperatives, and 14 municipally owned electric utilities. Together, these 19 utilities serve approximately 200,000 customers. The three investor-owned utilities are NSP-W, a subsidiary of Xcel Energy; UMERC, a subsidiary of WEC Energy Group; and UPPCo, which is the largest of the UP investor-owned utilities with just over 53,000 customers. The four electric cooperatives are Alger Delta, Bayfield, Cloverland, and Ontonagon County Rural Electrification Association, with Cloverland being the largest at 43,000 customers. Of the 14 municipal electric utilities, Marquette Board of Light and Power is the largest, serving over 17,000 customers. Escanaba is the second largest at 7,000 customers. Half of UP customers are served by a municipal electric utility or a cooperative. 10% of Lower Peninsula customers are served by a municipal electric utility or cooperative.[2]

[2] Customer data taken from EIA Form 861.

According to the 2020 census, approximately 300,000 people live in the Upper Peninsula. While the UP's more than 16,000 square miles accounts for approximately 30% of the state's land mass, only 3% of the state's population calls the UP home. The difference in population between the UP and the Lower Peninsula is mirrored in differences in electricity demand between the two peninsulas. In 2023, UP electric demand was approximately 4.2 million megawatt hours (MWh) across approximately 200,000 customers; while in the Lower Peninsula, electric demand exceeded 100.1 million MWh across 4.8 million customers.

Population density is also a significant difference between the peninsulas that impacts the energy landscape. With fewer people per square mile in the UP (less than 19 people per square mile in the UP vs. 240 people per square mile in the Lower Peninsula), there are fewer customers per line mile on the energy system which increases the cost per customer.

Population, land area, and total number of utilities serving the UP population are all differences that contribute to an energy landscape in the UP that is different from that in the Lower Peninsula. However, to understand and analyze the UP's energy landscape, it is critical to understand customer demand as well as the history and development of the UP's energy system. The development of this system was, in part, a direct result of the development of different industries in the UP, and this development continues to be reflected in how the UP system is used by customers.

Demand

Another defining factor of the UP is the portion of the UP's energy demand that comes from industrial customers. While total UP energy demand in 2023 exceeded 4 million MWh, more than half of that demand (2.3 million MWh) was attributable to industrial customers. Comparatively, in the Lower Peninsula, only 30% of the electric demand comes from industrial customers.

Industrial customers in the UP fall into several broad categories. Verso Corporation and Systems Control have substantial manufacturing operations in Escanaba and Iron Mountain, respectively. Forestry and the wood products industry have long been present in the UP and continue to have a presence there. Besse Forest Products Group, Louisiana-Pacific Corporation, Neenah Paper, and Billerud operate various facilities across the UP. Additionally, the UP is home to eight universities and colleges and four major hospitals. Tourism and recreation are also a significant part of the UP's economy with facilities dotted across the peninsula.

The Cleveland-Cliffs Tilden Mine has the largest electric load in the UP. The mine, which began operations in 1965, is an open-pit iron mine located southwest of the City of Marquette. In 2021, Tilden Mine produced 7.7 million long tons of iron ore pellets per year, which are transported by rail to Marquette, loaded on freighters, and sent to Cleveland-Cliffs steel mill facilities via the Great Lakes.[3] Mining the ore and

[3] Technical Report Summary on the Tilden Property, Michigan, USA S-K 1300 Report, p. 1.

processing it into pellets is an energy intensive, continuously running process. Energy expenses account for 25% of Tilden's costs. All told, the direct mining and processing operations, along with related transportation, operations employ more than 1,000 people in the UP. Today, the Tilden Mine makes up more than half of UMERC's total load.

UP residential load is also a bit different from the Lower Peninsula. Residential customers in the UP utilize air conditioning in the summer months less than customers in the Lower Peninsula due to the lower summer temperatures. The combined result of lower summer residential customer load and a larger percentage of total electric load being industrial customers is that the UP winter and summer electric peaks are not distinctly different. There are even years where the UP experiences peak electrical load in the winter.

Electric Generation

The electrical system of the UP developed around the distinct industrial load centers and the surrounding population. This generation largely took the form of hydroelectric facilities, small diesel generators, and coal plants. As large industry developed across the UP, including mining and paper milling, electric generation developed to support their operations. Over time, these industry-owned facilities were sold to utilities resulting in an intertwined electrical system that connects dispersed load pockets that are geographically and electrically distinct. Although the use of coal-fired electric generation facilities in the UP has ceased, the islanded nature of generation and the load centers it serves has remained largely unchanged.

Generation Changes Since RICE Approval

UMERC requested approval for procurement of 100 MW of solar generation in its 2021 Integrated Resource Plan (IRP) application in Case No. U-21081.[4] The Commission approved the settlement agreement between all parties in the case in May 2022. UMERC evaluated the acquisition of solar through its request for proposal (RFP). UMERC evaluated all projects of varying sizes that were available in the MISO interconnection queue within the UP.[5] At the end of 2023, UMERC sought approval to purchase the Renegade Solar project, a 100 MW solar generation facility. The expected in-service date of the Renegade Solar project is the end of 2026.[6] The Commission's April 11, 2024, Order in Case No. U-21081 approved UMERC's acquisition of the project.

On June 21, 2024, the Upper Peninsula Power Company (UPPCo) filed an application requesting approval of a power purchase agreement (PPA) to acquire 62.5 MW of the output of the Groveland Mine Solar project in Dickinson County housed at the

[4] MPSC Case No. U-21081, Direct Testimony and Exhibits of UMERC witness Richard F. Stasik, p. 4.
[5] Order May 12, 2022, Case No. U-21081, Exhibit A, p. 4.
[6] Application December 1, 2023, Case No. U-21081, p. 6.

site of a long-vacant iron mine. This request is consistent with the Company's 2019 Integrated Resource Plan in Case No. U-20350 that included the acquisition of a total 125 MW of solar capacity. After evaluation of the responses to its 2020 RFP, UPPCo chose the Groveland Mine Solar project. This PPA was approved by the Commission on August 22, 2024, in Case No. U-20350.

UPPCo also intends to acquire 62.5 MW of solar from a Build-Transfer Agreement with the purchase of the Republic Solar, a 62.5 MW solar facility to be located in Marquette County.[7] This project application was submitted to the Commission for approval on November 21, 2024, and is currently pending before the Commission.

Based on the energy storage targets established by PA 235, Staff expects there will be approximately 60 MW of energy storage added across the Upper Peninsula in the coming years. However, the storage locations are unknown. Given the smaller size of many of the UP electric providers, Staff expects that some of this added storage capacity will be distribution-connected.

Generation Siting Difficulties

The UP has not been immune to the challenges related to siting renewable energy facilities experienced by Lower Peninsula utilities and developers. For example, it took UPPCo until 2024 to obtain a viable contract for some of the solar approved in the company's 2019 IRP in part due to siting constraints. The initial 125 MW of solar that UPPCo originally intended to contract with was canceled due to the project's failure to receive the required land use permits. A similar situation happened with a 40 MW wind project. After having all RFP respondents resubmit bids, as described in the preceding section, UPPCo plans to contract 62.5 MW of company-owned solar from the Republic Solar project and has gained Commission approval for a 62.5 MW solar PPA from the Groveland Solar project.[8] Due largely to permitting issues, it took UPPCo 4 years to procure 125 MW of renewables.

In addition to siting challenges, when compared to prices in the Lower Peninsula, solar energy project development tends to be more expensive in the UP. There are many reasons for this price difference, including: UP geology which requires solar facilities to be ballasted rather than anchored in the ground; lower capacity factors; and more expensive construction logistics. The combination of these differences would result in a similar sized project in the UP being more expensive, potentially resulting in fewer projects planned in the UP.

Impact of a Shifting Generation Mix: Decarbonization in the UP

The Upper Peninsula has decarbonized faster than the Lower Peninsula. In 2019, with the closure of PIPP by UMERC and MBPL's retirement of the Shiras Steam Power

[7] MPSC Case No. U-20350, IRP Status Report June 20, 2024, p. 5.
[8] MPSC Case No. U-20235 IRP Status Report June 2024, 2024, p. 2-5.

Plant, the UP eliminated all its coal-fired generation – an achievement that was reached more than a decade before the Lower Peninsula is expected to meet this benchmark. With the UP's significant hydroelectric generation resources and, more recently, UMERC's acquisition of Renegade Solar and UPPCO's acquisition of Groveland Solar and planned acquisition of Republic Solar, the UP is ahead of the Lower Peninsula in terms of both decarbonization and overall renewable resource portfolio. Even before these solar resources come online, the UP electric sector has reduced its CO_2 emissions by approximately 71% between 2013 and 2022, according to U.S. Energy Information Administration (EIA) data. While the Clean Energy Standard is not based on a baseline year, it is important to acknowledge the UP utilities' accomplishments to date.

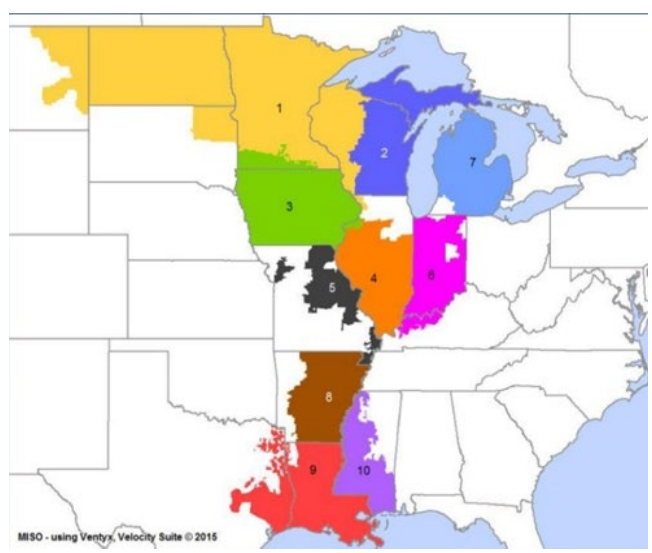
Transmission

The UP's transmission system has been the subject of several studies over the last 20 years.

Since the early 2000s, the transmission system across much of the United States has been operated by RTOs or Independent System Operators (ISOs). These organizations have many functions, one of the most important being to ensure the reliability and stability of the transmission system. All of the UP is within the Midcontinent Independent System Operator (MISO) (see Figure 1) and much of the UP is in MISO Zone 2[9] (see Figure 2). MISO conducts studies and Staff can make recommendations regarding projects to improve system reliability. These projects are then reviewed by a Board of Directors that makes decisions regarding project

Figure 1: MISO Regions

Figure 2: MISO Zones

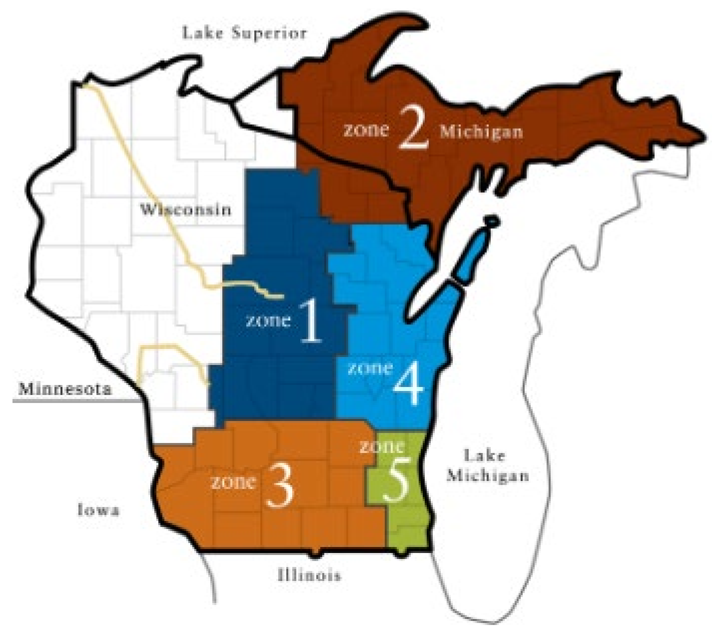


[9] A portion of the far Western UP, served by NSP and Bayfield Electric Co-op, falls within MISO Zone 1. Together, NSP and Bayfield serve approximately 9,000 customers.

approval. Costs for approved projects are determined based on the approved MISO tariffs. These tariffs are approved by the Federal Energy Regulatory Commission (FERC), which has jurisdiction over all the RTOs and ISOs operating across the country.

American Transmission Company (ATC) owns and operates approximately 10,000 miles of transmission across five ATC Planning Zones. Michigan's UP is a part of ATC's planning Zone 2 where ATC operates 138 kV and 69 kV lines.[10] A map of ATC Planning Zones is provided as Figure 3.

Figure 3: ATC Planning Zones



Following a study conducted by MISO into the ATC UP system, in 2011 the MISO Board of Directors approved the Mackinac High Voltage Direct Current (HVDC) Flow-Control Project.[11] Due to weak transmission system conditions on both sides of the Straits of Mackinac, ATC constructed a Back-to-Back Voltage Source Converter HVDC[12] station. This technology is used to control flows, including loop flows around Lake Michigan, and provides reliability and frequency stability between Michigan's Lower and Upper Peninsulas. The Mackinac HVDC Converter Station was placed in service in 2014.

Transmission owners and operators need to ensure that the system can continue to operate during both planned and unplanned outages. This requires that system operators and owners study the system to ensure that the system will operate under a variety of conditions. Ongoing system planning is crucial to ensuring that the transmission system can support the needs of customers and MISO facilitates an annual planning process to identify concerns and devise solutions to address them. During regular planning that occurred in 2012, ATC and MISO identified "urgent reliability concerns" on the ATC transmission system.[13]

In transmission system planning, a contingency is an event that may occur and impact the system causing it to operate differently than it does under normal conditions. When ATC studied the transmission in the UP system, no single

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[10] The western most edge of the UP is operated by NSP-W and there is no transmission infrastructure in Michigan, only distribution system infrastructure.
[11] Mackinac HVDC Flow-Control Project Fact Sheet, http://www.atc-projects.com/wp-content/uploads/2012/08/StraitsFlow-FactSheet.pdf, retrieved August 14, 2024.
[12] HVDC is an abbreviation for high voltage direct current
[13] MPSC Case No. U-17272 Application, p. 2.

contingency (planned or unplanned) on its own caused a problem on the system. However, when ATC studied the single contingency analysis in conjunction with a planned outage (for instance, an outage for system maintenance where power is routed through a different circuit), as well as under multiple contingency outages, the study showed that the system was vulnerable to a loss of load (i.e. there would not be enough electricity to meet demand due to the transmission system failure).[14] The studied scenarios were not just hypothetical. In May of 2011, a single contingency occurred during a planned outage. In that instance, lightning struck a double circuit 138 kV line. While this strike alone would not have been enough to cause the resulting outage, at the time of the strike, a separate 345 kV line was offline for maintenance.[15] The resulting outage impacted the western two-thirds of the UP.[16]

Following the identification of this urgent reliability concern, ATC sought a Certificate of Public Convenience and Necessity (CPCN) in MPSC Case No. U-17272 for the construction of a new 138 kV transmission line.[17] In that case, ATC proposed the Holmes to Old Mead Road project, which is a 58 mile long 138 kV line from Holmes substation, near the Wisconsin border in Menominee County, to the Escanaba area.[18] Ultimately, the Commission approved an uncontested settlement agreement and ATC built the line,[19] which was placed into service on August 11, 2016.[20]

One benefit that RTOs and ISOs provide, in addition to monitoring the transmission system within their respective footprints, is to allow for the movement of electricity across the footprint in an economical manner. One type of electric generation can cost more or less than another type and the ability of the RTOs and ISOs to project anticipated demand and to direct generation owners to start their generating units (or "dispatch" them) or to turn them off means that utilities can take advantage of lower cost generation which saves their customers money. While several factors are taken into consideration when dispatching generating units, the RTOs and ISOs use "economic dispatch" to the extent they are able. This means they dispatch the lowest cost available generation first and then work up to more expensive generation until customer demand is met.

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[14] MPSC Case No. U-17272 Direct Testimony and Exhibits of ATC witness Stephen D. Feak, p. 16.
[15] Id. at p. 7.
[16] ATC Restarting electric system in Michigan Upper Peninsula. ATC News release issued May 10, 2011. Available at https://www.atc-projects.com/news-releases/atc-restarting-electric-system-in-michigans-upper-peninsula/ retrieved October 25, 2024.
[17] Public Act 30 of 1995 requires that a transmission company apply to the Commission for a Certificate of Public Convenience and Necessity (CPCN) before constructing a major transmission line. A major transmission line is 5 miles or more in length through which electricity is transferred at system bulk supply voltage of 345 kilovolts or more. A transmission company may voluntarily file an application with the Commission for a CPCN for a proposed transmission line other than a major transmission line.
[18] MPSC Case No. U-17272 Direct Testimony and Exhibits of ATC witness Jane L. Petras, p. 7.
[19] MPSC Case No. U-17272 Order dated January 23, 2014.
[20] MPSC Case No. U-17272 Project In-Service Notification filed August 23, 2016.

The ability to dispatch generation across the footprint can be limited by circumstances on the transmission system referred to as "transmission constraints." When there is transmission congestion or reliability needs that result in the RTO or ISO needing to dispatch generation out of economic merit order (i.e., dispatching a more expensive generating unit before dispatching a less expensive unit) in order to maintain system operations, this is referred to as a binding constraint. An area that experiences a binding constraint more than 500 hours in a 12-month period is referred to as a "narrowly constrained area."

The Upper Peninsula is contained in the MISO-defined North Wisconsin and Upper Michigan System Narrowly Constrained Area (NWUMS NCA). In 2021, NWUMS NCA experienced 1,659 hours of binding constraint. In 2023 (the most recently published numbers), NWUMS NCA experienced 1,785 hours of binding constraint. There have been several transmission studies of the UP which have identified potential solutions that could have alleviated this condition.[21]

In 2016, the Michigan Agency for Energy (MAE) and the Michigan Public Service Commission requested that MISO conduct an exploratory study for informational purposes. The study, called MISO Michigan Phase II Study, was originally intended to analyze production cost savings, reliability, and resource adequacy benefits of potential transmission expansion to better connect the Eastern Upper Peninsula to Ontario at Sault Ste. Marie. MISO expanded that study to consider the viability of generation alternatives in the Eastern UP and the Lower Peninsula directly across the Straits of Mackinac. Some of the transmission alternatives studied extended far west into the UP, while others were firmly in the Eastern UP. The study found that strengthening the transmission network in the Eastern UP did not provide an economic benefit; none of the transmission upgrades that were studied to connect generation in the Northern Lower Peninsula or Ontario provided a benefit-cost ratio greater than one.[22] This means that relieving the UP of being narrowly constrained though transmission expansion was deemed uneconomical at the time of the study.

In September 2016, ATC voluntarily performed a high level, steady-state screening of transmission facilities in the Upper Peninsula. This was done to assist generation developers with the preliminary identification of potential locations where existing transmission facilities may have been able to accommodate new and/or additional generation capacity. This study analyzed possible interconnection points under single contingency analysis. Those that were not suitable for generation interconnection were eliminated. Those that appeared to be able to accommodate

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[21] MISO IMM, Narrow Constrained Area Threshold Reports 2021, 2023, 2024, retrieved 11/22/2024.
https://cdn.misoenergy.org/2021_NCA_Threshold_Update554960.pdf
https://cdn.misoenergy.org/2023_NCA_Threshold_Update_FINAL629129.doc
https://cdn.misoenergy.org/2024_NCA_Threshold_Update633129.pdf
[22] Appendix H

100 MW or more were studied under multiple contingency analysis.[23] Most of the interconnection points that were capable of hosting generation in 2016 were able to host only a small amount of generation, between 15-85 MW of generation. There were fewer than 10 interconnection locations that were capable of hosting 100 MW or more and were possible interconnection points for generation to replace PIPP upon retirement. The final report is attached as Appendix I.

Transmission Changes Since 2016

The transmission system is ever changing. As load increases or decreases, generation comes online or retires, or as individual assets of the transmission system age, the transmission system must change in response to function properly. The transmission system of the UP has changed at a slower rate than that of the Lower Peninsula.

ATC conducts an annual 10-Year Assessment. This assessment is used to determine what projects are needed to maintain system baseline reliability,[24] facilitate generation interconnections,[25] and conduct other projects such as age and condition or local reliability needs assessments. Staff cross-referenced the annual ATC 10-Year Assessment[26] from 2017 through 2023 with MISO's list of in-service transmission projects to identify all the projects that have been completed in the UP since the MISO and ATC studies of the UP transmission system started in 2016 and completed in 2017. Of the projects completed, only one was considered a baseline reliability project. The other two projects were required to allow new generation to come online and were identified through the MISO Generation Interconnection Queue process. These projects are known as Generation Interconnection Projects. Since 2017, there have been four age and condition projects, which replace aging or damaged transmission assets. The most notable of these projects, and the largest project completed in the UP since 2017, is the replacement of the underwater electrical cables in the Straits of Mackinac which were severed by an anchor strike in 2018. There are six projects that have been completed in the UP that satisfied either local reliability needs or other local needs. As suggested by the names of these categories, the projects are needed due to local changes or minor changes needed to substations. These projects are not expected to have a major effect on the wider transmission system. The largest of these projects was to upgrade the

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[23]Contingency analysis refers to a method for evaluating the impact of problems on the transmission system such as generation power outages or transmission line outages. Multiple contingency analysis is analyzing more than one contingency happening at the same time.
[24] Baseline reliability projects are transmission projects that are needed to properly maintain the transmission system and are required to meet NERC planning requirements.
[25] Generation Interconnection Projects (GIP)s include facilities to interconnect to the grid and any upgrades to the transmission system that are required due to modeled negative effects of increased injection of electricity with the interconnected new generation.
[26] https://www.atc10yearplan.com/, retrieved 11/21/2024.

communication network used to control and monitor the transmission system and has been completed.

In general, the changes to the UP transmission system have strengthened the system's reliability under its current configuration. However, these projects have not resulted in significant changes in ability to flow energy into, across, and out of the UP. Therefore, the Commission expects that these earlier studies still have value in understanding the UP transmission system's capabilities. However, as part of the Commission's response to the directive in PA 235, further study is ongoing with ATC and MISO, with final results expected in 2025. These studies are aimed at better understanding potential impacts of generation transformation across the broader UP.

The Unique Role of the RICE Units Placed in Service to Facilitate the Retirement of Coal-fired Generation Located in the UP After the RTO Imposed SSR Charges

The build out and design of the UP's transmission system was directly impacted by the generating facilities used to meet the energy needs of UP customers. The largest facility was the Presque Isle Power Plant (PIPP). PIPP was a coal-fired power plant originally built in the 1950s by Cleveland-Cliffs to serve both the Tilden and the Empire Mines. The size of the plant allowed it to serve other loads in the UP, and it was the main source of electricity generation for the peninsula. Subsequently, the transmission system was built up around PIPP and the facility became critical to transmission system operations.

As mentioned above, PIPP was sold to UPPCo in the 1980s, then later to Wisconsin Electric Power Company (WEPCo). In 2013, Cleveland-Cliffs began to contract for electric service from an alternative energy supplier (AES) to serve its mining operations, which resulted in WEPCo announcing it would suspend operations at PIPP. Cleveland-Cliffs entered into an agreement with WEPCo to return to regulated service in February 2015, but the retirement of PIPP and need for a replacement solution was imminent.[27]

When a utility in the MISO territory plans to retire a generation facility, it must file an Attachment Y notice with MISO which triggers a study of the role of the generator in the transmission system. If retirement of the generator will compromise transmission system operations, the generator is designated as a system support resource (SSR), and it may not be retired until a solution can be implemented to maintain transmission system operations. There can be a significant cost impact to customers when a generator is declared an SSR. While operational costs for a generator are traditionally spread over a number of years, costs for an SSR are paid

[27] Case No. U-17829. https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t0000001UNu6AAG.

by ratepayers in the year that they are incurred. The result can be a drastic increase in rates while the SSR is operational.

When WEPCo submitted the Attachment Y to MISO seeking to retire PIPP, the Attachment Y reliability study determined that PIPP could not retire without violating the North American Electric Reliability Council's transmission planning criteria and compromising transmission system operations.[28] For this reason, and because a mitigating solution could not be implemented before the proposed retirement, PIPP was designated as an SSR. PIPP SSR payments ultimately caused a 20% increase in rates in the UP while the SSR payments were ongoing.[29]

In response to WEPCo's desire to retire PIPP, but prior to PIPP's SSR designation, MISO performed a study to determine how much generation would be required to maintain system reliability if PIPP were to retire. The PIPP Generator Replacement Screening Study looked at many different variables and combined them into four scenarios with many different sensitivities.[30] After review of the expected operation of the ITC HVDC device, discussed earlier, and the transmission upgrades that were expected to be implemented at that time, MISO determined that the most likely future state of the transmission system was one where the HVDC device did not flow power into the UP and therefore approved two reinforcement projects.[31] With the approval of these projects, there was a need for between 80 MW to 370 MW of new generation to facilitate the retirement of PIPP. The precise amount varied based on the number of units and electric system loading. MISO determined that if there were four units at a generation site between 80 MW and 250 MW of generation, it would be adequate to allow PIPP's retirement. The data showed as the number of units at a generation site increased, the amount of generation needed decreased, regardless of loading conditions.

In late 2016, WEC Energy Group created the load serving entity, Upper Michigan Energy Resources Corporation (UMERC), a wholly owned subsidiary utility serving only Michigan customers.[32] UMERC was created as a Michigan-only jurisdiction

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[28] MPSC Case No. U-18224 Direct Testimony and Exhibits of Daniel P. Krueger, Exhibit A-_(DKP-1), p. 8-9, MISO Tariff Section 32.2.7.a, MISO Business Practice Manual, p. 152-156.
[29] MPSC Case No. U-18224 Direct Testimony and Exhibits of Daniel P. Krueger, Exhibit A-_(DKP-1), p. 8-9.
[30] MPSC Case No. U-18224 Direct Testimony and Exhibits of Joann Henry, Exhibit A-__(JH-1).
[31] These transmission projects considered in the study were not a total transmission solution to PIPP retirement but were transmission projects that were already planned and would be required even with a generation replacement for PIPP.
[32] WEC Energy Group agreed to seek the formation of UMERC as a Michigan-only utility as part of the multi-party agreement that resulted in the "Upper Michigan Energy Solution". This agreement was memorialized in the Amended and Restated Settlement Agreement (ARSA) approved by the Commission in Case No. U-17682, when it approved WEC's acquisition of Integrys. As part of the ARSA, it was agreed that (1) WEC would develop a Michigan-only jurisdictional utility and seek Commission approval for that utility and (2) the Michigan-only jurisdictional utility would develop "new, clean generation" that would provide a "long term solution" to the UP's energy needs.

utility to facilitate the ability for UP solutions independent of Wisconsin that would be wholly paid for by UP customers. In response to the PIPP Generator Replacement Screening study, UMERC proposed to build several Reciprocating Internal Combustion Engine (RICE) units to replace PIPP. These types of generating units are well suited to providing reliable power at all times because RICE units are modular generation units of between 9-20 MW[33]. The modular nature of the units means that if there are several units at a single location and one unit experiences an outage, the outage will have less of an effect on the transmission system because the remaining units continue to operate independently. Natural gas RICE units, like those proposed by UMERC, also have a lower heat rate compared with traditional natural gas-fired combustion turbines which makes them more efficient and economical to operate.[34] RICE units are also well suited to operating in conjunction with a high renewable energy portfolio because they have very fast ramp rates, are dispatchable at all times, and are not limited to short operating durations.

On January 30, 2017, in Case No. U-18224, UMERC applied for a certificate of necessity, pursuant to MCL 460.6s, for two RICE facilities. Following a contested case proceeding, the Commission approved UMERC's request to construct the RICE facilities, with generating capacity totaling 183 MW at a cost of up to $277,200,000.[35,36] The approved facilities ultimately became the 7-unit, 131.6 MW, F.D. Kuester Generation Station in Negaunee Township and the 3-unit, 56.4 MW, A.J. Mihm Generation Station in Baraga Township. These facilities began commercial operations on March 31, 2019.[37]

In addition to replacing a portion of the generating capacity of PIPP, the location of the RICE facilities at two different sites in the Upper Peninsula also eliminated the need for the construction of more costly transmission solutions to facilitate PIPP's retirement, which would have required building $373 million[38] in transmission

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In June 2016, WEC filed an application in Case No. U-18061 seeking authorization to form UMERC and transfer the Michigan-based non-generation assets of Wisconsin Electric and Wisconsin Public Service Corporation to UMERC. On October 19, 2016, a unanimous settlement was reached to resolve all the issues in this proceeding, and the Commission approved that settlement on December 9, 2016. UMERC was formed and began operating effective January 1, 2017. All Michigan-located customers of Wisconsin Electric and Wisconsin Public Service Corporation were transferred to UMERC effective on that date except the Tilden Mine, which remained a Wisconsin Electric customer until the RICE units were placed in service.

[33] MPSC Case No. U-18224 Direct Testimony and Exhibits of UMERC witness Joann Henry, p. 11.

[34] Heat rate is the amount of heat produced by the fuel through the combustion process that is required to produce one MWh of energy. The lower the heat rate, the more efficient the thermal generator.

[35] October 24, 2017 MPSC Order in Case No. U-18224, p. 118

[36] https://www.michigan.gov/-/media/Project/Websites/mpsc/consumer/info/briefs/MPSC_Issue_Brief_--_Upper_Peninsula_Generation_Project.pdf?rev=567425db07a446dda68f3c9aec23f282

[37] MPSC Case No. U-18224 UP Gen Project annual Progress Report, p. 2, EIA Form 860 2022.

[38] Project estimates were determined in 2019 and have not subsequently been adjusted for inflation.

upgrades, which included the "Plains to National" 138 kV line.[39] These transmission projects would have taken substantially longer to build and place in service than the UMERC RICE generators resulting in a longer period of time that UP customers would be subject to SSR payments. Approval of the UMERC RICE units allowed for the cancellation of all ATC transmission projects that were a partial solution to the PIPP SSR, saving UP customers an estimated $373 million in transmission upgrade costs and ended all future SSR payments.[40]

Just as importantly, the development of UMERC's RICE units has helped maintain reliability for the UP. Had PIPP retired before a solution was implemented, there would have been periods of controlled load curtailment in order to prevent a collapse of the UP transmission system. Controlled curtailment, or loss of load, could have meant that specific customers (i.e., the Tilden Mine or other large energy users) would not be able to run or could have resulted in widespread brownouts or blackouts. How widespread these loss of load events would have been, and their duration, is not known, but the RICE units have proven to be a robust solution that prevented such a scenario. The RICE units provide both generation and a solution to the transmission system challenges. They fulfill a vital role in ensuring the reliability of the UP's electric system.

At approximately the same time that UMERC was considering retiring PIPP, the Marquette Board of Light and Power was considering shutting down its coal-fired Shiras Steam Plant. The Shiras Plant was built in the 1960s, with additional units added in the 1970s. Shiras had become less reliable and less economical due to both the age of the units and market forces. MBLP considered many possible replacements, including renewable generation, natural gas, coal generation, and bilateral contracts for energy and capacity. Due to transmission constraints at the time, ATC did not have enough transmission capacity to provide MBLP with firm service, rendering any options for a bilateral contract moot and limiting MBLP to a generation solution. MBLP sought a solution that was dispatchable to avoid load curtailment.[41] MBLP elected to build RICE units due to a combination of reliability and affordability factors, and its ability to run on both natural gas and fuel oil, which provided fuel security during times of fuel price fluctuation. The result was the 51 MW Marquette Energy Center, which was brought online in 2017.

MBLP dispatches these units when the cost to purchase energy from MISO is higher than the cost to run the RICE units. By removing their load from the MISO market, MBLP is reducing the severity and duration of price spikes as well as transmission congestion in the UP while also ensuring MBLP customers have reliable electricity if ATC's transmission system is experiencing higher levels of congestion at times of elevated demand across the UP.

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[39] MPSC Case No. U-18224 Direct Testimony and Exhibits of Joann Henry, p. 6.
[40] MPSC Case No. U-18224 UP Gen Project annual Progress Report, p. 2.
[41] Load curtailment is synonymous with load shed and means the involuntary reduction of load on the system. Load curtailment typically involves restricting power to industrial customers first before impacting residential customers.

While additional information is expected as part of the ongoing study with MISO, any future scenario that would replace the UP RICE units will need to be equally robust and cannot introduce service interruptions during a transition period.

The Upper Michigan Energy Resources Corporation and Cleveland-Cliffs

Cleveland-Cliffs was uniquely tied to PIPP as its builder and original owner. Similarly, the Cleveland-Cliffs Tilden Mine has a unique relationship with UMERC and the RICE units – a relationship that enabled their development and secured transmission system benefits across the entire UP.

The Commission's Order on October 25, 2017, provided approval of two key components to ensuring electric reliability for UP customers. In that order, the Commission approved UMERC's application for a certificate of necessity pursuant to MCL 460.6s for two RICE facilities (the UP Generation Project), one in Baraga Township and one in Negaunee Township. In its approval, the Commission stated that, "UMERC demonstrated that the UP Generation Project is the most reasonable and prudent means of meeting the power need relative to other options." Also, "[f]Following the closure of PIPP, the UP Generation Project will serve a unique need to maintain reliability in the UP without incurring additional transmission costs." The Commission's Order also approved a special contract between UMERC and Tilden, the Tilden Mine Special Contract (TMSC). This contract was the final critical milestone to ensuring the RICE units came online, facilitating the retirement of PIPP, the cancellation of the SSR, and obviating the need for other, more costly transmission system upgrades – all of which would have impacted UP customer rates. Pursuant to the contract, UMERC would pay 100% of the capital cost for the RICE units. However, Tilden would reimburse UMERC for 50% of the capital costs on a levelized basis over the 20-year period of the special contract.[42]

Tilden's investment in the RICE units is not the only benefit UP ratepayers receive from the relationship between Tilden and UMERC. Almost all of the Tilden Mine's load is curtailable, which means that the load can be proactively reduced as part of MISO's emergency planning procedures prior to involuntary load shed if there is a system emergency event. The Tilden Mine load is also a capacity resource. While capacity resources may generally be thought of as generating resources, the ability to reduce load on demand can be credited to utilities as a capacity resource. Pursuant to the TMSC, Tilden's load can be curtailed under certain conditions, limited to MISO emergency procedures (i.e., unplanned situations where load must be reduced in order to maintain transmission system operations) and "non-emergency conditions related to transmission outages or other bulk system conditions." This does not include being curtailable for economic reasons, for example, curtailment that provides an economic benefit to UMERC or Tilden.[43]

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[42] Appendix C
[43] Appendix C

Due to Tilden Mine's curtailment status, UMERC can use the Tilden Mine's curtailment as a capacity credit that is equal to 50% of the UMERC's planning load share. This saves UMERC customers money because, absent that capacity credit for Tilden Mine's curtailment capability, UMERC customers would have increased costs to acquire capacity to satisfy its capacity obligation.[44] [45]

This contract also provides UMERC and its ratepayers the capacity of the RICE units, less the small portion of non-curtailable mine load. The RICE unit capacity is critical to meeting MISO's Planning Reserve Margin Requirement and the annual capacity demonstration established in MCL 460.6W. UMERC customers also receive the benefits of ancillary services and energy for any difference in energy output between what the RICE units are committed to in the MISO market and the energy required by Tilden for its mine operation.[46] Furthermore, as demonstrated by the RICE units providing a solution that allowed the Presque Isle Power Plant to retire, the presence of the RICE units have additional benefits for the UP including providing system reliability, system stability, and reduced transmission congestion, which results in lower local energy prices.[47]

While the details of both the size and profile of Tilden's load are confidential, the load is significant. Staff engaged Cleveland-Cliffs in several discussions and asked a number of questions to gain an understanding of Tilden's impact on the UP electric system and economy. Based upon information gathered through these interactions, Cleveland-Cliffs does not expect that there will be any changes to the Tilden load for the duration of the special contract with UMERC, which runs through 2039.[48] Tilden also does not anticipate any major electrification projects that would significantly increase its load in the UP or alter the broader UP energy dynamics.[49]

Changes in Electric Demand, Including Changes from Mining-Related Economic Development Projects, That May Influence the Utilization of the Reciprocating Internal Combustion Units

Public Policy

Understanding anticipated load changes is critical to appropriately assessing opportunities for compliance with the 2023 energy laws and any potential compliance challenges. While individual customer behavior, including behaviors and

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[44] Capacity Obligation is the amount of capacity an electric provider must acquire to meet the MCL 460.6W capacity demonstration requirements.
[45] MPSC Case No. U-18224 Testimony and Exhibits of UMERC witness James O. Sherman, p. 7.
[46] MPSC Case No. U-18224 Testimony and Exhibits of UMERC witness James O. Sherman, p. 9.
[47] *Id.*
[48] Appendix C
[49] Appendix C

decisions of both residential and industrial customers, will impact future load changes, public policy (like the 2023 energy laws) will also play a role. One public policy initiative that is likely to impact load growth is the MI Healthy Climate Plan and the goals it aims to achieve.

The MI Healthy Climate Plan was developed pursuant to the issuance of Executive Directive 2020-10 by Governor Gretchen Whitmer. The Executive Directive called for economy-wide carbon neutrality by 2050, and it charged the Michigan Department of Environment, Great Lakes, and Energy with establishing the MI Healthy Climate Plan to identify opportunities to achieve this goal. The precise impact upon the UP is unknown, but the electrification of industry, transportation, home heating and other appliances, and other applications will result in increased electric load. While some portion of this increase can be offset by advancements in energy waste reduction and increased energy efficiency, much of this load increase is likely to remain on the system and will require other solutions. However, the precise size of this load and how long it will take to get to the expected long-term peak demand, is uncertain because electrification is heavily driven by customer uptake and acceptance. Appropriate timing of grid investment to correspond to customer uptake is key. Investing too early results in increased rates to customers unnecessarily while investing too late results in the inability for new load to connect to the system or customers to electrify when they wish. Understanding when and where these loads will appear on the system is vital to knowing what investments are most reasonable and prudent.

Industrial Customer Changes

In addition to potential load growth from consumer choices and public policy, there is the possibility of increased load growth from other large industrial customers that include mining operations and the development of data centers. The UP has been home to mining operations for decades. Recent media reports related to the Eagle nickel mine and proposed copper mining signal the possibility of significant load increases. In addition, as the need for critical minerals and other raw materials continues to increase, there is the possibility that abandoned mines once deemed uneconomical could find new life. Data centers are a new industry experiencing aggressive growth. Data centers may favor the UP given its climate with mild summers because a significant portion of data center load is used for cooling. While there is nothing definitive, discussions with UP utilities suggested that any of these loads have the potential to increase electric demand substantially, particularly in relation to the UP's current energy usage. The average data center uses 10 to 50 times the energy per floor space of a typical commercial office building.[50] Given the UP's current generation resource portfolio and its current UP-wide customer demand, a single data center could increase the load of a given utility substantially.

[50] Data Centers and Servers | Department of Energy

Electric Provider Forecast Challenges

Electrification growth relies on several variables for which there is currently no firm data, which makes predicting future load growth difficult. In conversations with UP utilities, Staff requested information on potential load growth within each utility's service territory and the utilities shared that they do not currently have any information related to projected load changes and they lack clarity around the pace of potential future electrification. For these reasons, they do not expect significant load growth in the foreseeable future. Separately, the MPSC is in the process of completing a statewide electrification potential study which is expected to be completed by August 2025. Once completed, the electrification potential study will give lawmakers and the MPSC greater insight into load growth potential.

Options to Reduce the Carbon Intensity of the Existing Reciprocating Internal Combustion Units, with Particular Focus on How the Unique Geological Conditions Within the Upper Peninsula Influence the Feasibility of Deploying Clean Energy Systems

Hydrogen

A potential option for reducing RICE units' carbon emissions involves the blending of hydrogen gas with natural gas fuel, or even replacing natural gas with hydrogen to power the units. Because burning hydrogen does not release greenhouse gases, electric generation using hydrogen as fuel would qualify as "clean" under PA 235. However, a complete shift to hydrogen-fueled generation would not be necessary to realize a reduction in carbon emissions as blending varying amounts of hydrogen to offset natural gas consumption at the RICE units could result in emissions reductions.

In March 2023, UMERC performed a hydrogen blending demonstration project at the A. J. Mihm RICE generating facility with the Electric Power Research Institute (EPRI).[51] The study looked at replacing a percentage of the normal volume of combusted natural gas fuel for the RICE unit with hydrogen gas without any physical modification to the RICE unit's equipment or mechanisms. A single unit at

[51] The full report is available only to EPRI members. The Executive summary can be found at https://www.google.com/url?sa=t&source=web&rct=j&opi=89978449&url=https://www.wartsila.com/docs/default-source/energy-docs/technology-products/white-papers/executive_summary_hydrogen_blending_demonstration_wartsila50sg.pdf%3Fsfvrsn%3D99bd3d43_5&ved=2ahUKEwiVvPnsjviJAxVt5ckDHaGxMHoQFnoECBoQAQ&usg=AOvVaw3YKtnqOn0JV0auIgmrPUyn, retrieved 11/25/2024.

the facility was tested at various loading conditions with up to a 25% hydrogen blend. At lower engine loading levels[52] (an electric generation output of 50%), blending of hydrogen into natural gas showed a slight improvement in efficiency. This improvement in efficiency during low engine loading conditions was attributed to a more complete combustion of natural gas with the addition of hydrogen. CO_2 emissions from the blending of hydrogen were reduced but it was not a linear reduction. For example, a 25% hydrogen blend resulted in a CO_2 emissions reduction of approximately 10%. A reduction of NO_x emissions was also observed with the addition of hydrogen at lower loading conditions. At 75% loading level, the efficiency increases seen when adding hydrogen to the fuel mix at lower loading levels were lost and the efficiency was comparable when run on pure natural gas.

At higher hydrogen blending levels and high loading levels, the results were more mixed. There was an increase in NO_x emissions with a 25% hydrogen blend at loading levels of 75% or higher. There seems to be an increase in carbon emissions at maximum loading for higher hydrogen blends as well. The unit was unable to achieve a 100% loading level with a 25% hydrogen blend. The highest level achieved was 95% loading.

These results did illustrate that hydrogen blending is possible but there are challenges that include unit design and compatibility and the availability of hydrogen. If the fuel system was designed around hydrogen or hydrogen blending, the result could be improved at maximum loading. It should be noted that the study was performed under standard operating conditions for natural gas; there was no tuning performed on the RICE units to optimize for burning hydrogen. While blending is technologically feasible, the design of the existing RICE units limits the amount of hydrogen that could be incorporated which impacts the opportunity for emissions reductions. The manufacturer of the RICE units is currently working on a design that would allow for new RICE units to operate using 100% hydrogen, thus making hydrogen blending a viable solution from a compatibility standpoint. However, the availability of hydrogen fuel is not yet widespread.

The availability of hydrogen fuel for the RICE units presents a challenge for two reasons. First, there is no reliable source of hydrogen in the quantities needed to fuel the RICE units with 100% hydrogen because this market does not exist at this time. Second, making and delivering hydrogen in the quantities needed to fuel the units requires the development of significant infrastructure. Hydrogen is just beginning to emerge as a potential fuel source and its future potential is not yet fully understood. However, while the costs associated with hydrogen fuel and the infrastructure necessary to supply it to UMERC's RICE units are currently unknown, it is not unreasonable to presume that such costs could be significant. Therefore, hydrogen may be a viable alternative in the future, but only if these challenges can be overcome.

[52] Loading levels refers to the load on the RICE unit. A high loading level means that the unit must supply a larger amount of electricity to meet the demand. A low loading level means that the unit can meet demand by generating a lower amount of electricity.

Renewable Natural Gas

Another opportunity to reduce the emissions of the RICE units could be found through the combustion of renewable natural gas (RNG). RNG is a fuel that is produced by capturing methane from organic waste sources such as landfills, wastewater treatment plants, and livestock farms. RNG is retrieved by capturing methane that would otherwise be released into the atmosphere, resulting in a net reduction of greenhouse gas emissions when used as fuel compared to traditional fossil natural gas fuel. In terms of its chemical composition, RNG is similar to fossil natural gas and can be used interchangeably with it. While PA 235 does not explicitly identify RNG in the definition for a Clean Energy System that could be used to comply with Michigan's clean and renewable energy standards, MCL 460.1003 (i),[53] the Commission could consider initiating a rulemaking proceeding or the legislature could amend PA 235 to explicitly include RNG as a clean resource.

If RNG were designated a clean fuel, or even as a renewable energy resource, then another option to reduce the carbon emissions of the RICE units and achieve compliance with the standards in PA 235 would be to power the units with RNG rather than conventional natural gas. The use of RNG would not require additional infrastructure to deliver fuel to existing natural gas-fired generation facilities because it could utilize existing natural gas pipelines. While there are challenges to the deployment of RNG, there is potential for RNG development in Michigan that could support the power industry.

Pursuant to Public Act 87 of 2021, the MPSC commissioned a report into the potential for RNG development in Michigan. As part of that report, two scenarios for Michigan-based RNG production were analyzed examining demand, costs, technological development, and policies that could support RNG project development. The "achievable" production scenario captured 18% of RNG feedstock resources in Michigan while the "feasible" scenario captured 47% of Michigan RNG feedstock resources.[54] Under the "achievable" scenario, Michigan could produce 57.2 tBTu of RNG from 18% of the total feedstock inventoried in the report. In 2023, the two UMERC-owned RICE facilities and the Marquette Energy Center used 7,227,069 MMBtu (7.2 tBTu) worth of natural gas.[55] While the needs of the UP RICE generating facilities could be met under the "achievable" scenario, it is likely that designation of RNG as "clean" or "renewable" would drive up demand for the fuel across all utilities in the state.

While sufficient RNG could be produced in Michigan to support the operation of the RICE units in the UP (provided other utilities are not also attempting to be supplied

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[53] PA 235 of 2023, Section 3, subsection (i)(*iv*) states that clean energy systems are generation facilities that fit one of four criteria, including technologies defined as clean by the Commission as consistent with the purposes of the Act through a rulemaking process.
[54] Michigan Renewable Natural Gas Study, September 23, 2022, submitted to the Michigan Public Service Commission, p. 3.
[55] EIA Form 923 2023 early release data.

by those same resources), there are cost challenges. RNG and the environmental attributes that certify it is a clean fuel are sold separately. RNG purchased with environmental attributes is more costly than typical natural gas. Therefore, the use of RNG would increase the cost of operating the RICE units in the UP, which would likely impact customer rates. When the Commission's RNG report was issued, RNG prices ranged from $9.92-$70.86/MMBtu.[56] According to the July 2024 issue of Waste Today Magazine, the average National price for RNG was $15/MMbtu. The Henry Hub natural gas spot price for July 2024 was $2.07/MMBtu. While the price for natural gas is volatile, the highest average monthly spot price for the last five years was $8.81 in August 2022.[57]

Different feedstocks and production methods produce RNG in different price ranges. There are two main methods to produce RNG: anaerobic digestion and thermal gasification. Anaerobic digestion is the breaking down of organic matter feedstock using microorganisms that thrive in anoxic conditions.[58] Thermal gasification is where feedstock goes through a partial oxidation reaction, producing H_2 and CO. These gasses then go through a reaction to produce methane.[59] There are different price ranges based on the feedstock for anaerobic digestion. The lowest cost of these is landfill gas, which has a price range of $9.92-$26.85/MMBtu. Other feedstocks have a higher price range. For example, animal manure has a range of $14.53-$49.17/MMBtu and water resource recovery facilities have a production cost of between $10.90-$70.86/MMBtu.[60]

There are 16 candidate landfills that either flare or do not capture their methane emissions in Michigan. Combined, these landfills produce 12.3 tBTu worth of methane that could be captured and pumped into natural gas pipelines, and thus sold as renewable natural gas.[61] While low-cost RNG production from landfills would produce enough RNG to operate the UP RICE units, the cost increase in procuring certified RNG would be significant.

While RNG faces several challenges to adoption, attempts to address any of them are moot unless RNG is classified as either a renewable or a clean resource. Should that classification occur, a tracking process would need to be implemented, and cost challenges would need to be addressed before it could be a viable solution.

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[56] Michigan Renewable Natural Gas Study, September 23, 2022, submitted to the Michigan Public Service Commission, p. 6.
[57] EIA Henry Hub Natural Gas Spot Price. https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm
[58] Michigan Renewable Natural Gas Study, September 23, 2022, submitted to the Michigan Public Service Commission, p. 18.
[59] Michigan Renewable Natural Gas Study, September 23, 2022, submitted to the Michigan Public Service Commission, p. 19.
[60] Michigan Renewable Natural Gas Study, September 23, 2022, submitted to the Michigan Public Service Commission, p. 6.
[61] Michigan Renewable Natural Gas Study, September 23, 2022, submitted to the Michigan Public Service Commission, p. 29-31.

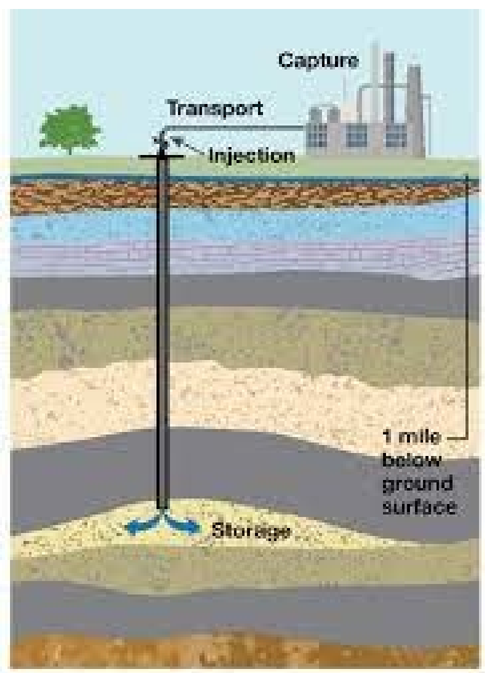
Carbon Capture and Sequestration

Carbon Capture and Sequestration (CCS) is referenced in PA 235 as a technology that could be paired with natural gas generation to meet the clean energy criteria if the CCS is sufficiently effective. CCS is a technology whereby the CO_2 from an emissions stream of thermal generation (for instance a coal or natural gas facility) is separated and concentrated then stored permanently so that it cannot enter the atmosphere. This is done geologically, where the CO_2 is injected into rock layers at depths where it cannot escape. Often, the CO_2 must be transported to the geological feature that can accommodate it. This is done using CO_2 pipelines or via truck or rail transportation.

To understand whether CCS is a viable solution for addressing compliance in the UP, Staff investigated the UP's geological potential for sequestration. The Oil, Gas, and Minerals Division at the Michigan Department of Environment, Great Lakes, and Energy (EGLE OGMD) met with Staff to discuss the suitability of the Upper Peninsula for CCS and provided information about the geological requirements for CCS.

As a threshold matter, federal requirements state that injection wells must not endanger underground sources of drinking water (USDW). Therefore, if the water at a specific depth is considered drinkable and is connected to either a public water supply or wells that are being used for drinking water, all types of injection, including CO_2, are prohibited. In addition, two geological features must be present in order to effectively store gases geologically. The first is rock with enough porosity to accommodate the injected CO_2, and the second is a layer of impermeable rock that prevents the upward migration of the gases called a continuous confining zone.

Figure 4: Carbon Capture and Sequestration



While the structures to accommodate the injection of gases exist in both the Lower and Upper Peninsulas, there is a marked difference when considering USDW requirements. In the Lower Peninsula, the water table turns brackish and becomes saline below 300 to 800 ft of depth. However, in the Upper Peninsula, even at a depth of 2000 ft below the surface, there is still drinkable water and, due to the permeability of the rock, the water at this depth is still connected to wells that are used for drinking water.[62]

Explorative tests done by Amaco Production Company drilled down to 6,500 ft below the surface in Alger County (located east of Marquette County) and found no rock formation appropriate for a confining zone. Due to the presence of USDW at extreme depths, and a lack of rock appropriate for a confining zone, the central and eastern portion of the UP are not suitable for CCS. While there has been less exploration of the western portion of the UP, it is unknown if there is a confining zone that would separate the western portion of the UP from the central and eastern UP's drinking water.[63]

Without a feasible underground storage option in the UP, utilizing carbon capture would require transporting CO_2 to sequestration sites in either Wisconsin or the Lower Peninsula. While such transportation is technically possible, the economic feasibility of carbon capture and sequestration is reduced as transportation distances increase.

For these reasons, CCS is likely not technically feasible in the central or eastern UP, may not be technically feasible in the western UP, and faces transportation cost related challenges thereby reducing its suitability as a compliance tool.

Other Information That May Be Relevant to the Development of Strategies to Satisfy the Clean Energy Standard for an Electric Provider Whose Rates are Regulated by the Commission and that Owns and Operates Reciprocating Internal Combustion Engine Units in the Upper Peninsula

Joint MISO/ATC Transmission Study

MPSC Staff has engaged both ATC and MISO to perform a transmission study (the MISO/ATC transmission study) analyzing the effects and feasibility of limiting fossil generation in the UP. The study seeks to understand two key issues. First, assuming that all electric providers meet compliance with the renewable energy standard enacted in PA 235, how much dispatchable generation or what transmission solutions would be needed to maintain system operability within applicable planning standards? Second, are the 2016–2017 UP transmission and generation studies still valid or have the study results changed since the transmission reinforcements have been completed and renewable generation installations increased?

[62] Appendix K, p. 1-3.
[63] Appendix K, p. 3.

The study assumes the UP will achieve the 60% renewable portfolio standard (RPS) by 2035 and the UP portion of the energy storage standard, as required by PA 235. Therefore, the MISO/ATC transmission study assumes that 1) 60.3 MW of battery storage was installed on the UP transmission system, and 2) Renegade, Groveland, and Republic solar all come online at their intended operation dates. Even when these planned renewable energy projects are added, additional renewable generation is needed to meet the 60% RPS. The balance of renewable energy generation needed to meet the 60% RPS requirement is slightly less energy than would be generated by the renewable projects within the UP that are currently being studied in the MISO generation interconnection queue.[64] Therefore, as a proxy for meeting the renewable portfolio standard, the MISO study assumes that all the MISO generation queue renewable projects are built.

Due to time constraints with completing the transmission study and the limited availability of MISO modeling staff, the MISO/ATC transmission study has been tailored to leverage existing data to the extent possible. Given the December 1, 2024, deadline for this report and the time it will take to complete the MISO/ATC transmission study, the final transmission study will be shared with the Legislature when it is received from MISO in early 2025.

Preliminary MISO Study Results

Preliminary results of the MISO transmission study were derived from a steady-state analysis. This means that the system was modeled under one set of operating conditions and those conditions did not change throughout the study, as compared to a dynamic study. Dynamic studies are more labor intensive to model.

Based on the steady-state analysis, MISO has indicated that when all diesel generation is offline, but the UMERC and Marquette RICE units remain online, there are no apparent system concerns. When the same steady-state analysis is done with all diesel and RICE generation offline, there were times of generation redispatch[65] that alleviated many of the system concerns. Additional concerns were alleviated by installing a shunt reactor[66] on the system.

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[64] The MISO Generation Interconnection Queue represents proposed generation projects within MISO. Projects in the queue have been proposed by utilities or developers and are being studied to understand what, if any, transmission system impacts would be expected from the project and to identify subsequent upgrades necessary to facilitate their interconnection with the system. As indicated above, there are currently enough projects in the queue to meet the renewable energy standard applicable to UP load-serving entities. Historically, a significant number of projects that enter the queue are not built. While it is advisable to assume that not all of the proposed projects will be built, these projects do serve as a useful proxy for purposes of the study.

[65] Generation redispatch means that MISO instructs a generator to change its output power to ensure transmission system stability.

[66] A shunt reactor is a device used in high-voltage power transmission systems to control voltage and increase energy efficiency.

While many concerns can be addressed with generation redispatch or through the installation of a shunt reactor, approximately 7% of the modeled system overloads[67] are not able to be mitigated by either of these solutions. These remaining system concerns could only be alleviated with transmission system modifications to ensure that load curtailment would not be necessary. Transmission system modifications could result through either ATC planned projects or included as projects within Tranche 2.2 of MISO's Long Range Transmission Planning (LRTP) process. LRTP is a MISO planning activity focused on "improv[ing] the ability to move electricity across the MISO region from where it is generated to where it is needed - reliably and at the lowest possible cost."[68]

It is important to note that the projects necessary to alleviate the remaining 7% of system overloads are projects that are not currently identified. As indicated by MISO, these system issues could be studied as part of MISO LRTP Tranche 2.2 or through ATC planned projects. Currently ATC does not have planned projects that address these concerns.

ATC planned projects could be developed through either generation projects that are being studied in the generation interconnection queue to determine the system impact of interconnecting the proposed generation or through ATC's transmission planning process. Projects developed through the ATC planning process could result in a significant cost burden to either developers (for generator interconnection projects) or UP customers (for other projects) because they are typically paid by the ATC's local planning zone so costs would largely be allocated to UP customers.

MISO LRTP Tranche 2.2 is not expected to start until 2026 and may take a year or more to complete. Previous MISO LRTP Tranches did not include Michigan's clean energy and renewable energy standards because the studies were already underway when the 2023 energy legislation was passed. MISO LRTP Tranche 2.2 projects are projects that will have been found to have regional benefit. If projects were identified through that process, the costs would be allocated to customers on a regional basis determined by a transmission customer's load share ratio.[69] Transmission projects typically take 4-6 years to build once approved by the MISO Board of Directors.

Given these uncertainties and the system concerns that were not alleviated through existing transmission system ability or expected new projects, further study concerning the system impacts is necessary. Further study should include dynamic studies of the transmission system to better understand impacts to system stability

[67] System overloads refer to either voltage or thermal overloads that exceed the operational constraints of the system, thereby putting the transmission system equipment at jeopardy.
[68] https://www.misoenergy.org/planning/long-range-transmission-planning/
[69] Load share ratio refers to the load of a specific transmission customer as compared to the total load of the region at a specific time.

as well as loss of load expectation studies to understand how well the UP system is expected to meet the MISO reliability standard of one day in ten years.[70]

Energy Waste Reduction

Energy waste reduction (EWR) programs create opportunities for utilities to save energy by investing in technologies, actions, or equipment that use energy more efficiently thereby reducing their overall load without sacrificing customer comfort. Utility EWR programs, authorized and required by statute, typically include initiatives that encourage customers to utilize programable thermostats, install energy efficient lighting, improve home insulation, upgrade home windows, or replace older appliances or furnaces with new, more efficient models. EWR-related load reductions may help to offset some potential long-term load increases that could result from moves toward electrification technologies by UP customers. Pursuant to Michigan law, utilities may administer their own EWR programs or offer EWR programs through the state administrator who operates these programs on behalf of the participating utilities. Each investor-owned utility is required to offer an EWR program to its customers and, beginning January 1, 2025, municipally owned and cooperative electric utilities are also required to again offer these programs to their customers.[71] Information concerning the energy waste reduction programs and energy savings achieved by investor-owned utilities from 2018-2023 is shared below.

UMERC has achieved between 1.06% and 1.59% savings over the past 5 years. It utilizes Efficiency United, the state plan administrator, to administer its program.[72] UPPCo achieved between 1.34% and 2.5% savings annually over the past 5 years. UPPCo plans to increase its EWR to 1.75% for program years 2024 and beyond.

NSP-W achieved between 0.79% and 1.56% savings over the past 5 years. It utilizes Efficiency United, the state plan administrator, to administer its program.

Prior to 2022, MBLP met its annual EWR targets and used a third-party EWR provider to administer its program. With the passage of Public Act 229 (PA 229) and the reapplication of EWR targets for municipal utilities, MBLP plans to once again use a third-party EWR provider. Given the recent change in application of the EWR requirements, MBLP had not completely developed its future EWR plans at the time of Staff's discussions with the utility.

Wisconsin Public Power Inc. (WPPI) uses a third-party administrator to run the EWR program for its UP members. It is currently achieving 0.08% energy savings

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[70] "MISO one day in ten years" refers to a standard used by the MISO that aims to ensure the transmission grid experiences a loss of load event (outage) no more than one day every ten years.
[71] Public Act 342 of 2016 exempted non-rate regulated utilities from offering EWR programs beginning January 1, 2022. However, Public Act 229 of 2023 reinstated this requirement beginning January 1, 2025.
[72] PA 295 Utility Energy Waste Reduction Programs Implementation, 2019-2023 Annual Reports, Reports and Studies, retrieved 11/30/2024.

compared to previous year's sales. With the passage of PA 229, WPPI's members in the UP are considering moving away from a third-party administrator to self-implementation, allowing them to run their own EWR programs to reach their goals or to make compliance payments in lieu of operating a program, as permitted by the statute.

Escanaba administers its own EWR program and has an energy savings of 0.13% annually. It is planning to contract with a third-party to administer the higher standards required by PA 229.

Cloverland administers their program through the Michigan Electric Cooperative Association and achieved 1.21% savings over their previous year's sales in 2021. Cloverland is also subject to the 1.5% required by PA 229 beginning in 2025.

Increased EWR may be part of a potential compliance solution in the UP. PA 229 establishes a target of 1.5% EWR as a minimum for electric utilities, but some utilities set a higher target as EWR is generally viewed as a least-regrets path towards providing reliable service to their customers through customer participation in beneficial EWR programs. However, EWR is not a replacement for retiring generation as it does not provide energy or capacity to serve load. Likewise, EWR cannot provide voltage support for the transmission system. While EWR would not obviate the need for any identified generation or transmission solutions, it could reduce the size, and ultimately the cost, of those solutions to fully or partially offset the need to add additional generation and/or transmission to meet growing energy demand. Indeed, the Commission estimates that on a statewide basis, EWR programs have avoided the need to build two new 1000 MW power plants, at a fraction of the costs needed to construct those facilities.

Staff is currently engaging a third-party consultant to conduct the electrification and EWR potential studies required by PA 235. The EWR potential study should provide visibility into the technical and feasible potential of EWR in the UP. Utilities should be encouraged to develop cost effective EWR programs with special consideration for lower income customers and vulnerable populations within utility service territories.

Demand Response

One tool that can be used to reduce load on the system and preserve system functionality is demand response (DR). DR allows the utility to call upon customers in DR programs to temporarily reduce their usage to alleviate system demand. These programs operate pursuant to Commission approved tariffs and offer benefits to participating customers, typically in the form of a lower rate, in exchange for the customer's willingness to reduce their electric demand by a set amount when called upon by the utility to do so.

DR that is registered at MISO as a resource can be registered such that it can be called upon for meeting different system needs. Some DR is available at any time and bid into the daily market and can also be available for use at the electric provider's discretion. Some DR is registered such that it is available only when there is a system emergency. Utilities may count load served pursuant to a MISO DR tariff as a resource to meet its capacity obligation (capacity requirement) under both the MISO resource adequacy requirements and the Michigan capacity demonstrations pursuant to MCL 460.6w. Because utility demand response programs can be used to reduce demand on the system, utilities can use these programs as a capacity resource which reduces the amount of generation resources necessary to meet their capacity or resource adequacy requirement. DR inherently has limitations to frequent use. Although it can aid in meeting capacity needs to satisfy either State or MISO resource adequacy requirements, it provides only infrequent and short-duration system support and is not a long-term solution in lieu of new generation or upgraded transmission needs.

Several utilities in the Upper Peninsula have DR or industrial interruptible/curtailable load. UPPCo and UMERC cover the largest portion of their capacity requirement through DR. Excluding the Tilden Mine load, UMERC has an additional 15% to 20% of its resource adequacy requirement satisfied by DR, depending on the capacity season. When the non-firm load of the Tilden Mine is included, 60%-71% of UMERC's capacity requirements are satisfied by DR, depending on the capacity season.[73] Most of the DR in UMERC's portfolio comes from industrial load, regardless of whether the Tilden Mine is included.

According to UPPCo's 2019 IRP, approximately 55% of its capacity requirements were served by DR.[74] Even though this was before MISO changed over to a seasonal capacity construct, UPPCo has confirmed that it will still rely heavily on DR to meet MISO capacity requirements. It is largely industrial load that is providing the DR resource, and its load has remained flat. Because of this, its DR portfolio is likely to be similar to what was provided by UPPCo in its 2019 IRP.

While both UPPCo and UMERC are heavily leveraged in terms of DR, albeit most of the DR is emergency use only, the municipal and co-op electric providers have small or even non-existent DR programs. MBPL lacks any DR program but can self-serve its load and has purposefully sized and built its resources to avoid the need for such programs.[75] WPPI has 3.5 MW of DR in the UP and plans to launch a thermostat-based DR program in the coming year. Escanaba does not have a defined DR program; however, if there were to be a transmission emergency, Escanaba would be expected to shed 8.5 MW of load, or approximately 33% of its total load. However, Escanaba's required load shed is similar to UMERC's DR because it is able to be dispatched only under emergency conditions and is in the last phase of the emergency measures taken by MISO to stabilize the transmission system.

In addition to commercial and industrial DR programs, many utilities also offer DR programs for residential customers. While these programs are certainly important in reducing load during peak demand, the load reduction that these programs offer

[73] Id.
[74] Case No. U-20350 Direct Testimony and Exhibits of Gradon R. Haehnel. Exhibit A-1, p. 121.
[75] Appendix F

can be relatively limited given the pattern of residential customers usage. For instance, many residential DR programs rely on customers who agree to allow the utility to interrupt, or otherwise cycle, their air conditioning unit. In the UP, however, air conditioning load is relatively small compared to other areas of the state because the summer temperatures are cooler than other parts of the state in the summer. This, along with other potentially limiting factors, limits the potential effectiveness of expanding these programs, though such expansion could still demonstrate a benefit.

DR expansion has added limitations, one of which is the implementation of MISO's seasonal capacity construct. The use of the seasonal construct adds complexity, as certain types of DR programs are accredited capacity in certain seasons but not others (for instance, residential DR programs allowing for air conditioner cycling would be accredited for the summer but not for the winter).

Additionally, DR is a capacity-only resource, which means that its primary value is rooted in "providing" electricity during peak demand by reducing demand rather than by generating power and is only required to be available when needed to respond to high demand. By their very nature, DR programs have a limited number of times that they can be called to curtail load and are generally used to provide emergency relief or occasional economic benefit. Not only does DR not provide power, but it also cannot provide voltage support on the transmission system the way that generation or other technologies can. While DR can be used to solve some transmission issues, it is usually confined to addressing those issues that are transient in nature, for instance, addressing temporary increases in demand. While an increase in DR may reduce the cost of any solution that is ultimately chosen, it cannot stand as a solution on its own.

Functional Equivalence

As discussed throughout this report, system reliability and affordability concerns are top of mind when considering the UP energy system, and flexibility may be needed as opportunities to achieve compliance are explored. One such opportunity for incorporating flexibility while achieving the goals of the MI Healthy Climate Plan may be to expand the generating units to which "functional equivalence" for compliance purposes applies. To this end, the Legislature could consider expanding the definition of "clean energy system" to include broader "functional equivalence" language.

The MI Healthy Climate Plan,[76] developed in response to Executive Directive 2020-10,[77] aims for Michigan to achieve 100% economy wide carbon neutrality by 2050,

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[76] The MI Healthy Climate Plan was released in April 2022. https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-healthy-climate-plan

[77] Executive Directive 2020-10 was signed by Governor Gretchen Whitmer on September 23, 2020. https://www.michigan.gov/whitmer/news/state-orders-and-directives/2020/09/23/executive-directive-2020-10

and PA 235 codifies both a renewable energy standard and a clean energy standard designed to help meet this goal. Pursuant to PA 235, electric utilities in Michigan must have a 100% clean energy portfolio by 2040. Under the statute, "clean energy" includes electricity generated without creating greenhouse gas emissions, natural gas generation with various levels of effective carbon capture technology, other technologies the Commission defines as clean through a rulemaking, and

> "an independently owned combined cycle power plant fueled by natural gas that has a power purchase agreement with an electric provider [on or before February 27, 2024] and that by 2030 receives approval from the commission for a plan that achieves functional equivalence with the clean energy standard in section 51(1)(b) through reduction of greenhouse gas emissions using carbon capture and sequestration and other available applications, including, but not limited to, carbon removal technologies."

The term "carbon removal technologies" is not defined by the statute.

A similar provision for electric providers in the UP and more broadly throughout Michigan may provide for flexibility while also aligning with the MI Healthy Climate Plan's goal of economy wide carbon reductions. Electric providers have opportunities to work closely with their customers, especially those that consume significant energy through industrial processes and those with broader industry throughout Michigan, to advance the MI Healthy Climate Plan's economy wide carbon reduction goals in the most reasonable and prudent way possible. UMERC and its customer Cleveland-Cliffs provide a prime example of the potential for collaboration.

In contemplating "functional equivalence" broadly, open-air carbon capture technologies, also known as direct air capture (DAC) could be considered. Interest in the development of these technologies has been increasing. While these technologies are in early development, they are generally costly. However, should these technologies prove successful, and should they become cost competitive, they could help to achieve the overarching goal of economy-wide greenhouse gas emissions reductions by pairing with generation technologies necessary to address system reliability and/or affordability concerns that do not otherwise meet the statutory definition of "clean energy." This pairing could further the goals of the MI Healthy Climate Plan, PA 235, and address both reliability and affordability concerns.

Direct Air Capture entails CO_2 being removed directly from the atmosphere rather than from the waste stream of combustion. Because there is a much lower concentration of CO_2 in the atmosphere than in a waste stream of combustion, it requires more energy and is more expensive to use than CCS.[78] The International

[78] DOE Explains...Direct Air Capture https://www.energy.gov/science/doe-explainsdirect-air-capture.

Energy Agency estimates the current cost of DAC as between $125 to $335 per ton of CO_2 sequestered,[79] whereas CCS on a natural gas-fired power plant has an estimated cost between $75 to $125 per ton of CO_2 captured.[80] However, DAC can be sited on top of geological features that are being used to sequester CO_2 and is not limited to the geology at the location of the CO_2 emitting source. If the CO_2 is tracked properly (similar to the above discussion regarding renewable energy credits and RNG contract tracking), a CO_2 emitting source could be considered CO_2 neutral even if it is not equipped with CCS technology. For instance, a UP utility could establish a DAC at, or close to, a sequestration site in the Lower Peninsula and use the carbon captured at that location to offset the carbon emitted from the UP facility.

Because the UP is unsuitable for carbon management through CCS due to its geology, DAC may be the preferred carbon capture technology to the extent that carbon capture is the most reasonable and prudent option. However, in addition to the referenced cost challenges, allowing for such a scenario would require an amendment by the Legislature or rulemaking by the Commission.

Other Considerations

Renewable Energy

The MI Healthy Climate Plan lays out a pathway to reach 100% carbon neutrality by 2050. As one component of reaching this goal, the 2023 energy laws set Michigan on a path to 100% clean energy including meeting at least 60% of these energy needs with renewable energy resources by 2035.

When identifying opportunities and implementing strategies to achieve this carbon neutral future, it is important to consider what has already been achieved. As mentioned previously, UP utilities have already accomplished much regarding integrating renewable energy resources into their generation portfolios and reducing carbon emissions. Not only do UP utilities produce significant amounts of hydroelectric power, but they have significantly expanded other forms of renewable energy as well. Furthermore, utility-owned, coal-fired generation in the UP has been entirely retired and replaced with natural gas-powered RICE units with significantly lower emissions, as well as increasing wind and solar resources. These retirements in the UP happened years before utilities in the Lower Peninsula are expected to retire their coal-fired generation. According to the U.S. Energy Information Administration (EIA), the coal retirements and additions of renewable generation have resulted in a

[79] Direct Air Capture: A key technology for net zero, https://www.iea.org/reports/direct-air-capture-2022, International Energy Agency, 2022, p. 9.
[80] Technology Readiness and Costs of CCS, https://www.globalccsinstitute.com/resources/publications-reports-research/technology-readiness-and-costs-of-ccs/, Global CCS Institute, 2021, p. 29.

71% decrease in carbon emissions from the UP electric sector between 2013 and 2022.

A number of renewable energy facilities have been installed in the UP and additional renewable energy development undertaken to meet the RPS will further reduce the total carbon emissions from the electric sector.

While renewable resources are important for achieving carbon neutrality, these resources do have some limitations that support a measured approach and are, therefore, only one part of the solution for achieving this goal. One factor which supports a measured approach in adding renewable energy facilities in the UP relates to cost. While renewables are the least expensive form of new generation, there is still a cost to build them, and by law this cost is recovered by utility ratepayers. To the extent that new facilities are not needed to meet current electric demand, for instance, because this demand is being met by another already built resource, costs will increase for customers as they effectively pay for additional, otherwise unneeded, generation facilities.

Technical challenges also support a measured approach to incorporating additional renewables into the UP's energy mix. To better understand the anticipated impacts to the UP's transmission system with the incorporation of significantly higher levels of wind and solar generation, as discussed above, the Commission requested that MISO model these potential impacts to the transmission system as part of the study that is expected in early 2025. The study will assume that all renewable resources currently pending in the MISO interconnection queue for development in the UP are developed by 2040. The results of this study should provide a better understanding of how the 60% renewable energy standard will impact the UP's transmission system and will identify broader transmission system needs.

Biomass

Biomass generation facilities produce electricity by primarily burning wood waste along with small amounts of other waste products. Traditionally many of these facilities incorporate a small amount of tire derived fuel (TDF or scrap tires) into the fuel mix that would otherwise be sent to landfills or improperly disposed of. This small amount of TDF improves the efficiency of the biomass units, which means that the units generate more energy per amount of fuel, thereby resulting in lower carbon emissions per MW of energy produced. Biomass facilities generate dispatchable power and provide support to the transmission system. Biomass generation plays an important role in both ensuring generation diversity and maintaining the environment by providing non-landfill disposal opportunities for forest products waste, lumber industry waste, old railroad ties, and scrap tires. Biomass facilities throughout Michigan, including in the UP, provide stable sources of electric power and industrial processing, often in a carbon neutral way when considering the lifecycle of the fuel source. In addition to the environmental and transmission system benefits, these facilities often provide significant support to their typically more rural communities in the form of high paying jobs, community tax base, and other less formalized community support including, for instance, charitable donations. One such facility is located in L'Anse, Michigan. The L'Anse Warden Electric Company's (LWEC) biomass facility not only allows for non-landfill disposal of wood waste with a small amount of TDF, but it also supplies steam needed for CertainTeed's industrial operations.

While biomass generation has traditionally been considered a renewable generation technology, PA 235 excludes biomass facilities that co-fire TDF from the definition of renewable energy resource, even if the facility uses effective emissions control equipment. The exclusion of facilities that co-fire TDF from the definition of renewable energy resource may have a profound impact on the ability to maintain existing biomass facilities because the reduced efficiency from excluding TDF from the fuel mix has a direct impact on the economics of running the facilities. If biomass facilities are no longer able to co-fire with TDF, they are likely to see an increase in operational costs. There is also a likelihood that if these facilities' generation no longer creates renewable energy credits, the contracts for power that these facilities operate under may not continue or be renewed.

Emissions from biomass facilities are governed by the Industrial, Commercial, and Institutional Boilers and Process Heaters: National Emission Standards for Hazardous Air Pollutants (NESHAP) for Major Sources that were established by the EPA to govern hazardous air pollutants from biomass facilities under its jurisdiction. The L'Anse Warden Electric Company's biomass facility in L'Anse is one such facility. The company's biomass boiler has a permitted carbon emissions limit of 0.3 lb/MMBtu.

During the Commission's tour of the UP, Commissioners and Staff visited LWEC's biomass boiler facility and were able to learn more about the impacts of co-firing TDF with the biomass fuel[81] and requested further information on the impact of co-firing TDF on carbon emissions. LWEC provided Staff a technical memo, included as Appendix J, which includes the comparison of operations with and without utilizing TDF. The comparison measures emissions on two days, one week apart, with facility operations occurring under similar load and weather conditions. For purposes of the comparison, the facility used TDF mixed with biomass fuel one day and on another did not use TDF. The data from this comparison shows a 16% reduction in daily average carbon emissions on a lb/MMBtu basis when TDF was used in the fuel mix.

While perhaps counter intuitive, the data demonstrates that the use of TDF with biomass fuel results in lower emissions. TDF has a high Btu content, meaning that it burns much hotter than other fuels as compared to the volume of fuel. The high heat content combined with a reduced sensitivity to temperature and humidity helps to dry the biomass fuel and ensures a more complete combustion, thereby improving efficiency. While TDF lowers emissions and improves efficiency, it is worth noting that there is a limit to the amount of TDF that can be cost-effectively co-fired

[81] TDF is added to the fuel mix in a low percentage in effort to maximize combustion of the wood waste product. During combustion, TDF acts as a drying agent for the wood waste by burning hotter and therefore ensures a complete combustion. Without TDF, more carbon is produced because combustion temperatures are lower, resulting in incomplete combustion.

with biomass. The co-fired blend includes a relatively small amount, approximately 10%, TDF in the fuel mix. Co-firing more than 10% TDF with the biomass fuel can result in increased maintenance in the boiler.

Not only does excluding co-fired TDF from the definition of a renewable energy resource threaten to increase emissions from these facilities, but this change has also already disrupted efforts to dispose of scrap tires. The Michigan Department of Environment, Great Lakes, and Energy (EGLE) works closely with biomass facilities to ensure that tires throughout Michigan are properly disposed of. Many of these tires were made into TDF for use as a fuel at biomass facilities or other industrial heat processes.[82] The abrupt halt to the use of TDF in biomass facilities has resulted in an inability to dispose of millions of tires because other industrial facilities cannot accommodate the increased amount of scrap tires or the transportation costs to move scrap tires to facilities that would be able to accommodate them are too high to make economic sense. While other avenues for disposing of these tires are being explored, including using ground tire powder in road construction, these other options require much more processing and transportation therefore increasing the cost to dispose of scrap tires, costs that are ultimately passed on to consumers. Furthermore, while these other avenues could likely absorb these additional scrap tires eventually, these other avenues are not yet at full volume, leaving many tires undisposed and possibly creating the hazards TDF was developed to help alleviate.

In light of the data and demonstrated early impacts on efforts to dispose of scrap tires, the Legislature could re-evaluate the exclusion of biomass that is co-fired with TDF as a renewable resource or specifically consider it to be a clean resource so long as the facility can demonstrate that the amount of carbon removed through the biomass lifecycle exceeds the amount of carbon emitted through electric generation. Limits as to the amount of co-fired TDF could be considered to ensure that the combustion of biomass results in the lowest possible carbon emissions. Additionally, biomass facilities could be required to demonstrate that the overall lifecycle of the fuel results in net carbon neutrality or net carbon negativity. In the alternative, the Legislature could consider a transition period that would allow biomass facilities to move away from TDF gradually or over a longer period of time than what was provided for under PA 235. This phased in approach would also create the opportunity for EGLE to develop and ramp up alternative disposal options.

New and Emerging Generation Technologies

While not yet widely available at a commercial scale, a number of new generation and capacity technologies are in various stages of development including some technologies that are in the pilot stages while others remain only theoretical.

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[82] TDF was developed in response to Part 169, Scrap Tires, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended, to eliminate large piles of tires throughout Michigan, including along Great Lakes shorelines.

Long Duration/Multi-Day Energy Storage

Long duration energy storage (LDES) and multi-day energy storage (MDES) technologies are rapidly developing. PA 235 defines LDES as an energy storage system that has the capability of continuously discharging electricity at its full rated capacity for more than 10 hours. Likewise, PA 235 defines MDES systems as having the capability of continuously discharging electricity at its full rated capacity for more than 24 hours.[83] There are four main categories of LDES/MDES technologies: thermal, mechanical, electrochemical, and chemical. Each category of storage technology has strengths and weaknesses and may be better suited for some applications or situations than others.

Thermal Storage

Thermal storage converts energy to heat and stores it until the energy is needed. Most commercial thermal storage technologies are designed for industrial applications. These technologies seek to use electricity to heat a thermal storage medium (i.e., bricks, salt, or crushed rock[84]) when it is inexpensive and then provide steam, heated air, or combined heat and power when discharging. Most of these technologies are through the pilot phase and are currently in commercial demonstration.[85] Opportunities for thermal storage to provide a solution to home heating needs are also being explored.[86]

Chemical Storage

Chemical storage refers to storage technology that puts and pulls electrical power in and out of chemical bonds. Fossil fuels are one of the most common examples of storing energy in a chemical bond. Chemical storage releases energy when the bonds in chemical compounds are broken. Energy is also stored in other chemical forms such as biomass, hydrogen, and methane gases. Energy carrying chemicals can be produced from a variety of sources. Converting energy from those sources into chemical forms creates a high energy density fuel. For instance, hydrogen can be stored as a compressed gas, liquid hydrogen, or inside other materials. Depending upon how it is stored, it can last for a long time in a high energy density form. Chemical storage scientists are working closely with national laboratories to continue developing energy storage options.

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[83] PA 235 of 2023, Section (7), MCL 460.1007.
[84] https://www.technologyreview.com/2024/04/15/1091042/thermal-batteries-heat-energy-storage/, accessed November 9, 2024.
[85] Long Duration Energy Storage Council, YouTube, Long Duration Energy Storage 101: All About Thermal Energy Storage Technologies Part 1.
[86] https://www.nrel.gov/news/program/2023/exploring-thermal-energy-storage-solutions-for-energy-efficient-buildings.html, accessed November 9, 2024.

Electrochemical Storage

Electrochemical LDES/MDES stores energy using the same process as lithium-ion batteries and is, therefore, the energy storage technology that is probably most familiar to people and likely to be the first to come to mind when thinking of energy storage. Like lithium-ion batteries, electrochemical battery technologies charge and discharge electricity through chemical reactions in the battery. However, LDES/MDES batteries can use different chemistries than lithium-ion batteries and many new chemistries are being investigated and developed. Electrochemical storage technologies typically raise questions and concerns around thermal runaway. Thermal runaway is a situation where the temperature of the battery increases, causing a chemical reaction in the battery that increases the battery temperature and perpetuates the chemical reaction and, in some cases, causing battery damage or, if the battery is large enough, a fire that is extremely difficult to put out. While thermal runaway is a concern for some electrochemical energy storage technologies, many of the chemistries being explored for LDES/MDES have no risk of thermal runaway.[87]

Most electrochemical energy storage technologies have a discharge duration under 24 hours before needing to recharge (depending on the battery chemistry used), so these technologies are primarily classified as LDES under PA 235. There is one known technology under development that would qualify as MDES because it is designed to operate for 100 hours between full cycles.[88]

Many of these electrochemical technologies have completed behind the meter pilot demonstrations and approximately half are moving into the utility scale pilot phase in the 2025–2026 time frame.[89] Manufacturing challenges are often experienced in the development and rollout of new technologies, and this is true of energy storage technologies as well. Two companies have announced that they will reach a one gigawatt a year production capacity in the 2028-2030 time frame.[90] This means that the maximum capacity that one of these technologies could deploy across the world in a year is one gigawatt of nameplate capacity. The transition to intermittent generation will require significant amounts of energy storage. When the need for energy storage is coupled with the popularity of electrochemical storage technologies, demand for these technologies may quickly outpace production capacity resulting in supply shortages and increased cost.

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[87] Long Duration Energy Storage Council, YouTube, Long Duration Energy Storage 101: All About Electrochemical Energy Storage Technologies. https://www.youtube.com/watch?v=59nfKYVTzwg, retrieved 11/30/2024

[88] Id.

[89] Id.

[90] Id.

Mechanical Storage

Mechanical storage involves storing electrical energy in the form of potential energy or kinetic energy. Kinetic energy is stored in flywheels while potential energy can be stored in compressed gas or in the lifting of weights. Compressed gas is usually stored geologically and traditionally has utilized natural gas fuel to reheat the expanded gas in order to compress it again. Some companies are working to develop a new generation of compressed gas storage that requires neither natural gas to reheat the expanded gas nor geological features in which to store it.[91] In exploring opportunities for the UP, these developments are promising for two reasons. First, the UP does not have geological features that would allow for compressed gas storage so the development of technologies that are not reliant on such features is critical if compressed gas storage is to be a viable option for the UP. Second, this new generation of compressed gas storage seeks to store the heat created by compressing the stored gas and to use it to reheat the expanding gas, making these technologies carbon neutral.[92] Most of the new generation of compressed gas storage technologies would be 8- to 24-hour storage and are in the commercial demonstration phase.[93]

The most commercially advanced form of mechanical energy storage is pumped hydro storage. This technology has been commercially viable for several decades. In a pumped hydro system, water is pumped from a lower reservoir to a higher reservoir when excess electricity is available on the system. The water is stored in the higher reservoir until the energy is needed and then the water is released to run through the turbines, generating electricity, and returns to the lower reservoir. Most pumped hydro facilities were installed in the 1970s, with Michigan's own Ludington Pumped Storage Plant serving as a prime example. Like Ludington, pumped hydro storage is traditionally an open system and requires a significant height difference between the upper and lower reservoir. The number of suitable sites in the U.S. is limited by geography and is further limited by aesthetic, environmental, and permitting considerations. There are companies trying to develop closed loop system sites that either utilize existing infrastructure, such as run of river dams, or use a fluid that has a higher specific gravity than water.[94] Fluids with higher specific gravity than water increase energy production because the fluid creates more pressure at the same height differential thereby increasing power generation when released through the turbine due to the greater force on the turbine blades.

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[91] Long Duration Energy Storage Council, YouTube, Long Duration Energy Storage 101: All About Mechanical Energy Storage Technologies.
[92] Id.
[93] Id.
[94] Long Duration Energy Storage Council, YouTube, Long Duration Energy Storage 101: All About Mechanical Energy Storage Technologies.

Pumped Underground Hydro Storage

Pumped Underground Storage Hydro (PUSH) is another type of storage with potential application in the UP. PUSH utilizes retired mines to act as a pumped storage solution. Though there has yet to be such a facility commissioned, with the increase of intermittent resources across the globe, there has been increased interest in the technology. The UP has many retired mines that could theoretically be converted to operate in such a fashion. Michigan Technological University and the Keweenaw Energy Transition Lab explored this possibility in a case study using the Mathers mine in Negaunee, Michigan.

The study estimated the volume based on maps of the mine and conversations with former mine workers and determined the anticipated volume and head[95] for the upper and lower reservoirs in such a facility. Assuming that the upper reservoir was a surface pond and the lower reservoir was the deepest part of the Mathers mine, and assuming the reservoirs were charged (i.e., water was pumped into the upper reservoir) and discharged (i.e., water moved through the turbines to the lower reservoir) daily, the low volume estimate allowed for the build out of a 655 MW facility.[96] However, the study concluded that a facility this size in the Mathers mine was not realistic because it would require unreasonable flow rates through the main mining shafts between the upper and lower reservoirs making the mining shafts, not projected mine volume, the limiting factor for PUSH.

Mine volume and shaft limitations are not the only challenges to PUSH. The costs of implementing large volumes of this technology are presently very high, between $1.34 million/MW and $4.85 million/MW.[97] Based on this estimate, the cost to construct 234 MW of PUSH, which equals the combined capacity of the UMERC and MBLP RICE units, would be $313.56 million to $1.14 billion. For comparison, the UMERC RICE units cost $277.2 million.

While LDES/MDES technologies hold promise for addressing the energy challenges of the UP and enabling compliance with the 2023 energy laws, these technologies are in early stages of their development, not yet broadly commercially proven, and/or not yet cost competitive to offer a viable solution in the immediate future.

Small Modular Nuclear Reactors

Small Modular Reactors (SMR) are nuclear reactors that can range in size from 10 MW to 300 MW, whereas traditional nuclear reactor plants vary in size from about

[95] Refers to the volume of fluid stored and vertical height difference between the upper and lower reservoir.
[96] PUSHing for Storage A Case for Repurposing Decommissioned Mines for Pumped Underground Storage Hydro (PUSH) in the United States, p.28.
[97] Id. at 36.

600 MW to 1200 MW.[98] SMRs are prefabricated and produced in an offsite facility and shipped to the site where they will be interconnected to the grid and operated for installation, allowing for potential cost reductions through standardized manufacturing and accelerated construction.[99] SMRs are also expected to be safer and simpler than traditional nuclear reactors because they utilize a standard design and rely on passive physical phenomena to cool the reactor core. This change in reactor core cooling also provides flexibility regarding the location of these reactors because access to large bodies of water for cooling purposes is unnecessary.

Due to their reduced size, it is also expected that SMRs would need to be refueled less frequently than a traditional nuclear reactor[100] which is typically refueled approximately every 18-24 months. The decrease in needed refueling should also provide cost savings compared to traditional nuclear reactors. There are a handful of SMRs that are either operational or under construction in China, Russia, Japan, and Argentina, but most SMRs are in the design and development phase. Holtec, the owner of the Palisades Nuclear Plant in Covert, Michigan, is also currently developing SMRs as well. There are currently 80 different designs from multiple countries being developed for varying niche applications, such as electric power generation, co-generation, district heating, and desalinization.[101]

While SMRs hold promise, including the carbon free nature of the generation and flexibility of facility siting, it is still early in the development of this technology.

Joint Utility Planning

PA 235, Section 4, subsection (a) allows two or more municipally owned electric utilities to jointly file a proposed clean energy plan for the purpose of compliance with the clean energy and renewable energy standards. Allowing for a joint filing facilitates joint planning of resources to the extent that a municipality finds that to be in the interest of its customers. Joint planning may be critical for achieving compliance for smaller utilities because resources are not necessarily perfectly sized for each individual utility's needs for meeting its compliance requirement. Allowing for joint planning may be particularly well suited to the UP given the large number of utilities serving a relatively small customer base, and also because the diversity of generation between utilities may make joint planning efforts mutually advantageous. Joint planning may also allow for increased access to the capital needed to invest in renewable and clean resources as well as energy storage systems. The Legislature should consider expanding the ability for joint clean energy

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[98] European Commission, Small Modular Reactors Explained. https://energy.ec.europa.eu/topics/nuclear-energy/small-modular-reactors/small-modular-reactors-explained_en
[99] International Atomic Energy Agency, What Are Small Modular Reactors (SRMs)? https://www.iaea.org/newscenter/news/what-are-small-modular-reactors-smrs
[100] Id.
[101] Advances in Small Modular Reactor Technology Developments: A Supplement to: IAEA Advanced Reactors Information Systems (ARIS) 2022 edition, p. 2.

planning that is described for municipalities in MCL 460.1051(3) to include all electric providers serving under 100,000 customers. Joint planning for smaller electric providers would allow for joint solutions and combined capital investment to facilitate the ability to more cost-effectively achieve Michigan's clean energy goals and storage targets. More specifically, this would allow for UP-wide solutions to be considered.

Conclusion and Recommendations

The UP can be viewed as a series of discrete load pockets connected by transmission lines generally running lengthwise across the peninsula. Generation is predominantly sited next to the load it serves. The Commission has engaged MISO and ATC to conduct a forthcoming study which will analyze the effects and feasibility of limiting fossil generation in the UP and provide a better picture of what unique conditions are influencing potential generation and transmission solutions for achieving the Renewable Portfolio Standard and Statewide Energy Storage Target.

As the State of Michigan embarks on its path toward net zero economy-wide and state-wide emissions, it is important to take a holistic view, focusing not just on electric generation and not just the Upper Peninsula, but the state as a whole. The UP has already achieved significant decarbonization milestones that the Lower Peninsula has yet to reach. The retirements of Presque Isle Power Plant and Shiras Steam Plant occurred in 2019. The UP retired its coal units more than a decade before the Lower Peninsula, which currently isn't set to fully retire coal until 2032. Because of this, and the extensive amount of hydro generation already present in the UP, between 2013 and 2022, the UP reduced its electric generation CO_2 emissions by approximately 71%. Renewables will continue to be procured by UP utilities to meet renewable energy standards.

The RICE units operated by UMERC and MBLP played critical roles in achieving the substantial decrease in carbon emissions by enabling the retirement of the UP's coal-fired electric generation units, and in UMERC's case, allowing for the lifting of costly system support resource charges imposed by MISO on PIPP and passed through to UP customers.

The existence of UMERC's RICE units is closely tied to Tilden Mine, as it was through the Tilden Mine Special Contract, approved by the MPSC, that these units came to be. As it stands, there is not anticipated to be any great change in Tilden's demand for the foreseeable future.

There remains a need for generation in the UP to support reliability. MPSC Staff has engaged both ATC and MISO to perform a transmission study analyzing the effects and feasibility of limiting fossil generation in the UP with a focus on finding transmission and generation solutions necessary along with the new generation expected due to the renewable energy standard and the UP portion of the Statewide Energy Storage Target. This study is forthcoming and will be provided to the Legislature once it is completed.

There is a plethora of potential options for further reduction of the UP's energy sector carbon emissions, but the UP faces unique challenges to implementation. Demand-side solutions like DR and EWR offer affordable options for avoiding the need to expand a utility's generation capacity but are not standalone solutions. Generation would still need to be built; these solutions simply reduce the size of that need. Renewable generation, like wind and solar, face their own unique challenges in the UP. The geology of the UP often necessitates costly ballasting of solar panels due to the shallow depth of the topsoil not allowing for anchoring, as is done in the Lower Peninsula. There are emerging technologies, like LDES solutions and SMRs, that may one day be viable options for the UP, but right now they are still in the early stages of development and commercialization. There are also potential options for reducing the carbon emissions of the existing RICE units themselves, but they face their own challenges. It is possible to blend hydrogen gas with natural gas to fuel the RICE units and it may be possible in the future to run them entirely on hydrogen. However, there currently is not an economic or practical way to supply the RICE units with sufficient amounts of hydrogen, much less at a competitive cost. Renewable natural gas may also be a potential solution but is currently limited due to supply and lack of statutory consideration as a clean energy source. Carbon capture and sequestration would avoid the need for such alternative fuel sources, but the geology of the UP is unsuited for sequestration within its geology and transportation would add significant cost. Direct air capture, which could achieve functional equivalence to the statutory standards, may represent a compromise solution, as it need not be sited where the carbon is emitted and can thus be placed over suitable geology for sequestration.

Ultimately, the path forward will require a thoughtful approach and care to ensure the integrity of the UP electric system while addressing the need of UP residents for affordable energy and a sustainable future. To that end, the Commission makes the following observations and recommendations:

- The Commission believes it would be helpful to understand whether the UP can accommodate more EWR than what PA 229 requires. To that end, as part of the implementation of the 2023 energy legislation, a potential study that quantifies the economic/technical/achievable potential of EWR in the UP is underway. Results are expected Q3 of 2025.
- Additional clarity concerning the breadth of technologies that can be considered clean energy systems could help electric providers as they seek to determine the most reasonable and prudent path forward. A clear understanding of the types of technologies that can be considered clean energy systems is necessary to develop a clean energy plan, reducing risk and uncertainty for electric providers. Two possible paths to further define clean energy systems are: 1) for the legislature to further define clean energy systems in statute, and/or 2) for the Commission to embark on a rulemaking process to add technologies that qualify as clean energy systems, consistent with statute. Tire-derived fuels, renewable natural gas, and direct air capture technologies are not expressly identified as clean energy technologies in the law. If either the Legislature or Commission rules resulted in the inclusion of biomass with TDF as part of the fuel source, such

a change should include a demonstration that the amount of carbon removed through the biomass lifecycle exceeds the amount of carbon emitted through electric generation.

- Under PA 235, the limitation on distributed generation resources increased from 1% of a utility's average peak load to 10%. This change is likely to increase interest in opportunities to aggregate distributed generation and other distributed energy resources. At the same time, the issuance of Order 2222 by FERC in September 2020 provides a pathway for aggregated distributed energy resources to participate in wholesale energy markets, potentially providing a cost-effective, distributed approach for customer-owned resources to contribute to maintaining reliability and participating in the energy transition in the UP. In its December 21, 2022 order in Case No. U-21099, the Commission partially lifted the prohibition on the ability of aggregated demand response resources from participating in regional power markets as part of the Commission's ongoing efforts to bolster Michigan's energy capacity. However, the actions taken to date only apply to retail commercial and industrial customers with a minimum enrolled load of 1 megawatt, with the Commission noting that "additional work surrounding customer protections is warranted" before allowing participation by residential and smaller commercial customers. The Legislature should work to enact a statutory framework that provides meaningful consumer protections while providing a pathway for aggregated DERs to participate in the regional wholesale electricity markets, consistent with FERC Order 2222.
- The Legislature should consider expanding the concept of "functional equivalence" to include accelerated economy-wide carbon reduction as a carbon reduction option for power generation by including consideration of carbon reduction in another sector. Considerations of "functional equivalence" should apply to more than just power generation, taking a more holistic view accounting for all sources of carbon emissions. The aim of the MI Healthy Climate Plan is economy-wide emissions reduction, and these efforts could help to offset hard-to-abate emissions in the power sector. In the alternative, the Commission could consider whether the rulemaking authority provided for in PA 235 includes an opportunity to build on the concept of "functional equivalence."
- The Legislature should consider expanding the idea of joint clean energy planning that is described for municipalities in MCL 460.1051(3) to include all electric providers serving under 100,000 customers. Joint planning for smaller electric providers would allow for joint solutions and combined capital investment to facilitate the ability to achieve Michigan's clean energy goals and storage targets in a more economical way. More specifically, this would allow for UP-wide solutions to be considered.

Appendices

Appendix A: Acronyms

ATC: American Transmission Company

CCS: Carbon Capture and Sequestration

CHP: Combined Heat and Power

DAC: Direct Air Capture

DR: Demand Response

EGLE OGMD: Department of Environment, Great Lakes, and Energy's Oil, Gas, and Minerals Division

EIA: U.S. Energy Information Administration

EPA: Environmental Protection Agency

EPRI: Electric Power Research Institute

EWR: Energy Waste Reduction

HVDC: High Voltage Direct Current

LDES: Long Duration Energy Storage

MAE: Michigan Agency for Energy

MBLP: Marquette Board of Light and Power

MCL: Michigan Code of Law

MISO: Midcontinent Independent System Operator

MPSC: Michigan Public Service Commission

MWh: Megawatt Hour

NSP: Northern States Power Company

NWUMS NCA: Northern Wisconsin and Upper Michigan Narrowly Constrained Area

O&M: Operation and Maintenance Cost

PIPP: Presque Isle Power Plant

PPA: Power Purchase Agreement

PUSH: Pumped Underground Storage Hydroelectric

RFP: Request for Proposal

RICE: Reciprocating Internal Combustion Engine

RNG: Renewable Natural Gas

SRM: Small Modular Nuclear Reactors

SSR: System Support Resource

TMSC: Tilden Mine Special Contract

UMERC: Upper Michigan Energy Resources Corporation

UP: Upper Peninsula

UPPCO: Upper Peninsula Power Company

USDW: Underground Sources of Drinking Water

WPPI: Wisconsin Public Power Inc.

Appendix B: Comments from UP Residents

Jed Perry, June 30, 2024:

Dear Commissioners Scripps, Peretick, and Carreon: We are writing on behalf of the United Steelworkers (USW) Local 4974 regarding Case. No. U-21572 to express concern about the impacts of Public Act 235 of 2023 on Cleveland-Cliffs Tilden Mine. The United Steelworkers represent approximately 750 employees at Tilden Mine. We are proud to represent the individuals that mine and process iron ore, which serves as a key ingredient for domestic steelmaking, and our role in the state economy. In part, the iron ore we produce at Tilden Mine supplies Cleveland-Cliffs Dearborn Works steel mill in Dearborn, Michigan, which in turn produces steel for the automotive sector, including in Southeast Michigan. Our members have dual interests in this proceeding. First, it is critical to us that the Tilden Mine, which is the last operating iron ore mine in Michigan, remain competitive. The Tilden Mine provides our employees with good paying, middle-class jobs and supports the economy and communities in which we live. Second, as Upper Peninsula residents, we understand the energy challenges and high electric power costs that face our region. We are deeply concerned that Public Act 235 of 2023 failed to recognize the unique energy landscape of the Upper Peninsula. We believe this legislation should have accounted for the $275 million investment that was made in new natural gas generation in Negaunee and Baraga to benefit Tilden Mine and all UP ratepayers and which recently came online in 2019. We are concerned about the cost implications of meeting new clean energy standards so early in the life of these assets. Moreover, the natural gas plants are extremely efficient. They replaced the old coal-fired Presque Isle Power Plant, already achieving tremendous greenhouse gas reductions of 86% per year. We are supportive of efforts to transition towards cleaner energy standards. However, we believe that should be done with a thoughtful approach and with consideration for the impact it will have on workers, employers and our electric bills. We are deeply concerned that Public Act 235 of 2023 failed to adequately consider the circumstances of the Upper Peninsula. As a result, we urge you to highlight the multiple benefits of the natural gas plants in your report and inform a legislative or regulatory solution that will preserve electric reliability and affordability by allowing their continued operation through the remaining useful life of those generating assets. Thank you for your consideration.

Jo Foley, June 31, 2024:

1) I think the urgency of addressing climate change gets lost in the acronyms and details of each law. Should be emphasized at the beginning of every statement of the law, public hearings, conclusions. We should never forget why we are going through all this. 2) The UP is unique in Michigan, [though] some of that uniqueness is shared with Northern Lower Michigan. It is also shared with northern Wisconsin and northern Minnesota which share shorelines with Lake Superior. Cooperation and

collaboration with our watershed partners could decrease duplication and increase innovation suitable to our climate and topography. 3) Working toward energy independence for each small community and isolated homestead would decrease demands on the grid, decrease the need for miles of electric lines and pipelines, and foster jobs of installation and maintenance in each community. Community energy, not big company energy, is what rural areas need. 4) Energy conservation MUST be emphasized. The quickest way to decrease energy use is to weatherize all buildings, make electricity use visible to each consumer, and incentivize using less; not only of energy but of things in general as each requires energy to produce.

Dan Ruokolainen, August 2, 2024:

All, We would like to thank you for holding the open comment here in Marquette Michigan yesterday July 30, 2024, and allowing us the opportunity to give our thoughts on the new energy bills. Also, we appreciate you all taking the time to tour the Tilden mine to get a better understanding of our perspective and concerns. We hope that the tour was information and helpful in your investigational process. Please feel free to reach to us at Local 4950 anytime. You can call me personally on my cell anytime. The number is [REDACTED].

Tonya Swenor, August 2, 2024:

The Superior Watershed Partnership (SWP supports) Public Act 235, which establishes the new clean energy standard and updates the renewable energy standard. The SWP is a Grantee for the Michigan Energy Assistance Program and the MI Impact program and has assisted over 8,000 U.P. households with utility assistance since 2013. We have conducted over 1,400 home energy assessments, 180 weatherizations and 26 residential solar installations to help our U.P. clients reach energy security. In total, 17% of our households receiving utility assistance have received energy waste reduction services. There is still much work to do. The SWP would like the MPSC to take the following factors into consideration when planning for the energy transition in the U.P.: 1. The U.P. needs more affordable, more sustainable electric rates. 2. In order to move families away from public assistance programs we should focus on making homes energy efficient. 3. The U.P. needs a trained workforce with competitive long-term positions, preferably Yoopers and those transitioning from fossil fuels to clean energy jobs. 4. Many homes need health and safety measures completed before weatherization and/or electrification is feasible. 5. Households who work with social service programs develop long-term trust which can be essential for connection to energy waste reduction services.

Anne Childs, August 5, 2024:

Commissioners: I am writing to comment on Edocket # U-21572. I recently drove 2 hours to attend the hearing held at NMU campus in Marquette, and thank you for your presence there. While I did not comment then, I wish to comment now. I am very distressed that Governor Whitmer would remove the local voice by allowing industrial wind turbines and solar arrays to be built without local consent. This is not government by the people. Michigan's Upper Peninsula is a natural treasure which should be protected for future generations. A unique landscape, and the unique lifestyles of those inhabiting it, should be given greater consideration than, say, an enormous tract of open land in Indiana. The installation of industrial turbines and solar arrays will do irreparable harm to our pristine forests, will jeopardize migratory bird flyways (in the case of the Keweenaw Peninsula), will compromise our tourism industry (which brings significant revenues into our area), and will mar the beauty, quietness, and remoteness that have drawn most, if not all, of the residents of this area. In addition, new roads will damage significant areas and the wind turbines, once defunct and rarely dismantled by the companies who installed them, will remain a forever blot on the spectacular natural beauty of this area. My research shows that wind turbines only make sense to investors because of government subsidies. Investors are often foreign or at least not living in the affected areas, and care little about the ultimate impact on local economies or way of life. The cost of creating these turbines to the decommissioning of these massive machines is astronomical, and the amount of resources consumed in manufacturing them is also rarely considered. I urge you to look beyond the rhetoric and say "no" to industrial wind turbines and solar arrays in Michigan's one-of-a-kind Upper Peninsula. Thank you.

John Childs, August 5, 2024:

Michigan Public Service Commission Case # U21572 I was an attendee at the public meeting in Marquette and voiced some concerns there. I now follow that up with a written response to the topic of the renewable energy developments after the Michigan ruling on land use surfaced. We had spent, over the time of many months throughout 2021-2023, much effort to counter the development of huge wind farms in the U.P. and specifically Houghton and Keweenaw counties. The same had been done earlier in Baraga county. Please give due diligence to the material from those encounters. As residents we do not want to see the damaging visual effects of wind farms nor the social conflicts that arise. Consider the National Park Service written research on “viewscapes” and the example of social conflict that enfolded the Garden Peninsula when turbines were erected there. This is in addition to the pseudo economics that inspires a guy like Warren Buffet to comment that investment wouldn’t even be feasible without government subsidies. --Sounds like public taxes and government (also public) debt going into investor pockets. There is much more rational to oppose the program. Please listen to the variety of approaches. Have the power companies even been challenged to foot the complete bill for wind turbines? Would they, if it is such a profitable enterprise? The whole country is full of this dynamic. The whole scenario develops when higher up game planners create “laws” that press for extreme environmental regulations and then people like you all are forced to push them on the public. These regulations whether it be energy, agricultural, land use, etc. (to say nothing of the now debunked recent medical mandates) ultimately function to fence in the people and herd them like cattle. Let’s make Michigan into a truly progressive community not an oppressive one. Retain local control over localities. Thank you for your considerations.

Janet Curtis, August 5, 2024:

I am concerned about the thought of putting wind turbines in the UP. I believe that it would hurt our economy here in the Keweenaw which depends on tourism. It's our natural beauty here that others come to enjoy and in return help our economy. They only last so long and then where can they be disposed? The current energy here serves our needs and is dependable. Rarely are we without heat and electricity especially during the cold weather. If it's not windy then we'd not have power.

Sandy Karnowski, August 6, 2024:

In the Matter, on the Commission’s Own Motion, to Report on the Unique Conditions Influencing Electric Generation, Transmission, and Demand in Michigan’s Upper Peninsula, to Fully Comply with Public Act 235 of 2023, MPSC Case No. U-21572

- Good evening, Commissioners and Commission staff.
- My name is Ryan Korpela and I serve as General Manager of Cleveland-Cliffs’ Tilden Mine here in Marquette County.
- Cleveland-Cliffs (Cliffs) has been mining in the Upper Peninsula continuously since the founding of our company in 1847. Today, Tilden Mine, together with our LS&I short line railroad, Marquette ore dock and Cliffs’ Technical Group research lab in Ishpeming, employ more than 1000 individuals.
- The workforce at Tilden is represented by the United Steelworkers Local 4974 and USW Local 4950.
- We all look forward to hosting the Commission and staff at Tilden for a tour tomorrow.
- During your tour, I urge you to note the importance of energy to Cleveland-Cliffs’ production of environmentally friendly iron ore pellets. Energy represents approximately 25% of our cost structure.
- Tilden’s peak electricity demand is 180 MW. A majority of that demand is derived from the Tilden pellet plant that employs huge electric motors to grind, concentrate and pelletize iron ore.
- Tilden consumes 1.1 million MWh of electricity each year, or the equivalent needed to power 100,000 homes.

- Beginning in 2013, the Upper Peninsula found itself in an electric power crisis arising from plans to retire the Presque Isle Power Plant (PIPP) in Marquette. Following that announcement, MISO mandated that PIPP must continue operating for reliability purposes and imposed an SSR that cost UP energy customers $6 million per month.
- In the face of this crisis, Cleveland-Cliffs worked in close alignment with the State of Michigan, Wisconsin Electric, the MPSC and other UP stakeholders, arriving at an innovative solution to allow for the retirement of the oversized, coal-fired PIPP, the establishment of clean, right-sized generation in the UP and the termination of the costly SSR. This innovative solution also led to the establishment of UMERC – a Michigan-only jurisdictional utility that put an end to years of cost allocation disputes between the UP and Wisconsin.
- As part of this solution, Tilden Mine entered into a 20-year special contract with UMERC that supported construction of two, natural gas RICE generating facilities in Negaunee and Baraga.
- These new generating plants, brought online in 2019, resolved reliability issues plaguing the UP and enabled the retirement of PIPP, leading to a remarkable 86% estimated reduction in Greenhouse Gas emissions.
- As part of this ongoing study, we urge the Commission to recognize the reality in the UP: that UMERC's RICE units were the perfect solution to a difficult problem; that ratepayers (including Cliffs) have already borne the cost of the new generating assets; and that the GHG-efficient RICE plants are and will remain critical to the reliability and affordability of electric power in the UP.
- Finally, we urge the Commission to recommend a legislative and/or regulatory solution that will allow these RICE units to operate through the remaining useful life of the plants without requiring a costly and duplicative buildout of new generation or the procurement of renewable energy credits.
- We look forward to working with other UP stakeholders, the State of Michigan and the MPSC to ensure that the Michigan's Clean Energy Act achieves its objectives without producing unintended consequences for Tilden and the 1000+ families that rely on our mine for good paying, middle class union jobs.
- Thank you for allowing me to testify. I look forward to answering your questions.

Maddie Manderfield, August 6, 2024:

- Lots of very good points, John. Thank you for taking the time to write them. I hope and pray we make a difference and win this.

Laura Skrumbellos, August 6, 2024:

- I attended the public hearing in Marquette. I heard a lot of college students voice their concerns, mostly about green energy. Most college students don't pay utilities, don't own homes, don't work, want to play and party, and are not responsible for our earth and the knowledge other than what they are brainwashed with in college. They don't know what it is like to feed hungry children, and to protect them from the cold and the dark. The Upper Peninsula is already at their percentage for green, so these endeavors need to go back to southern lower Michigan where they are behind in their quotas for green energy. We have a beautiful and rare place in the UP, and to darken it with wind towers and solar panels is a grave mistake. Tourists come for our unique beauty, not for unsightly industrial projects. Put money back into hydro, and nuclear if anything. The youth don't want clean air as they are huffing and vaping, and screaming clean air. What are they doing in their parent paid homes to obtain clean air? Are they putting solar on their rooftops, wind in their backyards? No, they want government handouts and only see the tourist attractions that do not show the unsightliness and destruction of our beautiful UP. I fought to keep the Groveland Mine Solar project off state land. State land is our land, not the DNR, not the Governor, it is we the people's land. You deem things "brownfields" and then think you can clutter that land up with wind and solar. Keep it off state land. If it is a brownfield, then so be it. It can stay that way. Who is protecting our wildlife, the wolves, the bears, the cougars (that we "don't have", the beavers, the migratory birds, the bats, the salamanders, the endangered species, from encroaching on their homes in these so-called brownfields? You? The Governor? The DNR? Just because college students come to your forums after being coached, and get credit for, does not mean they are the VOICE of the people! You know who is? The ones who worked hard their whole lives to be able to sit back and enjoy the beauty and creation that was God given to enjoy, to protect for their children, and their grandchildren, and for future generations. Which also included these snotty nosed brats who think they know everything and want to change the world instead of protecting it. Take away their cell phones and see how dysfunctional they become. Please keep the UP unblemished and pristine, do not come and take away the very reason we all live here.

Laura Ferris, August 6, 2024:

Thank you for allowing public comments regarding wind turbines. In the first place I don't think the governor should be making decisions to place wind turbines in the U.P. when the people have already said no. In the second place, the U.P. depends a lot on tourism: people coming here to enjoy the out of doors and majestic scenery we have. The atmosphere would be radically changed to have wind turbines dotting the landscape. Also the environment impact of clearing trees, making roads, the impact of migratory birds, and our already faltering bat population, would take a huge toll. Let the U.P. have the chance to vote on the wind turbine issue.

Rene Skrumbellos, August 7, 2024:

[I] attended the public hearing in Marquette, Michigan and I just want to say first off that the board did a fantastic job in a very professional manner. With that being said, a lot of the people who stepped up to the podium talked about clean energy and green energy. How many board members, or the people for the green energy in the Upper Peninsula drive electric vehicles if they are so concerned with clean air? My guess would be none. If you listen to the media or these college students that spoke at the meeting, you would think that the Upper Peninsula is under blackout all of the time, which is not true, except during winter storms and high winds that take trees down over power lines that are not kept cleared. This power that would be created by solar and wind would likely not stay in the Upper Peninsula. These industrial solar and wind projects are too large in size, they need to be toned down and not take up a large footprint. It seems like somebody has stock in solar panels that usually amount to 85% produced in China or a China based company. This is money laundering at its best. Instead of making industrial solar "farms", give incentives to homeowners and business to put it on their roofs. We are at our quota in the Upper Peninsula for green energy. There is no need to put any solar or wind in the Upper Peninsula. Thank you for your time.

Michael Furmanski, August 8, 2024:

I believe that the RICE generators located in the UP are vital to keeping the lights on and everyone involved in this process should be doing everything they possibly can to keep them operational. Additionally, they are great partners for renewable generation due to their fast ramp rate.

Jim Ferris, August 8, 2024:

I am opposed to giving all the decision making power to a small number of people in Lansing when it comes to siting wind and solar generating facilities in the UP. I acknowledge that the state has an interest in sustainable power systems but local people understand the local issues and impacts much better than folks in Lansing. We need to have an equal voice in these decisions.

Chris Swartz, August 8, 2024:

Boozhoo Aaniin, members of the Michigan Public Service Commission, My name is Chris Swartz, and I am writing on behalf of the KBIC NRC who hold treaty rights in what is now known as the state of Michigan. As we discuss these new laws which are proposed to make changes to requirements related to Integrated Resource Plans, establish a clean energy standard, increase the Renewable Energy and Energy Waste Reduction standards, and create a voluntary siting process at the Commission for renewable energy and energy storage projects of statewide significance, it is crucial that we consider the profound impacts these public acts will have on our treaty-protected resources within the ceded territories reserved for Lake Superior bands of Chippewa Indians. Treaty Impact Assessment First and foremost, I urge the Commission to conduct a thorough Treaty Impact Assessment. This assessment should be comprehensive, encompassing the potential impacts on wildlife, air, water, and the ecosystems within our ceded territories. Our treaties are not just historical documents; they are living agreements that guarantee our rights to hunt, fish, and gather on these lands. Any mining project, large-scale utility project, whether it be sulfide or nickel, wind or solar, must be evaluated for its potential to negatively impact these treaty protected rights. Environmental and Cultural Considerations The environmental impacts of these projects cannot be understated. Wind turbines, Nickel mines and solar farms, can have significant adverse effects on ecosystems, local wildlife, including migratory birds, fish and deer populations. These species are not only vital to the ecological balance but are also integral to our cultural and subsistence practices. A comprehensive Treaty Impact Statement will help us understand and mitigate these impacts, ensuring that our treaty-protected resources are preserved for future generations. Co-Management Authority Furthermore, I request the establishment of a co-management authority. This would allow for the adaptation of strategies to monitor and respond to the impacts on treaty resources throughout the ceded territories. By involving Native American tribes in the management and decision-making processes, we can ensure that our traditional ecological knowledge is integrated into the planning and operation of these projects. This collaborative approach will not only protect our treaty rights but also enhance the sustainability and effectiveness of renewable energy initiatives. Support from KBIC Natural Resources Department The Keweenaw Bay Indian Community (KBIC) Natural Resources Department (NRD) has extensive experience in managing and protecting natural resources within the L'Anse, Marquette, and Ontonagon reservations, as well as the western Upper Peninsula of Michigan. The NRD administers programs that include fishery assessments, stream assessments, surface and groundwater monitoring, wildlife and wetland management, and environmental assessments. These programs are guided by a 10-year Integrated Resource Management Plan and the KBIC Strategic Plan. The NRD's work in monitoring metallic mining and exploration activities, as well as their participation in the protection and enhancement of Lake Superior, demonstrates their commitment to preserving the environment and ensuring the health of local ecosystems. Their expertise and resources can be invaluable in conducting thorough Treaty Impact Assessments and implementing co-management strategies. Executive Order 13175 Additionally, I would like to highlight Executive Order 13175, which requires agencies to engage in regular and meaningful consultation with tribes when developing policies that have tribal implications. This order underscores the importance of respecting tribal sovereignty and ensuring that Native American tribes are consulted prior to enacting public acts that may affect their treaty protected rights and resources. The Keweenaw Bay Indian Community expects such consultation to occur when acting with delegated authority from EPA ensuring that our voices are heard and our treaty rights are protected. Conclusion In conclusion, as we move towards a cleaner and more sustainable energy future, it is imperative that we do so in a manner that respects and upholds the treaty rights of Native American communities. By conducting a thorough Treaty Impact Assessment and establishing a co-management authority, we can work together to protect our environment, our culture, and our way of life. We are advocating for responsible and sustainable practices because we have seen firsthand how mining can threaten vital water resources, fish (giigoon), deer (waawaaskashii), and wild rice (manoomin), which are essential to our cultural and environmental heritage. Protecting our water and natural resources ensures that future generations can enjoy a healthy environment. Transitioning to a green economy should not come at the expense of further environmental harm. Instead, we should explore sustainable alternatives that balance economic growth with environmental stewardship and a recognition of tribal inherent sovereignty.

Katherine Moore, August 9, 2024:

Attached, please find the full comments of the Geothermal Exchange Organization.

https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs000003nFQtAAM

Roger Line, August 9, 2024:

https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs000003nxJIAAI

Richard Stasik, August 9, 2024:

https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs000003rO5nAAE

Catherine Andrews, August 12, 2024:

August 9, 2024 Dear Commissioners, Thank you for your recent visit to Marquette for the July 30th Public Hearing regarding the energy legislation that passed last November. I am opposed to any plans to modify or replace the RICE facility in Pelkie. It is working well and when something is working, it doesn't need to be "fixed." I am also opposed to shutting down the L'Anse Warden Electric Company. I and many others in the community worked diligently to get LWEC cleaned up. The EPA became involved when the DEQ failed to protect local residents, and many improvements were implemented to remedy the complaints. I trust the current manager to continue to maintain the safety and integrity of the plant well into the future. As a former L'Anse Township Planning Commission member, and former democrat, I strongly oppose the State takeover of Township siting authority on Industrial Wind, Solar and Battery Storage facility projects. I worked to help collect 987 signatures in Baraga County to get a proposal on the November ballot to rescind this legislation. As you know, our petition drive fell short. However, you need to know that many democrat voters who signed the petition assumed the legislation was written by Republicans. It was incredulous to those on the left that any democrat would be so brazen as to take away our rights to make important decisions on the local level. This is the most tyrannical legislation to be passed in Michigan that I know of. As a result, I and many others, have joined the effort to unseat Jenn Hill as our Representative. As for the meeting in Marquette, I'm sure you saw through the ruse of the coordinated effort by an employee of Circle Power and a couple of others to fill the Public Hearing with college students who are not "Yoopers." It seems plausible that they may have gotten "extra credit" for commenting from the same playbook. It's clear that Renewable Energy is not renewable when one takes into consideration the cost of the necessary complete overhaul of our nation's grid system, the environmental and human cost of extracting critical minerals in countries with oppressive human rights records, the transportation costs of shipping these minerals halfway around the world, and the huge footprint these projects have on the landscape during their brief life cycle. All this expense for an unreliable, intermittent energy source that is destined to destroy the earth to "save" the climate. And to make matters even worse, public-private stakeholders are supporting drastic new electricity demands for EVs and data mining often based upon "emerging" technologies that don't even exist. This makes no sense and JD Vance articulates it better than anyone else. Please proceed with caution.

Kathleen J. Peterson, August 12, 2024:

Dear Sir/M'am, I am writing to share my thoughts re this issue... The U.P. is a beautiful place in the state of MI...it's a pristine area, the jewel of MI actually, that people flock to from downstate MI, Chicago, WI, MN and many other places. I so desire it to STAY the way it is...and it is worth so much to the people who live here to keep that as tourism is such a huge part of our livelihood. Every piece of land should not be messed up by these kind of projects. So because of that we in the Upper Peninsula do not want wind turbines OR acres of solar panels cluttering up our beautiful landscape. Over-all, we believe that all this 'green energy' thinking is wrong to begin with. There are just as many scientific truths against all the climate change issues as there are for them. So, let's not jump into all this without considering all the high cost of proceeding. We don't get enough sunshine in the UP to even have solar panels. We have some on our house and regret getting them as they are not producing as we were told they would. There are also so many issues with wind turbines: the lights that bother people who live by them, what you do when they the blades break down or fall off (a big issue of waste and environmental concern), damage to birds, AND they need fossil fuel to even run the motors that help them turn, plus just the ugliness of them and no one can deny that putting them all over a landscape pretty much destroys the natural beauty of those surroundings. We've even heard that in Marquette, the solar panels used by the power company there don't do much in winter as they are covered with snow and it costs more to remove the snow than the electricity they could make at that time. We would just like people to use some common sense here...people in government who represent 'we the people'...as long as planet earth has existed, there have been cyclical changes in climate and who does man think he is, that he can literally change that. Anything that would be done would be minuscule in the big picture... The financial cost of all these projects to 'we the people' is enormous...with NO guarantee that it will all have been worthwhile in the end. I am not totally against making wise decisions/choices as technology improves...but it really needs to be thought through very clearly and all factors be considered. I'm not against electrical cars, altho I believe a hybrid is way better. BUT I do object to mandates...as a citizens we are guaranteed free choices by our United States and MI constitutions. It's time we get back to that perspective. And in the end, I am totally against these type of decisions being made by a group of UN-elected appointees and taking away our local control!!!!! Thank you for letting me share my point of view...and listening.

Bruce Peterson, August 12, 2024:

Dear Ma'am/Sir, I am quite involved in studying the rights of the people under the United States Constitution, and it does not give the government the right to take the people's land for any reason. Isn't that socialism and communism. In fact, we have an elder neighbor from China, and she tells us nobody over there owns any land; the government owns it all. Most people live in the country, and as I understand it, they are allowed to keep a portion of what they make. But how can they get ahead? it's like they're renting from the government. That is NOT how America was established. Even the PREAMBLE to the Michigan Constitution states, "We, the people of the State of Michigan, grateful to Almighty God FOR THE BLESSINGS OF FREEDOM, and earnestly desiring to secure these blessings UNDIMINISHED to ourselves and our posterity, do ordain and establish this constitution." Both the US and the Michigan Constitutions begin, "We the people." So the government should honor the intent of these documents. I'm passing this letter on to some of my fellow American Patriots here in the UP.

Appendix C: Cleveland-Cliffs Responses to MPSC Staff Questions

Responses to MPSC Staff Questions Letter Dated February 23, 2024 to

Ryan M. Korpela, P.E., General Manager Cleveland-Cliffs, Inc. Michigan Operations

Information regarding the role of the Tilden Mine special contract in facilitating the development of the RICE facilities and information regarding any stipulations of the special contract that would affect potential changes in the operation of those facilities;

a. Role of the Tilden special contract in facilitating the development of the RICE units

- On January 30, 2017, UMERC filed for approval in MPSC Case No. U-18224 of: 1) a certificate of necessity ("CON") to construct the RICE units; 2) certificates of public convenience and necessity ("CPCNs") to construct, own and operate the RICE units; and
  3) approval of a special contract dated August 12, 2016 for electric service to the Tilden Mine ("Tilden special contract"). Approval for construction of the RICE units and the Tilden special contract were submitted as a single-package.
- Construction of the RICE units: 1) saved UMERC ratepayers money over a 30-year period as compared to business-as-usual; 2) allowed for the retirement of the costly and aging coal-fired Presque Isle Power Plant ("PIPP") with new clean generation in the UP; 3) avoided $373 million in transmission upgrades that would otherwise have been needed to retire PIPP; 4) enhanced electric reliability in the UP by constructing the RICE units in two different locations; and 5) avoided future system support resource ("SSR") costs in the UP.
- The right-sized RICE units modular design permits capacity adjustments to align with the needs of the UP.
- The construction of the RICE units fulfilled the objective of the Amended and Restated Settlement Agreement approved by the MPSC in Case No. U-17682, which resulted in the creation of UMERC; UMERC was formed to facilitate a long-term generation solution for the UP. The new Michigan-only utility avoided relying on a Wisconsin- based utility for electric power used to serve the UP and avoided multi-state jurisdictional cost allocation issues.
- The Tilden special contract was a critical requirement for the construction of the RICE units, which provided a long-term solution to the UP's energy needs.
- Under the Tilden special contract, Tilden committed to paying: 1) 50% of the RICE units capital costs applicable to Tilden's non-firm planning load level; 2)

100% of the actual RICE units O&M costs; 3) a specified amount of A&G expenses of the RICE units; 4) 100% of the distribution costs for service to Tilden; 5) 100% of the natural gas costs to fuel the RICE units; and 6) a pass-through of ATC, MISO, energy and other charges and credits.

- UMERC testified that the UP generation solution could not be achieved without the Tilden special contract and that Tilden is a critical stakeholder in any long-term UP energy solution.

a. Stipulation of the special contract that would affect potential changes in the operation of those facilities

- The Tilden special contract specifies that UMERC will provide service using RICE electric generation facilities. Section 2.2.1
- The definitions of "Generation Resource" and "Generation Resources" expressly prohibit purchases of Capacity and/or Energy from any sources other than the RICE units, unless agreed to
- UMERC is obligated to provide Tilden with the expected availability of the RICE units prior to the MISO Day Ahead Market close and to notify Tilden of any changes. Sections 2.4.2 and 2.4.3
- UMERC is obligated to offer the full capability and flexibility of the RICE units in the MISO Day-Ahead Market at UMERC's cost of operation consistent with MISO's Tariff and Good Utility Practice. Section 2.4.3.1
- UMERC must also use its discretion to offer the RICE units into MISO's Real-Time Market consistent with MISO's Tariff and Good Utility Practice. Section 2.4.3.1.2
- Pricing under the Tilden special contract is tied specifically to the operation of the RICE units. Section 2.1
- The term of the Tilden special contract runs for 20 years to March 31, 2039. Section 2.0.4

Changes in electric demand, including changes from mining-related economic development projects, that may influence the utilization of the RICE units;

- No anticipated significant electric load changes during the term of the Tilden special contract

Information related to the curtailment provisions in the special contract or UMERC tariff;

- The Tilden special contract is a "Retail Large Curtailable Special Contract"
- Curtailment provisions are contained within Section 2.3 Capacity of the Special Contract and Section 2.6 Buyer's Curtailment Obligations
- The Special Contract is a 100% curtailable contract that can be adjusted by Tilden upon 2 years' prior written notice of the beginning of a MISO Planning

Year, subject to certain conditions Section 2.3.4.2

- [redacted]
- Tilden is subject to curtailment requirements as instructed by MISO, ATC or other reliability authority "under non-emergency conditions related to transmission outages or other bulk system conditions." Section 2.6.3. Economic curtailments are not permitted.

Information about Cleveland-Cliffs' current greenhouse gas emission reduction goals and how these goals and the actions Cleveland-Cliffs has taken to date involving industrial carbonization might inform strategies to be included in the UP Study involving the application of the clean energy standards within the UP energy context; and Cleveland-Cliffs sustainability goals

  - Cleveland-Cliffs set a target to reduce its Scope 1 (direct) and Scope 2 (indirect) greenhouse gas emissions by 25 percent by 2030 on an absolute basis (metric tons per year) compared to 2017 baseline levels. The Company achieved its goal ahead of schedule.
  - Furthermore, Cleveland-Cliffs continued a downward trend of Scope 1 and 2 GHG emissions intensity per ton of crude steel. Cleveland-Cliffs' BF-BOF average emissions intensity was reduced to 1.54 metric tons CO2e per metric ton of crude steel produced (from 1.60 in 2022), a number 28% lower than the 2023 global average of 2.15.
  - Cliffs also maintains a goal to reduce Company-wide energy intensity 10% over 10 years.
  - Cleveland-Cliffs has a target to purchase 2 million MWh of renewable energy annually that is newly developed or additional to the grid

- Projects at Tilden that supported achieving these goals include enabling construction of the RICE units to replace PIPP and reduce Scope 2 emissions, as well as transitioning from use of coal to natural gas at Tilden indurating furnaces that creates cleaner steelmaking feedstock.

- Do not anticipate major electrification projects at this time that would contribute to the UP energy context.

Information about demand response and energy waste reduction (EWR) as it impacts the overall load and demand of the Upper Peninsula.

- Tilden does and will continue to participate in the EWR program, over the last five years Tilden has completed 30 projects that have saved over 18 million kwhs.
- Tilden is a curtailable customer under the Special Contract and a Load Modifying Resource with MISO and does not envision adding additional demand response load in the future.

Appendix D: Escanaba Responses to MPSC Staff Questions

1. What percentage of Escanaba total energy need on a MWh basis is currently met with renewable resource generation? At a high level, how is Escanaba planning to reach the 50% RPS in 2030 and 60% RPS in 2035? What options is Escanaba actively pursuing?

> Historically, Escanaba's existing solar facility provides approximately 1.5% of its total energy, which generates approximately 2000 REC's per year. Based on current loads, it is estimated that Escanaba's 50% RPS requirement will be 65,000 REC's per year and the 60% requirement will be 78,000 REC's per year. Our current Power Purchase Agreement with NextEra does not include renewable energy. At this time, Escanaba is planning to purchase REC's from other utilities to meet the RPS requirements. Escanaba plans to install an additional 2 MW of solar in the next few years, which is estimated to generate an additional 3000 REC's per year. Escanaba will also explore options to buy into future renewable generation projects with other electric utilities.

2. Does Escanaba have any high-level plan for reaching the 80% clean energy standard in 2035 and 100% clean energy standard in 2040? Are there options that the Company is actively pursuing?

> Escanaba's high-level plan is to pursue new Power Purchase Agreements to purchase clean energy to meet the 80% and 100% requirements. Escanaba will also look at options to buy into existing or future clean energy projects.

3. Please describe the current percentage of sales savings that Escanaba achieves through its EWR programs. Does it administer its own programs or rely on a third party to administer programs? What plans does Escanaba have for future compliance and does Escanaba envision increasing the EWR achievement in future years?

> Escanaba currently administers its own EWR program. The calculated 2023 annual savings were 175,772kWh, which is 0.13% of total sales. Escanaba plans to contract with a third party to administer its EWR program to meet compliance requirements for the 2026 calendar year and beyond.

4. How much demand response does Escanaba have in its UP portfolio? In the last 5 years, how many times was the demand response called on to reduce load? How many MWs of load reduction did the demand response resource provide?

> I'm not aware that Escanaba has demand response requirements. We have not had to reduce load for any events in the past 5 years. I understand that UPPCO is the Local Balancing Authority for our area, and they have enough interruptible customers to handle required capacity load shedding events in our area.

5. What are any current restrictions on the interruptible programs? Are there ways in which Escanaba could increase its interruptible programs? What are the limitations to program expansion?

Escanaba does not have an interruptible program. Escanaba does have automatic Underfrequency Loadshedding requirements through ATC and MISO. Escanaba is required to automatically shed 8.3MW or 33% of its load in the case of an underfrequency event.

6. What concerns does Escanaba have regarding resource adequacy should the UMERC and MBLP RICE units be forced to retire or be curtailed?

If the UMERC and MBLP RICE units are retired or curtailed, Escanaba's concern is the overall grid stability for Delta County and the rest of the Upper Peninsula. We purchase nearly 100% of our power from the grid. If generators are removed from the Upper Peninsula, this could potentially lead to grid instability, which could affect all utilities in the Upper Peninsula.

7. Explain any concerns Escanaba has with how the renewable energy standard of clean energy standard will impact customers or UP resource adequacy.

Escanaba's biggest concern is the price we'll have to pay for both Renewable Energy Certificates and for Clean Energy. Escanaba's average annual household income is low. We take pride in our historically low electric rates, which is significant for our low income customers. It is currently unknown how high the cost of REC's will climb and what the cost of clean energy will be. We feel it is very important to allow out of state nuclear power to meet Michigan's Clean Energy requirements.

8. Are there specific UP transmission upgrades that Escanaba would support?

Escanaba is in favor of additional or upgraded transmission lines to supply power to the Upper Peninsula.

9. Does Escanaba have plans to acquire additional generation currently?

Escanaba plans to install 2MW of additional solar generation, which will generate a small portion of its usage and REC's. Other than that, Escanaba has no plans to build generation. We may consider buying into a third-party clean energy generator if the opportunity arises.

10. At a high level, please describe any contracts for capacity or energy, approximately how many ZRCs, etc? When does the contract expire?

Escanaba has a contract with NextEra for energy through 2033 and capacity through 2030. Escanaba's contracted ZRC's are as follows:

• 2024/25 – 25 ZRC's

• 2025/26 – 24 ZRC's

• 2026 through 2030 – 23 ZRC's

11. What load growth has Escanaba seen in the last 10 years? Does Escanaba expect significant load changes in the next 10 years? 20 years?

> Escanaba's load has been declining approximately 1% per year on average for the past 10 years. We've been seeing increased construction in the area this year and planned construction projects in the next few years, all of which is encouraging. Escanaba is expecting a flat or slightly declining load curve for the next 10 to 20 years.

12. Has Escanaba applied for grants for solar generation? Has Escanaba been successfully?

> Escanaba has applied for a Michigan Public Service Commission Renewable Energy and Electrification Infrastructure Enhancement and Development (RE-EIED) Grant to install a solar facility on a brownfield site. Grants will be awarded in the 4th quarter 2024.

13. Does Escanaba have any information that they could share with the MPSC Staff regarding the geological conditions or hurdles regarding the possibility of carbon capture and sequestration in the UP?

> Escanaba has no generation that will require carbon capture or sequestration. We are not familiar with carbon capture technology, so we have no information to provide.

Appendix E: MBLP Responses to MPSC Staff Questions

Questions for Marquette Board of Light and Power

1. What role does MBLP's RICE unit play in its generation portfolio? What is its value to MBLP?

   The Marquette Energy Center (MEC) is the primary piece of our generation portfolio. It is incredibly important to us as it allows us the flexibility to keep our system reliable and our rates competitive. Because of where we are located and our climate, we do not have the same accessibility to the power markets that others across Michigan have. With limited transmission access, limited natural gas capacity, and limited viability of renewable resources we cannot plan for and execute a power supply portfolio in the same way as a utility that is in the lower peninsula of Michigan can. Because of this we rely immensely on the MEC and its unique operating characteristics to give us clean, reliable, and affordable power for our 17,000 customers.

2. Please describe MBLP's recent resource transition and explain the reason MBLP acquired the RICE unit.

   Prior to the installation of the MEC our main resource was the Shiras Steam Plant. The plant was first built in the early 1960's with additional units added to it in the 1970's and early 1980's. The Shiras Plant contained 3 coal fired boilers of which only 1 was still in use as the plant reached its end of life. Prior to closing the Shiras plant supplied over 90% of the power needed for our customers for 50 years.

   Due to the age and operating characteristics of the Shiras Plant it was becoming less reliable and less economic to run. In 2013 we started studying what our next steps should be to maintain a robust power supply with the least impact to our customer base. This study looked wholistically at our needs and all the possible ways we could meet them. The study considered developing new resources (wind, solar, hydro, coal, natural gas, etc.) and purchasing from the energy markets using bilateral agreements with other parties.

   At the time of the study the American Transmission Company (ATC) did not have enough capacity on the transmission system to provide us with Firm service. Being a curtailable load was not acceptable from a reliability perspective so we chose to install a generation resource behind our meter that we could control. The Natural Gas RECIP engines were chosen due to

their efficiency, flexible operating characteristics, multiple generators that operate independently, and the ability to utilize both natural gas and fuel oil as fuel. This combination of attributes was able to give us the level of reliability, affordability, and clean operations that we desired.

Currently we dispatch the RECIP engines into the MISO market economically. Because the machines can start and stop in 5 minutes, we are able to utilize them in a way that shapes our generation to match the economics of the market on an hourly basis. Operating this way has saved our customers millions of dollars since the MEC began operations. Reliability has also been improved as having dual fuel generators behind our meter has kept us from curtailing customer load when the ATC transmission system is not able to supply our needs.

The change in operations from the Shiras Plant to the MEC is also much more environmentally friendly Our emissions output has drastically decreased with Sulfur Dioxide emissions down over 99%, Nitrogen Oxide is down 93%, Carbon Monoxide is down 96%, Carbon Dioxide is down 75% and we are no longer disposing of 17,000 tons of ash in a landfill.

3. Please provide the following characteristics of MBLP's portfolio of resources:
   a. Name of each Unit
   b. Commercial Operation Date
   c. Siting locations
   d. Nameplate capacity
   e. Capacity factor †
   f. Average annual energy production by facility †
   g. MISO seasonal accreditation by facility †
   h. Expected retirement or relicense of each facility †
   i. Total cost†
   j. Planned retirement date prior to passage of PA 235 of 2023

   † Not made public for confidentiality concerns

A	B	C	D	J
Marquette Energy Center	2017	City of Marquette	51 MW	Beyond 2050
Tourist Park Hydro	1920's	City of Marquette	0.75 MW	no plans to retire
Forestville Hydro	1920's	City of Marquette	3.6 MW	no plans to retire
Combustion Turbine	1978	City of Marquette	25 MW	no plans to retire

**** Combustion Turbine is not regularly dispatched**

- **We also have a small community solar garden (155 KW). I did not include this in the table above as it is not large enough to materially affect our system.**

4. Please explain how MBLP is paying for its RICE unit investment. Is it doing so through a bond? When does MBLP expect the RICE unit to be fully paid for?

   The project was paid for with a bond. Anticipated to be fully paid off in 2036

5. Please describe the potential impact to MBLP and its customers should the RICE unit be operationally constrained.

   We are concerned that both reliability and affordability will be impacted if the MEC is operationally constrained.

   Current renewable projects are much more costly than operating the MEC. Transitioning away from how we currently operate will increase our costs substantially. This will also leave us with a stranded investment. The facility was intended to be operational for 40 years or more. To stop using it less than halfway through its useful life would keep us from reaping the economic benefits of owning and operating the plant for its intended lifespan.

   The MEC was constructed in large part because of the reliability it provides. Restricting its operations could have a significant impact on our ability to ensure that reliability. Renewable resources and batteries have not yet developed to a point that they can replace a dispatchable generating facility like the MEC.

6. Does MBLP have plans to acquire additional generation at this time?

- **No**

7. Has MBLP considered the possibility of any type of carbon reduction or carbon elimination technology for its RICE unit's emissions?

   This technology does not exist in a commercially available form. Even if it were available Upper Michigan most likely lacks the proper geology to sequester the carbon in the ground.

8. What would the impact be should MBLP's RICE unit retire prior to its intended retirement date? Are there suitable renewable alternatives to replace the fossil generation? What would the impact be to customers in MBLP's service territory, or the broader UP to the extent that the MBLP generation provides some reliability to the UP beyond the City of Marquette?

- **There are not suitable renewable alternatives to replace the MEC generation. Costs will go up and reliability could go down (see #5 above)**

9. How much demand response does MBLP have in its portfolio? In the last 5 years, how many times was the demand response used? How many MWs of load reduction did the demand response resource provide.

- **We currently do not have any demand response. We intentionally built out our resources in a way that provides enough capacity to supply all our needs along with a reserve margin. This ensures the highest level of reliability for our customers with no concerns that they may have an interruption in service.**

10. Does MBLP think that there is potential for more customer participation in demand response? What is the technical maximum that MBLP could possibly increase its DR portfolio to without compromising reliability for its customers?

- **n/a**

11. Please describe how MBLP complies with its state assigned EWR targets.

We met the prior targets by working with a 3rd party EWR service provider. We will likely take a similar approach in the future. Our plan has not been completely developed yet.

12. How much load growth has MBLP experienced in the past 10 years? Does it expect significant load growth changes in the next 10 years?

- **Our load has not grown in the last 10 years. We are expecting an increase over the next 10 years. How much of an increase will depend on the end use customers behavior, namely adoption of electric vehicles and electrification of the home (heating, appliances).**

13. Do critical facilities within the City of Marquette have back-up generation?

Yes

Appendix F: UMERC Responses to MPSC Staff Questions

Questions Asked by MPSC Staff to UMERC regarding RICE units, DR, and EWR

1. When did UMERC make the decision to retire Presque Isle Power Plant? What was the reason?

   Response:

   WEC Energy Group ("WEC"), via Wisconsin Electric Power Company ("Wisconsin Electric")[1] originally moved to retire PIPP when the Tilden Mine (Cliffs) shifted to an alternative energy provider in 2013. This meant there was not sufficient load to justify the operating costs of the Presque Isle Power Plant and at that time Wisconsin Electric announced the retirement of the Presque Isle Power Plant (PIPP). At that time MISO designated PIPP as a System Support Resource, which resulted in a dispute pertaining to how those costs would be allocated between Michigan and Wisconsin customers (within MISO Zone 2).

   By the time of WEC's acquisition of Integrys, Cliffs agreed to return as a customer as part of the multi-party agreement that resulted in the "Upper Michigan Energy Solution". This agreement was memorialized in the Amended and Restated Settlement Agreement ("ARSA") approved by the Commission in Case U-17682, when it approved WEC's acquisition of Integrys. As part of the ARSA, it was agreed that (1) WEC would develop a Michigan-only jurisdictional utility and seek Commission approval for that utility and (2) that Michigan-only jurisdictional utility would develop modern, clean, flexible gas units that would be built in two locations to serve the mines and UMERC customers, while improving reliability and lowering emissions.

   In June of 2016 WEC filed an application in Case U-18061 seeking authorization to form UMERC and transfer the Michigan-based non-generation assets of Wisconsin Electric and Wisconsin Public Service Corporation to UMERC. On October 19, 2016, a unanimous settlement was reached to resolve all the issues in this proceeding, and the Commission approved that settlement on December 9, 2016. UMERC was formed and began operating effective January 1, 2017. All Michigan-located customers of Wisconsin Electric and Wisconsin Public Service Corporation were transferred to UMERC effective on that date

[1] Wisconsin Electric is currently an affiliate of and was a predecessor Michigan-jurisdictional utility to UMERC.

except the Tilden Mine, which remained a Wisconsin Electric customer until the RICE Units were placed in service.

On January 31, 2017, UMERC filed an application in Case U-18224 seeking approval of Certificates of Need (CONs) to construct the two UP RICE generation facilities and a new special contract between the Tilden mine and UMERC. The new special contract would take effect upon the RICE units being placed in service. On October 25, 2017 the Commission issued an order approving the CONs and the new special contract. The RICE units were constructed and placed in service in May 2019 and at that time the Tilden Mine was transferred to UMERC which provided service under the approved new special contract.

2. Does UMERC see RICE units as a technology that is useful to the situations similar to those in the UP to provide both capacity, energy and transmission support in remote areas or does it view RICE units as more multifunctional?

   Response:

   WEC, including UMERC, sees the RICE Units as a technology that offers an extremely high level flexibility to meet a multitude of needs. These capabilities include providing energy, capacity, transmission support as well as multifunctional capabilities (e.g., serve as spinning reserves, provide inertia to the bulk electric system, etc.). The RICE technology is an ideal technology to "backstop" renewable generation to ensure energy assurance and reliability due to its capability to adjust generation output extremely quickly.

   In WEC's view, the RICE technology's flexibility makes it an appropriate resource for any environment - from a very remote area, such as the UP, to the most densely populated urban areas. In Case U-18224, the Commission concluded that RICE technology was the least cost option to meet the unique power and reliability needs of the UP relative to other resource options, while avoiding the costs of building additional transmission.

3. Does UMERC's holding company have plans to add additional RICE units in its sister utilities outside of Michigan? If plans exist to add additional RICE units, to what purpose are they being added?

   Response:

   Yes, WEC has already added a seven-unit RICE facility at the Weston Generation Campus in Weston, WI. That facility was placed in service in July 2023 and is being used to provide identified capacity and energy needs of the two utilities that jointly own the facility – Wisconsin Electric Power Company and Wisconsin Public Service Corporation – both affiliates of UMERC. The units are currently fueled with natural gas. The units also supply necessary grid stability services.

Wisconsin Electric Power Company filed a CPCN application with the Public Service Commission of Wisconsin on April 5, 2024 to construct a seven-unit RICE facility at the Paris Generation Campus in Paris, WI. That facility is projected to be placed in service in mid-2026 and is being proposed to provide identified capacity and energy needs of Wisconsin Electric Power Company. This facility will be collocated with the Paris Solar generation project which is a 250 MW utility-owned solar project and will be fueled with natural gas. The units are also expected to supply necessary grid stability services.

4. How would UMERC use the RICE units if they were to be operationally constrained in the future?

   Response:

   UMERC's UP RICE units would still serve in their current capacity role, unless operational constraints limited their ability to comply with MISO instructions. MISO's capacity rules reduce the capacity value of resources that are not available (including environmental and / or operational constraints) when MISO needs them.

   UMERC's UP RICE units would also supply energy and grid stability attributes, although at lower levels. Such constrained operation would also, by definition, have the effect of increasing costs of energy supply to Tilden under the Special Contract as well as UMERC's non-mine customers.

5. If the RICE units were operationally constrained, would this have any effect on their seasonal capacity accreditation with MISO?

   Response:

   Yes. Operational constraints will reduce the seasonal capacity accreditation of the resource. MISO's capacity rules, including the recently filed Direct Loss of Load (DLOL) accreditation methodology, will reduce the capacity value of resources that are not available when MISO needs them, as noted in the response to question 4 above. MISO's capacity rules are designed to send a signal that resource unavailability, regardless of the reason, negatively affects the capacity value of that resource.

6. What would be the implications for the Tilden Mine special contract if UMERC were forced to retire the RICE units before the expiration of the contract?

   Response:

   Prior to responding to specific elements of the contract that would likely be impacted, UMERC notes that if the RICE units were required to be retired prior to the expiration of the Tilden Special Contact, the result would be the re-establishment of the conditions that existed prior to the comprehensive Upper Michigan Energy Solution reached as part of the Amended and Restated Settlement Agreement in Case U-17682—which UMERC would like to avoid repeating as that history caused many policymakers to express concerns over reliability throughout the Upper Peninsula. Such a situation would provide significant uncertainty not only to Cliffs but to all UMERC customers with regard to how reliable electric generating capacity, energy, and grid stability services will be supplied to the UP – and at what cost.

The practical implication of the forced retirement of the RICE units would be to eliminate the energy value Tilden receives from the RICE units as a hedge against the cost of energy from the MISO market.

The "Generation Resources Operational Expense" (operation and maintenance cost), the "Energy Charge – Generation" (natural gas cost and MISO market charges), and the "Generation Resources Volume Credit" (MISO LMP payments) would fall to zero.

The remaining provisions of the contract would remain intact, including Tilden's ability to terminate the contract with 60 days written notice and the payment of the liquidated damages outlined in the contract for such termination. If Tilden were to execute that provision of the contract in such a scenario, the result would be that the remaining costs Tilden would be scheduled to pay under the Special Contract would no longer apply and the costs would be recovered from UMERC's non-mine customers.

7. Has UMERC considered the possibility of carbon capture and sequestration, or other carbon reduction or elimination technologies, for its RICE units?

Response:

UMERC has not considered these potential options at this time due to the significant costs associated with those options given the current state of advancement and availability of those technologies.

8. Does UMERC know if there is suitable geology to store CO_2 underground within or nearby its service territory?

Response:

No. While UMERC is not aware of any suitable geology to store CO_2 underground in the UP at this time, we have not studied that. While the lower peninsula of Michigan is known to have such storage capacity, it would require significant costs to transport sequestered CO_2 to a location in the lower peninsula (or elsewhere) where there is known geology that could be used for its storage. Such costs would include either the construction or repurposing an existing pipeline, plus the costs to maintain that pipeline or to deliver the sequestered carbon via tanker truck.

9. Would UMERC consider the use of direct air capture? Would that be economically feasible?

   Response:

   Yes, but direct air capture technology is in early stage trials. A point source capture (from the plant stacks themselves) would be the most likely scenario to deploy this technology. That said, besides the cost of capturing the CO_2, as noted in UMERC's response to question 8 above, there are uncertainties regarding where to store it, how to get it there, and how much that will cost.

10. Would UMERC be willing to provide the results of the pilot it conducted for the use of hydrogen in its RICE units that it performed in partnership with EPRI?

    Response:

    The detailed technical report is only available to EPRI members and cannot be forwarded to non-members. UMERC was able to obtain and receive permission to share the executive summary of the report, which has been attached to these responses.

11. What concerns does UMERC have for fuel availability if the RICE units were converted to 100% Hydrogen?

    Response:

    At the present time, UMERC would have significant concerns regarding fuel availability if the RICE units were converted to 100% Hydrogen. There is currently not a meaningful market for hydrogen to be used in the quantity need to fuel the RICE units exclusively on Hydrogen making the availability and cost of that fuel a noteworthy concern. Additionally, and similar to the infrastructure needed for the transportation of sequestered carbon, the costs that would be required for the construction or repurposing of an existing pipeline are unknown, plus the costs to maintain that pipeline or to deliver the hydrogen via tanker truck and store it on site. Such concerns may be addressed in the future if a market for Hydrogen develops that provides for its availability at an economical level.

12. Is there a blended percentage of hydrogen with natural gas where UMERC would have similar fuel availability concerns as it currently does with natural gas?

    Response:

Please see UMERC's response to question 11 above.

13. What concerns does UMERC have for fuel availability for natural gas?

Response:

NOTE: Portions of this response contain information deemed confidential – all such information is shaded in grey within UMERC's response.

UMERC has contracted for [******]dth/day of firm transportation service from the [*****] interstate pipeline (until [****]). This pipelin789ijkl.e service allows for access to procure supply from a supply basin with sufficient liquidity of supply at regionally competitive prices. There have not been any recurring fuel availability issues during the first 5 years of the RICE units operations. UMERC also does not foresee any fuel availability issues for its current level of firm transportation service in the future.

While UMERC commonly arranges for a volume of fuel delivery [****] its firm rights, that volume [******] its firm rights is considered [****], and subject to reliability constraints. Given that the [*****] pipeline does not currently have any [******] deliverability capabilities on this part of their system, UMERCs only concern is a [****] in the [*****] for volumes over its [******] rights.

14. If UMERC decided to retire the RICE units, what zero carbon emissions options would it consider to maintain resource adequacy under the current MISO capacity construct?

Response:

UMERC believes that the RICE units remain the best resource to provide the UP with the capacity, energy and grid stability services needed to ensure reliability in the UP. Absent a legislative or regulatory directive to retire the RICE units, UMERC has no such plans

If UMERC were provided such a directive, it would have to rely on a combination of new generation and new transmission to provide service to its customers in the Upper Peninsula. UMERC would need to procure or construct significant over-capacity of renewable generation (wind and / or solar) paired with lithium-ion storage - enough to weather a multi-day event without recharging. Alternatively, the Company could build gas plants in Wisconsin and use such capacity for the UP, if additional transmission facilities were constructed to allow for the delivery of that energy to the UP. Either of these options would come with significant incremental costs to UMERC's customers (both Tilden and non-mine customers) as well as those of other utilities in the UP and would be inconsistent with the MPSC approval of the Amended and Restated Settlement Agreement in the Integrys acquisition in Case U-17682 as well as the MPSC's resulting approval of UMERC;s formation (Case U-18061) and the CON authorizing the construction of the RICE Units and the Approval of the Tilden Special Contract (Case U-18224).

15. If UMERC decided to retire the RICE units, what would UMERC consider to maintain grid synchronization?

Response:

ATC and MISO are better positioned to provide a response to this question. UMERC expects that additional transmission line infrastructure and technologies such as Static VAr Compensators (SVC), synchronous condensers, Flexible Alternating Current Transmission System (FACTS), and other power-electronic based devices are potential candidates. All such options though, would require imposing additional costs on UMERC customers (Tilden and non-mine customers) as well as the customers of other UP utilities.

16. What Percentage of EWR has UMERC been able to achieve?

Response:

UMERC has not studied this issue because its EWR (energy waste reduction), or energy efficiency, program is performed by Efficiency United, the Michigan sanctioned administrator.

17. Does UMERC know what percentage of EWR is technically feasible and for how long if the Tilden Mine load is excluded?

Response:

UMERC has not studied this issue because its EWR (energy waste reduction), or energy efficiency, program is performed by Efficiency United, the Michigan sanctioned administrator.

18. Does UMERC know what percentage of EWR is technically feasible and for how long if the Tilden Mine load is included?

Response:

UMERC has not studied this issue because its EWR (energy waste reduction), or energy efficiency, program is performed by Efficiency United, the Michigan sanctioned administrator.

19. Has UMERC done any forecasting of electrification in its service territory?

Response:

UMERC has not forecasted electrification in its service territory.

20. How much DR does UMERC use towards its PRMR with MISO for each of the capacity seasons?

Response:

DR Capacity Accreditation including Tilden	***Summer***	***Fall***	***Winter***	***Spring***
PY23	180.4	192.9	201.1	208.7
PY24	183.7	190.2	203.5	212.2

DR Capacity Accreditation excluding Tilden	***Summer***	***Fall***	***Winter***	***Spring***
PY23	19.6	20.2	22.5	22
PY24	20	18.9	24	22

As shown the data above, the vast majority of this demand response is the non-firm load of the Tilden mine.

21. What percentage of its resource adequacy requirement from MISO is fulfilled with DR for each of the capacity seasons?

Response:

%DR/PRMR including Tilden	***Summer***	***Fall***	***Winter***	***Spring***
PY23	63.2%	67%	60.8%	70.5%
PY24	66.8%	69.5%	66.5%	70.3%

%DR/PRMR Excluding Tilden	***Summer***	***Fall***	***Winter***	***Spring***
PY23	15.7%	17.5%	14.8%	20.1%
PY24	18%	18.5%	19%	19.7%

22. Could UMERC theoretically increase its amount of DR? Is this practically feasible?

    Response: The amount of DR is dependent upon customer eligibility and customers choosing an applicable tariff rate. Not all customers are eligible. The applicable tariffs are:

    - General Primary Full Requirements Service Curtailable Rate Cp3 – WEPCo Rate Zone
    - Large Commercial & Industrial Service – Interruptible Rider Cp-I – WPSC Rate Zone
    - Tilden Special Contract

    UMERC's largest customer is already participating in DR to its maximum capability and would unlikely be able to increase its DR without significant investment. While there may be other eligible customers, the available rate options have been in existence for many years and have attracted little interest from customers, presumably because they do not have operations that would lend themselves to prolonged demand curtailment, or are otherwise not interested in participating in DR.

23. Are there issues with increasing the amount of DR that UMERC counts towards its resource requirement?

    Response:

    See UMERC's response to question 22 above. In addition, the DR's capacity accreditation depends on historical availability of the interruptible/curtailable demand. Furthermore, MISO occasionally commits the UMERC RICE engines to operate around the clock for multiple days on end to support transmission system maintenance outages. In these instances, the engines may be providing voltage support or injecting energy at specific locations to prevent transmission line overloads or both.

    DR is unable to provide a similar level of dynamic voltage support and is unlikely to replace the impact of RICE generation energy injection. DR is generally unable to provide load reduction for days on end. Previous experience with DR suggests that calling for lengthy load curtailments often leads to customers withdrawing from these programs. Thus, DR should be considered a short-term and transitory reliability solution rather than a long term one.

24. What limitations does UMERC have on the use of its DR? For example, is it limited to MISO emergency use only? Or a certain number of events per calendar year?

Response:

The limitations on UMERC's ability to call upon DR are defined in its tariffs and in its MPSC approved special contract and are summarized below:

<u>General Primary Full Requirements Service Curtailable Rate Cp3 – WEPCo Rate Zone</u>

- Available 0800-2200 EPT Everyday
- Max duration = 8 hours, 300 hours/year

<u>Large Commercial & Industrial Service – Interruptible Rider Cp-I – WPSC Rate Zone</u>

- Available 1000-2000 EPT Monday-Friday October – May
- Available 1000-2300 EPT Monday-Friday June- September
- No single event limit. 600 Hour Limit per year
- Emergency and Economic events

<u>Tilden Special Contract</u>

- Available 0000-2400 EPT Everyday

25. Does UMERC have expectations of load changes over the next 20 years? Please describe them.

Response:

Not at this time, although we note that the cooler temperatures and availability of water in the UP are situations that could make the UP a potential location for data center operations.

26. Has UMERC conducted any modeling of the UP system with a replacement technology for the RICE units? If so, can UMERC summarize its results?

Response:

UMERC has not performed modeling of the UP system with a replacement technology for the RICE units; however, as noted in UMERC's response to question 14 above, there are essentially two options that could be pursued to supply the UP with the necessary capacity and energy. First, UMERC could procure or construct significant over-capacity of renewable generation (wind and / or solar) paired with lithium-ion storage to replace the capabilities of the RICE units. The second option would entail the construction of significant transmission facilities to deliver energy and capacity to the UP. However, both options would increase costs to customers in the UP and a transmission build out would not likely supply necessary grid stability services, such as voltage support.

Appendix G: UPPCo Responses to MPSC Staff Questions

Questions for UPPCo

1. Once UPPCo has ownership, or has contracted for, the renewable resources that were the results of the settlement in the Company's last approved IRP, what percentage RPS will the Company have?
    a. Approximately 55%
2. Does UPPCo foresee issues with meeting the 2030 or 2035 Renewable Energy Standard?
    a. Potential issues include:
        i. Construction/supply chain/equipment delays
        ii. Renewable project siting approval
        iii. Changes in retail load causing additional resources to be needed to meet the 2030/2035 RES.
3. Does UPPCo foresee issues with meeting the 2035 or 2040 clean energy standard? What, if any, concerns does UPPCo foresee with meeting the 2035 and 2040 clean energy standard?
    a. Potential issues include:
        i. Limited clean energy resource options that are suitable for a company of UPPCO's size to implement.
        ii. Availability of sufficient renewable/clean capacity within the U.P.
4. Does UPPCo anticipate filing a resource plan and associated analysis for meeting the 2035 and 2040 clean energy standard in its next IRP application?
    a. Yes.
5. Does UPPCo plan on pursuing the relicensing of its existing hydroelectric facilities? If the Company does not have a definitive response at this time, does the Company plan to analyze relicensing of these facilities as part of its next IRP filing?
    a. Yes.
6. What Percentage of EWR has UPPCo been able to achieve annually in the past 5 years?
    a. 1.5%-1.75% deemed savings.
7. Does UPPCo expect to maintain, increase, or decrease its EWR throughout the next 15 years?
    a. Maintain and perhaps increase, dependent upon the incremental cost of energy savings.
8. Has UPPCo done any forecasting of electrification in its service territory? If so, can the results be made available to Staff?
    a. Preliminary. UPPCO intends to present additional analysis in its upcoming IRP.

9. Does UPPCo believe it could theoretically increase its amount of DR? Why or why not?
    a. Perhaps, by a small amount. UPPCO's capacity portfolio is already heavily based upon industrial customer demand response. There is little/no opportunity for additional industrial level demand response. Similarly, there is significantly less electric air/space conditioning load throughout UPPCO's residential customers, and therefore current opportunities are limited. UPPCO is evaluating the potential for additional residential class demand response programs that may present themselves throughout the deployment of beneficial electrification measures.
10. Are there issues with increasing the amount of DR that UPPCo counts towards its resource requirement?
    a. Yes. As noted previously, UPPCO already relies upon a significant amount of demand response to meet its capacity obligations. With increased DR, if it were even attainable, there may be performance issues when the demand response resource is called upon in real time.
11. What limitations does UPPCo have on the use of its DR? For example, is it limited to MISO emergency use only? Or a certain number of events per calendar year?
    a. It is limited to a certain number of events per year, as detailed by UPPCO's CP-I tariff, and RTMP tariff.
12. Does UPPCo have expectations of load changes over the next 20 years? Please describe them. How does the Company anticipate this affecting EWR and DR opportunities, REP requirements, and ability to meeting the clean energy standard?
    a. Generally speaking UPPCO does not anticipate significant changes in its native load over time. UPPCO is evaluating the effects of electrification on both energy and demand requirements that would be experienced by the Company under several assumed electrification adoption scenarios.
13. Did UPPCo retire the Gladstone generating unit in 2022 as planned in its most recent IRP, Case No. U-20350? If yes, what replaced it?
    a. UPPCO has not retired the Gladstone facility.
14. If UPPCo did not retire the Gladstone unit in 2022. what are the Company's future plans for the unit and what was the reason for the delay?
    a. UPPCO will identify an updated retirement assumption for Gladstone in it's upcoming IRP. In short, until UPPCO is able to replace the capacity accredited to UPPCO by the Gladstone facility in an economic way, UPPCO will continue to offer it into the MISO market as an emergency-only resource.
15. What role, if any, do the RICE units located outside of UPPCo's service territory in the UP play in UPPCo's system reliability? Or UPPCo's system generally?

    a. The RICE units are interconnected directly to the Transmission system (ATC), and therefore do not directly support UPPCO's distribution system. RSG charges applied through market settlement (per the MISO tariff) compensate these (and any other) unit for operation that is to the benefit of the bulk electric system.

16. Please describe, in as much detail without breaking confidentiality, the difficulties in resource procurement that UPPCO has experienced since its last IRP.
    a. As noted in its IRP annual reports in Case U-20350, the primary difficulty in procuring additional renewable resources has been primarily attributed to siting/special use/land use permitting from the local units of government.

Appendix H: MISO Michigan Phase II Study
* Includes internal appendix

I. Executive Summary

On August 17, 2016, Michigan's Governor Rick Snyder and the Michigan Agency for Energy (MAE) requested the Midcontinent Independent System Operator (MISO) to conduct a near and long term regional evaluation of potential production cost savings, reliability, and resource adequacy benefits of transmission and generation expansion in MISO's northern footprint, specifically Michigan's eastern Upper Peninsula (part of Zone 2) up to Sault Ste. Marie, Ontario and northern Lower Peninsula (Zone 7) at the Straits of Mackinac down to the northernmost portion of the existing 345 kV transmission line near Gaylord, MI. Further, MAE was interested to know the impacts that a new natural gas-fired electric generating station located strategically in northern Lower Michigan could have on the bulk electric system (BES), especially in conjunction with the transmission upgrades. MAE requested MISO to model the production cost savings, reliability, resource adequacy, and power flows that would result from a natural gas-fired generating station located in the northcentral Lower Peninsula of Michigan1.

This Michigan Exploratory Transmission Study, which is Phase II of Michigan's request, consisted of a 2021, 2026, and 2031 fact-finding exploratory analysis of potential generation and transmission additions in Michigan using PROMOD software. Additionally, a powerflow analysis was performed using PSSE software to identify reliability concerns addressed by or caused by generation and transmission additions. PROMOD is a market simulation tool that analyzes the transmission system for every hour in a defined year. PROMOD outputs include Adjusted Production Costs (APC) and Load Costs. PROMOD was used to determine the APC savings with the addition of transmission and generation siting. The MISO Transmission Expansion Plan (MTEP) 2017 PROMOD and powerflow models were used as a starting point and incorporated base model updates, future assumptions updates, and sensitivities identified by Michigan.

Sixteen transmission ideas were analyzed during the study. These transmission ideas ranged from utilizing and upgrading existing electrical infrastructure to large transmission buildouts. As there are no current transmission connections between Ontario and Michigan's Upper Peninsula, all of the transmission options included a new tie line between the two regions. MISO coordinated with Canada's Independent Electricity System Operator (IESO) for connections to the transmission system in Ontario. In addition to transmission, generators sited in Michigan's Kalkaska County and Chippewa County were also studied.

Reliability analysis, coordinated with IESO, identified limitations to the amount of power that could be reasonably transferred between Ontario and Michigan without causing significant reliability issues necessitating costly upgrades to the existing transmission system. A transfer capability level of 125 MW was set as the maximum due to significant and widespread reliability issues identified at higher transfer capability levels. Additionally, for a transmission line connecting Ontario and Michigan, a flow control device would be required to control flows due to significant phase angle differences. Phase Angle Regulators (PARs) are currently

[1] See Appendix A, Letter to MISO from MAE dated August 17, 2016

installed on the Ontario/Michigan tie lines in the Lower Peninsula to help control flows caused by these angle differences. Alternatively, an existing combined cycle unit in Sault Ste. Marie, Ontario could be isolated from the IESO system and connected radially to the Upper Peninsula (Sault Ste. Marie, MI) which would not require a flow control device. This was one of the options analyzed during the study.

The economic analysis determined that all of the transmission and generation solutions did not provide enough economic benefit to cover costs. Due to significant and widespread reliability issues identified at higher transfer limitations (greater than 125 MW) and relatively high costs, the amount of economic potential was limited. Generation and transmission in the Upper Peninsula provided comparable amounts of economic benefits for similar costs.

II. Introduction and Background

On August 9, 2016, MAE and the Michigan Public Service Commission (MPSC) requested MISO to conduct a study to help Michigan better understand the effects of declining reserve margins and the impact of several retiring coal plants, particularly during high load emergency conditions. Specifically, they requested that MISO assess and inform Michigan of vulnerabilities associated with planned or unplanned outages at the Palisades and Fermi 2 nuclear power plants in 2018, while at the same time experiencing very hot weather similar to that experienced in the summer of 2012 when both nuclear plants were down during a hot weather alert.[2] MISO performed a study (Phase I) to address MAE's and MPSC's request.

Phase I determined that under high demand conditions in 2018, demand response programs planned by Michigan load-serving entities as outlined in recent MPSC filings, as well as building additional peaking capacity, would be necessary to meet reserve margins. The demand response programs become increasingly important when the system is stressed due to high demand and/or unexpected plant outages. In addition to implementing demand response programs, 400 MW of additional peaking capacity should be considered in the near term. The need for peaking capacity could be delayed by further increasing demand response in Michigan.

As a supplement to the first request, Governor Snyder and MAE requested MISO to conduct a study of near and long term transmission expansion options to better connect the Upper Peninsula of Michigan to the Province of Ontario as well as to the Lower Peninsula of Michigan on August 17, 2016. The study would examine potential production cost savings, reliability, and resource adequacy benefits of transmission and generation expansion in MISO's northern footprint. Further, MAE was interested to know the impacts that a new natural gas-fired electric generating station located strategically in northern Lower Michigan could have on the BES, especially in conjunction with the transmission upgrades.[3] Assumptions and results of the Phase I of the study were used as inputs into Phase II.

[2] See Appendix B, Letter to MISO from MAE and MPSC dated August 9, 2016

[3] See Appendix A, Letter to MISO from MAE dated August 17, 2016

Model Development and Assumptions

The base models and assumptions for this study started with the MTEP17 powerflow and PROMOD models using the Existing Fleet future assumptions. Michigan staff reviewed and worked with MISO staff to provide updates to the base models. The study focused on the Michigan footprint, with the IESO footprint modeled to study increased imports from Canada. After the base models were constructed, incremental models were created to include proposed transmission and generation ideas.

1) Local Resource Zones

Michigan is located in two of MISO's Local Resource Zones (LRZ): LRZ 2 and LRZ 7 (Figure 1). Michigan also has a very small amount of load in MISO Zone 1 in the western Upper Peninsula, which has been excluded from this study. Michigan's Upper Peninsula is in LRZ 2, which includes Local Balancing Authorities Michigan Upper Peninsula and Upper Peninsula Power Company. LRZ 7 Local Balancing Authorities include Consumers Energy – METC and Detroit Edison Company. Based on a load ratio share of energy, about 3% of Michigan's load is in LRZ 2, about 97% is in LRZ 7, and less than 1% is in LRZ 1.

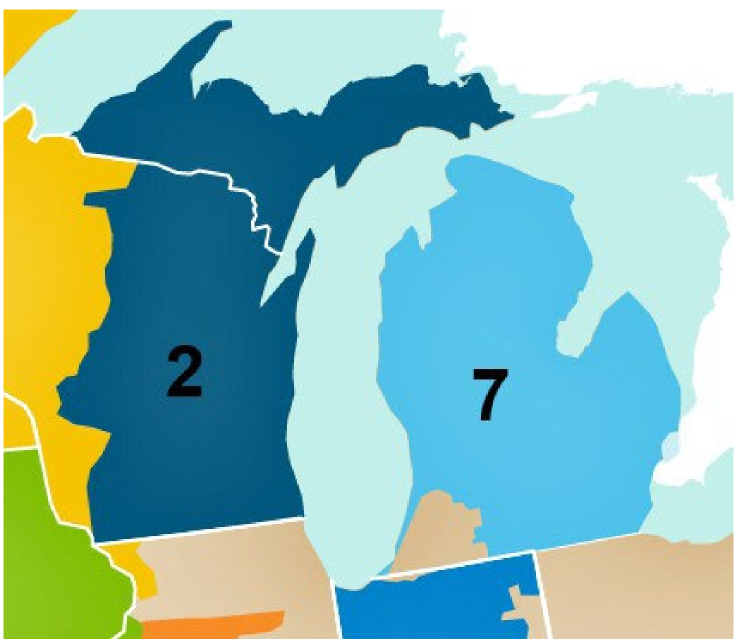


Figure 1: Michigan in Local Resource Zones 2 and 7

2) Natural Gas Price Forecast

The natural gas price forecast of the study base model – the MTEP17 Existing Fleet future – was developed with stakeholder input during the MTEP17 futures development process. This forecast is derived from NYMEX spot prices for years 2016-2017 and the average of Energy Information Administration and Wood MacKenzie forecasts for years 2018-2035. The natural gas price forecast for Michigan generators for the study period is below (Figure 2).

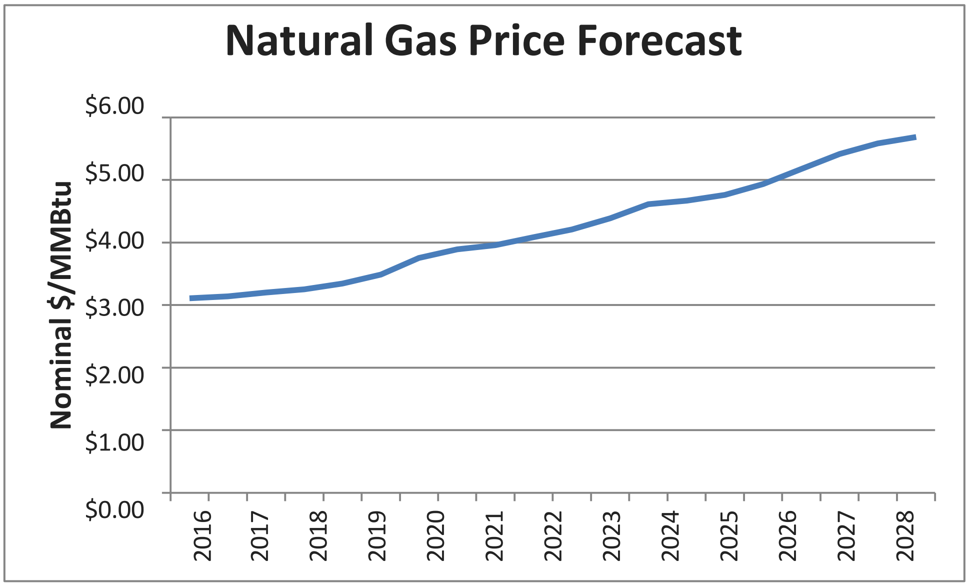


Figure 2: Natural Gas Price Forecast for Michigan Generation

3) Load Forecast

The load forecast for the MISO region in the MTEP17 Existing Fleet future was based on Module E submitted data growing at a 50% lower rate. However, Michigan specific demand and energy growth rates have been adjusted based on current data and models. The growth rates used in LRZ models of MISO's Mid-Term Clean Power Plan analysis are included below for comparison (Table 1). Additionally, Michigan has requested that MISO's model assume that the Empire Mine load in the Upper Peninsula be retired in 2016. The peak demand and energy for Michigan is listed by year in Table 2.

	MISO MTEP17 Existing Fleet Future Growth Rate	MI Phase II Growth Rates	LRZ 2 Mid-Term Analysis Growth Rate	LRZ 7 Mid-Term Analysis Growth Rate
Demand	0.37%	0.88%	0.6%	0.3%
Energy	0.37%	0.52%	0.6%	0.3%

Table 1: Demand and Energy Growth Rates

Type	2016	2017	2018	2019	2020	2021	2022	2023
Demand	21,689	21,857	22,021	22,175	22,309	22,444	22,582	22,722
Energy	105,715	105,406	105,221	105,128	105,069	105,074	105,142	105,273

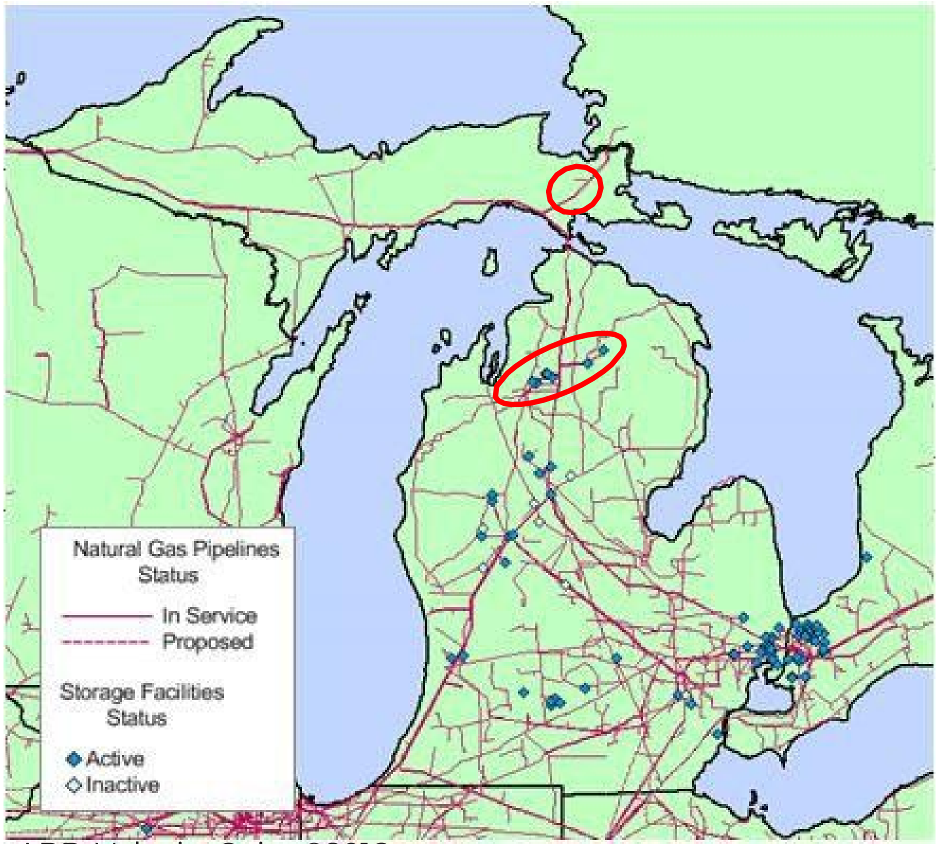
Type	2024	2025	2026	2027	2028	2029	2030	2031
Demand	22,865	23,008	23,219	23,471	23,726	23,985	24,247	24,513
Energy	105,466	105,717	106,352	107,240	108,191	109,202	110,276	111,411

Type	2032	2033	2034	2035
Demand	24,782	25,055	25,332	25,612
Energy	112,608	113,867	115,188	116,588

Table 2: Phase II Michigan Yearly Peak Demand and Energy

4) <u>Natural Gas Pipelines and Storage</u>

Michigan natural gas pipeline and storage facilities are mapped below (Figure 3). These were used to site potential natural gas generating units. One unit was sited near the natural gas storage and 345 kV systems in Otsego/Kalkaska counties, circled below. One unit was sited in the Eastern Upper Peninsula, also circled below.



MISO – Using ABB, Velocity Suite ©2016

Figure 3: Natural Gas Pipeline and Storage in Michigan

5) Generator Retirements

The following table shows Michigan's study generation retirements for analysis from Michigan's request (Table 3). Additional generation is retired based on the MTEP17 Existing Fleet future definitions. This includes retiring oil and gas units once they reach 55 years of age, and coal units when they reach 65 years.

Name	MW	Retired
Harbor Beach	121	2013
Trenton Channel	240	2016
B.C. Cobb	312	2016
Karn	312	2016
Whiting	345	2016
Endicott	55	2016
White Pine	20	2016
De Young	63	2017
Eckert	335	2018
Presque Isle	450	2020
River Rouge	651	2020-23
St. Clair	633	2022
Belle River	1177	2030

Table 3: Michigan Generator Retirements

6) Nuclear Generation:

The Michigan request included the following statuses for nuclear generation in or near Michigan.

Palisades: The existing Power Purchase Agreement expires in 2022, and the operating license expires in 2031. Entergy has announced retirement of the unit effective October 2022. The unit will be retired accordingly for this study.

Fermi: The nuclear unit at Fermi will be treated as though the operating license will be renewed. This unit will be in service for this study.

Quad Cities: The Quad Cities nuclear units were set to retire on June 1st, 2018. This retirement has since been retracted. These units will remain in service for this study.

Clinton: The Clinton nuclear unit has announced retirement beginning June 1st, 2017. The retirement has since been retracted. The unit will be retired in 2027 for this study.

7) Generation Additions:

The Michigan request specified certain generation additions to be included in the study. These units were considered as base case assumptions in this analysis (Table 4). Additional generation was added to account for retired generation and growing load, based on the future variables for the Existing Fleet future (Table 5).

Name	Type	MW	In-Service
Alpine	Combustion Turbine	410	2016
Cross Winds II	Wind	44	2018
Pine River Wind	Wind	161	2019
J703	Internal Combustion	128	2020
J704	Internal Combustion	55	2020
J572	Combined Cycle	165	2018

Table 4: Michigan Generator Additions

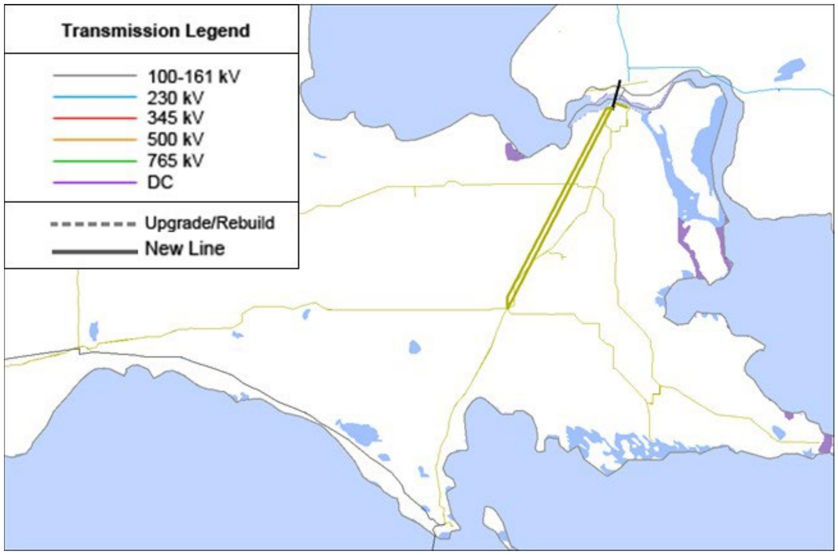
Name	Category	MW	Commission	POI
RRF MISO CT: 006	CT Gas	50.0	1/1/2023	Keystone 138 kV
RRF MISO CT: 009	CT Gas	100.0	1/1/2024	Thetford 138 kV
RRF MISO CT: 013	CT Gas	100.0	1/1/2024	Gaylord 138 kV
RRF MISO CT: 019	CT Gas	200.0	1/1/2025	Monroe 345 kV
RRF MISO CT: 022	CT Gas	200.0	1/1/2025	Zeeland 345 kV
RRF MISO CT: 030	CT Gas	100.0	1/1/2024	Super 120 kV
RRF MISO CT: 031	CT Gas	100.0	1/1/2024	Toll Road 120 kV
RRF MISO CT: 032	CT Gas	100.0	1/1/2024	Super 120 kV
RRF MISO CT: 035	CT Gas	100.0	1/1/2024	Super 120 kV
RRF MISO CT: 037	CT Gas	200.0	1/1/2025	Hancock 120 kV
RRF MISO CT: 051	CT Gas	300.0	1/1/2030	B. Foot 345 kV
RRF MISO CT: 059	CT Gas	100.0	1/1/2026	N. East 120 kV
RRF MISO CT: 062	CT Gas	100.0	1/1/2026	Thetford 138 kV
RRF MISO CT: 091	CT Gas	200.0	1/1/2029	Cobb 138 kV
RRF MISO PV: DG CONS	Solar PV	29.0	1/1/2021	Top 10 loads
RRF MISO PV: DG DECO	Solar PV	35.4	1/1/2021	Top 10 loads
RRF MISO PV: DG WPSC	Solar PV	1.8	1/1/2021	Top 10 loads
RRF MISO PV: Tier 1 - 16	Solar PV	50.0	1/1/2021	Nelson Road 345 kV
RRF MISO Wind: RGOS MI-B	Wind	45.0	1/1/2026	Bauer 345 kV
RRF MISO Wind: RGOS MI-C	Wind	45.0	1/1/2026	Rapson 345 kV
RRF MISO Wind: RGOS MI-D	Wind	45.0	1/1/2026	Rapson 345 kV
RRF MISO Wind: RGOS MI-E	Wind	45.0	1/1/2026	Bauer 345 kV
RRF MISO Wind: RGOS MI-F	Wind	45.0	1/1/2026	Greenwood 345 kV
RRF MISO Wind: RGOS MI-I	Wind	45.0	1/1/2026	Palisades 345 kV
RRF MISO Wind: RGOS MI-B	Wind	48.0	1/1/2031	Bauer 345 kV
RRF MISO Wind: RGOS MI-C	Wind	48.0	1/1/2031	Rapson 345 kV
RRF MISO Wind: RGOS MI-D	Wind	48.0	1/1/2031	Rapson 345 kV
RRF MISO Wind: RGOS MI-E	Wind	48.0	1/1/2031	Bauer 345 kV
RRF MISO Wind: RGOS MI-F	Wind	48.0	1/1/2031	Greenwood 345 kV
RRF MISO Wind: RGOS MI-I	Wind	48.0	1/1/2031	Palisades 345 kV

Table 5: Michigan Generator Expansions for the Existing Fleet Future

III. Transmission Ideas

Sixteen transmission ideas were submitted for study in Phase II. These options ranged from using/upgrading existing infrastructure to major transmission additions. Every solution to the options studied involved a new transmission line connection to Ontario. Some of the solutions included an option to isolate a generator in Sault Ste. Marie, Ontario from the IESO transmission system and connect it to the Michigan system via new transmission. The following section describes the transmission ideas that were studied.

1. <u>Transmission Idea MI-1</u>



i) Michigan Facilities:

(1) New 115/69 kV substation (NEWSUB) tapping the existing Magazine St. – 3 Mile 69 kV line
(2) New 115/69 kV transformer at NEWSUB
(3) New 69 kV line from Magazine St. to Portage
(4) Two new 69 kV lines from NEWSUB to Pine River
(5) Reconfigure Pine River 69 kV substation. Remove the Straits – Pine River 69 kV connection and tie the line to one of the new 69 kV lines from NEWSUB. Use the newly opened terminal at Pine River for the 2nd 69 kV line from NEWSUB.

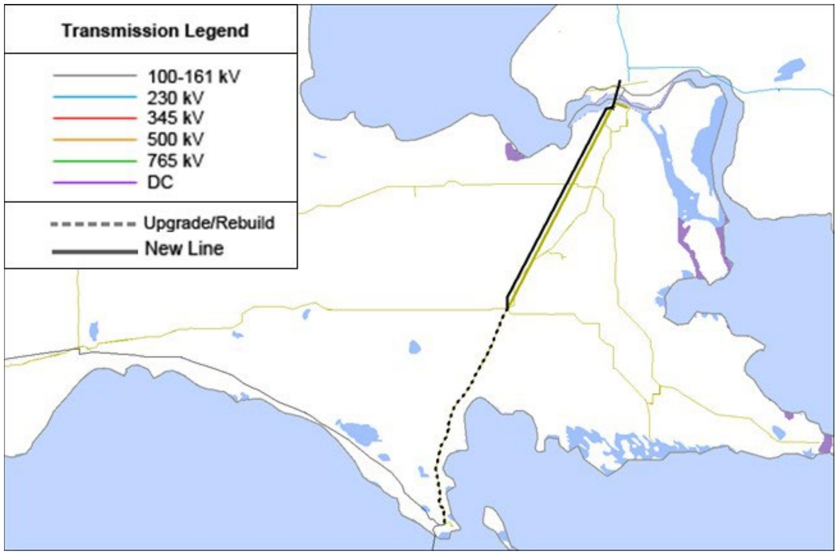
ii) Interconnection:

(1) New 115/115 kV Phase Angle Regulating transformer at NEWSUB
(2) New 115 kV tie line from NEWSUB to Clergue TS (IESO)

Or

(3) Two new 138 kV lines connecting an existing combined cycle gas power plant in Sault Ste. Marie to NEWSUB. Adjust system to disconnect the existing plant from Ontario's system.
(4) Change the voltage of NEWSUB and associated transformer from 115/69 kV to 138/69 kV.

2) <u>Transmission Idea MI-2</u>



i) Michigan Facilities:

(1) New 138/115/69 kV substation (NEWSUB) tapping the existing Magazine St. – 3 Mile 69 kV line
(2) New 138/115 kV transformer at NEWSUB
(3) New 138/69 kV transformer at NEWSUB
(4) New 69 kV line from Magazine St. to Portage
(5) New 138 kV line from NEWSUB to Pine River
(6) New 69 kV line from NEWSUB to Pine River
(7) Reconfigure Pine River 69 kV substation. Remove the Straits – Pine River 69 kV connection. Tie the line to the new 138 kV line from NEWSUB and operate at 138 kV. Use the newly opened terminal at Pine River for the new 69 kV line from NEWSUB.

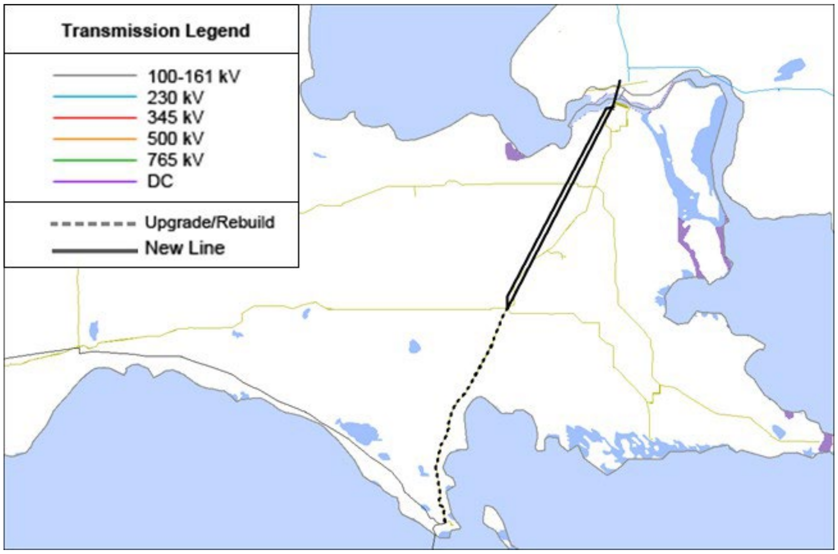
ii) Interconnection:

(1) New 115/115 kV Phase Angle Regulating transformer at NEWSUB
(2) New 115 kV tie line from NEWSUB to Clergue TS (IESO)

Or

(3) Two new 138 kV lines connecting an existing combined cycle gas power plant in Sault Ste. Marie to NEWSUB. Adjust system to disconnect the existing plant from Ontario's system.
(4) The 138/115 kV transformer will no longer be needed

3) <u>Transmission Idea MI-3</u>



i) Michigan Facilities:

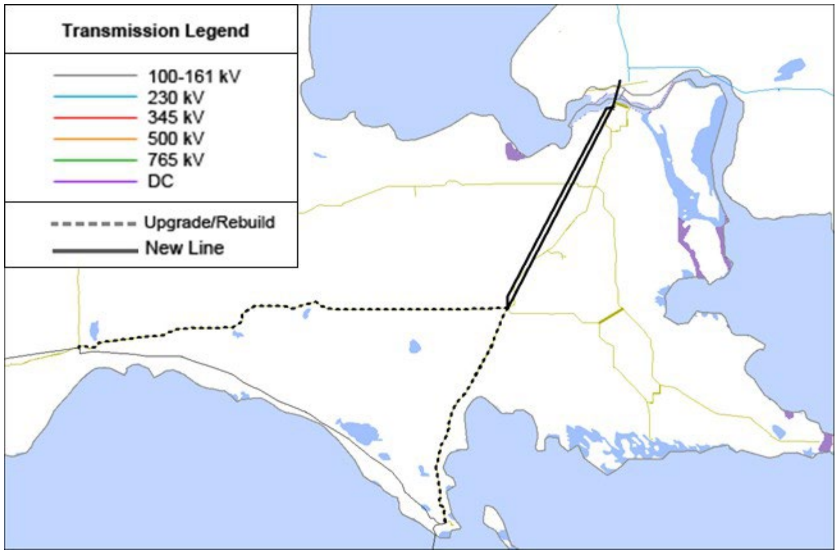
(1) New 138/115/69 kV substation (NEWSUB) tapping the existing Magazine St. – 3 Mile 69 kV line.
(2) New 138/115 kV transformer at NEWSUB
(3) New 138/69 kV transformer at NEWSUB
(4) New 69 kV line from Magazine St. to Portage
(5) Two new 138 kV lines from NEWSUB to Pine River
(6) New 138 kV switching station at Pine River
(7) New 138/69 kV transformer at Pine River
(8) New 69 kV line from NEWSUB to Pine River
(9) Reconfigure Pine River 69 kV substation. Remove the Straits – Pine River 69 kV connections. Tie the lines to the new 138 kV switching station. Use a newly opened terminal at Pine River for the new 138/69 kV transformer.

ii) Interconnection:
(1) New 115/115 kV Phase Angle Regulating transformer at NEWSUB
(2) New 115 kV tie line from NEWSUB to Clergue TS (IESO)

Or

(3) Two new 138 kV lines connecting an existing combined cycle gas power plant in Sault Ste. Marie. Adjust system to disconnect the existing plant from Ontario's system.
(4) The 138/115 kV transformer will no longer be needed

4) Transmission Idea MI-4



i) Michigan Facilities:

(1) New 138/115/69 kV substation (NEWSUB) tapping the existing Magazine St. – 3 Mile 69 kV line.
(2) New 138/115 kV transformer at NEWSUB
(3) New 138/69 kV transformer at NEWSUB
(4) New 69 kV line from Magazine St. to Portage
(5) New 69 kV from Pickford to a tap on Pine River – Rockview
(6) Rebuild Pine River – Hiawatha 69 kV line to 138 kV
(7) Two new 138 kV lines from NEWSUB to Pine River
(8) New 138 kV switching station at Pine River
(9) New 138/69 kV transformer at Pine River
(10) New 69 kV line from NEWSUB to Pine River
(11) Reconfigure Pine River 69 kV substation. Remove the Straits – Pine River 69 kV connections. Tie the lines to the new 138 kV switching station. Use a newly opened terminal at Pine River for the new 138/69 kV transformer.

ii) Interconnection:
(1) New 115/115 kV Phase Angle Regulating transformer at NEWSUB
(2) New 115 kV tie line from NEWSUB to Clergue TS (IESO)

Or

(3) Two new 138 kV lines connecting an existing combined cycle gas power plant in Sault Ste. Marie. Adjust system to disconnect the existing plant from Ontario's system.
(4) The 138/115 kV transformer will no longer be needed

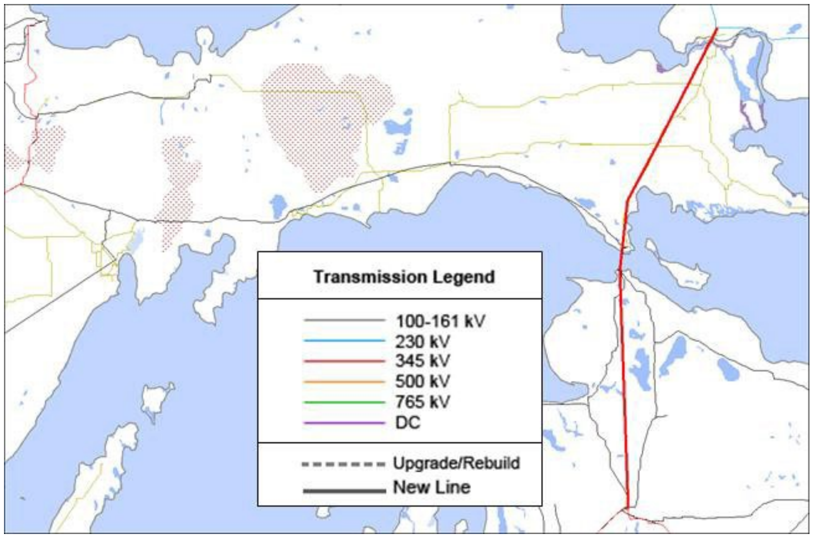
5) <u>Transmission Idea MI-5</u>
The base transmission for MI-5 is the same as MI-1. The difference is the voltage level of the tie line. For MI-5, the interconnection is an increase to a new 230 kV line from NEWSUB to Third Line (IESO). This also entails changing the voltage level and associated transformer of NEWSUB to 230/69 kV.

6) <u>Transmission Idea MI-6</u>
The base transmission for MI-6 is the same as MI-2. The difference is the voltage level of the tie line. For MI-5, the interconnection is an increase to a new 230 kV line from NEWSUB to Third Line (IESO). This also entails changing the voltage level and associated transformers of NEWSUB to 230/138/69 kV.

7) <u>Transmission Idea MI-7</u>
The base transmission for MI-6 is the same as MI-2. The difference is the voltage level of the tie line. For MI-5, the interconnection is an increase to a new 230 kV line from NEWSUB to Third Line (IESO). This also entails changing the voltage level and associated transformers of NEWSUB to 230/138/69 kV.

8) <u>Transmission Idea MI-8</u>
The base transmission for MI-6 is the same as MI-2. The difference is the voltage level of the tie line. For MI-5, the interconnection is an increase to a new 230 kV line from NEWSUB to Third Line (IESO). This also entails changing the voltage level and associated transformers of NEWSUB to 230/138/69 kV.

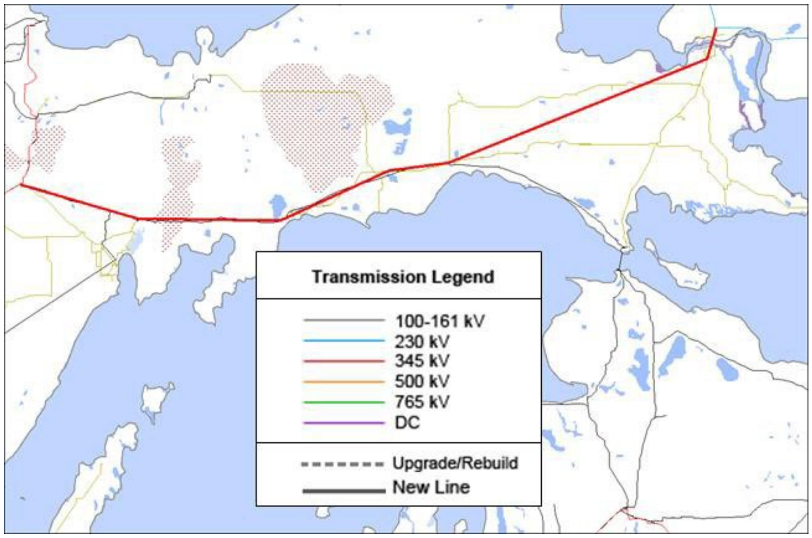
9) Transmission Idea MI-9



i) Facilities:

(1) New 345 kV line from Livingston to Third Line (IESO)
(2) New 345 kV substation at Third Line (IESO)
(3) New 345/230 kV transformer at Third Line (IESO)

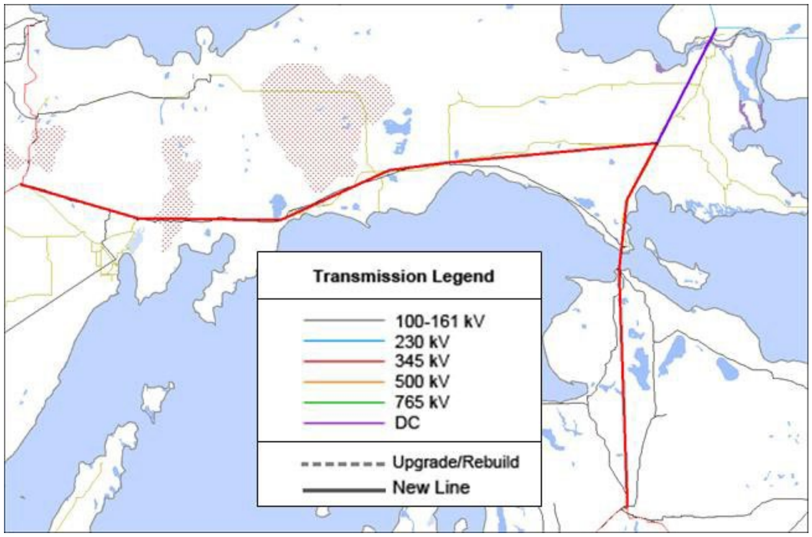
10) <u>Transmission Idea MI-10</u>



i) Facilities:

(1) New 345 kV line from Arnold to Third Line (IESO)
(2) New 345 kV substation at Third Line (IESO)
(3) New 345/230 kV transformer at Third Line (IESO)

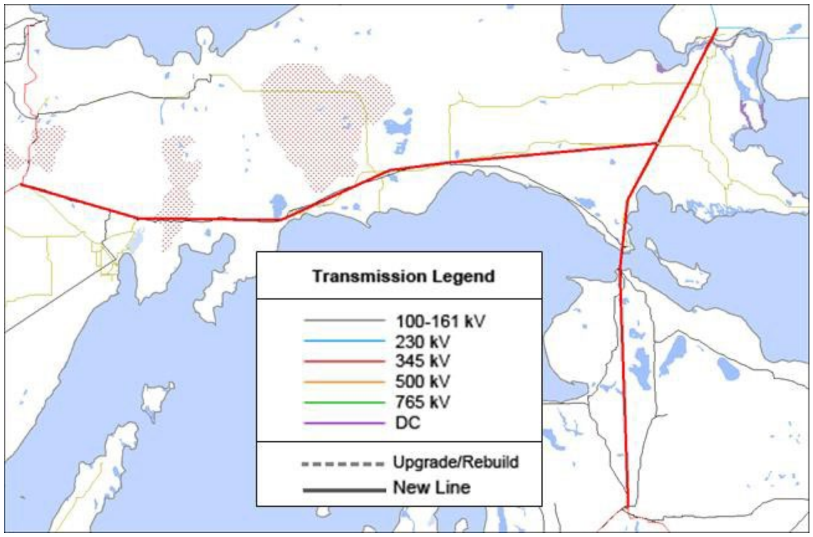
11) <u>Transmission Idea MI-11</u>



i) Facilities:

(1) New 345 kV line from Arnold to Pine River
(2) New 345 kV line from Livingston to Pine River
(3) New 345 kV substation at Pine River
(4) New 345 kV line from Pine River to Third Line (IESO)
(5) New HVDC/345/230 kV substation at Third Line (IESO) (back to back AC/DC/AC)

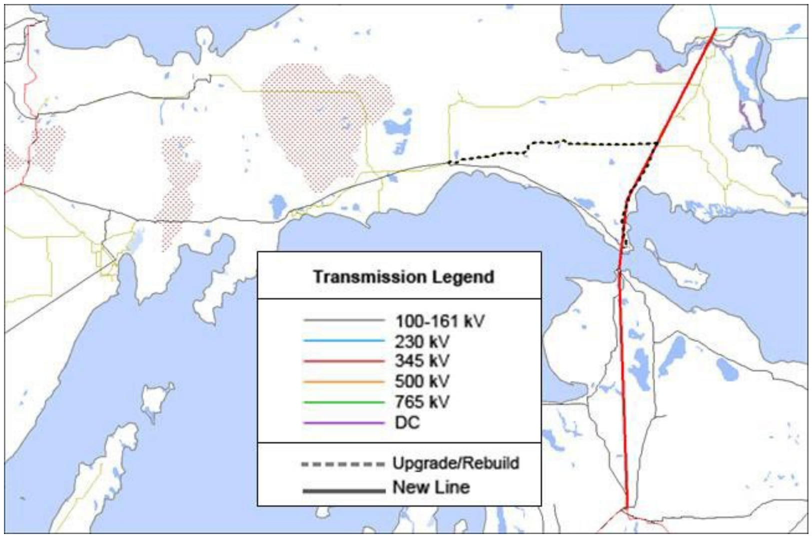
12) <u>Transmission Idea MI-12</u>



i) Facilities:

(1) New 345 kV line from Arnold to Pine River
(2) New 345 kV line from Livingston to Pine River
(3) New 345 kV substation at Pine River
(4) New 345 kV line from Pine River to Third Line (IESO)
(5) New 345kV substation at Third Line (IESO)
(6) New 345/230 kV transformer at Third Line (IESO)

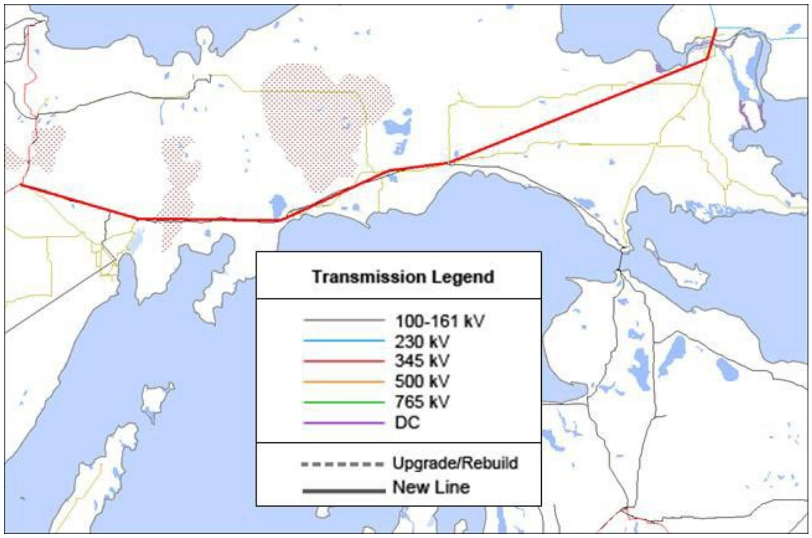
13) <u>Transmission Idea MI-13</u>



i) Facilities:

(1) New 345 kV line from Livingston to McGulpin
(2) New 345 kV substation at McGulpin
(3) New 345/138 kV transformer at McGulpin
(4) New 345 kV line from McGulpin to Pine River
(5) New 345/138 kV substation at Pine River
(6) New 345/138 kV transformer at Pine River
(7) New 138/69 kV transformer at Pine River
(8) Reconfigure Pine River 69 kV substation. Move Pine River – Straits 69 kV lines (2) to the 138 kV station and operate at 138 kV
(9) New 345 kV line from Pine River to Third Line (IESO)
(10) New 345 kV substation at Third Line (IESO)
(11) New 345/230 kV transformer at Third Line (IESO)
(12) Rebuild 69 kV line from Hiawatha to Pine River to 138 kV

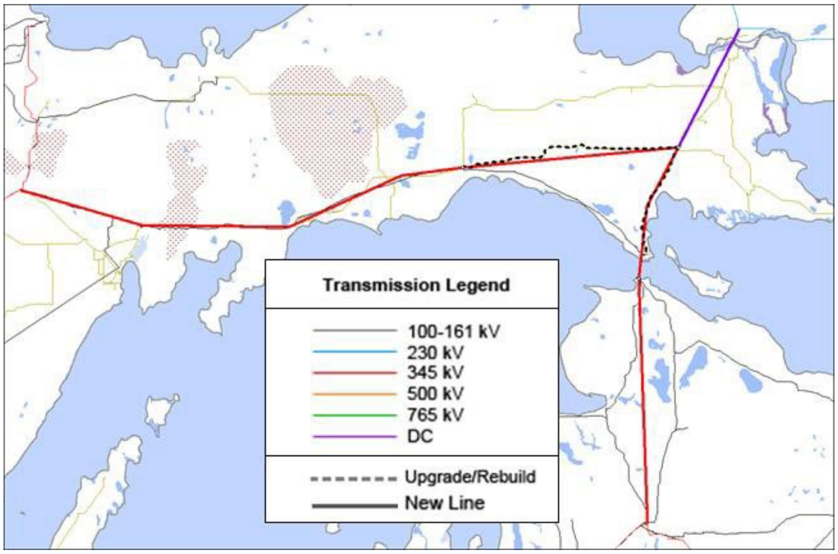
14) <u>Transmission Idea MI-14</u>



i) Facilities:

(1) New 345 kV line from Arnold to Hiawatha
(2) New 345 kV substation at Hiawatha
(3) New 345/138 kV transformer at Hiawatha
(4) New 345 kV line from Hiawatha to Third Line
(5) New 345 kV substation at Third Line (IESO)
(6) New 345/230 kV transformer at Third Line (IESO)
(7) Rebuild 69 kV line from Hiawatha to Pine River to 138 kV

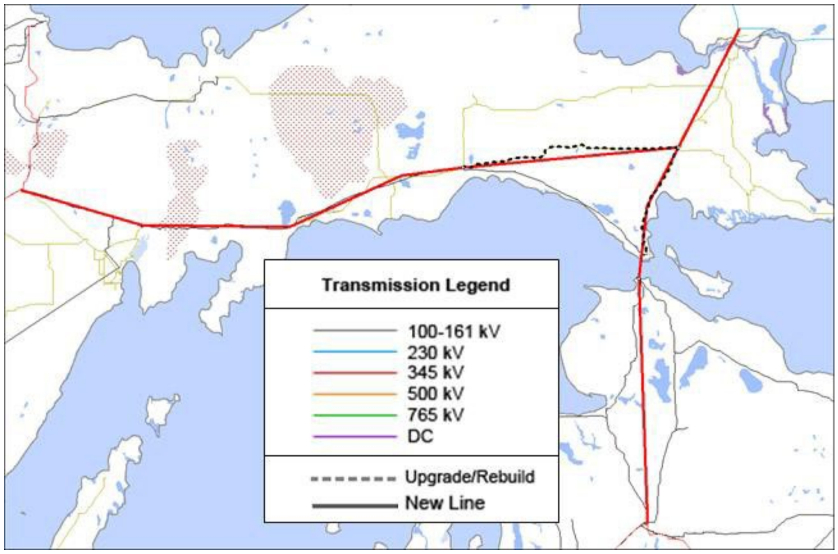
15) Transmission Idea MI-15



i) Facilities:

(1) New 345 kV line from Arnold to Hiawatha
(2) New 345 kV substation at Hiawatha
(3) New 345/138 kV transformer at Hiawatha
(4) New 345 kV line from Hiawatha to Pine River
(5) New 345 kV line from Livingston to McGulpin
(6) New 345 kV substation at McGulpin
(7) New 345/138 kV transformer at McGulpin
(8) New 345 kV line from McGulpin to Pine River
(9) New 345/138 kV substation at Pine River
(10) New 345/138 kV transformer at Pine River
(11) New 138/69 kV transformer at Pine River
(12) Reconfigure Pine River 69 kV substation. Move Pine River – Straits 69 kV lines (2) to the 138 kV station and operate at 138 kV
(13) New 345 kV line from Pine River to Third Line (IESO)
(14) New HVDC/345/230 kV substation at Third Line (IESO) (back to back AC/DC/AC)
(15) Rebuild 69 kV line from Hiawatha to Pine River to 138 kV

16) <u>Transmission Idea MI-16</u>



i) Facilities:

(1) New 345 kV line from Arnold to Hiawatha
(2) New 345 kV substation at Hiawatha
(3) New 345/138 kV transformer at Hiawatha
(4) New 345 kV line from Hiawatha to Pine River
(5) New 345 kV line from Livingston to McGulpin
(6) New 345 kV substation at McGulpin
(7) New 345/138 kV transformer at McGulpin
(8) New 345 kV line from McGulpin to Pine River
(9) New 345/138 kV substation at Pine River
(10) New 345/138 kV transformer at Pine River
(11) New 138/69 kV transformer at Pine River
(12) Reconfigure Pine River 69 kV substation. Move Pine River – Straits 69 kV lines (2) to the 138 kV station and operate at 138 kV
(13) New 345 kV line from Pine River to Third Line (IESO)
(14) New 345kV substation at Third Line (IESO)
(15) New 345/230 kV transformer at Third Line (IESO)
(16) Rebuild 69 kV line from Hiawatha to Pine River to 138 kV

IV. Cost Estimates

Transmission cost estimates were provided by MISO's Competitive Transmission Administration team. These costs are high level estimates that are not comparable to MISO planning or scoping level cost estimates. Generator cost estimates were sourced from MTEP17 capital costs assumptions for combined cycle (CC) and combustion turbine (CT) power plants. Reciprocating internal combustion engine (RICE) power plant cost estimates were sourced from the UMERC Certificate of Need Case No. U-18224. Detailed cost breakdowns for each option can be found in Appendix C.

Transmission Idea	IESO Tie Cost ($M)	Radial Gen Cost ($M)
MI-1	85.4	89.8
MI-2	92.9	89.8
MI-3	112.1	109.1
MI-4	183.4	180.4
MI-5	93.8	
MI-6	102.3	
MI-7	121.6	
MI-8	192.9	
MI-9	347.1	
MI-10	490.0	
MI-11	1,138.9	
MI-12	787.0	
MI-13	460.0	
MI-14	572.4	
MI-15	1,259.2	
MI-16	907.4	
Kalkaska CC	430.0	
Chippewa County CC	108.0	
Chippewa County RICE	132.4	
Chippewa County CT	92.0	

Table 6: High Level Cost Estimates

V. Reliability Analysis and Results

MISO conducted a reliability analysis of the transmission and generation ideas. This analysis entailed running P1 and P2 (single element) outages in Michigan. MTEP17 Shoulder Peak and Summer Peak models were used for analysis. Additionally, IESO performed an analysis of the Ontario system, specifically around Sault Ste. Marie area, to identify transfer capabilities of the Ontario system. IESO's analysis determined three levels of transfer, depending on the amount of system enhancements that were to be made to transmission system[4]. Accordingly, MISO studied the three transfer levels on the MISO system.

Scenario	Export Capability		Description
	Summer	Winter	
Without system enhancements	50 MW	25 MW	Limited by thermal ratings on the local, 115 kV transmission system
With system enhancements	125 MW	75 MW	Required enhancements: - Mitigation of thermal constraints on the 115 kV system - Reconfiguration of 230 kV circuits supplying the SSM system[2] Limited by Third Line TS autotransformers and the thermal rating of 115 kV circuits connecting Steelton/Patrick St. TS and Clergue TS
With system enhancements	325 MW	275 MW	Required enhancements: - New 230 kV circuit from Clergue TS to Third Line TS (approximately 5 km) - Reconfiguration of 230 kV circuits supplying the SSM system - Additional voltage control facilities Limited by thermal ratings of 230 kV circuits supplying SSM system

Table 7: IESO Reliability Analysis[5]

When adding the transmission ideas that included a transmission tie between the Ontario and Michigan transmission systems, the base case showed overloads and high flows on the tie lines flowing into Michigan. Phase angle differences between the Ontario and MISO systems resulted in high, uncontrollable flows along the tie lines. To address these concerns, MISO incorporated Phase Angle Regulating transformers into the transmission ideas tying to the Ontario system. This is reflected in the transmission idea descriptions and costs in previous sections.

When studying the various transfer levels, significant and widespread reliability issues were identified at the 325 MW transfer level. Accordingly, MISO determined this was an unreasonable transfer level due to the high cost associated with mitigating the numerous issues. As such, the lower voltage options (MI-1 to MI-8) were deemed more appropriate due to the low transfer limitations (125 MW maximum).

[4] See Appendix D, Sault St. Marie Export Study For MISO

[5] Export Capability is based on current system conditions and is provided for the purpose of the Michigan Exploratory Transmission Study. It is subject to change based on future system conditions. The acronym "SSM" stands for "Sault Ste. Marie".

No reliability issues were seen in any of the transmission ideas when analyzing the 50 MW transfer level. The 125 MW transfer level showed reliability issues for MI-1, MI-2, MI-5, and MI- 6 due to limited power transfer capabilities of the local system near the new Michigan/Ontario tie. The transmission options do not provide enough outlet capacity for the new transfer. Because the transmission ideas are incremental in terms of transmission build out, issues seen in the lower-numbered options are addressed by the transmission upgrades in higher- numbered options. Option MI-3 and MI-7 had a few 69 kV thermal issues for one contingency only. Option MI-4 showed no reliability concerns at the 125 MW transfer level. Adding a 100 MW power plant in Chippewa County, MI also showed no reliability issues when studied.

VI. Economic Analysis and Results

MISO performed a production cost analysis using the models developed specifically for Phase II. PROMOD was used to perform simulations for each hour of three study years: 2021, 2026, and 2031. MISO studied all transmission and generation ideas in the study.

The higher voltage solutions (MI-9 to MI-16) were studied in parallel with the reliability assessment. As such, these scenarios were studied at a 400 MW transfer level. The reliability analysis determined a 125 MW transfer to be a reasonable transfer limit. The results of the 400 MW transfer for options MI-9 to MI-16 are still included for reference. Reliability upgrades and associated costs are not included in these results.

While initially studied at a 200 MW transfer level due to the parallel economic and reliability analysis, the lower voltage options (MI-1 to MI-8) were re-studied at the 125 MW transfer level, as per the reliability analysis. Due to the reliability concerns with MI-1, MI-2, MI-5, and MI-6, economic results are not shown for these options. The remaining transmission options incorporate the reliability upgrades that would be necessitated. The economic results for MI-3, MI-4, MI-7, and MI-8 are reported at the 125 MW transfer level. MISO used a combined cycle power plant located in Sault Ste. Marie, Ontario to simulate up to 125 MW of power transfer from Ontario to Michigan. This unit was used for both the radial generator connection and tie line options. A phase angle regulator was part of the tie line options, as previously described.

The following economic results list the 20 year present value costs, 20 year present value adjusted production cost (APC) benefits, 20 year present value net impact, and 20 year present value benefit to cost ratios. The 20 year present value costs are created using the costs previously listed, and applying a MISO gross-plant weighted average discount rate and inflation rate for 20 years. Similarly, the APC benefits are extrapolated using the APC savings from the 2021, 2026, and 2031 study years over a 20 year timeframe. The net impact is calculated by subtracting the project costs from the project benefits. Negative numbers (red) indicate costs higher than provided benefits. A benefit to cost ratio (B/C) is a similar comparison. It is calculated by dividing the total benefits by the total cost. A 1.0 B/C indicates the project costs are equal to the benefits. Ratios below 1.0 indicate costs outweighing the benefits provided. Ratios above 1.0 indicate benefits outweighing costs.

Project IDs	Assumed Max Import (MW)	20 Year PV Cost (M$)	20 Year PV MI APC Benefit (M$)	20 Year PV Net Impact	20 Year PV B/C Ratio
MI-3	125	(145.42)	19.00	(124.81)	0.13
MI-4	125	(240.51)	28.00	(210.89)	0.12
MI-7	125	(162.09)	23.00	(128.73)	0.14
MI-8	125	(257.17)	29.00	(217.81)	0.11
MI-9	400	(462.91)	198.00	(264.91)	0.43
MI-10	400	(653.49)	218.00	(435.49)	0.33
MI-11	400	(1518.71)	242.00	(1276.71)	0.16
MI-12	400	(1049.53)	219.00	(830.53)	0.21
MI-13	400	(613.48)	202.00	(411.48)	0.33
MI-14	400	(763.35)	218.00	(545.35)	0.29
MI-15	400	(1679.24)	244.00	(1435.24)	0.15
MI-16	400	(1210.06)	230.00	(980.06)	0.19

Table 8: Transmission Options Economic Analysis

Project IDs	Generator Capacity (MW)	20 Year PV Cost (M$)	20 Year PV MI APC Benefit (M$)	20 Year PV Net Impact	20 Year PV B/C Ratio
Kalkaska CC	400	(573.43)	287.00	(286.43)	0.50
Chippewa County CC	100	(144.02)	27.00	(117.02)	0.19
Chippewa County RICE	100	(176.59)	30.00	(146.59)	0.17
Chippewa County CT	100	(122.69)	12.51	(110.18)	0.10

Table 9: Generation Options Economic Analysis

In addition to the generation only and transmission only options, generation was also combined with the transmission ideas to explore the combined impact to the production costs. Additionally, the voltage source converter (VSC) Mackinac Straits flow control device was simulated at current operating limitations as well as maximum equipment capabilities.

1) <u>Combined Generation and Transmission</u>

   The PROMOD analysis showed economic benefits that were additive. When comparing the “generator only” benefits and the “transmission only” benefits to the benefits of combined generation and transmission scenarios, the benefits of the combined scenarios were comparable to the sum of the “generator only” benefits and the “transmission only” benefits. Accordingly, economic results are reported separately (generation only and transmission only).

2) VSC Sensitivity

The VSC was tested at maximum capability (+/- 226 MVA) as well as current operating limitations for generation only, transmission only, and combined generation and transmission scenarios. The economic benefits of allowing the VSC to operate at the maximum equipment capabilities were within 0%-5% higher than operating the VSC at the current operational limitations. To increase the VSC capabilities, reliability upgrades would be required in addition to transmission ideas to reliably handle the higher flows.

3) Radial Generator vs. Ontario System Tie Line

The two scenarios resulted in comparable economic benefits/production costs. The difference between the two options is the costs associated with each option and are listed in Table 6.

VII. Conclusions

The economic and reliability analyses determined that all of the transmission and generation solutions did not provide enough economic benefit to cover the costs of such projects. Due to low transfer limitations (125 MW) identified by the reliability analysis, as well as relatively high costs associated with the projects, the amount of economic potential was limited. Generation and transmission options in the Upper Peninsula provided comparable amounts of economic benefits for similar costs.

Appendix A

RICK SNYDER
GOVERNOR

STATE OF MICHIGAN
EXECUTIVE OFFICE
LANSINCr

BRIAN CALLEY
LT. GOVERNOR

August 17, 2016

John Lawhorn
Senior Director of Policy and Economic Studies
Midcontinent Independent System Operator
P.O. Box 4202
Carmel, IN 46082-4202

Dear Mr. Lawhorn,

The Michigan Agency for Energy (MAE) requests that the Midcontinent Independent System Operator (MISO) conduct system analyses to help the State of Michigan better understand the potential production cost savings, reliability, and resource adequacy benefits of transmission including increased import capability, and generation expansion in Michigan. MISO's regional planning and modeling expertise will be invaluable to us as we set Michigan on a path toward adaptable, reliable, affordable and environmentally protective energy. Specifically, we would ask that MISO conduct a near and long term evaluation of transmission expansion better connecting the Upper Peninsula of Michigan to our Canadian neighbors as well as to lower Michigan.

Many fundamental characteristics of the Bulk Electric System (BES) have evolved over the last five years on both sides of the international border, and change to the system is expected to accelerate within Michigan. With so many changes to the overall MISO system, but especially the challenges that Michigan residents and business face, it is critical for Michigan that MISO conduct analyses that consider updated system assumptions and scenarios specific to Michigan's unique peninsulas. For MISO's consideration, an attachment to this letter outlines recent and expected changes to the electricity system that could have an impact in Michigan.

Specifically, MAE requests that MISO conduct a near and long term regional evaluation of potential production cost savings, reliability, and resource adequacy benefits of transmission and generation expansion in MISO's northern footprint, specifically Michigan's eastern Upper Peninsula (part of Zone 2) up to Sault Ste. Marie, Ontario and northern Lower Peninsula (Zone 7) at the Straits of Mackinac down to the northernmost portion of the existing 345 kV transmission line near Gaylord, MI. Alternatively, MAE requests MISO update its 2012 Northern Area Study for these same Michigan areas, but in that event, to work more closely with the Ontario grid operators to ensure possible benefits are fully studied, as we understand the interconnection is to an area that has high production potential compared to the load but constrained transmission. Ontario's next Long-Term Energy Plan process will commence this summer, so this may be an excellent opportunity to work together.

Further, MAE is interested to know the impacts that a new natural gas-fired electric generating station located strategically in northern lower Michigan could have on the BES, especially in conjunction with the transmission upgrades. As you know, Michigan is likely to have to add capacity, likely in the form of a natural gas plant, in the near term. An evaluation as to the ability of strategic location of that plant to be part of an overall cost-lowering strategy is something that would be especially beneficial at this time.

Specifically, MAE would like MISO to model the production cost savings, reliability, resource adequacy, and power flows that would result from a natural gas-fired generating station located in the northcentral Lower Peninsula of Michigan. The optimal site to model new gas-fired generation is near existing underground natural gas storage fields in Otsego and Kalkaska counties, intrastate natural gas pipelines, and 345 kV electric transmission lines in the northern Lower Peninsula.

MAE appreciates your consideration of this request and are happy to address any additional questions you would have. MAE staff would be happy to provide any technical assistance, government-to-government outreach, or any other support that would be requested by MISO to assist it in conducting this study.

Sincerely,

Valerie Brader

Rick Snyder
Governor

Valerie Brader
Executive Director

Michigan Agency for Energy

Attachment

Appendix B

August 9, 2016

Mr. John Lawhorn
Senior Director of Policy and Economic Studies
Midcontinent Independent System Operator
P.O. Box 4202
Carmel, IN 46082-4202

Dear Mr. Lawhorn,

The Michigan Agency for Energy (MAE) and the Michigan Public Service Commission (MPSC) request that the Midcontinent Independent System Operator (MISO) conduct a study to help the State of Michigan better understand the effects of declining reserve margins in emergency situations. As you know, Michigan has recently experienced a large number of plant retirements in the very recent past, and MISO's regional planning and modeling expertise is necessary and invaluable to us as we look to determine whether Michigan is on track to continue meeting its reliability goals, including the goal never to experience a massive outage due to a lack of supply.

Many fundamental characteristics of the Bulk Electric System (BES) have evolved over the last five years, and change to the system is expected to accelerate. With system-wide capacity shortfalls in MISO anticipated as soon as 2018 per the 2016 MISO-OMS Survey, it is critical for Michigan to understand whether our system still can support the level of reliability it was able to show a few years ago. To that end, we request that MISO conduct a scenario analysis that considers updated system assumptions specific to Michigan's unique structure. An attachment to this letter outlines recent and expected changes to the electricity system that could have an impact in Michigan.

Declining reserve margins in MISO and in Michigan require that we more fully understand the implications on Michigan, specific from MISO, of certain energy emergencies. As such, MAE requests that MISO assess and inform Michigan of vulnerabilities associated with simultaneous planned or unplanned outages at Palisades Power Plant (Palisades) and Fermi, Unit 2 (Fermi 2) nuclear energy facilities. These two facilities are capable of producing a combined 1,855 MW of reliable baseload power.

We did not pick this scenario randomly. Rather, it is our goal to understand what would happen in the summer of 2018 if we had a recurrence of the events that occurred in the summer of 2012, when there were simultaneous outages at these two nuclear facilities while MISO was under a hot weather alert. Obviously, in 2012, we were able to sustain the grid in those conditions. We would like to know if that would still be expected to be true.

Accounting for the retirement of numerous coal-fired generation this summer and other expected future changes to the system, we request that MISO conduct an analysis that assumes Palisades and Fermi 2 are offline, and then determines for MISO zone 7 (1) what internal generating capacity, (2) what contracted capacity, (3) what import capability; and (4) what capacity and transmission service from outside of Michigan, could be available to serve Michigan load. We appreciate your consideration of this request and are happy to address any additional questions you would have and provide any technical assistance that would be requested in support of this study.

Sincerely,

Valerie Brader
Executive Director
Michigan Agency for Energy

Sally Talberg
Chairman
Michigan Public Service Commission

System Conditions for MISO's Consideration

Generation

1. Retirement of coal-fired generators in Michigan:
   a. In 2013, one DTE Harbor Beach unit (121 MW) retired.
   b. In 2016:
      i. Two DTE Trenton Channel units (7a and 8) (240 MW) retired.
      ii. Two CE BC Cobb units in Muskegon (312 MW) retired.
      iii. Two CE JC Karn-Weadock units in Essexville (312 MW) retired.
      iv. Three CE JR Whiting units in Erie (345 MW) retired.
      v. One Michigan South Central Power Agency's Endicott unit in Litchfield (55 MW) retired.
   c. In 2017, three Holland Board of Public Works DeYoung units (3, 4, and 5) (63 MW) retiring.
   d. In 2018, six Lansing Board of Water and Light Eckert units (335 MW) retiring.
2. Palisades Nuclear power station offline after 2022 (PPA Expiration) (NRC operating license expires in 2031).
3. Fermi 2 nuclear power station remains online after 2025 (NRC license renewal is expected)
4. Announced retirement of Quad Cities nuclear power station on June 1, 2018.
5. Announced retirement of Clinton nuclear power station on June 1, 2017.
6. New Wolverine 410 MW Alpine natural gas simple cycle generating unit in Elmira Township, MI.
7. New 280 MW (summer peak) natural gas combined cycle generation in Marquette County, MI with expected in-service date in December 2019 (Project J394).
8. Impact of generation pseudo-ties out of MISO.

Load

9. Retirement of Empire Mine in 2016.

Transmission

10. Plains to National proposed transmission line moved to MTEP Appendix B.
11. 230 kV underground line from Sault Ste. Marie, Ontario to Sault Ste. Marie, MI. Presidential Permit granted.
12. Congestion mitigation of Lake Michigan loop flow.
13. Increased transfer capability across the Straits of Mackinac.
14. Maintenance flexibility for northern Lower Peninsula transmission.

15. Management flexibility of Ludington Pumped Storage asset.
16. Contribution of high voltage, direct-current flow control device and associated substation in eastern Upper Peninsula.
17. Approved MTEP reliability projects in advanced stages of development.

Other Considerations

18. New Michigan Upper Peninsula (MI-UP) Load Balancing Authority area.
19. Updated MTEP Models and Futures Scenarios.
20. Impacts voltage and local reliability (VLR) constraints and Revenue Sufficiency Guarantee (RSG) make-whole payments.

Appendix C: Detailed Cost Breakdowns

Transmission Idea MI-1								
Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	115/69	NEWSUB			New substation for connection to Ontario's system	11.8	
Reconfigure	Substation	69	Pine River			Remove connection of 1 of 2 of the Pine River - Straights 69 kV lines. Tie the line to 1 of 2 of the new Sub A - Pine River 69 kV lines. Use the newly opened terminal at Pine River to connect the 2nd Sub A - Pine River 69 kV line.	0.2	0.2
New	Transformer	115/69	NEWSUB			New transformer to tie to the local 69 kV system	7.5	
New	Line	115	NEWSUB	Clergue	7	New tie line to Ontario	8.7	
Reroute	Line	69	Magazine St.	3 Mile	1.0 + 3.0	Reroute existing line Magazine St. - 3 Mile through the new substation	4.7	4.7
New	Line	69	Magazine St.	Portage	1	New line from Magazine St. to Portage	1.2	1.2
New	Line	69	NEWSUB	Pine River	25	New Line 1 of 2 from new sub to Pine River	23.6	23.6
New	Line	69	NEWSUB	Pine River	25	New Line 2 of 2 from new sub to Pine River	23.6	23.6
New	PAR	115/115	NEWSUB			New phase angle regulating transformer	4.3	
New	Substation	138/69	NEWSUB			New substation for connection to Ontario's system		11.8
New	Transformer	138/69	NEWSUB			New transformer to tie to the local 69 kV system		7.5
New	Line	138	NEWSUB	Local Gen	7	New tie line to Ontario		8.7
New	Line	138	NEWSUB	Local Gen	7	New tie line to Ontario		8.7

Transmission Idea MI-2								
Adjustment Type	**Facility Type**	**Voltage (kV)**	**From Substation**	**To Substation**	**Estimated Length (Miles)**	**Description**	**IESO Tie Cost (M$)**	**Radial Generator Cost (M$)**
New	Substation	138/115/69	NEWSUB			New substation for connection to Ontario's system	11.8	11.8
Reconfigure	Substation	69	Pine River			Remove connection of 1 of 2 of the Pine River - Straights 69 kV lines. Tie the line to the new Sub A - Pine River 138 kV line and operate at 138 kV. Use the newly opened terminal at Pine River to connect the Sub A - Pine River 69 kV line.	0.2	0.2
New	Transformer	138/69	NEWSUB			New transformer to tie to the local 69 kV system	7.5	7.5
New	Transformer	138/115	NEWSUB			New transformer	7.5	
New	Line	138	NEWSUB	Pine River	25	New Line 2 of 2 from new sub to Pine River	23.6	23.6
New	Line	115	NEWSUB	Clergue	7	New tie line to Ontario	8.7	
Reroute	Line	69	Magazine St.	3 Mile	1.0 + 3.0	Reroute existing line Magazine St. - 3 Mile through the new substation	4.7	4.7
New	Line	69	Magazine St.	Portage	1	New line from Magazine St. to Portage	1.2	1.2
New	Line	69	NEWSUB	Pine River	25	New Line 1 of 2 from new sub to Pine River	23.6	23.6
New	PAR	115/115	NEWSUB			New phase angle regulating transformer	4.3	
New	Line	138	NEWSUB	Local Gen	7	New tie line to Ontario		8.7
New	Line	138	NEWSUB	Local Gen	7	New tie line to Ontario		8.7

Transmission Idea MI-3								
Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	138/115/69	NEWSUB			New substation for connection to Ontario's system	11.8	11.8
New	Substation	138	Pine River			New substation or switching station at Pine River	11.8	11.8
Reconfigure	Substation	69	Pine River			Move connections of the Pine River - Straights 69 kV lines to the 138 kV switching station and operate at 138 kV.	0.2	0.2
New	Transformer	138/69	Pine River			New transformer to tie to the local 69 kV system	7.5	7.5
New	Transformer	138/69	NEWSUB			New transformer to tie to the local 69 kV system	7.5	7.5
New	Transformer	138/115	NEWSUB			New transformer	7.5	
New	Line	138	NEWSUB	Pine River	25	New Line 2 of 2 from new sub to Pine River	23.6	23.6
New	Line	138	NEWSUB	Pine River	25	New Line 1 of 2 from new sub to Pine River	23.6	23.6
New	Line	115	NEWSUB	Clergue	7	New tie line to Ontario	8.7	
Reroute	Line	69	Magazine St.	3 Mile	1.0 + 3.0	Reroute existing line Magazine St. - 3 Mile through the new substation	4.7	4.7
New	Line	69	Magazine St.	Portage	1	New line from Magazine St. to Portage	1.2	1.2
New	PAR	115/115	NEWSUB			New phase angle regulating transformer	4.3	
New	Line	138	NEWSUB	Local Gen	7	New tie line to Ontario		8.7
New	Line	138	NEWSUB	Local Gen	7	New tie line to Ontario		8.7

Transmission Idea MI-4								
Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	138/115/69	NEWSUB			New substation for connection to Ontario's system	11.8	11.8
New	Substation	138	Pine River			New substation or switching station at Pine River	11.8	11.8
Reconfigure	Substation	69	Pine River			Move connections of the Pine River - Straights 69 kV lines to the 138 kV switching station and operate at 138 kV.	0.2	0.2
New	Transformer	138/69	Pine River			New transformer to tie to the local 69 kV system	7.5	7.5
New	Transformer	138/69	NEWSUB			New transformer to tie to the local 69 kV system	7.5	7.5
New	Transformer	138/115	NEWSUB			New transformer	7.5	
Rebuild	Line	138	Hiawatha	Pine River	48	Rebuild the 69 kV line from Hiawatha to Pine River to 138 kV and tie to the new station at Pine River.	59.5	59.5
New	Line	138	NEWSUB	Pine River	25	New Line 2 of 2 from new sub to Pine River	23.6	23.6
New	Line	138	NEWSUB	Pine River	25	New Line 1 of 2 from new sub to Pine River	23.6	23.6
New	Line	115	NEWSUB	Clergue	7	New tie line to Ontario	8.7	
Reroute	Line	69	Magazine St.	3 Mile	1.0 + 3.0	Reroute existing line Magazine St. - 3 Mile through the new substation	4.7	4.7
New	Line	69	Magazine St.	Portage	1	New line from Magazine St. to Portage	1.2	1.2
New	Line	69	Pickford	Tap	10	New 69 kV line from a tap on the Pine River - Rockview 69 kV to Pickford 69 kV	11.8	11.8
New	PAR	115/115	NEWSUB			New phase angle regulating transformer	4.3	
New	Line	138	NEWSUB	Local Gen	7	New tie line to Ontario		8.7
New	Line	138	NEWSUB	Local Gen	7	New tie line to Ontario		8.7

Transmission Idea MI-5								
Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	230/69	NEWSUB			New substation for connection to Ontario's system	11.8	11.8
Reconfigure	Substation	69	Pine River			Remove connection of 1 of 2 of the Pine River - Straights 69 kV lines. Tie the line to 1 of 2 of the new Sub A - Pine River 69 kV lines. Use the newly opened terminal at Pine River to connect the 2nd Sub A - Pine River 69 kV line.	0.2	0.2
New	Transformer	115/69	NEWSUB			New transformer to tie to the local 69 kV system	7.5	7.5
New	Line	230	NEWSUB	Third Line	10	New tie line to Ontario	13.6	13.6
Reroute	Line	69	Magazine St.	3 Mile	1.0 + 3.0	Reroute existing line Magazine St. - 3 Mile through the new substation	4.7	4.7
New	Line	69	Magazine St.	Portage	1	New line from Magazine St. to Portage	1.2	1.2
New	Line	69	NEWSUB	Pine River	25	New Line 1 of 2 from new sub to Pine River	23.6	23.6
New	Line	69	NEWSUB	Pine River	25	New Line 2 of 2 from new sub to Pine River	23.6	23.6
New	PAR	230/230	NEWSUB			New phase angle regulating transformer	7.8	

Transmission Idea MI-6								
Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	230/138/69	NEWSUB			New substation for connection to Ontario's system	11.8	11.8
Reconfigure	Substation	69	Pine River			Remove connection of 1 of 2 of the Pine River - Straights 69 kV lines. Tie the line to the new Sub A - Pine River 138 kV line and operate at 138 kV. Use the newly opened terminal at Pine River to connect the Sub A - Pine River 69 kV line.	0.2	0.2
New	Transformer	230/138	NEWSUB			New transformer	8.5	8.5
New	Transformer	138/69	NEWSUB			New transformer to tie to the local 69 kV system	7.5	7.5
New	Line	230	NEWSUB	Third Line	10	New tie line to Ontario	13.6	13.6
New	Line	138	NEWSUB	Pine River	25	New Line 2 of 2 from new sub to Pine River	23.6	23.6
Reroute	Line	69	Magazine St.	3 Mile	1.0 + 3.0	Reroute existing line Magazine St. - 3 Mile through the new substation	4.7	4.7
New	Line	69	Magazine St.	Portage	1	New line from Magazine St. to Portage	1.2	1.2
New	Line	69	NEWSUB	Pine River	25	New Line 1 of 2 from new sub to Pine River	23.6	23.6
New	PAR	230/230	NEWSUB			New phase angle regulating transformer	7.8	

Transmission Idea MI-7								
Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	230/138/69	NEWSUB			New substation for connection to Ontario's system	11.8	11.8
New	Substation	138	Pine River			New substation or switching station at Pine River	11.8	11.8
Reconfigure	Substation	69	Pine River			Move connections of the Pine River - Straights 69 kV lines to the 138 kV switching station and operate at 138 kV.	0.2	0.2
New	Transformer	230/138	NEWSUB			New transformer	8.5	8.5
New	Transformer	138/69	Pine River			New transformer to tie to the local 69 kV system	7.5	7.5
New	Transformer	138/69	NEWSUB			New transformer to tie to the local 69 kV system	7.5	7.5
New	Line	230	NEWSUB	Third Line	10	New tie line to Ontario	13.6	13.6
New	Line	138	NEWSUB	Pine River	25	New Line 2 of 2 from new sub to Pine River	23.6	23.6
New	Line	138	NEWSUB	Pine River	25	New Line 1 of 2 from new sub to Pine River	23.6	23.6
Reroute	Line	69	Magazine St.	3 Mile	1.0 + 3.0	Reroute existing line Magazine St. - 3 Mile through the new substation	4.7	4.7
New	Line	69	Magazine St.	Portage	1	New line from Magazine St. to Portage	1.2	1.2
New	PAR	230/230	NEWSUB			New phase angle regulating transformer	7.8	

Transmission Idea MI-8								
Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	230/138/69	NEWSUB			New substation for connection to Ontario's system	11.8	11.8
New	Substation	138	Pine River			New substation or switching station at Pine River	11.8	11.8
Reconfigure	Substation	69	Pine River			Move connections of the Pine River - Straights 69 kV lines to the 138 kV switching station and operate at 138 kV.	0.2	0.2
New	Transformer	230/138	NEWSUB			New transformer	8.5	8.5
New	Transformer	138/69	Pine River			New transformer to tie to the local 69 kV system	7.5	7.5
New	Transformer	138/69	NEWSUB			New transformer to tie to the local 69 kV system	7.5	7.5
New	Line	230	NEWSUB	Third Line	10	New tie line to Ontario	13.6	13.6
Rebuild	Line	138	Hiawatha	Pine River	48	Rebuild the 69 kV line from Hiawatha to Pine River to 138 kV and tie to the new station at Pine River.	59.5	59.5
New	Line	138	NEWSUB	Pine River	25	New Line 2 of 2 from new sub to Pine River	23.6	23.6
New	Line	138	NEWSUB	Pine River	25	New Line 1 of 2 from new sub to Pine River	23.6	23.6
Reroute	Line	69	Magazine St.	3 Mile	1.0 + 3.0	Reroute existing line Magazine St. - 3 Mile through the new substation	4.7	4.7
New	Line	69	Magazine St.	Portage	1	New line from Magazine St. to Portage	1.2	1.2
New	Line	69	Pickford	Tap	10	New 69 kV line from a tap on the Pine River - Rockview 69 kV to Pickford 69 kV	11.8	11.8
New	PAR	230/230	NEWSUB			New phase angle regulating transformer	7.8	

Transmission Idea MI-9

Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	345	Third Line			New substation in Ontario	11.8	11.8
New	Transformer	345/230	Third Line			Tie the new voltage to the local 230 kV system	8.5	8.5
New	Line	345	Livingston	Third Line	115.5	New 345 kV tie from Livingston to Ontario	326.9	326.9

Transmission Idea MI-10

Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	345	Third Line			New substation in Ontario	11.8	11.8
New	Transformer	345/230	Third Line			Tie the new voltage to the local 230 kV system	8.5	8.5
New	Line	345	Arnold	Third Line	166	New 345 kV tie from Arnold to Ontario	469.8	469.8

Transmission Idea MI-11

Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	HVDC/345/230	Third Line			New substation in Ontario with 230 kV AC/DC/ 345 kV AC conversion	372.1	372.1
New	Substation	345	Pine River			New substation or switching station at Pine River	15.4	15.4
New	Line	345	Arnold	Pine River	150	New 345 kV Line	424.5	424.5
New	Line	345	Livingston	Pine River	82.5	New 345 kV Line	233.5	233.5
New	Line	345	Third Line	Pine River	33	New tie line to Ontario	93.4	93.4

Transmission Idea MI-12								
Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	345	Third Line			New substation in Ontario	11.8	11.8
New	Substation	345	Pine River			New substation or switching station at Pine River	15.4	15.4
New	Transformer	345/230	Third Line			Tie the new voltage to the local 230 kV system	8.5	8.5
New	Line	345	Arnold	Pine River	150	New 345 kV Line	424.5	424.5
New	Line	345	Livingston	Pine River	82.5	New 345 kV Line	233.5	233.5
New	Line	345	Third Line	Pine River	33	New tie line to Ontario	93.4	93.4

Transmission Idea MI-13								
Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	345/138	Pine River			New substation or switching station at Pine River	15.4	15.4
New	Substation	345	McGulpin			New substation or switching station at McGulpin	15.4	15.4
New	Substation	345	Third Line			New substation in Ontario	11.8	11.8
Reconfigure	Substation	69	Pine River			Move connections of the Pine River - Straights 69 kV lines to the 138 kV switching station and operate at 138 kV.	0.2	0.2
New	Transformer	345/230	Third Line			Tie the new voltage to the local 230 kV system	8.5	8.5
New	Transformer	345/138	McGulpin			New transformer	7.5	7.5
New	Transformer	345/138	Pine River			New transformer	7.5	7.5
New	Transformer	138/69	Pine River			New transformer to tie to the local 69 kV system	7.5	7.5
New	Line	345	Livingston	McGulpin	52	New 345 kV Line	147.2	147.2
New	Line	345	McGulpin	Pine River	30.5	New 345 kV Line	86.3	86.3
New	Line	345	Third Line	Pine River	33	New tie line to Ontario	93.4	93.4
Rebuild	Line	138	Hiawatha	Pine River	48	Rebuild the 69 kV line from Hiawatha to Pine River to 138 kV and tie to the new station at Pine River.	59.5	59.5

Transmission Idea MI-14								
Adjustment Type	**Facility Type**	**Voltage (kV)**	**From Substation**	**To Substation**	**Estimated Length (Miles)**	**Description**	**IESO Tie Cost (M$)**	**Radial Generator Cost (M$)**
New	Substation	345	Hiawatha			New substation or switching station at Hiawatha	15.4	15.4
New	Substation	345	Third Line			New substation in Ontario	11.8	11.8
New	Transformer	345/230	Third Line			Tie the new voltage to the local 230 kV system	8.5	8.5
New	Transformer	345/138	Hiawatha			New transformer	7.5	7.5
New	Line	345	Arnold	Hiawatha	102	New 345 kV Line	288.7	288.7
New	Line	345	Hiawatha	Third Line	64	New tie line to Ontario	181.1	181.1
Rebuild	Line	138	Hiawatha	Pine River	48	Rebuild the 69 kV line from Hiawatha to Pine River to 138 kV and tie to the new station at Pine River.	59.5	59.5

Transmission Idea MI-15								
Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	HVDC/345/230	Third Line			New substation in Ontario with 230 kV AC/DC/ 345 kV AC conversion	372.1	372.1
New	Substation	345/138	Pine River			New substation or switching station at Pine River	15.4	15.4
New	Substation	345	Hiawatha			New substation or switching station at Hiawatha	15.4	15.4
New	Substation	345	McGulpin			New substation or switching station at McGulpin	15.4	15.4
Reconfigure	Substation	69	Pine River			Move connections of the Pine River - Straights 69 kV lines to the 138 kV switching station and operate at 138 kV.	0.2	0.2
New	Transformer	345/138	Hiawatha			New transformer	7.5	7.5
New	Transformer	345/138	McGulpin			New transformer	7.5	7.5
New	Transformer	345/138	Pine River			New transformer	7.5	7.5
New	Transformer	138/69	Pine River			New transformer to tie to the local 69 kV system	7.5	7.5
New	Line	345	Arnold	Hiawatha	102	New 345 kV Line	288.7	288.7
New	Line	345	Hiawatha	Pine River	48	New 345 kV Line	135.8	135.8
New	Line	345	Livingston	McGulpin	52	New 345 kV Line	147.2	147.2
New	Line	345	McGulpin	Pine River	30.5	New 345 kV Line	86.3	86.3
New	Line	345	Third Line	Pine River	33	New tie line to Ontario	93.4	93.4
Rebuild	Line	138	Hiawatha	Pine River	48	Rebuild the 69 kV line from Hiawatha to Pine River to 138 kV and tie to the new station at Pine River.	59.5	59.5

Transmission Idea MI-16								
Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	345/138	Pine River			New substation or switching station at Pine River	15.4	15.4
New	Substation	345	Hiawatha			New substation or switching station at Hiawatha	15.4	15.4
New	Substation	345	McGulpin			New substation or switching station at McGulpin	15.4	15.4
New	Substation	345	Third Line			New substation in Ontario	11.8	11.8
Reconfigure	Substation	69	Pine River			Move connections of the Pine River - Straights 69 kV lines to the 138 kV switching station and operate at 138 kV.	0.2	0.2
New	Transformer	345/230	Third Line			Tie the new voltage to the local 230 kV system	8.5	8.5
New	Transformer	345/138	Hiawatha			New transformer	7.5	7.5
New	Transformer	345/138	McGulpin			New transformer	7.5	7.5
New	Transformer	345/138	Pine River			New transformer	7.5	7.5
New	Transformer	138/69	Pine River			New transformer to tie to the local 69 kV system	7.5	7.5
New	Line	345	Arnold	Hiawatha	102	New 345 kV Line	288.7	288.7
New	Line	345	Hiawatha	Pine River	48	New 345 kV Line	135.8	135.8
New	Line	345	Livingston	McGulpin	52	New 345 kV Line	147.2	147.2
New	Line	345	McGulpin	Pine River	30.5	New 345 kV Line	86.3	86.3
New	Line	345	Third Line	Pine River	33	New tie line to Ontario	93.4	93.4
Rebuild	Line	138	Hiawatha	Pine River	48	Rebuild the 69 kV line from Hiawatha to Pine River to 138 kV and tie to the new station at Pine River.	59.5	59.5

Study of Export Capabilities of the Sault Ste. Marie Transmission System

Prepared for MISO by Transmission Integration

August, 2017

Appendix D

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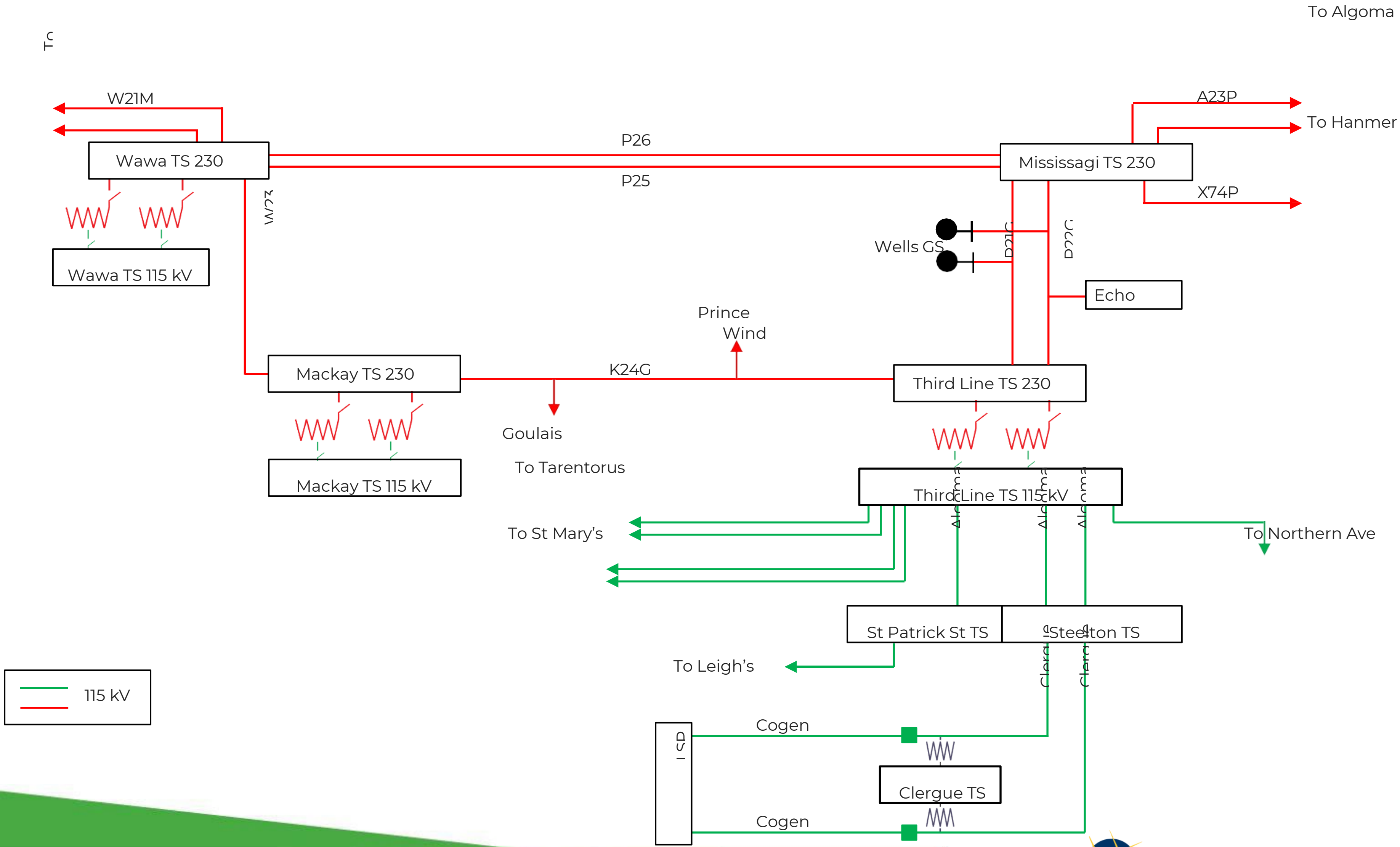
- The IESO carried out a high level study to assess the capability of the transmission system in the Sault Ste. Marie ("SSM") area to export capacity to Michigan
- The study was completed to support MISO's exploratory study of options to meet capacity needs in Michigan
- The IESO's study assumes the export would occur via a new intertie constructed under the St Mary's river; the intertie is one of various options MISO's study will consider

- The study used the following assumptions and simplifications:
  - The new intertie will either be:
    - Connected to a new bus near Clergue TS (115 kV)
    - Require a new 230 kV line from near Clergue TS to Third Line TS (230 kV)
  - Exports were modeled as a load with 0.9 lagging power factor
  - Only active and contracted local generation facilities were considered available to supply local load and exports
  - No margin was considered for local electrical load growth in the SSM region (i.e. any long term export deal would also need to consider future load growth in the SSM area)
  - Remedial action schemes or emergency operational tools were not considered in the study

Single Line Diagram of the Existing SSM Transmission System



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Summary of Key Findings

- Export capability was assessed for both summer and winter conditions with the benefits of certain system enhancements considered:

Scenario	Export Capability[1]		Description
	Summer	Winter	
Without system enhancements	50 MW	25 MW	Limited by thermal ratings on the local, 115 kV transmission system
With system enhancements	125 MW	75 MW	Required enhancements: - Mitigation of thermal constraints on the 115 kV system - Reconfiguration of 230 kV circuits supplying the SSM system[2] Limited by Third Line TS autotransformers and the thermal rating of 115 kV circuits connecting Steelton/Patrick St. TS and Clergue TS
With system enhancements	325 MW	275 MW	Required enhancements: - New 230 kV circuit from Clergue TS to Third Line TS (approximately 5 km) - Reconfiguration of 230 kV circuits supplying the SSM system[2] - Additional voltage control facilities Limited by thermal ratings of 230 kV circuits supplying SSM system

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[1] The assessed capability is based on current system conditions and is provide for the purpose of MISO's exploratory study. It is subject to change based on future system conditions.

[2] Currently these circuits share a number of towers, they would need to separated to achieve the

Conclusions & Next Steps

- **Based on the evaluated system conditions, the Sault Ste. Marie transmission system can accommodate:**
  - A 50 MW (summer) or 25 MW (winter) export from a new 115 kV bus near Clergue TS before the 115kV system becomes limiting
  - A 125 MW (summer) or 75 MW (winter) export from a 115 kV bus near Clergue TS, assuming:
    - Thermal issues on the 115 kV were mitigated
    - The 230 kV circuits supplying SSM were reconfigured
  - A 325 MW (summer) or 275 MW (winter) export from a 230 kV bus near Clergue TS, assuming:
    - A new 230 kV line is constructed from Third Line TS to near Clergue TS
    - 230 kV circuits supplying SSM were reconfigured
    - Voltage control facilities are installed to maintain adequate voltage at Third Line TS under peak load and export conditions
- **More detailed studies and analysis would be required to assess:**
  - Effect of local electrical load growth on export capabilities
  - Cost and full scope of the required system enhancements
  - Level of reliability or "firmness" required for power exports

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Appendix I: UP Generation Integration Screening Study

Upper Peninsula Generation Integration Screening Study

September 2016

ATC voluntarily performed a high level, steady-state screening of transmission facilities in Michigan's Upper Peninsula. This was done to assist generation developers with the preliminary identification of potential locations where existing transmission facilities may be able to accommodate the addition of new and/or additional generation capacity. All potential locations were screened for single contingency steady-state limitations. Locations that could not accommodate generation for a single contingency were removed from the Tables that were produced through this effort. ATC has not performed any analysis to identify the scope or cost of work to eliminate the limit(s) that were identified for any of the contingencies that were noted. ATC may choose to perform similar screening studies of other portions of its footprint in the future, as system conditions and circumstances warrant.

Additional steady state, multiple contingency analysis was performed for locations that appeared to be capable of hosting 100 MW or more of generation under steady state, single contingency conditions. The multiple contingency analysis resulted in reduced generation capacity from the single contingency screen being indicated for some locations. Other locations could not accommodate any new generation under multiple contingency conditions and, as such, were removed from the Tables. ATC has not performed any analysis to identify the scope or cost of work to eliminate the limit(s) that were identified for any of the contingencies that were noted.

ATC's screening did not include any stability analysis. Previous studies in the UP have identified sensitivity to stability issues. Since different types of generating units may have substantially different stability performance characteristics, a stability analysis would not be generally applicable. Furthermore, this study did not consider the number or size of units necessary to be a replacement for Presque Isle Power Plant. Finally, the study analyzed only one potential generation site at a time and, as such, the results are not necessarily additive.

The Tables that follow below identify the location, screening results and the U.P. sub-zone where existing transmission facility is located. The attached map is divided into six sub zones for ease in finding the locations identified in the Tables. Tables 1 illustrates the results of the multiple contingency analysis. Table 2 provides the results of the single contingency analysis sorted by sub-zone.

Additional disclaimers: This was a high level screening study using a single steady-state model and a particular set of assumptions, as described herein. The study results listed in the Tables below may not be indicative of the results that would be produced via the MISO Tariff Attachment X Generation Interconnection process. System stability, both angular and voltage, were not considered in this screening study. ATC makes no representations, either expressed or implied, that the scope of the interconnection facilities or transmission upgrades required to connect generation at these sites would be minimal, or even feasible. Single contingency screening results do not reflect any possible reductions required for multiple contingencies. The analysis considered 69kV, 138kV and 345kV nodes in the power flow model, but did not consider actual bus configuration or the existence of buses for constructability at the locations that were studied. Corresponding interconnection facilities and transmission upgrades will be determined by the MISO Tariff Attachment X process. This non-binding, voluntary study is presented for informational purposes only and ATC makes no guarantee or warranty that the information presented herein is accurate or complete.

Additional Steady- State Analysis Base Assumptions

Presque Isle Generating Plant Output: 0 MW

Interconnection with the City of Marquette: 0 MW

interchange Mackinac HVDC flow modeled as: 20 MW North

to South White Pine Generating Plant Output: 0 MW

Empire Mine Load: 0 MW

Preliminary Results with Multiple Contingency Screen

Table 1

Location	Voltage	Potential Generation Amount (MW)	Sub Zone	Contingency Screen
Atlantic	69kV	77	1	Multiple
M-38	138kV	75	1	Multiple
Presque Isle	138kV	274	3	Multiple
National	138kV	260	3	Multiple
Empire	138kV	240	3	Multiple
Freeman	138kV	149	3	Multiple
Big Bay	138kV	136	3	Multiple
Tilden	138kV	124	3	Multiple
Barnum	138kV	107	3	Multiple
North Lake	138kV	107	3	Multiple
Perch Lake	138kV	103	3	Multiple

Preliminary Results Using Single Contingency Screen				
Table 2				
Location	Voltage	Potential Generation Amount (MW)	Sub Zone	Contingency Screen
M-38	69kV	68	1	Single
Elevation St.	69kV	61	1	Single
Winona	69kV	60	1	Single
Atlantic	138kV	59	1	Single
Winona	138kV	58	1	Single
Boston	69kV	56	1	Single
Osceola	69kV	56	1	Single
Mass	69kV	50	1	Single
Henry St.	69kV	48	1	Single
MTU	69kV	48	1	Single
Lake Mine	69kV	39	1	Single
Toivola	69kV	39	1	Single
Ontonagon	69kV	37	1	Single
Ontonagan	138kV	34	1	Single
Portage	69kV	33	1	Single
White Pine Mine	69kV	33	1	Single
Rockland	69kV	32	1	Single
White Pine Village	69kV	32	1	Single
Baraga	69kV	31	1	Single
L'Anse	69kV	30	1	Single
UPSCO	69kV	27	1	Single
Victoria	69kV	26	1	Single
Keweenaw	69kV	21	1	Single
Twin Lakes	138kV	77	2	Single
Aspen	69kV	70	2	Single
Iron Grove	69kV	55	2	Single
Lakota Rd.	138kV	47	2	Single
Strawberry Hill	69kV	41	2	Single
Crystal Falls	69kV	40	2	Single
Peavy Falls	69kV	35	2	Single
Lincoln	69kV	32	2	Single
Florence	69kV	30	2	Single
Lakehead	69kV	25	2	Single
Pine	69kV	22	2	Single
Conover	69kV	20	2	Single
Lakota Rd.	69kV	20	2	Single
Michigamme	69kV	16	2	Single

Preliminary Results Using Single Contingency Screen Table 2 (Continued)				
Location	**Voltage**	**Potential Generation Amount (MW)**	**Sub Zone**	**Contingency Screen**
Bruce Crossing	69kV	15	2	Single
Land O Lakes	69kV	15	2	Single
Watersmeet	69kV	13	2	Single
Forsyth	69kV	93	3	Single
North Lake	69kV	60	3	Single
Barnum	69kV	52	3	Single
Alger Delta	69kV	46	3	Single
Chatham	69kV	46	3	Single
Munising	69kV	46	3	Single
Forest Lake	69kV	45	3	Single
AD Hiawatha	69kV	44	3	Single
Mineral Proc.	69kV	43	3	Single
Munising	138kV	40	3	Single
Gwinn	69kV	39	3	Single
Timber Products	69kV	29	3	Single
Greenstone	69kV	25	3	Single
Sawyer	69kV	21	3	Single
MTF	69kV	13	3	Single
Perch Lake	69kV	13	3	Single
Randville	69kV	73	4	Single
Watson	69kV	51	4	Single
Mountain	69kV	48	4	Single
Harris	69kV	36	4	Single
Sagola	69kV	34	4	Single
Old Mead Rd.	69kV	86	5	Single
Lakehead Rapid River	69kV	56	5	Single
North Bluff	69kV	53	5	Single
Masonville	69kV	52	5	Single
West Side	69kV	51	5	Single
Bay View	69kV	50	5	Single
Cornell	69kV	48	5	Single
Escanaba	69kV	45	5	Single
Gladstone	69kV	45	5	Single
Blaney Park	69kV	84	6	Single
Engadine	69kV	84	6	Single
Valley	69kV	83	6	Single
Gould City	69kV	82	6	Single
Curtis	69kV	81	6	Single
Manistique	69kV	73	6	Single

Preliminary Results Using Single Contingency Screen				
Table 2 (Continued)				
Location	**Voltage**	**Potential Generation Amount (MW)**	**Sub Zone**	**Contingency Screen**
Glen Jenks	69kV	59	6	Single
3 Mile	69kV	54	6	Single
9 Mile	69kV	54	6	Single
Newberry	69kV	49	6	Single
Sault	69kV	49	6	Single
Louisiana Pacific	69kV	48	6	Single
NBHSPL 69	69kV	48	6	Single
Newberry Village	69kV	48	6	Single
Roberts	69kV	47	6	Single
Portage St	69kV	46	6	Single
Tone	69kV	42	6	Single
Kincheloe	69kV	41	6	Single
Rudyard	69kV	41	6	Single
Eckerman	69kV	39	6	Single
Hulbert	69kV	39	6	Single
MI Limestone	69kV	37	6	Single
Raco	69kV	37	6	Single
Rexton	69kV	36	6	Single
Rockview	69kV	36	6	Single
Brimley	69kV	35	6	Single
Trout Lake	69kV	34	6	Single
Pine Grove	69kV	33	6	Single
Detour	69kV	32	6	Single
Goetzville	69kV	32	6	Single
Magazine	69kV	32	6	Single
Pickford	69kV	32	6	Single
Seney	69kV	31	6	Single
Talentino	69kV	31	6	Single
Dafter	69kV	27	6	Single
St. Ignace	69kV	26	6	Single
MLQ	69kV	25	6	Single

Appendix J: Biomass with Tire Derived Fuel Emissions Study

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Technical Memo

SUBJECT: L'Anse Warden Electric Company (LWEC): CO Emissions

DATE: September 13, 2024 PROJECT NO.: 240888

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Introduction

During a recent tour of the LWEC site, members of the Michigan Public Service Commission (MPSC) asked about carbon monoxide (CO) emissions from the boiler, especially as CO emissions vary when burning biomass compared to tire-derived fuel (TDF). Completing a comparison at LWEC is difficult as the plant always burns a fuel blend that includes wood chips, creosote-derived wood (like railroad ties or utility poles), and other forms of biomass along with TDF. One fuel is never burned exclusively for any period of time. Information used in permitting this and other biomass facilities was used to explain how CO emissions vary when burning biomass. Information on CO emissions from LWEC are also provided.

Background

When reviewing permits for biomass-fired boilers as well as Federal Rules that affect biomass-fired boilers, it is clear that USEPA anticipates higher CO emissions when burning biomass. CO BACT Analyses are often required when permitting a biomass-fired boiler. A list of biomass-fired boilers in Michigan and their CO emission limit is provided in Attachment 1. This table indicates that the 0.30 lb/mmbtu per hour (averaged over 24 hours) is one of the lower CO permit limits for biomass-fired boilers in Michigan. Though it should also be noted that changes in the legislation associated with defining “renewable energy” have forced the closure of several plants on that list.

In addition to CO BACT Analyses, the Industrial, Commercial, and Institutional Boilers and Process Heaters: National Emission Standards for Hazardous Air Pollutants (NESHAP) for Major Sources includes higher CO limits for biomass boilers than for boilers firing fossil fuels as indicated in the graphic below:[1].

Type of Boiler	Pollutant	Limit/Averaging Time
Stokers/sloped grate/others designed to burn wet biomass fuel	CO (or CO CEMS)	1,500 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (720 ppm by volume on a dry basis corrected to 3-percent oxygen 30-day rolling average)
Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	CO	460 ppm by volume on a dry basis corrected to 3-percent oxygen
Fluidized bed units designed to burn biomass/bio-based solid	CO	470 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3-percent oxygen, 30-day rolling average)
Suspension burners designed to burn biomass/bio-based solid	CO	2,400 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3-percent oxygen, 10-day rolling average)
Dutch Ovens/Pile burners designed to burn biomass/bio-based solid	CO	770 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3-percent oxygen, 10-day rolling average)
Fuel cell units designed to burn biomass/bio-based solid	CO	1,100 ppm by volume on a dry basis corrected to 3-percent oxygen
Hybrid suspension grate units designed to burn biomass/bio-based solid	CO (or CEMS)	3,500 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3-percent oxygen, 30-day rolling average)

Graphic 1. NESHAP CO Emission Limits for Industrial Boilers and Process Heaters at Major Sources

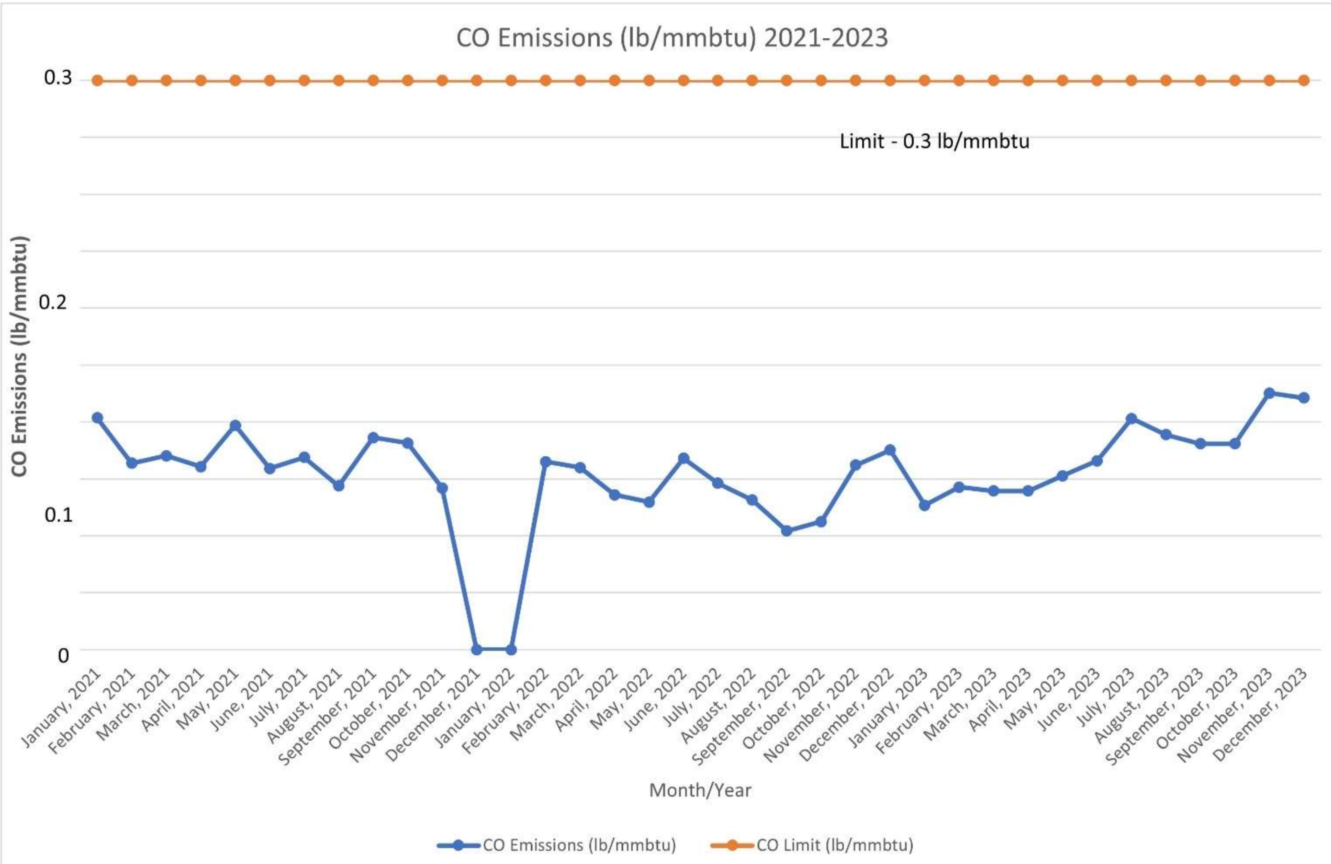
Wet biomass fuels can be more variable than traditional fuels and may not burn as evenly. This variability can result in higher CO emissions. Commentors explained that wet biomass fuels vary depending on the type of fuel and the weather. Higher moisture contents that occur with wet weather make the fuel burn more unevenly. Wood residue can also vary in size and type, which can contribute to higher CO emissions. During the winter and spring, biomass fuels can be high in moisture meaning that additional fuels will have to be burned to make up the load lost to energy expending in evaporating the additional moisture. The TDF does not absorb water and is unaffected

[1] It should be noted that CO is used as a surrogate for volatile organic hazardous air pollutant (HAP) emissions. CO is not a HAP.

by wet or frozen conditions. LWEC must carefully manage its fuel blend to ensure that the boiler heat input is adequate to accommodate additional moisture during these times.

CO Emissions at LWEC

Because LWEC has a continuous emissions monitoring system (CEMS) for CO, the plant is able to provide monthly CO emissions averages from 2021 through 2023, which are summarized below:



Graphic 2. CO Emissions 2021-2023

It should be noted that the plant went through a major outage during December, 2021 through January, 2022, and no CO emissions were generated. This chart indicates that there is some variability in CO emissions during the year. When the wood is cold and wet, the CO emissions tend to be higher. Adding TDF or other fuels which are not as sensitive to temperature and moisture will allow for more complete combustion and lower CO emissions. Because the plant uses a blend of fuels, its difficult to use plant CO emissions data to indicate the affects of the different fuels, operating conditions and weather on the CO emissions. Plant operators blend fuels and adjust boiler load to ensure compliance with the various emission limits, including the CO emission limit.

The MPSC specifically requested CO emissions when the plant was burning TDF as compared to when the plant is burning a fuel mix that does not include TDF. Because a number of variables affect CO emissions when burning biomass, and operating conditions change from day to day, a comparison is difficult. Though in one instance, no TDF was included in a fuel blend where the boiler operated at a similar load and weather just a week earlier. In that case, CO emissions on May 15, 2022, would be expected to be similar to emissions on May 22, 2022. But they are not. On May 15, 2022, the fuel blend included TDF and CO emissions were almost 20% higher.

	Daily Generation		Fuel			Emissions Daily Average			
Date	Steam Flow	Gross MW	RR Ties	Wood Chips	TDF	02%	Opacity %	CO PPM	CO lb/mmBTU
05/15/22	3,783,900	406,350	161.96	277.92	26.91	9.8	2	64.1	0.084
05/22/22	2,727,200	296,980	157.06	361.32	0.00	12.4	2.6	58.5	0.100

Graphic 3. CO Emissions While Burning TDF and Without TDF

Because of the number of variables that affect CO emissions, a more detailed analysis might not provide more helpful information.

Carbon Footprint

Biomass is considered an alternative energy source to fossil fuels. While burning both fossil fuels and biomass release CO_2, source plants for biomass capture almost as much CO_2 through photosynthesis as biomass releases when burned, which makes biomass a carbon neutral source. [2] Burning biomass can also reduce the amount of material disposed of in landfills. In addition, using forest biomass for energy results in a "carbon debt" when burning biomass releases CO_2 into the atmosphere. This debt can be repaid when forests grow back. Using biomass as a fuel also promotes sustainable forest management. When wood residues are left to decompose or burn in open-air fires, harmful pollutants are released into the air. Collecting the wood and using it as fuel encourages sustainable forest management practices including selective logging and reforestation. These sustainable forest management practices can be funded through the sale of this wood (which is often waste wood) and can be an important part of preventing forest fires.

[2] Source: U.S. Energy Information Administration, *Monthly Energy Review*, Environment section note; see Note 2: Accounting for carbon dioxide emissions from biomass energy combustion.

Attachment 1 - Summary of Michigan Biomass-fired Boilers CO Limits

L'Anse Warden Electric Company CO Emissions Information

SRN	Facility	Location	Year Permitted	Rating (mmbtu/hr)	CO limit	Units	Averaging Time
B4260	L'Anse Warden Electric Company	L'Anse. Michigan	2008 (modified)	324	0.3	lb/mmbtu	24 hr
			BACT Limit		97.2	lb/hr	Hourly
N0890	National Energy	Lincoln. Michigan	1986	230	0.25	lb/mmbtu	24 hr
			BACT Limit		57.5	lb/hr	24-hr
N1160	National Energy	McBain, Michigan	1986	230	0.25	lb/mmbtu	24 hr
			BACT Limit		57.5	lb/hr	24-hr
N1266	Hillman Power Company	Hillman, Michigan	1985	300	120	lb/hr	24-hr
			BACT Limit		140	lb/hr (incl SS)	24-hr
N1395	Cadillac Renewable Energy	Cadillac, Michigan	1993	523	0.4	lb/mmbtu	24-hr
			BACT Limit		209.2	lbhr	24-h4
N2388	Grayling Generating Station, LP	Grayling, Michigan	1992	523	0.4	lb/mmbtu	24-hr
			BACT Limit		209.2	lb/hr	24-hr
N3570	Genessee Power Station LP	Flint, Michigan	1992/2011	523	0.35	lb/mmbtu	24-hr
			BACT Limit		183.1	lb/hr	24-hr

* The Hillman limit is equivalent to 0.47 lb/mmbtu.

Appendix K: UP Carbon Sequestration Feasibility Study

Upper Peninsula Geology/Hydrogeology and Feasibility of Carbon Sequestration

Background

On May 24, 2024, staff from the Michigan Department of Environment, Great Lakes, and Energy (EGLE), Oil, Gas, and Minerals Division (OGMD) met with staff from the Michigan Public Service Commission (MPSC), Energy Resources Division (ERD) to discuss the potential feasibility of carbon sequestration within the geologic formations within the Upper Peninsula through utilization of Class VI Underground Injection Control (UIC) wells.

The United States Environmental Protection Agency (US EPA) administers the federal UIC program, and it is currently comprised of six classes of injection wells. Modern injection well requirements date back to 1974 with the passage of the Safe Drinking Water Act (SDWA). Since that time there have been significant amendments to the SDWA and UIC rules (on both the federal and state levels) regarding the construction and operation requirements of injection wells to ensure that groundwater, the environment, and public health and safety are protected. Class VI wells are a relatively new category under the UIC program. There are currently no Class VI Carbon Sequestration Wells in Michigan and about a dozen or so in the United States. Wells of this type are currently dually permitted by the OGMD and the US EPA. Michigan would permit a Carbon Sequestration Well under the Part 625 Mineral Well program as a Waste Disposal Well. However, EGLE is pursuing Class VI delegated authority and expects that there will be statutory framework and associated administrative rules in the near future to address these types of wells in Michigan under a new type of program. Class VI wells inject carbon dioxide (CO2) which is captured and stored underground where it remains geologically sequestered permanently. Wells of this type can reduce the amount of greenhouse gas emissions that are added to the atmosphere and would be used by power generation sectors and other industrial sources. Paramount to all federal and state UIC regulations is that considerations of a variety of measures are incorporated to assure that injection activities will not endanger Underground Sources of Drinking Water (USDWs). USDWs are defined as an aquifer or portion of an aquifer that currently supplies a public water supply system or an aquifer or portion of an aquifer that contains sufficient quantity to supply a public water system and is currently being used for human consumption and contains fewer than 10,000 mg/L of total dissolved solids. For more information about injection wells in Michigan please refer to the OGMD website.

Geology and Hydrogeology

The Paleozoic-aged Michigan Basin is comprised of a thick package of layered sedimentary formations (sandstones, shales, limestones, evaporate deposits, etc.) that are conducive to extraction (oil and gas) and injection (brine and waste disposal) due to the higher porosity and permeability of these formations and the presence of continuous confining zones. A confining zone is a sufficiently thick interval of rock that serves as a barrier to the upward migration of oil, gas, and injectate and is required by the US EPA and EGLE above injection intervals within bedrock formations. The Michigan Basin sedimentary formations are present throughout the entire lower peninsula and are also found in the central and eastern portions of the upper peninsula. While the basin formations of the upper and lower peninsulas are geologically correlative, they are distinctly different when considering the presence of USDWs. For example, groundwater quality within the basin formations of the lower peninsula changes with from freshwater to brackish and high-salinity brines fairly rapidly with depth. A US Geological Survey investigation from 1996 delineates the freshwater and saline-water interface within a 22,000-square-mile area of the central Michigan Basin (*Westjohn and Weaver, 1996*). The investigation found that this interface is located between approx. 300 and 800 feet above mean sea level (ft amsl) across the lower peninsula. Saline-water (many times orders of magnitude greater than 10,000 mg/L that defines a USDW) is present below this interface and the permitting of injection wells could be feasible given all other permitting requirements have been met.

However, in the Upper Peninsula, there has been observed water supply wells that were drilled deep into the Michigan Basin Paleozoic sedimentary formations near Manistique, Michigan and remain within USDWs (up to 2,030 feet below the ground surface, or more than -1,380 ft amsl). See the Department of Natural Resources *Thompson Fish Hatchery Well ID No. 77000000403* record for more information. For reference, the surface of Lake Michigan is approx. 578 ft amsl, and the surface of Lake Superior is approx. 600 ft amsl.

The central and western portions of the Upper Peninsula are underlain by bedrock that is Precambrian in age and much older than the Paleozoic rocks of the Michigan Basin. These geologic formations are crystalline igneous, volcanic and metamorphosed rocks as well as sedimentary rocks. Some of these Precambrian sedimentary formations have higher transmissivities, like the Jacobsville Sandstone, and are commonly used as a freshwater aquifer. Other formations may exhibit structural features, such as fractures, that may be utilized as USDWs but typically have much lower yields. In a report published by the US Geological Survey that details hydrogeologic conditions by county for the State of Michigan (*Apple and Reeves, 2007*), some central and western upper peninsula counties report the use of the Precambrian bedrock as the source for drinking water wells for up to 75% of the wells documented in EGLE's Wellogic Database. This database contains information for different types of water supply wells for single-home residential use to municipal wells serving entire communities.

Feasibility Analysis

Generally, the geology and hydrology of the Upper Peninsula makes the permitting of Class VI wells difficult. The presence of deep USDWs in the Paleozoic formations of the central and eastern portions of the upper peninsula would require exploration more than 2,000 feet below ground surface to determine where the freshwater/saline-water interface is located. In fact, the Amoco Production Company completed a permitted test well in Alger County that encountered sandstone formations down to approx. 6,500 feet below ground surface (see the *St. Amour 1-29R test well log, Permit #021-871-202* for more information). Additionally, the geophysical logs from this test well indicate that no rock formation encountered during drilling is appropriate for use as a confining zone. This means that the demonstration must still be made that the injection of CO_2 would occur beneath the lowest USDW zone with a sufficiently thick confining layer.

Some of the western Upper Peninsula Precambrian geologic formations may have sufficient permeability and porosity for injection, such as the Precambrian sedimentary formations, while other crystalline formations may have carbon sequestration capacity within the structural features such as fractures, faults, etc. However, determining the feasibility is a challenge without additional significant exploration to confirm that these formations are conducive to injection with structural features that are regional and interconnected providing volume capacity, and/or exhibit sufficient permeabilities and porosities. The presence of confining zones separating the USDWs of the upper peninsula from the zone of injection is also of great importance and these types of geologic formations may not be present in sufficient lateral and vertical extents in either the Paleozoic or Precambrian geologic formations.

References

Michigan Public Act No. 235 of 2023
Michigan Natural Resources and Environmental Protection Act, 1994 PA 451

Underground Injection Control Program, 40 CFR 144.12

Safe Drinking Water Act, Public Law 93-523
Injection Wells in Michigan: https://www.michigan.gov/egle/about/organization/oil-gas-and-minerals/oil-and-gas/injection-wells-in-michigan

Configuration of Freshwater/Saline-Water Interface and Geologic Controls on Distribution of Freshwater in a Regional Aquifer System, Central Lower Peninsula of Michigan; 1996, D.B. Westjohn and T.L. Weaver

Water Well Log of Department of Natural Resources Thompson Fish Hatchery Well ID No. 77000000403

Test Well Log of the St. Amour 1-29R, Amoco Production Company, Permit No. 021-871-202

Summary of Hydrogeologic Conditions by County for the State of Michigan; U.S. Geological Survey, Open- File Report 2007-1236, Beth A. Apple and Howard W. Reeves

Exhibit A-2 (RFS-2)

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2024 Long-Term Reliability Assessment

December 2024

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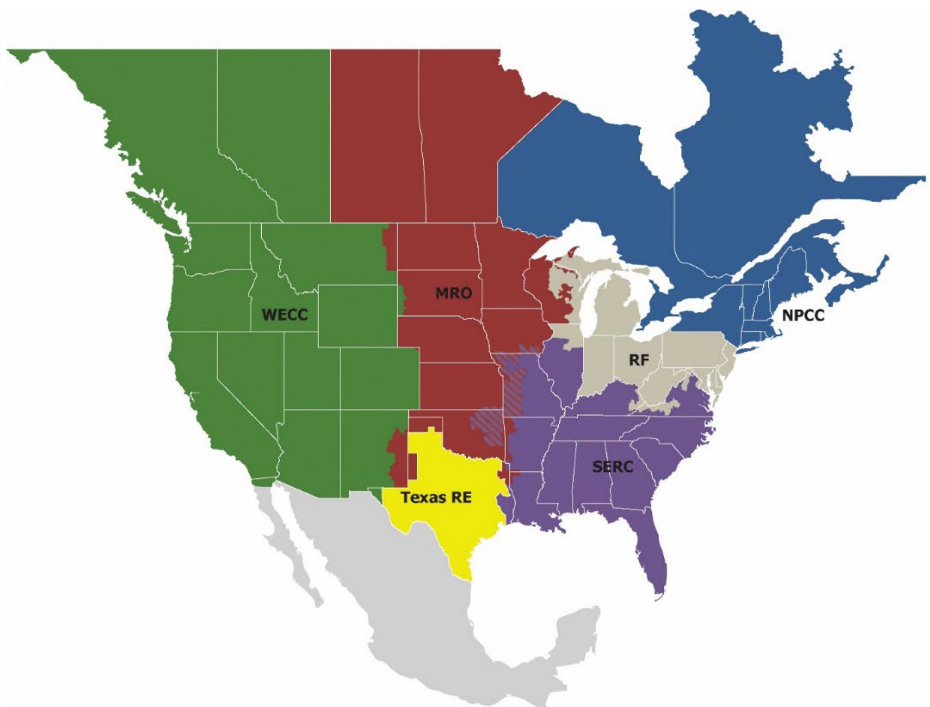
Preface

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 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

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, RAS 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.

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

This assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.[5] Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2024 about known system changes with updates incorporated prior to publication. This *2024 LTRA* assessment period includes projections for 2025–2034; however, some figures and tables examine data and information for the 2024 year. 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; it 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, policymakers, and regulators as well as to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

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[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 *2024 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 2024. 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:

1. **A reliability assessment of the North American BPS with the following goals:**
    a. Evaluate industry preparations that are in place to meet projections and maintain reliability
    b. Identify trends in demand, supply, reserve margins, and probabilistic resource adequacy metrics
    c. Identify emerging reliability issues
    d. Focus the industry, policymakers, and the general public's attention on BPS reliability issues
    e. Make recommendations based on an independent NERC reliability assessment process
2. **A regional reliability assessment that contains the following:**
    a. A 10-year data dashboard
    b. Summary assessments for each assessment area
    c. A focus on specific issues identified through industry data and emerging issues
    d. A description of 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

In the *2024 LTRA*, NERC finds that most of the North American BPS faces mounting resource adequacy challenges over the next 10 years as surging demand growth continues and thermal generators announce plans for retirement. New solar PV, battery, and hybrid resources continue to flood interconnection queues, but completion rates are lagging behind the need for new generation. Furthermore, the performance of these replacement resources is more variable and weather-dependent than the generators they are replacing. As a result, less overall capacity (dispatchable capacity in particular) is being added to the system than what was projected and needed to meet future demand. **The trends point to critical reliability challenges facing the industry: satisfying escalating energy growth, managing generator retirements, and accelerating resource and transmission development.**

This *2024 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 10 years; 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. Summaries of the report sections are provided below.

Capacity and Energy Risk Assessment

The **Capacity and Energy Risk Assessment** section of this report identifies potential future electricity supply shortfalls under normal and extreme weather conditions. NERC's evaluation of resource adequacy in the LTRA considers both the capacity of the resources and the capability of resources to convert inputs (e.g., fuel, wind, and solar irradiance) into electrical energy. NERC used both a probabilistic assessment and a reserve margin analysis to assess the risk of future electricity supply shortfalls. Both are forward-looking snapshots of resource adequacy that are tied to industry forecasts of electricity supplies, demand, and transmission development.

Areas categorized as **High Risk** fall below established resource adequacy criteria in the next five years. High-risk areas are likely to experience a shortfall in electricity supplies at the peak of an average summer or winter season. Extreme weather, producing wide-area heat waves or deep-freeze events, poses an even greater threat to reliability. **Elevated-Risk** areas meet resource adequacy criteria, but analysis indicates that extreme weather conditions are likely to cause a shortfall in area reserves. **Normal-Risk** areas are expected to have sufficient resources under a broad range of assessed conditions. The results of the risk assessment are depicted in **Figure 1**.

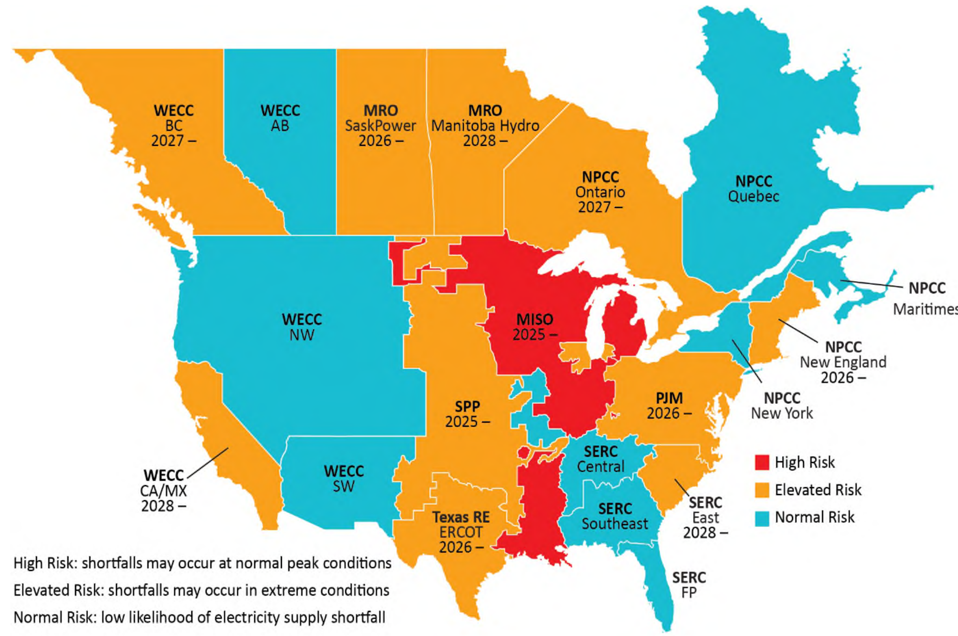


Figure 1: Risk Area Summary 2025–2029

Regional Assessments Dashboards

The **Regional Assessments Dashboards** section contains dashboards and summaries for each of the 20 assessment areas, developed from data and narrative information collected by NERC from the six Regional Entities. Probabilistic Assessments (ProbA) are presented that identify energy risk periods and describe the contributing demand and resource factors.

Table 1: Capacity and Energy Risk Assessment Area Summary			
Area	**Risk Level**	**Years**	**Risk Summary**
MISO	High	2025 -	Resource additions are not keeping up with generator retirements and demand growth. Reserve margins fall below Reference Margin Levels (RML) in winter and summer.
Manitoba	Elevated	2028 -	Potential resource shortfalls in low-hydro conditions, driven by rising demand.
SaskPower	Elevated	2026 -	Risk of insufficient generation during fall and spring when more generators are off-line for maintenance.
Southwest Power Pool (SPP)	Elevated	2025 -	Potential energy shortfalls during peak summer and winter conditions arise from low wind conditions and natural gas fuel risk.
New England	Elevated	2026 -	Strong demand growth and persistent winter natural gas infrastructure limitations pose risks of supply shortfalls in extreme winter conditions.
Ontario	Elevated	2027 -	Reserve margins fall below RMLs as nuclear units undergo refurbishment and some current resource contracts expire. Demand growth is also adding to resource procurement needs.
PJM	Elevated	2026 -	Resource additions are not keeping up with generator retirements and demand growth. Winter seasons replace summer as the higher-risk periods due to generator performance and fuel supply issues.
SERC-East	Elevated	2028 -	Demand growth and planned generator retirements contribute to growing energy risks. Load is at risk in extreme winter conditions that cause demand to soar while supplies are threatened by generator performance, fuel issues, and inability to obtain emergency transfers.
ERCOT	Elevated	2026 -	Surging load growth is driving resource adequacy concerns as the share of dispatchable resources in the mix struggles to keep pace. Extreme winter weather has the potential to cause the most severe load-loss events.
California-Mexico	Elevated	2028 -	Demand growth and planned generator retirements can result in supply shortfalls during wide-area heat events that limit the supply of energy available for import.
British Columbia	Elevated	2027 -	Drought and extreme cold temperatures in winter can result in periods of insufficient operating reserves when neighboring areas are unable to provide excess energy.

Risk from Additional Generator Retirements

Plans for generator retirements continue at similar pace and scale to levels reported in the *2023 LTRA*. Confirmed generator retirements (52 GW by 2029 and 78 GW over the 10-year period) are accounted for in the Capacity and Energy Risk Assessment above. Economic, policy, and regulatory factors spur further fossil-fired generators to retire in the 10-year horizon. Announced retirements, which include many generators that have not begun formal deactivation processes with planning entities, total 115 GW over the 10-year period. The effect of all retirements on the assessment area Planning Reserve Margins (PRM) can be seen in **Figure 2**. On-peak reserve margins fall below RMLs; the levels required by jurisdictional resource adequacy requirements) in the next 10 years in almost every assessment area, signaling an accelerating need for more resources.

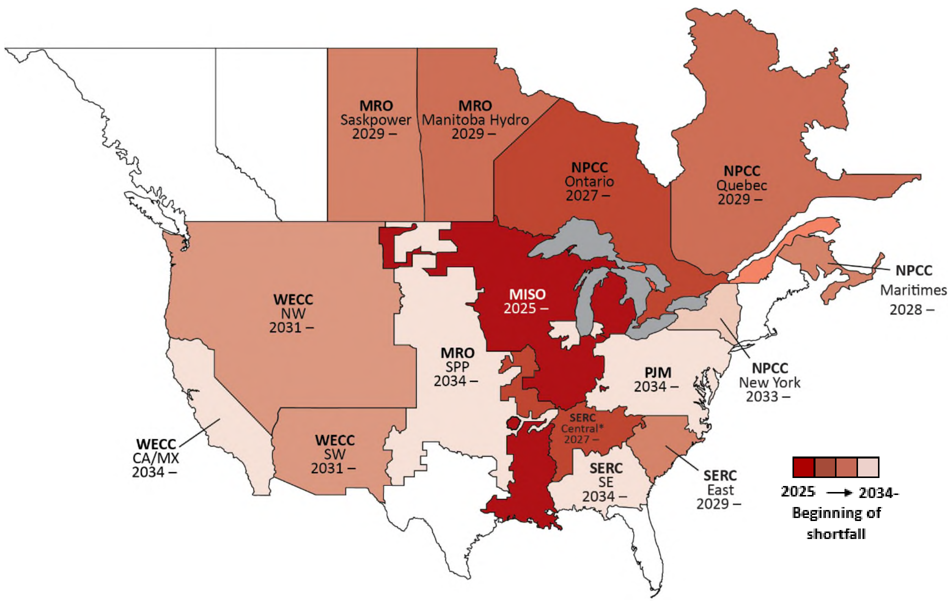


Figure 2: Projected Reserve Margin Shortfall Areas

Changing Resource Mix and Reliability Implications

New resource additions continue at a rapid pace. Solar PV remains the overwhelmingly predominant generation type being added to the BPS followed by battery and hybrid resources, natural-gas-fired generators, and wind turbines. New resource additions fell short of industry's projections from the *2023 LTRA* with the notable exception of batteries, which added more nameplate capacity than was reported in development last year.

As older fossil-fired generators retire and are replaced by more solar PV and wind resources, the resource mix is becoming increasingly variable and weather-dependent. Solar PV, wind, and other variable energy resources (VER) contribute some fraction of their nameplate capacity output to serving demand based on the energy-producing inputs (e.g., solar irradiance, wind speed). The new resources also have different physical and operating characteristics from the generators that they are replacing, affecting the essential reliability services (ERS) that the resource mix provides. As generators are deactivated and replaced by new types of resources, ERS must still be maintained for the grid to operate reliably.

Natural-gas-fired generators are a vital BPS resource. They provide ERSs by ramping up and down to balance a more variable resource mix and are a dispatchable electricity supply for winter and times when wind and solar resources are less capable of serving demand. Natural gas pipeline capacity additions over the past seven years are trending downward, and some areas could experience insufficient pipeline capacity for electric generation during peak periods.

Trends and Reliability Implications

Demand and transmission trends affect long-term reliability and the sufficiency of electricity supplies. A summary for each is provided below and further discussed within the **Demand Trends and Implications** and **Transmission Development and Interregional Transfer Capability** sections.

Demand Trends

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb; demand growth is now higher than at any point in the past two decades. Increasing amounts of large commercial and industrial loads are connecting rapidly to the BPS. The size and speed with which data centers (including crypto and AI) can be constructed and connect to the grid presents unique challenges for demand forecasting and planning for system behavior. Additionally, the continued adoption of electric vehicles and heat pumps is a substantial driver for demand around North America. The aggregated BPS-wide projections for both winter and summer have increased massively over the 10-year period:

- The aggregated assessment area summer peak demand forecast is expected to rise by 15% for the 10-year period: 132 GW this LTRA up from over 80 GW in the *2023 LTRA*.
- The aggregated assessment area winter peak demand forecast is expected to rise over almost 18% for the 10-year period: 149 GW this LTRA up from almost 92 GW in the *2023 LTRA*.

Transmission Trends

For the first time in recent years, transmission projections reported for the LTRA reflect a significant increase in transmission development. This year's cumulative level of 28,275 miles of transmission (>100 kV) in various stages of development for the next 10 years is substantially higher than the *2023 LTRA* 10-year projections (18,675 miles) and is above the average of the past five years of NERC's LTRA reporting on average (18,900 miles of transmission planning projects in each 10-year period published in the last five LTRAs). Transmission in construction has yet to increase substantially; rather, the large increase in transmission projects is seen in planning stages of development.

New transmission projects are being driven to support new generation and enhance reliability. Transmission development continues to be affected by siting and permitting challenges. Of the 1,160 projects that are under construction or in planning for the next 10 years, 68 projects totaling 1,230 miles of new transmission are delayed by siting and permitting issues, according to data collected for the LTRA. Questions of cost allocation and recovery can also challenge transmission development when the benefits apply to more than one area, as often occurs with projects that enhance interregional transfer capability.

In NERC's separate Interregional Transfer Capability Study (ITCS), which was performed to meet requirements contained in the Fiscal Responsibility Act of 2023, NERC found that an additional 35 GW of transfer capability across the United States would strengthen energy adequacy under extreme conditions. Increasing transfer capability between neighboring transmission systems has the potential to alleviate energy shortfalls in some areas identified in this LTRA's **Capacity and Energy Risk Assessment**. Conversely, when resource plans are developed that address these same energy shortfalls, such as through resource additions, demand-side management initiatives, or changes to generator retirement plans, the need for increased transfer capability will also change. Planners have options for reducing energy adequacy risks from extreme weather. Selecting the best course of action will depend on weighing these options against various engineering, economic, policy, reliability, and resilience objectives.

The ITCS provides foundational insights that facilitate stakeholder analysis and actions; it is not a transmission plan. In the future, NERC will extend the study beyond the congressional mandate to include transfer capabilities from the United States to Canada and among Canadian provinces.

Emerging Issues

The **Emerging Issues** section discusses developments and trends that have the potential to substantially change future long-term demand and resource projections, resource availability, and reliable operations of the BPS. Topics include data centers and large industrial loads, battery energy storage systems, electric vehicles and load, and energy drought. NERC's RSTC has formed new task forces where needed to address emerging issues.

Recommendations

To address the energy and capacity risks identified in this LTRA, NERC recommends the following priority actions:

1. **Integrated Resource Planners, market operators, and regulators: Carefully manage generator deactivations.** Independent System Operator/Regional Transmission Organizations (ISO/RTOs) should evaluate mechanisms and process enhancements for obtaining information on expected generator retirements that would support early identification of reliability risks. State and provincial regulators and ISO/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 developed and placed in service.
2. **NERC and Regional Entities: Improve the LTRA by incorporating new analysis and criteria to inform stakeholders of future reliability risks.** NERC increased the frequency of the ProbA from biennial to annual and included unserved energy and load-loss metrics as the basis for risk analysis in this year's LTRA. To be more effective in using energy criteria and outputs of probabilistic analysis, NERC must specify consistent methods and assumptions for assessment areas to follow in preparing the annual ProbA. NERC and the Regional Entities, in consultation with the RSTC, should also continue to enhance NERC's LTRA to assess ERSs in the future system and the potential impact of new and evolving electricity market practices, regulations, or legislation on resource adequacy. Finally, NERC should work with the Regional Entities to perform wide-area energy analysis with modeled interregional transfer capability. Wide-area energy analysis will support the evaluation of extreme weather and regional fuel supply issues on an interconnection level.
3. **Regulators and Policymakers: Streamline siting and permitting processes to remove barriers to resource and transmission development.** As ISO/RTOs continue looking for opportunities to speed transmission planning processes, delays from siting and permitting activities will need to be reduced. These are the most common causes for delayed transmission projects. Support from regulators and policymakers at the federal, state, and provincial levels is urgently needed.
4. **Regulators, electric industry, and gas industry member organizations: Implement a framework for addressing the operating and planning needs of the interconnected natural gas-electric energy system.** Various initiatives were launched in the past year to address the reliability needs that arise from the complexity of interconnecting natural gas and electric infrastructure. Voluntary actions taken by the natural gas industry in response to the North American Energy Standards Board (NAESB) Forum report are a positive step toward improving winter readiness. The National Association of Regulatory Utility Commissioners (NARUC) launched its Gas-Electric Alignment for Reliability (GEAR) task force this year and recently created the Natural Gas Readiness Forum. For its part, NERC continues to collaborate extensively with industry and policymakers. NERC has enhanced its Reliability Standards requiring generators to prepare for winter extremes, implement training, and establish communication protocols between generators and grid operators. Current standards projects encompass extreme weather planning and energy assurance requirements. NERC will continue to provide full support to initiatives aimed at achieving a reliable interconnected energy system and urges regulators and policymakers to support needed avenues of coordination between the two sectors.
5. **Regional transmission organizations, independent system operators, and FERC: Continue to ensure essential reliability services are maintained.** The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate ERSs.[7] Retiring conventional generation is being replaced with large amounts of wind and solar; planning considerations must adapt with more attention to ERSs. As replacement resources are interconnected, these new resources should be capable of supporting voltage, frequency, ramping, and dispatchability. Many technologies can contribute to ERSs, including variable energy resources; however, policies and market mechanisms need to reflect these requirements to ensure these services are provided and maintained. Regional transmission organizations, independent system operators, and FERC have taken steps in this direction, and these positive steps must continue.

In addition to these priorities, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. All recommendations are listed in the **Recommendations and ERO Actions Summary** section.

[7] Essential Reliability Services: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/ERS%20Abstract%20Report%20Final.pdf

Capacity and Energy Assessment

The resource mix transformation is making traditional capacity-based adequacy criteria obsolete. Resource Planners and state and provincial policymakers use resource adequacy criteria to ensure sufficient resources are available to meet demand. In their application, current capacity-based adequacy criteria were not designed to differentiate between the scenarios, size, frequency, duration, and timing of energy shortfalls. This has become increasingly important as the resource transformation evolves from capacity-based resources with assured and stored energy supplies to energy-constrained resources that are increasingly impacted by weather and environmental conditions. Therefore, supplemental criteria must be adapted to properly assess system adequacy and help determine appropriate solutions. This year's LTRA includes probabilistic indices to measure these additional dimensions of risk and provide a more robust approach to understanding risk of inadequacy in future plans.

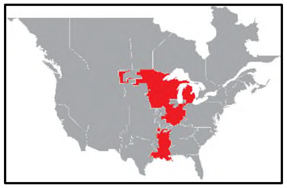
Assessment Approach

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:

- Assessing load-loss metrics determined from probability-based simulation of projected demand and resource availability over all hours. This approach identifies high-risk periods and potential energy constraints resulting in load-loss events. The 2024 ProbA is performed for each assessment area and examines the system as planned for the years 2026 and 2028. Loss-of-load hours (LOLH) and expected unserved energy (EUE) from NERC's ProbA are used to identify risk levels.
- Comparing the margin between projected resources and peak net demand, or reserve margin, to a reserve margin target (known as RML) that represents the accepted level of risk based on a probability-based loss-of-load analysis.

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.

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. Regulatory authorities or market operators establish resource adequacy targets. Most targets in North America are currently based on a 1-day/event load loss in a 10-year planning requirement. See the **Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area**. Recently, regulators and policymakers in many states and market areas have begun considering or developing resource adequacy targets based on additional criteria that can better address energy risks and extreme weather-related supply disruption.[8] High-risk areas are likely to experience a shortfall in electricity supplies at the peak of an average summer or winter season. Unusual heat waves or deep-freeze events pose an even greater threat to reliability.

For the *2024 LTRA*, assessment areas are classified as high risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2025–2029):

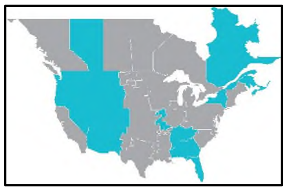
- Annual LOLH exceeds 2.4 hours/year for one or more years in the ProbA.
- Annual normalized EUE exceeds 0.002% (20 ppm) for one or more years in the ProbA.
- Resource adequacy target(s) established by regulatory authority or market operator are not met.

An assessment area is considered an **elevated risk** when it meets the established resource adequacy target or requirement, but probabilistic or deterministic analysis of conditions that are plausible but more extreme than normal seasonal peaks are likely to cause shortfall in area reserves. 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. In the analysis, elevated risk may be found by modeling above-normal demand and low resource availability. The risk can also be identified by examining output data from probabilistic analysis tools to determine the underlying conditions for load-loss events. Simply put, elevated-risk areas meet resource adequacy requirements but may face challenges meeting load under extreme conditions. For the *2024 LTRA*, assessment areas are classified as elevated risk based

[8] See the NERC-National Academy of Engineering Workshop Report *Evolving Planning Criteria for a Sustainable Power Grid*.

on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2025–2029):

- Annual LOLH is between 0.1 and 2.4 hours/year for one or more years in the ProbA.
- Annual normalized EUE is less than 0.002% (20 ppm) but non-zero for one or more years in the ProbA.
- Resource adequacy target(s) established by regulatory authority or market operator are met, but plausible scenarios of above-normal demand and/or low-resource conditions associated with a once-per-decade event indicate risk of load loss.



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[9] conditions, they are not immune to the effects of high-impact, low-frequency weather events that affect demand and generation simultaneously. For the *2024 LTRA*, assessment areas are classified as normal risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2025–2029):

- Annual LOLH is below 0.1 hours/year.
- Annual normalized EUE is negligible or zero.
- Resource adequacy target(s) established by regulatory authority or market operator are met and reserves are expected to be available in plausible scenarios of above normal demand and/or low resource conditions associated with a once-per-decade event indicate risk of load loss.

Application of the Risk Criteria: NERC uses industry-provided demand and resource information and the results from probabilistic assessments performed by NERC Regional Entities, ISO/RTOs, and regulated utilities to determine risk of energy and capacity shortfalls. The methods, assumptions, and approaches used by entities to perform probabilistic assessments affect the results and outputs. In this year's LTRA, NERC incorporated new probabilistic assessment criteria (LOLH and EUE) from the NERC-National Academy of Engineering Workshop Report *Evolving Planning Criteria for a Sustainable Power Grid* alongside established reserve margin criteria. In instances where an assessment area's probabilistic assessment results and reserve margins give mixed indications as to the risk category, adherence to resource adequacy targets (e.g., required RML and load-loss criteria) established by regulatory jurisdictions took precedence. Any other apparent contradictions with metrics and criteria were generally assessed according to results of all-hours probabilistic analysis.

High-Risk Area Details

Most areas are projected to have electricity supply resources to meet demand forecasts associated with normal weather. However, the following areas (listed in order of appearance on the **Regional Assessments Dashboards**) do not meet resource adequacy criteria at some point during the next five years, indicating that the supply of electricity for these areas is likely to be insufficient and more firm resources are needed.

MISO

Additional coal-fired generator retirements and slower-than-anticipated resource additions since the *2023 LTRA* have caused a sharp decline in anticipated resources beginning next summer (2025). In addition, MISO's peak demand forecast has risen in 2026 and later, further lowering reserve margins compared to the *2023 LTRA*. PRMs in MISO for both summer and winter are projected to fall below the RML reserve margin requirements as new generation is insufficient to make up for generator retirements and load growth (**Figure 3** and **Figure 4**). Delays to generator construction in MISO result in a 2.7 GW shortfall by 2029. MISO reports 56 GW of nameplate generating capacity, predominantly solar and batteries, with signed generation interconnection agreements as of July 2024 that can help meet resource adequacy needs if connection is completed.

[9] Plausible extreme conditions considered by NERC in this assessment are similar to those experienced during Winter Storm Elliott, Winter Storm Uri, and the 2020 Western Wide Area Heat Dome.

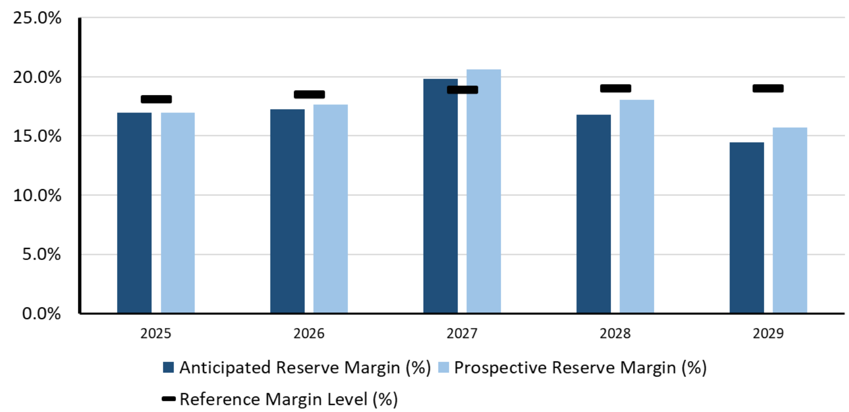


Figure 3: MISO Five-Year Planning Reserve Margin–Summer

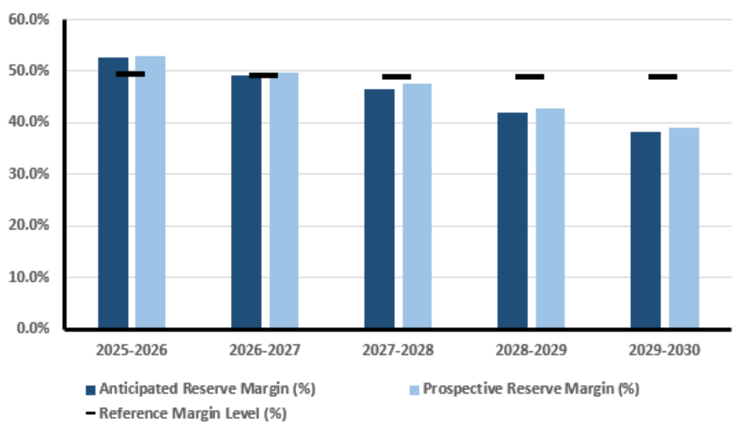


Figure 4: MISO Five-Year Planning Reserve Margin–Winter

MISO is at high risk of experiencing electricity supply shortfalls beginning in Summer 2025 based on PRMs derived from anticipated resources and demand forecasts. To establish the RMLs that define the minimum reserve margins for resource adequacy, MISO performs its annual probabilistic Loss-of-Load Expectation (LOLE) Study per MISO tariff. The study produces seasonal RMLs for the upcoming planning year that are used in MISO's planning resource auction. These RMLs are calculated such that they define the minimum PRM that will meet an LOLE of 1 day in 10 years. Because MISO is projected to have ARM below these RMLs, resource adequacy criteria are not met, indicating it is likely that supplies would be insufficient during normal summer and winter peak demand and outage conditions. All-hours probabilistic studies of the MISO system show that shortfall risks can also occur during spring and fall, months that are not peak demand seasons for MISO. See the **MISO** assessment area pages.

Elevated-Risk Area Details

The below areas are projected to meet resource adequacy criteria and have energy and capacity for normal forecasted conditions but are at risk of supply shortfall in extreme conditions. Areas are listed in order of appearance in the **Regional Assessments Dashboards** section.

MRO-Manitoba Hydro

The electricity demand forecast in the province of Manitoba has increased since the *2023 LTRA*, driven by expected economic activity and adoption of electric vehicles. Resource projections have not changed significantly.

As in prior probabilistic assessments, Manitoba Hydro's 2024 ProbA indicates that there is some risk of load loss and unserved energy associated with very low hydro conditions (see **Table 2**). Electricity demand peaks in winter, making this the higher-risk season. However, electricity supplies could fall short during either peak summer or winter conditions should an extreme and prolonged drought affect hydro production.

Table 2: MRO-Manitoba Hydro ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	7.23	**4.71**	**68.87**
EUE (PPM)	0.29	**0.18**	**2.50**
LOLH (hours per year)	0.01	**0.06**	**0.91**
Operable On-Peak Margin	13.5%	**18.8%**	**15.6%**

** Year 2026 Results from the 2022 ProbA provided for trending*

MRO-SaskPower

Resource projections for Saskatchewan over the 10-year period have increased since the *2023 LTRA*, rising to just over 1 GW and include two new 377 MW gas-fired generation facilities, expansion of existing gas-fired generation facilities, and new geothermal resources. The peak demand forecast growth rate (1.35% annually) has changed little since the *2023 LTRA*.

The ProbA for SaskPower indicates there is some risk of load loss and unserved energy that diminishes with the new resource additions that are planned for 2027 (**Table 3**). Saskatchewan is a winter-peaking system; however, the unserved energy risks are more closely associated with the planned outages of large generators that typically occur in the fall and spring shoulder periods. The months of September and October are the highest risk periods because of the potential for high temperatures to unexpectedly extend beyond summer and into the maintenance period.

Table 3: MRO-SaskPower ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	117.0	**75.64**	**8.55**
EUE (PPM)	4.4	**2.81**	**0.30**
LOLH (hours per year)	0.9	**0.54**	**0.08**
Operable On-Peak Margin	24.6%	**24.8%**	**30.8%**

** Year 2026 Results from the 2022 ProbA provided for trending*

MRO-SPP

New resource capacity in the interconnection queue—primarily solar, battery, and wind—is currently projected to keep up with rising peak demand forecasts. DR programs are also increasing over the next 10 years. Resource adequacy issues can arise, however, if generators retire earlier than anticipated or new resource additions connect more slowly. Currently, there are over 8 GW of coal and gas-fired generators that have indicated that they may retire within the next 10 years, making the resource outlook unclear. SPP's summer reserve margins, based on installed generator capacity, remain above RMLs through 2029 (see **Figure 5**).

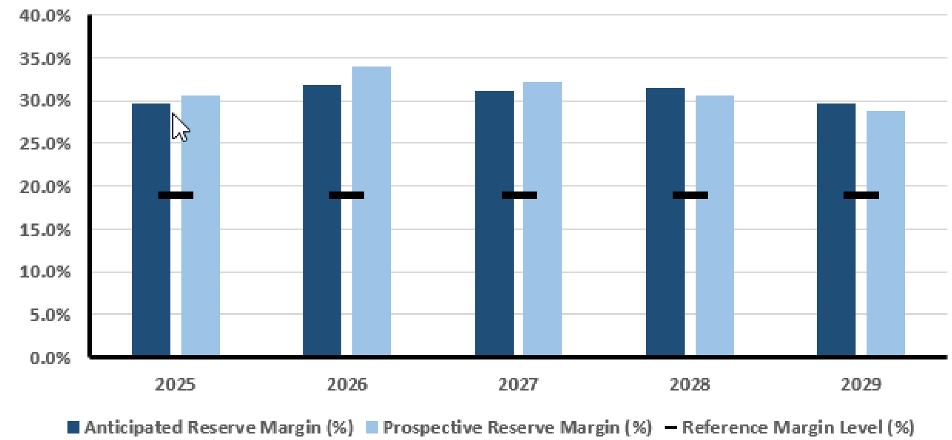


Figure 5: MRO-SPP Five-Year Planning Reserve Margin–Summer

All-hours probabilistic analysis performed by SPP shows that resource adequacy challenges are shifting from summer (when area demand is at its highest) to winter months (when the new resource mix is less capable of performing reliably). Annual results of the ProbA are in **Table 4** below. SPP's 2023 loss-of-load expectation (LOLE) study results indicate that a separate RML and seasonal resource capacity contributions are needed for the summer and winter seasons to effectively provide for resource adequacy.

Table 4: MRO-SPP ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	0.84	**0.00**	**6.61**
EUE (PPM)	0.00	**0.00**	**0.02**
LOLH (hours per year)	0.00	**0.00**	**0.01**
Operable On-Peak Margin	19.6%	**19.5%**	**16.0%**

** Year 2026 Results from the 2022 ProbA provided for trending*

NPCC-New England

New England is forecasting unprecedented demand growth driven by electrification of heating and transportation. Wind, solar, and batteries make up the projected resource additions, along with growth in distributed energy resources. Since the *2023 LTRA*, the peak demand forecast is relatively unchanged. New England has among the strongest winter demand forecast growth rates of any assessment area, rising over 7 GW in the 10-year period, or 35% from its current peak demand forecast.

The 2024 ProbA for NPCC-New England reveals increasing risk of load loss and unserved energy compared to the 2022 ProbA (see **Table 5**). Higher-demand forecast and replacement of dispatchable resources with more VERs contribute to this trend. In the ProbA modeling, supply shortfall risk is limited to the summer months and is associated with periods of above-normal demand and low resource output (e.g., low wind, solar, or high thermal outages).

Table 5: NPCC-New England ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	0.55	**10.69**	**67.40**
EUE (PPM)	0.00	**0.09**	**0.06**
LOLH (hours per year)	0.00	**0.07**	**0.03**
Operable On-Peak Margin	27.8%	**12.4%**	**13.7%**

** Year 2026 Results from the 2022 ProbA provided for trending*

While NPCC's ProbA results indicate that the risk of unserved energy in New England is concentrated in summer months, 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. Potential natural gas transportation constraints can affect supply to generators during extreme cold temperatures, when natural gas demand for space heating is also peaking. Most natural-gas-fired generators in the area do not have firm natural gas transportation service and can be subject to supply curtailment during peak conditions. Many natural-gas-fired generators in New England can also operate with stored oil, providing for assured electricity supply in extreme winter conditions while oil stores are procured and maintained. Scenarios of extended and extreme cold weather that affect the availability of natural gas and oil replenishments present a reliability risk but were not within the scope of the 2024 ProbA.

NPCC-Ontario

Near- and long-term resource adequacy challenges continue in the NPCC-Ontario assessment area as the Independent Electricity System Operator (IESO) manages lengthy refurbishment outages at nuclear generators and demand growth driven by agriculture and electrification. The beginning of projected shortfalls occurs in 2027 when some contracts for firm capacity are set to expire (see **Figure 6**). However, a number of resources with expiring contracts between 2026 and 2029 are anticipated to be re-committed for five-year terms through the IESO's second medium-term procurement, which is underway. As such, Ontario's Anticipated Reserve Margins (ARM) and Prospective Reserve Margins shown in **Figure 6** (which do not include this set of expiring resources) are conservative. Recommitment of these resources is expected to raise margins above the reference level in 2029 and help maintain reliability through the end of the decade. In May 2024, the IESO finalized long-term commitments for new-build battery storage facilities (1,784 MW) and new-build natural gas and biogas facilities (411 MW). Early operation incentives anticipated to bring a portion of these resources online as early as 2027 could help alleviate the reserve margin gap. The IESO also launched procurements for new capacity and energy-producing resources to be online as early as 2029. In addition, the IESO finalized an agreement with Hydro-Québec for capacity sharing in November 2024, providing 600 MW of firm imports to Ontario starting in Summer 2025 through Summer 2031. This capacity is also expected to help alleviate shortfalls indicated in 2027.

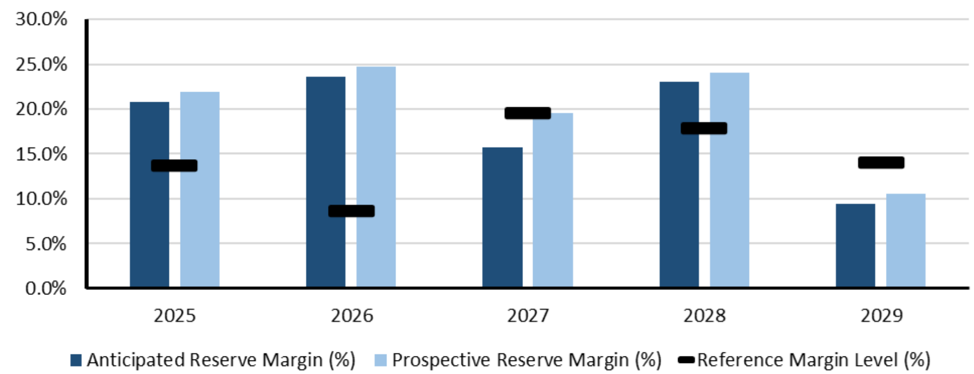


Figure 6: NPCC-Ontario Five-Year Planning Reserve Margin–Summer

The probabilistic assessment for Ontario performed by NPCC provides further insights into the potential for load loss and unserved energy. There is negligible risk of unserved energy and load loss in 2026 and earlier years; however, a small risk of load loss (< 0.01 hours) emerges after 2026 (**Table 6**). The 2024 ProbA study included only years 2026 and 2028, both of which have projected capacity surpluses above RMLs (see **Figure 6**). If 2027 and 2029 had been included in the ProbA, it can be expected that there would have been higher amounts of LOLH and unserved energy. ProbA results are also helped by the inclusion of electricity transfers from neighboring areas and modeling for some operating procedures used to manage supply shortfalls.

Table 6: NPCC-Ontario ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	72.16	**0.04**	**4.97**
EUE (PPM)	0.49	**0.00**	**0.03**
LOLH (hours per year)	0.44	**0.00**	**0.01**
Operable On-Peak Margin	-6.7%	**13.3%**	**9.5%**

** Year 2026 Results from the 2022 ProbA provided for trending*

PJM

PJM's projections for generator additions in 2025 and 2026 are scaled back dramatically from the *2023 LTRA* while demand forecasts continue to rise. As a result, ARMs for future years have fallen by as much as nine percentage points from last year. The trends in demand growth and resource additions create resource adequacy and system planning challenges for PJM as it carefully manages generator deactivation requests from the aging fossil and nuclear fleet.

PJM's ProbA results provide indication of the increasing resource adequacy risk to the system (see **Table 7**). EUE and LOLH are found in both ProbA assessment years (2026 and 2028) with risk concentrated in the winter months (especially January). The risk occurs on days where temperatures are very low across the entire PJM area, which results in high loads. While normal resource performance can meet these demand forecasts, resource performance from thermal resources on very cold days has historically been below normal due to freezing and fuel supply issues. Furthermore, solar resources are not likely to contribute during some of the coldest hours, resulting in very low total electricity supply and thus projections of load loss. ProbA analysis shows some summer load-loss and unserved energy risk but at much lower levels. Summer shortfall events are most likely to occur during wide-area heat events that coincide with low wind and low solar output, or very high outage and derates in the thermal generation.

Table 7: PJM ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	0.00	**537.52**	**1,043.44**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.12**	**0.22**
Operable On-Peak Margin	29%	**17.8%**	**17.7%**

** Year 2026 Results from the 2022 ProbA provided for trending*

SERC-East

The addition of solar resources is helping to raise summer on-peak reserve margins in the assessment area, despite rising demand forecasts and additional coal-fired generator retirements. Since the *2023 LTRA*, solar PV resources have grown from 1.5 GW to an expected 4.7 GW by the end of 2024. An additional 2 GW of solar PV resources are in the process of connecting. The summer peak demand forecast has also risen since the *2023 LTRA*, increasing by 2.8 GW (6.3%) over last year's projection. The area reserve margins have increased in the near term as a result of the solar resource additions then drop off after 2028 due to higher demand forecasts and planned generator retirements.

Despite these resource additions and higher summer reserve margins, the 2024 ProbA reveals growing resource adequacy risk in SERC-East (see **Table 8**). Measures of unserved energy and load-loss have increased since the 2022 ProbA as demand has risen and the resource mix has changed. SERC-East has changed from a summer-peaking area to one with peak electricity demand occurring in both the summer and winter seasons. This change is the result of added solar PV generation that shaves off summer peak demand and trends toward electrification in heating that drives up winter peak demand. The ProbA shows that the risk of unserved energy and load loss is concentrated in winter (January–February) months when wide-area extreme cold weather can affect electricity demand, generator performance, generator fuel supplies, and the availability of electricity imports. Based on current forecasts, resource adequacy risk will increase in SERC-East after 2028 due to the planned retirement of over 1,800 MW in coal-fired generation and continued load growth.

Table 8: SERC-East ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	92.49	**143.35**	**207.26**
EUE (PPM)	0.40	**0.60**	**0.81**
LOLH (hours per year)	0.08	**0.09**	**0.17**
Operable On-Peak Margin	16.1%	**14.2%**	**11.1%**

** Year 2026 Results from the 2022 ProbA provided for trending*

Texas RE-ERCOT

ERCOT is forecasting explosive demand growth, driven by data center projects, Bitcoin operations, development in oil- and natural-gas-producing areas, and industrial facilities. Over 20 GW of newly contracted large loads, in addition to other organic load growth, is projected to be added to ERCOT by 2028. Substantial amounts of solar PV and battery resources are being added to help meet rising demand, but there are significant reliability challenges to address during this period of rapid growth. Resource adequacy risks are mounting as fewer dispatchable resources comprise the resource mix. One of the strategies to address this risk is state implementation of a dispatchable resource generation loan program called the Texas Energy Fund. Furthermore, the forecasted growth in loads and resources poses significant challenges for transmission system planners.

Load growth and the characteristics of the resource mix are contributing to higher levels of unserved energy and load loss in probabilistic analysis (see **Table 9**). In the 2024 ProbA, EUE for the analyzed 2026 ERCOT system has risen to 19 ppm (0.0019 %) of the total annual supplied energy compared to the same analysis in the 2022 ProbA. The 2024 ProbA shows an improving trend in the analyzed 2028 ERCOT system, enabled by additional generation capacity from ERCOT scenarios developed to support rapid growth in large loads.[10]

A deeper analysis of the probabilistic assessment results reveals the unique characteristics of winter and summer risk. While peak winter loads can persist for 48 hours or longer, peak summer periods generally only last for a few hours. This is manifested in the duration and depth of the winter firm load-shed events that appear in the ProbA and has significant implications for the reliability contribution of energy-limited and non-dispatchable resources. The most extreme winter event modeled for 2026 was 16 hours in duration and up to 29 GW in load loss. In contrast, most summer unserved energy events were 1–2 hours in duration.

Table 9: Texas RE-ERCOT ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	1,235	**11,090**	**781**
EUE (PPM)	2.63	**18.95**	**1.12**
LOLH (hours per year)	0.30	**1.57**	**0.16**
Operable On-Peak Margin	35.9%	**28.8%**	**46.9%**

** Year 2026 Results from the 2022 ProbA provided for trending*

A key conclusion from the Texas RE-ERCOT 2024 ProbA is that matching the area's demand growth with a resource mix that is more variable and less fully dispatchable is increasing the risk of supply shortfalls that can result in load loss and unserved energy. When the seasonal characteristics of demand and resources are considered, Resource Planners can appropriately focus efforts to reduce the risk of potentially severe, long-duration winter shortfall events. The Public Utility Commission of Texas established a Reliability Standard and accompanying reliability assessment process in August 2024. The reliability standard is based on multiple probabilistic reliability measures that capture the different dimensions of loss-of-load events: average event frequency (LOLE), maximum event duration, and maximum event magnitude.

WECC-CA/MX

Resource additions continue to improve the overall resource adequacy outlook for the WECC California-Mexico assessment area. Since the 2022 ProbA, the planned extension of the Diablo Canyon nuclear plant (2.2 GW) and resource additions (over 5 GW nameplate in batteries, 3.3 GW nameplate in solar PV, and 0.2 GW in natural-gas-fired and geothermal generation) have alleviated supply shortfalls that were driving unserved energy and load-loss metrics in year 2026, as shown in the results of the 2024 ProbA performed by WECC (see **Table 10**).

Table 10: WECC-CA/MX ProbA Case Summary of Results

	2026*	2026	2028
EUE (MWh)	37,305	0	19,662
EUE (PPM)	136	0	70.07
LOLH (hours per year)	0.72	0	0.38
Operable On-Peak Margin	30.7%	43.2%	41.2%

** Year 2026 Results from the 2022 ProbA provided for trending*

Demand growth and planned generator retirements cause energy adequacy risks to re-emerge in future years. With a resource portfolio that includes a substantial amount of solar PV, the risk of supply shortfall is associated with summer evening periods when demand is high and solar output is diminished. WECC's analysis for the 2024 ProbA found only a small occurrence (<1 hour) of resources falling below margin levels for reliability in the 2028 study year. WECC further observed that load-loss and unserved energy risk was localized in the Mexico portion of the assessment area, reflecting localized resource and transmission system constraints.

[10] Due to the inclusion of an additional 20 GW of large loads based on newly signed interconnection agreements, study-year 2028 included additional generation capacity from the "High Large Load Adoption" scenario of the ERCOT 2024 Long-Term System Assessment (LTSA), which included 22 GW of combustions turbines (CT) and 4 GW of combined cycles (CC).

The CA/MX 2028 system analyzed by WECC for the 2024 ProbA reflects the continued rapid transformation of the power grid. The analysis assumes forecasted demand growth of 3.5 GW, substantial resource additions (4.6 GW of solar PV, 7.6 GW in batteries, and 0.8 GW of natural-gas-fired generation imported from repowered coal units in Utah), and the retirement of over 3 GW of gas-fired generation. As demand grows and the resource mix becomes increasingly variable, periods of supply shortfalls can emerge. Battery additions and transfers help make up for energy shortfalls that can arise during evening solar down ramps.

WECC-BC

BC has a predominantly hydroelectric generation system with vast amounts of energy storage provided by its reservoirs. Winter peak demand in the province is forecast to grow modestly over the next 10 years, from 11,966 MW this winter to 12,305 MW at the end of the 10-year period. Since the *2023 LTRA*, the winter peak demand compound annual growth rate (CAGR) has fallen from 1.0% to 0.3%. Growth rate and reserve margins are higher. While the overall resource adequacy outlook has improved, the 2024 ProbA indicates the area continues to be at an elevated risk of supply shortfall during extreme conditions. Drought and extreme cold temperatures in winter can result in periods of insufficient operating reserves when neighboring areas are unable to provide excess energy.

Western Interconnection-wide probabilistic analysis performed by WECC for the 2024 ProbA reveals that risk of reserve shortages emerges after 2026, potentially resulting in unserved energy and load-loss events during extreme weather. WECC's analysis identified over five hours in 2028 when high demand and low supply from WECC-BC's internal resources were not able to be remedied with imports from neighboring areas experiencing similar conditions (see **Table 11**). In contrast, 2026 had no unserved energy or load-loss periods. An examination of hourly results showed that imports from neighbors were more available in 2026 to cover periods of potential shortfalls in BC Hydro's internal resources.

Table 11: WECC-BC ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	24	**0**	**103,132**
EUE (PPM)	0.71	**0**	**1,456**
LOLH (hours per year)	0.00	**0**	**5.52**
Operable On-Peak Margin	12.7%	**16.9%**	**9.4%**

** Year 2026 Results from the 2022 ProbA provided for trending*

WECC's interconnection-wide analysis simulates the probabilistic performance of resource types using historic hourly output data to identify future risk periods. Operators of systems with large hydroelectric storage facilities make adjustments to generation based on the level of demand and shape the water use within the day, week, month, or between years. These actions help posture hydroelectric generation for expected conditions and can reduce energy shortfall risks.

BC's supply margins relative to demand are lowest during winter peak demand periods. Imports from neighbors in the U.S. Northwest are common during these periods, and often during the overnight hours of 23:00 to 4:00 local. WECC's analysis shows the need for imports growing year to year throughout most of the LTRA forecast horizon. A widespread, extreme cold weather event in the Northwest that limits transfer capability is thus a risk to BC. Even though WECC-BC is expecting only moderate demand growth and relatively few retirements, diminished surplus capacity in neighboring areas is negatively affecting the resource adequacy outlook.

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).

Resource and Demand Projections

The **Capacity and Energy 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 forecast areas. The future electricity supply will come from a resource mix that is more variable, weather-dependent, and reliant on natural gas for fuel, requiring broad coordination and careful attention to manage reliability risks. 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 continue rising dramatically over the *2024 LTRA* assessment period, exceeding their highest rates in recent years. Ongoing challenges with resource and transmission development and the continued pace of generator retirements raise concerns that, in the future, the risk assessment map will expand with more elevated and high-risk areas.

Risk from Additional Generator Retirements

Accelerated retirements of the existing coal, natural gas, and nuclear generators can have a profound and negative effect on the resource adequacy and reliability of the BPS in the next 10 years. In this preceding **Capacity and Energy Assessment** NERC accounted for nearly 79 GW of fossil-fired and nuclear generator retirements that are anticipated through 2034. Environmental regulations and energy policies have the potential to influence generators to seek deactivation during the 10-year assessment period.[11] An additional 43 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 retirements, along with the confirmed retirements, contribute to declining reserve margins in the assessment areas over the next 10 years (see **Table 12**). As a result of demand growth and generator retirements, ARM is projected to fall below RML in 18 of the 20 assessment areas by 2034. While forecasts such as this factor into resource planning and market mechanisms to obtain resources needed for resource adequacy, it underscores the significant resource growth needed across North America. The lack of dispatchable resources and diverse generator fuel types in the interconnection processes makes the future resource mix look alarmingly unreliable. The potential for capacity and energy shortfalls and a higher-risk resource mix is heightened by economic and policy factors that place pressure on existing thermal generators.

The yearly projections of future retirements and an assessment area view are provided in the **Risk from** Additional Generator Retirements section.

[11] The Environmental Protection Agency (EPA) issued a final rule on May 9, 2024, establishing Greenhouse Gas Standards and Guidelines for Power Plants (the "GHG Rule"). This rule was released concurrently with three other EPA regulations that impact fossil-fueled power generation: Coal Combustion Residuals, Effluent Limitations Guidelines, and Mercury and Air Toxics Standards. Collectively, these four new regulations impose considerable financial and operational challenges on coal-fired generators.

Table 12: Anticipated Reserve Margins with Announced Retirements											
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MISO	17.7%	10.3%	10.3%	13.2%	8.6%	7.1%	10.6%	8.2%	7.5%	4.2%	-2.5%
MRO-Manitoba	12.5%	21.3%	18.4%	18.0%	15.0%	9.8%	0.5%	-0.6%	-1.7%	-2.9%	-4.2%
MRO-SaskPower	28.9%	27.8%	26.6%	31.1%	29.4%	7.0%	28.8%	28.0%	26.7%	26.8%	1.2%
MRO-SPP	28.3%	26.7%	26.0%	25.0%	20.8%	19.1%	26.7%	24.9%	23.5%	22.4%	8.1%
NPCC-Maritimes	18.9%	20.6+%	25.5%	25.1%	18.6%	3.9%	23.4%	20.7%	19.1%	17.7%	-1.5%
NPCC-New England	20.4%	25.0%	25.0%	26.3%	24.9%	23.5%	22.0%	20.1%	19.7%	17.1%	14.6%
NPCC-New York	18.4%	17.1%	21.4%	22.5%	22.4%	21.6%	20.7%	18.3%	16.7%	14.9%	13.6%
NPCC-Ontario	22.5%	20.8%	23.6%	15.7%	23.0%	9.5%	5.1%	-0.2%	-1.4%	-3.9%	-5.5%
NPCC-Quebec	12.5%	12.2%	13.1%	14.2%	12.6%	11.3%	9.8%	6.2%	3.5%	0.5%	-2.2%
PJM	29.8%	34.9%	35.7%	28.1%	21.4%	18.2%	23.1%	21.6%	20.1%	18.5%	10.3%
SERC-C	28.2%	18.9%	18.9%	15.0%	16.0%	15.2%	17.3%	17.1%	18.4%	21.1%	11.8%
SERC-E	30.4%	27.3%	25.8%	24.6%	20.6%	14.4%	14.3%	10.2%	6.3%	4.6%	-2.2%
SERC-FP	27.0%	25.4%	26.0%	23.2%	22.1%	20.9%	18.4%	22.0%	20.4%	18.2%	16.0%
SERC-SE	44.9%	39.9%	35.9%	31.5%	24.5%	21.4%	27.7%	25.8%	24.7%	23.7%	13.0%
TRE-ERCOT	24.3%	30.2%	32.5%	29.7%	25.6%	25.4%	27.8%	28.0%	28.4%	28.9%	24.9%
WECC-AB	36.3%	35.8%	35.7%	38.5%	41.7%	41.9%	35.4%	41.2%	33.6%	27.8%	27.0%
WECC-BC	20.9%	25.2%	25.2%	15.8%	15.9%	22.3%	22.1%	21.6%	21.2%	13.4%	19.9%
WECC-CA/MX	38.6%	45.5%	45.2%	38.4%	43.1%	28.8%	29.6%	23.3%	25.0%	15.2%	11.1%
WECC-NW	34.5%	40.3%	38.9%	35.6%	30.7%	24.5%	18.3%	12.2%	10.2%	8.1%	5.9%
WECC-SW	28.6%	37.0%	35.6%	31.6%	24.2%	17.4%	11.3%	7.7%	0.2%	-4.7%	-9.6%

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 Executive Summary.

Resource Mix Changes

Capacity Versus Energy: Changes in the Way to Plan for Resource Adequacy

Industry's methods of planning for resource adequacy need to change. The modern power system requires the enhancement of assumptions and supplementation of risk information for a better characterization of the risk. Historically, the resource adequacy criterion has been based on the LOLE metric, which should be no more than 1 event-day in 10 years when the generating resources are less than load (commonly known as "1-day-in-10"). This has been a design basis for the U.S. electric grid for at least 70 years (with its first formal mention in a 1951 American Institute of Electrical Engineers paper by C. W. Watchorn) and has historically served the industry well. Two important related but separate discussion topics include considerations for assumptions in the calculation of LOLE and other metrics and the establishment of the resource adequacy criteria (i.e., traditionally in terms of LOLE-1-day-in-10). The 1-day-in-10 LOLE criterion is commonly converted into a minimum capacity requirement resulting in a target or RML. In doing this, planners determine the minimum PRM required to maintain a 1-day-in-10 LOLE level. Historically, systems with an actual PRM above the minimum generally have sufficient resources and provide adequate energy and ERSs that operators need to reliably operate the BPS. Issues can arise in resource adequacy planning processes when planners solely rely on the RML comparison as the system transforms from an era of certain to more uncertain fuel sources and load behavior. In recent years, NERC has documented warnings of potential energy shortages in its reliability assessments, while in many cases the RML comparison indicates no shortfall. Substantial uncertainty has been introduced into planning the system with the addition of energy-constrained resources (variable energy resources such as wind and solar, and, at times, just-in-time fuels such as natural gas) that are highly dependent on weather and environmental conditions. Uncertainty in energy sufficiency is increasing as the types of resources change, leaving fewer resources that can be dispatched (dispatchable resources) in response to the variable resource availability and greater exposure to constraints in fuel supplies, reservoir levels, or battery discharge capabilities. Historical generator reliability assumptions based on the idea of well-maintained, well-invested units with an anticipated long life are no longer adequate. This increases uncertainty as a greater proportion of fossil-fueled resources continue to be retired, often with little notice to system planners. Nameplate values of variable energy resources are not as meaningful as projected energy availability, and environmental conditions can adversely impact the simultaneous availability of thousands of megawatts.

Probabilistic analysis enhances deterministic transmission planning from an energy adequacy standpoint given the following factors:

- Considers likelihood of events: It uses historical data to estimate how often different outages and weather conditions might occur.
- Provides more information: It calculates the average impact of these events, including how often and how long power outages might last.
- Helps compare options: It enables the selection of the upgrade(s) that provide the best balance between cost and reliability over time to be chosen.

Detailed recommendations are included in a recently published NERC report:
Evolving Planning Criteria for a Sustainable Power Grid: A Workshop Report, June 2024

Changes in Existing BPS Resource Capacity

Thermal generator retirements and new resource additions continue at a rapid pace. Since the *2023 LTRA*, over 8 GW of coal-fired generation has been retired, while substantial solar and battery resources have connected to the grid (see **Table 13**). From a strictly on-peak capacity perspective, there has been little change (8,348 MW is 0.8% of the total BPS summer on-peak resource capacity.)

Table 13: Existing BPS Resource On-Peak Capacity

	2023 Capacity (MW)	2024 Capacity (MW)	Difference (MW)
Coal	188,856	180,402	-8,454
Petroleum	32,107	30,987	-1,120
Natural Gas	483,391	484,148	757
Biomass	7,273	7,381	108
Solar[12]	52,998	66,293	13,295
Wind[13]	32,320	31,370	-950
Geothermal	4,319	3,881	-438
Conventional Hydro	103,368	105,792	2,424
Run of River Hydro	1,565	2,047	482
Pumped Storage	19,463	19,422	-41
Nuclear	106,173	105,385	-788
Hybrid & Battery	5,593	9,909	4,316
Other	2,217	774	-1,443
Total	1,039,643	1,047,791	8,348

This year-on-year change in on-peak capacity continues the general trend of declining baseload and dispatchable generation—which includes coal-fired, natural gas, and nuclear generators—and rising VERs. **Figure 7** shows the trend continuing through 2034, where 20% of the generating capacity will be provided by VERs. Focusing on the relatively small change in total on-peak capacity since 2023 can mask risks to reliability that result when important attributes of the retiring generation resources are not inherent in the replacement resource mix. Thermal generation resources, such as coal-fired generators, have the capability to be dispatched when needed and provide system inertia, dynamic reactive support, and frequency response for stable grid operation. Most types of replacement resources have limited or none of these attributes. Further, retirements in the thermal generator fleet are making the resource mix less effective in meeting winter energy needs.

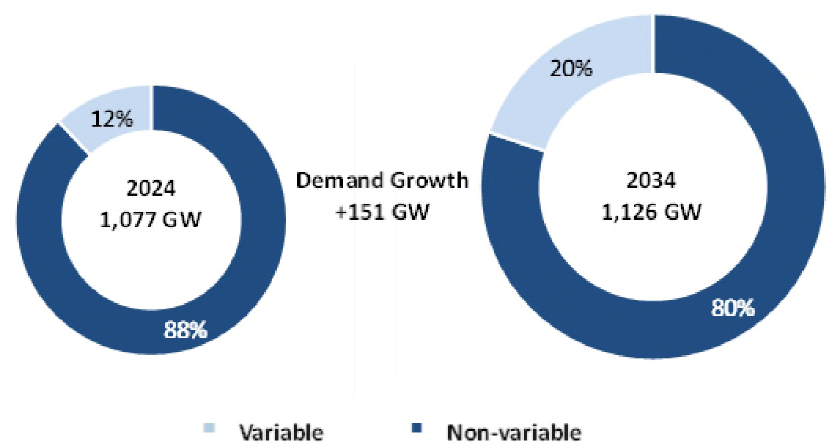


Figure 7: North America Total Generation Capacity in 2024 and 2034

Capacity Additions

New generation is added to the BPS through the area interconnection planning processes. Solar PV is the overwhelmingly predominant generation type being added to the BPS, followed by battery and natural-gas-fired generators, wind turbines, and hybrid resources. Batteries are now the second most predominant resource in the North America BPS interconnection queues. A summary of generation resources in the interconnection planning queues is shown in **Figure 8**.

Capacity in planning has grown since the *2023 LTRA* by over 44 GW (12%). In general, **Tier 1** resources are in the final stages for connection, while **Tier 2** resources are further from completion (see text box). Some projects that are in the earlier stages of the interconnection queue process will be withdrawn before completion due to supply chain issues, planning and siting challenges, and business or economic factors. While interconnection queues continue to swell, considerable uncertainty

[12] The capacity values in this table represent the on-peak contribution of solar resources. The total installed (nameplate) capacity of BPS solar in 2024 is 111,102 MW. See Table 11.
[13] The capacity values in this table represent the on-peak contribution of wind resources. The total installed (nameplate) capacity of BPS wind in 2024 is 176,636 MW. See Table 11.

surrounds the timing and amount of resource additions. (See an analysis of projected and actual additions on the next page).

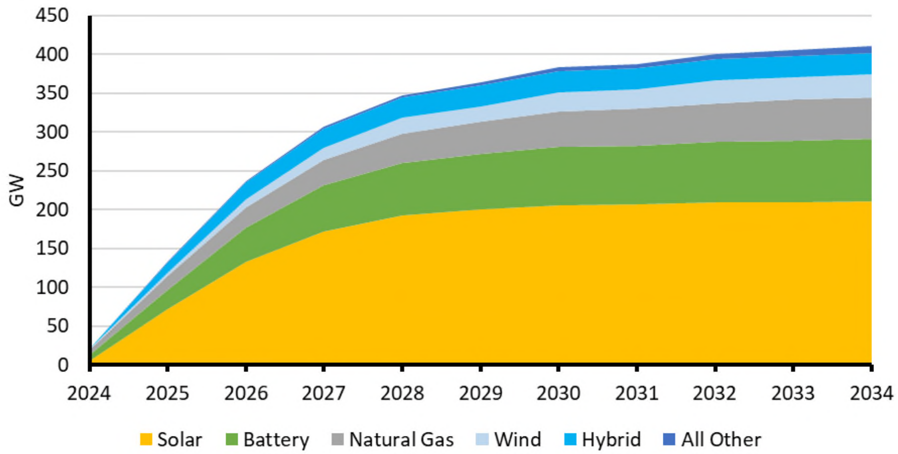


Figure 8: Tier 1 and 2 Planned Resources Projected Through 2034

Solar PV and wind nameplate capacity, both existing and planned, vary widely by area. **Figure 9** and **Figure 10** show current solar PV and wind installed capacities and the capacity in the planning process through 2034 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.

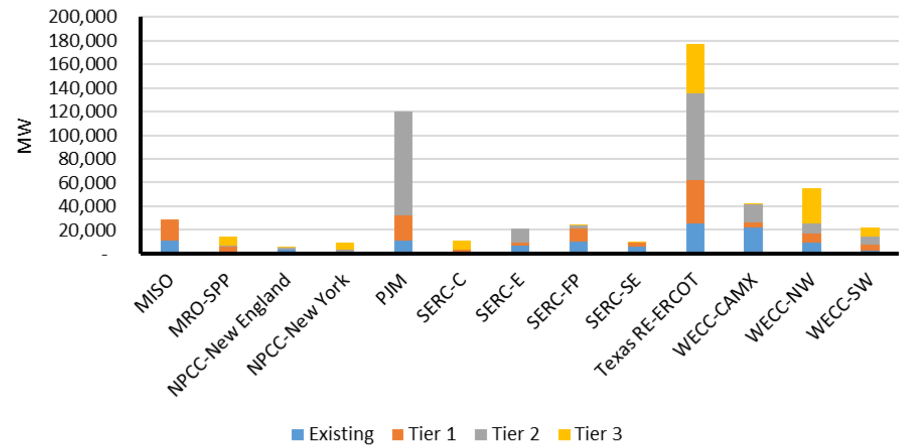


Figure 9: Solar Nameplate Capacity Existing and Planned through 2034

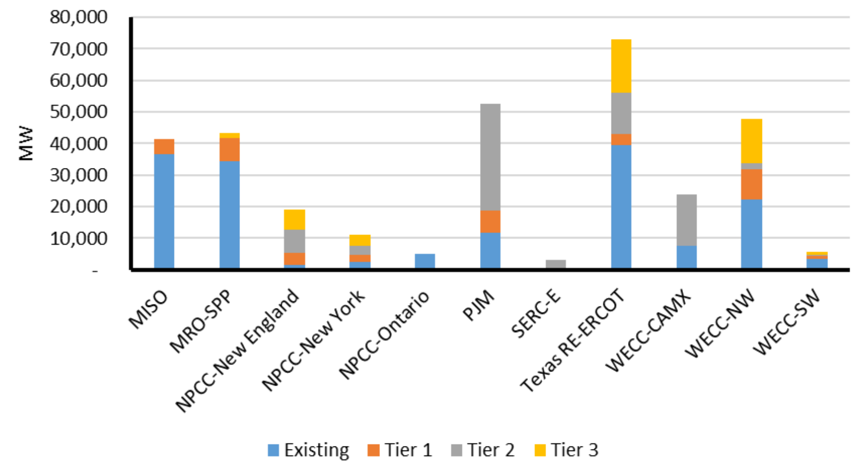
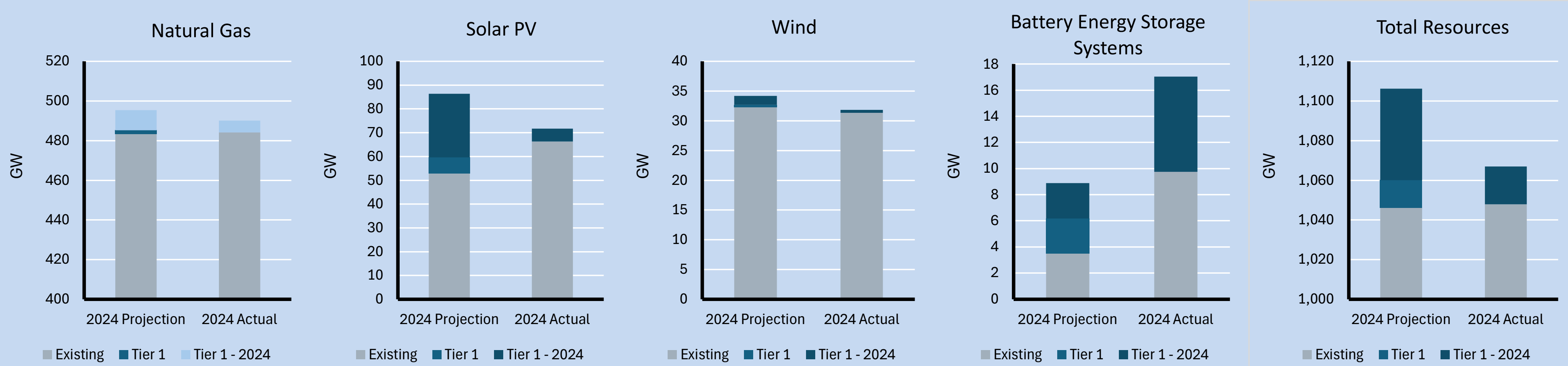


Figure 10: Wind Nameplate Capacity Existing and Planned through 2034

Resource Additions – How Much and When?

The added resource capacity on the BPS over the past year fell short of industry's projections, raising concerns that demand growth has the potential to outpace supply resources. The figures below compare the *2023 LTRA* projection of this year's installed capacity against the actual current installed capacity derived from data collected for this LTRA. Natural gas, solar PV, and wind resources were all over-projected last year. This gives evidence to industry reports of construction delays that prevented the expected interconnection of new resources. To a lesser extent, project withdrawals prior to commercial operation also contributed to lower-than-expected resource additions. One key exception—battery energy storage systems (BESS)—came in higher than last year's projections. As baseload and dispatchable generation continue to retire, delayed addition of new resources presents a challenge to near- and long-term planning.



Comparison of Projected Capacity from the 2023 LTRA to the Actual Capacity in the *2024 LTRA*

The sluggish rate at which new generation moves through the interconnection queue and begins service has been a cause for concern for long-term reliability planning. The Lawrence Berkeley National Laboratory published the results of an interconnection queue study in April 2024 assessing that less than one-fifth of generation capacity projects seeking interconnection between 2000 and 2018 actually came to fruition by the end of 2023.[14] Wait times have also been on the rise: According to the same study, the time from initiating a request for interconnection to the start of commercial operations has increased from less than two years, as was the case from 2000–2007, to more than four years from 2018–2023. The delay in bringing new generation capacity online in assessment areas that are anticipating steady or accelerated thermal capacity retirements, as well as increased demand, presents a significant reliability risk.

In recognition of the interconnection backlog risk, some regional transmission organizations have taken steps to address the lagging completion rates. MISO has assigned multiplication factors to generator requests based on the study phase and the likelihood of that resource coming on-line to more accurately gauge the likely incremental capacity in its footprint.[15] MISO also continues to advance the Joint Targeted Interconnection Queue (JTIQ) with SPP to resolve binding constraints that have delayed the interconnection process. PJM analyzed the completion rate of its interconnection queue and reported that less than 16% of resources submitted into the queue between 1999 and 2023 went into operation. The ISO has also applied a reduction to the nameplate capacity of value of Tier 1 resources to reflect the historical addition rate of new generation. PJM's interconnection process subcommittee is working on enhancements for new generation to interconnect as a capacity resource. These measures and others are examples of the broader effort to streamline generator additions and thus offset retiring capacity.

Offshore wind plants are increasingly entering interconnection queues, located around the Northeastern United States. **Figure 11** shows the current planned capacity in the planning process through 2034 by assessment area. Currently, the existing offshore wind nameplate capacities are small in comparison: a single 29 MW plant in NPCC-New England and a 12 MW plant in PJM.

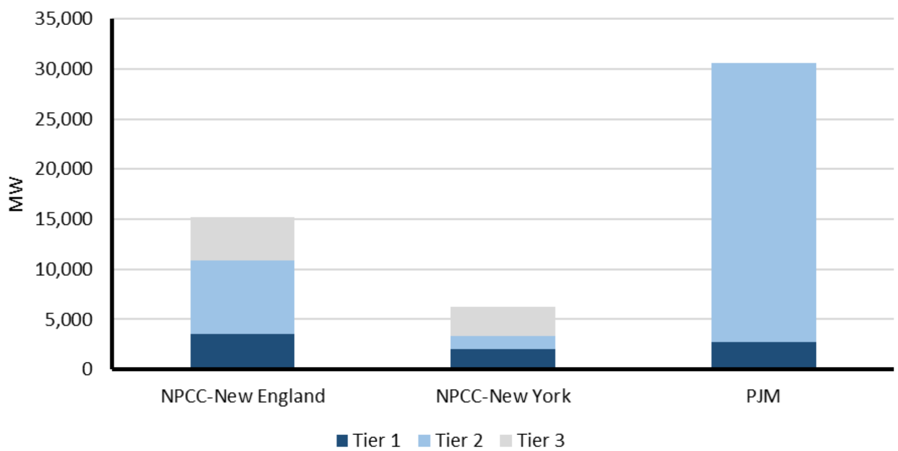


Figure 11: Offshore Wind Capacity Planned through 2034

Battery Resources

As the BPS increases the share of energy provided by VERs, the ability to provide energy by BESS or hybrid-solar PV and wind plants is increasingly important. While currently installed capacity totals just over 17 GW, an additional 306.5 GW of BESS are in planning. **Figure 12** shows the nameplate capacity of BESS resources currently in operation and in planning for connection to the BPS through 2034.

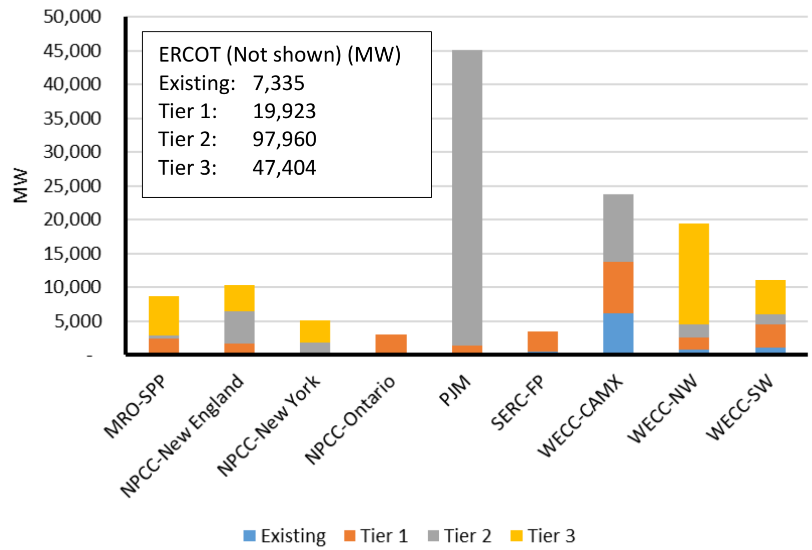


Figure 12: Battery Resource Capacity Existing and Planned through 2034

BESS are improving reliability by helping to offset the variability and uncertainty of inverter-based resources (IBR). 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*[16] 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.

Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. **Table 14** shows the nameplate value and the capacity contribution of existing wind, solar PV, hydro, and energy storage systems resources at the peak demand hour for each assessment area. During risk periods after peak demand (e.g., U.S. assessment areas in WECC), contributions of solar PV resources output is diminished during evening periods and additional resources are needed.

[16] NERC–WECC *2022 California Battery Energy Storage System Disturbances*

Table 14: BPS Wind, Solar, Hydro, and Battery Generation Resources by Assessment Area Year 2024												
Assessment Area	Wind			Solar			Hydro			Energy Storage Systems		
	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)
MISO	41,349	5,715	13.8%	30,502	5,305	17.4%	2,450	1,576	64.3%	401	84	21.0%
MRO-Manitoba Hydro		52	-	-	-	-	6,434	5,704	88.7%	-	-	-
MRO-SaskPower	815	164	20.1%	30	-	-	864	862	99.8%	-	-	-
MRO-SPP	34,475	5,134	14.9%	703	275	39.1%	5,633	4,079	72.4%	2	2	100%
NPCC-Maritimes	-	261	-	-	5.1	-	1,361	1,312	96.4%	-	-	-
NPCC-New England	2,548	127	5.0%	3,361	308	9.2%	1,917	1,469	76.6%	26	9	34.9%
NPCC-New York	2,706	461	17.1%	1,039	240	23.1%	4,915	3,736	76.0%	60	30	50.2%
NPCC-Ontario	4,943	1,364	28%	478	-	0.0%	8,748	6,215	71.0%	18	-	0.0%
NPCC-Québec	3,820	1,375	36.0%	10	-	0.0%	40,907	39,354	96.2%	-	-	-
PJM	11,701	1,760	15.0%	10,735	4,808	44.8%	3,071	2,367	77.1%	222	100	44.8%
SERC-C	982	172	17.5%	2,308	771	33.4%	4,995	3,364	67.4%	100	50	50.0%
SERC-E	-	-	-	6,777	4,753	70.1%	3,170	3,016	95.1%	15	6	38.4%
SERC-FP	-	-	-	10,121	5,618	55.5%	-	-	-	538	523	97.2%
SERC-SE	-	-	-	7,267	5,414	74.5%	3,293	3,260	99.0%	115	40	34.9%
Texas RE-ERCOT	39,532	11,062	28.0%	31,058	19,098	61.5%	583	458	78.6%	10,720	-	0.0%
WECC-AB	5,559	1,867	33.6%	3,042	-	0.0%	894	285	31.9%	270	264	97.8%
WECC-BC	776	279	36.0%	2	-	0.0%	16,902	12,623	74.7%	-	-	-
WECC-CA/MX	7,694	1,158	15.0%	24,905	14,641	58.8%	10,211	3,582	35.1%	11,883	11,155	93.9%
WECC-NW	23,518	3,489	14.8%	12,787	6,877	53.8%	41,257	21,168	51.3%	1,909	1,231	64.5%
WECC-SW	3,784	628	16.6%	5,944	2,527	42.5%	1,025	721	70.3%	2,997	2,592	86.5%

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 over 123 GW by the end of this 10-year assessment period (up from 89 GW reported in the *2023 LTRA*, an increase of 38%). There are currently 58.7 GW of installed BTM solar PV across the North American BPS.

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 13** shows the current and projected BTM solar PV by area through 2034.

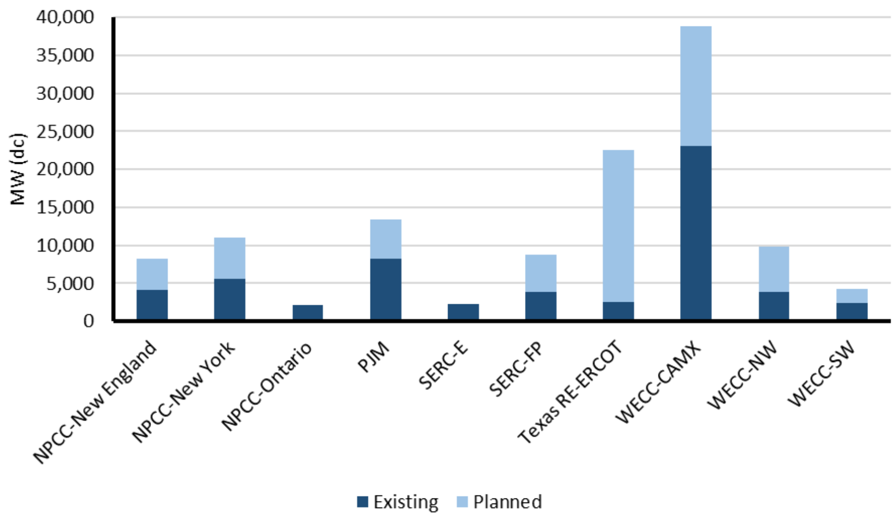


Figure 13: Solar PV DER Capacity Existing and Planned through 2034

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 79 GW of fossil-fired and nuclear generating capacity is being retired over this assessment period (see **Figure 14**), a small decrease from the 83 GW in retirements reported in the *2023 LTRA*. 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.

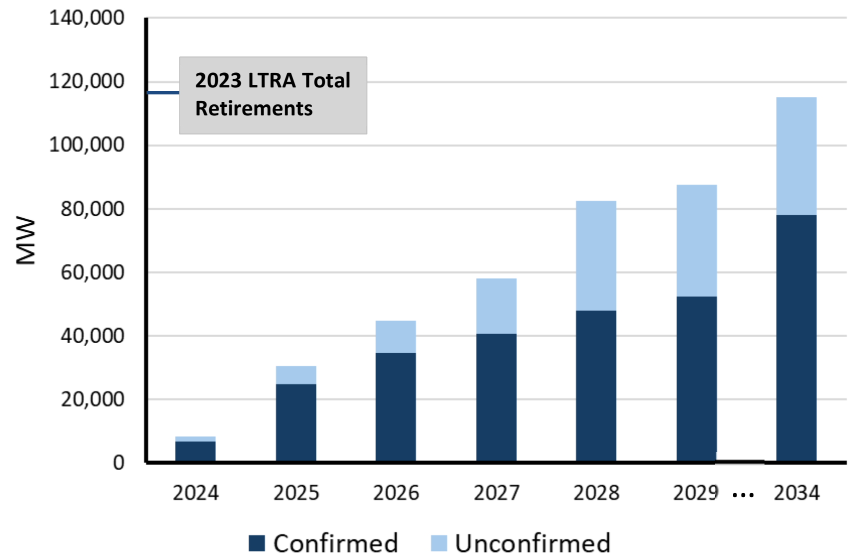


Figure 14: Projected Generation Retirement Capacity through 2034

Additional fossil-fired generator retirements are expected and would result in further loss of existing 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. Wholesale electricity market areas, where merchant electric generators make up a large part of the generating fleet, have more uncertainty around future generator retirements, making resource planning and adequacy assessment difficult. Figure 15 shows the total capacity of reported retirements (i.e., reported to ISO/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.[17] This total of confirmed and announced-potential retirements over the next 10 years is over 115 GW (3 GW lower than 10-year projections in the *2023 LTRA*).

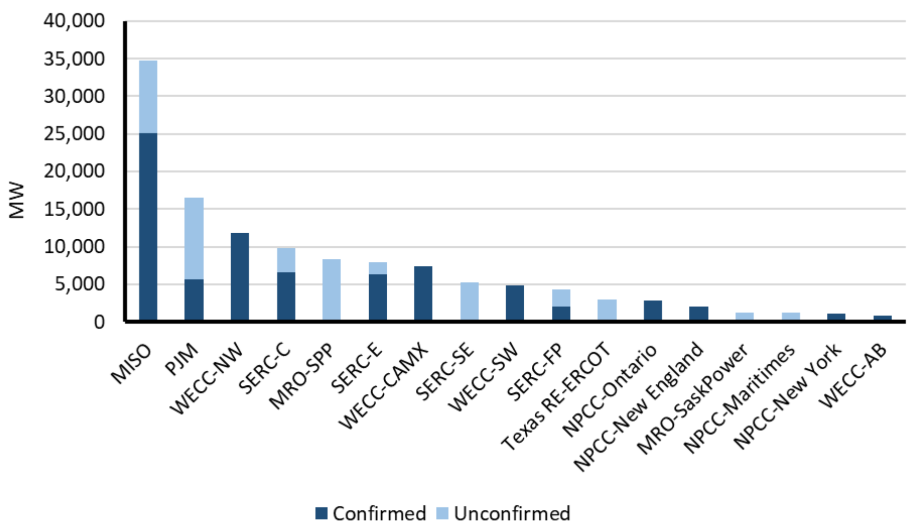


Figure 15: Projected Capacity Retirements of Nuclear and Fossil Generation 2024–2034

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. 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.

As the generation resource mix evolves and becomes more weather-dependent, fuel assurance becomes increasingly critical when conducting reliability assessments. Until recently, comparing seasonally available capacity to a predetermined PRM level has sufficed as a means to assess resource adequacy. However, resource adequacy is now only the first step of a meaningful reliability assessment. Energy adequacy must now be layered on top to assess the risk that available capacity may be rendered unavailable due to phenomena including low wind or solar output and/or natural gas supply and transportation issues.

This year, the Energy Information Administration (EIA) projected that more than 40% of delivered natural gas would be consumed by power generators, more than 0.6 Bcf/d higher than was consumed by power generators in 2023 and 7% higher than what the EIA had projected for 2024 in the fall of last year. Natural-gas-fired power plants generated 42% of the electrical energy consumed by end-use electricity customers in 2023 and are on track to maintain that share of generation this year. A significant percentage of natural-gas-fired power plants rely upon as-available, non-firm gas supply and transportation arrangements. Non-firm natural gas supply and transportation is generally sufficient for electric generators most of the year. However, during extreme cold weather, demand for natural gas by both generators and natural gas distribution companies (generally firm shippers) can at the same time dramatically increase. In these instances, generators that lack firm supply and transport arrangements are at risk of fuel unavailability, and when winter weather impacts gas production facilities, the resulting imbalance in pipeline injections and withdrawals can put at risk even firm pipeline customers as preparatory linepack is rapidly depleted.

[17] Confirmed generator retirements are reported to NERC by each assessment area in this *2024 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.

The *2024 LTRA* projects that an additional 6,500 MW of new natural-gas-fired generation will be added in North America over the next five years. While some assessment areas project net decreases in natural-gas-fired capacity, other areas report increases ranging from 3% to over 50%.

In the United States, 8 out of 13 assessment areas are adding capacity to their fleet of natural-gas-fired power plants over the next 10 years, amounting to over 10 GW of new natural-gas-fired power capacity. Altogether, those additions translate to an increase in natural gas use for power generation of more than 84 Bcf (245 MMcf/d). Whether this increase in natural gas generation capacity is sufficient to meet the increase in net internal demand projected for these same assessment areas remains to be seen, but based on the capacity additions alone, some areas are set to see an insufficient increase in gas pipeline capacity, as per the EIA's database of nationwide U.S. gas pipeline projects. (see **Figure 16**).

PJM is one such area, projected to see a 3% increase in natural-gas-fired generation capacity (+2,500 MW). Net internal electricity demand in PJM is forecasted to rise by 25 GW over the planning horizon at the same time that non-variable resources are expected to shrink their share of the capacity mix from 96% to 88%. To the extent that variable resources are uncertain during times of peak stress on the grid, there is a risk of gas delivery capacity being insufficient for the amount of natural gas supply that could be required to meet the demand increase. SPP is another assessment area where natural-gas-fired power capacity is set to rise, by 5%, or roughly 1,500 MW. In both PJM and SPP, there is a risk of a shortfall in natural gas pipeline capacity that could facilitate delivery of the additional fuel that is necessary to meet their capacity expansion plans.

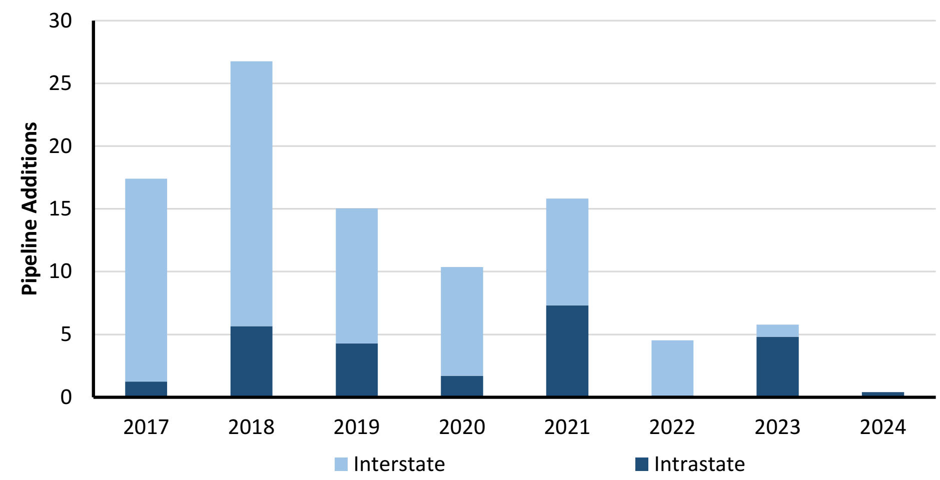


Figure 16: Annual U.S. Natural Gas Pipeline Capacity Additions by Type (2017–2024) Bcf/d (Source: U.S. Energy Information Administration)

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.

Maintaining ERSs for Grid Support

For the grid to operate reliably, it needs resources that are not only sufficient for meeting demand and energy requirements but also capable of controlling voltages, maintaining stable frequency across the system, and flexibly ramping up or down to dispatch control at all times. Conventional generators, such as nuclear, coal, and natural gas-fired generators, provide much of the ERSs that support reliable operation today. New resources on the grid are almost all IBRs, which have different physical and operating characteristics that affect the level of ERSs that they can provide. Without the spinning mass or traditional excitation systems providing the voltage control of a hydroelectric or thermal generator, most IBRs have limited capability for maintaining system voltages and stability. Batteries, with their fast response time, have some ERS capability that wind and solar do not. They are useful in regulating system frequency and are helping to balance variability from VERs in ERCOT and California where wind and solar make up a large portion of the resource mix.[18] As generators are deactivated and replaced by new types of resources, ERSs must still be maintained for the grid to operate reliably.

Accelerated generator retirements, especially unanticipated requests for deactivation, can cause ERS-related reliability issues in parts of the system due to the future loss of the generator's reliability attributes. This reduction in the level of ERSs can result in voltage violations or system instability. System planning and generator deactivation processes evaluate these changes to the system and ensure plans proceed only when reliability criteria, including ERS-related considerations, are met. For example, PJM's deactivation process identified reliability concerns to the system as a result of the requested deactivation of the Brandon Shores power plant (1,280 MW) in 2023. Until necessary system upgrades are completed to address identified system voltage and other reliability issues that would occur with the deactivation, PJM has requested that the Brandon Shores generators at the plant remain in service through the reliability-must-run process.[19]

To ensure the future system can operate reliably, market operators, system planners, regulators, and policymakers need to ensure effective mechanisms are in place to provide for the ERS needs of the future system. Long-term activities can provide incentives to generators with needed reliability attributes. Effective backstops will also be needed to prevent the loss of critical generators when analysis finds deactivation would violate reliability criteria.

Specific and actionable recommendations are contained in the **Recommendations and ERO Actions Summary** section of this report.

[18] See the *2023 Special Report on Battery Storage* from the California ISO.
[19] Information on this and other proposed deactivations in PJM are found on PJM's Generator Deactivations page.

Demand Trends and Implications

Demand and Energy Projections

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb higher than at any point in the past two decades. The aggregated assessment area summer peak demand forecast is expected to rise by over 132 GW, and aggregated winter peak demand forecasts are increasing by 149 GW. The growth rates of forecasted peak demand (see **Figure 17**) and energy (see **Figure 18**) continue to rise sharply since the 2022 LTRA, reversing an almost two-decade trend of falling or flat growth rates. See **Figure 17** for seasonal peak demand growth over the current and prior assessment periods and **Figure 18** for net energy growth. A map of the primary demand drivers for the North American BPS is illustrated for each assessment area in **Figure 19**.

Electrification and Demand Growth

Electrification of household appliances (e.g., heat pumps for household heating) and projections for electric vehicle growth over this assessment period are components of the demand and energy estimates provided by each assessment area. Since the *2023 LTRA*, peak season CAGR has risen in all assessment areas except two: NPCC-Maritimes' winter CAGR fell from 0.98% to 0.63% and WECC-BC's winter CAGR fell from 1.05% to 0.28%. Rising peak demand forecasts are contributing to the lower reserve margins projected for nearly all assessment areas.

Large Commercial and Industrial Loads

Increasing amounts of large commercial and industrial loads are connecting rapidly to the BPS. Emerging large loads, such as data centers (including crypto and AI) and hydrogen fuel plants, present unique challenges to forecasting and planning for increased demand. Earlier this year, NERC's RSTC established a Large Loads Task Force to better understand the reliability implications of growth in large loads and develop solutions.

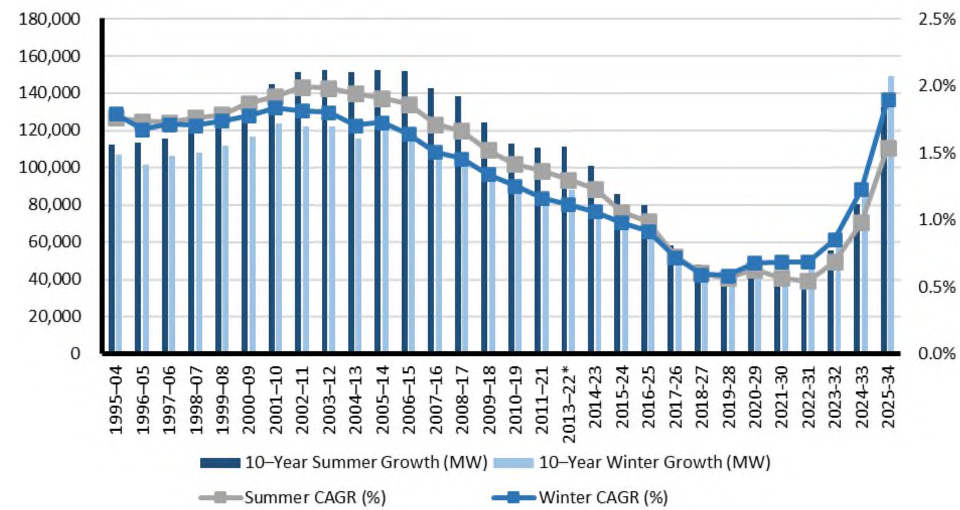


Figure 17: 10-Year Summer and Winter Peak Demand Growth and Rate Trends

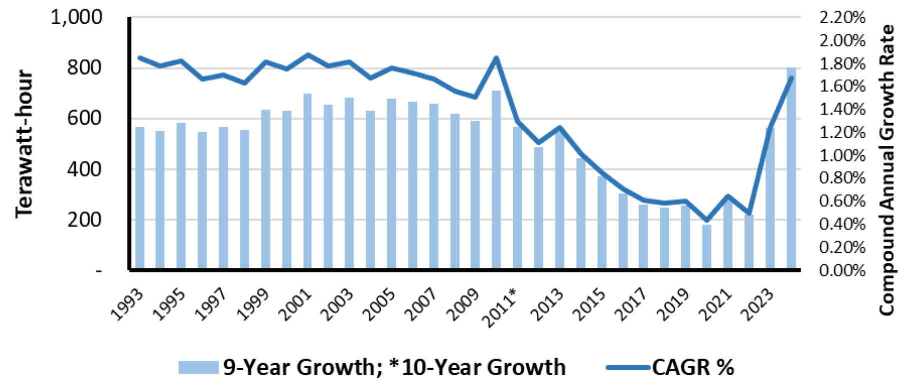


Figure 18: Net Energy for Load Growth and Rate Projections

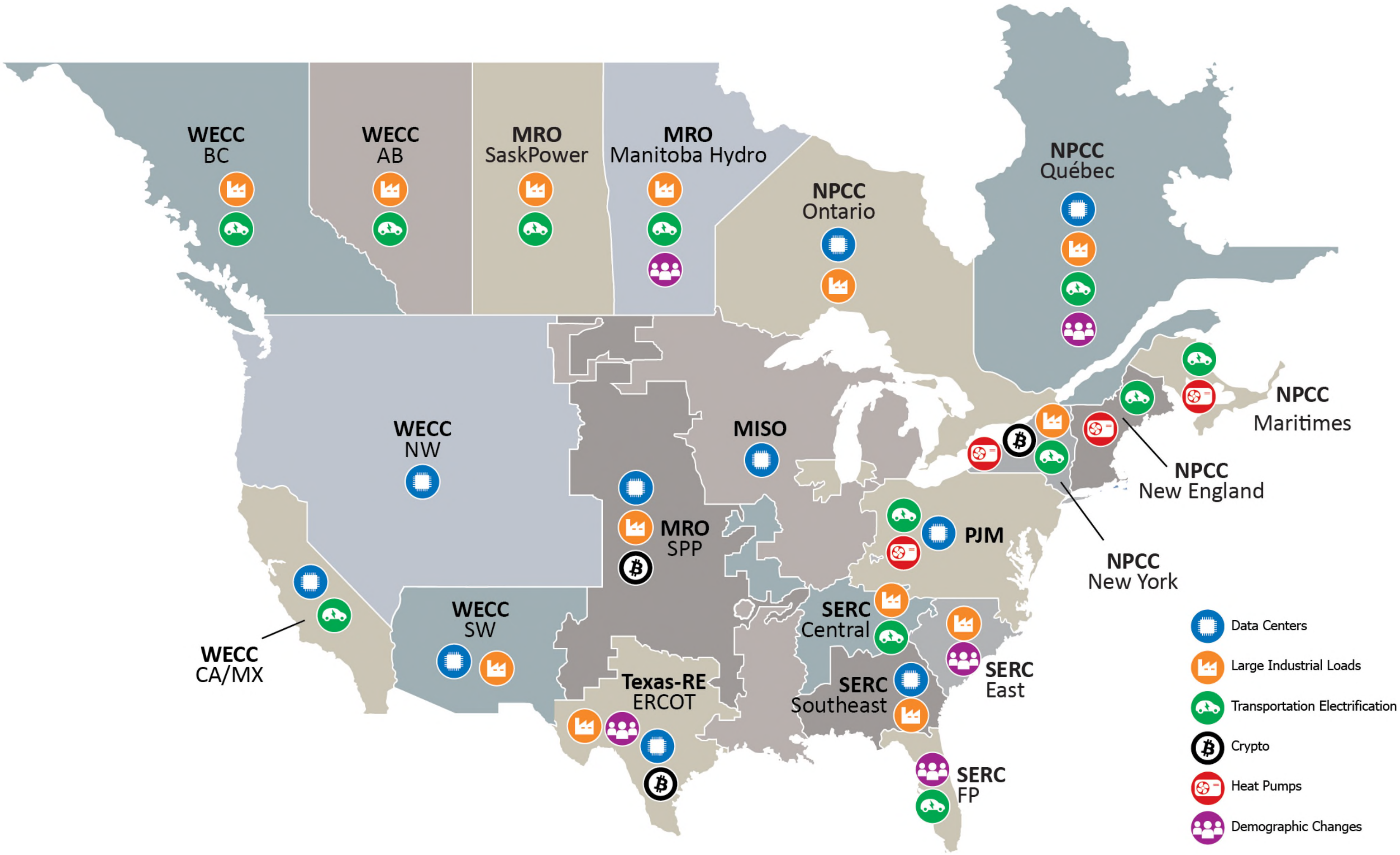


Figure 19: Primary Demand Drivers by Assessment Area

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 electric vehicles (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 and fuel risks are 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 to late-2030s)
- NPCC-Ontario (2030)

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 distributed energy resource 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 large commercial and industrial loads, electrification, electric vehicle 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 a 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 and Interregional Transfer Capability

Transmission Projects

This year's cumulative level of 28,275 miles of transmission (>100 kV) in construction or stages of development for the next 10 years (see **Figure 20**) is substantially higher than the *2023 LTRA* 10-year projections (18,675 miles) and is above the average of the past five years of NERC's LTRA reporting on average (18,900 miles of transmission planning projects in each 10-year period published in the last five LTRAs). Transmission in construction has yet to increase substantially; rather, the large increase in transmission projects is seen in planning phases.

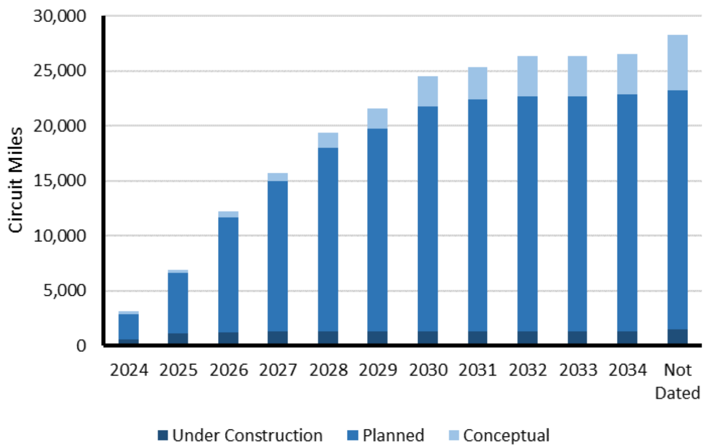


Figure 20: Future Transmission Circuit Miles >100 kV by Project Status

New transmission projects are being driven to support new generation and enhance reliability. **Figure 21** 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. Nearly 70 of the 1,160 transmission projects in development are for tie-lines and tie-line upgrades, which support transfer capability between neighboring Balancing Authority areas. See the transmission summaries at the end of each assessment area's pages (in the **Regional Assessments Dashboards**) for current transmission development details.

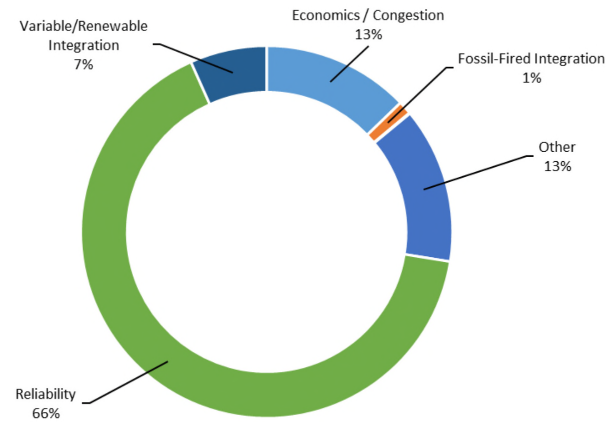


Figure 21: Future Transmission Circuit Miles by Primary Driver

Transmission development in some areas is hampered by siting and permitting challenges. Of the 1,160 projects that are under construction or in planning for the next 10 years, over 110 projects are currently delayed from their expected in-service dates. Siting and permitting issues are the most common cause for delays, affecting 68 projects (totaling 1,230 miles of new transmission). Other reasons for delays include economic impacts, planning and construction issues, or changing needs.

Interregional Transfer Capability Study (ITCS)

The Fiscal Responsibility Act of 2023[20] required NERC to conduct a comprehensive study of existing and future interregional transfer capability between each Transmission Planning Region[21] (TPR) to make recommendations for prudent additions to the amount of power that can be moved or transferred between neighboring TPRs and to make recommendations on how to meet and maintain transfer capability. In addressing this legislation, NERC identified additions to transfer capability that could support energy adequacy.[22] NERC filed the completed study report with FERC on November 19, 2024.[23]

Transfer Capability is the measure of the ability of the interconnected electric systems to reliably move or transfer electric power from one area to another area by way of all the transmission lines (or paths) between those areas under specific system conditions. The units of transfer capability are in terms of electric power, generally expressed in MW.

To provide further opportunities for stakeholder engagement and consultation, the project was divided into several stages, each with an accompanying report.

- **Overview of Study Need and Approach[24]:** Provided background and context regarding transfer capability calculations and the approach for recommending prudent additions, laying the foundation for the ITCS as a whole and its associated methods. (published in June 2024)
- **Transfer Capability Analysis (Part 1)[25]:** Addressed the first part of the congressional directive, which mandated a transfer capability analysis between each pair of neighboring TPRs, as well as the simultaneous import capability of each TPR. (published in August 2024)
- **Prudent Additions Recommendations (Part 2) and Meet/Maintain Recommendations (Part 3)**: Contained an energy margin analysis and resulting recommendations for prudent[26] additions to the transfer capability between neighboring TPRs to improve energy adequacy during, for example, extreme weather events. It also discussed how to meet and maintain transfer capability as enhanced by these prudent additions.
- **Canadian Analysis:** Due to the interconnected nature of the BPS, NERC will extend the study beyond the congressional mandate to identify and make recommendations to transfer capabilities from the United States to Canada and among Canadian provinces.[27]

Transfer Capability Analysis (Part 1)

Adequate transfer capability is fundamental to the reliable operation of the BPS. Balancing Authorities may rely on their neighbors to supply energy for various purposes, including economic or policy reasons. Transfer capability is also essential under stressed operating conditions, allowing Balancing Authorities to maintain reliability by importing needed energy from their neighbors. As the resource mix becomes increasingly dependent on just-in-time and weather-dependent fuel and energy for wind and solar, the ability to transfer electrical energy from areas of surplus to areas experiencing fuel or energy constraints has become essential to maintaining reliable delivery of electricity to end-use customers.

The ITCS is a congressionally mandated study to evaluate transfer capability and recommend additions to strengthen reliability.

A holistic view of the interconnected system and a thorough understanding of its behavior are essential when calculating or increasing transfer capability. When neighboring TPRs transfer energy over a highly interconnected system, the energy flows over many different lines based on the electrical characteristics, or impedance, of traveling each route, unless there is specific equipment used to control flows. As a result, energy typically flows not only across the tie lines that directly connect the exporting (source) TPR to the importing (sink) TPR but over many routes, some of which

[20] H.R.3746 - 118th Congress (2023–2024): Fiscal Responsibility Act of 2023 | Congress.gov | Library of Congress
[21] For the purposes of the ITCS, this term refers to the study regions as described in ITCS Overview of Study Need and Approach, Chapter 2.
[22] As evidenced during recent operational events including Western Interconnection Heatwave (2020), Winter Storm Uri (2021) and Winter Storm Elliott (2022), more needs to be done to support energy adequacy to be able to continuously meet customer demand. This is the reliability risk that the ITCS seeks to identify and mitigate through additions to transfer capability.
[23] NERC filing of the Interregional Transfer Capability Study, FERC Docket AD25-4-000.
[24] The ITCS Overview of Study Need and Approach can be found here.
[25] The ITCS Transfer Capability Analysis (Part 1) report can be found here.
[26] FERC defines prudence as the determination of whether a reasonable entity would have made the same decision in good faith under the same circumstances at the relevant point in time. See, e.g., New England Power Co., 31 FERC ¶61,047 at p. 61,084 (1985); and PotomacAppalachian Transmission Highline, LLC, 140 FERC ¶61,229 at P 82 2012 (Sept. 20, 2012).
[27] The ITCS Part 1 evaluated transfer capability from Canada into the United States.

may be running through third-party systems. The way electrical energy flows has broad implications for calculating and using transfer capability in an interconnected system, especially when traveling over long distances. For example, maintaining and increasing transfer capability may be highly dependent on the system conditions within the source and sink TPRs as well as surrounding areas. Likewise, transfer capability does not correlate one-to-one with the rating of new or upgraded transmission facilities.

Part 1 Key Findings

- Transfer capability varies seasonally and under different system conditions that limit transmission loading—it cannot be represented by a single number.
- Transfer capability varies widely across North America, with total import capability varying between 1% and 92% of peak load.
- Observed transfer capabilities are generally higher in the West Coast, Great Lakes, and Mid-Atlantic areas but relatively lower in the Mountain States, Great Plains, Southeast, and Northeast. There is limited transfer capability between interconnections

The transfer capability results in the Part 1 report reflect the conditions studied and are not an exhaustive evaluation of the potential for energy transfers. This study used a set of cases representative of stressed system conditions most relevant for the Part 2 analysis. As such, the study did not attempt to maximize transfer capability values for each interface through optimal generation re-dispatch, system topology changes, or other operational measures. Consequently, higher transfer capabilities may be available under different conditions. Changes to future resource additions, resource retirements, load forecast changes, and/or transmission expansion plans have the potential to significantly alter the study results.

Recommendations for Prudent Additions (Part 2) and to Achieve Transfer Capability (Part 3)

Part 2 of the ITCS evaluated the energy adequacy of the BPS should past weather conditions occur again in 2033. Specifically, the study applied 12 past weather years to the 2033 loads and resource mix using the current transfer capabilities as calculated in Part 1. The Part 2 study then evaluated the impact that additional transfer capability could have in mitigating the identified resource deficiencies[28] during extreme events, thereby improving energy adequacy. Using a six-step process, the ITCS developed a list of recommended additions to transfer capability. Figure 22 shows the existing and potential new interfaces where additional transfer capability is recommended. While there are several factors that Transmission Planners consider, including reliability, economics, and policy objectives, given NERC's role as the ERO, the ITCS focused solely on reliability, specifically in terms of energy adequacy, for these recommendations.

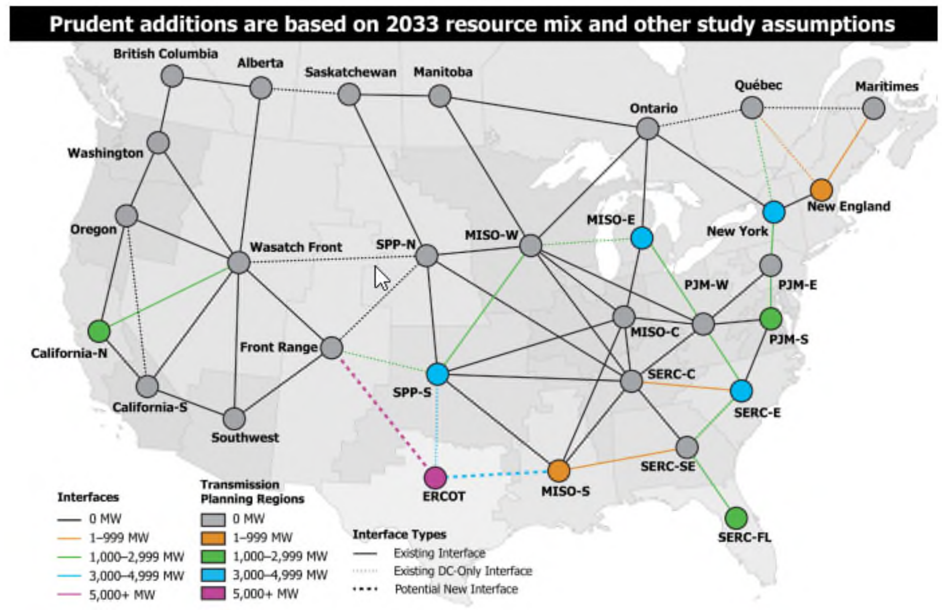


Figure 22: Prudent Additions to Transfer Capability

[28] For the purposes of this study, "resource deficiency" is used to describe instances where available resources, including energy transfers from neighbors, are insufficient to meet the projected demand plus minimum margin level.

The resulting recommendations for prudent additions to transfer capability (Part 2 study) were published in a report along with recommendations to meet and maintain transfer capability as enhanced by the prudent additions (Part 3).[29] Planners have multiple options for reducing the energy adequacy and extreme weather risks. In addition to the transmission enhancements that were in scope for the ITCS, due consideration should also be given to constructing local generation and storage, demand-side management approaches, and grid resilience projects. The ITCS recommended that planners consider all options and balance reliance on external resources vs. internal resources, noting that there may be better options than an over-reliance on one or the other.

Part 2 Key Findings

- Import capability required to reliably serve customers during extreme conditions varied significantly across the country, so a one-size-fits-all requirement would be inefficient and ineffective.
- Transmission limitations and the potential for energy inadequacy were identified in all 12 years studied.
- 35 GW of additional transfer capability is recommended across the United States to improve energy adequacy under extreme conditions.
- Some identified transmission needs could be alleviated by projects already in the planning, permitting, or construction phases. If completed, these projects could mitigate several risks highlighted by the ITCS, reinforcing their importance for grid resilience.
- The ITCS provides foundational insights for further discussion, and decisions. Transmission upgrades alone will not fully address all risks, and a broader set of solutions should be considered, emphasizing the need for local resources, energy efficiency, demand-side, and storage solutions.

See the *ITCS Final Report* for Detailed Key Findings

[29] The ITCS report *Recommendations for Prudent Additions to Transfer Capability (Part 2) and Recommendations to Meet and Maintain Transfer Capability (Part 3)* can be found here.

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.

Data Centers and Large Industrial Load

Growth in large load parcels like data centers and industrial facilities pose various challenges for system planners and operators, in addition to fueling rapid demand growth discussed elsewhere in this report. **Figure 23** shows one estimate of data center growth in the United States by 2027.[30] Other types of large industrial loads include 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. The behavior of large data centers during normal grid faults is also an emerging concern because customer-initiated automatic disconnecting of sizeable load can cause operating issues. Sudden and unexpected disconnecting load during a grid fault is analogous to well-known IBR performance issues and poses similar reliability risks. Planners and operators need to consider the characteristics of these loads as they begin to proliferate and support NERC RSTC's Large Loads Task Force to share best practices.

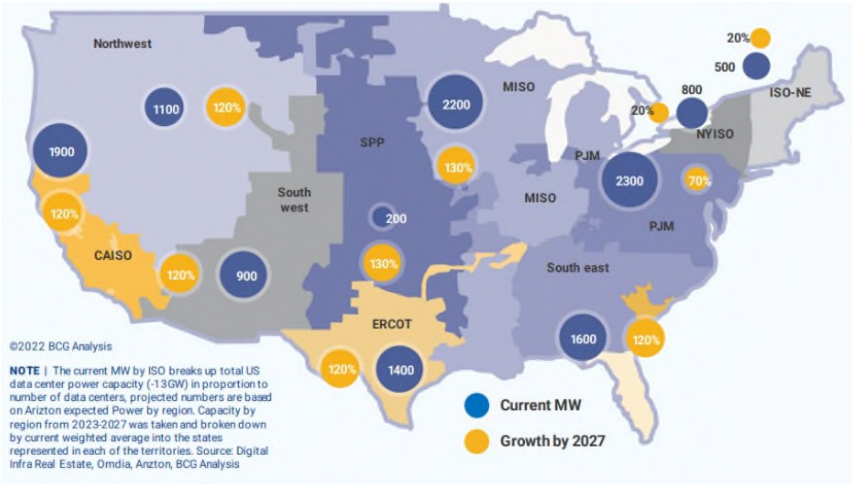


Figure 23: Projected Growth in Data Centers in the United States

Battery Energy Storage Systems

Planners and operators are focused on requirements to model, study, and operate the BPS with increased BESS and hybrid resources. BESS are increasingly being relied upon in areas with substantial amounts of solar PV resources to reduce ramping requirements on other resources by discharging in late afternoon as solar PV output rapidly declines. BESS are also often used for ancillary services, such as frequency response. Accurately accounting for BESS in operating and planning studies is a challenge because it requires assumptions and modeling capabilities for battery charging and discharging behavior. In real-time operations, system operators often do not have visibility into battery state-of-charge, a necessary condition for reliably integrating batteries into system operating plans. Without such information, operators may be surprised should battery resources fail to deliver when needed. In Texas, where battery resource growth is among the highest in North America, ERCOT uses a battery storage data collection program to obtain operational information and is pursuing market rules for state-of-charge accounting in unit commitment processes. System planners in many areas will be counting on new BESS facilities to manage variability and demand and resources. Obtaining the benefits of these resources requires careful integration into operating, planning, and market designs.

[30] *Grid Strategies: The Era of Flat Power Demand is Over*: https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf

Electric Vehicles and Electric Load

With increased adoption of electric vehicles (EV), which use batteries to store energy, there is a need to understand the impact of battery charging on system performance. EV forecasting is important for resource adequacy and system planning to account for changing load and load patterns. It is also important for system studies to include EV modeling and parameterization that account for the behavior of battery charging systems on system performance. In January 2024, NERC released the *EV Charging Study*, noting that the behavior of large amounts of EV chargers in operation can affect the BPS response to common outages. The RSTC established an EV Task Force to promote collaboration among the electric power industry and automotive representatives on areas of grid reliability.

Energy Drought

More reliance on wind, solar, and hydro resources in the resource mix has the potential to expose the electric system to supply shortages under abnormal weather patterns. When two or more resource types are simultaneously affected by conditions that cause below-normal resource output, operators can face challenges in meeting demand. Analysis of U.S. historical hourly generator data indicates that there are regional patterns to energy drought that can be expressed in terms of duration, magnitude, and seasonality (See **Figure 24**). There is also a higher likelihood for energy droughts to be more likely occur during high-load periods than at other times, underscoring the importance in considering such events in planning for resource and storage needs.[31]

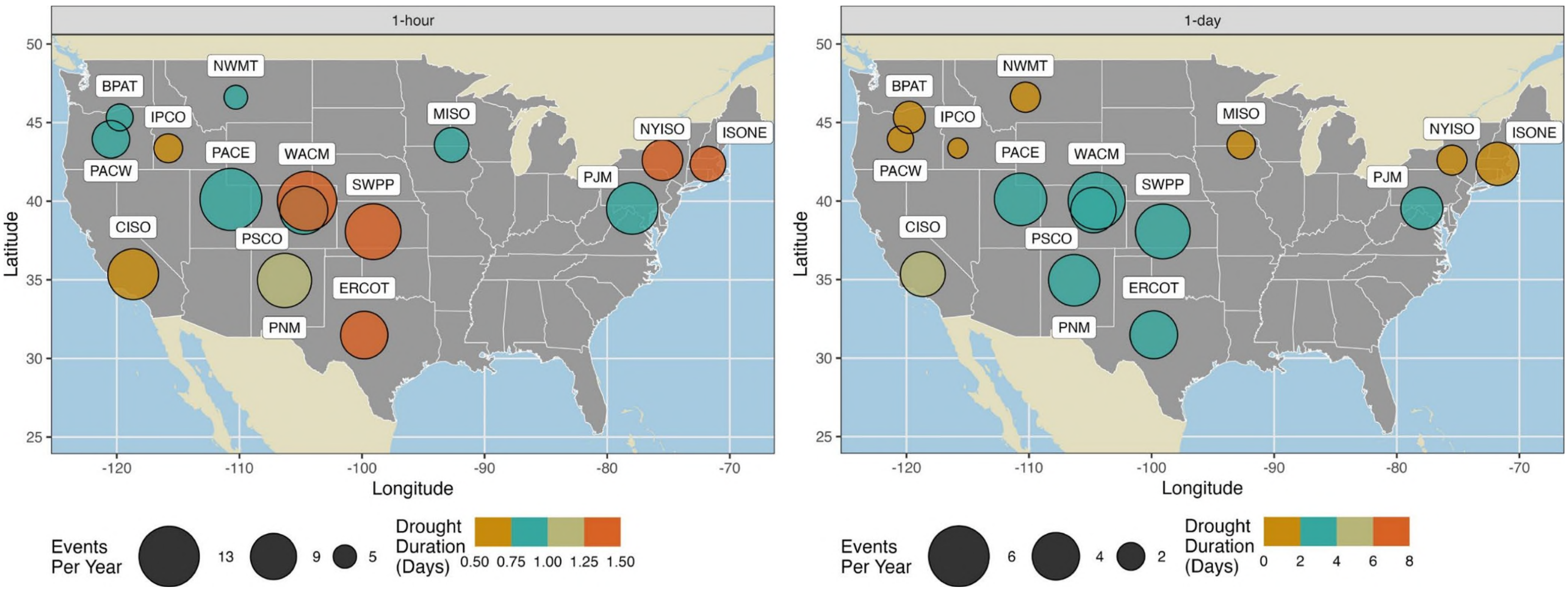
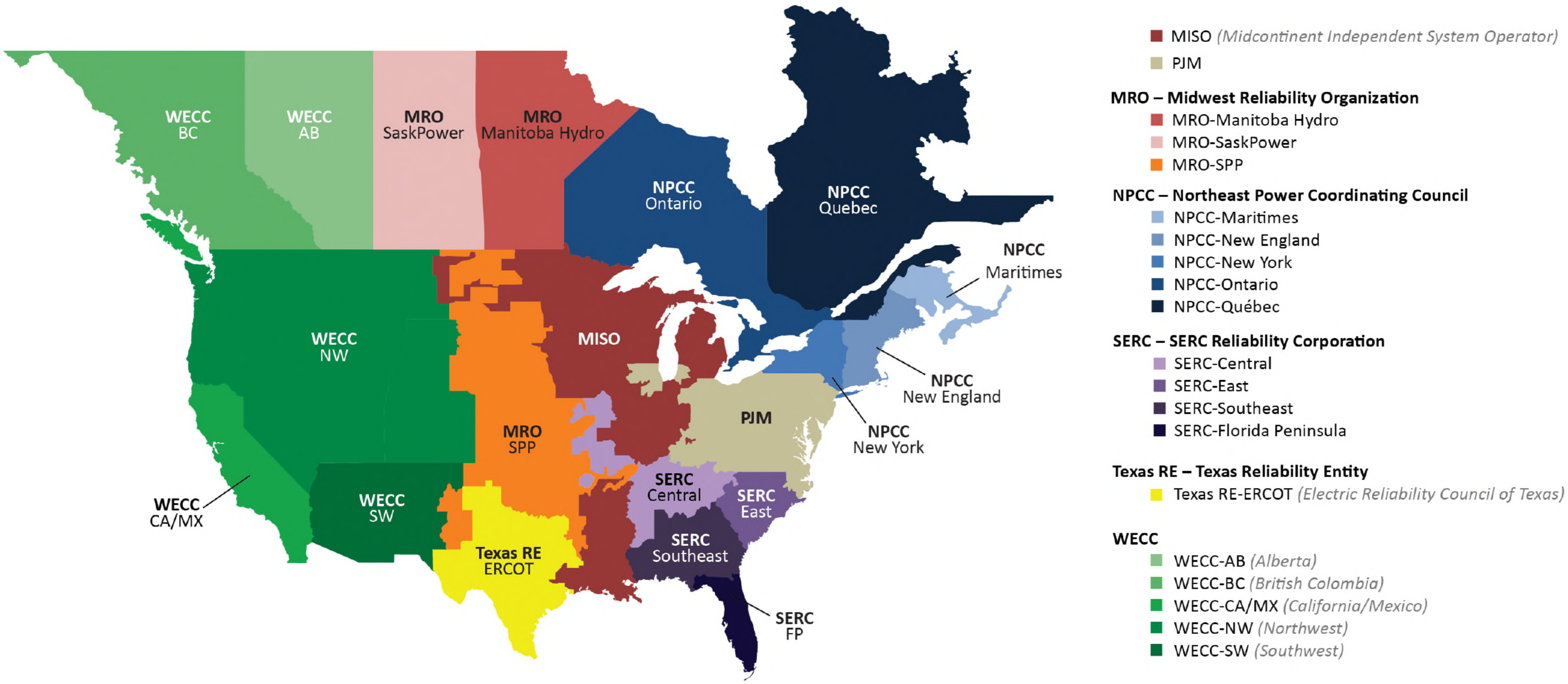


Figure 24: Frequency and Duration of Hourly (Left Panel) and Daily (Right Panel) Energy Droughts. Source: Pacific Northwest National Laboratory

[31] See Standardized benchmark of historical compound wind and solar energy droughts across the Continental United States

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Demand Assumptions and Resource Categories** table. On-Peak Reserve Margin bar charts show the ARM compared to the RML established for the area to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the Demand and Resource Tables), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the Demand and Resource Tables) and the extreme winter peak demand determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the WRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios.

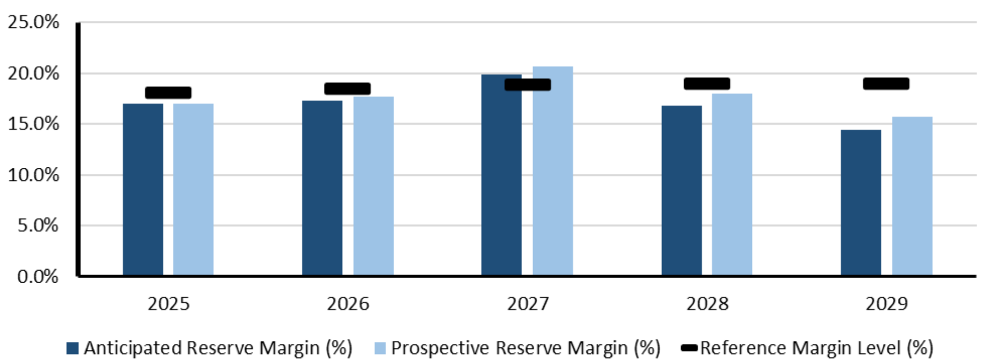


MISO

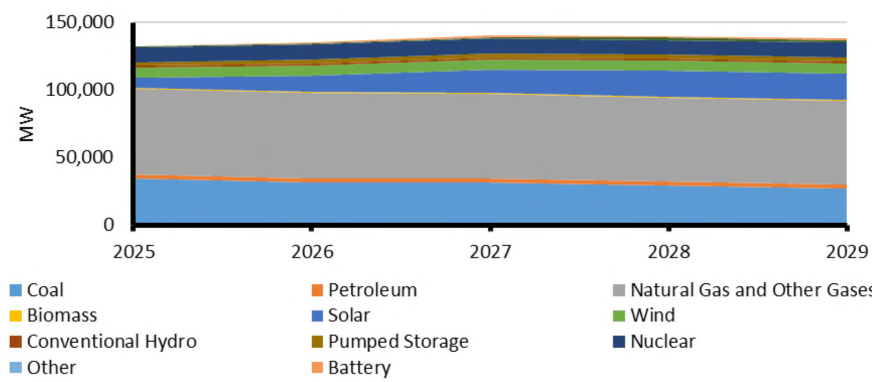
Midcontinent Independent System Operator, Inc. (MISO) is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authority and 394 market participants, serving approximately 42 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.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	122,328	124,343	126,073	128,700	129,401	130,120	130,493	131,327	131,952	131,952
Demand Response	8,205	8,221	8,058	8,065	8,074	8,077	8,079	8,075	8,075	8,075
Net Internal Demand	114,122	116,122	118,015	120,635	121,327	122,043	122,414	123,252	123,877	123,877
Additions: Tier 1	4,959	11,376	18,275	21,501	22,205	22,205	22,205	22,205	22,205	22,205
Additions: Tier 2	19	464	916	1,486	1,486	1,486	1,486	1,486	1,486	1,486
Additions: Tier 3	803	3,686	8,252	13,017	15,546	16,399	16,542	16,608	16,659	16,659
Net Firm Capacity Transfers	1,320	1,270	1,165	925	855	750	549	549	549	549
Existing-Certain and Net Firm Transfers	128,520	124,787	123,153	119,397	116,669	112,823	110,273	110,273	106,838	106,838
Anticipated Reserve Margin (%)	17.0%	17.3%	19.8%	16.8%	14.5%	10.6%	8.2%	7.5%	4.2%	4.2%
Prospective Reserve Margin (%)	17.0%	17.7%	20.6%	18.0%	15.7%	11.9%	9.4%	8.7%	5.4%	5.4%
Reference Margin Level (%)	18.1%	18.5%	18.9%	19.0%	19.0%	19.3%	19.5%	19.8%	20.1%	20.1%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- MISO's capacity resource turnover continues to occur with coal unit contributions being primarily replaced by solar, wind, and battery facilities. Furthermore, generation installation delays result in uncertainty throughout the assessment timeframe. As a result of these factors, MISO is facing capacity shortfalls beginning in 2025.
- MISO's reduction in capacity resources since the *2023 LTRA* has primarily been in the coal fleet with a reduction of 6,200 MW in the first year of the assessment.
- MISO has continued the seasonal capacity auction construct and has found growing evidence of risk in non-peak (e.g., spring and fall) seasons. Countering the risk during these off-peak seasons requires more resources to be available, and this can result in less opportunity for generators to pursue their maintenance needs. During peak seasons when high levels of generator availability are expected, short-notice unplanned outages and higher forced outages could occur as a result of deferred maintenance and challenge reliability.

MISO Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	34,637	31,706	31,618	29,067	26,841
Coal*	27,450	24,362	23,203	17,977	16,744
Petroleum	3,065	3,058	3,060	3,050	3,050
Petroleum*	2,992	2,990	2,992	2,992	2,992
Natural Gas	63,051	62,977	62,616	62,394	62,009
Natural Gas*	62,576	61,543	62,396	62,394	62,009
Biomass	577	571	553	481	481
Solar	8,091	12,538	17,318	19,174	19,763
Wind	6,954	7,236	7,536	7,632	7,660
Conventional Hydro	1,527	1,527	1,527	1,527	1,527
Pumped Storage	2,528	2,528	2,578	2,578	2,578
Nuclear	11,027	11,127	11,127	11,127	11,127
Other	72	72	72	72	72
Battery	208	582	1,011	1,358	1,377
Total MW	132,159	134,892	140,263	139,973	138,018
Total MW*	124,423	126,048	131,562	128,826	127,864
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to MISO are removed from the resource projection where marked.					

MISO Assessment

Planning Reserve Margins

The planning reserves across the MISO footprint in the summer and winter are projected to fall below reserve margin requirements as new generation is insufficient to make up for generator retirements and load growth. MISO's delays in generator construction result in a 2.7 GW shortfall. It is important to note that there is 56 GW of generation with signed generation interconnection agreements that are yet to come online as of July 5, 2024, so there is an opportunity to accelerate installation speeds.

Increased coordination between MISO and its members will be critical to ensuring reliability throughout this resource transition of integrating new intermittent resources and continuing to retire conventional resources. Resource adequacy is a key function of MISO, and the MISO annual planning resource auction (PRA) provides a mechanism for capacity sellers to provide resources that meet the needs of load-serving entities for each of the four seasons in the upcoming year. MISO's resource adequacy construct complements the jurisdiction that regulatory authorities have in determining the necessary level of adequacy.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

The introduction of the seasonal PRA and inputs to the process provide more granularity and reliability planning for non-peak hour times during the year. In addition to that change, MISO conducts seasonal resource assessments evaluating generation availability, outage rates, and forecasted load variation across all four seasons.

Probabilistic Assessments

To establish RMLs that define the minimum reserve margins for resource adequacy, MISO performs its annual probabilistic Loss-of-Load Expectation (LOLE) Study per MISO tariff. In recent years, MISO improved its LOLE study modeling by including seasonal outage rates, correlated cold weather outage adder profiles, a probabilistic distribution of non-firm support, and 30 years of hourly wind and solar profiles. The LOLE study produces seasonal RMLs for the upcoming planning year that are used in MISO's planning resource auction. These RMLs are calculated such that they prescribe the minimum PRM that will meet an LOLE of 1 day in 10 years. Because MISO is projected to have ARM below these RMLs, resource adequacy criteria are not met, indicating it is likely that supplies would be insufficient during normal summer and winter peak demand and outage conditions.

For more information on the seasonal LOLE Study, visit:
https://cdn.misoenergy.org/LOLE%20Study%20Report%20PY%202024-2025631112.pdf.

MISO also performed a probabilistic analysis for the 2024 ProbA. Because MISO used the same model for both the ProbA and the LOLE study, transmission limitations were not included explicitly in the simulations. It is appropriate for MISO to make this assumption for the LOLE study and for determining capacity needs in the MISO system because MISO accounts for transmission limitations elsewhere in the resource adequacy process. However, for an adequacy assessment like the ProbA, the assumption can overvalue resource performance by not accounting for transmission constraints on the deliverability of energy resources. The resulting 2024 ProbA metrics in the table below can understate the risk of unserved energy and load loss.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	68.8	**0.000**	**0.000**
EUE (PPM)	0.108	**0.000**	**0.000**
LOLH (hours per year)	0.393	**0.000**	**0.000**
Operable On-Peak Margin	13.9%	**11.3%**	**11.3%**

* Provides the 2022 ProbA Results for Comparison

All-hours probabilistic studies of the MISO system performed apart from the 2024 ProbA show that shortfall risks can also occur during spring and fall in months that are not peak demand seasons for MISO. The 2022 NERC ProbA Regional Risk Scenario Sensitivity Case included seasonal forced-outage rates and correlated cold weather outages instead of annual average outage rates. MISO found that not only did EUE increase in this sensitivity, but it was also spread throughout the year. Since this study, MISO implemented enhancements to its LOLE study and PRA to address seasonal resource needs.

Demand

The peak demand forecast has increased from the *2023 LTRA* by close to 3 GW (~2.5%), and, while the load forecasts still vary across year to year, the load at the end of the study horizon is ~5 GW higher (~4%). Load-serving entities do not include DR resources in the load forecast, and MISO does not have much insight into the amount of electrification built into the load forecasts. There are other studies at MISO investigating electrification and transportation industry impacts to load forecasts through the MTEP report. MISO contracted with Applied Energy Group (AEG) to evaluate the MISO footprint's electrification potential. This is documented in the report and has been utilized to update the MISO Futures Report.

Demand-Side Management

DR programs continue to play a significant role in providing capacity to MISO. DR is steady around 8 GW in the summer and 6.5 GW in the winter and is projected to remain constant during the study horizon. MISO's transition to seasonal auctions highlights accreditation of DR and availability during non-summer seasons.

Distributed Energy Resources

Behind-the-meter generation (BTMG) resources contribute about 4.2 GW of capacity across the study horizon, of which ~1.2 GW are distributed PV. MISO's transition to seasonal auctions highlights the availability of DERs across the four seasons, and MISO is working with stakeholders to derive adequate methods of aggregating, reporting, and allowing DER participation in MISO markets.

Generation

The departure of MISO's coal fleet has continued with a reduction in capacity of around 6 GW in the past year, and a projected reduction of a further 12 GW over the next five years. Solar continues to rise in capacity contributions with a growth of 1,200 MW since the *2023 LTRA* and growth of 3,200 MW in the first year of the study.

There are ~56 GW installed capacity (ICAP) of generation (predominantly solar and battery) with signed generation interconnection agreements in MISO that are projected to come on-line over the next few years. There have been some supply chain and tariff issues that have delayed the commercial operation of these resources.

Due to the large size in the MISO interconnection queue, in the 2022 LTRA (similarly to the OMS-MISO Survey), prospective generation in the queue gets multiplied by a factor based on the study phase and likelihood of that resource coming on-line and gets added into the footprint over time. This reduction is utilized to minimize the impact of prospective generation projects that will not come to fruition through the queue cycle. MISO continues to pursue queue reform efforts to expedite the process by ensuring projects being studied are of adequate certainty.

Transmission

The MISO Transmission Expansion Plan (MTEP) 2021 included the Long-Range Transmission Plan (LRTP) tranche 1 projects totaling $10.3 billion in investment for reliability and economic benefits estimated at $23–52 billion across the MISO footprint while also facilitating the integration of ~53 GW of new resources. In MTEP22, $4.3 billion in transmission projects were approved with $550 million going toward integrating new resources, $550 million going toward baseline reliability projects, and the age and condition category for the rest. MTEP23 includes a further $9 billion investment into the MISO footprint to address the local needs of the region. MISO is also pursuing LRTP tranche 2 with an expected investment of $18-23 billion to implement a 765 kV backbone into the northern portion of the footprint. These projects are expected to be included as part of MISO's MTEP24 project portfolio. In MTEP24, $6.7 billion in transmission projects have been submitted for board approval. MISO is also pursuing LRTP tranche 2.1 with an expected investment of $21.8 billion to implement a 765 kV backbone into the midwestern portion of the footprint. Tranche 2.1 brings reliability and economic benefits estimated at $51.7–101 billion across the MISO Midwest footprint, facilitating integration of ~115.7 GW of new resources.

Energy Storage

MISO's energy storage resources are still primarily in the future with only 84 MW of online storage. The MISO interconnection queue does have a significant amount of energy storage upcoming, but these are primarily Tier 3 resources at present.

Capacity Transfers

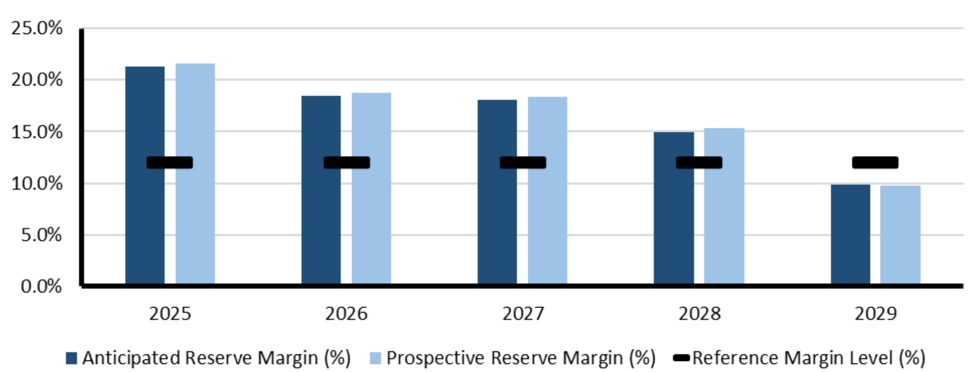
MISO benefits from significant transfer capacity with neighboring assessment areas due to the geographic location. MISO and SPP continue to finalize the Joint Targeted Interconnection Queue (JTIQ) portfolio to resolve the binding constraints that have traditionally delayed the interconnection process. MISO's utilization of capacity transfers is identified in the LOLE report and memorialized through the MISO PRA.

MRO-Manitoba Hydro

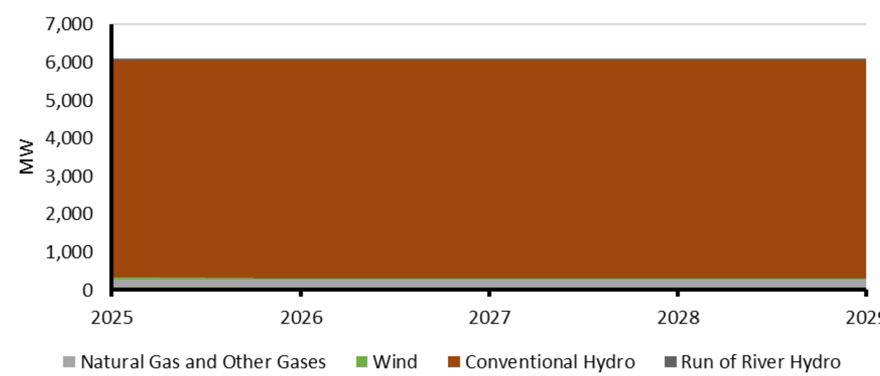
Manitoba Hydro is a provincial Crown Corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro provides electricity to approximately 616,000 electric customers in Manitoba and provides approximately 296,000 customers with natural gas in 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 Balancing Authority. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	4,797	4,923	4,968	5,037	5,268	5,366	5,427	5,486	5,556	5,629
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	4,797	4,923	4,968	5,037	5,268	5,366	5,427	5,486	5,556	5,629
Additions: Tier 1	30	51	64	64	64	64	64	64	64	64
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	-113	-113	-93	-167	-172	-565	-565	-565	-565	-565
Existing-Certain and Net Firm Transfers	5,786	5,780	5,800	5,726	5,721	5,328	5,328	5,328	5,328	5,328
Anticipated Reserve Margin (%)	21.3%	18.4%	18.0%	15.0%	9.8%	0.5%	-0.6%	-1.7%	-2.9%	-4.2%
Prospective Reserve Margin (%)	21.6%	18.8%	18.4%	15.3%	9.8%	0.5%	-0.6%	-1.7%	-3.0%	-4.2%
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

Highlights

- The electricity demand forecast in the province of Manitoba has increased since the *2023 LTRA*, driven by expected economic activity and adoption of EVs. Resource projections have not changed significantly.
- The ARM falls below the RML of 12% beginning in Winter 2029–2030 due to load growth and the reduction of winter import capacity transfers. Manitoba Hydro is performing analysis to inform its integrated resource plan and support future decisions for resources.

MRO-Manitoba Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	**2026–2027**	**2027–2028**	**2028–2029**	**2029–2030**
Natural Gas	278	278	278	278	278
Wind	52	31	31	31	31
Conventional Hydro	5,705	5,726	5,739	5,739	5,739
Conventional Hydro*	5,705	5,726	5,739	5,739	5,721
Run of River Hydro	856	856	856	856	856
Total MW	6,094	6,094	6,107	6,107	6,107
Total MW*	6,094	6,094	6,107	6,107	6,089
*** Capacity with additional generator retirements.** Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.					

MRO-Manitoba Hydro Assessment

Planning Reserve Margins

The winter ARM falls below the Reference Margin Level of 12% in 2029–2030. No resource adequacy issues are anticipated until Winter 2029–2030. 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 (PREP), 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 the assessment period.

The ARM falls below the Reference Margin Level of 12% beginning in Winter 2029–2030 due to net load growth and the reduction of winter import capacity transfers. Manitoba Hydro's Integrated Resource Plan was published in Summer 2023. Further analysis is underway and will help inform Manitoba Hydro's future resource decisions for resources in the 2029 timeframe.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Under normal water conditions, over 95% of the generation in Manitoba Hydro's system is from renewable energy—primarily hydro generation and wind generation. As the operator of a predominantly hydro system, Manitoba Hydro frequently performs an all-hours energy adequacy analysis of the near-term through seasonal time periods to manage reservoir energy storage and meet system demand. Additionally, Manitoba Hydro conducts specific analyses to determine short-term storage and minimum flow requirements for maintaining Manitoba and extra-provincial resource adequacy obligations. As there are modest levels of wind and solar on the Manitoba Hydro system, the resource adequacy risk on the Manitoba Hydro system over the next five years and under normal water conditions is expected to coincide with peak demand hours.

There are a number of influencing factors associated with Manitoba Hydro's resource adequacy performance, such as the water resource conditions, energy and capacity exchanges with neighboring jurisdictions, forecast load level, uncertainties in load forecast and load variation profiles, demand responses, wind penetration, and generation fleet availability. Most of Manitoba Hydro's generating facilities are use-limited or energy-limited hydro units. The annual energy output of these facilities is mostly dependent on the availability of the water resource. In the 2024 ProbA, Manitoba Hydro examines the impact of the most significant factor over the long run—variations in water conditions.

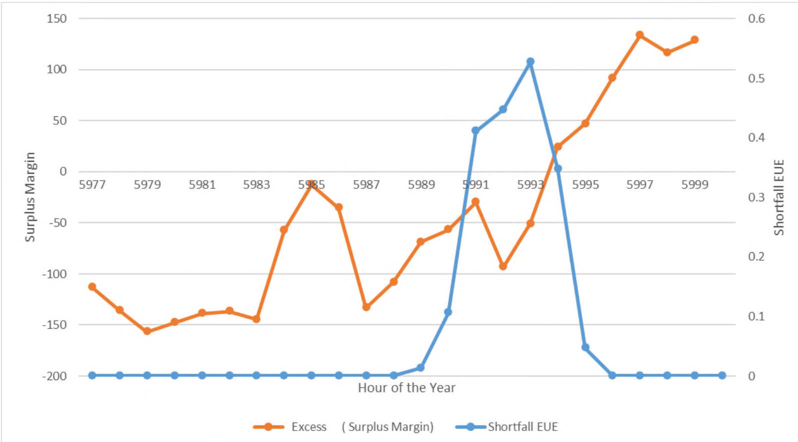
Nonzero LOLH and EUE are observed for both reporting years of 2026 and 2028 and shown in the table below. The LOLH and EUE indices are higher compared to the 2022 assessment mainly due to the increase in the forecast peak demand. Water flow conditions of 10th percentile or lower tend to increase the LOLH and EUE. As a small winter-peaking system on the northern edge of a large summer peaking system (MISO), there generally is assistance available, particularly in MISO's off-peak hours, to provide energy to supplement hydro generation in low-flow conditions in winter. Management of energy in reservoir storage in accordance with good utility practice provides risk mitigation under low water flow conditions.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	7.23	**4.711**	**68.870**
EUE (PPM)	0.29	**0.176**	**2.504**
LOLH (hours per year)	0.01	**0.059**	**0.914**
Operable On-Peak Margin	13.5%	**18.8%**	**15.6%**

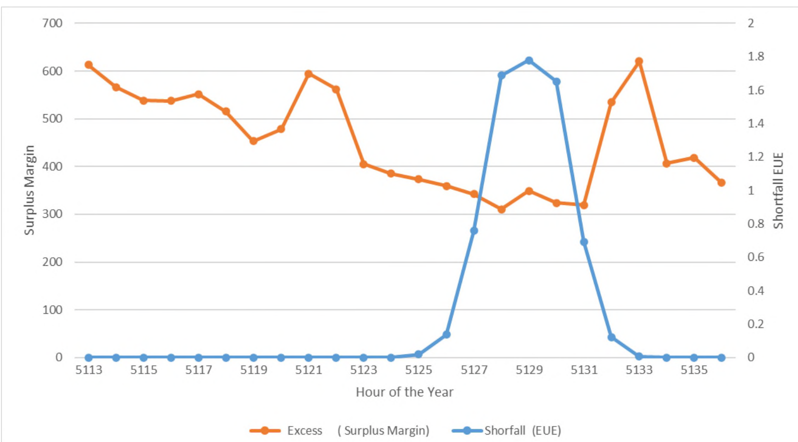
* Provides the 2022 ProbA Results for Comparison

The Monthly EUE and LOLH for 2026 and 2028 show that the highest LOLH and EUE contribution are from July and November, respectively, for 2026 and 2028.

The two graphs below show the hourly energy availability on the Manitoba Hydro system during the ProbA's highest risk days in 2026 and 2028. Surplus energy and shortfall EUE are plotted for the day when the highest loss of load event happens in the ProbA analysis. The Probability Weighted Average (PWA) surplus margin is negative, which indicates possible loss of loads for 2026. However, the PWA surplus energy is higher for 2028 during the day when the highest loss of load event is observed. This is because the surplus is an average for different water year data and the average surplus may not represent the event when loss of load occurs.

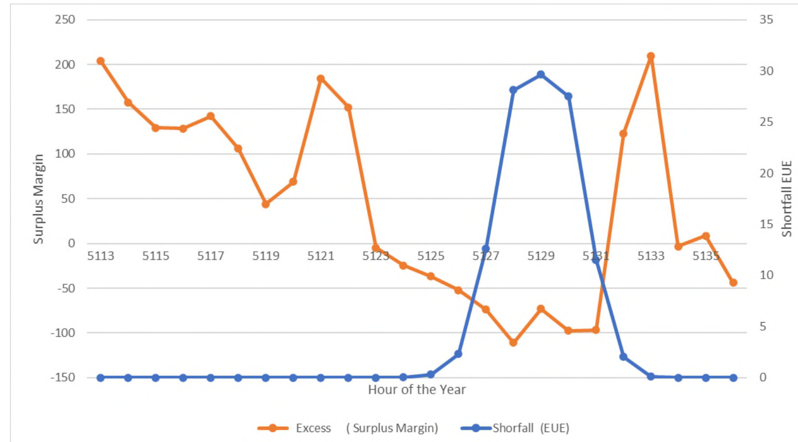


Hourly PWA Surplus Margin and Shortfall EUE for 2026 Representative Risk Day (Summer)



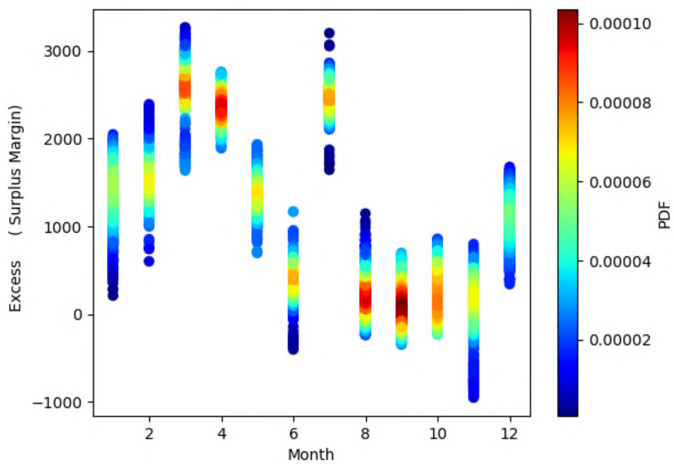
Hourly PWA Surplus Margin and Shortfall EUE for 2028 Representative Risk Day (Summer)

The figure below shows the surplus margin and shortfall EUE for 2028 under extreme drought conditions. It can be seen that the loss-of-load event occurs when the surplus margin becomes negative. This surplus energy shown in the figure is the average value for this hour for the entire simulation. It may not represent each individual loss-of-load event during simulation. By plotting the hourly surplus and unserved energy for the low-water years, it is possible to see what risk periods are likely to emerge during extreme drought.



Hourly PWA Surplus Margin and Shortfall EUE for 2028 Representative Risk Day (Summer) During Extreme Drought Condition

The scatter plots of surplus energy vs. month for 2026 and 2028 are shown in the figures below. In the months of June and August to November, the PWA surplus energy is relatively lower compared to the other months due to less import from MISO. The PWA surplus energy in July 2026 is high due to higher hydro energy availability for July. However, since PWA is the result of averaging, positive surplus energy does not mean that there will be no loss-of-load events.



PWA Surplus Energy Versus Month for 2026

Demand

Manitoba Hydro's load-growth forecast is up around 3.2% over the assessment period in comparison with the forecast used for the *2023 LTRA*. Factors considered in load-growth projections include economic activity, EV 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 percent of new vehicles sold in Canada will be zero-emission by 2026, at least 60 percent by 2030, and 100 percent by 2035.

Manitoba Hydro is anticipating load growth of 1.3% over the last half of the assessment period. Limited surplus firm generation resources (resource adequacy) have the potential to slow the connection of very large new industrial loads. In order to limit load growth, Manitoba Hydro has been directed by the Province of Manitoba to suspend processing of cryptocurrency load connections until 2026.

Demand-Side Management

Manitoba Hydro currently does not have any form of directly controllable and dispatchable DR programs. Manitoba Hydro does have an indirectly controllable and dispatchable DR program called the Curtailable Rate Program.

The Curtailable Rate Program provides approximately 160 MW of load reduction through up to 16 load curtailments of 4¼ hours each on five minutes notice. The program is intended for peak load management. In addition, one product provides 50 MW of contingency reserves, also on five minutes' notice.

The terms and conditions of the Curtailable Rate Program were updated in August 2023 to require an annual curtailment test, increase the number of possible curtailments, extend the notice period for conversion to firm service, and make minor editorial changes.

Distributed Energy Resources

Manitoba is not currently experiencing large additions of wind and solar resources being seen in other regions; hence, emerging reliability issues arising from such large wind and solar resource additions are not anticipated in the next five years. Additions of energy storage resources in the next 10 years are not anticipated at this time. There is a potential for significant solar DER resources in the latter half of the assessment period, and plans are being developed to study the impacts on the Manitoba Hydro system. The potential for future solar DER may be dependent on solar PV subsidies and/or incentives.

Generation

Manitoba Hydro is monitoring federal and provincial policy/strategies/regulations related to electricity/energy. The Canadian federal government is considering significant carbon emission regulations. Through Environment and Climate Change Canada, it is taking multiple steps to develop clean electricity regulations that aim for Canadian electricity generation to achieve net-zero greenhouse gas emissions by 2035 by 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 not proposed to 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 which may be released in Fall 2024. As details are not yet available, it is too early to determine any potential impacts.

Energy Storage

Manitoba Hydro currently has no energy storage resources, and none have been committed to over the next 10-year period.

The hydro generation resources, while not storing electricity directly, do store water in a reservoir for conversion to electricity and have been in use for over 100 years. For most hours of the year, the only dispatchable resources online are hydro generation resources which therefore serve most operational, reliability, and economic functions.

Capacity Transfers

Manitoba Hydro has coordination and tie-line agreements with neighboring assessment areas, such as MISO, SaskPower, and the IESO. In accordance with these agreements, planning- and operating-related issues are discussed and coordinated through respective committees. In addition to this planning and operating committee work, Manitoba Hydro engages with the neighboring utilities of Minnesota Power, Xcel Energy, Otter Tail Power, Minnkota Power Cooperative, SaskPower, and Hydro One regularly to share information, discuss issues, and coordinate activities. Manitoba Hydro also coordinates planning studies (for example, transmission service request studies and requests for generation interconnections) with its neighboring assessment areas. In addition, capacity transfers are verified from a resource adequacy perspective with adjacent regions/entities. Significant capacity transfer limitations from MISO into Manitoba may have the potential to cause reliability impacts but only in extreme conditions occurring simultaneously.

Transmission

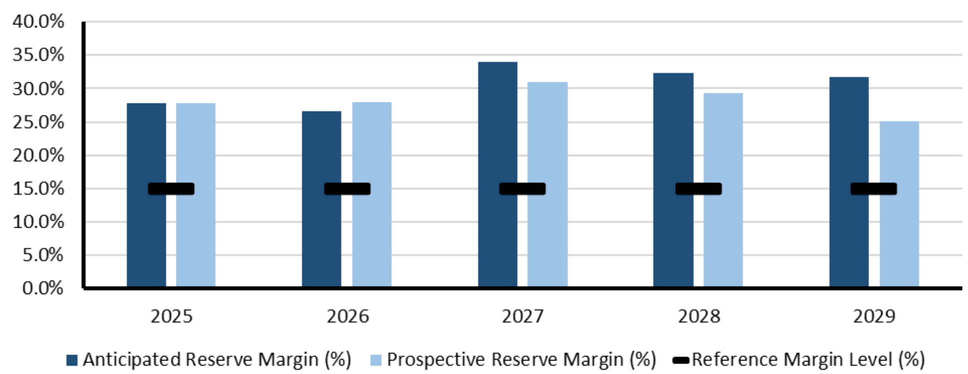
Manitoba Hydro has identified aging components of its HVdc system as a potential reliability issue that is unique to the assessment area. The concern is that the oldest HVdc system components could be approaching end of life. Studies have been initiated to study/evaluate modernization options and alternatives. The studies and procurement of replacement equipment could take up to 10 years to implement based on the current HVdc market capability. There is currently spare capacity on the HVdc system, and the end-of-life failure of a single pole would not create reliability issues. The further end-of-life failure of a second pole, while believed to be a very low probability, has the potential to create reliability concerns under peak winter loads if mitigation measures are not implemented. Mitigation measures to minimize the likelihood of experiencing this quantity of long-term outages are being actively pursued.

MRO-SaskPower

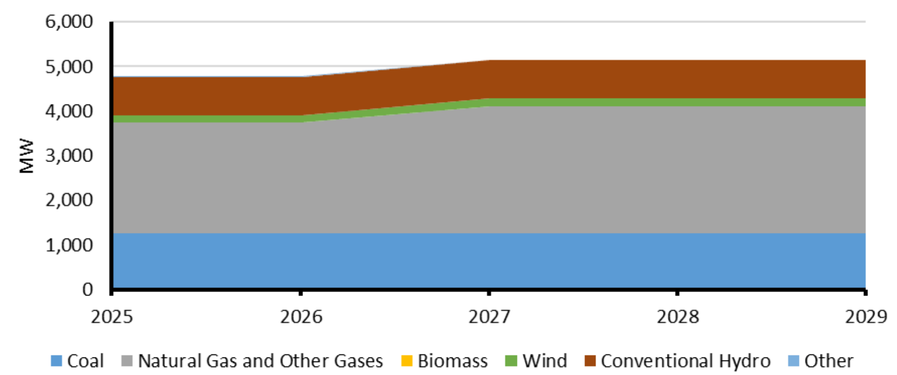
MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles), with a population of 1.2 million and approximately 550,000 customers. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (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 Bulk Electric System (BES) and its interconnections.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	3,917	4,025	4,149	4,189	4,210	4,242	4,271	4,315	4,359	4,408
Demand Response	72	72	72	72	72	72	72	72	72	72
Net Internal Demand	3,845	3,953	4,077	4,117	4,138	4,170	4,199	4,243	4,287	4,336
Additions: Tier 1	507	507	883	883	883	883	883	883	883	883
Additions: Tier 2	0	55	175	175	928	928	928	928	928	928
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	290	290	315	315	315	315	315	315	315	315
Existing-Certain and Net Firm Transfers	4,407	4,497	4,582	4,566	4,566	4,489	4,490	4,490	4,552	4,566
Anticipated Reserve Margin (%)	27.8%	26.6%	34.0%	32.4%	31.7%	28.8%	28.0%	26.6%	26.8%	25.7%
Prospective Reserve Margin (%)	27.8%	28%	31.0%	29.3%	25.1%	22.3%	20.8%	19.5%	19.8%	18.7%
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

Highlights

- SaskPower's ARM is above the RML throughout the assessment period. No resource adequacy issues are anticipated.
- Saskatchewan is adding approximately 1,064 MW of generation under Tier 1 within the next five years. This includes a 200 MW wind generation facility, two new 377 MW gas generation facilities, and the expansion of two existing natural gas facilities totaling 90 MW. The remaining capacity addition comes from geothermal and flare gas.

MRO-SaskPower Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	**2026–2027**	**2027–2028**	**2028–2029**	**2029–2030**
Coal	1,249	1,249	1,249	1,249	1,249
Coal*	1,249	1,249	1,088	1,088	188
Natural Gas	2,487	2,487	2,863	2,863	2,863
Biomass	3	3	3	3	3
Wind	164	164	162	162	162
Conventional Hydro	856	856	856	856	856
Other	22	17	17	1	1
Total MW	4,781	4,775	5,150	5,134	5,134
Total MW*	4,781	4,775	4,989	4,973	4,073
*** Capacity with additional generator retirements.** Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.					

MRO-SaskPower Assessment

Planning Reserve Margins

Saskatchewan uses a criterion of 15% as the reference reserve margin and has assessed its PRM for the upcoming 10 years considering the summer and winter peak hour loads, available existing and anticipated generation resources, firm capacity transfers, and available demand response for each year. Saskatchewan's ARM ranges from approximately 19% to 34% and does not fall below the Reference Margin Level.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Saskatchewan performs energy assessments using probabilistic methods to inform the area's resource adequacy requirements. Saskatchewan evaluates non-peak hour risks and diminishing capacity credits associated with higher penetration levels of VERs as part of the long-term planning process.

Results of the 2024 ProbA are provided in the table below. Based on the deterministic calculations within this assessment, Saskatchewan's ARM is 27.8% and 34.0% for years 2026 and 2028, respectively. Since the 2022 ProbA, the reported forecast reserve margin for 2026 has remained consistent. The minor variation in the reserve margin is due to a slight change in the schedule of generator outages. EUE is also comparable to the 2022 ProbA, with some variation attributed to updated hydro energy dispatch, which is able to reduce the EUE in the months where it was highest in the prior ProbA.

Base Case Summary of Results			
	2026*	2026	2026
EUE (MWh)	117.0	**75.641**	**8.553**
EUE (PPM)	4.4	**2.807**	**0.300**
LOLH (hours per year)	0.9	**0.547**	**0.078**
Operable On-Peak Margin	24.6	**24.4%**	**30.5%**

* Provides the 2022 ProbA Results for Comparison

Saskatchewan does not anticipate resource adequacy issues during its off-peak hours. Currently, its resource mix consists of baseload and fast ramping generation resources, with little penetration of VERs. The main factor contributing to EUE is the amount of planned generator outages. When these short-term reliability issues are identified in advance, they can be mitigated by rescheduling the maintenance. The hourly EUE heat maps in the following figures show that risk of unserved energy is at its highest in the summer months. Risk can also be found in months before or after summer and be driven by unseasonable temperatures driving above-normal demand that coincides with generator maintenance periods. Winter risks of shortfall are associated with extreme cold weather and unexpected generator outages.

Hourly EUE Heat Map : 2026

EUE	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Feb-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mar-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apr-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
May-26	1.2	1.2	1.1	1.2	1.2	1.3	1.3	1.3	1.4	1.5	1.6	1.8	1.8	1.7	1.7	1.6	1.6	1.6	1.5	1.5	1.5	1.6	1.5	1.3
Jun-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Jul-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.1	0.0	0.0	0.0	0.0	0.0
Aug-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.0
Sep-26	0.5	0.6	0.6	0.6	0.6	0.5	0.6	0.7	0.7	0.8	0.9	1.2	1.2	1.3	1.4	1.5	1.5	1.6	1.4	1.5	1.7	1.3	1.0	0.7
Oct-26	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.4	0.3	0.3
Nov-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Dec-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.1	0.1

Hourly EUE Heat Map : 2028

EUE	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Feb-28	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mar-28	0.0	0.0	0.0	-	-	-	-	0.0	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apr-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
May-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Jun-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0
Jul-28	0.0	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.2	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
Aug-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Sep-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oct-28	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.1
Nov-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0
Dec-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0

Hourly EUE Heat Maps (in MWh)

Demand

Saskatchewan experiences its peak-season in the winter. Saskatchewan's system peak load forecast is based on econometric variables, weather normalization, and individual level forecasts for large industrial customers. The average annual summer and winter peak demand growth is expected to be approximately 1.35% throughout the assessment period.

Demand-Side Management

Saskatchewan's EE and energy conservation programs include incentive-based and education programs focusing on installed measures and products that provide verifiable, measurable, and permanent reductions in electrical energy, and demand reductions during peak hours.

Saskatchewan's DR consists of contracts with industrial customers for interruptible load based under conditions specified in demand response programs. The first of these programs provides a curtailable load, currently up to 72 MW, with a 12-minute event response time. Other programs are in place providing access to additional curtailable load requiring up to two hours notification time.

Distributed Energy Resources

The current BTM DER installed capacity in Saskatchewan is approximately 50 MW, which includes approximately 48 MW of solar PV and the remaining approximately 2 MW of distributed wind projects. An additional 25 MW of DER solar PV are expected to be added in the next five years. BTM DER installations are incorporated into the load forecast models, which are used in supply and transmission planning study models.

Small power producers contribute an additional 5 MW 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 2 years based on the currently approved Power Generation Partner program. These projects are included as generation additions, but currently their capacity is not considered in reliability planning.

Generation

Saskatchewan is adding approximately 1,064 MW into its resource mix of generation under the Tier 1 category within the next five years. The includes a 200 MW wind generation facility, expansion of two existing natural gas facilities totaling 90 MW, two new natural gas facilities totaling 754 MW, 15 MW of flare gas generation, and 5 MW of geothermal generation.

Under Tier 2, over 1,717 MW of new generation is projected in the assessment period. This includes 754 MW of natural gas, 600 MW of wind generation, 300 MW of utility-scale solar generation, and 63 MW of co-generation.

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 battery storage system, a 20 MW/20 MWh unit, under commissioning. There are plans to expand this site by an additional 60 MW/60MWh 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

SaskPower has three interfaces with its neighboring areas. The interface with Manitoba is 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 event of a prior outage of tie lines between SaskPower and Manitoba Hydro, as well as nearby transmission facilities supporting the interface. This could only impact reliability if it is coincident with the extreme winter or summer peak demand and a prior outage of one or more larger 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 demand response and short-term load shedding.

Transmission

SaskPower's major transmission projects in the first five years of the assessment period are related to the interconnection expansion with SPP and the 650 MW of new transmission service. This includes two new international power lines between Saskatchewan and North Dakota. Within Saskatchewan, a total of approximately 180 kilometers of new 230 kV lines, a new 230 kV transmission station, expansion of several existing transmission stations, and installation of two phase-shifting transformer interfaces and two static var systems are being added.

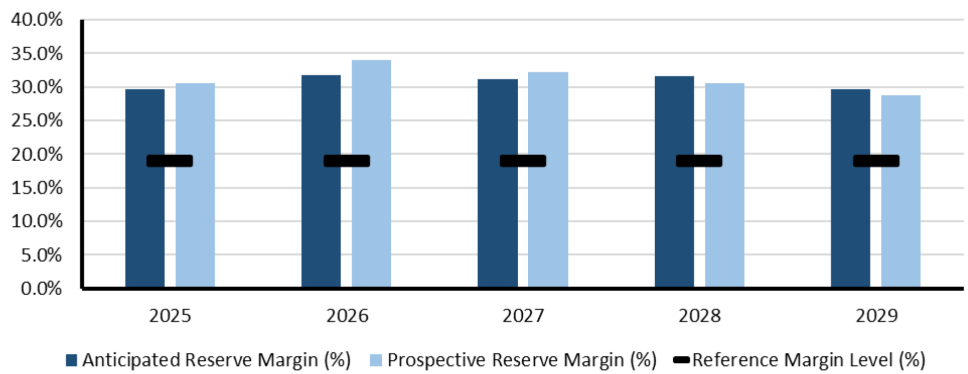
The remaining other transmission projects (approximately 460 circuit kilometers) are under the planning and conceptual phase in the 5-to-10-year planning horizon. These projects are driven by load growth, new generation additions, and reliability needs.

MRO-SPP

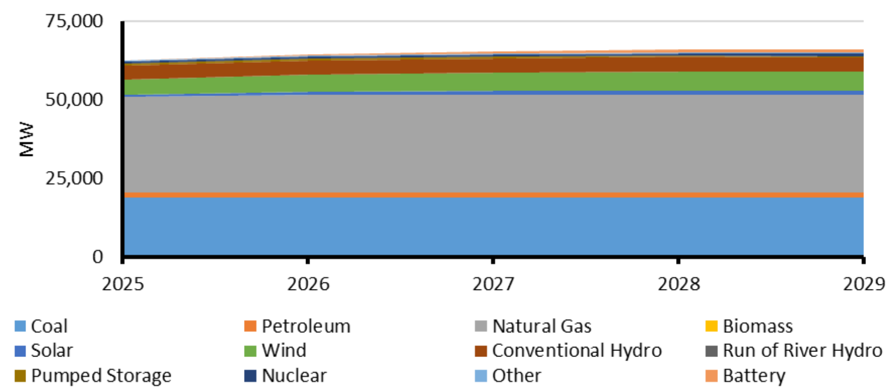
The Southwest Power Pool (SPP) Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported 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.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	55,669	57,171	59,031	59,764	60,596	61,963	62,490	63,287	63,764	64,172
Demand Response	1,463	1,771	2,057	2,124	2,172	2,222	2,259	2,465	2,467	2,472
Net Internal Demand	54,206	55,400	56,975	57,640	58,424	59,741	60,231	60,822	61,297	61,700
Additions: Tier 1	2,123	4,966	6,750	7,843	7,957	7,957	7,957	7,957	7,957	7,957
Additions: Tier 2	1,239	2,454	2,756	2,756	2,756	2,756	2,756	2,756	2,756	2,756
Additions: Tier 3	6,823	16,770	22,655	28,948	28,948	28,948	28,948	28,948	28,948	28,948
Net Firm Capacity Transfers	-1,097	-1,077	-1,136	-1,131	-1,131	-1,131	-1,131	-1,133	-1,133	-1,133
Existing-Certain and Net Firm Transfers	68,157	68,039	67,981	67,984	67,799	67,749	67,253	67,175	67,055	67,094
Anticipated Reserve Margin (%)	29.7%	31.8%	31.2%	31.6%	29.7%	26.7%	24.9%	23.5%	22.4%	21.6%
Prospective Reserve Margin (%)	30.6%	34.1%	32.2%	30.6%	28.7%	25.2%	23.3%	22.0%	20.6%	19.6%
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

Highlights

- There are over 8 GW of coal and gas-fired generators that have indicated they plan to retire over the next 10 years in SPP. Without sufficient dispatchable generation, SPP can experience energy shortages when output from wind resources is low.

MRO-SPP Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	18,952	18,952	18,919	18,919	18,919
Coal*	17,934	16,647	16,614	14,062	14,062
Petroleum	1,629	1,629	1,631	1,631	1,631
Petroleum*	1,629	1,629	1,575	1,575	1,575
Natural Gas	30,471	31,098	31,098	31,098	31,098
Natural Gas*	29,896	30,220	29,924	29,812	29,812
Biomass	20	20	20	20	20
Solar	495	864	1,149	1,283	1,283
Wind	4,974	5,456	5,928	6,117	5,909
Conventional Hydro	4,526	4,541	4,573	4,605	4,628
Pumped Storage	472	472	472	472	472
Nuclear	769	769	769	769	769
Other	281	281	281	281	281
Battery	41	290	555	930	1,044
Total MW	62,630	64,370	65,392	66,124	66,053
Total MW*	61,037	61,188	61,858	59,925	59,855
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to SPP are removed from the resource projection where marked.					

MRO-SPP Assessment

Planning Reserve Margins

The Existing-Certain and Net Firm Transfers Reserve Margin for the SPP assessment area is projected to fall below the current coincident summer season RML of 19% in 2027. The current summer season reserve margin target for SPP is 15%, but that is based on the non-coincident peak demand of load-responsible entities (LRE) in the SPP assessment area. For purposes of NERC assessments, the 15% target is converted, along with forecasted demand values, to an SPP coincident peak representation based on the latest calculated diversity factor. This results in an RML of 19%. Based on resources submitted in the ARM calculation, including the impact of retirements, SPP is forecasted to be above the 19% RML for the 10-year horizon.

Like the generation unavailability scenario in NERC's *2024 Summer Reliability Assessment*, SPP shows the potential to utilize all the current projected capacity and there could be times of capacity shortfall based on performance impacts during high-load periods. While the potential to all available capacity has a lower probability, the assumptions and projections are based around historical unavailability during peak periods. Current LTRA projections are based on the latest resource adequacy data submittals, which are provided by the LREs and Generator Owners in SPP.

SPP performs a biennial LOLE study to establish a reserve margin target such that the LOLE for the applicable planning year (3- and 6-year study) does not exceed 1 day in 10 years, or 0.1 day per year. The target is determined using probabilistic methods by altering capacity through the application of generator forced outages and forecasted demand with load uncertainty to ensure that the LOLE does not exceed 0.1 day per year.

SPP's 2023 LOLE study results indicate that separate PRMs and capacity requirements are needed for the summer and winter seasons to recognize the seasonal balance of risk. Also, as colder temperature outages increase with the incorporation of additional wind and solar resources, the loss-of-load risk shifts to the winter season. Due to the shift in seasonal risk, it would be appropriate to consider a maximum LOLE threshold for the winter season or incorporation of an EUE reliability metric to complement the LOLE metric.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

As the resource mix continues to change from a standard base load conventional thermal and hydro resources to VERs and short-term energy storage resources (ESR), SPP is incorporating energy adequacy metrics (i.e., EUE) in the determination of PRMs, RMLs, additional reliability policies, and resource accreditation enhancements.

SPP will begin performing a yearly energy adequacy assessment and assessment of reliability attributes (inertia, primary frequency response, ramp, regulation, contingency reserves, voltage and reactive support capability, fuel assurance, flexibility, and blackstart capability). Results of the analysis will be presented annually to SPP stakeholders. The results will also be used to identify needs for new market products, changes to market functionality, or changes to resource adequacy policies and requirements.

The 2024 ProbA performed for the NERC LTRA used assumptions and methods that reflect SPP's Loss of LOLE studies. Results are shown in the following table.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.84	0.00	6.61
EUE (PPM)	0.00	0.00	0.02
LOLH (hours per year)	0.00	0.00	0.01
Operable On-Peak Margin	19.6%	19.5%	16.0%

*Provides the 2022 ProbA Results for Comparison

With the current SPP fleet, there was no loss of load for the 2026 study that included Tier 1 resource additions and 600 MW in generator retirements. The 2028 analysis included both Tier 1 and Tier 2 resource additions and 2,700 MW in generator retirements. The result was a small amount of EUE (6.61MWh) and LOLH (0.01hr/year). The loss of load/hour occurred mostly during the summer season (0.007hr/yr), while the winter season had 0.0004hr/yr. SPP is a summer-peaking region, and the results also supported that. The demand was highest in the afternoons between 13:00 and 19:00 during July and August.

Study improvements for 2024 from the previous NERC ProbAs include additional weather years, seasonal forced-outage modeling, and incremental cold weather outages.

SPP uses the Strategic Energy & Risk Valuation Model (SERVM) for the ProbA. It is a production-cost modeling tool that uses the Monte Carlo method to solve LOLE. Each weather year was simulated 300 times to simulate a multitude of random forced outage draws. Taking 300 draws for each weather year (43) and multiplying by 8,760 hours gets to a total of over 113 million simulated hours, from 1980 to 2022. Each iteration was performed on an 8,760-hour basis.

The study input model consisted of multiple modeling assumptions including multiple historical weather years (1980–2022); hourly load, solar, and wind profiles; load forecast uncertainty; random forced outages draws and variability; physical and economic resource parameters; resource retirements; future resource additions; zonal transmission limitations; and incremental conventional resource forced outages due to extreme cold temperature.

The generating resources modeled in the Probabilistic Assessment reflect the data supplied in the *2024 LTRA*. Existing and projected resources were included in the Probabilistic Assessment along with reported confirmed retirements. As mentioned previously, wind and solar resources, as well as historical weather years, were modeled at historical hourly values using 2012 to 2022 weather years. There were six study zones, and SPP modeled a projected 8,760 hourly demand profile for each area to provide load variability and volatility for chronological hours during simulation. Each local resource zone was modeled with an import and export limit based on a separate power flow transfer analysis. SPP used unit-specific outage rates within the analysis based on NERC Generation Availability Data System (GADS) data from 2015 to 2022. External assistance only included firm contracts from external entities with firm transmission service.

Demand

SPP peak load occurs during the summer season; the 2024 net internal demand forecast is projected to peak at 53,094 MW, which is projected to increase compared to the previous year's LTRA forecast for the 2022 summer season. The diversity factor used to convert the non-coincident peak demand forecast to an SPP coincident peak demand forecast was consistent with the ~3.5% applied in the *2023 LTRA*. SPP forecasts the coincident annual peak growth based on member submitted data over the 10-year assessment timeframe. One risk that SPP has noted is that the aggregated noncoincident demand forecast submitted by members in recent years, which is based on a 50/50 forecast and is weather normalized, is tracking at a lower demand level than what the BA has observed.

Demand-Side Management

SPP's energy efficiency (EE) and conservation programs are incorporated into the reporting entities' demand forecasts. There are no known impacts to the SPP assessment area's long-term reliability related to the forecasted increase in EE and DR across the assessment area. In addition, SPP is constructing a new policy to more appropriately categorize DR based on the flexibility of the program, which will ultimately be reflected in the accreditation process.

Distributed Energy Resources

The SPP Model Development, Economic Studies, and Supply Adequacy working groups are developing policies and procedures around DERs. SPP resource adequacy implemented policies for DERs that mandate certain testing, reporting, and document requirements for resources and programs not registered in the SPP Integrated Market. Accreditation methodology policies are being constructed and are planned to be approved in late 2024.

Generation

SPP currently has approximately 900 MW of installed solar generating facilities. In the ARM calculation, SPP is reporting nameplate capacity of approximately 11 GW of Tier 1, 2, and 3 wind resources, approximately 18 GW of Tier 1, 2, and 3 solar resources, approximately 9.8 GW of Tier 1, 2, and 3 battery resources and approximately 2.7 GW of Tier 1, 2, and 3 gas resources.

In 2024, SPP filed conventional based performance accreditation and effective load carrying capability (ELCC) methodology for wind and solar resources. The goal is for these policies to become effective in the 2026/2027 timeframe for both the summer and winter seasons.

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 impact of river conditions on coal shipments, which could cause generators to run at a derated level to conserve supplies.

Energy Storage

Currently, SPP is studying approximately 17,000 MWs of energy storage and hybrid resource projects in the generator interconnection queue process. There are approximately 50 MWs of energy storage under contract by SPP members. These resources are being modeled as generation in the planning assumptions both near and long term.

Capacity Transfers

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 coordinate 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 executed a Coordination Plan that superseded the prior coordination agreement. The Coordination Plan addresses operational issues for coordination of the dc ties between the Texas Interconnection and Eastern Interconnection, block load transfers (BLT), and switchable generation resources (SWGR). Under the terms of the Coordination Plan, SPP has priority to recall the capacity of any SWGRs that have been committed to satisfying the resource adequacy requirements contained in Attachment AA of the SPP Open Access Transmission Tariff. Annually, SPP and ERCOT update the

Coordination Plan based on the latest discussions and business decisions, and it was updated in June 2024.

Transmission

In the 2023 ITP Assessment, SPP approved 44 transmission projects, including 150 miles of new transmission. Additionally, the study calls for 93 miles of transmission to be rebuilt.

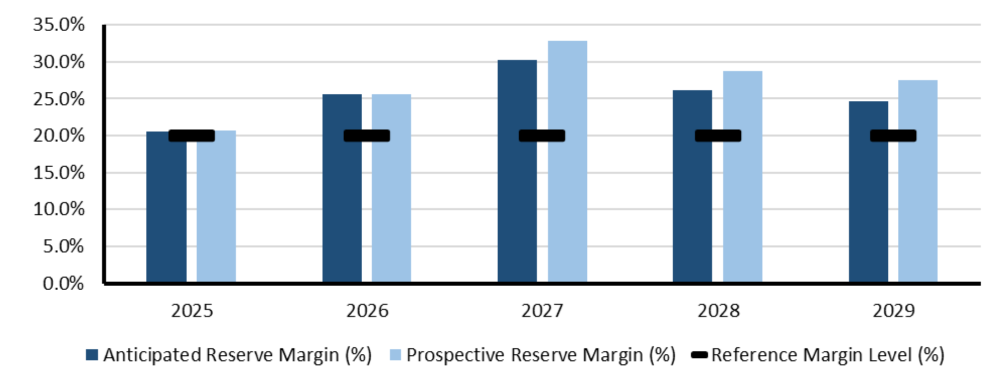
SPP is observing a number of transmission projects that are currently delayed. SPP is actively tracking these projects and discussing them throughout its stakeholder process. Many delays are driven by supply chain issues or increasing length of construction times. The delays of these transmission projects do not currently seem to be driving reliability issues.

NPCC-Maritimes

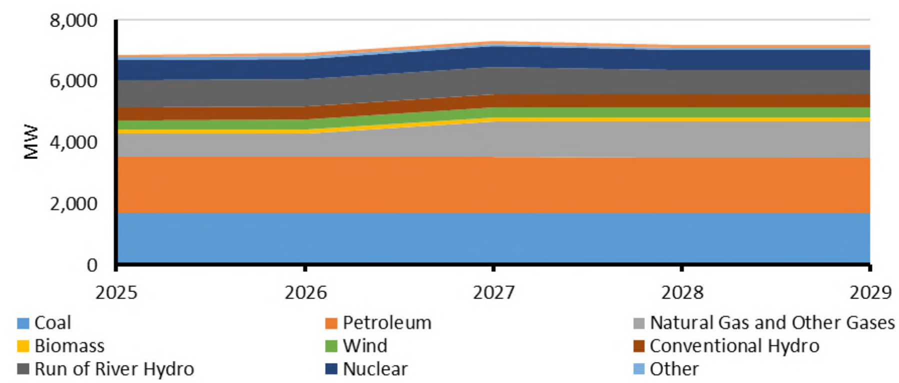
The Maritimes assessment area is a winter peaking NPCC sub-region with a single Reliability Coordinator and two Balancing Authority Areas (New Brunswick and Nova Scotia). It is comprised of the Canadian provinces of New Brunswick (NB), Nova Scotia (NS), and Prince Edward Island (PEI) and the northern 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.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	6,201	6,056	6,095	6,141	6,216	6,272	6,331	6,398	6,474	6,560
Demand Response	274	293	309	317	317	317	317	317	317	318
Net Internal Demand	5,927	5,763	5,786	5,825	5,899	5,954	6,014	6,081	6,157	6,242
Additions: Tier 1	108	171	579	579	579	579	579	579	579	579
Additions: Tier 2	6	4	447	600	1,398	1,398	1,398	1,398	1,398	1,398
Additions: Tier 3	0	13	80	127	197	255	267	279	291	291
Net Firm Capacity Transfers	289	322	215	145	145	145	145	145	145	145
Existing-Certain and Net Firm Transfers	7,038	7,063	6,959	6,771	6,771	6,771	6,679	6,665	6,665	6,752
Anticipated Reserve Margin (%)	20.6%	25.5%	30.3%	26.2%	24.6%	23.4%	20.7%	19.1%	17.7%	17.4%
Prospective Reserve Margin (%)	20.7%	25.6%	32.8%	28.8%	27.5%	26.3%	23.5%	21.9%	20.4%	20.1%
Reference Margin Level (%)	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Since the *2023 LTRA*, the overall resource outlook has improved with expected new natural-gas-fired generators coming into service in 2027. Winter peak demand forecasts for this assessment area have risen through 2030; however, ARMs are currently projected to remain above the RML of 20% until 2031 when the ARM dips to 19.7%.

NPCC-Maritimes Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	**2026–2027**	**2027–2028**	**2028–2029**	**2029–2030**
Coal	1,696	1,696	1,696	1,696	1,696
Coal*	1,696	1,696	1,396	1,248	467
Petroleum	1,831	1,831	1,825	1,819	1,819
Natural Gas	757	757	1,157	1,157	1,157
Biomass	148	148	148	148	148
Solar	5	5	5	5	5
Wind	293	321	329	329	329
Conventional Hydro	412	412	412	412	412
Run of River Hydro	902	902	902	791	791
Nuclear	663	663	671	671	671
Other	77	77	77	77	77
Battery	72	99	99	99	99
Total MW	6,856	6,911	7,321	7,204	7,204
Total MW*	6,856	6,911	7,021	6,756	5,975
*** Capacity with additional generator retirements.** Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.					

NPCC-Maritimes Assessment

Planning Reserve Margins

The NPCC-Maritimes assessment area is comprised of NB, NS, PEI, and NM. The RML for the assessment area is 20%; however, this reserve margin is not mandated. The ARM over the study period for the Maritimes area ranges between 17% and 30% during the winter period and between 88% and 93% during the summer period.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

During off-peak hours, the Maritimes area has surplus generation and no constraints with converting the capacity to energy.

Probabilistic Assessments

Two Balancing Authorities within the Maritimes area are members of NPCC and jointly prepare annual probabilistic assessments that cover three- to five-year forward-looking periods and evaluate the adequacy of the Maritimes' transmission system and resources. In addition, the Maritimes area also supports NERC's annual seasonal ProbAs, which provides an evaluation of generation resource and transmission system adequacy that will be necessary to meet projected seasonal peak demands and operating reserves. Results of the 2024 ProbA are in the table below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	3.87	**5.02**	**0.28**
EUE (PPM)	0.14	**0.17**	**0.01**
LOLH (hours per year)	0.07	**0.09**	**0.02**
Operable On-Peak Margin	22.9%	**17.9%**	**29.0%**

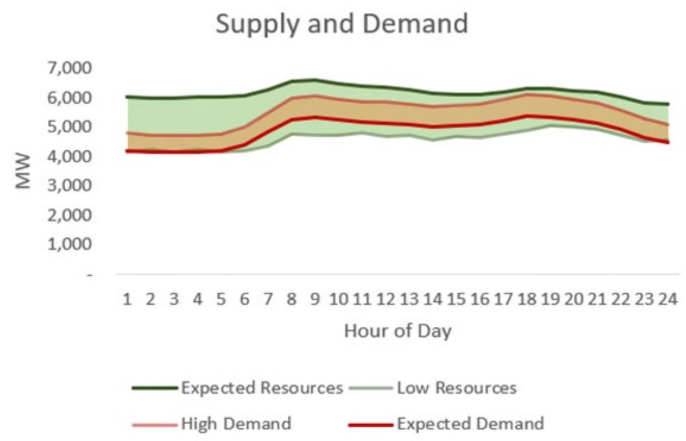
* Provides the 2022 ProbA Results for Comparison

The following table of LOLH for 2028 provides a depiction of risks across the calendar year and highlights the concentration of risk in winter. Most load-loss risk occurs in winter months of December–February, with some additional risk occurring in shoulder months. 2026 has a similar risk distribution.

Month of Year (2028)

Day of Month	1	2	3	4	5	6	7	8	9	10	11	12
1	0.08	0.00	0.00	-	-	-	-	-	-	-	-	-
2	0.04	-	0.00	-	-	-	-	-	-	-	-	-
3	0.00	0.00	0.00	-	-	-	-	-	-	-	0.00	-
4	-	-	-	-	-	-	-	-	-	-	-	-
5	0.03	-	-	-	-	-	-	-	-	-	-	-
6	0.00	-	-	-	-	-	-	-	-	-	-	-
7	0.00	-	-	-	-	-	-	-	-	-	-	0.00
8	-	0.00	-	-	-	-	-	-	-	-	-	-
9	-	0.00	-	-	-	-	-	-	-	-	-	0.00
10	-	-	-	-	-	-	-	-	-	-	-	0.00
11	-	-	-	-	-	-	-	-	-	-	-	0.00
12	-	-	-	-	-	-	-	-	-	-	-	0.00
13	-	-	-	-	-	-	-	-	-	-	-	-
14	-	0.00	-	-	-	-	-	-	-	-	-	-
15	-	0.00	-	-	-	-	-	-	-	-	-	-
16	-	0.00	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-	-	-
18	0.00	-	-	-	-	-	-	-	-	-	0.01	0.00
19	0.02	-	-	-	-	-	-	-	-	-	-	-
20	0.00	-	-	-	-	-	-	-	-	-	-	-
21	0.00	-	-	-	-	-	-	-	-	-	-	-
22	0.05	-	-	-	-	-	-	-	-	-	0.00	-
23	-	0.00	-	-	-	-	-	-	-	-	-	-
24	0.00	-	0.00	-	-	-	-	-	-	-	0.00	-
25	-	-	-	-	-	-	-	-	-	-	-	-
26	0.00	-	-	-	-	-	-	-	-	-	-	-
27	0.01	-	-	-	-	-	-	-	-	-	-	-
28	0.00	-	-	-	-	-	-	-	-	-	-	0.00
29	-	-	-	-	-	-	-	-	-	-	-	-
30	-	-	-	-	-	-	-	-	-	-	-	-
31	-	-	-	-	-	-	-	-	-	-	-	-

Hourly demand and resource projections for a typical risk-day in 2026 are shown in the figure below. Expected resource contributions are observed to cover expected demand on the risk day. However, the greatest risk for this assessment area is in the form of lower-than-expected resource contributions. If this were to occur, expected demand for all hours would not be met. This risk would be exaggerated by the addition of a higher-than-expected demand event. Reliance on external assistance may be necessary in these events. A risk day in 2028 has a similar profile.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

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 the LTRA assessment period. The area peak loads are expected to increase by 4.2% during summer and by 6.4% during winter seasons over the 10-year assessment period. This translates to compound average growth rates of 0.4% in summer and 0.6% in winter. The Maritimes Area annual energy forecasts are expected to increase by a total of 5.9% 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 using 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 20 MW to 169 MW while the annual amounts for winter peak demand reductions rise from 168 MW to 629 MW.[32]

Distributed Energy Resources

The DER installed capacity in NS is approximately 245 MW at present, including distribution-connected wind projects under purchase power agreements, small community wind projects under a feed-in tariff, and BTM solar.

LTRA wind capacity for NB, NS, and PEI is derated between 18% and 33% using probabilistic methods to calculate equivalent perfect capacities for each sub-area excluding NM, which uses seasonal capacity factors. BTM solar is assumed to have an ELCC of 0% during winter period. The Maritimes area has shown embedded BTM solar PV projections of 149 MW in 2024 rising to 881 MW by 2034. These projects include distributed small-scale solar (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 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 the area's system peak, which occurs either before sunrise or after sunset in the winter period.

Generation

NB assumes extending 28 MW of diesel-fired generator starting in 2025 and recently upgraded 290 MW of natural-gas-fueled resource completed in 2023. There are 25.2 MW of wind power purchase agreements (PPA) also slated to start in 2025. An anticipated replacement PPA contract, a long-term firm energy contract from a neighboring jurisdiction, and opportunities to buy in day-ahead and real-time markets will be utilized to maintain the overall resource adequacy.

NB Tier 1 resources include 71 MW of wind and 400 MW of combustion turbines. Tier 2 resources include 200 MW of wind resources and Tier 3 includes 400 MW of wind.

In NS, Tier 1 resources include wind projects with a total nameplate capacity of 473 MW phased in from 2024–2027 with an ELCC of 10%, 150 MW battery storage, 4 MW tidal power, 2 MW biomass unit, and a small 0.14 MW solar farm. Tier 2 resources in NS include 250 MW of battery storage (2026–2032), 600 MW of combustion turbines (2027–2033), a 150 MW conversion of a coal-fired unit to natural gas (2028), 450 MW in conversion of coal-fire units to oil (2030), 220 MW of solar generation,

[32] Current and projected energy efficiency effects based on actual and forecasted customer adoption of various DSM 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.

and 416 MW of wind generation. Tier 3 resources in NS include natural gas additions (combustion turbines) of 50 MW in 2029 and new wind generation with a nameplate capacity of 850 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 generation capacity (Tier 1) of up to 21 MW were being installed in PEI in 2024, along with 10 MW of new hybrid energy storage (Tier 1). PEI also has 30 MW of Tier 2 wind, 111 MW Tier 3 wind, and 140 MW of Tier 3 petroleum-based generation and 10 MW of Tier 3 batteries.

NB derates its wind capacity using a calculated year-round equivalent capacity of 22%. NS and PEI derate 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 150 MW (4-hour duration) nameplate standalone battery resource as a Tier 1 resource and a 250 MW (4-hour duration) nameplate capacity standalone battery resource added as a Tier 2 resource phased in from 2026 through 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 1 resource starting summer of 2024 and another 10 MW nameplate capacity energy storage system as a Tier 3 resource. This project will provide a storage option for the output from the 10 MW solar facility that is planned to come online during the same time frame. This project will provide fuel savings and may assist in providing additional reliability if a generation outage occurs.

NB Power has not included any energy storage resources in the *2024 LTRA* submission; however, the value of energy storage options is expected to increase as the technology improves and as 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, 5 MW of tidal, and 50 MW of 4-hour duration battery storage in February 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 battery storage resources. Ongoing internal analyses are conducted by NB Power to determine the cost and benefit associated with battery storage options and dispatching these resources to reduce/shift peaks and/or balance intermittent resources, such as wind, to provide additional flexibility to the system.

Capacity Transfers

ProbA studies show that the Maritimes area is not reliant on inter-area capacity transfers to meet NPCC resource adequacy criteria.

Transmission

NS has multiple new transmission line projects compared to the *2023 LTRA*; most being shorter runs to enable the connection of renewable resources, with one major project of 165 miles designed to improve the reliability of the existing tie between NS and NB.

Reliability Issues

The Maritimes area has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind (derated), dual fuel oil/gas, tie benefits, and biomass with no single 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.

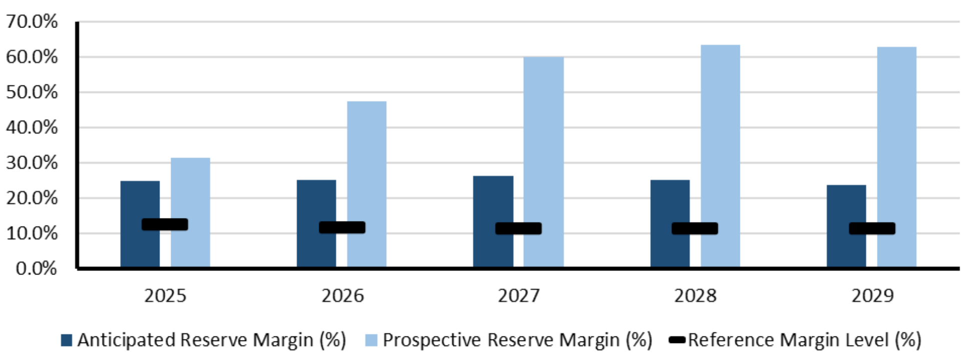
NPCC-New England

NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont served by ISO New England Inc. (ISO-NE). 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. Note: Northern Maine is not directly connected to the transmission system administered by ISO-NE.

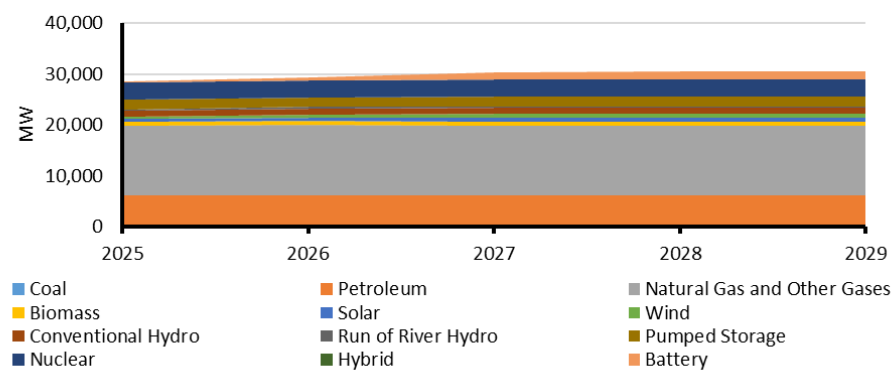
The New England BPS serves approximately 15.1 million customers over 68,000 square miles.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	24,579	24,702	24,845	25,076	25,364	25,706	26,100	26,547	27,052	27,567
Demand Response	566	588	544	544	544	544	544	544	544	544
Net Internal Demand	24,013	24,114	24,301	24,532	24,820	25,162	25,556	26,003	26,508	27,023
Additions: Tier 1	660	1,492	2,374	2,748	2,748	2,748	2,748	3,168	3,168	3,168
Additions: Tier 2	337	3,089	5,911	7,084	7,425	7,766	7,766	7,766	7,766	7,766
Additions: Tier 3	1,404	1,765	5,106	7,906	9,221	9,355	9,721	10,432	10,432	10,432
Net Firm Capacity Transfers	1,248	567	465	84	84	84	84	84	0	0
Existing-Certain and Net Firm Transfers	29,354	28,658	28,327	27,946	27,946	27,946	27,946	27,946	27,862	27,862
Anticipated Reserve Margin (%)	25.0%	25.0%	26.3%	25.1%	23.7%	22.0%	20.1%	19.7%	17.1%	14.8%
Prospective Reserve Margin (%)	31.4%	47.3%	60.1%	63.3%	62.8%	62.0%	59.5%	58.3%	55.0%	52.0%
Reference Margin Level (%)	12.7%	11.8%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- New England is forecast to have sufficient ARMs to meet consumer demand for electric energy for the first five years (2025–2029) of the assessment period and not require any Tier 2 resources.
- ISO-NE is addressing the issues brought on by grid transformation through several planning, operational, and market measures. A significant project is the redesign of the capacity market from a forward, annual auction to a prompt, seasonal auction with resource accreditation. The Capacity Auction Reforms (CAR) project began in Q2 2024 and is expected to be in place for the 19th Capacity Commitment Period (CCP 19) beginning on June 1, 2028. Additionally, New England has made tariff modifications to its Longer-Term Transmission Planning process to facilitate the New England states' achievement of their policy-based goals by enabling the development of transmission infrastructure. ISO-NE is also working with regional stakeholders to develop a regional energy shortfall threshold (REST) that defines the region's tolerance for energy shortfalls during low-probability extreme weather conditions.

NPCC-New England Projected Generating Capacity by Energy Source in Megawatts (MW)[33]					
	2025	2026	2027	2028	2029
Coal	541	541	541	541	541
Coal*	445	445	445	7	7
Petroleum	5,703	5,703	5,687	5,687	5,687
Natural Gas	13,651	13,724	13,708	13,708	13,708
Biomass	780	780	780	780	780
Solar	533	663	663	663	663
Wind	391	594	819	819	819
Conventional Hydro	1,209	1,209	1,209	1,209	1,209
Run of River Hydro	289	289	289	289	289
Pumped Storage	1,860	1,860	1,860	1,860	1,860
Nuclear	3,331	3,331	3,331	3,331	3,331
Hybrid	34	35	35	35	35
Other	74	74	74	74	74
Battery	159	584	1,242	1,616	1,616
Total MW	28,553	29,385	30,237	30,611	30,611
Total MW*	28,458	29,290	30,141	30,077	30,077
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to ISO-NE are removed from the resource projection where marked.					

[33] MW totals reflect Existing and Tier 1 generation. Generator retirements in this timeframe would be captured if a resource submits a retirement request through the ISO-NE capacity market.

NPCC-New England Assessment

Planning Reserve Margins

ISO-NE's installed capacity requirement (ICR) is based on the capacity needed to meet the ISO-NE and NPCC resource adequacy reliability criterion of an LOLE of 0.1 day/year. The ICR varies from year to year depending on projected system conditions. The ICR is calculated on an annual basis, in advance of the capacity auctions for each Capacity Commitment Period. The latest ICR calculations result in an annual RML of 12.70% in 2025, 11.82% in 2026, and 11.33% in 2027, expressed in terms of the annual 50/50 peak demand forecast published in the *2024 Capacity, Energy, Loads, and Transmission (CELT) Report*. For the years 2028 through 2034, which are beyond the current forward capacity market timeframe, ISO-NE continued to use the last available RML value of 11.33%. The ISO-NE RML is relatively low compared to other regions due to the impact of reflecting external assistance from neighboring control areas and the continued increase in BTM solar facilities.

Non-Peak Hour Risk, Energy Assurance, and Probabilistic-Based Assessments

ISO-NE routinely prepares 21-day energy forecasts. These forecasts incorporate weather, transmission topology, resource capability and availability, fuel inventories and constraints, and projected imports/exports. If the forecasted 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 energy shortfalls is expected to inform market participants such that actions can be taken to increase the expected availability of generating resources as needed.

ISO-NE recently completed work with the Electric Power Research Institute (EPRI) to develop the Probabilistic Energy Adequacy Tool (PEAT) framework. This tool is a framework that has three major steps (weather modeling, risk screening/scenario generation, and 21-day energy assessment), which were subsequently applied to assess the summers and winters of 2027 and 2032.

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 reflect the changing resource characteristics, probabilistic study assumptions, and changes to national and regional criteria. Coordinated planning activities with neighboring systems will continue and help support the New England states' policy objectives of providing access to a greater diversity of clean resources to meet environmental compliance obligations. Results from the 2024 ProbA, shown in the table below, reveal a slight increase in load-loss and unserved energy risk from the 2022 analysis, but values remain small. ISO-NE is considered to have sufficient resources for the planning horizon to meet NPCC resource adequacy criteria.

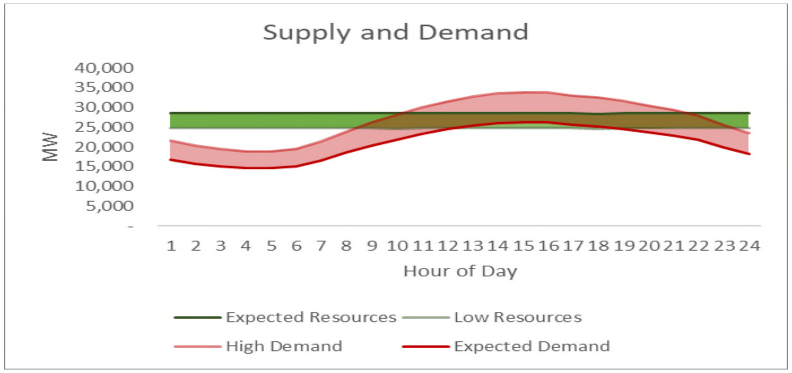
Base Case Summary 2024 ProbA of Results

	2026*	2026	2028
EUE (MWh)	0.551	**10.69**	**7.40**
EUE (PPM)	0.004	**0.09**	**0.06**
LOLH (hours per year)	0.002	**0.07**	**0.03**
Operable On-Peak Margin	27.8%	**12.4%**	**13.7%**

* Provides the 2022 ProbA Results for Comparison

NPCC's ProbA results indicate that the risk of unserved energy in New England is concentrated in summer months (June–August).

Hourly demand and resource projections for a typical summer risk day in 2026 are shown in the figure below. Although expected resource contributions meet expected demand, there is risk that above-normal peak demand could exceed resources. Demand could be 25–30% higher than expected, which could cause strain on the system from the hours beginning 10:00 a.m. through 10:00 p.m. Also, below-normal resource performance from unexpected generator outages or low solar output could also cause supply shortfalls. If resource contributions are less than expected, strain on the system could be seen from the hour beginning 12:00 p.m. through 7:00 p.m. on a typical peak day. Reliance on external assistance may be necessary in these extreme conditions. A risk day in 2028 has a similar profile.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

Fuel availability during extreme winter conditions is a persistent reliability concern in New England that is not modeled in detail in the ProbA. Potential natural gas transportation constraints can affect supply to generators during extreme cold temperatures, when natural gas demand for space heating is also peaking. Most natural-gas-fired generators in the area do not have firm natural gas transportation service and can be subject to supply curtailment during peak conditions. Many natural-gas-fired generators in New England can also operate with stored oil, providing for assured electricity supply in extreme winter conditions while oil stores are procured and maintained. Scenarios of extended and extreme cold weather that affect the availability of natural gas and oil replenishments present a reliability risk and were not modeled in the 2024 ProbA.

Demand

Over the 10-year LTRA planning horizon, the forecast net internal summer peak demand increases by 2,988 MW from 24,579 MW in 2025 to 27,567 MW in 2034 (roughly 2% decrease from the 2023 forecast in the later years). The corresponding net internal winter peak demand increases by 7,342 MW from 20,639 MW in 2025–2026 to 27,981 MW in 2034–2035 (roughly a 2.5% decrease from the 2023 forecast). Net energy for load is forecast to grow by 24,701 GWh from 119,285 GWh in 2025 to 143,986 GWh in 2034 (roughly 10% decrease from the 2023 forecast). The changes from the 2023 forecast were in part due to continued enhancements of the heating and transportation electrification forecasts.

The higher winter peak growth rate due to anticipated electrification results in significant convergence with summer peak projections by the end of the 10-year period, such that New England's transition to a winter-peaking system is currently anticipated by the mid-2030s. It is also expected that the timing of the peaks will likely occur in the morning by this time, with heating electrification in particular inducing a greater tendency for morning peaks due to electrified residential and commercial heating.

Demand-Side Management

For the summer of 2025, ISO-NE forecasts 566 MW of controllable and dispatchable demand-side management (DSM) resources, and that amount is projected to decrease by 22 MW to 544 MW by 2034. For the summer of 2025, ISO-NE forecasts 1,873 MW of passive DSM resources (EE and conservation). Demand-side resources are projected to peak in 2030 at 2,117 MW and then begin to decrease to 1,978 MW by 2034. This decrease in the later years is due to expiring EE measures outpacing new passive DSM additions.

Distributed Energy Resources

For summer months, the BTM PV forecast is incorporated as estimated reductions to the ISO-NE gross demand forecast. In 2025, New England forecasts 1,141 MW of peak load reduction (4,533 MW nameplate) of BTM PV. BTM PV is forecast to grow to 1,299 MW of peak load reduction (8,217 MW nameplate) by 2034. The BTM PV peak load reduction values are calculated as a percentage of ac nameplate. The percentages include the effect of diminishing PV production at the time of the system peak as increasing PV penetrations shift the timing of peaks later in the day. The BTM peak load reduction decreases from 25.2% of nameplate in 2025 to 15.8% in 2034.

ISO-NE recently adopted a new planning procedure (PP12) to formalize and standardize data collection for DERs. Under this procedure, distribution providers would be responsible for providing installation-level data on DERs connected to their system. Additionally, transmission providers would be responsible for providing basic data to translate feeder IDs into substation names and other useful identifying information. Among the other benefits that this procedure will lead to is "*proper accounting for the location, size, and type of DER which will lead to more accurate study outcomes.*"

Generation

The largest change that will impact New England's generation fleet is ISO-NE's CARs.

Specifically, to better ensure power system reliability and cost efficiency as New England's resource mix evolves, ISO-NE is proposing a CAR that would transition the capacity market from a forward/annual market to a prompt/seasonal market with accreditation reforms. This initiative has three primary components that would be in place for the Capacity Commitment Period (CCP) scheduled to start on June 1, 2028.

- Prompt auction: Instead of taking place three years in advance, the capacity auction would take place shortly before the CCP, reflecting more accurate information about projected electricity supply and demand.
- Seasonal CCP: The CCP changes from annual to sub-annual (seasonal) commitment periods to better address the distinct reliability challenges of winter and summer, as well as variations in resource performance from season to season.
- Accreditation reforms: Work began in 2022 via the former "Resource Capacity Accreditation in the Forward Capacity Market" project to identify and implement methodologies that will more accurately reflect resource contributions to resource adequacy in the capacity market. It is critical to the reliable and efficient clean-energy transition that the accreditation methodologies are updated to reflect resources' capabilities and how those capabilities contribute to resource adequacy. This work continues through CAR in the context of the proposed market constructs.

Energy Storage

New England currently has a total of 1,899 MW of energy storage capacity. This number includes about 39 MW of battery storage (BESS) and hybrid solar/battery storage. The largest energy storage resource(s) in New England are three pumped-storage hydro-electric facilities that can supply a combined 1,860 MW of quick-start 10-minute operating reserve capability, and with full reservoirs, and can deliver over 11,800 MWh of energy to the BPS.

Over the next five years (2025–2029), the nameplate capacity of energy storage devices (BESS, integrated-hybrid, and co-located-hybrid) are projected to increase significantly (Tier #1 [1,607 MW], Tier #2 [5,047 MW], and Tier #3 [4,955 MW]). No new pumped-storage facilities are planned for the region. Over the next 10 years, those total Tier 1–3 capacities do not increase from the five-year projection. All the above capacity totals reflect summer seasonal claimed capability ratings.

Capacity Transfers

New England is interconnected with the three BAs of Québec, the Maritimes, and New York. ISO-NE considers the tie benefits associated with these BAs within its capacity market methodology to reduce the installed capacity requirement to meet the regional resource adequacy criterion. Assumed assistance from tie benefits ranges from 1,830 MW in 2025 to 2,115 MW in 2027. Aside from such assistance, ISO-NE's firm capacity imports are projected to range from a maximum of 1,248 MW in the summer of 2025 down to 465 MW in the summer of 2027. There is one long-term firm import contract of 84 MW that extends through the summers of 2028 through 2032. There are currently no firm imports projected for the summers of 2033 and 2034. In addition, there are no firm exports identified over the 10-year assessment.

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 using IBRs, and changes to mandatory planning criteria promulgated by NERC, NPCC, and regional stakeholders have driven the need for longer-term transmission assessments.

The future reliable and economic performance of the BPS is expected to be maintained as a result of approximately $1.5 billion of planned transmission upgrades over the next 10 years. 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. Interregional import capability will also increase with the completion of the 1,200 MW HVdc New England Clean Energy Connect (NECEC) tie line between Québec and Maine, scheduled to be in service by the beginning of 2026.

In addition, transmission improvements will also be needed to support state policies to access remotely located sources of clean energy and serve increased load as transportation and heating are electrified. Transmission assessments and resultant plans are being developed throughout the region to meet these future system needs.

Reliability Issues

New England's BPS is transitioning to a system with unprecedented demand growth, due to electrification of heating and transportation, and a growing number of renewables, clean energy resources, VERs, and DERs. ISO-NE is engaged in the implementation of revised interconnection standards for VERs and DERs that will ensure overall BPS reliability and facilitate the economic development of IBRs.

ISO-NE has observed some delays in projected in service dates for system upgrades due to supply chain issues. In these cases, ISO-NE develops operating plans to work around any issues caused by these delays. Additionally, the New England Transmission Owners have indicated that supply chain issues are causing a notable increase in project costs.

New England has already experienced constraints on electric energy production due to constraints on fuel infrastructure that have an impact on 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, best practices, and, more recently, through 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 (IEP) 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.

The just-in-time delivery of a generator's 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.

ISO-NE is actively working on numerous major projects to prepare for the clean energy transition and ensure continued reliability. The following is a short list of major projects in which ISO-NE has engaged:

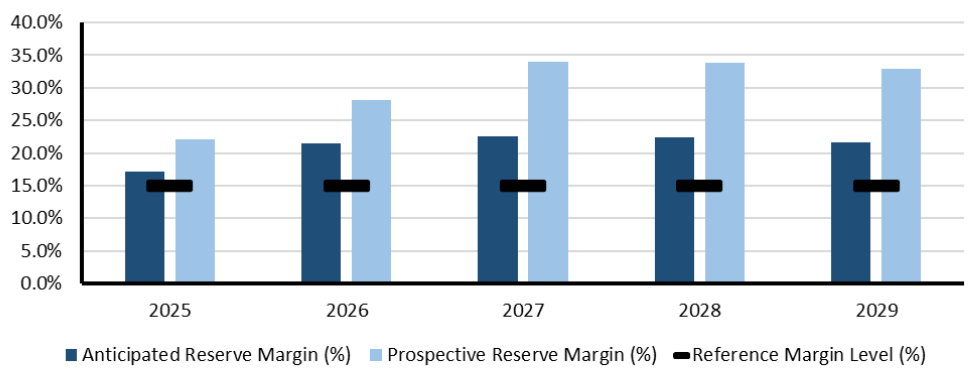
- **CAR Project**
- **Operational Impacts of Extreme Weather Events**
- **Regional Energy Shortfall Threshold**
- **Day-Ahead Ancillary Services Initiative**
- **Economic Planning for the Clean Energy Transition (EPCET)**
- **Extended-Term Transmission Planning Tariff Changes**
- **Longer-Term Transmission Studies**
- **Storage As Transmission Only Asset (SATOA)**
- **FERC Order No. 1920 Project**
- **FERC Order No. 2023 & 2023-A Project**
- **FERC Order No. 2222 Project**
- **FERC Order No. 881 Project**

NPCC-New York

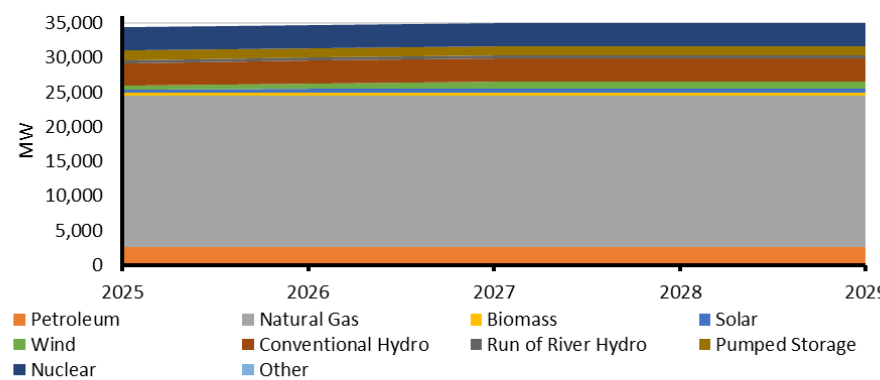
NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only Balancing Authority within the state of New York. The BPS encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this LTRA, the established RML is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities 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). The NYSRC approved the 2025–2026 IRM at 24.4%.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	31,650	31,900	32,110	32,130	32,340	32,580	32,880	33,320	33,830	34,210
Demand Response	897	897	897	897	897	897	897	897	897	897
Net Internal Demand	30,754	31,004	31,214	31,234	31,444	31,684	31,984	32,424	32,934	33,314
Additions: Tier 1	495	858	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144
Additions: Tier 2	1,558	2,090	3,572	3,572	3,572	3,572	3,572	3,572	3,572	3,572
Additions: Tier 3	1,381	4,384	6,384	7,928	8,383	8,383	8,383	8,383	8,383	8,383
Net Firm Capacity Transfers	1,600	2,880	3,186	3,186	3,186	3,186	3,186	3,186	3,186	3,186
Existing-Certain and Net Firm Transfers	35,511	36,790	37,096	37,097	37,097	37,097	36,687	36,687	36,687	36,687
Anticipated Reserve Margin (%)	17.1%	21.4%	22.5%	22.4%	21.6%	20.7%	18.3%	16.7%	14.9%	13.6%
Prospective Reserve Margin (%)	22.1%	28.2%	34.0%	33.9%	33.0%	32.0%	29.5%	27.7%	25.7%	24.3%
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

Highlights

- Public policies, such as New York state's 2019 Climate Leadership and Community Protection Act (CLCPA), are driving rapid changes in New York's electric system, 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 increasing the demand for electricity and placing New York on a trajectory to be a winter-peaking system 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 reliability and resilience of the New York grid.
- NYISO's reliability studies identified actionable reliability needs starting 2025 in New York City. The reliability need is primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City affected by state legislation and regulations promulgated by the New York State Department of Environmental Conversation, commonly known as the Peaker Rule,[34] to limit emissions. Following a solicitation for proposed solutions to the reliability need, NYISO retained several plants in New York City that would have otherwise been deactivated to comply with the Peaker Rule. NYISO's 2024 Reliability Needs Assessment (RNA), targeting completion in the fourth quarter of 2024, identifies transmission security violations of reliability criteria primarily driven by a combination of forecasted increases in peak demand, limited additional supply, and the assumed retirement of generation in New York City in response to state law and regulations.
- Driven by public polices, new supply, large loads, 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 and to connect new resources upstate to downstate load centers where demand is greatest. Planning for new transmission to support offshore wind is underway in NYISO's Public Policy Transmission Planning Process.
- To achieve the mandates of the CLCPA, new dispatchable emission-free resources (DEFR) with the necessary reliability services will be needed to replace the capabilities and attributes of today's generation. These types of resources, which can achieve the necessary attributes by a combination of solutions, must be significant in capacity and have attributes similar to traditional generation plants, such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, provide ERSs, and adapt to meet rapid, steep ramping needs. 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 battery storage as well as distributed energy resources. Demand management programs are also under development as a measure to facilitate achievement of CLCPA targets. By lowering the peak load and avoiding system buildout to serve the highest demand hour, fewer DEFRs will be needed and fewer fossil fuel-fired plants will be needed to meet lower peaks during the transition.

[34] Subpart 227-3 of Title 6 of the New York Codes, Rules an3,323d Regulations.

NPCC-New York Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Petroleum	2,631	2,631	2,631	2,631	2,631
Petroleum*	2,628	2,628	2,628	2,628	2,628
Natural Gas	21,907	21,907	21,907	21,907	21,907
Biomass	334	334	334	334	334
Solar	545	586	586	586	586
Wind	461	785	1,070	1,070	1,070
Conventional Hydro	3,323	3,323	3,323	3,323	3,323
Run of River Hydro	413	413	413	413	413
Pumped Storage	1,410	1,410	1,410	1,410	1,410
Nuclear	3,330	3,330	3,330	3,330	3,330
Battery	50	50	50	50	50
Total MW	34,405	34,769	35,054	35,054	35,054
Total MW*	34,401	34,765	35,051	35,051	35,051
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to NYISO are removed from the resource projection where marked.					

NPCC-New York Assessment

Planning Reserve Margins

The LTRA anticipated and prospective margins are above 15% with the exception of year 9 (2033) and year 10 (2034). However, the system margins are narrowing throughout the assessment period. 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 its 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 2024 Reliability Needs Assessment, which is underway and targets completion in Q4 2024, will likely identify reliability criteria violations.

NYISO also provides support to the NYSRC in conducting an annual IRM 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 "1 day in 10 years." The current IRM for the 2024–2025 capability year is 22% 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 22%. Additionally, the NYISO performs an annual study to identify the locational minimum installed capacity requirements (LCR) for the upcoming capability year.

Energy Assessment, Including Non-Peak Hour Risk

New York State's CLCPA mandates to decarbonize 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, the system will need dispatchable emission-free resources (DEFR) and long-duration resources 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 future offshore wind energy and to connect new resources upstate to downstate load centers where demand is greatest.

NYISO performs long-range assessments (10-year and beyond planning horizon), and certain energy aspects are accounted for in the hourly modeling and simulations performed under the resource adequacy studies through NYISO's reliability planning processes along with the production cost simulations performed under its System and Resource Outlook.

NYISO performs and supports energy assessments, including a fuel and energy security study, a study assessing potential impacts related to climate change, and weekly analysis of fuel and energy security based on load profiles and fuel inventories reported through NYISO's Generator and Fuel Emissions Reporting (GFER) data portal. These assessments are based on data and information provided by resources on an annual, weekly, and as-needed basis considering system operating conditions. These assessments have 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 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 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 using GE's Multi-Area Reliability Simulation (MARS) as part of its reliability planning processes as well as to determine annual IRM LCRs. 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 (CAF) for various capacity accreditation resource classes. The groundbreaking proposal was accepted by FERC in May 2022. The CAFs will reflect the marginal reliability contribution of the ICAP Suppliers within each Capacity Accreditation Resource Class toward meeting NYSRC resource adequacy requirements for the upcoming capability year, starting with the capability year that began in May 2024.

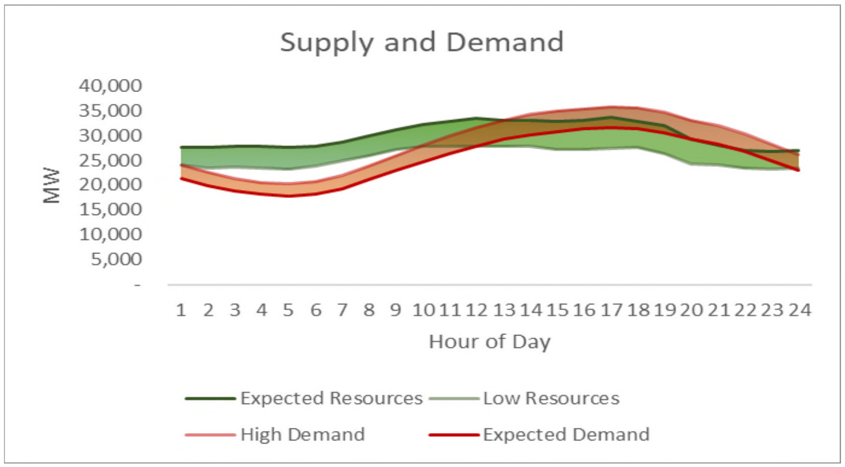
Additionally, NPCC provides results into NERC's ProbA process under the LTRA. The results from the ProbA performed in 2024 by NPCC are shown below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.06	1.91	1.30
EUE (PPM)	0.00	0.01	0.01
LOLH (hours per year)	0.00	0.01	0.01
Operable On-Peak Margin	16.7%	14.0%	15.0%

* Provides the 2022 ProbA Results for Comparison

Most load-loss and unserved energy risk is in the summer months of late June through August.

Hourly demand and resource projections for a typical summer risk day in 2026 are shown in the figure below. Although expected resource contribution is enough to meet expected demand, there is risk that above-normal peak demand could exceed resources. Demand could be 10–13% higher than expected, which could cause strain on the system from the hours beginning 2:00 p.m. through 11:00 p.m. Also, below-normal resource performance from unexpected generator outages or low-solar output could also cause supply shortfalls. If resource contributions are less than expected, strain on the system could be seen from hour beginning 12:00 p.m. through 12:00 a.m. on a typical peak day. Reliance on external assistance may be necessary in these events. A risk day in 2028 has a similar profile.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

NPCC's Directory 1 defines a compliance obligation for the NYISO, as a Resource Planner and Planning Coordinator, to perform a resource adequacy study evaluating a five-year planning horizon. NYISO delivers a report every year under this study process to verify the system against the 1-day-in-10-years LOLE criterion, which is usually based on NYISO's latest available reliability assessment results and assumptions. NYSRC Reliability Rules have recently included a requirement defining NYISO's obligation to deliver a Long-Term Resource Adequacy Assessment Report every year during which the NYISO publishes a Reliability Needs Assessment (RNA) and an annual update in the intervening year between RNAs.

Demand

NYISO employs a multi-stage process to develop load forecasts for each of the 11 zones within the New York Control Area (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 is projected to shift into the evening as additional BTM solar 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 forecast horizon, BTM solar generation becomes less coincident with the NYCA peak hour, and BTM solar 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 10-year annual average energy (+1.7%) and summer peak demand (+0.8%) growth rates are higher than last year's forecast. Increases in growth rates relative to the prior forecast are primarily attributed to the significant impacts of interconnecting large load projects. Baseline energy and coincident peak demand increase significantly throughout the 30-year forecast period, driven largely by large load project growth in the early forecast years and electrification of space heating, non-weather sensitive appliances, and EV charging in the outer forecast years. New York is projected to become winter-peaking in future decades due to space heating electrification and EV penetration. To account for forecast uncertainty during winter due to electrification and large loads, NYISO implemented a winter dynamic load forecast uncertainty in the resource adequacy models for its 2024 RNA.

Demand-Side Management

NYISO is working on developing market concepts to encourage the participation of flexible load, which will become increasingly important as the levels of weather-dependent intermittent resources on New York's grid increase in response to the state's climate and clean energy policies. Many of New

York's utilities are piloting several load management programs (e.g., smart EV charging, home-thermostat use, and 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.

DR participation for the summer capability period has increased slightly from 1,234 MW to 1,281 MW since the *2023 LTRA*. There are currently 425 MW of DR participating in ancillary services programs and providing either 10-minute spinning reserves or 30-minute non-synchronous reserves.

Distributed Energy Resources

NYISO has implemented in 2024 a plan to integrate DERs, including DR resources, into the markets it administers. The DER Participation Model project aims to enhance participation of DERs in the 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, provides 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 deployed its DER participation model in 2024.

Generation

The pace of renewable project development and existing generation retirement is unprecedented and driving a need to increase the pace of transmission expansion, 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 energy targets under the CLCPA. 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 unparalleled.

Currently, 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. However, the grid will evolve to achieve the policy mandates, and those changes will affect the nature and amount of resources.

For the 2024 RNA, gas availability is derated during winter to further account for cold weather risks.

To achieve the CLCPA mandate of an emission-free grid by 2040, DEFRs 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.

ERSs usually provided to 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. In May 2023, the New York State Public Service Commission (PSC) initiated a process to examine the need for resources to ensure the reliability of the CLCPA mandate for a zero-emissions electric grid by 2040. The PSC seeks to identify innovative technologies to ensure the reliability of a zero-emissions electric grid. Numerous other initiatives at both state and federal levels are in progress and may impact the grid of the future.

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 to participate in the market as a single resource. Additionally, the resource adequacy simulation tools (such as GE's MARS) used in system planning by NYISO 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's 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 to New York City, which is reflected in the LTRA summer total transfers starting in 2026. Additionally, the probabilistic model that NYISO uses to assess the adequacy of resources in the reliability planning processes employs several methods aimed at preventing overreliance on the external systems support. For example, NYISO employs limiting emergency assistance from neighbors by modeling a total limit of 3,500 MW, modeling five simultaneous peak days, modeling the long-term purchases and sales with neighboring control areas, and not modeling emergency operating procedure steps for the neighbors.

New York is fortunate to have strong interconnections with neighboring regions and has enjoyed reliability and economic benefits from such connections. As the energy policies in neighboring regions evolve, New York's imports and exports of energy could vary significantly due to the resulting changes in neighboring grids. The availability of energy for interchange is predicted to shift fundamentally as policy achievement progresses. As New York's and other regions' grids evolve, continuous monitoring and collaboration with our neighboring states will be required.

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:

- The Northern New York Priority Transmission Project upgrading the transmission corridors from the renewable generation pocket in the north country to central New York
- The 1,250 MW Champlain-Hudson Power Express HVdc line from Hydro-Québec to New York City
- The AC Public Policy Transmission Projects that consist of upgrading transmission corridors in central New York and the lower Hudson Valley, which projects target completion of the majority of the components by December 2023
- The transmission project selected to address the Long Island Offshore Wind Expert Public Policy Transmission Need and that adds three new dc tie lines and a 345 kV backbone across western/central Long Island with an in-service date in 2030

Additionally, there are significant transmission projects either recently selected or under study that have not yet met the criteria to be in the reliability model. For instance, the PSC recently identified a new public policy transmission planning need for NYISO to solicit proposed solutions and that is intended to support the integration of 4.7 GW of wind resources in New York City.

Furthermore, in 2020, the PSC ordered the New York utilities to undertake planning assessments and make investment proposals to facilitate the cost-effective development of renewable and emissions-free resources while maintaining the reliability of New York's electric grid. The Coordinated Grid Planning Process (CGPP) was approved by the PSC in August 2023. The process is designed to assess the state's electric grid using a 20-year planning horizon. The CGPP is intended to identify electric grid expansions that can aid in unlocking renewable generation capacity and provide energy headroom for the purpose of meeting New York's clean energy goals while providing value to customers. Moreover, the CGPP is designed to identify opportunities for expansion of the bulk transmission system to advance the mandates of CLCPA. This provides another opportunity to inform the PSC's consideration of whether to establish a public policy transmission need for NYISO to solicit and evaluate proposed solutions.

Reliability Issues

The 2024 RNA, targeting completion in the fourth quarter of 2024, identifies transmission security violations of reliability criteria primarily driven by a combination of forecasted increases in peak demand, limited additional supply, and the assumed retirement of generation in New York City in response to state law and regulations. Accounting for these factors, the planned bulk power transmission system will not be able to securely and reliability serve the forecasted demand in New York City. When accounting for forecasted economic growth and policy-driven increases in demand, the New York City (Zone J) will be deficient starting in summer 2033 by as much as 17 MW for 1 hour and increasing to 97 MW for 3 hours in summer 2034 on the peak day during expected weather conditions. The Reliability Need occurs within the transmission district owned by Consolidated Edison Company of New York, Inc. ("Con Edison"). Con Edison is designated as the Responsible Transmission Owner in the NYISO's transmission planning process and required to submit a regulated backstop solution to address the need, which may be triggered if sufficient market-based solutions do not materialize.

Prior to the 2024 RNA, the NYISO completed the 2023 Q2 STAR on July 14, 2023. This assessment found a reliability need beginning in summer 2025 in New York City primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City affected by the New York Department of Environmental Conservation (DEC) Peaker Rule. The reliability need is a deficiency in the transmission security margin. 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. To ensure the continued reliability of electric service in New York City, NYISO designated the generators on the Gowanus 2 & 3 and Narrows 1 & 2 barges as necessary for reliability to temporarily remain in operation after the Peaker Rule compliance date until permanent solutions to the need are in place, for an initial period of up to two years (May 1, 2027).

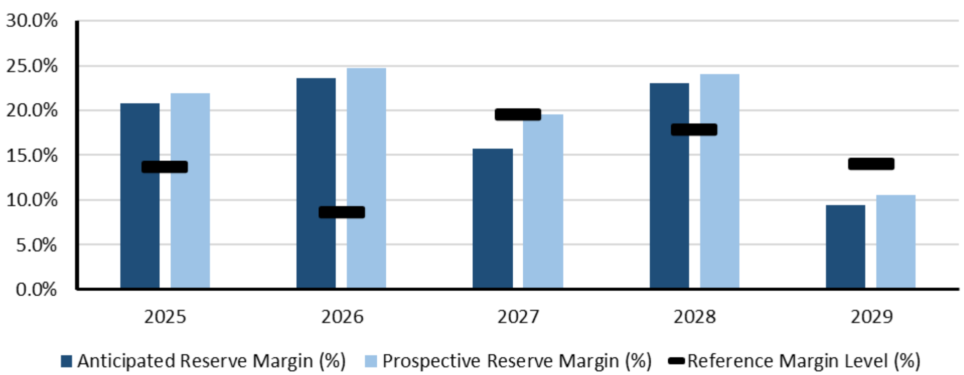
The transition to a cleaner grid in New York is leading to an electric system that is increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation and may lead to increasing reliability issues on the New York system. Reliability margins are shrinking. Generators needed for 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. The system is projected to become winter-peaking in the next decade due to electrification and decarbonization policies. Large loads are being proposed to interconnect to the system. New York's current reliance on neighboring systems is expected to continue through the next 10 years. 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 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. 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.

NPCC-Ontario

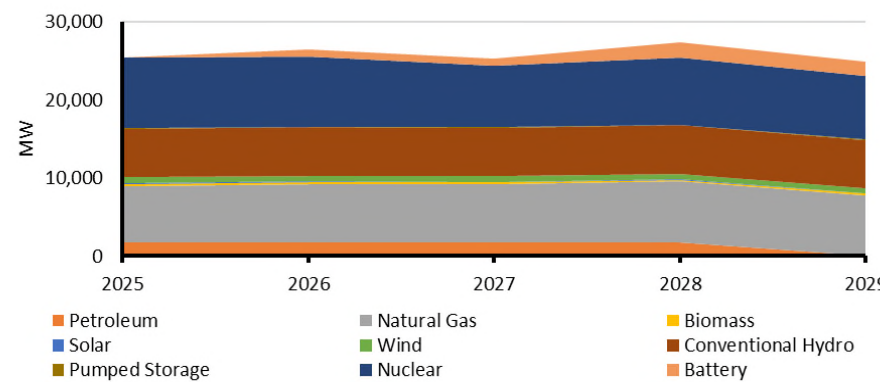
NPCC-Ontario is an assessment area in the Ontario province of Canada. The IESO is the Balancing Authority for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 16 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	23,385	23,860	24,264	24,627	25,248	26,038	26,473	27,373	27,974	28,789
Demand Response	1,791	1,914	1,914	1,914	1,914	1,914	1,914	1,914	1,914	1,914
Net Internal Demand	21,594	21,946	22,350	22,713	23,333	24,123	24,559	25,458	26,060	26,875
Additions: Tier 1	617	1,737	1,735	3,012	3,302	3,300	3,843	4,385	4,384	5,128
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	600	600	500	600	600	600	600	0	0	0
Existing-Certain and Net Firm Transfers	25,470	25,394	24,133	24,924	22,242	22,051	20,660	20,705	20,671	20,257
Anticipated Reserve Margin (%)	20.8%	23.6%	15.7%	23.0%	9.5%	5.1%	-0.2%	-1.4%	-3.9%	-5.5%
Prospective Reserve Margin (%)	22.0%	24.8%	19.5%	24.1%	10.5%	6.1%	0.8%	-0.5%	-2.9%	-4.6%
Reference Margin Level (%)	13.7%	8.6%	19.5%	17.8%	14.1%	9.4%	17.2%	8.1%	6.8%	8.5%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- While potential reserve margin shortfalls are forecast for 2027 and 2029, they are mainly driven by changes in the IESO's resource adequacy assessment methodology since the *2023 LTRA*. Last year, reserve margin calculations included the continuation of existing resources (following contract expiry) for the entire outlook period. For this LTRA, reserve margins reflect the contribution of existing resources only until the end of their contract or commitment period. This change to the methodology is more conservative and helps to better identify system needs in the IESO's planning assessments to establish resource acquisition targets and address anticipated needs.
- The IESO has two capacity sharing agreements with Hydro-Québec providing firm summer capacity, which will help to address future shortfalls this decade.
- The IESO has completed a broad set of actions to secure new capacity for this decade to ensure that Ontario's power system needs are met during a period of nuclear retirements and refurbishments and economy-wide demand growth. This includes securing long-term commitments amounting to 2,195 MW of new capacity to be on-line by 2028, with early operation incentives anticipated to bring a portion on-line as early as 2027 to help alleviate the reserve margin gap.
- The annual capacity auction, which helps to meet needs in the short term by securing capacity for up to one year at a time, has historically secured more capacity than targeted. Trends suggest that this should continue, as the November 2024 auction (which will help to ensure reliability through summer 2025 and winter 2025–2026) also secured more capacity than targeted.
- The IESO is taking steps that will address future shortfalls around the end of this decade and heading into the 2030s. The next round of medium- and long-term procurements was recently launched to ensure that capacity and energy needs continue to be met. The second medium-term procurement aims to re-commit existing resources with contracts expiring over the 2026–2029 period, while the second long-term procurement aims to secure capacity and energy from new resources (to be online as early as 2029), to meet needs emerging in the early 2030s.
- The IESO is also responsible for implementing new provincial policy as outlined in the Ontario government's July 2023 Powering Ontario's Growth report, which includes developing new nuclear projects, transmission expansions, and expanded conservation and demand management programs. The IESO will also incorporate changes stemming from the federal release of the final Clean Electricity Regulations, anticipated toward the end of 2024.

NPCC-Ontario Projected Generating Capacity by Energy Source in Megawatts (MW)

	2025	2026	2027	2028	2029
Petroleum	1,695	1,695	1,695	1,695	5
Natural Gas	7,275	7,465	7,465	7,847	7,761
Biomass	297	294	257	209	209
Solar	100	100	100	100	100
Wind	743	722	711	711	602
Conventional Hydro	6,215	6,212	6,212	6,212	6,202
Pumped Storage	38	38	38	38	38
Nuclear	9,008	9,008	7,895	8,639	8,142
Battery	118	998	996	1,886	1,885
Total MW	25,487	26,531	25,368	27,336	24,944

NPCC-Ontario Assessment

Planning Reserve Margins

The ARM falls below the RML starting in 2027. While expected nuclear retirements, the ongoing nuclear refurbishment program, and demand growth are resulting in increased needs this decade, the reserve margin shortfalls indicated in 2027 and 2029 are primarily driven by the change in the IESO's resource adequacy assessment methodology described above.

Mid-decade capacity needs that were identified in the 2022 *Annual Acquisition Report* have been met through a series of competitive procurements. Since May 2023, the IESO has secured over 3,600 MW of new capacity from battery storage, natural gas, and biogas facilities, expected to come on-line between 2025 and 2028. In addition, the 2023 capacity auction secured 1,867 MW of summer capacity and 1,311 MW of winter capacity above targets of 1,400 and 850 MW, respectively. The IESO continues to actively procure existing and new resources to meet longer-term needs, using the mechanisms in the Resource Adequacy Framework.

Ongoing refurbishments at Bruce Nuclear Generating Station (NGS) and Darlington NGS will see between one and three reactors concurrently off-line through Summer 2033. Refurbishments remain on or ahead of schedule and outages continue to be managed to limit impacts to the grid. Following the return to service of refurbished units at Bruce, each unit is expected to be uprated, with the additional capacity anticipated to be available in the early 2030s.

The Ontario government has also announced a plan to deliver three additional small modular reactors in addition to the 300 MW unit already underway (anticipated on-line in 2029). The provincial government's July 2023 Powering Ontario's Growth plan directed the IESO to conduct an impact assessment on potentially adding 4,800 MW of large-scale nuclear capacity to Bruce NGS. Approval was granted from the federal nuclear regulator in October 2024 to extend operation of four units at Pickering NGS (previously scheduled for decommissioning in 2025) through September 2026. The government is also supporting the refurbishment of the four units at Pickering, with refurbishment of the first unit anticipated to be completed in 2031.

To address resource adequacy needs emerging mid-decade due to the combined effect of nuclear retirements and refurbishments, as well as expiring generation contracts, the IESO has employed competitive acquisition mechanisms from the Resource Adequacy Framework in part via the capacity auction referenced above. The IESO's first long-term procurement concluded in May 2024 and secured long-term commitments from 10 battery storage facilities for 1,784 MW of new capacity and three natural gas/biogas facilities for 411 MW of new capacity. Facilities are anticipated to be in service as early as May 2027.

The IESO calculates the reserve margin requirement on an annual basis and publishes this in the Annual Planning Outlook (APO). The requirement is calculated 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 *2024 LTRA* is derived from the capacity requirement in the 2024 APO, plus any material changes to demand and supply following APO publication.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Energy adequacy assessments are conducted annually for the APO by using a deterministic approach in the IESO's economic dispatch model. In addition, the IESO's capacity adequacy assessments consider the system's ability to serve load in all hours of the year (i.e., during peak hours as well as non-peak load hours).

As demand requirements increase, nuclear refurbishments continue, and some units at the Pickering NGS retire in 2024, Ontario's energy needs are expected to be met this decade by the resources secured through the IESO's recently completed procurements. The second medium-term procurement, which was recently launched, aims to secure capacity and energy from existing resources reaching contract end; this is expected to help alleviate energy risks in the latter half of this decade. The second long-term procurement that is underway aims to acquire new capacity and energy-producing resources and is anticipated to alleviate energy risks in the early 2030s.

Factors that could increase energy adequacy risks include aging resources and the potential for decreased performance, market exit of resources reaching contract end, extreme weather, and decarbonization policies and risks presented by new resources, including in-service delays or a high risk of forced outages during the initial period of operation. Deliverability challenges for new resources and long lead times required to build new transmission may also increase energy adequacy risks. Demand-side factors include materialization of data centers, increased industrial automobile production and EV supply chain loads, and climate change impacts on weather-sensitive load.

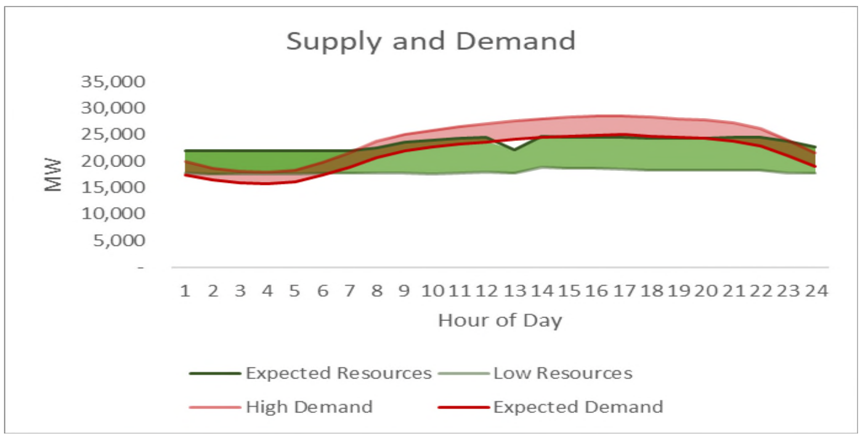
Looking forward, with the federal government's proposed Clean Electricity Regulations to decarbonize Canada's electric system by 2050, the IESO is assessing the role of natural gas generation as a flexible resource in the interim as new sources of non-emitting supply are added to the system.

The IESO conducts probabilistic resource adequacy assessments annually in conjunction with NPCC to identify regional capacity resource needs and to comply with NPCC and NERC reliability requirements. Results from the 2024 ProbA are shown in the table on the next page. The low risk of unserved energy is concentrated in the summer peak period, which typically occurs in late August.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	72.16	**0.04**	**4.97**
EUE (PPM)	0.49	**0.00**	**0.03**
LOLH (hours per year)	0.44	**0.00**	**0.01**
Operable On-Peak Margin	-6.7%	**13.3%**	**9.5%**

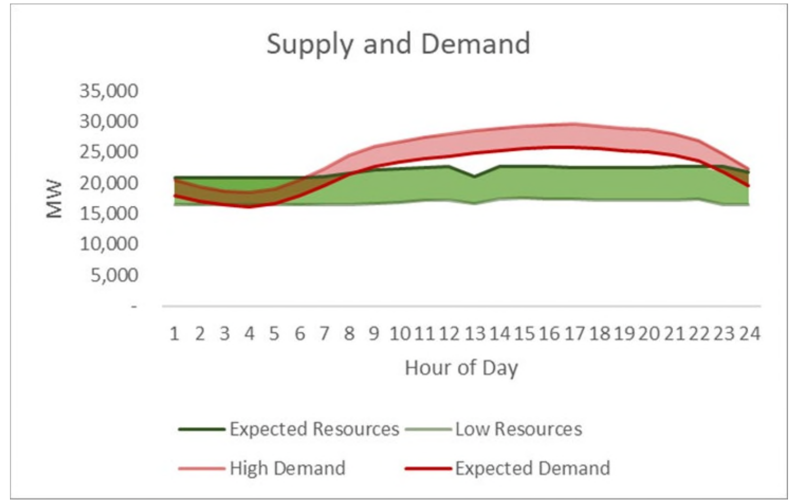
* Provides the 2022 ProbA Results for Comparison

Hourly demand and resource projections for a representative summer risk-day in 2026 are shown in the figure below. Expected resource contributions are not sufficient to meet expected demand on the risk day. The risk could be exacerbated by either a lower-than-expected resource contribution event or a higher-than-expected demand event, with greater risk being due to a larger variability in resource contribution. There is expected strain on the system from the hours beginning 12:00 p.m. through 8:00 p.m. If resource contributions are less than expected, strain on the system at expected demand conditions could be seen for almost all hours of the day beginning at 7:00 a.m. Reliance on external assistance may be necessary during peak conditions.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

In 2028, the EUE and LOLH are higher than 2026. Risk occurs during the same summer peak period but also during winter peak conditions in December. Demand growth that is forecasted to occur between 2026 and 2028 contributes to higher loss-of-load risk compared to the 2026 result. The risk day in 2028 has the same drivers as the 2026 result noted above.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2028

Demand

Forecasted demand for this *2024 LTRA* outlook period (relative to the *2023 LTRA* outlook period) indicates 10% higher annual energy demand, 8% higher summer peak demand, and 9% higher winter peak demand.

With an expanding agricultural and greenhouse sector, along with increasing electricity use for home heating and transportation, summer and winter peaks are anticipated to converge over the forecast period, leading Ontario to be dual-peaking by 2030. In the near term, the peak magnitude is expected to increase slightly as the province exits the remnants of the post-pandemic inflationary cycle, and new industrial projects supporting decarbonization begin commercial operation. Over this assessment period, the IESO projects total internal demand growth to increase at a compound annual growth rate of 2.34% for summer and 2.75% for winter. Offsetting the growth in demand are reductions from conservation, including savings from EE programs and codes and standards regulations, electricity price responsiveness and increased output by embedded generation.

Ontario’s Industrial Conservation Initiative (ICI) acts as a critical peak pricing program leading to reductions in demand at peak and is expected to reduce around 1,500 MW if the hour of annual system peak demand occurs in the summer or around 1,000 MW if it occurs in the winter. It is expected to scale based on increased industrial growth in future years, with reductions in 2034 of 2,000 MW for a summer peak demand hour and over 1,400 MW for a winter peak demand hour.

Demand-Side Management

DR capacity, from both dispatchable loads and hourly DR resources (e.g., residential or commercial and industrial load), is procured through the IESO’s annual capacity auction. Starting with the 2023 capacity auction, the IESO implemented a capacity qualification process for all resource types eligible to participate, which applies resource-specific calculation methodologies to determine the amount of unforced capacity (UCAP) each resource is eligible to offer into the auction.

In June 2023, the IESO launched Peak Perks, a residential DR program where participants help reduce demand by up to 150 MW through brief, time-limited thermostat adjustments during periods of peak electricity demand in the summer months.

In July 2023, the IESO launched an interruptible rate pilot to provide large-load customers with an interruptible rate in exchange for agreeing to temporarily reduce demand when directed by the IESO. The pilot spans a three-year period and up to 15 events of up to four-hour duration can be called, primarily in the day-ahead timeframe but also on shorter notice.

Forecast savings from the IESO’s 2021–2024 Conservation and Demand Management Framework were included in the forecast and resulted in a decrease in demand. Savings from the 2021–2024 CDM framework are expected to persist beyond the end of 2024. In February 2024, Ontario’s minister of energy asked the IESO to examine options and analysis for a post-2024 EE framework and programs.

Distributed Energy Resources

The IESO estimates that contracted DERs contributed more than 3,400 MW of capacity and 5.3 TWh of energy in 2023, more than half of which is solar PV, one-third wind, and modest contributions from hydroelectric and biomass resources. While the IESO has little insight into uncontracted DERs, it has observed energy contributions of approximately 2 TWh in 2023.

Generation

Recent generation procurements are provided in the PRM section.

The transmission-connected supply mix in Ontario has shifted over the past decade from having only synchronous generation facilities to one with more IBRs including wind, solar, and storage. Previous assessments performed by the IESO indicate that Ontario is expected to have sufficient inertia and frequency response to ensure stable operation up to 2025.

Going forward, the addition of over 2,900 MW of new battery storage resources in the next few years will increase the proportion of IBRs on the system. With the shift toward a higher proportion of IBRs, further areas that will be explored include the sufficiency of the resource mix to provide system inertia, primary frequency response, operating reserve, ramping capability, reactive support, and voltage control. If needs are identified, the IESO’s procurements may be used as one avenue to acquire resources that can provide the required services.

The IESO has also been taking a proactive approach to dealing with challenges posed by IBRs. This includes working to optimize the location of IBR resources acquired through the IESO’s procurements to minimize performance issues and initiating a review of the IESO’s Market Rules to align with the latest IEEE 2800 standard, which aims to establish uniform technical minimum requirements for interconnection, capability, and lifetime performance of IBRs.

Energy Storage

By May 2028, over 2,900 MW of new battery storage resources are expected to come on-line, including the 250 MW/1,000 MWh Oneida battery storage facility (expected to be operational in June 2025), and 2,714 MW of battery storage resources secured through the IESO’s first set of long-term procurements. Of this, 930 MW is expected to reach commercial operation by May 2026 and the remaining 1,784 MW by May 2028. These standalone battery storage resources (with a minimum four-hour duration) are expected to support the reliable operation of Ontario’s electric system through the ability to be dispatched by the IESO and ramp up and down quickly. The resources are also located in areas of Ontario where transmission security or resource adequacy needs were identified.

Newly acquired energy storage facilities through the IESO’s first set of long-term procurements will be required to be available during peak hours.

Capacity Transfers

Firm capacity imports and exports with neighboring jurisdictions are included in the IESO’s planning studies. For non-firm imports, the IESO assumes a limited amount for the purposes of its reliability assessments. Non-firm imports are assumed to be 250 MW for summer and 240 MW for winter, an amount considered likely to flow throughout the year, including under tight supply conditions and prices.

In November 2024, the IESO and Hydro-Québec finalized a new capacity sharing agreement for a swap of a minimum of 600 MW of capacity per season. Under this agreement, the IESO will deliver capacity to Québec during the winter period and Hydro-Québec will deliver capacity to Ontario during the summer period. The agreement commences in the Winter 2024–2025 season and runs to October 2031, with an option for an extension for an additional three years. Other terms of the agreement are expected to include the option for the IESO to increase the minimum amount provided to Québec each year and to bank any amount of the 600 MW from Québec for use in a future summer period over the term of the agreement.

The 2023 capacity auction secured 300 MW of system-backed imports from Québec for the Summer 2024 obligation period. As part of the 2016 capacity sharing agreement between Ontario and Québec, the IESO may call on a total of 500 MW of firm imports from Hydro-Québec, which may be requested all in one summer or in smaller amounts over multiple summers. The IESO's recent assessments indicate the intention to utilize the 500 MW of firm imports from June to September 2027 to help meet resource adequacy needs. However, depending on the outcomes of the ongoing procurements and changes to Ontario's resource adequacy outlook, the IESO may choose to utilize this capacity in another year.

Transmission

The existing transmission system in northeastern Ontario has insufficient capability to reliably supply forecasted load growth; as such, the IESO has recommended several new transmission reinforcements in the region to address this need. Several of the recommended reinforcements are in the early project development stage and one is undergoing a transmitter selection process.

The IESO recently recommended additional transmission reinforcements in southwest Ontario to support the area's medium-term needs, including a double circuit, 230 kV line from Lambton transmission station to Chatham substation, expected in-service by 2028, and a new 500 kV transmission line connecting Longwood and Lakeshore transmission stations, to be in-service by 2030. These projects will ensure that transfer capability continues to be sufficient as additional load continues to connect in the area.

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 nuclear refurbishment reserve to account for the risk of refurbishment delays and increased forced outage rates pre- and post-refurbishment. In addition, advanced outage approvals are provided solely when Ontario is adequate under extreme weather.

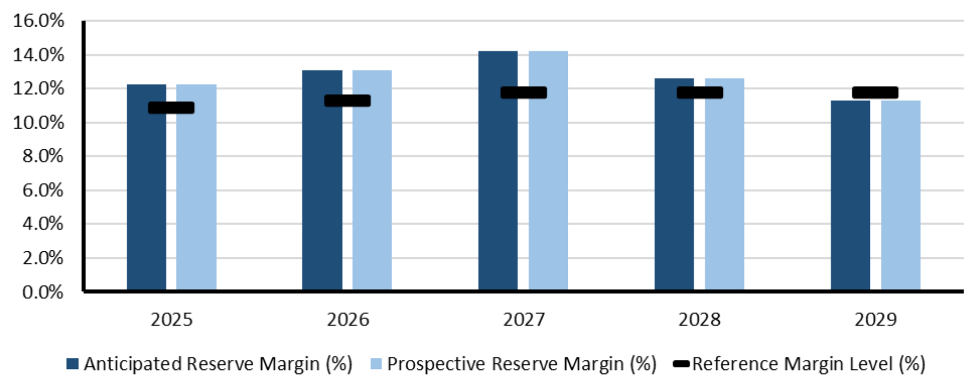
Other factors that may pose reliability risks include supply chain issues, conditions in neighboring jurisdictions, extreme weather, decarbonization-driven changes to supply and demand, policy and regulatory uncertainty, asset health, and potential market exit of existing resources.

NPCC-Québec

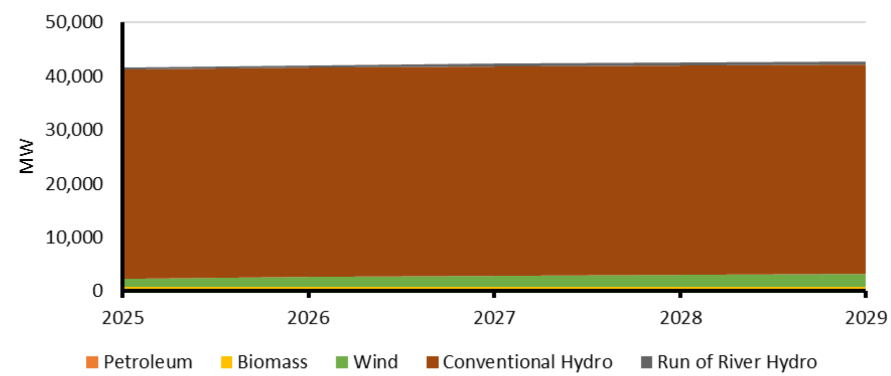
The Québec assessment area (Province of Québec) is a winter-peaking NPCC subregion that covers 595,391 square miles with a population of 8.5 million. Québec is one of the four NERC Interconnections in North America with ties to Ontario, New York, New England, and the Maritimes. These ties consist of either HVdc ties, radial generation, or load to and from neighboring systems.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	41,497	41,954	42,476	43,385	44,070	44,784	45,577	46,635	47,828	49,041
Demand Response	4,732	4,896	5,068	5,258	5,322	5,377	5,388	5,388	5,388	5,388
Net Internal Demand	36,765	37,058	37,408	38,127	38,748	39,408	40,189	41,247	42,440	43,652
Additions: Tier 1	73	469	665	835	1,016	1,016	1,016	1,016	1,016	1,016
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	-390	-145	455	455	455	600	0	0	0	0
Existing-Certain and Net Firm Transfers	41,185	41,429	42,066	42,103	42,103	42,256	41,656	41,656	41,656	41,656
Anticipated Reserve Margin (%)	12.2%	13.1%	14.2%	12.6%	11.3%	9.8%	6.2%	3.5%	0.5%	-2.2%
Prospective Reserve Margin (%)	12.2%	13.1%	14.2%	12.6%	11.3%	9.8%	6.2%	3.5%	0.5%	-2.2%
Reference Margin Level (%)	10.9%	11.3%	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM and PRM remain above the RML until 2029 (winter 2029–3030).
- A total of 4,048 MW wind generation capacity (1,016 MW capacity value at peak time) is expected to be in service by 2030.
- Two new transmission projects connecting Québec with New England and New York are expected to be in service by the end of 2025 and May 2026, respectively.

NPCC-Québec Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Petroleum	429	429	429	429	429
Biomass	400	400	400	400	400
Wind	1,449	1,807	2,002	2,173	2,354
Conventional Hydro	38,925	38,962	38,999	39,036	39,036
Run of River Hydro	446	446	446	446	446
Total MW	41,648	42,043	42,276	42,483	42,664

NPCC-Québec Assessment

Planning Reserve Margins

The ARM is based on existing and anticipated generating capacity and firm capacity transfers. The Québec area projects an ARM above the RML over the first five winters of the assessment period (2024–2025 to 2028–2029). The ARM is under the RML for the winters 2029–2030 to 2034–2035 mainly due to the demand growth.

The RML is derived from the NPCC 2023 Québec Balancing Authority Area Comprehensive Review of Resource Adequacy, which was approved by NPCC's Reliability Coordinating Committee on December 5, 2023. The demand uncertainty captured in the reserve ratio reflects both weather and economic uncertainty. The methods and assumptions can be found in the *Comprehensive Review* report available on the NPCC website.

The assumptions used for this assessment, including demand forecast and resources, are consistent with the Hydro-Québec 2023 Supply Plan update, which was filed with the Régie de l'énergie on November 1, 2023.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

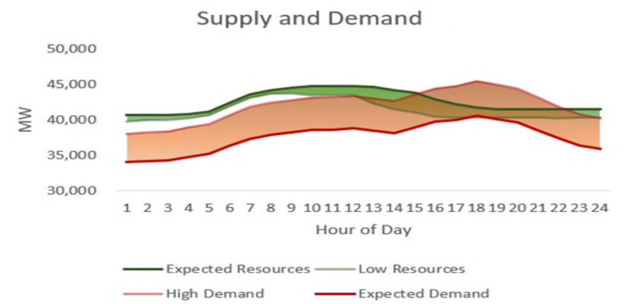
The main energy risk for the Québec area is associated with a series of dry years, hence the energy reliability criterion established by the Régie de l'énergie. This risk surpasses the energy risk associated with the other renewable resources over the horizon of this study. The potential impact of climate change on the water inflows could be an issue for energy reliability and is therefore the subject of various ongoing internal studies.

Hydro-Québec conducts probabilistic resource adequacy assessments annually in conjunction with NPCC to identify regional capacity resource needs and comply with NPCC and NERC reliability requirements. Results from the 2024 ProbA are shown in the table below. The low risk of unserved energy is concentrated in the winter peak period, which typically occurs in late January to early February.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**8.21**	**4.97**
EUE (PPM)	0.00	**0.04**	**0.03**
LOLH (hours per year)	0.00	**0.01**	**0.01**
Operable On-Peak Margin	-2.3%	**9.8%**	**11.9%**

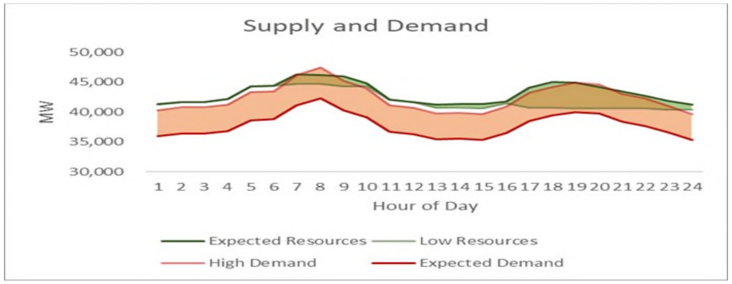
* Provides the 2022 ProbA Results for Comparison

Hourly demand and resource projections for a typical winter risk day in 2026 are shown in the figure below. Although expected resource contribution is expected to be enough to meet expected demand, there is risk that above-normal demand could exceed resources. Demand could be 10–15% higher than expected, which could strain the system from the hours beginning 3:00 p.m. through 10:00 p.m. Also, if resource contributions are less than expected, the peak hour beginning at 6:00 p.m. could lead to a loss-of-load situation. Reliance on external assistance may be necessary in these events.



Hourly Probabilistic Assessment Results | Representative Winter Risk Day 2026

Hourly demand and resource projections for a typical winter risk day in 2028 are shown in the figure below.



Hourly Probabilistic Assessment Results | Representative Winter Risk Day 2026

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.

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 2,784 MW on winter 2024–2025 peak demand. The area is also expanding its existing interruptible load program for commercial buildings, which will grow from 611 MW in 2024–2025 to 889 MW by the end of the period study. Another similar program for residential customers is in operation and should gradually rise from 166 MW for Winter 2024–2025 to 621 MW for Winter 2028–2029.

New dynamic rate options for residential and small commercial or institutional customers will also contribute to reducing peak load during winter periods by 371 MW for Winter 2024–2025 and 445 MW for Winter 2034–2035. Moreover, data centers specializing 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 the study 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 862 MW in 2035. Solar PV is accounted for in the load forecast. Nevertheless, since Québec is a winter-peaking area, DERs' on-peak contribution ranges from 2 MW for Winter 2024–2025 to 5 MW for the last winter period. No potential operational impacts of DERs are expected in the Québec area considering their low contribution.

Generation

Four wind projects with a total installed capacity of 4,000 MW are expected to be commissioned during the assessment period. The first project, Apuiat (204 MW), is expected to be commissioned in 2024–2025. The second project (1,144 MW divided into 6 wind farms) is expected to be commissioned in December 2026. The third project is Des Neiges (1,200 MW) and is divided into three phases (400 MW each). The first phase is expected to be operational in the winter of 2026–2027. The second and third phases are expected to be in service for the 2027–2028 and 2028–2029 winters, respectively. The fourth project is made of 1,500 MW divided into 8 wind farms, which are expected to be operational in the winters of 2027–2028, 2028–2029 and 2029–2030, depending on the location.

In addition to wind projects, unit replacement projects at existing hydroelectric facilities are being studied. Up to 2,000 MW of capacity could be added by replacing generating units with most recent models, as outlined in Hydro-Québec's Action Plan 2035.

Energy Storage

No energy storage facilities are planned to be commissioned during the assessment period.

Capacity Transfers

The governments of Québec and Ontario have signed an 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 Fall 2024 and will be in place from Winter 2024–2025 to winter 2030–2031. This agreement will be firm and allow Québec to import 600 MW from November to April. In summer, Québec will export 600 MW of firm capacity to Ontario from May to October.

Transmission

Appalaches-Maine Interconnection

This project, expected to increase transfer capability between Québec and Maine by 1,200 MW, has resumed construction. The project will connect to the New England Clean Energy Connect project (NECEC) in Maine. It involves the construction of a ±320 kV dc transmission line about 100 kilometers (62 miles) long from the 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 Lewiston, ME, where the power will be converted from dc to ac. The project in Québec also includes the construction of an dc to dc converter at the Des Appalaches substation and triggers the need of thermally upgrade two 735 kV lines in the south of the system. The project is expected to be in service in December 2025.

Hertel-New York Interconnection (CHPE)

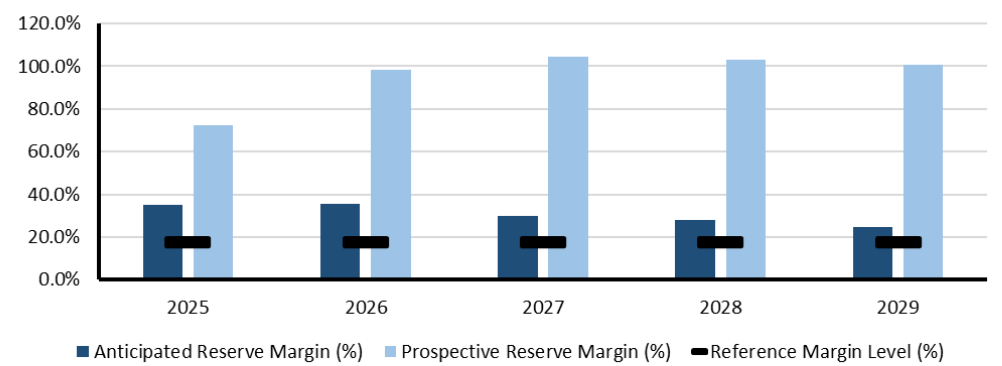
This project, expected to increase transfer capability between Québec and New York by 1,250 MW, is under construction. It involves the construction of a ±400 kV dc underground transmission line about 60 kilometers (37 miles) long from the Hertel 735/315 kV substation just south of Montréal to the Canada-United States border. The project will connect to the Champlain Hudson Power Express project (CHPE) 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 the Hertel substation. The project is expected to be in service in May 2026.

PJM

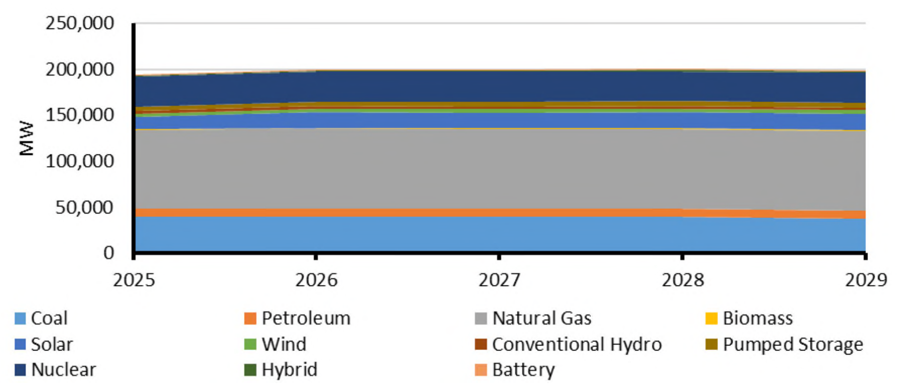
PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. 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.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	153,493	156,803	159,859	162,972	165,681	167,873	170,008	172,109	174,366	176,822
Demand Response	7,554	7,693	7,808	7,913	8,000	8,083	8,162	8,230	8,312	8,400
Net Internal Demand	145,939	149,110	152,051	155,059	157,681	159,790	161,846	163,879	166,054	168,422
Additions: Tier 1	11,056	17,047	17,139	17,784	17,911	18,155	18,155	18,155	18,155	18,155
Additions: Tier 2	55,112	93,845	112,827	122,781	127,059	131,113	131,287	133,652	133,652	133,652
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	4,502	4,347	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	185,828	185,270	180,552	180,552	178,577	178,577	178,577	178,577	178,577	178,577
Anticipated Reserve Margin (%)	34.9%	35.7%	30.0%	27.9%	24.6%	23.1%	21.6%	20.0%	18.5%	16.8%
Prospective Reserve Margin (%)	72.4%	98.3%	104.7%	103.3%	100.5%	96.5%	94.1%	92.9%	82.1%	79.5%
Reference Margin Level (%)	17.7%	17.7%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the RML until 2034 when it falls below the 17.6% RML level.
- PJM implemented a number of changes to the 2023 load forecasting process to improve model accuracy, switching from an annual to monthly end-use model for PJM's sector models to better determine heating, cooling, and other non-weather-sensitive load and moving to an hourly model to better capture new technologies and peak shifting. Additionally, higher expectations for data center loads now incorporate 15-year forecasts from impacted electric distribution companies (EDC).
- PJM's review of recent policies (e.g., state laws and federal environmental initiatives) indicates over 32 GWs of potential deactivations through 2034. The pace of retirements is being driven in large part by these state laws and federal environmental initiatives that create a clear near-term, date-certain requirement for generation to comply or retire. Conversely, there are multiple mandates with renewable portfolio standards (RPS) that account for the majority of over 150 GWs submitted projects.

PJM Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	39,735	39,735	39,325	39,325	37,747
Coal*	39,394	39,394	33,313	28,240	25,124
Petroleum	8,810	8,514	8,514	8,514	8,117
Natural Gas	85,541	87,245	87,245	87,245	87,245
Natural Gas*	85,541	87,245	87,228	87,228	87,228
Biomass	928	928	928	928	928
Solar	13,349	16,770	16,908	17,621	17,754
Wind	3,017	3,512	3,507	3,507	3,507
Conventional Hydro	2,934	2,922	2,934	2,934	2,944
Pumped Storage	5,189	5,189	5,189	5,189	5,189
Nuclear	32,535	32,535	32,535	32,535	32,535
Hybrid	1,315	1,742	1,739	1,739	1,739
Battery	393	982	982	994	994
Total MW	193,747	200,074	199,807	200,532	198,699
Total MW*	193,406	199,733	193,779	189,430	186,060
*** Capacity with additional generator retirements.** Generators that are forecasted to retire by PJM are removed from the resource projection where marked.					

PJM Assessment

Planning Reserve Margins

The ARM does not fall below the RML in PJM until 2034. PJM's growing demand profile and a change in resource mix that favors VERs, however, present a new level of risk.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

PJM is forecasting around 30% installed reserves (including expected committed demand resources), which is well above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion. Due to the current low penetration of energy-limited and VERs in PJM relative to PJM's peak load, the hour with most loss of load risk remains the hour with highest forecasted demand. To address future reliability concerns due to growing VER penetration and limitations associated with the performance of those resources, PJM's Effective Load Carrying Capability methodology calculates the reliability and energy contribution of limited and variable resources.

Some of PJM's assumptions for determining the resource mix to use in the ProbA differ from those used in developing the LTRA. Only a portion of the Tier 1 resource additions are used in the ProbA to more accurately reflect historical rates of development. Additionally, more generator retirements are used in the ProbA based on PJM's generator forecasting. These assumptions are more consistent with the assumptions included in official studies performed by PJM to support its capacity market. In addition, the information in the ProbA for winter seasons refers to the Winter 2026–2027 and Winter 2028–2029 because PJM's studies are based on "delivery years," which start on June 1 of a year and end on May 31 of the subsequent year.

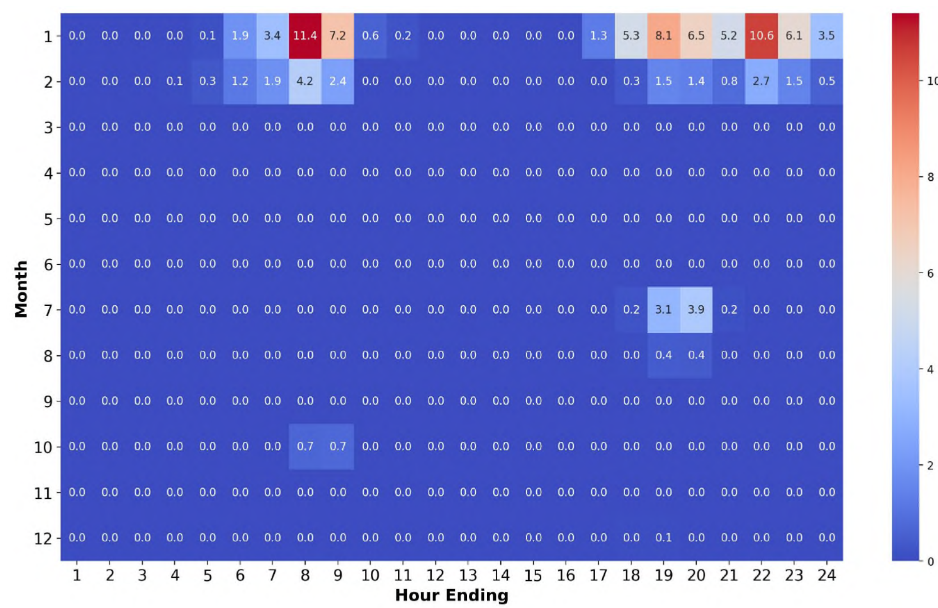
Results of the 2024 ProbA are provided in the table below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**537.52**	**1043.44**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.11**	**0.22**
Operable On-Peak Margin	29.0%	**17.8%**	**17.7%**

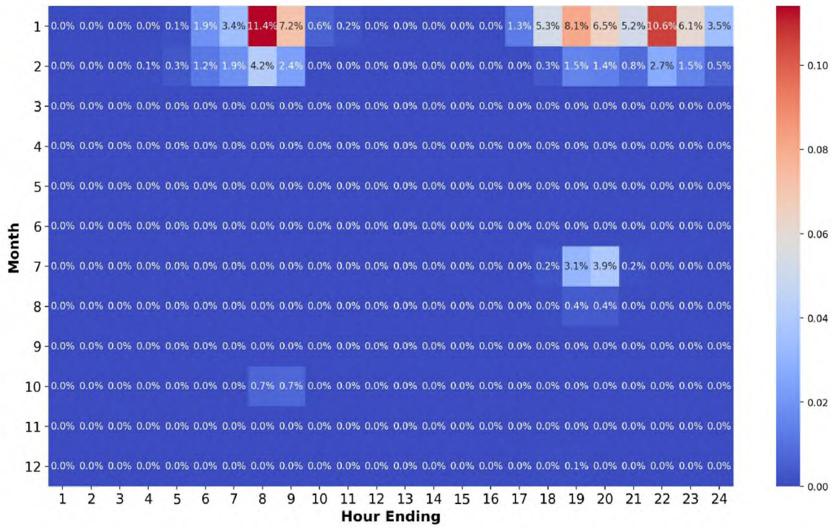
* Provides the 2022 ProbA Results for Comparison

In both 2026 and 2028, most EUE and LOLH are concentrated in the winter months (especially January), as shown in the following EUE heat maps. The risk occurs in days when temperatures are very low, which results in high loads across the assessment area. If resource performance were to occur at the levels expected during average winter days, the system should be able to serve these high loads. However, resource performance from thermal resources on very cold days, especially natural gas resources, is more likely to be poor. This, coupled with poor performance from solar resources, results in very low total electricity supply and causes loss-of-load events in the ProbA analysis. The winter load-loss events tend to occur during morning and evening demand peaks and coincide with poor thermal performance and poor solar performance.

The smaller shares of EUE and LOLH observed in the summer period for 2026 and 2028 are associated with high temperatures and high loads across the assessment area that drive load-loss events in the evening (hours ending 19 and 20) as grid-connected and BTM solar resource output declines. Low performance of wind resources and, to a lesser extent, slightly worse performance of thermal resources, also contribute to the load-loss events in the analysis.



2026 EUE Heat Map (Share of Annual EUE in %)



2028 EUE Heat Map (Share of Annual EUE in %)

PJM implemented capacity reforms (approved by FERC) at the start of 2024, which include using the loss-of-load model employed to perform the ProbA, as well as accreditation reforms based on the risk patterns identified by said model, for the capacity auctions starting with delivery year 2025–2026.

Demand

PJM is experiencing large growth in data centers that are in turn driving higher demand forecasts. Loudoun County, Virginia, in the PJM assessment area, is home to “Data Center Alley,” the largest concentration of data centers in the world. Electrification in transportation, heating, and industrial sectors is also spurring demand growth.

The PJM Interconnection produces an independent peak load forecast of total internal demand 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 its load forecast methodology and implements changes when improvements are identified.
Summer peak load growth in PJM is projected to average 1.6% per year over the next 10-year period and 1.6% over the next 15 years. The PJM summer peak is forecasted to be 176,822 MW in 2034, a 10-year increase of 25,575 MW, and reaches 190,752 MW in 2039, a 15-year increase of 39,505 MW. Annualized 10-year growth rates for individual zones range from 0% to 5.5% with a median of 0.5%.

Winter peak load growth for PJM is projected to average 1.9% per year over the next 10-year period and 1.8% over the next 15 years. The PJM regional transmission organization winter peak load in 2033–2034 is forecasted to be 163,069 MW, a 10-year increase of 28,410 MW, and reaches 176,195 MW in 2038–2039, a 15-year increase of 41,536 MW. Annualized 10-year growth rates for individual zones range from 0% to 5.0% with a median of 0.7%.

Net energy for load growth for PJM is projected to average 2.3% per year over the next 10-year period and 2.2% over the next 15 years. Total PJM energy is forecasted to be 1,021,955 GWh in 2034, a 10-year increase of 208,627 GWh, and reaches 1,120,928 GWh in 2039, a 15-year increase of 307,600 GWh. Annualized 10-year growth rates for individual zones range from 0.1% to 7.3% with a median of 0.7%.

Demand-Side Management

DR resources can participate in all PJM markets—capacity, energy, and ancillary services. DR is forecast to grow during summer peak season from 7,550 MW in 2025 to 8,400 MW in 2034.

Distributed Energy Resources

PJM expects 4,470 MW of solar DERs at the time of the peak in 2029 and 5,103 MW in 2034. The effects of solar DERs are included in the load forecast for PJM. No effect of solar DERs is incorporated in the winter load forecast since winter expected peak occurs after sundown.

Generation

Overall, new generation is coming on-line slower than anticipated. Generator retirements are outpacing the new generation replacing them. As a result, PJM could face future resource adequacy challenges, impacting system reliability and PJM’s ability to serve load. PJM could be at risk of facing resource adequacy challenges if these trends continue. PJM has applied an 11% reduction to the nameplate value of Tier 1 resources to reflect the historical rate of slower-than-anticipated addition of new generation.

PJM reviews the progression of generation interconnection to understand overall developer trends more fully and their impact on the interconnection process. Of new and expanded generation resources submitted in Queue A (1999) through December 31, 2023, 74,294 MW (or 15.8%) reached commercial operation, 33,166 MW (or 7%) were withdrawn from the interconnection process after Interconnection Service Agreement (ISA) execution, and 1,560 MW (or 0.3%) were withdrawn after wholesale market participant agreement (WMPA) execution but before construction. Overall, 20.4% of projects that requested uprates to existing capacity reached commercial operation.

Stakeholders at the June 6, 2023, Interconnection Process Subcommittee meeting approved an issue charge to examine how to enhance transfer of CIRs, which allow new generation to interconnect as a capacity resource, from deactivating resources to new generation. The goal is to develop a solution that both improves the efficiency of the process and clarifies that it applies to all energy-injecting capacity resource types. The existing provisions in the PJM Tariff, and related defined terms included in the Reliability Assurance Agreement (RAA), governing the CIR transfer process will be clarified to reduce confusion as to which capacity resource types the transfer process applies.

PJM's existing installed capacity reflects a fuel mix consisting of approximately 48% natural gas, 22% coal, and 18% nuclear. Hydro, wind, solar, oil, and waste fuels constitute the remaining 12%. A diverse generation portfolio reduces the system risk associated with fuel availability and reduces dispatch price volatility. Totaling nearly 125,000 MW of CIRs, renewable and hybrid fuels are changing the landscape of PJM's interconnection process. Solar energy makes up 40% of the new service requests in PJM's generation interconnection queue. State policies encouraging renewable generation are contributing to the rise in solar generation interconnection requests.

PJM's review of recent policies indicates over 32 GWs of potential deactivations through 2034. The pace of retirements is being driven in large part by state laws and federal environmental initiatives that create a clear near-term, date-certain requirement for generators to comply or retire. See *Energy Transition in PJM: Resource Retirements, Replacements, and Risks* (February 2023). Conversely, there are multiple mandates with RPS that account for the majority of over 150 GWs in submitted projects. Growing levels of intermittent and limited duration resources, such as wind, solar, and battery storage, do not replace conventional large-scale generation installations megawatt-for-megawatt but rather require multiple megawatts to replace one megawatt of dispatchable generation due to their limited availability in certain hours of the day and seasons of the year. Many megawatts from a range of generation technologies, available at different times, are required to replace a megawatt of thermal generating capacity. Looking out over the next 8 to 10 years of the energy resource transition, maintaining an adequate level of generation resources with operational and physical characteristics that support reliability will be crucial for PJM's ability to serve electrical demand reliably.

Energy Storage

Energy storage development continues in PJM. As solar generation increases in PJM, growth of storage is expected to follow since storage devices are frequently co-located with solar projects. Efficient grid operations in an era of rapid renewable energy resource growth will require greater system flexibility. Energy storage can offer grid operators another tool to maintain stable power supply under varying wind and solar power output driven by weather conditions or unit outages. Storage can also improve grid efficiency by increasing utilization of existing transmission lines. PJM continues to work with members, Department of Energy (DOE) national laboratories, and other industry entities to advance the use of energy storage and, in particular, enable its participation in PJM markets.

Today, there are approximately 177 GWs of solar, wind, battery, and hybrid in the PJM interconnection queue. Hybrid resources make up approximately 26 GWs and standalone storage makes up approximately 28 GWs.

Some developers are pairing storage with variable, renewable generation, such as solar 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 hybrid (in which the storage facility and generator share a common connection to the grid).

Capacity Transfers

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

PJM's Regional Transmission Expansion Plan (RTEP) continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. This shift is characterized by new wind and solar generating units driven by federal and state renewable incentives, generating plant deactivations, and market impacts introduced by DR and EE programs. As of December 31, 2023, renewable resources continue to represent a significant portion of PJM's new services requests.

The PJM board approved 48 new baseline projects during 2023 at an estimated $6.6 billion to ensure that fundamental system reliability criteria across the grid are met. The board also approved the inclusion of 93 new network transmission projects at an estimated $180 million into the RTEP.

Reliability Issues

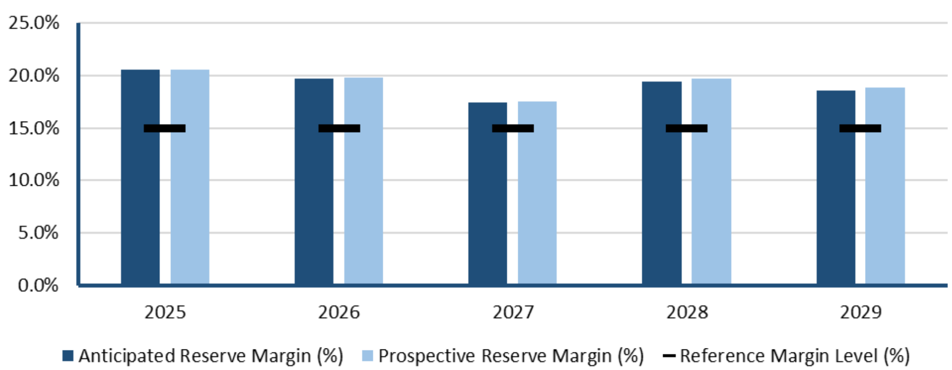
PJM's 2023 *Load Forecast Report* addressed the impact of industry changes that are reshaping system hourly loads. As a result, the level and timing of coincident peak and non-coincident peak demands across PJM have begun to shift. Solar-power penetration, expected impacts of EVs, state electrification programs, home battery storage, and a significant increase in data center loads are markedly increasing the complexity of PJM's load forecasting process. Driven by discrete and localized load growth, like Data Center Alley in Loudoun County, Virginia, in 2022, PJM and stakeholders conducted a review of data center load growth and identified growth rates of over 300% in some instances. As a result, the 2023 PJM *Load Forecast Report* incorporates adjustments to specific zones for data center load growth.

SERC-Central

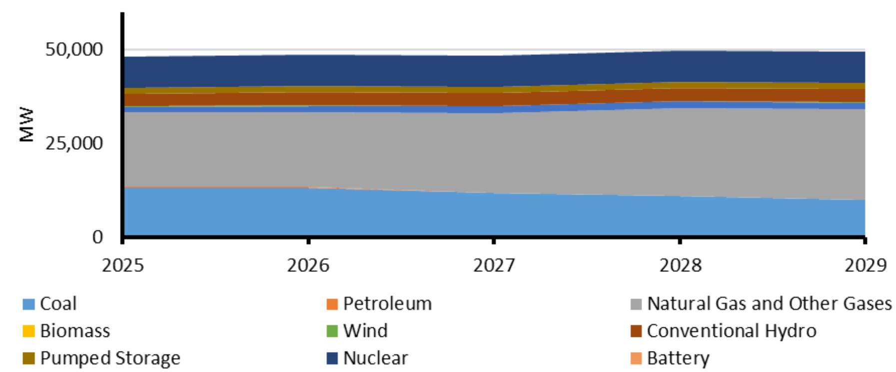
SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under 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 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	42,983	43,202	43,399	43,384	43,440	43,636	43,725	43,913	44,077	44,316
Demand Response	1,859	1,856	1,852	1,849	1,847	1,844	1,842	1,840	1,839	1,837
Net Internal Demand	41,124	41,346	41,547	41,535	41,593	41,792	41,883	42,074	42,239	42,479
Additions: Tier 1	1,123	1,540	2,970	4,983	5,841	5,841	5,841	7,609	8,935	9,598
Additions: Tier 2	20	20	20	120	120	120	120	120	120	120
Additions: Tier 3	135	263	415	1,118	3,395	4,198	4,965	5,368	5,745	6,198
Net Firm Capacity Transfers	1,240	765	190	-288	-288	-288	-288	-287	-287	-287
Existing-Certain and Net Firm Transfers	48,437	47,962	45,813	44,608	43,478	43,191	43,191	42,224	42,224	41,153
Anticipated Reserve Margin (%)	20.5%	19.7%	17.4%	19.4%	18.6%	17.3%	17.1%	18.4%	21.1%	19.5%
Prospective Reserve Margin (%)	20.8%	20.0%	17.7%	19.7%	18.9%	17.6%	17.4%	18.8%	21.4%	19.8%
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

Highlights

- The ARM remains above the 15% target RML for the assessment period.
- Projected coal generation retirements total 4,399 MW in the next 10 years. Resource additions include 6,838 MW of natural gas, 75 MW of BESS, and 760 MW of solar generation over the next 10 years.
- New transmission line additions total 209 miles through 2028. The entities also plan to upgrade 185 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows.

SERC-Central Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	13,348	13,348	11,774	11,047	9,917
Coal*	13,048	13,348	11,146	10,013	8,883
Petroleum	148	148	148	148	148
Natural Gas	19,857	19,857	21,287	23,300	24,158
Natural Gas*	19,476	19,476	20,906	22,919	23,777
Biomass	36	36	36	36	36
Solar	1,338	1,706	1,706	1,706	1,706
Wind	172	172	172	172	172
Conventional Hydro	3,393	3,393	3,393	3,393	3,393
Pumped Storage	1,673	1,673	1,673	1,673	1,673
Nuclear	8,280	8,280	8,280	8,280	8,280
Battery	75	125	125	125	125
Total MW	48,319	48,737	48,593	49,879	49,607
Total MW*	47,639	48,356	47,584	48,464	48,192
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Central Assessment

Planning Reserve Margins
The future reserve margins are above the RML for SERC-Central.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
The 2024 ProbA results shown in the table below indicate negligible unserved energy and load-loss. Analysis of detailed ProbA outputs shows that that this negligible risk occurring in 2026 is associated with hot summer conditions and upper levels of economic load forecast models.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**0.10**	**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%	**13.2%**	**14.9%**

* Provides the 2022 ProbA Results for Comparison

Demand
Drivers of load growth are commercial expansion, electrification of heating and transportation, and growth in residential load. Entities expect to continue to have increased economic growth that will drive both population and employment to the SERC-Central assessment area, but these gains in employment are slightly offset by improvements in efficiency.

Distributed Energy Resources
SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Generation
Projected coal generation retirements total 4,399 MW in the next 10 years. Resource additions include 6,838 MW of natural gas, 75 MW of BESS, and 760 MW of solar generation over the next 10 years.

Generator retirements are carefully managed by entities in the SERC-Central assessment area. Entities perform studies to determine the impacts of confirmed or unconfirmed retirements. Entities incorporate these studies into resource plans that highlight the significance of future generation projects. Additionally, there are no significant retirement plans that will affect reliability.

Capacity Transfers
Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas within the Region for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

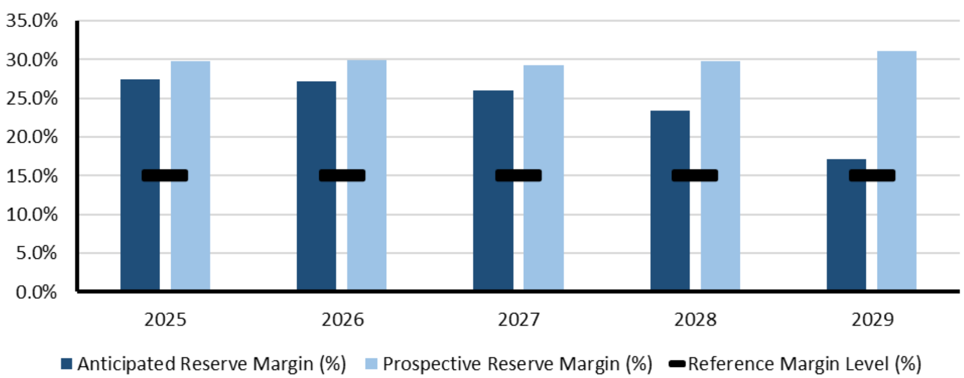
Transmission
The entities reported a total addition of 209 miles of new transmission lines until 2028. The entities are also planning to upgrade 185 miles of transmission lines in the next 10 years to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include 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.

SERC-East

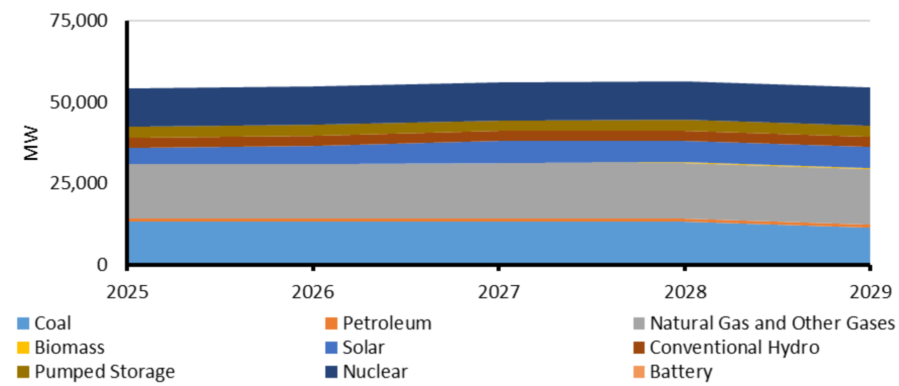
SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible 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 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	44,099	44,789	46,308	47,378	48,286	49,533	50,349	50,896	51,741	52,155
Demand Response	1,092	1,186	1,214	1,225	1,228	1,229	1,230	1,231	1,232	1,233
Net Internal Demand	43,007	43,603	45,094	46,153	47,058	48,304	49,119	49,665	50,509	50,922
Additions: Tier 1	772	1,330	2,777	2,818	2,818	2,818	2,818	2,818	2,818	2,818
Additions: Tier 2	38	217	506	1,975	5,577	8,032	9,766	11,595	13,978	16,767
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	593	593	593	593	593	593	593	593	593	593
Existing-Certain and Net Firm Transfers	54,039	54,129	54,045	54,118	52,301	52,395	51,316	49,998	49,998	48,636
Anticipated Reserve Margin (%)	27.4%	27.2%	26.0%	23.4%	17.1%	14.3%	10.2%	6.3%	4.6%	1.0%
Prospective Reserve Margin (%)	29.8%	30.0%	29.3%	29.8%	31.1%	33.0%	32.1%	31.7%	34.2%	35.9%
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

Highlights

- The ARM remains above the RML until 2030 when it falls below the 15.0% RML level.
- Since the *2023 LTRA*, solar PV resources have grown from 1.5 GW to an expected 4.7 GW by the end of 2024.

SERC-East Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	13,150	13,150	13,150	13,150	11,333
Coal*	13,108	12,564	12,564	11,910	10,093
Petroleum	1,044	1,044	992	992	992
Petroleum*	1,044	1,044	868	868	868
Natural Gas	16,627	16,717	17,061	17,121	17,121
Natural Gas*	16,601	16,691	17,061	17,121	17,121
Biomass	176	176	176	176	176
Solar	4,995	5,553	6,624	6,665	6,665
Conventional Hydro	3,102	3,102	3,102	3,102	3,102
Pumped Storage	3,324	3,324	3,324	3,324	3,324
Nuclear	11,795	11,795	11,795	11,808	11,808
Battery	6	6	6	6	6
Total MW	54,218	54,866	56,229	56,343	54,526
Total MW*	54,150	54,254	55,519	54,979	53,162
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-East Assessment

Planning Reserve Margins
The ARM falls below the RML starting in 2030 for SERC-East. Projected demand is expected to increase around 8.75% from 2024 to 2028 in the footprint.

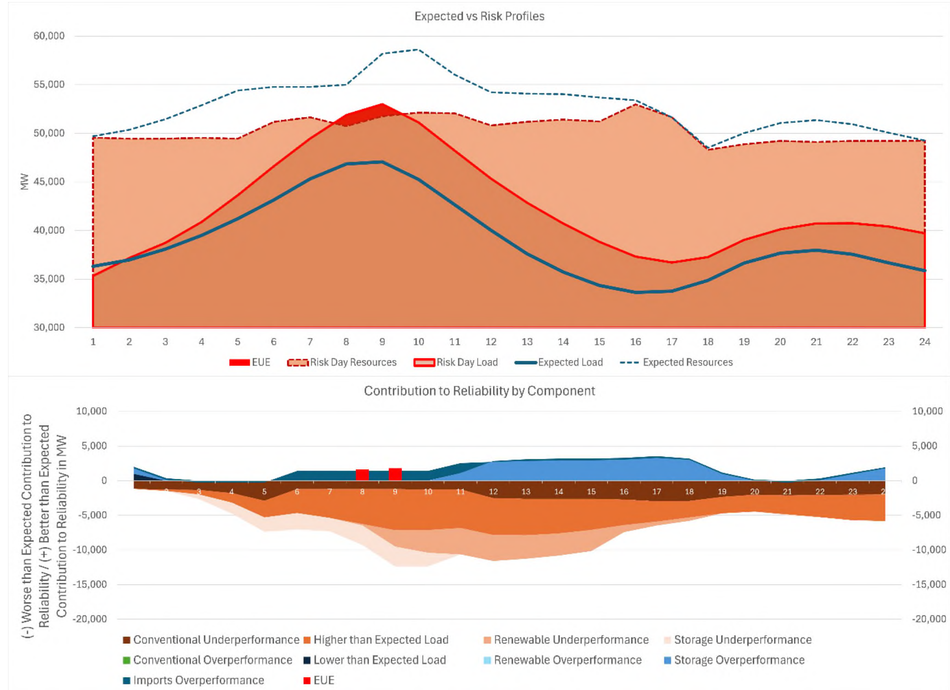
Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
SERC-East has an elevated risk of energy shortages based on results of the 2024 ProbA shown in the table below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	92.49	**143.35**	**207.26**
EUE (PPM)	0.39	**0.60**	**0.81**
LOLH (hours per year)	0.08	**0.09**	**0.17**
Operable On-Peak Margin	16.1%	**14.2%**	**11.1%**

* Provides the 2022 ProbA Results for Comparison

SERC-East has changed from a summer-peaking assessment area to a dual-peaking assessment area, with both a summer and winter peak. The addition of solar PV generation shaves off summer peak demand, and a trend toward electrification of heating drives up winter peak demand. The ProbA results for 2026 indicate some risk for SERC-East in the winter months of January and February. The annual EUE is 143.35 MWh but for a very short, expected duration of 0.09 hours. The risk occurs during winter morning hours around 8:00 a.m. due to a combination of higher loads and solar resources not yet ramped up. For extreme cold weather events that might impact a wide geographical footprint, there is also a limit on imports from neighboring areas.

For 2028, SERC-East continues to show winter risk with 207.26 MWh of EUE and 0.17 hours of LOLH. The load is expected to grow by over 2%. The load-loss events in the analysis are for very few hours and short duration, occur around 8:00 a.m., and are tied to extreme weather, higher forecasted load levels, and lower resource performance. This can be seen in the following figures showing the risk profile and resource performance for a likely event-day.



Demand
Population growth is driving demand forecast increases in SERC-East. Entities expect faster-than-average growth in the urban areas and overall increasing energy and demand in the 10-year forecast. While the economic indicators used in the forecast have growth rates that vary during each year, the economic outlook will contribute to increased energy and demand over the 10-year forecast. Some entities project their EE adoption to impact roughly 1% of annual retail sales (after opt-outs) during the 10-year forecast.

There are also many large commercial/industrial loads accounted for in the forecast that have been announced or in discussions with the entities to locate in the service territory. If the large sites come to fruition, it will drive significant increases in energy and demand during the later part of the 10-year forecast.

The projected EV adoptions are driving energy and demand increases during the later part of the 10-year forecast window. EVs are currently the most significant contributor of all electrification sources (e.g., heating, industrial) in the 10-year forecast.

Distributed Energy Resources

SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Capacity Transfers

Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission

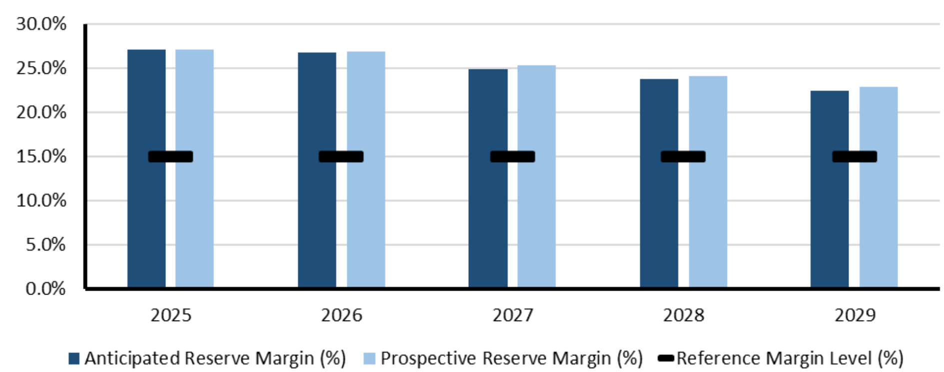
The entities reported a total addition of 286 miles of new transmission lines through 2028. The entities are also planning to upgrade 515 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, 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.

SERC-Florida Peninsula

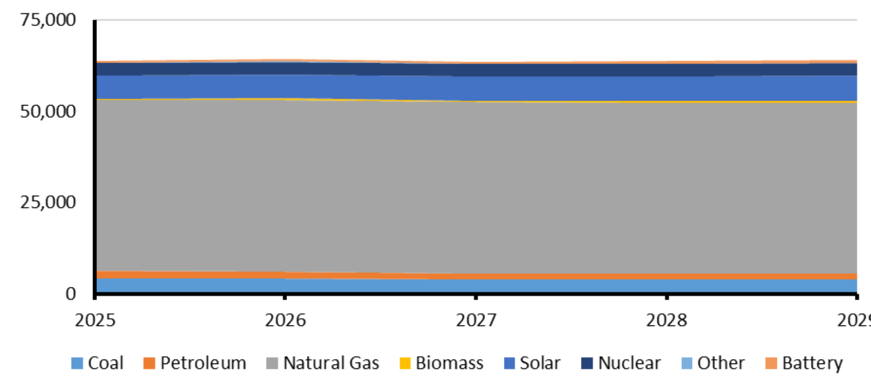
SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across 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 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	53,509	53,795	54,015	54,551	55,250	55,879	56,593	57,612	58,631	59,679
Demand Response	2,840	2,834	2,837	2,820	2,806	2,795	2,783	2,771	2,761	2,748
Net Internal Demand	50,669	50,961	51,178	51,731	52,444	53,084	53,810	54,841	55,870	56,931
Additions: Tier 1	871	1,497	1,573	1,785	2,018	3,421	3,927	4,545	4,547	4,549
Additions: Tier 2	0	40	200	200	200	200	200	200	200	200
Additions: Tier 3	0	39	39	39	39	39	39	39	39	39
Net Firm Capacity Transfers	494	293	293	200	200	200	200	200	200	200
Existing-Certain and Net Firm Transfers	63,521	63,121	62,366	62,230	62,230	61,725	61,725	61,493	61,493	61,493
Anticipated Reserve Margin (%)	27.1%	26.8%	24.9%	23.7%	22.5%	22.7%	22.0%	20.4%	18.2%	16.0%
Prospective Reserve Margin (%)	27.1%	26.9%	25.3%	24.1%	22.9%	23.1%	22.4%	20.8%	18.6%	16.4%
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

Highlights

- The ARM remains above the 15% target RML for the assessment period.
- Projected coal generation retirements total 459 MW in the next 10 years. Tier 1 additions include 484 MW of natural gas, 1,560 MW of BESS, and 1,792 MW of solar generation over the next 10 years.
- New transmission line additions total 668 miles through 2030. The entities also plan to upgrade 256 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows.

SERC-Florida Peninsula Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	4,367	4,367	3,908	3,908	3,908
Coal*	3,341	3,779	2,851	2,851	2,851
Petroleum	1,957	1,852	1,724	1,724	1,724
Petroleum*	1,892	1,786	1,477	1,477	1,477
Natural Gas	46,860	47,012	46,844	46,801	46,801
Biomass	310	310	310	310	310
Solar	6,255	6,635	6,711	6,853	6,997
Nuclear	3,502	3,502	3,502	3,502	3,502
Other	9	9	9	9	9
Battery	638	638	638	708	797
Total MW	63,898	64,324	63,646	63,815	64,048
Total MW*	62,807	63,671	62,343	62,512	62,745
* **Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Florida Peninsula Assessment

Planning Reserve Margins

The ARM is not expected to fall below the RML for any period of the assessment period.

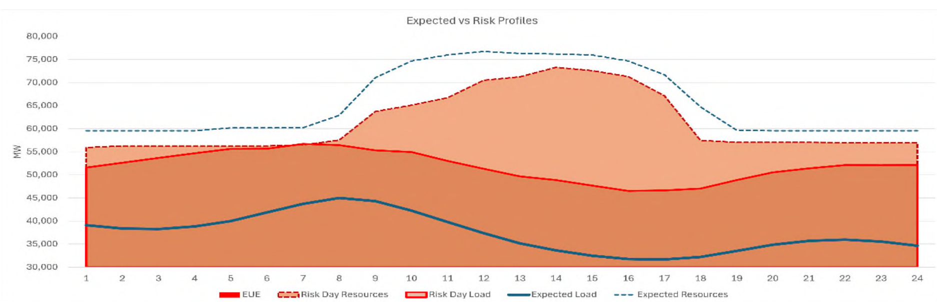
Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

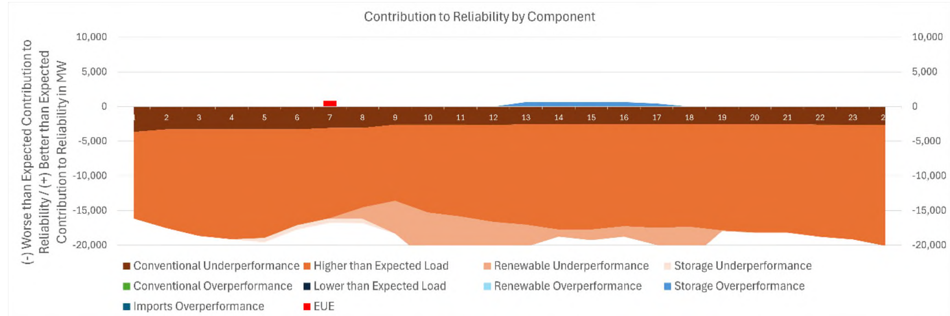
The 2024 ProbA results shown in the table below indicate negligible unserved energy and load loss. Analysis of detailed ProbA outputs shows that that the negligible risk in year 2026 is associated with hot late-summer or early fall conditions, high generator forced outages, and upper levels of economic load forecast models. The risk occurs in evening hours around 7:00 p.m. when contribution from solar generation is limited.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	1.13	**2.18**	**16.28**
EUE (PPM)	0.00	**0.01**	**0.06**
LOLH (hours per year)	0.00	**0.01**	**0.02**
Operable On-Peak Margin	18.6%	**19.2%**	**16.3**

* Provides the 2022 ProbA Results for Comparison

For study year 2028, the ProbA results shows very low risk with 16.28 MWh of EUE and 0.02 LOLH hours. The driver of the risk is mainly extreme winter weather, similar to conditions from 1989, when Florida experienced one of the worst winter freezes on record. With higher load levels and lower resources in 2028, the low risk shifts to late December, occurring in morning hours when contribution from solar generation is limited, and is associated with winter freeze events that limit imports.





Demand

The individual entities within the FL-Peninsula Subregion develop their load forecasts and the Florida Reliability Coordinating Council (FRCC) then aggregates these forecasts to calculate a non-coincident seasonal peak for the subregion. Each entity adjusts their forecasts annually to account for their actual peak demands, updated economic outlooks, population growth, weather patterns, conservation and energy efficiency efforts, and electric appliances usage patterns. Based on the data reported in the 2023 FRCC Regional Load and Resource Plan, the net energy for load (NEL) and summer peak demands are forecasted to grow when compared to previous forecasts. The current average annual growth rate for the NEL is 0.97% per year. Firm summer and winter peak demand growth are expected to increase to 1.19% and 1.17%, respectively.

Demand-Side Management

Controllable DR from interruptible and dispatchable load management programs within the FL-Peninsula Subregion is treated as a load-modifier, and it is projected to be constant at approximately 6% of the summer and winter total peak demands for all years of the assessment period.

Distributed Energy Resources

SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Generation

Generator retirements are carefully managed by entities in the SERC-Florida Peninsula assessment area. Entities perform studies to determine the impacts of confirmed or unconfirmed retirements. Entities incorporate these studies into resource plans that highlight the significance of future generation projects. Additionally, there are no significant retirement plans that will affect reliability.

Energy Storage

Electricity storage (ES) is still a growing capacity contributor in the assessment area. Over the next 10 years, a total of approximately 2,900 MW of ES generation is projected to be in service by 2032 and is included in the utilities' 10-year site plans (approximately 775 MW by 2029).

Individual entities in the assessment area that have installed or are projecting the installation of ES are developing operating protocols on the use and dispatch of these facilities. ES units are studied as part of the normal generation interconnection process and included in other FRCC studies and processes with members providing individual dispatch profiles and study levels in order to identify potential operational impacts.

Capacity Transfers

Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission

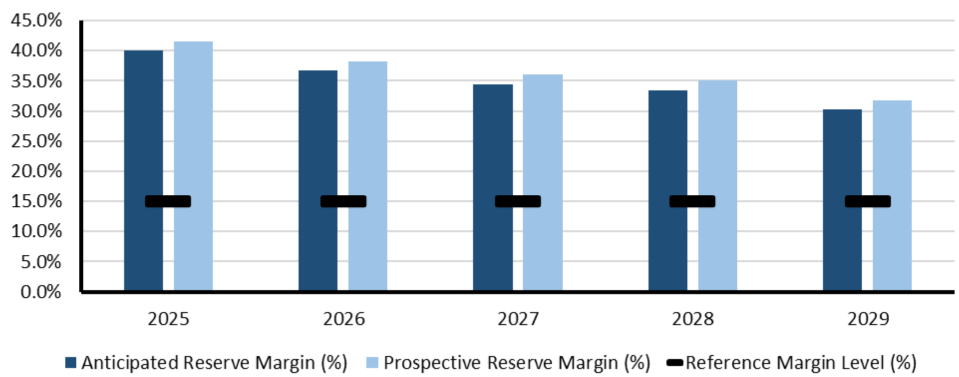
The entities reported a total addition of 668 miles of new transmission lines through 2030. The entities are also planning to upgrade 256 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability.

SERC-Southeast

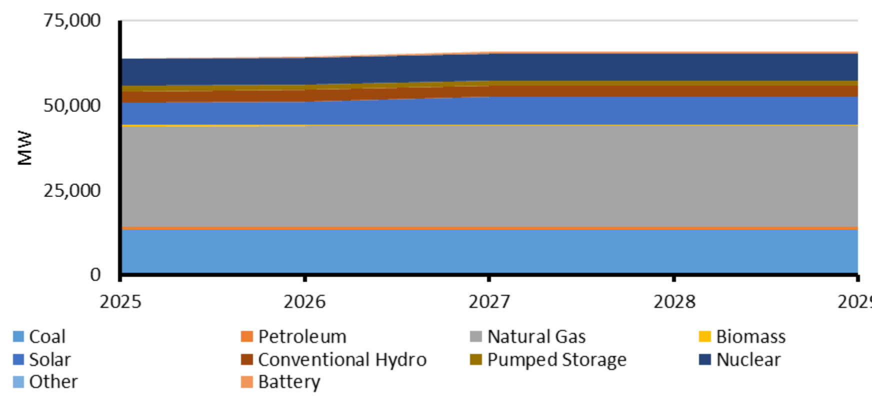
SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. 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 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	46,984	48,384	50,467	50,852	51,974	53,031	53,794	54,233	54,677	55,078
Demand Response	1,633	1,666	1,723	1,755	1,875	1,876	1,875	1,875	1,876	1,876
Net Internal Demand	45,351	46,718	48,744	49,097	50,099	51,155	51,919	52,358	52,801	53,202
Additions: Tier 1	1,248	1,486	3,050	3,050	3,050	3,129	3,129	3,129	3,129	3,129
Additions: Tier 2	105	105	218	218	218	218	218	218	218	218
Additions: Tier 3	366	366	366	366	366	366	366	366	366	366
Net Firm Capacity Transfers	-392	-392	-392	-392	-684	-684	-684	-684	-684	-684
Existing-Certain and Net Firm Transfers	62,257	62,413	62,472	62,472	62,180	62,180	62,180	62,180	62,180	62,180
Anticipated Reserve Margin (%)	40.0%	36.8%	34.4%	33.5%	30.2%	27.7%	25.8%	24.7%	23.7%	22.8%
Prospective Reserve Margin (%)	41.5%	38.2%	36.0%	35.0%	31.7%	29.2%	27.3%	26.2%	25.1%	24.2%
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

Highlights

- The ARM remains above the 15% target RML for the assessment period.

SERC-Southeast Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	13,275	13,275	13,275	13,275	13,275
Coal*	13,275	13,275	12,271	10,321	10,321
Petroleum	915	915	915	915	915
Petroleum*	915	915	915	899	899
Natural Gas	29,639	29,795	29,854	29,854	29,854
Natural Gas*	29,564	29,387	29,446	28,426	28,426
Biomass	424	424	424	424	424
Solar	6,597	6,835	8,021	8,021	8,021
Conventional Hydro	3,293	3,293	3,293	3,293	3,293
Pumped Storage	1,632	1,632	1,632	1,632	1,632
Nuclear	8,018	8,018	8,018	8,018	8,018
Battery	105	105	483	483	483
Total MW	63,897	64,291	65,914	65,914	65,914
Total MW*	63,822	63,883	64,502	61,516	61,516
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Southeast Assessment

Planning Reserve Margins

The future reserve margins are above the RMLs for SERC-Southeast.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

The 2024 ProbA results shown in the table below indicate negligible unserved energy and load loss.

Base Case Summary of Results			
	2026*	2026	2028
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	30.8%	**29.6%**	**25.6%**

* Provides the 2022 ProbA Results for Comparison

Demand

Data centers, cryptocurrency facilities, and large commercial and industrial load are driving demand forecast growth in the assessment area. Metro areas are experiencing a higher growth rate compared to rural areas.

Demand-Side Management

Entities within the SERC-Southeast assessment area use a variety of controllable and dispatchable DR programs to reduce peak demand. One entity manages a voluntary DSM water heater program designed to allow system operators to control the appliances' usage during peak demand periods. Another entity monitors and dispatches DR programs commensurate with 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.

Distributed Energy Resources

SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Generation

Generator retirements are carefully managed by entities in the SERC-Southeast assessment area. Entities perform studies to determine the impacts of confirmed or unconfirmed retirements. Entities incorporate these studies into resource plans that highlight the significance of future generation projects. Additionally, there are no significant retirement plans that will affect reliability.

Capacity Transfers

Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas within the Region for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission

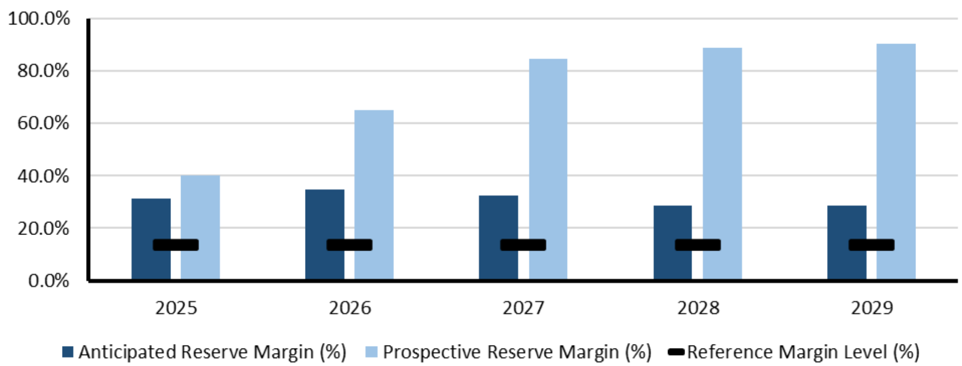
The entities reported a total addition of 1,078 miles of new transmission lines in the next 10 years. The entities are also planning to upgrade 694 miles of transmission lines during this time to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability.

Texas RE-ERCOT

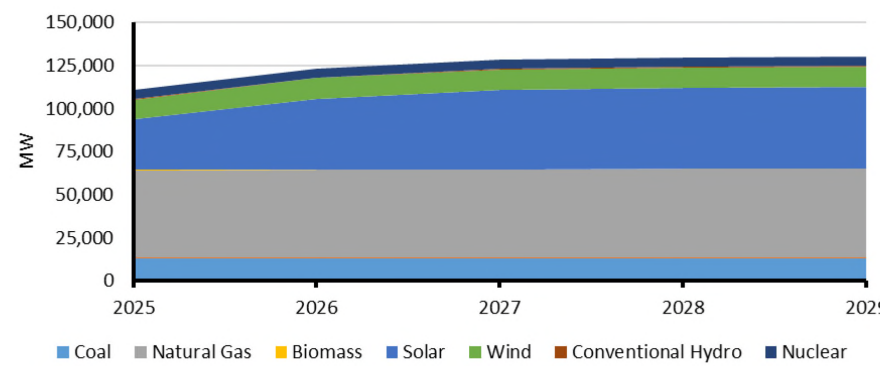
The Electric Reliability Council of Texas (ERCOT) is the ISO for the Texas Interconnection and is located entirely in the state of Texas; it operates as a single BAand performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises 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 and covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,250 generation units, and serves more than 27 million people. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	88,873	95,721	101,405	105,417	106,365	106,951	106,772	106,463	106,062	106,961
Demand Response	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652
Net Internal Demand	86,220	93,069	98,753	102,765	103,713	104,298	104,119	103,811	103,410	104,309
Additions: Tier 1	11,187	23,684	28,725	29,226	29,903	29,903	29,903	29,903	29,903	29,903
Additions: Tier 2	7,281	27,876	51,414	62,225	65,786	65,939	65,939	65,939	65,939	65,939
Additions: Tier 3	7,252	17,627	29,082	41,174	45,318	47,062	47,062	47,062	47,062	47,062
Net Firm Capacity Transfers	20	20	20	20	20	20	20	20	20	20
Existing-Certain and Net Firm Transfers	101,906	101,645	102,003	103,088	103,338	103,338	103,338	103,338	103,338	103,338
Anticipated Reserve Margin (%)	31.2%	34.7%	32.4%	28.8%	28.5%	27.8%	28.0%	28.3%	28.8%	27.7%
Prospective Reserve Margin (%)	40.3%	65.2%	84.6%	88.8%	90.3%	88.8%	89.1%	89.7%	90.4%	88.8%
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

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 (2025–2034). The ARM peaks at 34.7% by Summer 2026, reflecting the expected addition of about 23,680 MW of Tier 1 capacity, most of which is solar PV.
- The Public Utility Commission of Texas (PUCT) established a reliability standard and accompanying reliability assessment process in August 2024. The reliability standard is based on multiple probabilistic reliability measures that capture the different dimensions of loss-of-load events: average event frequency (LOLE), maximum event duration, and maximum event magnitude. ERCOT will begin performing reliability assessments required by the new standard in 2026.
- ERCOT's summer peak demand is forecast to increase by 4.6% per year from 2025 through 2029. In comparison, the five-year summer peak demand growth projection for the *2023 LTRA* was 1.1%. This high growth level is driven by a large amount of newly contracted loads planned for interconnection during this period. These contracted loads are mainly comprised of Permian Basin oil and gas production facilities, data centers, crypto-mining operations, and industrial facilities.

Texas RE-ERCOT Projected Generating Capacity by Energy Source in Megawatts (MW)

	2025	2026	2027	2028	2029
Coal	13,568	13,568	13,568	13,568	13,568
Coal*	13,568	13,568	12,913	12,353	12,353
Petroleum	10	10	10	10	10
Natural Gas	50,568	50,694	50,845	51,458	51,458
Natural Gas*	49,709	49,928	48,823	49,436	49,436
Biomass	163	163	163	163	163
Solar	29,557	41,201	45,984	46,485	47,163
Wind	11,332	11,908	12,166	12,166	12,166
Conventional Hydro	458	458	458	458	458
Nuclear	4,973	4,973	4,973	4,973	4,973
Total MW	110,628	122,975	128,167	129,281	129,958
Total MW*	109,769	122,208	125,490	126,044	126,721

*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.

Texas RE-ERCOT Assessment

Planning Reserve Margins

The summer ARM is above the RML (13.75%) for all 10 years of this assessment period (2025–2034). The ARM peaks at 34.7% by Summer 2026, reflecting the expected addition of about 23,680 MW of Tier 1 capacity, most of which is solar PV. However, the high reserve margin belies concerns over the continuing trend toward less fully dispatchable resources and more IBRs like solar PV and wind. While thermal resource availability and adequate gas supplies are still concerns during extreme winter weather events, the fleet performed well during Winter Storm Heather in January 2024, indicating that new weatherization standards, fully implemented in 2023, are effective.

Non-Peak Hour Risk and Energy Assurance

The PUCT established a reliability standard and accompanying reliability assessment process in August 2024. The reliability standard is based on multiple probabilistic reliability measures that capture the different dimensions of loss-of-load events: average event frequency (LOLE), maximum event duration, and maximum event magnitude. The latter two measures have an "exceedance tolerance," which is the maximum acceptable percentage frequency of loss-of load events that exceed the permissible thresholds based on a probabilistic simulation.

For non-winter months, ERCOT continues to experience the highest reserve scarcity risk during the early evening hours—peaking at hour ending (HE) 9:00 p.m.—based on probabilistic modeling of monthly peak load days. The elevated risk is due to the drop-off in solar generation and continued higher loads during those hours. The summer peak load hour continues to be 5:00 p.m. For winter, the peak load hour is HE 8:00 a.m. Risk modeling indicates elevated reserve scarcity risk for the morning hours (HE 7:00 a.m. to 9:00 a.m.) as well as the early evening hours.

ERCOT is experiencing transmission limitations as a result of load growth and resource development that affect energy delivery. On March 1, 2024, ERCOT introduced four new Interconnection reliability operating limits (IROL) in the South Texas region. This consists of two South Texas import constraints and two South Texas export constraints, which, if violated, could result in a thermal cascading condition. This is the first thermal IROL that could lead to a cascading condition in the Texas RE-ERCOT Region and has been attributed to the increase in generation capacity in South Texas and the rapid load growth in central Texas. To manage the South Texas export constraint, generation in South Texas must be curtailed to maintain transmission line flows below 100% of the impacted lines' thermal ratings. The risk of such curtailments, which is highest for the hours with the highest net peak loads (early evening), is included in the monthly probabilistic reserve risk assessments. ERCOT has approved two San Antonio Reliability projects that are expected to be completed in 2027 and should help alleviate some of risk drivers associated with these IROLs.

Probabilistic Assessment

Results of the 2024 ProbA are shown in the table below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	1,235	**11,090**	**781**
EUE (PPM)	2.63	**18.95**	**1.12**
LOLH (hours per year)	0.30	**1.57**	**0.16**
Operable On-Peak Margin	35.9%	**28.8%**	**46.9%**

* Provides the 2022 ProbA Results for Comparison

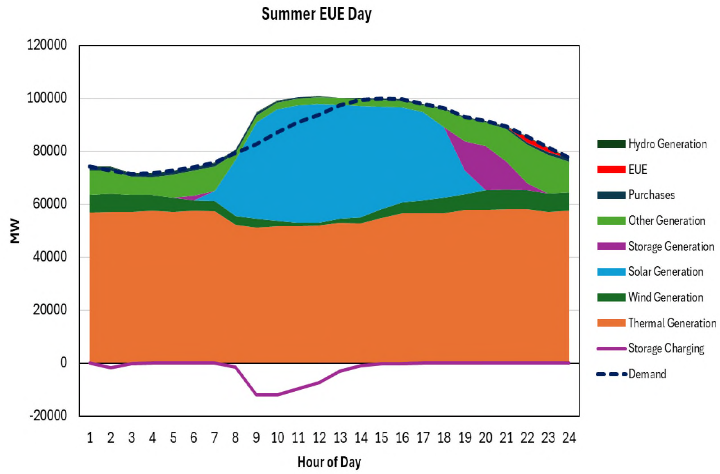
Increasing reliability risk in ERCOT is primarily driven by increasing large load demand anticipated from data centers, Bitcoin operations, continued load growth in oil and gas-producing areas (such as the Permian Basin), and growth in industrial facilities. Over 20 GW of newly contracted large loads, in addition to other organic load growth, is projected to be added to ERCOT by 2028. ERCOT also anticipates 1,860 MW of fossil-fueled plant capacity to be retired by Summer 2028. New planned units are primarily renewable and storage, which exhibit declining marginal reliability contributions. The reliability forecasts provided by this ProbA assessment for 2028 include resource capacity contributions from expansion planning analysis conducted for ERCOT's 2024 *Long-Term System Assessment*. While there is uncertainty around the deployment of these resources, the large load demand growth is also uncertain and large loads are subject to various requirements for being integrated into the grid.

All SERVM simulations for ERCOT and surrounding regions impose all relevant generator temporal constraints, including operating limitations on conventional units as well as state-of-charge on batteries, so this assessment accounts for energy adequacy. However, this assessment does assume fuel for conventional units will be available when needed.[35]

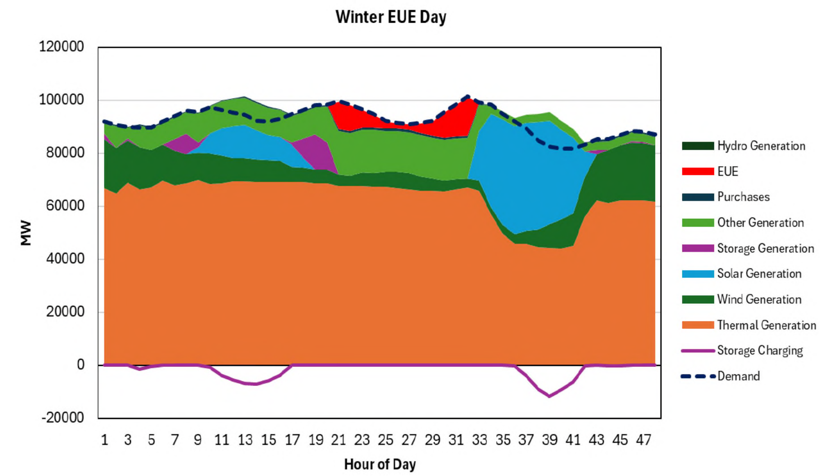
The unique characteristics of winter risk vs. summer risk can be seen in the following charts of a representative risk day. While peak winter loads can persist for 48 hours or longer, peak summer

[35] ERCOT and several other entities used SERVM software tool to perform the ProbA. Information about SERVM can be found at the company's website.

periods generally only last for a few hours. This has significant implications for the duration and depth of firm load-shed events in the winter as well as for the reliability contribution of energy limited and non-dispatchable resources. The most extreme winter event modeled for 2026 was 16 hours in duration and 29 GW in depth. The illustration below indicates a winter EUE event with duration >12 hours while most summer events were 1–2 hours in duration.



Metric	2026 Summer	2026 Winter	2028 Summer	2028 Winter
LOLE (days/year)	0.38	0.51	0.05	0.04
LOLH (hours/year)	1.41	1.57	0.18	0.16
EUE (MWh)	10,985	11,090	857	781
Max Hourly EUE (MWh)	29,124	29,266	17,762	16,851
Max EUE Duration (Hr)	15	16	12	11



From the hourly event data, ERCOT provided a multi-metric summary of the largest event showing the highest magnitude and longest-duration, as shown in the following figure.

Demand

ERCOT's long-term load forecast consists of the following individual components: (1) a base forecast that uses an econometric model with estimation data comprising 15 historical weather years, economic drivers, calendar information, and historical loads, (2) a roof-top PV forecast, (3) an EV forecast, a large flexible load forecast (crypto-mining facilities), and new "large loads" with a signed interconnection contract with their transmission or distribution service provider. Forecasts are provided for eight weather zones as well as system coincidental and non-coincidental demands. ERCOT's summer peak demand is forecast to increase by 4.6% per year from 2025 through 2029. In comparison, the five-year summer peak demand growth projection for the *2023 LTRA* was 1.1%. This high growth level is driven by a large amount of newly contracted loads planned for interconnection during this period. These contracted loads are mainly comprised of Permian Basin oil and gas production facilities, data centers, crypto-mining operations, and industrial facilities. (A negligible amount of new contracted loads reported by transmission service providers occur past 2029). The base peak load, which excludes these new contracted loads as well as load reductions due to rooftop solar installations, grows at a more modest 1.4%.

A major load forecasting change from last year is a new Texas Legislature requirement to include non-contracted loads in transmission planning studies. Non-contracted loads lack a signed Interconnection or facility expansion agreement. ERCOT's previous practice had been to exclude these more speculative loads from the load forecast. The non-contracted loads total about 3.6 GW for summer 2025 and reach about 31.7 GW by 2029. The non-contracted loads are not included in the LTRA's peak load forecast. ERCOT is evaluating how these non-contracted forecasted loads will be handled for future resource adequacy and other planning activities.

Demand-Side Management

Most of the demand-side resources available to ERCOT are dispatchable in the form of noncontrollable load resources providing responsive reserve service and ERCOT's Emergency Response Service. The ERCOT Emergency Response Service consists of 10- 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 provided by industrial loads and is procured on an hourly basis in the day-ahead market. During 2023, load resources started to participate in two other ancillary services, the Non-Spinning Reserve Service and ERCOT Contingency Reserve Service (ECRS), which are used to help balance the system during periods when there may be net-load ramps that cannot be met with conventional supply-side resources.

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 residential loads during energy emergency alert events.

Distributed Energy Resources

DERs that register with ERCOT to participate in wholesale energy and/or ancillary services markets are modeled and dispatched in ERCOT transmission planning studies similarly to transmission-connected resources participating in those markets. For DERs not participating in those markets, ERCOT relies on member TDSPs to provide information about individual DERs on their systems for shorter-term reliability and economic impact studies, typically a one-to-six-year timeframe.

A bill was approved in the 88th Texas Legislature (HB 3390) that outlines new DER reporting responsibilities. The bill authorizes ERCOT to require TDSPs to provide unregistered DER information that ERCOT deems necessary for grid reliability assessment. ERCOT is now developing annual data collection and maintenance processes.

A multi-phase aggregated DER (ADER) pilot program was implemented in 2022. As of May 2024, there were two ADERs with 13 MW of dispatchable capability actively participating in the pilot project with another nine ADERs in various stages of registration/qualification.

Generation

Natural-gas-fired generation makes up approximately 45% of the available generation inside the ERCOT footprint. Approximately 6% of the natural-gas-fired generation demonstrates firm fuel capabilities as part of ERCOT's Firm Fuel Supply Service required by the PUCT.

ERCOT has established formal working relationships with grid generators' fuel suppliers to gather operational and delivery information useful for its control room operators. ERCOT has focused the efforts on two fronts: (1) obtaining real-time (or near real-time) information on the health of the natural gas systems that serve the generators and (2) maintaining communication with pipelines to notify ERCOT of any planned or unplanned events that could impact deliveries to generators.

After the 2021 Odessa event, ERCOT intensified its efforts to find corrective measures to enhance the ride-through performance of IBRs and improve overall system resilience. The study, which recommended installing synchronous condensers at six locations in West Texas, has been completed, and the ERCOT board of directors endorsed the project in December 2023. The project is expected to be in service in 2027.

ERCOT has proposed new grid code requirements for IBRs to improve voltage ride-through (VRT) performance to align with IEEE Standard 2800. The proposed grid code requirements are continuing to go through ERCOT's stakeholder approval process. Until new rules go into effect, IBRs will be expected to maximize VRT capability and address existing performance failures (such as by reducing maximum output).

To provide an incentive to build new dispatchable resources, the PUCT adopted a new rule to establish a generation loan program, one of four incentive programs under the recently established Texas Energy Fund (TEF). The other three programs within the TEF include completion bonus grants for new dispatchable generation projects that consistently provide power generation over a 10-year period, grants for companies to establish or secure backup power resources, and grants to improve the resiliency and availability of electric utility service outside the ERCOT region. The TEF has $5 billion available for all four programs. These loans and grants have thus far resulted in 72 applications seeking funding under the TEF loan program. The PUCT staff-recommended portfolio represents 9,781 MW in potential new generation if all recommended applicants were to execute a loan agreement at the requested loan amounts.

Energy Storage

The current installed BESS capacity is 9,149 MW. These systems participate in ERCOT's Energy and Ancillary Service markets. Most have durations in the one-to-two-hour range. ERCOT is seeing an increase in longer-duration systems (three to four hours) to take advantage of energy-shifting and capacity-firming opportunities arising from continued high renewable generation penetration. For the first half of 2024, energy storage provided 87% of ERCOT's regulation up and 91% of responsive reserve service from primary frequency response (RRS-PFR). In June 2023, ERCOT implemented a new ancillary service, the ERCOT Contingency Reserve Service (ECRS), which, in part, is designed to address the ramping needs of the system. This ancillary service product provides additional opportunities for BESS ancillary service participation. To support larger BESS penetration levels, ERCOT submitted new proposed rules for state-of-charge accounting in energy dispatch and reliability unit commitment that are planned for implementation this year.

Based on the latest developer information for projects that are in the interconnection queue, ERCOT expects about 10,500 MW of additional battery energy storage capacity to be operational by year-end 2025. This capacity constitutes projects for which developers have posted financial security to build the interconnection facilities. By year-end 2029, the additional cumulative Tier 1 planned capacity reaches about 20,000 MW.

ERCOT currently assigns a 0% on-peak contribution for battery energy storage. ERCOT has changed its rule to adopt an ELCC methodology for battery storage of various durations. Extending the proposed ELCC methodology for BESS to current and forecasted resources in ERCOT would improve the anticipated reserve margins in the future.

Capacity Transfers

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

In September, the PUCT approved ERCOT's Permian Basin Reliability Plan. The plan consists of new and upgraded local transmission projects as well as building new import paths to load centers in other areas of the Texas RE-ERCOT region, including options for extra high voltage (EHV) infrastructure operating at 345 kW or 765 kV. The plan supports Permian Basin load growth that is currently expected to reach 24 GW by 2030 and over 26 GW by 2038.

ERCOT's 2023 Regional Transmission Plan (RTP) identified 173 reliability projects, with the majority consisting of 138 kV and 345 kV system upgrades. The 2023 RTP also included an economic assessment of the ERCOT transmission system for years 2025 and 2028 using production cost savings and generator revenue reduction tests.

The substantial increase in new loads from a year ago is expected to present challenges for transmission planning. The forecasted pace of the load growth could exceed the pace at which transmission capacity can be built to support it. ERCOT is working on major changes to its transmission planning process to address these challenges. For example, ERCOT is investigating a "generation hub" concept to indicate optimal generation location to address regional load growth and optimize transmission investments.

A new biennial report on grid resiliency—the Grid Reliability and Resiliency Assessment—evaluates extreme weather scenarios considering different levels of thermal and renewable generation availability and the potential outages caused by extreme weather conditions. The assessment also includes proposed transmission projects that may mitigate regional resiliency risks. The first report will be released by December 31, 2024.

New minimum deliverability criteria were included in ERCOT's 2023 RTP to ensure the deliverability of 100% of generation resource capacity and energy storage resources with a duration greater than or equal to two hours. For storage systems with a duration less than two hours, a prorated deliverability was ensured. Corrective action plans (CAP) were proposed to address any reliability violations under the contingencies defined for the minimum deliverability criteria.

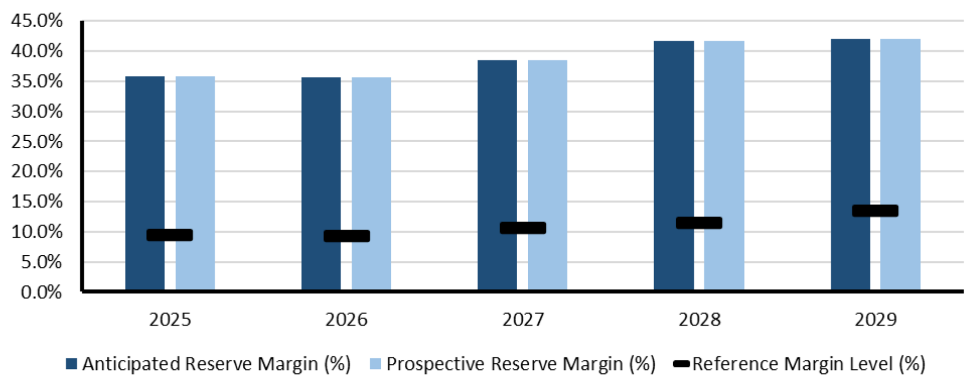
ERCOT has also started implementing the PUCT's amended rules relating to certification criteria and is in the process of integrating a new congestion cost savings test for economic projects evaluation.

WECC-AB

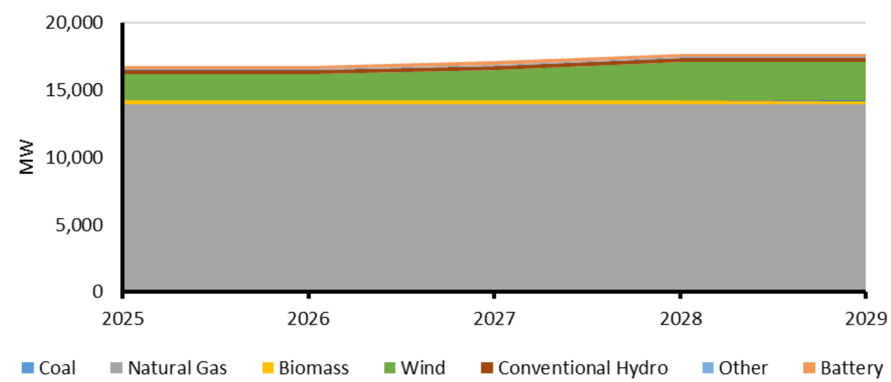
WECC-AB (Alberta) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 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 BC in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	12,411	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	12,411	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076
Additions: Tier 1	3,275	3,275	3,405	3,541	3,537	3,342	3,537	3,441	3,273	3,273
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	1,031	1,680	1,824	2,247	2,700	2,502	3,068	3,096	2,744	2,744
Net Firm Capacity Transfers	43	96	69	0	68	396	409	0	0	0
Existing-Certain and Net Firm Transfers	13,578	13,631	13,822	14,182	14,244	13,931	14,585	13,867	13,330	13,330
Anticipated Reserve Margin (%)	35.8%	35.6%	38.5%	41.7%	41.9%	35.4%	41.2%	33.6%	27.8%	27.0%
Prospective Reserve Margin (%)	35.8%	35.6%	38.5%	41.7%	41.9%	35.4%	41.2%	33.6%	27.8%	27.0%
Reference Margin Level (%)	9.4%	9.4%	10.6%	11.5%	13.6%	9.2%	13.2%	11.3%	9.0%	9.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML during the 2024–2034 timeframe.
- The peak hour of demand for Alberta occurs in the winter. The peak hour for total internal demand is expected to grow from about 12.3 GW in 2024 to 13.1 GW in 2034, a 6.5% load growth over the forecast horizon. The average year-to-year growth rate is 0.62%. There is a slight increase in the load forecast for this year's LTRA versus last year's.
- Despite low resource adequacy risk, operational risk is still present. Ensuring sufficient frequency response capability has been identified as the region's highest priority. Frequency response has been declining in the region due to the increasing share of IBR resources and declining baseload resources. This under frequency load shedding risk is exacerbated in islanded or near-islanded situations.
- Alberta's two remaining coal-fired generators completed their conversion to natural gas this year.

WECC-AB Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Natural Gas	13,932	13,932	13,941	13,930	13,920
Biomass	336	336	336	336	336
Wind	1,912	1,912	2,232	2,811	2,799
Conventional Hydro	285	285	303	302	312
Other	81	81	81	81	81
Battery	264	264	264	264	263
Total MW	16,810	16,810	17,157	17,723	17,713

WECC-AB Assessment

Planning Reserve Margins
The ARM does not fall below the RML during the 2024–2034 timeframe. From the 2032–2033 winter onward, Alberta shows a shortfall of existing-certain and net firm transfers. This indicates that imports may be necessary during this timeframe if new resources were to be significantly delayed.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based 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 (ODITY) 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 .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

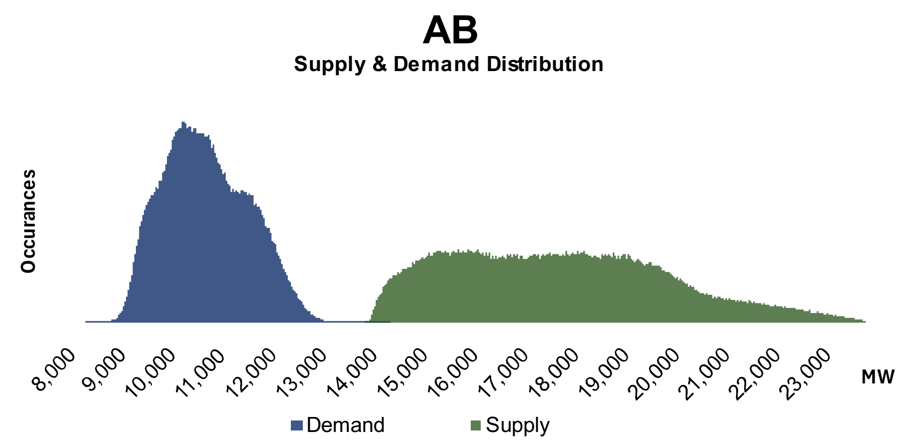
Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0	0	0
EUE (PPM)	0	0	0
LOLH (hours per year)	0	0	0
Operable On-Peak Margin	26.1%	41.6%	42.4%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the Multi-Area Variable Resource Integration Convolution (MAVRIC) model. The MAVRIC 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. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment. WECC also produces an annual reliability assessment called the *Western Assessment of Resource Adequacy* (WARA).[36]

The availability and demand distributions in the ProbA simulations do not overlap, indicating an extremely low probability of Alberta not being resource adequate over the next four years. For 2026 and 2028, the peak hour occurs in December at HE 18:00. Alberta does not show LOLH nor EUE in the LTRA forecast horizon. The gap between the demand distribution and the supply distribution shown in the figure below emphasizes that there is minimal resource adequacy risk in Alberta. The ARM appears to further validate this, as it is far above the RML for 2026 and 2028.



Demand
Peak demand for Alberta occurs in the winter. The peak hour for total internal demand is expected to grow from about 12.3 GW in 2024 to 13.1 GW in 2034, a 6.5% load growth over the forecast horizon. The average year-to-year growth rate is 0.62%. There is a slight increase in the load forecast for this year's LTRA versus last year's. Near-term load growth is driven by industrial loads, such as oil sands production, pulp and paper mills, and gas and oil processing. Long-term demand growth is driven by electrification of transportation and buildings as well as potential growth in emerging industries, such as hydrogen production.

[36] See WECC Reliability Assessments.

Distributed Energy Resources

BTM DERs are difficult to measure due to data gathering barriers. AESO released its updated 2022 Plan for DER Roadmap Integration Activities.

Generation

Over 6 GW of nameplate capacity are being added in Alberta through the end of 2028. There is significantly more solar, wind, and energy storage in this year's planned capacity additions than in the last LTRA. Additionally, several states and provinces in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions. Alberta's two remaining coal units have been converted to natural gas this year.

Energy Storage

Energy storage is being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage, but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers

In WECC's analysis, Alberta is not showing significant changes to capacity transfers. There is a slight increase in exports between 5:00 p.m. and 10:00 p.m. and in the later years of the assessment period.

Reliability Issues

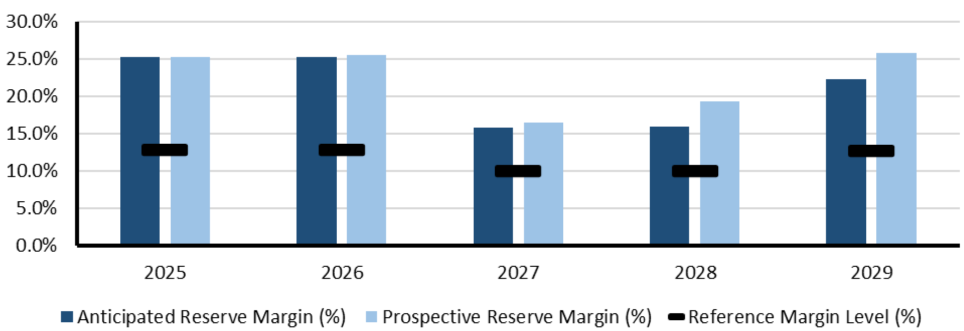
WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

WECC-BC

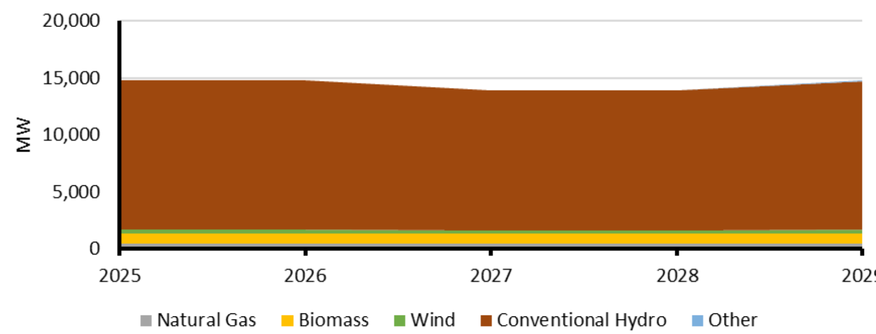
WECC-BC (British Columbia) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of BC, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 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 BC in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	11,986	11,959	12,015	11,983	12,075	12,082	12,130	12,174	12,237	12,305
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,986	11,959	12,015	11,983	12,075	12,082	12,130	12,174	12,237	12,305
Additions: Tier 1	956	956	893	893	956	956	956	956	893	956
Additions: Tier 2	0	41	79	398	419	748	1,077	1,077	1,012	1,405
Additions: Tier 3	0	5	5	5	6	6	59	59	56	59
Net Firm Capacity Transfers	184	188	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	14,054	14,022	13,019	12,998	13,812	13,795	13,795	13,795	12,982	13,795
Anticipated Reserve Margin (%)	25.2%	25.2%	15.8%	15.9%	22.3%	22.1%	21.6%	21.2%	13.4%	19.9%
Prospective Reserve Margin (%)	25.2%	25.6%	16.5%	19.2%	25.8%	28.3%	30.5%	30.0%	21.7%	31.3%
Reference Margin Level (%)	12.8%	12.8%	10.0%	10.0%	12.7%	12.7%	12.6%	12.6%	9.8%	12.5%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML during the 2024–2034 timeframe.
- BC shows a shortfall of existing-certain and net firm transfers for the 2027–2028 winter and the 2028–2029 winter. Shortfalls are also projected from the winter of 2033–2034 onward. This indicates that imports may be necessary during these periods if new resources were to be significantly delayed.
- The peak hour of demand for BC occurs in the winter. BC shows the lowest demand growth rate in the west. The peak demand is expected to grow from about 12.0 GW in 2024 to 12.3 GW in 2034, slightly less than in the previous LTRA forecast. This is an average annual growth rate of 0.28%, and a 2.8% load growth over the forecast horizon.
- BC is showing hours of demand at risk that are not fully mitigated by the addition of Tier 3 resources. Supply chain performance will play a significant role in BC's ability to reliably meet energy needs. Seasonal and daily fluctuations of hydro resource availability is also a risk. LOLH and EUE correlate with periods when river flows are at their lowest.

WECC-BC Projected Generating Capacity by Energy Source in Megawatts (MW)

	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Natural Gas	459	459	456	456	459
Biomass	920	920	914	914	920
Wind	279	279	268	268	279
Conventional Hydro	13,145	13,110	12,253	12,232	13,087
Other	22	22	22	22	22
Total MW	14,825	14,790	13,912	13,891	14,768

WECC-BC Assessment

Planning Reserve Margins

The ARM does not fall below the RML during the 2024–2034 timeframe. BC shows a shortfall of existing-certain and net firm transfers for the 2027–2028 winter and the 2028–2029 winter. Shortfalls are also projected from winter of 2033–2034 onward. This indicates that imports may be necessary during these periods if new resources were to be significantly delayed.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based 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 ODITY 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 .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk in 2026. In 2028, however, WECC's analysis identified over five hours where resources, including imports from neighbors, fall below margins for system reliability.

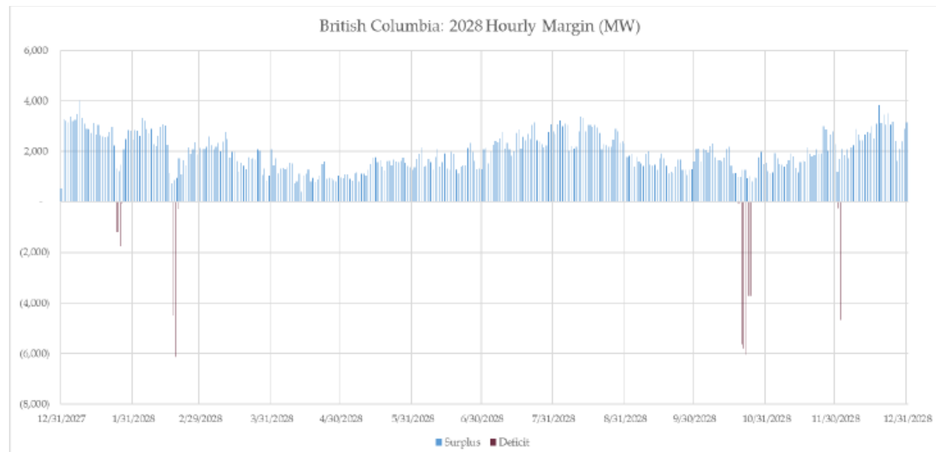
Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	24	0	103,132
EUE (PPM)	0.71	0	1,457
LOLH (hours per year)	0.002	0	5.52
Operable On-Peak Margin	12.7%	16.9%	9.4%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC 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. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment, as well as WECC's WARA.

For both 2026 and 2028, the peak hour occurs in December at HE 19:00. LOLH and EUE are not forecast in 2026 but do appear in 2028. No LOLH or EUE occurs at the peak hour. 88% of the EUE in 2028 occurs overnight between the hours of 23:00 and 4:00.

In 2026, the peak summer hour is HE 17:00 in September, and in 2028 the peak hour is HE 17:00 in August. There is no LOLH projected for 2026 or during peak hours. LOLH occurs in 2028 between the hours of 17:00 and 20:00.



Icicle Plot with Hourly Surplus and Deficits for British Columbia in 2028

WECC's interconnection-wide analysis simulates the probabilistic performance of resource types using historic hourly output data to identify future risk periods. Operators of systems with large hydroelectric storage facilities make adjustments to generation based on the level of demand and shape the water use within the day, week, month, or between years. These actions help posture hydroelectric generation for expected conditions and can reduce energy shortfall risks.

	1	2	3	4	5	6	7	8	9	10	11	12
0	(0)	(5)	-	-	-	-	-	-	-	(10)	-	-
1	(1)	(5)	-	-	-	-	-	-	-	(12)	-	-
2	(1)	(6)	-	-	-	-	-	-	-	(20)	-	-
3	(3)	(5)	-	-	-	-	-	-	-	(14)	(0)	-
4	(0)	(1)	-	-	-	-	-	-	-	(0)	(0)	-
5	-	(0)	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	(0)	-	-
8	-	(0)	-	-	-	-	-	-	-	(0)	-	(0)
9	(0)	(0)	-	-	-	-	-	-	-	-	-	(0)
10	-	(0)	-	-	-	-	-	-	-	-	-	(0)
11	-	-	-	-	-	-	-	-	-	-	-	(1)
12	-	-	-	-	-	-	-	-	-	-	-	(3)
13	-	(0)	-	-	-	-	-	-	-	-	-	(5)
14	-	-	-	-	-	-	-	-	-	-	-	(1)
15	-	(0)	-	-	-	-	-	-	-	-	-	(0)
16	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-	-	-	-	-
19	-	-	-	-	-	-	-	-	-	-	-	-
20	-	(0)	-	-	-	-	-	-	-	-	-	-
21	-	(0)	-	-	-	-	-	-	-	-	-	-
22	-	(0)	-	-	-	-	-	-	-	(0)	-	(0)
23	-	(2)	-	-	-	-	-	-	-	(5)	-	-

2028 Heat Map EUE (GW) - British Columbia

Demand

BC's average annual load growth in its forecast has fallen to a rate below Alberta's. The peak hour total internal demand for BC occurs in the winter. The peak demand is expected to grow from about 12.0 GW in 2024 to 12.3 GW in 2034, slightly less than in the last forecast. This is an average annual growth rate of 0.28% and a 2.8% load growth over the forecast horizon. BC's load growth is lower due to updated monthly profiles that reflect current trends and aggressive DSM which it includes as a demand reduction in the demand forecasts provided to WECC. Load growth in BC is primarily driven by EV and gas sector load growth and is partially offset by a decline in demand from the forestry sector.

Distributed Energy Resources

BTM DERs are difficult to measure due to data-gathering barriers. BC Hydro has net metering. Net metering for residential and commercial customer projects are up to 100 kW. The net metering program has no annual energy volume target.

Generation

Across WECC, several states and provinces as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

In BC, hydro and wind resources are being added to the system. The BC Hydro Authority (BCHA) is taking steps to mitigate risks associated with climate change by improving coastal watershed inflow forecasting to an hourly level and increasing investment in capital projects to increase the resiliency of its hydro-dominant portfolio. Drought conditions in BC have led to water conservation measures, such as encouraging generation at facilities located in less drought-impacted areas, revising discharge plans at storage capable sites, and importing power when available to reduce water consumption.

Capacity Transfers

WECC's probabilistic analysis indicates that BC's need for imports is increasing during the assessment period.

Transmission

Three transmission projects with voltage design of 500 kV and higher are planned in the BC region.

Reliability Issues

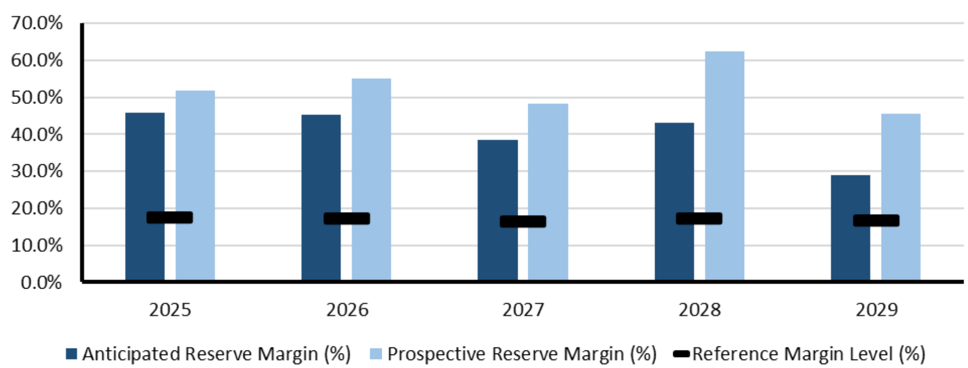
WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

WECC-CA/MX

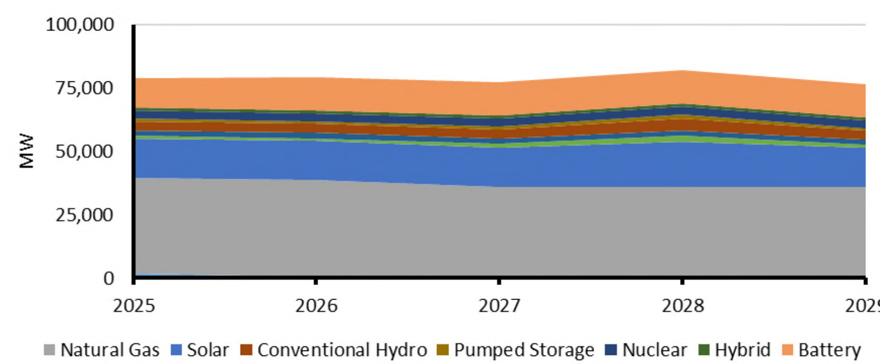
WECC-CA/MX (California/Mexico) is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, 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 82 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, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	56,619	57,274	59,291	60,131	61,289	61,067	62,336	65,876	67,251	69,064
Demand Response	795	797	793	793	793	794	794	794	794	794
Net Internal Demand	55,824	56,477	58,499	59,338	60,496	60,273	61,542	65,082	66,457	68,269
Additions: Tier 1	9,700	11,074	11,128	11,546	11,074	11,990	11,990	12,437	12,047	11,990
Additions: Tier 2	3,349	5,628	5,727	11,483	10,121	17,017	17,017	22,135	23,212	24,650
Additions: Tier 3	9	19	19	22	19	321	321	326	322	321
Net Firm Capacity Transfers	1,509	1,828	2,760	1,953	448	357	342	898	317	314
Existing-Certain and Net Firm Transfers	71,707	70,921	69,827	73,373	66,866	66,142	63,916	68,939	64,533	63,888
Anticipated Reserve Margin (%)	45.8%	45.2%	38.4%	43.1%	28.8%	29.6%	23.3%	25.0%	15.2%	11.1%
Prospective Reserve Margin (%)	51.8%	55.1%	48.2%	62.5%	45.6%	57.9%	51.0%	59.0%	50.2%	47.3%
Reference Margin Level (%)	17.4%	17.4%	16.4%	17.4%	16.6%	16.4%	16.1%	16.3%	14.9%	15.3%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM falls below the RML in Summer 2034, but the RML is covered by the PRM, which includes Tier 2 resource additions.
- Starting in Summer 2029 onward, CA/MX shows a shortfall of existing-certain and net firm transfers. However, with planned generation resource additions the shortfalls are eliminated. Imports may be necessary if the new resources were to be significantly delayed. LOLH and EUE are mitigated over the assessment horizon with the addition of Tier 2 resources and primarily correspond with the evening down ramp of solar and lingering demand after peak.
- The peak hour of demand for CA/MX occurs in the summer. Total internal demand at peak hour is expected to grow from about 56.4 GW in 2024 to 69.1 GW in 2034, a 22.5% load growth over the forecast horizon. The average annual growth rate is 2.07%.
- Diablo Canyon, a 2.2 GW nuclear site, will no longer be retired by 2025 and is now slated to be retired in 2030.

WECC-CA/MX Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	1,572	466	466	465	466
Coal*	1,122	16	16	15	16
Petroleum	185	185	185	184	185
Natural Gas	38,180	38,180	35,565	35,504	35,506
Biomass	726	726	727	726	726
Solar	15,464	15,464	15,501	17,990	15,464
Wind	1,158	1,158	1,428	2,144	1,158
Geothermal	2,004	2,059	2,061	2,056	2,059
Conventional Hydro	3,582	3,582	3,838	4,727	3,582
Pumped Storage	889	889	951	1,710	889
Nuclear	3,282	3,282	3,287	3,283	3,282
Hybrid	32	32	34	39	32
Other	32	32	32	32	32
Battery	12,792	14,111	14,119	14,106	14,111
Total MW	79,898	80,166	78,194	82,967	77,492
Total MW*	79,448	79,716	77,744	82,517	77,042
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

WECC-CA/MX Assessment

Planning Reserve Margins

The ARM falls below the RML in the summer of 2034. With the addition of Tier 2 resources, reserve margins remain above RML. Starting in Summer 2029 onward, CA/MX shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed.

The California Independent System Operator (CAISO) is responsible for much of the BPS that is in CA/MX. CAISO manages the transmission system, oversees transmission planning, and operates the wholesale electricity market for its territory. Other entities in CA/MX include the Balancing Authority of Northern California (BANC), the Imperial Irrigation District (IID), and Mexico's National Center for Energy Control (CENACE), which operates the connected Baja California system.

CAISO Only: The ARM falling below the RML in Summer 2034 and the shortfall of existing-certain and net firm transfers in Summer 2029 is consistent when looking at CA/MX or solely at CAISO. The RML of CAISO averages 0.7% higher than the CA/MX region RML over the LTRA horizon. This is due to the exclusion of natural gas and coal resource energy contributions from CA/MX entities outside of CAISO. Decreasing baseload generators results in increased variability, which in turn requires a greater RML to maintain the ODITY threshold. However, the gap between the anticipated, prospective, and existing reserve margins and the RML for CAISO are greater than the broader CA/MX region. The proportion of energy availability to anticipated net internal demand is larger for CAISO, accounting for this increase.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC 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. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment, as well as WECC's WARA.

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 ODITY 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 .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

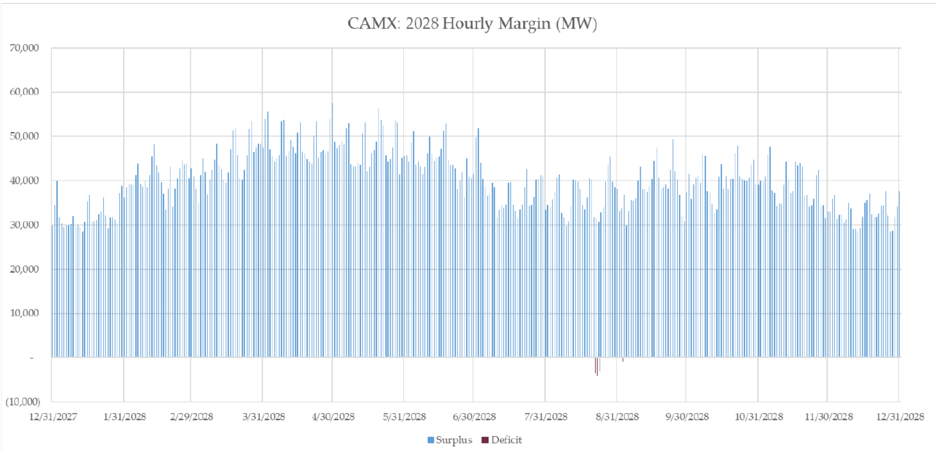
Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk in 2026. After 2026, however, WECC's analysis identified periods of unserved energy and load loss in CA/MX during June through October. Of note, this risk is limited to the Mexico portion of CA/MX (i.e., ProbA results for the CAISO do not indicate LOLH or EUE) until 2029, when the risk extends across the entire assessment area.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	37,305	0	19,662
EUE (PPM)	136	0	70.07
LOLH (hours per year)	0.721	0	0.38
Operable On-Peak Margin	30.7%	43.2%	41.2%

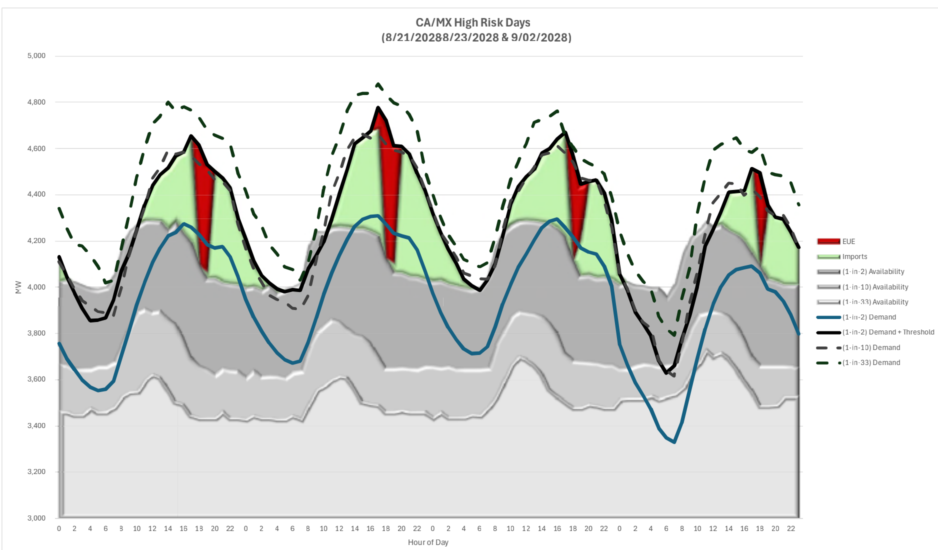
* Provides the 2022 ProbA Results for Comparison

Though the hour and month of peak demand are the same for both CAISO and the broader CA/MX region, CAISO shows the greatest amount of EUE and LOLH in September, whereas CA/MX shows the greatest amount of EUE and LOLH in August. This coincides with the seasonal reduction of solar irradiance in the fall and CAISO having a proportionally larger share of solar resources than the CA/MX region. Excluding regions external to CAISO results in a 96% reduction in LOLH events and EUE over the LTRA horizon.

The hour of peak demand in summer occurs at 5:00 p.m. The hours of highest risk, however, occur during periods after the peak demand hour as solar PV resource output diminishes. There is no LOLH projected for 2026; however in 2028, the ProbA reveals some LOLH between the hours of 5:00 and 8:00 p.m.



Icicle Plot with Hourly Surplus and Deficits for CA/MX in 2028



Demand

The peak demand for CA/MX occurs in the summer. The peak hour for total internal demand is expected to grow from about 56.4 GW in 2024 to 69.1 GW in 2034, a 22.5% load growth over the forecast horizon. The average annual growth rate is 2.07%. Transportation and building electrification are the primary drivers of demand growth.

CAISO Only: The demand forecast for CAISO grows at a slightly higher rate than the broader CA/MX region, with a load growth of 25.2% over the LTRA forecast horizon, and an average annual rate of 2.1%.

Demand-Side Management

A portion of the near-term decline in controllable and dispatchable DR for Summer 2024 is partly driven by regulatory changes in the CA/MX region. This includes making resource adequacy DR crediting adjustments based on historical performance and increasing DR availability requirements. The California Public Utilities Commission (CPUC) determined resource adequacy values of utility DR were overestimated during high load days. In response, the CPUC removed transmission gross-ups and some credits from utility DR resource adequacy values starting in 2024. The CPUC also directed that DR resource adequacy capacity must be available during all days the ISO calls a flex alert or issues a grid warning or on which the governor's office has issued an emergency notice, representing a significant increase in required availability. In addition, the CPUC now requires all DR capacity to be available a minimum of three days per week for at least four hours per day.

For CAISO, energy efficiency and conservation drops significantly when excluding non-CAISO entities from the CA/MX region. The entities outside of CAISO account for an average of 70% of the energy efficiency and conservation DSM for the CA/MX region for the LTRA timeframe.

Distributed Energy Resources

BTM DERs are difficult to measure due to data-gathering barriers. CAISO allows seven DER aggregators as market participants for energy and ancillary services. Additionally, PG&E's Partnership Pilot includes new or existing solar, storage, energy efficiency and demand response used via third party DER providers, vendors, or aggregators.

Generation

There is significantly more solar, wind, and energy storage in planned capacity additions than in the last LTRA. Additionally, several states in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

Energy Storage

Energy storage is being relied on to help mitigate ramping risk from afternoon net demand caused by increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers

CA/MX is showing increasing amounts of exports to the northwest, especially during winter months.

Transmission

Seventeen transmission projects with 500 kV and higher are planned.

Reliability Issues

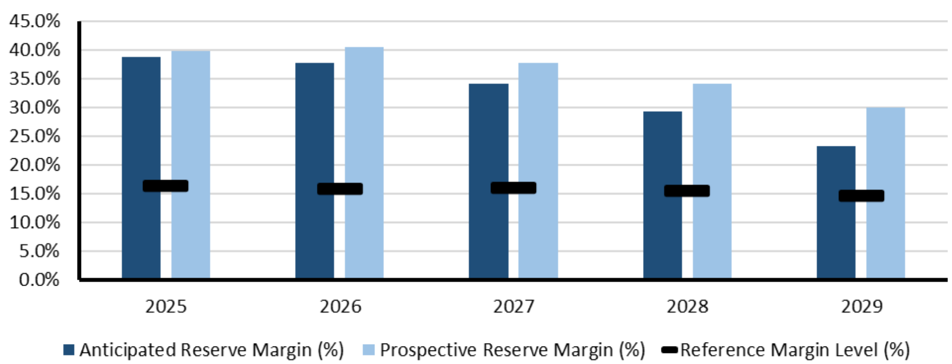
WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

WECC-NW

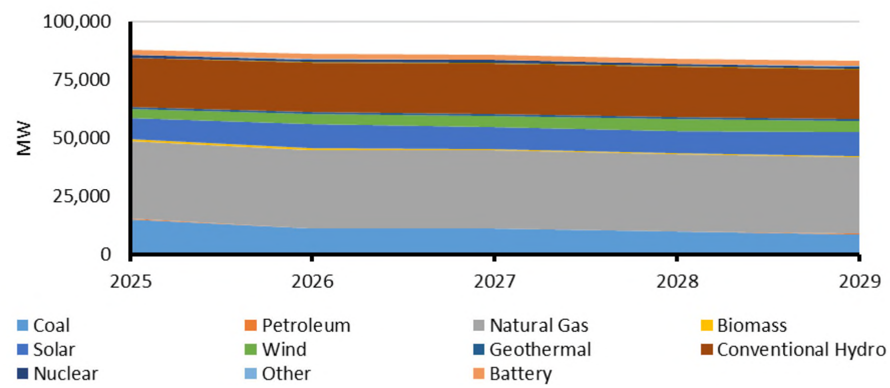
WECC-NW (Northwest) is a summer-peaking assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming and parts of California, Nebraska, Nevada, and South Dakota. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, 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 82 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, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	68,274	69,745	71,580	73,626	75,079	75,917	76,736	77,462	78,316	78,835
Demand Response	806	808	811	814	806	809	812	814	817	820
Net Internal Demand	67,469	68,936	70,768	72,811	74,273	75,108	75,925	76,647	77,499	78,016
Additions: Tier 1	7,000	9,386	9,295	9,489	9,752	9,752	10,141	10,141	9,915	10,141
Additions: Tier 2	788	1,955	2,628	3,595	5,046	6,593	7,258	7,273	6,935	7,253
Additions: Tier 3	2,945	8,874	14,008	21,247	28,296	33,802	40,239	42,260	41,876	43,809
Net Firm Capacity Transfers	5,627	8,796	9,087	9,863	8,462	6,037	2,783	2,423	2,370	2,140
Existing-Certain and Net Firm Transfers	86,609	85,564	85,605	84,618	81,788	78,094	74,003	73,297	72,810	71,446
Anticipated Reserve Margin (%)	38.7%	37.7%	34.1%	29.3%	23.3%	17.0%	10.8%	8.9%	6.7%	4.6%
Prospective Reserve Margin (%)	39.9%	40.6%	37.8%	34.2%	30.0%	25.7%	20.4%	18.4%	15.7%	13.9%
Reference Margin Level (%)	16.3%	15.8%	15.9%	15.4%	14.7%	14.5%	14.3%	14.2%	14.4%	13.8%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM falls below the RML starting in Summer 2031. With the addition of Tier 2 capacity, the PRM stays above the RML for all years in the LTRA time horizon.
- Starting in Summer 2029 onward, the Northwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed. Five GW of baseload resource retirements are anticipated between 2024 and 2028. The energy needs are to be replaced by solar and wind, supported by BESS. Supply chain issues preventing the construction of BESS resources are a concern as they assist in meeting demand during shoulder periods where solar availability is dropping but loads remain high. LOLH and EUE are mitigated over the assessment horizon with the addition of Tier 3 resources.
- The Northwest is dual peaking, so the peak hour can occur in either the summer or the winter. Probabilistic modeling efforts show a peak in the summer for this LTRA. The summer peak for the total internal demand is expected to grow from about 66.4 GW in 2024 to 78.8 GW in 2034, which is lower than in the previous LTRA. This represents a nearly 18.7% load growth over the forecast horizon, with an average growth rate of 1.73%.

WECC-NW Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	14,965	11,031	11,021	9,667	8,761
Coal*	14,661	10,223	10,607	9,349	8,060
Petroleum	321	321	319	319	316
Natural Gas	33,452	33,636	33,304	32,954	32,749
Biomass	729	723	683	683	604
Solar	9,086	10,191	9,350	9,431	10,379
Wind	3,924	4,566	4,939	4,939	4,561
Geothermal	884	934	933	1,007	997
Conventional Hydro	21,003	21,000	21,542	21,522	20,958
Pumped Storage	373	373	375	375	373
Nuclear	1,096	1,096	1,096	1,096	1,096
Other	64	64	64	64	64
Battery	2,084	2,219	2,188	2,188	2,219
Total MW	87,981	86,154	85,814	84,245	83,077
Total MW*	87,679	85,346	85,398	83,926	82,377
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

WECC-NW Assessment

Planning Reserve Margins
The ARM falls below the RML starting in Summer 2031. With the addition of Tier 2 capacity, the PRM stays above the Reference Margin for all years in the LTRA time horizon. Starting in Summer 2029 onward, the Northwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based 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 ODITY 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 .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	1,722	0	1
EUE (PPM)	4	0	0
LOLH (hours per year)	0.04	0	0
Operable On-Peak Margin	37.6%	36.1%	27.8%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC 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. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment, as well as WECC's WARA.

Imports to the Northwest from the CA/MX region grow throughout the LTRA forecast horizon. A calm, cloudy, extreme heat event occurring in the Northwest and CA/MX regions simultaneously poses a risk to the Northwest by limiting surplus energy in CA/MX to send northward.

Energy variability is greater in the Northwest than other WECC regions due to the large share of wind and hydro in the portfolio. More variability in energy output requires a greater reserve margin to maintain resource adequacy.

For 2026 and 2028, the peak hour occurs in August at HE 17:00. LOLH and EUE are not forecast in 2026 and only occur for a single hour in 2028. The LOLH occurred in August at HE 19:00, slightly after peak. The LOLH corresponds with the declining solar availability in the evening while demand remains high.

Demand
The Northwest is dual peaking, so the peak hour can occur in either the summer or the winter. Probabilistic modeling efforts show a peak in the summer for this LTRA. The summer peak for the total internal demand is expected to grow from about 66.4 GW in 2024 to 78.8 GW in 2034, which is lower than in the previous plan. This represents a nearly 18.7% load growth over the forecast horizon, with an average growth rate of 1.73%. There are significant differences between balancing areas, with some showing large load growth impacts while others showing a slight decrease in demand. Entities reporting large load growth cite new data centers as a primary driver.

Demand-Side Management
In the Northwest, Idaho Power implements a substantial dispatchable DR program focused on the agricultural sector with its Irrigation Peak Rewards Programs. This allows Idaho Power to remotely turn off specific irrigation pumps a minimum of four times during the summer. Participation varies year to year based on factors such as the availability of water and program parameters. In 2022, the utility lengthened the season and included additional evening hours, which drove some reduction in participation that carried over to the Summer 2024 availability.

PacifiCorp states in its most recent Integrated Resource Plan (IRP) that it hopes to reach 1,123 MW of demand response by 2042 in its preferred portfolio plan, which is a 21% increase by 2042 from its previous plan. PacifiCorp's dispatchable DR programs include residential, small commercial air-conditioner load control, irrigation load management, and 203 MW of interruptible contracts.

The Public Service Company of Colorado (PSCo) also offers a wide array of DR programs, such as Saver's Switch, which is a program where the air-conditioning unit of a customer may be controlled remotely and cycled during extreme heat events. Peak Day Partners allows for the direct load control and reduction of customers 0.5 MW or greater in size when system peaking conditions are met. The Interruptible Service Credit Option (ISOC) is a program where customers agree to reduce consumption in return for a rate discount with non-compliance being met with a fee.

Distributed Energy Resources

BTM DERs are difficult to measure due to data-gathering barriers. One example is Idaho Power's filing of annual DER Resources Status Reports by customer class and resource type, such as in 2023.

Generation

Five GW of baseload resource retirements are anticipated between 2024 and 2028. The energy needs are to be replaced by solar, wind, and BESS, further increasing variability in the portfolio. Given the retiring of baseload resources, supply chain issues preventing the construction of BESS resources are a concern as they assist in meeting demand during shoulder periods where solar availability is dropping but loads remain high.

There is significantly more solar, wind, and energy storage in planned capacity additions than in the last LTRA. Additionally, several states in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

Energy Storage

Energy storage is being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage, but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers

The Northwest is showing greatly increasing import needs over the 10-year time horizon, especially in the winter months. Most of the imports in the model simulations come from CA/MX, with a smaller portion coming from BC.

Transmission

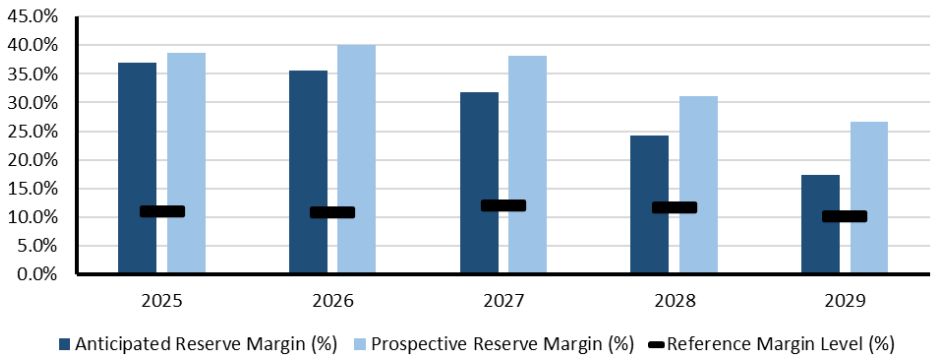
Twelve transmission projects with 500 kV and higher are planned.

WECC-SW

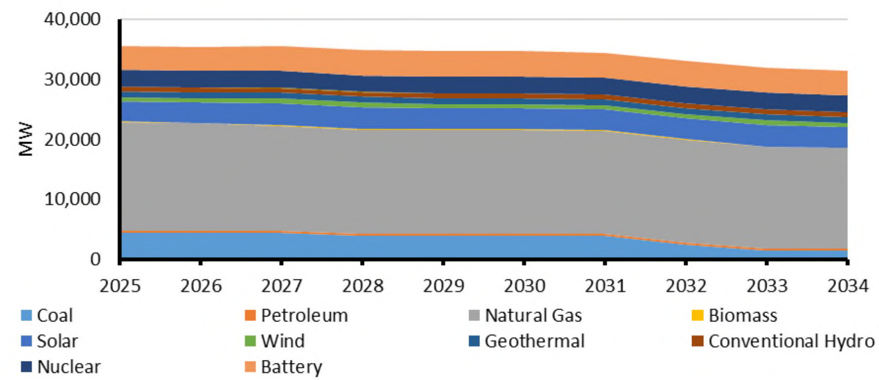
WECC-SW (Southwest) is a summer-peaking assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and part of California and Texas. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, 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 82 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 U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	28,347	29,184	30,098	30,905	31,684	32,401	33,082	33,676	34,301	34,886
Demand Response	417	392	396	424	373	389	392	396	424	373
Net Internal Demand	27,930	28,792	29,702	30,481	31,311	32,012	32,690	33,279	33,876	34,512
Additions: Tier 1	5,140	5,251	5,656	5,656	5,557	5,557	5,557	5,557	5,656	5,557
Additions: Tier 2	475	1,305	1,899	2,079	2,932	2,932	2,966	2,984	3,221	2,984
Additions: Tier 3	40	677	1,148	2,589	3,113	4,438	5,734	7,479	8,960	10,027
Net Firm Capacity Transfers	2,651	3,556	3,554	2,966	2,045	928	716	320	322	0
Existing-Certain and Net Firm Transfers	33,110	33,784	33,491	32,212	31,187	30,070	29,644	27,787	26,645	25,956
Anticipated Reserve Margin (%)	36.9%	35.6%	31.8%	24.2%	17.4%	11.3%	7.7%	0.2%	-4.7%	-8.7%
Prospective Reserve Margin (%)	38.6%	40.1%	38.2%	31.1%	26.7%	20.4%	16.8%	9.2%	4.9%	0.0%
Reference Margin Level (%)	11.0%	10.8%	12.0%	11.7%	10.2%	10.1%	9.9%	9.7%	10.8%	9.4%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML until Summer 2031, and the PRM falls below the RML in Summer 2032.
- Starting in Summer 2028 onward, the Southwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed. LOLH and EUE are mitigated over the assessment horizon with the addition of Tier 3 resources. Both supply chain and zoning issues have been cited as inhibiting project completion.
- The Southwest's peak demand in summer is forecast to grow at an average of 2.49%. Over the LTRA horizon, the forecast grows by a total of 27.8%, which is the highest forecasted growth in the WECC region. The Southwest's total internal demand forecast is nearly the same as last year's over the near and medium term, with a slight drop from last year's in the longer term, growing from a summer peak of 27.3 GW in 2024 to 34.9 GW by 2034.
- Natural gas derates during extreme heat events are a risk for the Southwest as these resources make up a large share of the resource portfolio in the area.

WECC-SW Projected Generating Capacity by Energy Source in Megawatts (MW)

	2025	2026	2027	2028	2029
Coal	4,436	4,436	4,432	3,939	3,941
Coal*	4,432	4,432	4,148	3,655	3,657
Petroleum	323	323	322	322	323
Natural Gas	18,165	17,933	17,520	17,323	17,343
Biomass	82	82	82	82	82
Solar	3,354	3,354	3,628	3,628	3,479
Wind	628	695	799	799	695
Geothermal	1,047	1,047	1,047	1,047	1,047
Conventional Hydro	721	721	721	721	721
Pumped Storage	104	104	104	104	104
Nuclear	2,724	2,724	2,711	2,711	2,724
Battery	4,016	4,061	4,226	4,226	4,240
Total MW	35,599	35,479	35,593	34,902	34,698
Total MW*	35,595	35,475	35,309	34,618	34,414

*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.

WECC-SW Assessment

Planning Reserve Margins

The ARM does not fall below the RML until Summer 2031, and the PRM falls below the RML in Summer 2032. This indicates that imports may be necessary if new resources were to be significantly delayed, as Tier 3 resources will be required for reserve margins to meet the RML. Starting in Summer 2028 onward, the Southwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based 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 ODITY 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 .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	84	0	19
EUE (PPM)	1	0	0.13
LOLH (hours per year)	0.003	0	0.00
Operable On-Peak Margin	18.3%	33.8%	22.5%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC 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. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment. Another report produced is a WECC report called the WARA.

For 2026 and 2028, the peak hour occurs in July at HE 17:00. LOLH and EUE are not anticipated in 2026 and are minimal in 2028. LOLH was only observed in August at HE 19:00. The LOLH corresponds with the evening down ramp of solar and lingering demand after peak.

Due to the significant share of natural gas resources in the Southwest portfolio, a concern for the Southwest is natural gas derates during extreme heat events. A strategy to assist with resource planning is to construct derate curves for natural gas resources as a function of temperature. Resource procurement practices have also changed to focus on adding resources that have no dependence on temperature.

Demand

The Southwest has the highest rate of load growth in the Western Interconnection for the LTRA horizon. Large industrial and commercial load additions, such as data centers, have been cited as the reason for this growth.

The Southwest's peak demand in summer is forecast to grow at an average of 2.49%. Over the LTRA horizon, the forecast grows by a total of 27.8%. The Southwest's total internal demand forecast is nearly the same as last year's over the near and medium term, with a slight drop from last year's in the longer term, growing from a summer peak of 27.3 GW in 2024 to 34.9 GW by 2034.

Demand-Side Management

Arizona Public Service (AZPS) has numerous DSM pilots and programs, such as the Residential Energy Storage Pilot and Commercial Advanced Rooftop Controls. In the Residential Energy Storage Pilot, residents may install a small BESS at their residence and enable it to be dispatched by AZPS in response to grid needs 100 times a year, but not below 20% of its capacity. AZPS is projecting an almost 50 MW increase in available DR from 2024 to 2025.

In 2023, the Salt River Project (SRP) subscribed 87 MW of DR capability through the installation of 76,143 smart thermostats and enrolled over 500 businesses as interruptible customers providing 41 MW of controllable DR capacity. The SRP aims to achieve 300 MW of dispatchable DR capability by 2035.

The Public Service Company of New Mexico (PNM) operates the Peak Saver and Power Saver programs. Peak Saver reduces demand from commercial customers greater than 50 kW in size during peak demand periods, and the Power Saver program cycles the compressor of air conditioners to reduce peak demand in the summer. One hundred hours of curtailment are available for both programs with a four-hour limit per curtailment, and it was found that both programs combined reduce peak demand by an average of 45 MW per curtailment event.

El Paso Electric (EPE) operates a smart thermostat program to cycle air conditioners with the potential to achieve 50 MW of relief by 2040.

Additionally, AZPS, SRP, PNM, and EPE all offer time of use (TOU) rate structures for their customers.

Distributed Energy Resources

BTM DERs are difficult to measure due to data gathering barriers. In the Southwest, NV Energy has added DER plans to its triennial IRPs.

Generation

Southwest entities have slightly under 10 GW of nameplate capacity Tier 1 solar resources planned between 2024 and 2028. Supply chain issues resulting in project delays or failure of completion are a concern for the Southwest. Zoning issues prohibiting the construction of new solar assets are also an issue.

There is significantly more solar, wind, and energy storage in planned capacity additions than in the last LTRA. Additionally, several states in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

Energy Storage

Energy storage is being relied on to help mitigate ramping risk from afternoon net demand caused by increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage, but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers

The Southwest is not showing a significant increase in reliance on imports in the model, with peak exports occurring between 5:00 p.m. and 10:00 p.m.

Transmission

Twelve transmission projects with 500 kV and higher are planned.

Reliability Issues

WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

Demand Assumptions and Resource Categories

Demand (Load Forecast)	
Total Internal Demand	This is the peak hourly load[37] for the summer and winter of each year.[38] Projected total internal demand is based on normal weather (50/50 distribution)[39] 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[40]	Load Forecasting Entity
MISO	Summer	Coincident	MISO LSEs
MRO-Manitoba Hydro	Winter	Coincident	Manitoba Hydro
MRO-SaskPower	Winter	Coincident	SaskPower
MRO-SPP	Summer	Noncoincident	SPP LSEs
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	
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	

[37] Glossary of Terms Used in NERC Reliability Standards.
[38] The summer season represents June–September and the winter season represents December–February. In this assessment, the year of a winter period is referred to by the year of the month of December (e.g., Winter 2025 is December 2025 – February 2026).
[39] 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.
[40] 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.

Demand Assumptions and Resource Categories

Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident**[40]	**Load Forecasting Entity**
WECC-SW	Summer	Noncoincident	

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[41]

- 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[42]

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 (non-firm) capacity transfers (imports minus exports): transfers without firm contracts but a high probability of future implementation.
- Less unconfirmed retirements.[43]

[41] Projected capacities are inputs to reserve margin calculations and probabilistic assessments. Projections are dependent on official retirement notices to system operators. If no notice is given, capacity projections assume no retirements, even if established trends for resource retirements show declines over past years

[42] Generators that have formally announced retirement plans. These units must have an approved generator deactivation request where applicable.

[43] 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.

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 at least one of the following guidelines (with consideration for an area’s planning processes):[44]
  - 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):[45]
  - 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.

[44] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)
[45] 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[46]
- 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.[47] NERC Reliability Standards are intended to establish requirements for BPS owners and operators so that the BES delivers an adequate level of reliability (ALR),[48] 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,[49] and/or voltage collapse under normal operating conditions or when subject to predefined disturbances.[50]
  - 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.

[46] 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
[47] BES Definition
[48] NERC Informational Filing (to FERC) on the Definition of Adequate Level of Reliability, Docket Number RR06-1, May 10, 2013.
[49] 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.”
[50] 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.”

- 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.

How NERC Evaluates Reserve Margins in Assessing Resource Adequacy

PRMs 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. PRMs 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 PRMs 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).

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.[51] 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"

[51] https://wa.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf

Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area

Reference Margin Levels for Each Assessment Area (2025–2029)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
MISO	2024-2025 Summer: 9.0% Fall: 14.2% Winter: 27.4% Spring (2025): 26.7%	Planning Reserve Margin	Yes: Established Annually[52]	0.1 day/Year Loss of Load Expectation (LOLE)	MISO
MRO-Manitoba Hydro	12.0%	Reference Margin Level	No	0.1 day/Year LOLE	Reviewed by the Manitoba Public Utilities Board
MRO-SaskPower	15.0%	Reference Margin Level	No	EUE and Deterministic Criteria	SaskPower
MRO-SPP	19.0%	Resource Adequacy Requirement	Yes: studied on Biennial Basis	0.1 day/Year LOLE	SPP Staff, Stakeholders, SPP Regional State Committee.
NPCC-Maritimes	20.0%[53]	Reference Margin Level	No	0.1 day/Year LOLE	Maritimes Sub-areas; NPCC
NPCC-New England	11.3–12.7%	Installed Capacity Requirement	Yes: three year requirement established annually	0.1 day/Year LOLE	ISO-NE, NPCC Criteria
NPCC-New York	15.0%[54]	Installed Reserve Margin	Yes: one year requirement, established annually by NYSRC based on full installed capacity values of resources	0.1 day/Year LOLE	NYSRC, NPCC Criteria
NPCC-Ontario	8.6–19.5%	Reserve Margin Requirement	Yes: established annually for all years	0.1 day/Year LOLE	IESO, NPCC Criteria
NPCC-Québec	10.9–11.8%	Reference Margin Level	No: established Annually	0.1 day/Year LOLE	Hydro-Québec, NPCC Reliability Coordinating Committee
PJM	17.6–17.7%	Installed Reserve Margin	Yes: established Annually for each of three future years	0.1 day/Year LOLE	PJM Board of Managers, ReliabilityFirst BAL-502-RFC-02 Standard
SERC-Central	15.0%[55]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities

[52] In MISO, the states can override the MISO PRM.
[53] The 20% RML is used by the individual jurisdictions in the Maritimes area with the exception of Prince Edward Island, which uses a margin of 15%. Accordingly, 20% is applied for the entire area.
[54] The NERC LTRA RML for NY is 15%; however, there is no PRM criteria in New York. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. Additionally, the 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 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 2025/2026 IRM at 24.4%. All values in the IRM calculation are based upon full installed capacity (ICAP) MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year.
[55] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.

Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area

Reference Margin Levels for Each Assessment Area (2025–2029)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
SERC-East	15.0%[56]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
SERC-Florida Peninsula	15.0%[57]	Reliability Criterion	No: Guideline	0.1 day/Year LOLP	Florida Public Service Commission
SERC-Southeast	15.0%[58]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
Texas RE-ERCOT	13.75%	Target Reserve Margin	No	0.1 day/Year LOLE plus adjustment for non-modeled market considerations	ERCOT Board of Directors
WECC-AB	9.0–13.6%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[59]
WECC-BC	9.8–12.8%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-CA/MX[60]	14.9–17.4%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-NW	13.8–16.3%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-SW	9.4–12.0%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]

[56] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[57] SERC-FP uses a 15% reference reserve margin as approved by the Florida Public Service Commission for non-IOUs and recognized as a voluntary 20% reserve margin criteria for IOUs; individual utilities may also use additional reliability criteria.
[58] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[59] WECC's RML in this table is for the hour of peak demand. Some hours in the year require a higher reserve margin to meet the 0.02% reliability criteria due to the variability in resource availability and resource performance characteristics.
[60] California is the only state in the Western Interconnection that has a wide-area RML, currently 17.5%: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage,

Recommendations and ERO Actions Summary

In addition to the recommendations in the Executive Summary, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. The ERO, industry, vendors/manufacturers, and stakeholders should continue acting on the following recommendations to inform system and operations planning, develop the transmission network, and address resource performance issues attributed to IBR characteristics, cold weather, and fuel supply limitations. 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.

LTRA Recommendations and Ongoing ERO Actions
Add new resources with needed reliability attributes and make existing resources more dependable. 1. **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs 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. Multi-metric criteria applied to results from probabilistic studies that include load loss, unserved energy, event magnitude, and event duration will support achieving the levels of reliability that are required for modern society. 2. **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 85% 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.[61] 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.[62] 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.[63] Guided by NERC's comprehensive Inverter-Based Resources Strategy and in response to FERC Order No. 901, the ERO, industry, and manufacturers should take additional steps to ensure that IBRs operate reliably and that the system is planned with due consideration for their characteristics.[64,65] 3. **Improve the performance of the generating fleet in extreme cold temperatures:** The ERO and industry need to complete enhanced requirements for generator cold-weather performance to address reliability related findings from the FERC, NERC, and Regional Entity joint staff inquiry into the February 2021 cold weather grid outages.[66] Revisions to Reliability Standard EOP-012-2 will improve the effectiveness of the standard and speed the implementation of corrective actions necessary to address unacceptable freezing issues. Findings of the inquiry into Winter Storm Elliott (December 2022) reinforce the urgency of this effort.[67]

[61] See the ERO's extensive IBR event reporting here: NERC Major Event Reports

[62] 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*.

[63] NERC's comprehensive initiatives to reduce IBR risks are detailed here: IBR Quick Reference Guide

[64] NERC IBR Activities

[65] Order No. 901 Work Plan

[66] *The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report*

[67] *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott*

LTRA Recommendations and Ongoing ERO Actions

4. **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. Collaborative assessments involving NERC, the Regional Entities, the National Labs, and natural gas and electric power industry participants are needed to identify natural gas fuel supply needs for reliable operation of the BPS. 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.[68]

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 Reliability Coordinators, Transmission Operators, and Balancing Authorities 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.[69]	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 statuses of NERC's extensive activities in each area are described in detail in the *IBR Activities Reference Guide.*[70] 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

[68] 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

[69] Project 2021-07

[70] IBR Activities

LTRA Recommendations and Ongoing ERO Actions		
	FERC issued an order in 2022 directing NERC to identify and register owners and operators of currently unregistered bulk power system-connected IBRs.[71] Working closely with industry and stakeholders, NERC is executing a FERC-approved work plan to achieve the identification and registration directive by 2026. Resources are also posted on the Registration page of the NERC website.	
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 RSTC. Refer to the RSTC-Approved Documents page.[72]	Reliability Guideline
Expand the transmission network to deliver supplies from new resources and locations to serve changing loads. 5. **Develop the transmission network:** ISOs and 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.		
Initiative	**Description**	**Product/Reliability Solution**
Interregional Transfer Capability Study (ITCS)	NERC completed the ITCS required by the Fiscal Responsibility Act of 2023 and filed the final report with FERC on November 19, 2024. The ITCS is the first-of-its-kind assessment of transmission transfer capability under a common set of assumptions. However, the ITCS is not a transmission plan or blueprint. Transmission expansion analysis, resource plans, and other inputs must be considered in effective system planning. The ITCS is designed to provide foundational insights that facilitate stakeholder analysis and actions. Due to the interconnected nature of the BPS, NERC will extend the study beyond the congressional mandate to identify and make recommendations for transfer capabilities from the United States to Canada and among Canadian provinces. The Canadian analysis will be published in 2025. See **Interregional Transfer Capability Study (**ITCS).	ERO Study and Recommendations

[71] FERC Order Issued November 17, 2022
[72] RSTC Approved Documents

LTRA Recommendations and Ongoing ERO Actions

Adapt BPS planning, operations, and resource procurement markets and processes to the realities of a more complex power system.

6. **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs 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. Multi-metric approaches to resource adequacy using load loss, unserved energy, and event magnitude and duration criteria and results from probabilistic studies will support achieving the levels of reliability that are required for modern society.
7. **Resource contributions must be accurately represented in resource planning, wholesale electricity markets, and operating models:** Resource Planners and wholesale market designers must use appropriate methods for determining the contribution of resources to meeting demand. Weather-dependent resources, fuel supplies, and demand profiles result in seasonal risks. This can be seen in the increasing winter resource adequacy risks observed in the 2024 ProbA for many traditionally summer-peaking areas. ISO/RTOs can help reduce seasonal risks by implementing seasonal resource adequacy procurement (e.g., spring, summer, fall, winter) based on reserve requirements and resource performance that are tailored to each season. 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.
8. **Maintain sufficient amounts of flexible resources and essential reliability services:** 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. [73]
9. **Include energy risks and 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. NERC and the industry should continue to prioritize completion of new reliability standards supporting energy assurance in operating and planning time horizons, and for the assessment of extreme heat and cold weather events in transmission system planning.
10. **Accommodate the growth of DERs:** Preparing the grid to operate with increasing levels of distributed resources is a priority for most areas. 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. ISO/RTOs must consider how the implementation of DER aggregators in the wholesale market will affect BPS planning and operations.[74]

[73] NERC ERS Measure 6 Forward Tech Brief
[74] A comprehensive guide to ERO activities on DERs can be found here: DER Activities

LTRA Recommendations and Ongoing ERO Actions		
Initiative	**Description**	**Product/Reliability Solution**
Energy Assessments Initiatives	NERC conducts seasonal long-term and probabilistic reliability assessments and issues reports like this *2024 LTRA* to advise industry and stakeholders 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] The working group is developing a technical reference document to inform registered entities on approaches and considerations for assessing and reducing the risk of energy shortfalls. 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
4: Strengthen relationships among reliability stakeholders.		
Initiative	**Description**	**Product/Reliability Solution**
Ongoing Strategic Engagements	NERC and the Regional Entities engage in frequent dialogue and conduct outreach with regulators and policymakers at the state/provincial, regional, and federal/national levels.	Constructive Partnerships

[75] ERAWG
[76] Project 2022-03
[77] Project 2023-07
[78] DER Activities

Exhibit A-3 (RFS-3)

Strategy Update: Reliability Imperative

MISO Board of Directors

September 19, 2024

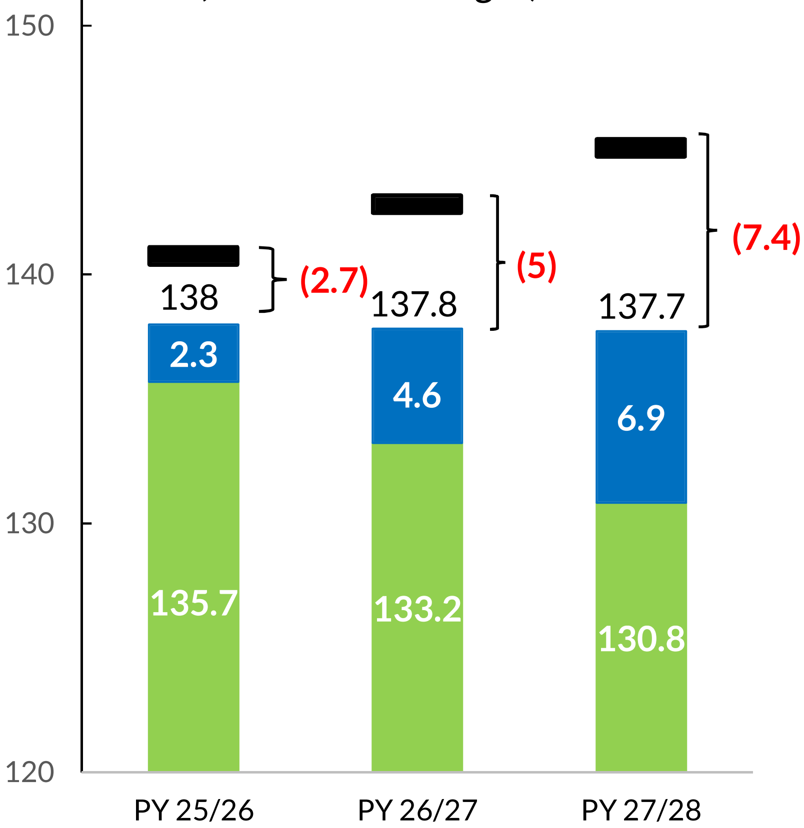
Executive Summary

- The OMS-MISO Survey shows capacity is insufficient to support expected load growth
- Broad agreement exists around significant load increases ahead although visibility into magnitude and timing is currently limited
- The Regional Resource Assessment shows only modest growth in accredited capacity
- Many approved new resources will be delayed getting online, and neighbors' capacity margins are declining quickly
- A coordinated transition plan is required, including deferring retirements until other options are available

2024 OMS-MISO Survey indicates increasing capacity deficits requiring a dramatically accelerated pace of new build to mitigate

OMS - MISO Survey Resource Adequacy Projections – Summer (Accredited GW)

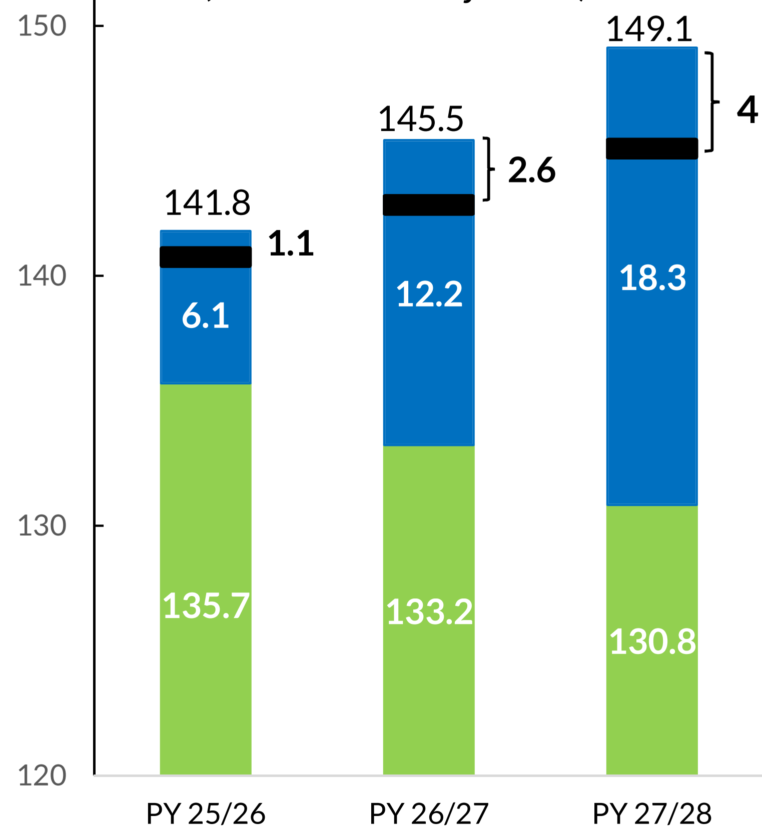
Assuming 2.3 GW/yr of Potential New Capacity added
*(Historical Averages)**



An unprecedented pace of new capacity additions to mitigate deficits would require:

- Easing of supply chain challenges
- Reduced permitting delays
- Adequate skilled labor
- Supportive commercial viability
- Continued queue improvements

Assuming 6.1 GW/yr of Potential New Capacity added
*(Alternative Projection)**



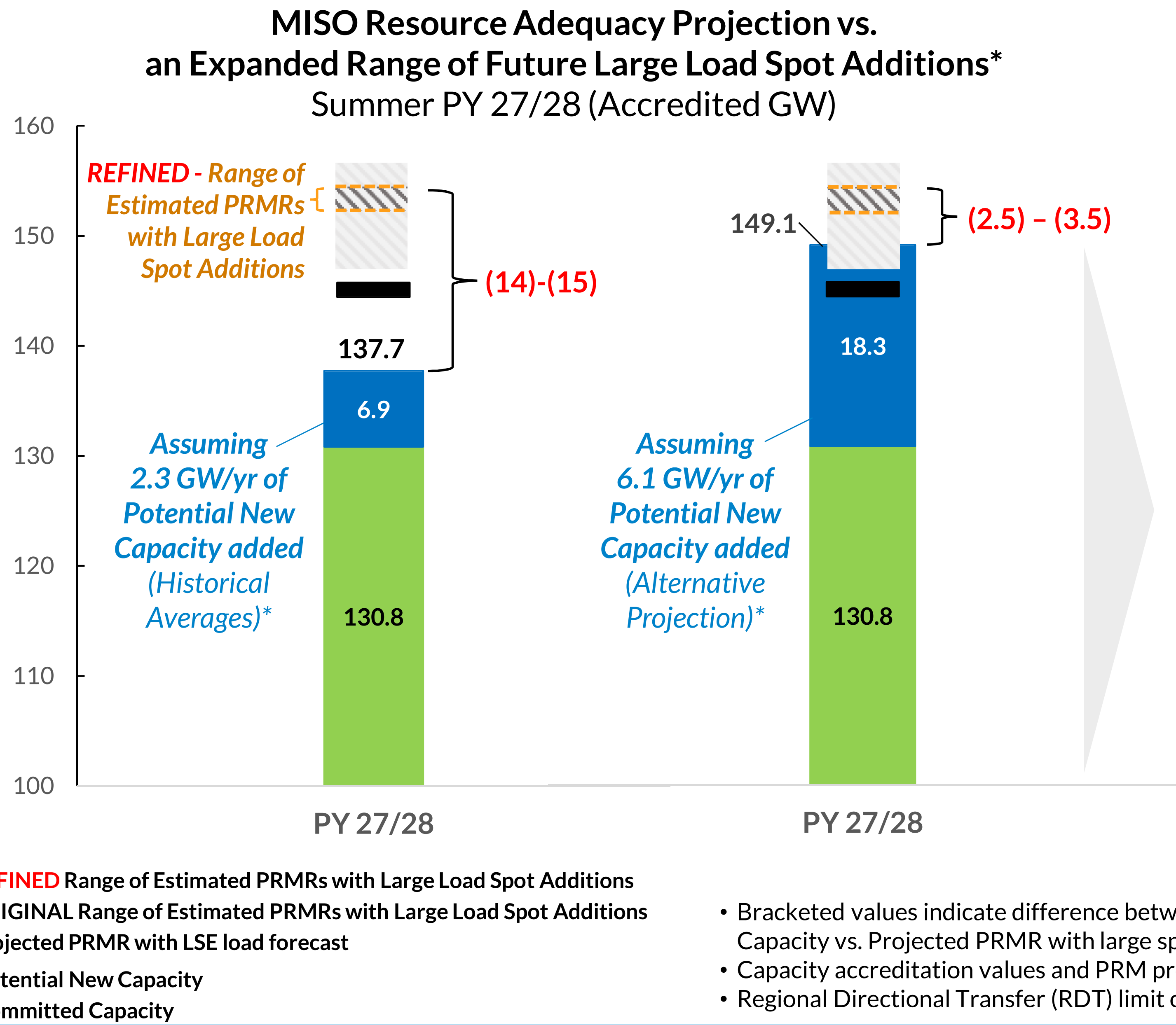
Projected PRMR
Potential New Capacity
Committed Capacity

- Bracketed values indicate difference between Committed+ Projected New Capacity and projected LSE PRMR
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1,900 MW is reflected in this chart

PRMR: Planning Reserve Margin Requirement *All references to capacity indicate Seasonal Accredited Capacity (SAC)*

** Using methods for Potential New Capacity described in 2024 OMS-MISO Survey presentation*

The trend of announced large load additions will exacerbate the urgency for new generation, including dispatchable, long-duration resources



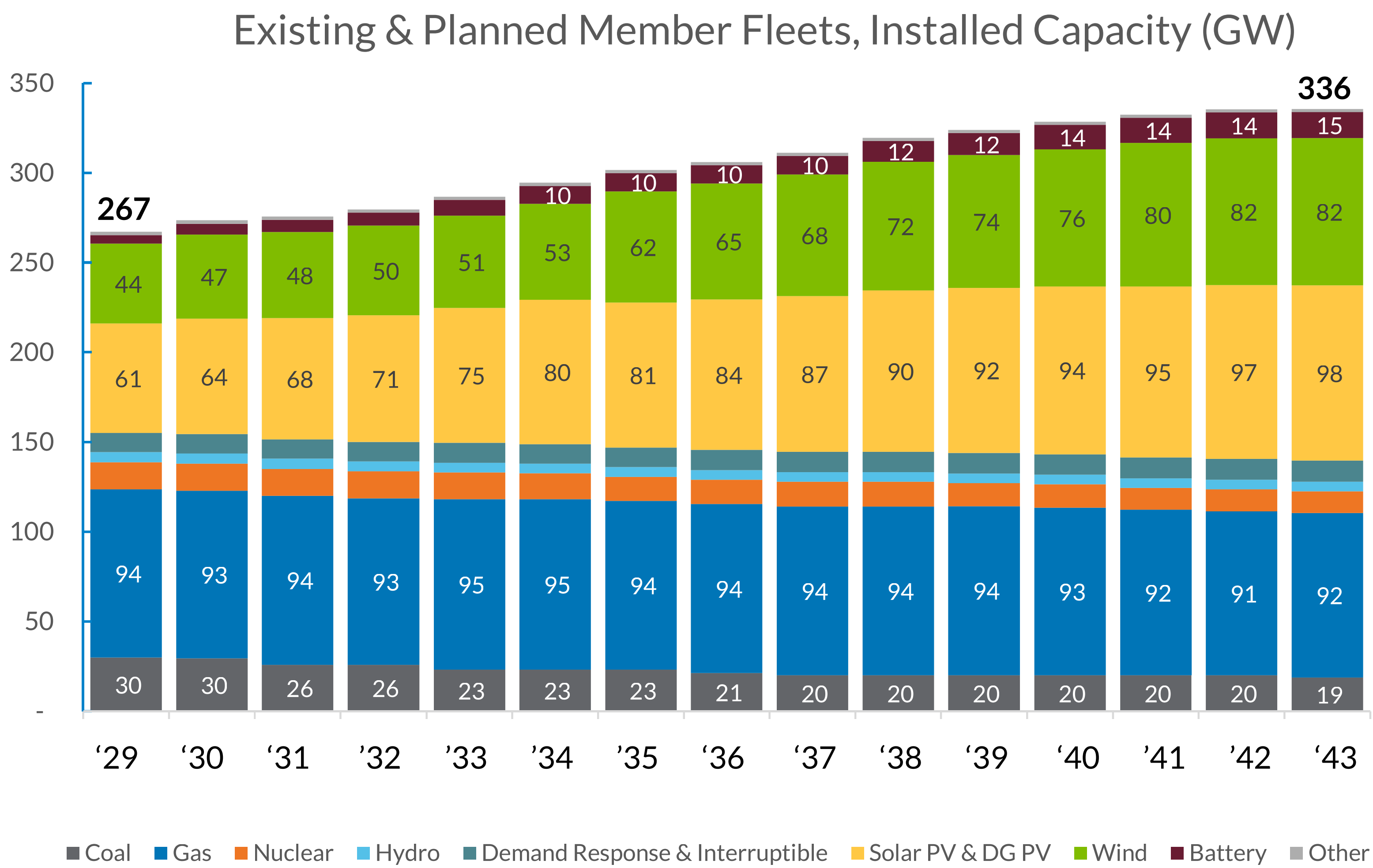
Meeting a high spot load addition scenario would require capacity be added at a rate even greater rate than the 6.1 GWs/year assumed here

- Bracketed values indicate difference between Committed + Projected New Capacity vs. Projected PRMR with large spot-load additions
- Capacity accreditation values and PRM projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

** Using methods for Potential New Capacity and Large Load Spot Additions described in 2024 OMS-MISO Survey presentation*

PRMR: Planning Reserve Margin Requirement

However, member-submitted plans in the 2024 Regional Resource Assessment (RRA) show new additions are primarily weather-dependent resources

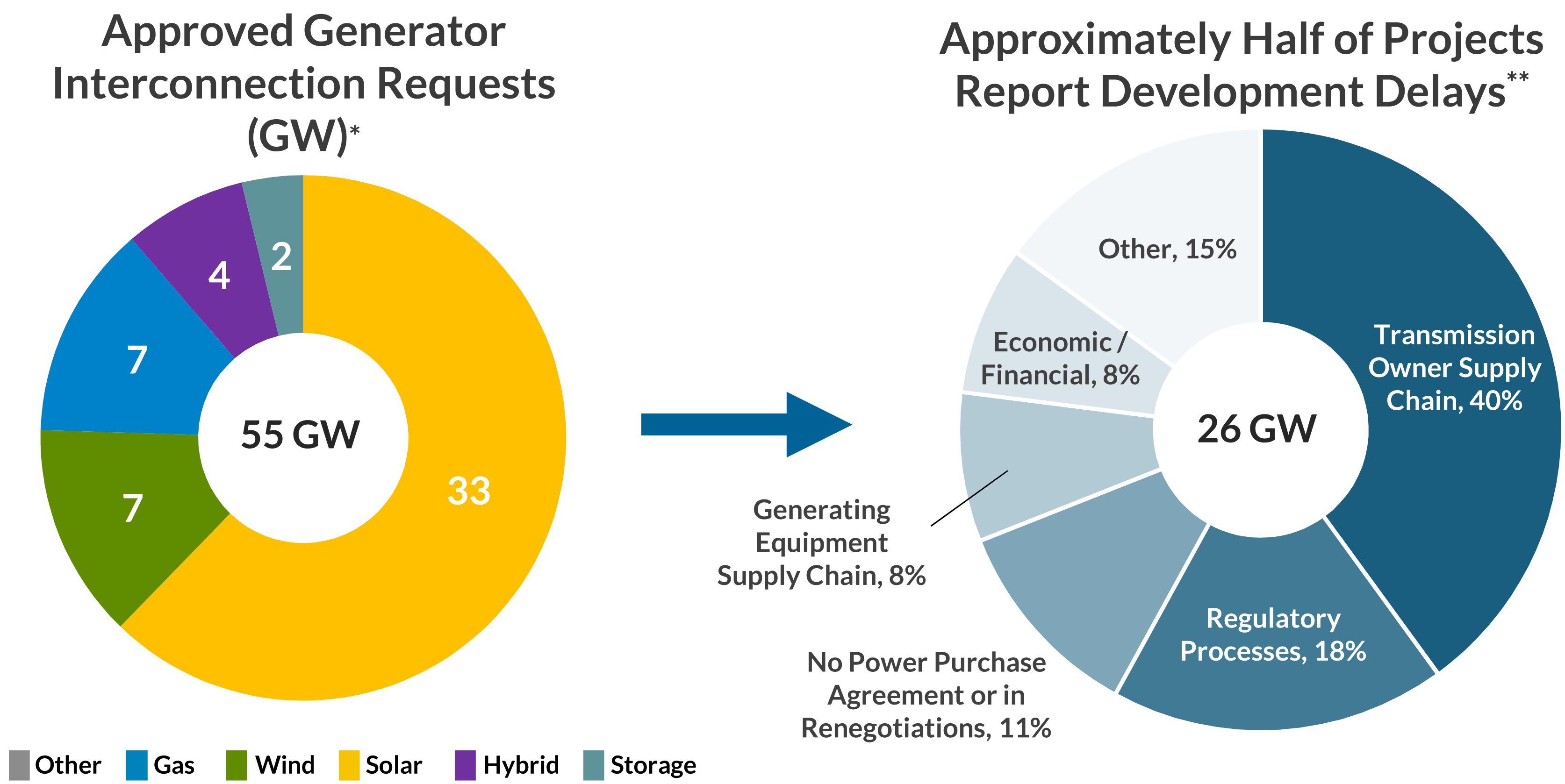


	2029	2043	Change
Installed Capacity (GW)			
	267	336	↗ 26%
Accredited Capacity (GW) *(Current Methodology*)*			
	183	193	↗ 5%
Accredited Capacity (GW) *(Draft Future Methodology**)*			
	~160	~160	→ 0%

** Current Methodology (Summer Season): Solar accredited at 50% through 2027, declines to 20% in 2037 and levels off. Wind accredited at 16.6%.*
***Future Methodology (Summer Season): Draft/Indicative-only: Solar accredited at < 10% by 2027, declining thereafter. Wind also approaches 10% in 2027, declining at a slower pace relative to solar.*

MISO

While we are approving more new resources, approximately half continue to experience delays in getting online



50 GW of resources approved through MISO's interconnection processes are in or awaiting construction with approximately 50% already signaling a delay

*Queue data as of September 4, 2024
** Reasons for delay based on responses from a subset of delayed projects

MISO

Capacity trends of our RTO neighbors point to declining availability of supportive transfers

PJM

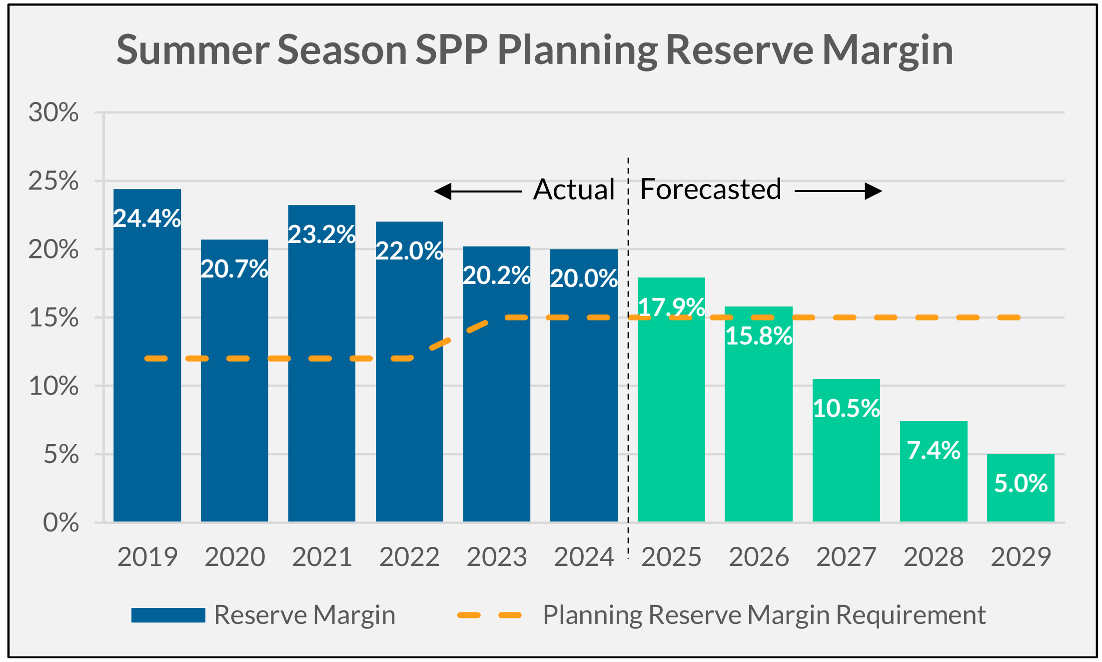
Significant year-over-year supply/demand changes resulted in record prices in capacity auction for 2025/26 delivery year

Offered Supply:	- 13.3 GW	*(down 8.8% vs. prior year)*
Load:	+ 3.2 GW	*(up 2% vs. prior year)*
Reserve Margin: (% above target)	0.7%	*(vs. 5.4% in prior year)*
Clearing Price:	~ $270 / MW-day	*(vs. ~$29 in prior year)*

Source: PJM 2025/2026 Base Residual Auction Report

Southwest Power Pool

No capacity auction but reserve margin projected to fall to requirement in 2026 and decline further



Excess capacity of 2,750 MW in 2024 becomes a deficit of 5,950 MW in 2029 due to:

- 10% increase in forecasted demand
- 3% reduction in capacity

Source: 2024 SPP Resource Adequacy Report

MISO has made considerable progress on evolving our processes and tools to support resource adequacy, but additional coordination can drive more efficient and effective resource planning

Recently Completed / In-Process

Initiative	Objective
Seasonal Requirements in Planning Resource Auction	More accurately reflect variations in resource capabilities and availability
Accreditation Enhancements	Improve alignment of capacity “value” with reliability contribution
Reliability-Based Demand Curve	Improve price signals for capacity and inform investment decisions
Shortage Pricing	Incentivize market participant real-time behavior and actions to avoid potential shortage situations

Next Opportunity

- As the fleet continues to evolve, visibility and clarity will be critical to support timely and prudent action.
- MISO processes and assessments provide insights into the region’s short- and long-term supply and demand picture:

Planning Resource Auction	**1 Year**
OMS-MISO Survey	**5 Years**
Regional Resource Assessment	**20 Years**
MISO Futures	**20 Years**

- A recent stakeholder survey uncovered a desire to evaluate streamlining MISO’s assessments, which may improve participation.

As MISO executes on Reliability Imperative priorities, broad coordination is needed to consider all actions to support reliability and load growth

- Delaying retirements / maintaining existing fleets continues to be the best immediate lever
- Consideration for relaxed renewable / clean energy goals, providing longer glidepath, to reflect the magnitude of landscape change since many of them were implemented
- Collaboration on potential options for expediting the most critical new resource additions
- Moving LRTP Tranche 1 projects forward quickly and preparations for the same on Tranche 2.1

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **UPPER MICHIGAN ENERGY RESOURCES CORPORATION** requesting approval of an amended renewable energy plan to comply with Public Act 235 of 2023.	)	Case No. U. 21813

DIRECT TESTIMONY AND EXHIBITS OF
JAIME CANO LOPEZ

FOR

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

(PUBLIC VERSION)

February 27, 2025

QUALIFICATIONS

OF

JAIME CANO LOPEZ

PART I

Q. Please state your name, business address, and position.

A. My name is Jaime Cano Lopez. My business address is 231 West Michigan Street, Milwaukee, Wisconsin 53203. I am a Senior Business Analyst in Fuel Cost Planning for WEC Energy Group, Inc. ("WEC"), the holding company that owns Upper Michigan Energy Resources Corporation ("UMERC" or the "Company").

Q. Please briefly describe your education, professional, and utility background.

A. I graduated from the University of Seville in Seville, Spain with a licentiate in Work Sciences in 2014; and from the University of Wisconsin-Madison, Madison, Wisconsin, with a Master of Science in Agricultural and Applied Economics with a concentration in Resource and Energy Demand Analysis degree in 2019. I have been employed by WEC as a Gas Buyer, a Senior Gas Planner, and a Senior Business Analyst since 2019.

Q. Are you submitting any exhibits with your direct testimony?

A. Yes, I am submitting two exhibits with my direct testimony. These exhibits are:

A-4 (JCL-1): Renewable Energy Plan Summary

A-5 (JCL-2): Renewable Energy Credit Forecast

Q. Were these exhibits prepared or compiled by you or at your direction?

A. Yes.

Q. What is the purpose of your direct testimony?

A. My direct testimony presents UMERC's economic modeling and analysis and the least-cost expansion plan for UMERC's Amended Renewable Energy Plan ("AREP") to comply with Michigan's renewable energy standards from PA 235 of 2023.

Q. How is your direct testimony organized?

A. First, I briefly describe the PLEXOS software and the components of UMERC's economic evaluation of its AREP. Second, I summarize the optimal capacity expansion plan and economic evaluation results that will achieve compliance with PA 235.

Q. Please summarize the results of UMERC's economic analysis.

A. The results of UMERC's economic modeling and analysis demonstrate a need for additional renewable generation and battery storage facilities to comply with PA 235. To develop an AREP that is fully compliant with PA 235 by 2040, which has a 100 percent clean energy requirement, a total of 500 MW of new wind, 275 MW of new solar[1], and 275 MW of battery storage facilities are required.

[1] Includes the already approved 100 MW Renegade solar farm.

PART II

I. UMERC USED PLEXOS TO EVALUATE ITS OPTIMAL LONG-TERM EXPANSION PLAN.

Q. What modeling software did UMERC use to evaluate its optimal long-term expansion plan?

A. UMERC used Energy Exemplar's ("EE") PLEXOS software, particularly the long-term capacity expansion capabilities provided by PLEXOS, to analyze the economic benefits of the optimal long-term expansion plan needed to comply with PA 235. PLEXOS is a comprehensive production-cost model with regional databases for conducting capacity expansion planning and allows UMERC to forecast future generation portfolios and locational marginal prices throughout the Midcontinent Independent System Operator, Inc.'s ("MISO") territory, identify least-cost resource options to meet UMERC's future system needs; and simulate the dispatch, costs, and revenues of those portfolios as part of the MISO market.

Q. How did UMERC use PLEXOS to evaluate the AREP?

A. UMERC used the PLEXOS model to economically dispatch its existing portfolio and economically select new "generic units" to meet future capacity and energy needs, while simultaneously comply with the AREP requirements.

Q. What were the base planning assumptions used in UMERC's economic modeling?

A. Any long-term capacity expansion analysis must be based on reasonable assumptions and forecasts to provide dependable results. UMERC made reasonable assumptions about the following elements drivers while developing its economic analysis:

- Study Period
- Discount Rate

- Inflation Rates
- Demand and Energy Forecasts
- Natural Gas Prices
- CO_2 Penalty Price
- Market Energy Prices
- Tax Credits
- Michigan AREP Compliance
- MISO Seasonal Reserve Margins and Capacity Accreditation
- Retirements
- Generic New Units

My direct testimony will next address each of these assumptions in the order listed above.

Q. What study period did UMERC use in its economic evaluation?

A. The study period used by UMERC is 28 years (2025 to 2052), which aligns with the PLEXOS capacity expansion model.

Q. What discount rate did UMERC assume?

A. The discount rate used in determining the PLEXOS-selected projects' net present value ("NPV") cost and savings was UMERC's authorized weighted average cost of capital ("WACC"). The WACC used in this evaluation is 7.16 percent, which is consistent with the Commission's most recent electric rate order for UMERC in Case U-21541. The NPV values in the economic evaluation are expressed in 2025 dollars.

Q. Please explain the inflation rate UMERC assumed in its analysis.

A. A general inflation rate is used to escalate costs in the PLEXOS model simulation. An inflation rate of 2.25 percent was used and is based on the embedded inflation rate used in the Annual Energy Outlook's ("AEO") 2023 natural gas price scenario when comparing their forecasted prices in real dollars to nominal dollars.

Q. What demand and energy forecasts did UMERC use in its evaluation?

A. UMERC's long-term demand and energy forecast incorporate an annual growth rate of [redacted] and [redacted], respectively, for all retail load, excluding the [redacted] The load forecast for the [redacted]. Figures 1 and 2 below, respectively, summarize UMERC's assumed demand and energy forecasts through 2040.

Figure 1 – UMERC's Monthly Demand Forecast (MW)

[redacted]

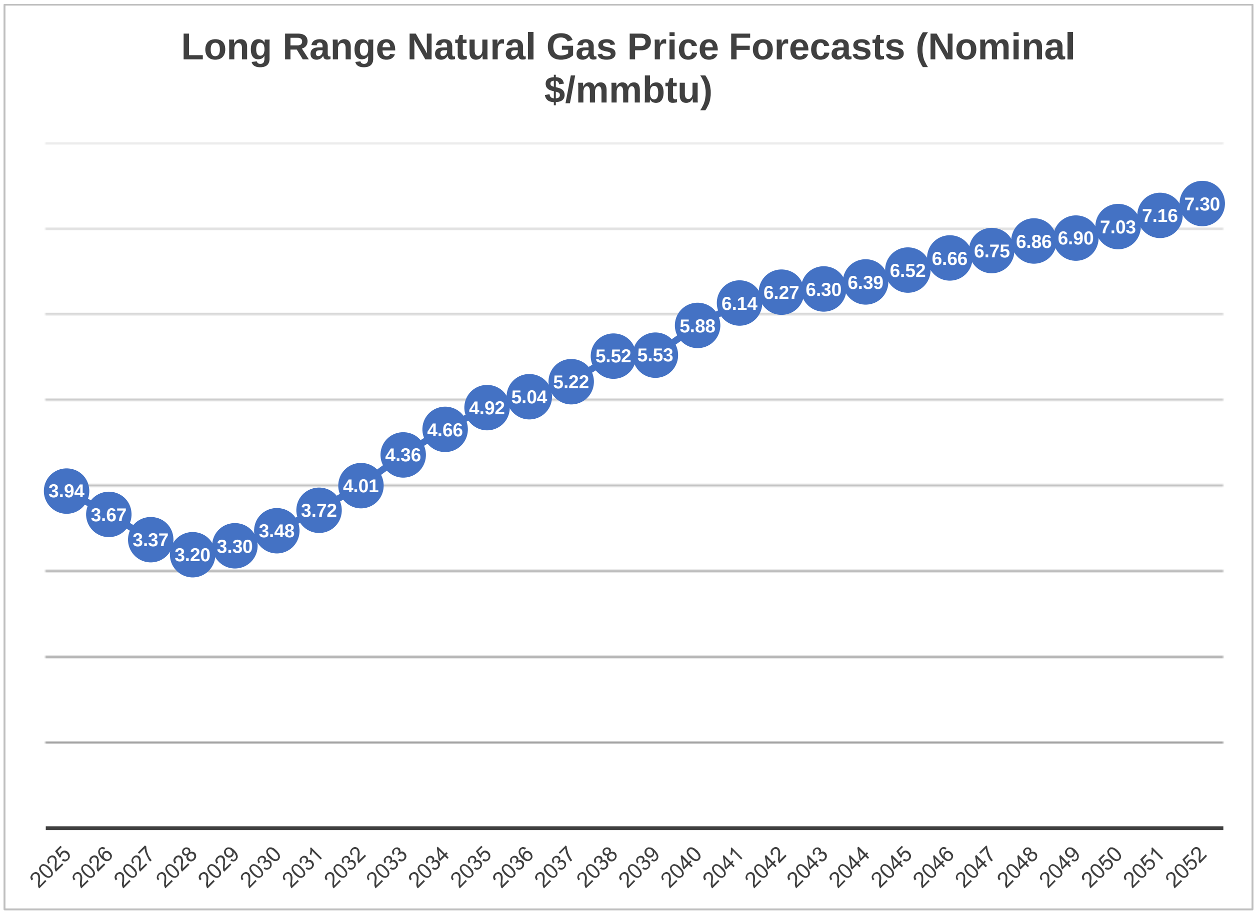
Figure 2 – UMERC's Annual Energy Forecast (MWh)

[redacted]

Q. What price forecasts did UMERC assume for natural gas in its modeling?

A. The natural gas price forecast UMERC used in each the planning future modeled for this case is the U.S. Energy Information Administration's ("EIA") 2023 AEO, specifically the Reference Case. Figure 3 below shows the wide variation in gas prices used in UMERC's economic evaluation.

Figure 3 – UMERC's Long-Range Natural Gas Price Forecast (nominal $/mmbtu)



Q. Please describe the CO_2 pricing mechanism UMERC used and how it was incorporated into UMERC's economic analysis.

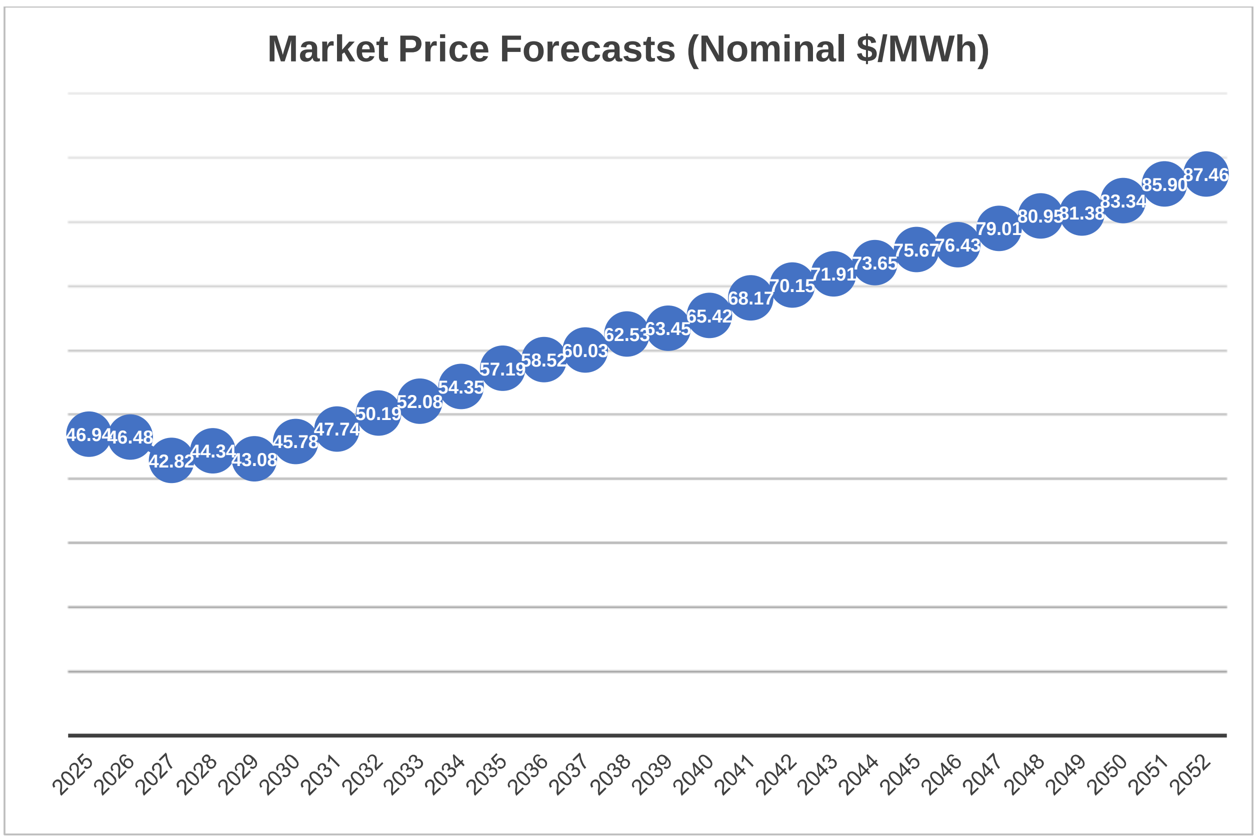
A. The CO_2 modeling assumptions UMERC included in PLEXOS is $30/ton in 2025 dollars, escalating each year at the general inflation rate of 2.25% as described earlier in my direct testimony.

Q. How did UMERC incorporate market prices in its economic analysis?

A. Forecasted locational marginal prices ("LMPs") were developed on an hourly basis for MISO load zone ("LRZ") 2 covering Wisconsin and the upper peninsula of Michigan. A

PLEXOS zonal model of the eastern interconnect was carved out specifically for the regions closest to LRZ 2 and used to develop the hourly market prices. In addition to LRZ 2, this also includes MISO LRZ 1 (North Dakota, Minnesota and Western Wisconsin), LRZ 3 (Iowa) and PJM's ComEd region directly south of LRZ 2. These hourly prices were then used in the specific control area capacity expansion model for UMERC. A summary of the annual forecast LMPs is provided in Figure 4 below.

Figure 4 – UMERC's Market Price Forecast (Nominal $/MWh)



Q. What assumptions did UMERC make regarding tax credits?

A. UMERC's economic analysis reasonably assumes the latest guidance on tax credits for renewable projects based on the Inflation Reduction Act and the most current rates for production and investment tax credits. For solar and wind, UMERC assumed a 100 percent production tax credit, and for battery facilities a 30 percent investment tax credit was assumed regardless of timing. Said differently, UMERC's modeling included assumptions that these tax credits continue at current levels throughout the study period. The annual tax credits were incorporated in the NPV calculations outside of the model based on the eligible unit selections and timing.

Q. Please describe the Act 235 compliance levels included in the PLEXOS model.

A. PA 235 sets forth compliance levels for both renewable energy and clean energy. UMERC intend to meet the clean energy compliance levels through renewable energy sources. To that end, UMERC's PLEXOS modeling assumed that it met the PA 235 levels based on the energy (MWh) requirements of its retail customers, which are:

- 15% requirement by 2025
- 50% requirement by 2030
- 80% requirement by 2035
- 100% requirement by 2040

Prior to the 2030 requirement of 50%, UMERC assumed it would meet the 15% renewable energy compliance threshold through a combination of generation from its 100 MW Renegade Solar Project approved by the Commission in Case U-21081 and currently under construction and market purchases of Michigan-based renewable energy credits ("MI RECs"). Starting in 2030, all requirements are met with generation assets and no market purchases of MI RECs.

The percentage of forecasted retail energy deliveries met by UMERC's proposed AREP from 2025 through 2052 are shown below:

2025	0%	2036	94%	2047	111%
2026	15%	2037	93%	2048	112%
2027	15%	2038	93%	2049	111%
2028	15%	2039	93%	2050	111%
2029	15%	2040	106%	2051	112%
2030	53%	2041	111%	2052	116%
2031	58%	2042	112%		
2032	58%	2043	114%		
2033	57%	2044	112%		
2034	58%	2045	112%		
2035	86%	2046	112%		

Q. How does UMERC's economic evaluation account for MISO's seasonal capacity construct and Direct Loss of Load ("DLOL") capacity accreditation methodology?

A. UMERC's modeling incorporates MISO's seasonal construct starting with MISO Planning Year 2024/25 and the corresponding MISO planning reserve margin ("PRM") installed capacity ("ICAP") percentage requirements for each season. The following PRMs were included for each season:

- Summer 17.7%
- Fall 25.2%
- Winter 49.4%
- Spring 40.8%

UMERC's modeling also takes into account that, over time, MISO is expected to decrease the level of accredited firm capacity provided by solar and battery resources seasonally as MISO implements its DLOL capacity accreditation methodology.

Q. Does UMERC include unit retirements in its modeling runs?

A. Yes. In order to comply with the clean energy requirements of PA 235, as currently in force, UMERC assumed its existing Mihm and Kuester RICE facilities are retired by 2040. However, UMERC included an alternative model run that assumed a continuation of status quo that assumes those units continue to operate through the study period and further renewable energy resources are not required.

Q. Please describe UMERC's assumptions for new units, and how those are incorporated in UMERC's economic modeling.

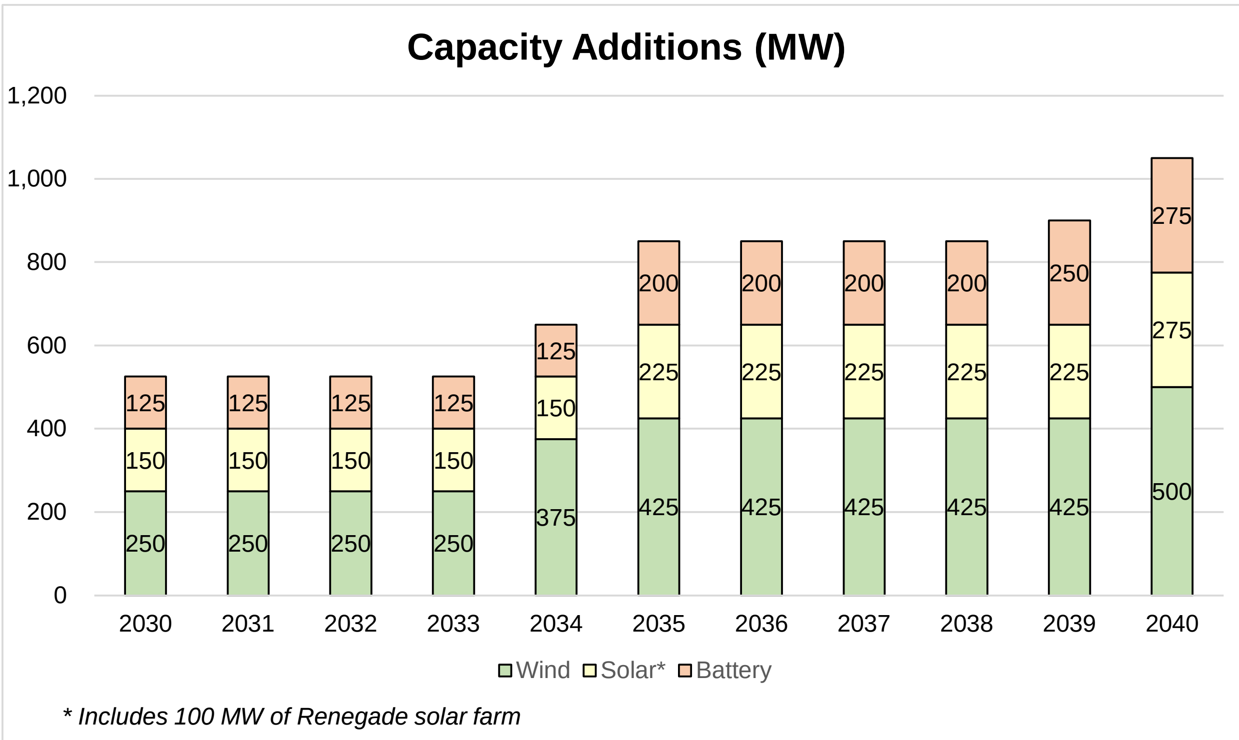
A. The PLEXOS model includes a list of alternatives the model may select as part of an optimal generation expansion plan. Assumed costs for these technologies are based on a combination of EIA's 2023 AEO technology assessment, adjusted for inflation, and internal data based on recent estimates from vendors. The table below summarizes the operating characteristics and cost information for each resource included as alternatives that PLEXOS could select as part of the optimal generation resource fleet.

Technology	Operating Capacity (MW)	Capacity Factor (%)	Overnight Cost (2023$) ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-year)	Firm Gas ($/kW-year)	Heat Rate (btu/kWh)
Combustion Turbine 1	105	varies	[redacted]				
Combustion Turbine 2	237	varies					
RICE - 7 unit site	128.8	varies					
Wind	25	35%					
Solar	25	23%					
Battery	25	<16%					

Q. What do the results of UMERC's capacity expansion modeling indicate relative to AREP compliance with Act 235?

A. Figure 5 below summarizes the optimal expansion plan with the additional units needed and timing of those units to comply.

Figure 5 – Optimal UMERC Expansion Plan for PA 235 Compliance



Q. What is the overall cost impact in order to comply?

A. The total build cost in year of occurrence dollars by 2040 is approximately $3.1 billion. However, the addition of these new units reduces annual fuel costs as a result of increasing zero cost renewable assets in the portfolio. On an NPV basis the overall impact over the study period is an increase in costs of approximately $517 million. In the alternative case, which is a continuation of status quo, prior to the existence of Act 235 renewable energy and clean energy standards, the PLEXOS model does not build any new generation because the forecasted load growth does not result in PRMs lower than MISO's seasonal ICAP PRM requirements through the study period. This indicates the addition of new generation in the model run for the AREP is a result of energy requirements of the AREP and not a need to add generation capacity to comply with MISO's capacity requirements.

Q. Why did the model run include batteries?

Regarding Batteries, their advantages are threefold. They support load during periods facing high peak demand; they shift the load from the peak and busy time to less demand time; and they smooth the fluctuating power supply provided by intermittent wind and solar.

Q. Do the costs you just mentioned include savings associated with tax credits?

A. Yes, they do.

Q. Does this conclude your direct testimony?

A. Yes.

EXHIBIT A-4 (JCL-1)

Confidential material will be provided pursuant to a signed Protective Order.

(MPSC Case No. U-21813)

EXHIBIT A-5 (JCL-2)

Confidential material will be provided pursuant to a signed Protective Order.

(MPSC Case No. U-21813)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **UPPER MICHIGAN ENERGY RESOURCES CORPORATION** requesting approval of an amended renewable energy plan to comply with Public Act 235 of 2023.	)	Case No. U-21813

DIRECT TESTIMONY AND EXHIBITS OF
CHELSEY A. BIERSACH

FOR

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

February 27, 2025

QUALIFICATIONS OF CHELSEY BIERSACH PART I

Q. Please state your name, position and business address.

A. My name is Chelsey Biersach. My business address is 231 West Michigan St., Milwaukee, WI 53203. I am employed by WEC Business Services, LLC ("WBS"), a subsidiary of WEC Energy Group, Inc. ("WEC"), as a Lead Analyst in the Finance Department.

Q. For whom are you providing testimony?

A. I am providing testimony on behalf of Upper Michigan Energy Resources Corporation ("UMERC" or the "Company"), a subsidiary of WEC.

Q. Please describe briefly your educational, professional, and utility background

A. I received a Master of Business Administration degree with a business analytics concentration from the University of Wisconsin – Milwaukee. I was hired by WEC Energy Group in January 2019 as an Associate Analyst on the Sales and Revenue Forecasting team in the Finance department. During my tenure on the Sales and Revenue Forecasting team I have prepared long-term electric and natural gas sales forecasts for multiple WEC operating utility subsidiaries. In 2024, I was promoted to Lead Analyst and am currently responsible for overseeing the development of the long-term sales forecasts for all of the electric operating subsidiaries of WEC, including UMERC.

CHELSEY BIERSACH
DIRECT TESTIMONY
PART II

Q. What is the purpose of your pre-filed direct testimony?

A. The purpose of my direct testimony is to provide an explanation of the methodology used to develop UMERC's electric sales and peak forecast supporting the renewable energy resources discussed in the direct testimony of Company Witness Jaime Cano Lopez.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibit which were prepared by me or under my direction and supervision:

- A-6 (CAB-1): Forecasted Customer Counts
- A-7 (CAB-2): Forecasted MWh
- A-8 (CAB-3): Forecasted Demand

Q. Please explain how UMERC's electric sales forecast was developed.

A. The Residential customer class sales forecast was developed using two statistical models for each Rate Zone: (i) an average use-per customer (UPC) model; and (ii) a customer count model. The average UPC forecast was developed by creating regression models in the Itron MetrixND forecasting application using normal weather and cooling efficiency variables for the regions associated with each Rate Zone. The customer count forecast was developed by creating regression models in MetrixND using population and household income variables for the regions associated with each Rate Zone. The historical model data was based on monthly customer counts and monthly sales in kWh from the period January 2013 through

May 2024. The monthly forecasted results from the average use-per customer and customer count were multiplied to calculate the monthly residential sales forecast for each Rate Zone.

The Commercial customer class sales forecast was developed using two statistical models for each Rate Zone: (i) an average use-per customer (UPC) model; and (ii) a customer count model. The average UPC forecast was developed by creating regression models in MetrixND using weather variables for the regions associated with each Rate Zone. The customer count forecast was developed by creating regression models in MetrixND using Household Income and Unemployment Rate variables for the regions associated with each Rate Zone. The historical model data was based on monthly customer counts and monthly sales in kWh from the period January 2013 through May 2024. The monthly forecasted results from the average use-per customer and customer count were multiplied to calculate the monthly commercial sales forecast for each Rate Zone.

The Industrial customer class sales forecast was developed using historical monthly billed sales by customer from January 2023 through December 2024. The individual customer forecasts were aggregated by rate schedule for each Rate Zone.

The Company Use sales forecast was based on averaging monthly volumes from January 2021 through June 2024.

The Special Contract (U-18224) and CpLC customer sales forecast was developed using historical monthly sales from January 2020 through December 2024.

The Lighting sales forecast for each Rate Zone was developed by using a 4-year average of calendar month historical sales from January 2021 through June 2024 for the respective Rate Zone.

Distribution losses were calculated by month for each customer class within each Rate Zone by multiplying the customer class sales forecasts, described above, by the customer class distribution loss factors, which was approved by the Commission in Case No. U-20541.

The UMERC peak demand forecast was prepared in the fall of 2024 and the methodology consisted of several steps.

The first step projected the non-coincident gross peak demand where gross was defined as firm and interruptible load. Econometric models were used to estimate the historical relationship between the monthly actual gross peak demand (dependent variable) and several independent variables representing energy usage, weather, day of the week and an annual trend. In addition, a binary variable was used to capture the impact of the COVID-19 pandemic in 2020 and 2021. Separate models were used for the MIUP.UMRC and WPS.UMRC MISO load zones. The WEPCo Rate Zone customer load is represented by MIUP.UMRC and the WPSC Rate Zone customer load is represented by WPS.UMRC. In both cases, demand from customers being served by alternative energy suppliers, also known as retail choice, were excluded.

In the second step, the gross non-coincident peak demand forecast from the first step was converted into a net non-coincident peak demand forecast by subtracting the curtailable and interruptible demand forecasts. The curtailable and interruptible demand forecasts for MIUP.UMRC were based on an analysis of historical demand during peak periods adjusted for any known customer changes. The two interruptible customers located in WPS.UMRC were forecasted individually. The firm and interruptible demand forecasts for the Special Contract (U-18224) and CpLC customers were prepared based on contractual obligations.

In the third and final step, a “50-50” forecast was developed by estimating weather impact using a weekly weather distribution based on historical actual weather from January 1996 through August 2024. The forecast assumes that 50% of the time the actual peak demand will exceed the forecast and 50% of the time the actual peak demand will be less than the forecast. MISO requires load serving entities to submit “50-50” forecasts of coincident peak demand.

Q. Please explain how normal weather was defined when developing the sales forecast.

A. Normal weather was defined as the average of the most recent 20 years using heating degree days with a set point of 65 degrees Fahrenheit and cooling degree days with a set point of 65 degrees Fahrenheit. For 2025, the annual total of 8,328 heating degree days was based on the 20-year period of 2004 through 2023; the total of 345 cooling degree days was based on the 20-year period of 2004 through 2023.

Q. Please explain the development of the weather data.

A. Actual heating degree days were calculated on a daily basis by subtracting the average daily temperature from the set point of 65 degrees Fahrenheit. The calculation used a floor value of zero which meant that an average daily temperature equal to or greater than 65 degrees resulted in zero heating degree days for the day. Actual cooling degree days were calculated on a daily basis by subtracting 65 from the average daily temperature in degrees Fahrenheit. The calculation used a floor value of zero which meant that an average daily temperature equal to or less than 65 degrees resulted in zero cooling degree days for the day. Each day’s average temperature was calculated by averaging all of the hourly temperature values for the day at the weather station located in Iron Mountain, Michigan. The hourly temperatures were provided by DTN, a third-party data, analytics and technology service provider.

Q. Does this complete your direct testimony at this time?

A. Yes, it does.

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
No.	**Forecasted Customer Counts**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
1	Residential (Rg1, Rg-1M, Rg2, Rg-OTOU-1M)	33,339	33,420	33,507	33,593	33,680	33,680	33,680	33,680	33,680	33,680	33,680
2	Small C&I (Cg1, Cg2, Cg5, Tss, Cg-1M, Cg-OTOU-1M)	3,903	3,913	3,924	3,937	3,949	3,949	3,949	3,949	3,949	3,949	3,949
3	Small C&I (Cg-3M, Mp-1M)	38	38	38	38	38	38	38	38	38	38	38
4	Large C&I (Cg3, Cg3C, Cp1, Cp-1M Sec, Cp-1M Pri, Special Contract 1)	77	77	77	78	78	78	78	78	78	78	78
5	Large C&I (Cp2, Cp3, Cp4, Schedule A, Cp-1M Tran)	4	4	4	4	4	4	4	4	4	4	4
6	Special Contract (U-18224) and CpLC	1	1	1	1	1	1	1	1	1	1	1
7	**Total**	**37,362**	**37,453**	**37,551**	**37,651**	**37,750**	**37,750**	**37,750**	**37,750**	**37,750**	**37,750**	**37,750**

Line	(a)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
No.	**Forecasted Customer Counts**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
1	Residential (Rg1, Rg-1M, Rg2, Rg-OTOU-1M)	33,680	33,680	33,680	33,680	33,680	33,680	33,680	33,680	33,680	33,680
2	Small C&I (Cg1, Cg2, Cg5, Tss, Cg-1M, Cg-OTOU-1M)	3,949	3,949	3,949	3,949	3,949	3,949	3,949	3,949	3,949	3,949
3	Small C&I (Cg-3M, Mp-1M)	38	38	38	38	38	38	38	38	38	38
4	Large C&I (Cg3, Cg3C, Cp1, Cp-1M Sec, Cp-1M Pri, Special Contract 1)	78	78	78	78	78	78	78	78	78	78
5	Large C&I (Cp2, Cp3, Cp4, Schedule A, Cp-1M Tran)	4	4	4	4	4	4	4	4	4	4
6	Special Contract (U-18224) and CpLC	1	1	1	1	1	1	1	1	1	1
7	**Total**	**37,750**	**37,750**	**37,750**	**37,750**	**37,750**	**37,750**	**37,750**	**37,750**	**37,750**	**37,750**

EXHIBIT A-7 (CAB-2)

Confidential material will be provided pursuant to a signed Protective Order.

(MPSC Case No. U-21813)

EXHIBIT A-8 (CAB-3)

Confidential material will be provided pursuant to a signed Protective Order.

(MPSC Case No. U-21813)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **UPPER MICHIGAN ENERGY RESOURCES CORPORATION** requesting approval of an amended renewable energy plan to comply with Public Act 235 of 2023.	)	Case No. U-21813

DIRECT TESTIMONY AND EXHIBITS OF
JAMES M. BEYER

FOR

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

February 27, 2025

DIRECT TESTIMONY AND EXHIBITS OF
JAMES M. BEYER

QUALIFICATIONS
OF
JAMES M. BEYER
PART I

Q. Please state your name, business address, and position.

A. My name is James M. Beyer. My business address is WEC Energy Group ("WEC"), 2830 South Ashland Avenue, Green Bay, WI 54304. I am a Project Specialist in the State Regulatory Affairs Department of WEC. Upper Michigan Energy Resources Corporation ("UMERC" or the "Company") is a wholly owned subsidiary of WEC.

Q. Please briefly describe your education, professional, and utility background.

A. I graduated from Northern Michigan University, Marquette, Michigan, with a Bachelor of Science Degree in Accounting in 2002; and from Lakeland College, Sheboygan, Wisconsin, with a Master of Business Administration ("MBA") degree in 2006. I have been employed by WEC and its predecessors, first as a Pricing Analyst and currently as a Project Specialist since 2004. In my current position, I perform and am otherwise involved in electric service rate-related studies and analysis, electric service and tariff administration, financial analyses, and electric service rate development and administration.

Q. Have you testified before a regulatory agency?

A. Yes. I have testified before the Public Service Commission of Wisconsin ("PSCW") and the Michigan Public Service Commission ("MPSC" or the "Commission"). Most recently I have provided direct testimony and exhibits in UMERC's most recent general electric rate case in Case No. U-21541, in annual reconciliations related to Renewable Energy (Case No. U-21554), Energy Waste Reduction ("EWR") (Case

No. U-21562) and Power Supply Cost Recovery ("PSCR") (Case No. U-21266) and in annual plans related to EWR (Case No. U-21326) and PSCR (U-21600). Outside of Michigan I have provided testimony and exhibits to the Public Service Commission of Wisconsin on many rate-making issues, most recently in 5-UR-110, as well as in multiple fuel reconciliation dockets.

PART II

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide a methodology to recover costs associated with the renewable energy resources discussed in the direct testimony of Company Witness Jaime Cano Lopez.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

- **A-9 (JMB-1)**: Renewable Energy Plan Surcharge Calculation;
- **A-10 (JMB-2)**: Forecasted Revenues Used to Derive Monthly Impacts;
- **A-11 (JMB-3)**: Annual Renewable Energy Plan Cost of Compliance
- **A-12 (JMB-4)**: Tariff Sheet

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes.

Q. Please describe Exhibit A-9 (JMB-1).

A. Exhibit A-9 (JMB-1) contains the Company's computation of and all components used to derive the Company's proposed daily, per-meter surcharge for the statutorily-required amended renewable energy plan ("AREP") for years 2026 – 2045, which is the subject of this case. This exhibit includes, among other data elements, forecasted MWh by class, forecasted meter counts by class. The calculation of the proposed Renewable Energy Surcharge is described in more detail below. In addition to the total revenue requirement to be recovered through the Company's proposed renewable energy surcharge, Exhibit A-9 (JMB-1) contains the calculation of the monthly impacts of the proposed renewable energy surcharge for each customer class.

Q. Please describe Exhibit A-10 (JMB-2).

A. Exhibit A-10 (JMB-2) summarizes the forecasted revenues use to derive the monthly customer impacts that are shown in Exhibit A-9 (JMB-1). The revenues were taken from the settlement reached and approved by the Commission in UMERC's most recently concluded electric rate case in Case U-21541.

Q. Please describe Exhibit A-11 (JMB-3).

A. Exhibit A-11 (JMB-3) summarizes UMERC's costs to comply with PA 235 by year from 2026 through 2045. As further explained below, the costs shown for compliance in 2026 are associated exclusively with the purchase of Michigan-sourced Renewable Energy Credits ("MIRECs"). UMERC assumes a cost $4 per MIRECs.

Compliance costs for the years 2027 through 2029 include the revenue requirements for the Renegade Solar Project ("Renegade Solar"), plus the cost of MIRECs, subject to the 5% limit of UMERC's total energy sales required to meet UMERC's current obligation under PA 235 to provide 15% of its annual energy sales.

Starting in 2030 through the study period that ends in 2045, compliance costs include the annual revenue requirement of Renegade Solar and the annual revenue requirement of all incremental renewable generation facilities that would be required to be built or acquired by UMERC to meet the compliance requirements of PA 235 as identified by the generation capacity expansion planning modeling explained and presented by Witness Jaime Cano Lopez in his direct testimony and exhibits in this case.

Q. How does UMERC propose to the recover the costs it expects to incur to meet the renewable energy requirements in PA 235?

A. UMERC proposes to recover the projected compliance costs – the full requirement of Renegade Solar, MIRECs and incremental renewable generation resources –via a daily per meter charge.

Q. How has UMERC derived the proposed daily charge for its full requirements customers?

A. First, the Company calculated the total revenue requirement for the resources required to comply with PA 235 for each year 2026 through 2045, as described above. The total renewable revenue requirement for each year is located on line 1 of Exhibit A-9 (JMB-1).

Next UMERC's customers were split into the classes as shown below, which is similar to the breakout UMERC uses in establishing the surcharge for the EWR program. The revenue requirements were allocated to each class based on its percentage of total forecasted MWh sales. Forecasted MWhs can be found in Company Witness Jaime

Cano Lopez's exhibits and the forecast methodology used is described in Witness Chelsey Biersach's testimony. Forecasted MWhs and the percentage breakout can be found on rows 4-18 of Exhibit A-9 (JMB-1). The reveneue requirement allocated to each class can be found on rows 28-34 of Exhibit A-9 (JMB-1). The grouping of rate schedules into customer classes used in this analysis is:

- Residential (Rg1, Rg-1M, Rg2, Rg-OTOU-1M)
- Small C&I (Cg1, Cg2, Cg5, Tss, Cg-1M, Cg-OTOU-1M)
- Small C&I (Cg3, Mp-1M)
- Large C&I (Cg3, Cg3C, Cp1, Cp-1M Sec, Cp-1M Pri, Special Contract 1)
- Large C&I (Cp2, Cp3, Cp4, Schedule A, Cp-1M Tran)
- Special Contract (U-18224) & CpLC

Finally, the surcharge for each class was calculated taking the allocated costs in rows 28 – 34 and dividing that value by the number of customers in each customer class found in rows 20-26. This value was then divided by 365 to derive a per meter per day charge. UMERC's proposed daily surcharge, but customer class can be found on rows 36-41 of Exhibit A-9 (JMB-1).

Exhibit A-12 (JMB-4) is a tariff sheet which reflects the proposed Renewable Energy charges for purposes of this biennial renewable energy plan filing 2026 and 2027. Rate schedules DG-1 and PG-1M have been added to the tariff for the purposes of clarification and consistency. DG-1 is a new net metering tariff approved in UMERC's most recent general electric rate case in Case No. U-21541 and PG-1M is net metering tariff currently in place for UMERC's WPSC Rate Zone.

UMERC is also proposing to remove the section of tariff Sheet D-7.00 assoicated with Voluntary Green Pricing ("VGP"). The Company intends to file its biennial VGP review in which it will be recommending and supporting the deletion of the renewable energy surcharge exemption. UMERC does not believe it is equitable for VGP customers to opt out of what the Company believes to be a new mandatory state policy to transition to renewable energy.

Q. Does this complete your direct testimony?

A. Yes it does.

EXHIBIT A-9 (JMB-1)

Confidential material will be provided pursuant to a signed Protective Order.

(MPSC Case No. U-21813)

EXHIBIT A-10 (JMB-2)

Confidential material will be provided pursuant to a signed Protective Order.

(MPSC Case No. U-21813)

EXHIBIT A-11 (JMB-3)

Confidential material will be provided pursuant to a signed Protective Order.

(MPSC Case No. U-21813)

M.P.S.C. No. 1 – Electric
Upper Michigan Energy Resources Corporation

WEPCo and WPSC Rate Zone
Fourth Revised Sheet No. D-7.00
Replaces Third Revised Sheet No. D-7.00

RENEWABLE ENERGY SURCHARGE

The following rate schedules shall receive a Power Supply Renewable Energy Surcharge per meter, per day, as indicated below. Company assumes one meter per service.

RATE SCHEDULE	***2026*** RATE	***2027 RATE***
Rg-1	$0.~~000000~~***0121***	***$0.2485***
Rg-2	$0.~~000000~~***0121***	***$0.2485***
Rg-1M	***$0.0121***	***$0.2485***
Rg-OTOU-1M	***$0.0121***	***$0.2485***
Cg-1	$0.~~000000~~***0406***	***$0.8348***
Cg-2	$0.~~000000~~***0406***	***$0.8348***
Cg5	***$0.0406***	***$0.8348***
TssM	***$0.0406***	***$0.8348***
TssU	***$0.0406***	***$0.8348***
Cg-1M	***$0.0406***	***$0.8348***
Cg-OTOU-1M	***$0.0406***	***$0.8348***
Cg-3M	***$0.4533***	***$9.3203***
Mp-1M	***$0.4533***	***$9.3203***
Cg-3	$~~0.000000~~***1.2468***	***$25.6362***
Cg3C	$~~0.000000~~***1.2468***	***$25.6362***
~~Cg-5~~***Cp1***	$~~0.000000~~***1.2468***	***$25.6362***
Cp-1M (Secondary)	***$1.2468***	***$25.6362***
Cp-1M (Primary)	***$1.2468***	***$25.6362***
Special Contracts (U-16967)	$***1.2468***	***$25.6362***
Cp-2	$~~0.00000~~***80.7237***	***$1,658.5822***
Cp-3	$~~0.00000~~***80.7237***	***$1,658.5822***
Cp-4	$~~0.00000~~***80.7237***	***$1,658.5822***
Schedule A	$~~0.00000~~***80.7237***	***$1,658.5822***
Cp-1M (Transmission)	***$80.7237***	***$1,658.5822***
CpLC	***$2,131.7114***	***$43,629.8811***
Special Contracts (U-18224)	***$2,131.7114***	***$43,629.8811***

The following rate schedules shall receive a Power Supply Renewable Energy Surcharge as indicated above consistent with the rate schedule under which the customer is served.

RATE SCHEDULE
Ds1
CGS Category 1 (only when a net purchaser from the Company)
DG-1 (only when a net purchaser from the Company)
PG-1M (only when a net purchaser from the Company)

~~VOLUNTARY GREEN PRICING RATE SCHEDULES~~

~~A customer electing a participation level of 50% or 100% under the ERER1 or ERER3 rate schedules is exempt from the Power Supply Renewable Energy Surcharge. A customer electing a participation level of 25% under the ERER1 or ERER3 rate schedules is subject to the Power Supply Renewable Energy Surcharge above, not prorated, consistent with the rate schedule under which the customer is served. A customer participating on the ERER2 rate schedule is exempt from the Power Supply Renewable Energy Surcharge for each billing period in which the customer's nominated block represents at least 50% of the customer's total kWh consumption for the billing period. If a customer's nominated block represents less than 50% of the customer's total kWh consumption for the billing period, the customer is subject to the Power Supply Renewable Energy Surcharge above, not prorated, consistent with the rate schedule under which the customer is served.~~

Issued xxxxxxxxxxxx
T. T. Eidukas
Vice-President,
Milwaukee, Wisconsin

Effective for service rendered on and after January 1, 2026
Issued under authority of the Michigan Public Service Commission
Dated xxxxxxxxxxx
in Case No. U-21813

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the application of **UPPER MICHIGAN ENERGY RESOURCES CORPORATION** requesting approval of an amended renewable energy plan to comply with Public Act 235 of 2023.	)	Case No. U-21813

PROTECTIVE ORDER

This Protective Order governs the use and disposition of Protected Material that Upper Michigan Energy Resources Corporation ("Applicant") or any other Party discloses to another Party during the course of this proceeding. The Applicant or other Party disclosing Protected Material is referred to as the "Disclosing Party"; the recipient is the "Receiving Party" (defined further below). The intent of this Protective Order is to protect non-public, confidential information and materials so designated by the Applicant or by any other party, which information and materials contain confidential, proprietary, or commercially sensitive information. This Protective Order defines "Protected Material" and describes the manner in which Protected Material is to be identified and treated. Accordingly, it is ordered:

I. "Protected Material" and Other Definitions

A. For the purposes of this Protective Order, "Protected Material" consists of trade secrets or confidential, proprietary, or commercially sensitive information to be provided by Disclosing Party and any testimony, exhibits, workpapers, discovery, audit responses, any witness' related exhibits and testimony, and any arguments of counsel describing or relying upon the Protected Material. Subject to challenge under Paragraph IV.A, Protected Material shall consist of non-public confidential information and materials including, but not limited to, the following information disclosed during the course of this case if it is marked as required by this Protective Order:

1. Trade secrets or confidential, proprietary, or commercially sensitive information provided in response to discovery, in response to an order issued by the presiding officer or the Michigan Public Service Commission ("MPSC" or the "Commission"), in testimony or exhibits filed later in this case, or in arguments of counsel;

2. To the extent permitted, information obtained under license from a third-party licensor, to which the Disclosing Party or witnesses engaged by the Disclosing Party is a licensee, that is subject to any confidentiality or non-transferability clause. This information includes reports; analyses; models (including related inputs and outputs); trade secrets; and confidential, proprietary, or commercially sensitive information that the Disclosing Party or one of its witnesses receives as a licensee and is authorized by the third-party licensor to disclose consistent with the terms and conditions of this Protective Order; and

3. Information that could identify the bidders and bids, including the winning bid, in a competitive solicitation for a power purchase agreement or in a competitively bid engineering, procurement, or construction contract at any stage of the selection process (i.e., before the Disclosing Party has entered into a power purchase agreement or selected a contractor).

B. The information subject to this Protective Order does not include:

1. Information that is or has become available to the public through no fault of the Receiving Party or Reviewing Representative and no breach of this Protective Order, or information that is otherwise lawfully known by the Receiving Party without any obligation to hold it in confidence;

2. Information received from a third party free to disclose the information without restriction;

3. Information that is approved for release by written authorization of the Disclosing Party, but only to the extent of the authorization;

4. Information that is required by law or regulation to be disclosed, but only to the extent of the required disclosure; or

5. Information that is disclosed in response to a valid, non-appealable order of a court of competent jurisdiction or governmental body, but only to the extent the order requires.

C. "Party" refers to the Applicant, MPSC Staff ("Staff"), the Michigan Attorney General, or any other person, company, organization, or association that is granted intervention in this Case No. U-21813 under the Commission's Rules of Practice and Procedure, Mich Admin Code, R 792.10401 et al.

D. "Receiving Party" means any Party to this proceeding who requests or receives access to Protected Material, subject to the requirement that each Reviewing Representative sign a Nondisclosure Certificate attached to this Protective Order as Attachment 1.

E. "Reviewing Representative" means a person who has signed a Nondisclosure Certificate and who is:

1. an attorney who has entered an appearance in this proceeding for a Receiving Party;

2. an attorney, paralegal, or other employee associated, for the purpose of this case, with an attorney described in Paragraph I.E.1;

3. an expert or employee of an expert retained by a Receiving Party to advise, prepare for, or testify in this proceeding; or

4. an employee or other representative of a Receiving Party with significant responsibility in this case.

A Reviewing Representative is responsible for assuring that persons under his or her supervision and control comply with this Protective Order.

F. "Nondisclosure Certificate" means the certificate attached to this Protective Order as Attachment 1, which is signed by a Reviewing Representative who has been granted access to Protected Material and agreed to be bound by the terms of this Protective Order.

II. Access to and Use of Protected Material

A. This Protective Order governs the use of all Protected Material that is marked as required by Paragraph III.A and made available for review by the Disclosing Party to any Receiving Party or Reviewing Representative. This Protective Order protects: 1) the Protected Material; 2) any copy or reproduction of the Protected Material made by any person; and 3) any memorandum, handwritten notes, or any other form of information that copies, contains, or discloses Protected Material. All Protected Material in the possession of a Receiving Party shall be maintained in a secure place. Access to Protected Material shall be limited to persons authorized to have access subject to the provisions of this Protective Order.

B. Protected Material shall be used and disclosed by the Receiving Party solely in accordance with the terms and conditions of this Protective Order. A Receiving Party may authorize access and use of Protected Material by a Reviewing Representative identified by the Receiving Party, subject to Paragraphs III and V below, only as necessary to analyze the Protected Material; make or respond to discovery; present evidence; prepare testimony, argument, briefs, or other filings; prepare for cross-examination; consider strategy; and evaluate settlement. These individuals shall not release or disclose the content of Protected Material to any other person or use the information for any other purpose.

C. The Disclosing Party retains the right to object to any designated Reviewing Representative if the Disclosing Party has reason to believe that there is an unacceptable risk of misuse of confidential information. If a Disclosing Party objects to a Reviewing Representative, the Disclosing Party and the Receiving Party will attempt to reach an agreement to accommodate that Receiving Party's request to review Protected Material. If no agreement is reached, then either the Disclosing Party or the Receiving Party may submit the dispute to the presiding officer. If the Disclosing Party notifies a Receiving Party of an objection to a Reviewing Representative, then the Protected Material shall not be provided to that Reviewing Representative until the objection is resolved by agreement or by the presiding officer.

D. Before reviewing any Protected Material, including copies, reproductions, and copies of notes of Protected Material, a Receiving Party and Reviewing Representative shall sign a copy of the Nondisclosure Certificate (Attachment 1 to this Protective Order) agreeing to be bound by the terms of this Protective Order. The Reviewing Representative shall also provide a copy of the executed Nondisclosure Certificate to the Disclosing Party.

E. Even if no longer engaged in this proceeding, every person who has signed a Nondisclosure Certificate continues to be bound by the provisions of this Protective Order. The obligations under this Protective Order are not extinguished or nullified by entry of a final order in this case and are enforceable by the MPSC or a court of competent jurisdiction. To the extent Protected Material is not returned to a Disclosing Party, it remains subject to this Protective Order.

F. Members of the Commission, Commission staff assigned to assist the Commission with its deliberations, and the presiding officer and any other administrative law judge ("ALJ") or ALJ staff member working on this matter shall have access to all Protected Material that is submitted to the Commission under seal without the need to sign the Nondisclosure Certificate.

G. A Party retains the right to seek further restrictions on the dissemination of Protected Material to persons who have or may subsequently seek to intervene in this MPSC proceeding.

H. Nothing in this Protective Order precludes a Party from asserting a timely evidentiary objection to the proposed admission of Protected Material into the evidentiary record for this case.

III. Procedures

A. The Disclosing Party shall mark any information that it considers confidential as "CONFIDENTIAL: SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-21813." If the Receiving Party or a Reviewing Representative makes copies of any Protected Material, they shall conspicuously mark the copies as Protected Material. Notes of Protected Material shall also be conspicuously marked as Protected Material by the person making the notes.

B. If a Receiving Party wants to quote, refer to, or otherwise use Protected Material in pleadings, pre-filed testimony, exhibits, cross-examination, briefs, oral argument, comments, or in some other form in this proceeding (including administrative or judicial appeals), the Receiving Party shall do so consistent with procedures that will maintain the confidentiality of the Protected Material. For purposes of this Protective Order, the following procedures apply:

> 1. Written submissions using Protected Material shall be filed in a sealed record to be maintained by the MPSC's Docket Section, or by a court of competent jurisdiction, in envelopes clearly marked on the outside, "CONFIDENTIAL — SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-21813." Simultaneously, identical documents and materials, with the Protected Material redacted, shall be filed and disclosed the same way that evidence or briefs are usually filed;
>
> 2. Oral testimony, examination of witnesses, or argument about Protected Material shall be conducted on a separate record to be maintained by the MPSC's Docket Section or by a court of competent jurisdiction. These separate record proceedings shall be closed to all persons except those furnishing the Protected Material and persons otherwise subject to this Protective Order. The Receiving Party presenting the Protected Material during the course of the proceeding shall give the presiding officer or court sufficient notice to allow the presiding officer or court an opportunity to take measures to protect the confidentiality of the Protected Material; and
>
> 3. Copies of the documents filed with the MPSC or a court of competent jurisdiction, which contain Protected Material, including the portions of the exhibits, transcripts, or briefs that refer to Protected Material, must be sealed and maintained in the MPSC's or court's files with a copy of the Protective Order attached.

C. It is intended that the Protected Material subject to this Protective Order should be shielded from disclosure by a Receiving Party only to the extent permitted by law. If any person files a request under the Freedom of Information Act with a governmental agency participating in this proceeding, including, but not limited to, the MPSC, the MPSC Staff, and the Michigan Attorney General, seeking access to documents subject to this Protective Order, the governmental agency shall promptly notify the Disclosing Party, and the Disclosing Party may take whatever legal actions it deems appropriate to protect the Protected Material from disclosure. In light of Section 5 of the Freedom of Information Act, MCL 15.235, the notice must be given at least five (5) business days before the governmental agency grants the request in full or in part.

IV. Termination of Protected Status

A. A Receiving Party reserves the right to challenge whether a document or information is Protected Material and whether this information can be withheld under this Protective Order. In response to a motion, the Commission or the presiding officer in this case may revoke a document's protected status after notice and hearing. If the presiding officer revokes a document's protected status, then the document loses its protected status after 14 days unless a Party files an application for leave to appeal the ruling to the Commission within that time period. Any Party opposing the application for leave to appeal shall file an answer with the Commission no more than 14 days after the filing and service of the appeal. If an application is filed, then the information will continue to be protected from disclosure until either the time for appeal of the Commission's final order resolving the issue has expired under MCL 462.26 or, if the order is appealed, until judicial review is completed and the time to take further appeals has expired.

B. If a document's protected status is challenged under Paragraph IV.A, the Receiving Party challenging the protected status of the document shall explicitly state its reason for challenging the confidential designation. The Disclosing Party bears the burden of proving that the document should continue to be protected from disclosure.

V. Retention of Documents

A. Protected Material remains the property of the Disclosing Party. The Protected Material only remains available to the Receiving Party, unless the Receiving Party is an agency/public official of the State of Michigan subject to state documentation retention schedules, until the time expires for petitions for rehearing of a final MPSC order in this Case

No. U-21813 or until the MPSC has ruled on all petitions for rehearing in this case (if any). Should the Receiving Party be an agency/public official of the State of Michigan who retains the Protected Material to comply with applicable state documentation retention schedules, it is acknowledged that this Order will continue in effect and said Receiving Party will be required to retain the Protected Material in accordance with this Order. On or before the time specified by the preceding sentences, the Receiving Party shall return to the Disclosing Party all Protected Material in its possession or in the possession of its Reviewing Representatives—including all copies and notes of Protected Material—or destroy the Protected Material and, at the request of the Disclosing Party, certify in writing that it has done so.

B. Notwithstanding the preceding paragraph, Counsel for a Receiving Party may maintain confidential files of Protected Material beyond the resolution of this proceeding, provided that this Order will continue in effect with respect to the Protected Material for so long as it is retained by counsel for any requesting Party. For purposes of this paragraph, the "resolution" of a case means the expiration of the period of judicial review of a final order of the Commission. Counsel for a Requesting Party shall have the right to retain copies of the pleadings, orders, transcripts, briefs, comments, and exhibits in these proceedings, but this protective order will continue in effect with respect to the Protected Material contained in these documents. If the Protected Material is relevant or reasonably calculated to lead to admissible evidence in another Commission proceeding relating to and involving the Disclosing Party, then it may be used subject to the issuing of a new protective order in that case.

VI. Limitations and Disclosures

The provisions of this Protective Order do not apply to a particular document, or portion of a document, described in Paragraph II.A if a Receiving Party can demonstrate that it has been previously disclosed by the Disclosing Party on a non-confidential basis or meets the criteria set forth in Paragraphs I.B.l through I.B.5. A Receiving Party intending to disclose information taken directly from materials identified as Protected Material must—before actually disclosing the information do one of the following: 1) contact the Disclosing Party's counsel of record and obtain written permission to disclose the information, or 2) challenge the confidential nature of the Protected Material and obtain a ruling under Paragraph IV that the information is not confidential and may be disclosed in or on the public record. The preceding sentence shall not apply to disclosures required under the Freedom of Information Act. Paragraph III C of this Order addresses the procedures for Freedom of Information Act disclosures.

VII. Remedies

If a Receiving Party violates this Protective Order by improperly disclosing or using Protected Material, the Receiving Party shall take all necessary steps to remedy the improper disclosure or use. This includes promptly notifying the MPSC, the presiding officer, and the Disclosing Party, in writing, of the identity of the person known or reasonably suspected to have obtained the Protected Material. A Party or person that violates this Protective Order remains subject to this paragraph regardless of whether the Disclosing Party could have discovered the violation earlier than it was discovered. This paragraph applies to both inadvertent and intentional violations. Nothing in this Protective Order limits the Disclosing Party's rights and remedies, at law or in equity, against a Party or person using Protected Material in a manner not authorized by this Protective Order, including the right to obtain injunctive relief in a court of competent jurisdiction to prevent violations of this Protective Order.

____

Administrative Law Judge

Attachment 1

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

****

In the matter of the application of **UPPER MICHIGAN ENERGY RESOURCES CORPORATION** requesting approval of an amended renewable energy plan to comply with Public Act 235 of 2023.	)	Case No. U-21813

NONDISCLOSURE CERTIFICATE

By signing this Nondisclosure Certificate, I acknowledge that access to Protected Material is provided to me under the terms and restrictions of the Protective Order issued in Case No. U-21813, that I have been given a copy of and have read the Protective Order, and that I agree to be bound by the terms of the Protective Order. I understand that the substance of the Protected Material (as defined in the Protective Order), any notes from Protected Material, or any other form of information that copies or discloses Protected Material, shall be maintained as confidential and shall not be disclosed to anyone other than in accordance with the Protective Order.

Reviewing Representative

Date: ____________________

____
Title:
Representing:

MICHIGAN DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS
PUBLIC SERVICE COMMISSION

ENTRY OF APPEARANCE IN AN ADMINISTRATIVE HEARING

This form is issued as provided for by 1939 PA 3, as amended, and by 1933 PA 254, as amended. The filing of this form, or an acceptable alternative, is necessary to ensure subsequent service of any hearing notices, Commission orders, and related hearing documents.

General Instructions:

Type or print legibly in ink. For assistance or clarification, please contact the Public Service Commission at 517-284-8090.

Please Note: *The Commission will provide* ***electronic*** *service of documents to all parties in this proceeding.*

THIS APPEARANCE TO BE ENTERED IN ASSOCIATION WITH THE ADMINISTRATIVE HEARING:

Case / Company Name: Upper Michigan Energy Resources Corporation Docket No. U- 21813

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name) Upper Michigan Energy Resources Corporation
2. (Name)
3. (Name)
4. (Name)
5. (Name)
6. (Name)
7. (Name)

Name Sherri A. Wellman

Address Miller Canfield

123 West Allegan Street, Suite 200

City Lansing State MI

Zip 48933 Phone 517-483-4954

Email wellmans@millercanfield.com

Date 02/27/2025

Signature: Sherri A. Wellman

Digitally signed by: Sherri A. Wellman
DN: CN = Sherri A. Wellman email = wellmans@millercanfield.com C = US O = Miller Canfield
Date: 2025.02.27 14:22:33 -05'00'

- ○ I am not an attorney
- ◉ I am an attorney whose:

Michigan Bar # is P-38989

________ Bar # is: ________
(state)

MICHIGAN DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS
PUBLIC SERVICE COMMISSION

ENTRY OF APPEARANCE IN AN ADMINISTRATIVE HEARING

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Case / Company Name: Upper Michigan Energy Resources Corporation Docket No. U- 21813

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name) Upper Michigan Energy Resources Corporation
2. (Name)
3. (Name)
4. (Name)
5. (Name)
6. (Name)
7. (Name)

Name Paul M. Collins

Address Miller Canfield

123 West Allegan Street, Suite 200

City Lansing State MI

Zip 48933 Phone 517-483-4908

Email collinsp@millercanfield.com

Date 02/27/2025

Signature: Paul M. Collins

Digitally signed by: Paul M. Collins
DN: CN = Paul M. Collins email = Collinsp@MillerCanfield.com C = US O = Miller, Canfield, Paddock and Stone, P.L.C. OU = Attorney at Law
Date: 2025.02.27 14:22:50 -05'00'

○ I am not an attorney

◉ I am an attorney whose:

Michigan Bar # is P-69719

__________ Bar # is: __________
(state)