6. **Initiating renewable resource builds in the nearer term provides the opportunity to realize tax incentives for customers.**

Ameren Missouri's Need for Energy Resources

Ameren Missouri's existing generation fleet has a total net capability of 10,142 MW. Of this, half is coal, 12% is nuclear, 8% is hydroelectric and other renewables, and 30% is gas or oil fired peaking generation. In contrast, coal currently provides approximately 70% of the energy produced by our fleet, with nuclear providing roughly 25% and renewables providing another 5%. Gas and oil fired resources provide less than 1% of the energy produced by our existing fleet. As coal-fired resources are retired or as their level of production decreases as a result of changes in operating efficiencies, CO_2 prices, other market conditions, regulatory constraints, or other factors, new energy resources will be needed to supplement the remaining generation. While the peaking generation will continue to provide capacity to meet peak demand and reserve margin needs, it will not be able to make up for the loss of coal-fired energy on its own. In fact, it is likely the production levels from these coal-fired energy assets will remain relatively low as they are dispatched in the Midcontinent Independent System Operator ("MISO") market and as they are operated in compliance with environmental permit constraints. The continued availability of these affordable coal-fired energy assets does allow Ameren Missouri to maintain reliability as increasing amounts of renewable energy are integrated into the system to meet customer needs.

Figure 10.3 Energy Comparison for Selected Plans – Low CO_2 Price

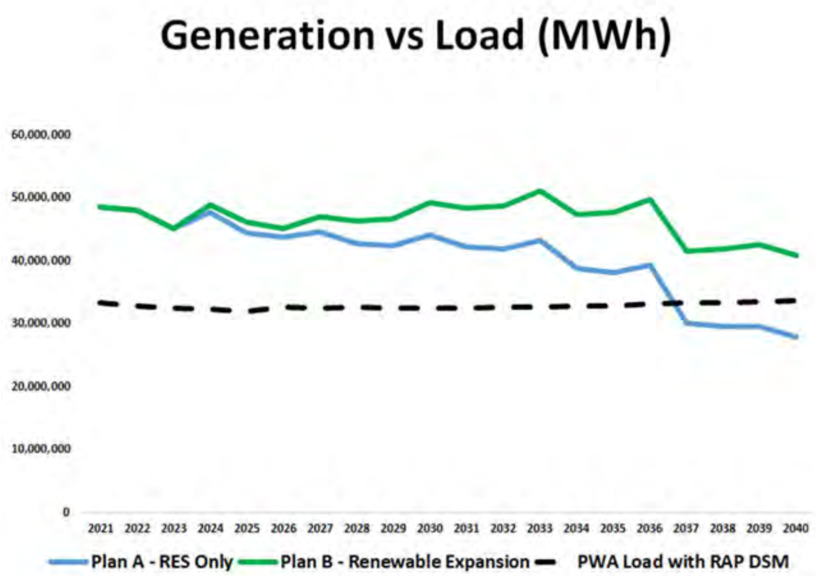
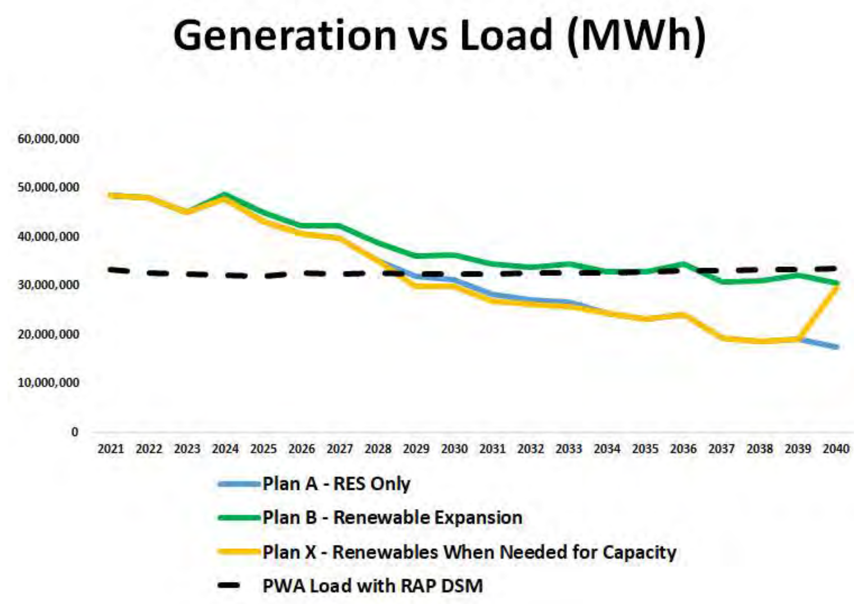


Figure 10.3 shows a comparison of the energy production from several of our alternative plans under our Low CO_2 price scenario. Figure 10.4 shows a similar comparison of energy production for several alternative plans under our High CO_2 price scenario, which

results in reduced levels of generation from coal resources (and also gas to a much lesser extent) compared to the levels of production under the Low CO_2 price scenario. The chart shows that for Plan 2 (RAP – RES Compliance), which does not include a large renewable buildout, Ameren Missouri would be generating less energy than its customers use by 2030 and that this shortfall would grow to over one-third of total load by 2040. Any acceleration of coal energy center retirements further exacerbates this issue.

Taken together, the charts in Figures 10.3 and 10.4 highlight a key consideration in the approach to our renewable resource expansion. There is significant uncertainty regarding the level of production from our existing fleet of resources. Differences in future CO_2 prices is only one source of this uncertainty, but it helps to highlight the broader issue. Other sources of uncertainty include natural gas prices, power prices, environmental regulation, and potential changes in climate policy. All of these and perhaps others could impact coal-fired resources and result in a much earlier need for new energy generation. Waiting until such needs are certain may result in suboptimal solutions and potential higher costs to customers. It could also result in an unintended but necessary reliance on fossil-fueled generation like natural gas combined cycle, deferring or displacing some renewable resource additions.

Figure 10.4 Energy Comparison for Selected Plans – High CO_2 Price



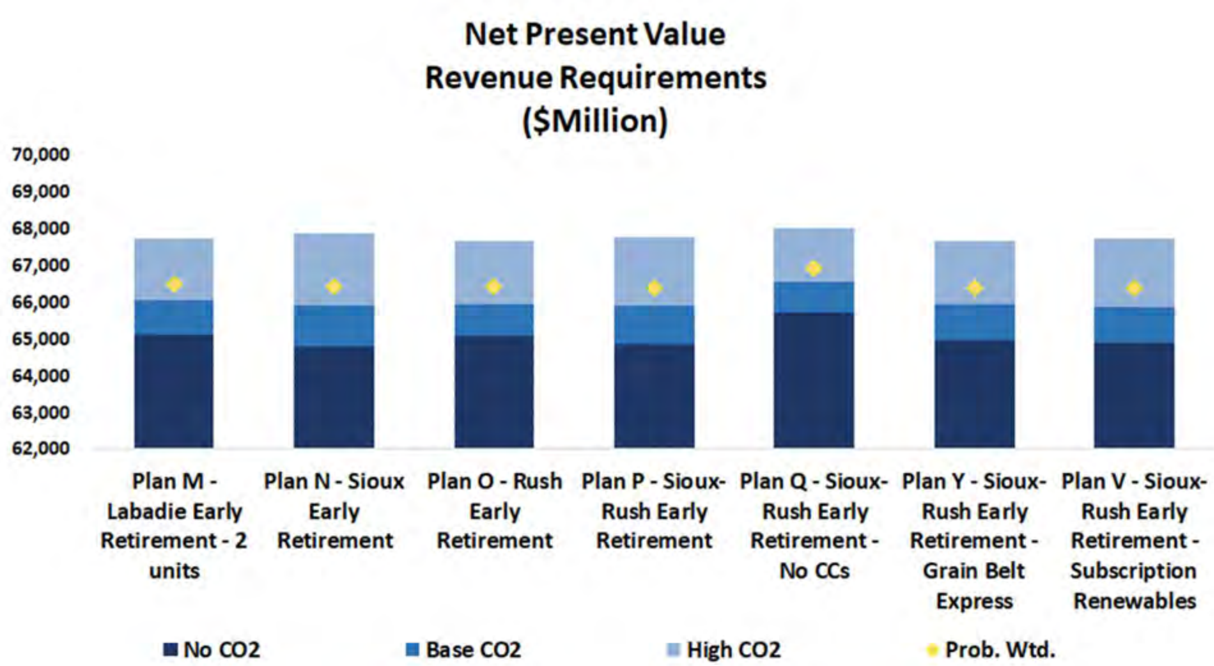
Risk Mitigation Benefits of Renewable Expansion

Our analysis shows that higher CO_2 prices have a beneficial impact on the economics of renewable resources and a detrimental effect on the economics of coal-fired resources. The impact on coal is somewhat obvious in that the CO_2 prices impose a cost directly on the energy production from coal generators. It is this cost imposed on coal and gas generators that also manifests itself in power market prices, as illustrated in Chapter 2.

The higher the CO_2 price, the higher the power price. Wind and solar generation, along with other non-carbon-emitting generating sources like hydro and nuclear, therefore see a benefit from CO_2 prices through the revenue they receive in the market. In contrast, the absence of a CO_2 price results in maximal benefits to coal-fired generation and minimal benefits to renewables, nuclear and hydro.

By expanding the share of renewable resources in our portfolio, we increase the balance of resources that from an economic perspective perform better as CO_2 prices rise and resources whose performance diminishes as CO_2 prices rise. This is not unlike the diversification of personal investments like those many hold in retirement funds like a 401(k) plan. By investing in a variety of resources, each of which perform well under different conditions, the overall risk of the portfolio can be mitigated. To illustrate this effect in the context of resource planning, we can simply examine how various alternative resource plans perform under different levels of CO_2 price. Figure 10.5 shows the PVRR results for several plans with different levels of renewable energy resources under the three different scenarios for CO_2 price used in our risk analysis.

Figure 10.5 PVRR Results for Selected Plans by CO_2 Price Scenario



As the chart in Figure 10.5 shows, the steady addition of wind and solar resources provides risk mitigation around the range of CO_2 prices used for risk analysis, with costs to customers under the No CO_2 price scenario being slightly higher than without the steady buildout and significantly lower under the high CO_2 price scenario. This is in addition to the risk mitigation highlighted by the discussion of energy needs above. Specifically, the steady addition of renewable resources mitigates risk with respect to numerous factors that could impact the production of coal-fired resources, including market prices for energy, environmental regulations and other energy policies.

Continuing Value of Ameren Missouri's Coal-fired Fleet

Ameren Missouri's coal-fired generators are among the most efficient and cost-effective in MISO. They, along with our nuclear and hydro resources, provide around-the-clock capability that serves as a foundation for reliable energy supply to our customers. While the challenges associated with coal-fired generation continue to increase, Ameren Missouri has found innovative ways to maintain affordability of reliable operations while meeting or exceeding current environmental standards. Our alternative resource plan demonstrates the ongoing viability of our Labadie and Rush Island Energy Centers as we prepare to manage our Meramec and Sioux Energy Centers to the ends of their useful lives during this decade.

The primary factor in our analysis influencing the long-term viability of Labadie and Rush Island is CO_2 prices. While high CO_2 prices would negatively affect the economics of these units, we are able to monitor climate policy developments and adjust our plans accordingly as future policies become clearer. In the meantime, we can continue to rely on these units to provide reliable energy in order to integrate increasing amounts of renewable energy, as well as to provide the resultant economic benefits to customers. As a result, we have an opportunity to build out a significant portfolio of cleaner and more diverse renewable resources that enhance customer affordability, mitigate the risks of CO_2 prices, and mitigate the risks of a potential urgent need for capacity that might otherwise need to be satisfied by gas-fired resources.

Customer and Policy Drivers of the Need for Renewable Resources

Customers are expressing an increasing preference for energy supplied by renewable resources. One way to meet this growing demand is to offer programs that allow customers to increase the share of their energy needs that is supplied by renewable resources. In addition to such programs, there has also been a growing sentiment that greater levels of renewable generation should be available to all customers. This is the sentiment that drove the adoption of Missouri's RES in 2008. Ameren Missouri will soon have the resources necessary to comply with the full requirement of the RES upon completion of 700 MW of wind generation projects in Missouri.[1]

Because of the success of Missouri's RES and the still growing demand for renewable energy resources, policymakers and advocates are continuing to push for energy policies to promote clean and renewable energy resources. This includes the potential for a federal Clean Energy Standard ("CES") and an increase in the requirements for the

[1] Since the time of the Company's 2020 IRP filing, the need for renewable resources for RES compliance has been reassessed, resulting in changes to the timing of need for solar resources as reflected in the Company's RES compliance plan and supporting workpapers filed April 15, 2021 (File No. EO-2021-0352).

Missouri RES in future years. Both policies could drive a further expansion of renewable resources.

Figure 10.6 Percentage of Retail Sales Served by Renewable Energy

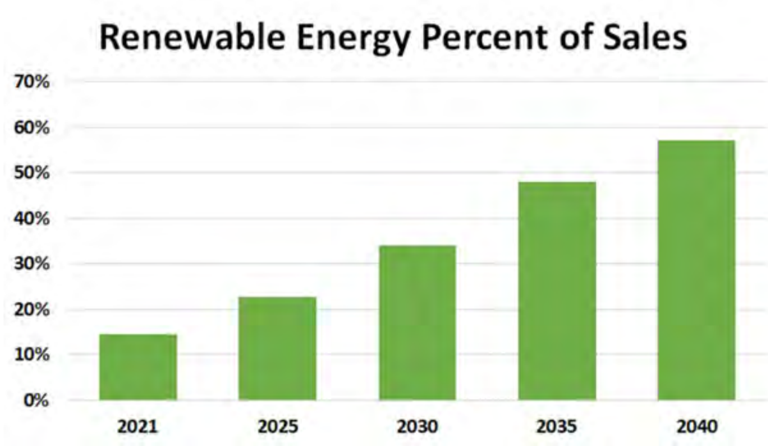


Figure 10.6 shows the percentage of customer sales generated by renewable resources with our Renewable Expansion portfolio. Should explicit policies requiring greater percentages of renewable resources than the current RES requires be enacted, this portfolio would better position Ameren Missouri to meet such requirements.

Practical Considerations for Large-Scale Renewable Expansion

It is one thing to set forth a plan to meet customer energy needs for the next twenty years. It is quite another thing to execute plans and construct the renewable energy resources to serve those needs. So while we have some time to build out the entire renewable resource portfolio, there are practical considerations that must be taken into account when embarking on the kind of portfolio transformation that Ameren Missouri believes is necessary to best meet our customers' future energy needs. These include practical limitations on project permitting, development and construction, environmental studies, the need for new transmission infrastructure to deliver renewable energy, and the ability to finance project construction. By spreading out the build of renewable resources, we mitigate practical project construction risks associated with the beneficial transformation of the generation portfolio and preserve flexibility to address these and possibly other potential roadblocks that may hamper resource acquisition.

As we have seen in recent years, the development, approval, and construction of renewable resources presents unique challenges. These include complications associated with permitting requirements, acquisition of land leases, and securing necessary regulatory approvals. Spreading out the addition of renewable resources allows us to maintain flexibility, reliability, and affordability in our acquisition and integration of those resources without the pressure of a clear and imminent capacity need.

Likewise, the need for transmission infrastructure can present unique and project-specific challenges that flexibility can help to overcome. As we saw with the planned Brickyard Hills wind project, the costs for transmission network upgrades associated with new projects can change dramatically depending on the capacity of the existing transmission network to accommodate additional wind generation and the amount of wind generating capacity seeking interconnection through the queue in a given Regional Transmission Organization ("RTO"). This could easily be true for large-scale solar projects as well, which are likely necessary to achieve the level of solar resources called for in our plan. By pursuing a steady buildout of wind and solar generation, we maintain flexibility to be selective and opportunistic with respect to projects for a host of reasons, including costs for necessary transmission system upgrades.

Another key consideration is Ameren Missouri's ability to raise the necessary capital to fund project construction. Ameren Missouri seeks to maintain sufficient credit metrics to ensure access to capital markets to fund not only renewable resource acquisition but also grid modernization and a number of other investments necessary to ensure safe, reliable and affordable service to our customers. We have evaluated the performance all of our alternative resource plans with respect to these credit metrics and have included the results in Chapter 9. We also included consideration of these credit metrics in our scorecard assessment of alternative resource plans as part of our Financial/Regulatory planning objective.

Table 10.6 Credit Metrics for Selected Plans vs. Target Metrics

Plan Description		FFO/Debt	FFO Interest Coverage
	Target Credit Metrics	25.0%	6.30
P	Sioux-Rush Early Retirement	23.9%	6.91
V	Sioux-Rush Early Retirement - Renewable Subscription	23.9%	6.89
X	Sioux-Rush Early Retirement - Renewables when needed	19.3%	6.46

Table 10.6 shows the credit metrics for three plans compared to our target credit metrics. These represent the minimum results for the period 2030-2040 for funds from operations ("FFO") to total debt and FFO to interest expense. As the table shows, the credit metrics for Plan X, in which renewable additions are included only when needed for capacity are significantly lower than those for Plans P and V, in which renewable additions are added throughout the planning horizon. Most notably, the FFO/Debt metric for Plan X is well below our target for this metric. While metrics for individual years during the 20-year planning horizon may not indicate a credit challenge, the degree to which the metrics vary from other plans provides an indication that such challenges may be more likely.

Capturing the Value of Available Tax Credits

Current tax law includes production tax credits ("PTC") for wind generation and additional investment tax credits ("ITC") for solar generation. Ameren Missouri has captured significant value for customers with the wind projects currently nearing completion through the PTC. Continuing our buildout of renewable energy projects allows us the opportunity to capture significantly more value from PTC and ITC for wind and solar projects in the next several years.

Weighing the Considerations Together

In accounting for the foregoing considerations and in conjunction with our rigorous risk analysis of alternative resource plans, we conclude that a continued buildout of renewable wind and solar resources throughout the planning horizon yields significant real and potential benefits for our customers with limited downside. It provide us with valuable risk mitigation regarding CO_2 prices and other factors, and valuable flexibility in managing the transformation of our generation portfolio.

Schedule MM-S28

Key Conclusions

- Transition of our resource portfolio to cleaner sources of generation is imperative
- Customers face significant risks if we do not execute on our planned portfolio transition as embodied in our IRP preferred plan
  - Loss of flexibility to manage execution risks
  - Loss of flexibility to effectively adjust plans in response to changing conditions
  - Decreased potential to take advantage of higher quality resource opportunities
  - Potential increases in financing costs and constraints
- Our planned transition substantially mitigates the risks described above
- Our planned transition also mitigates market risk rather than imposing an additional cost on customers to mitigate the risks described above
- Shareholders face various types of risk to the realization of expected equity returns

Risks to Customers if Transition Not Executed

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- Lost flexibility to manage execution risks
  - Permitting process
  - Project supply chain, capabilities and costs
  - Transmission infrastructure needs and interconnection costs
- Lost flexibility to respond to changing conditions that may accelerate the need for new generation sources
  - Changes in energy policy and regulation affecting coal-fired generation
  - More rapid increase in electrification demand
- Lost opportunities to acquire more beneficial projects from among a finite set of possibilities, including potential lost advantages of geographic diversity
- Higher cost of capital resulting from investor expectations and risk perceptions associated with carbon-emitting resources
  - $127 million increase in PVRR for every 10 basis points increase in ROE

Schedule MM-S28

Potential Implications of Lost Flexibility

- Could result in non-optimal solutions
  - Need to deploy alternative resources more rapidly
  - Greater reliance on the broader market
    - At the same time the broader power industry is also transitioning away from coal-fired generation
    - Potentially reliant on new transmission that may take years to design, permit and construct
- Risks to affordable reliable service if solutions cannot be efficiently deployed

Schedule MM-S28

Market Price Risk Mitigation

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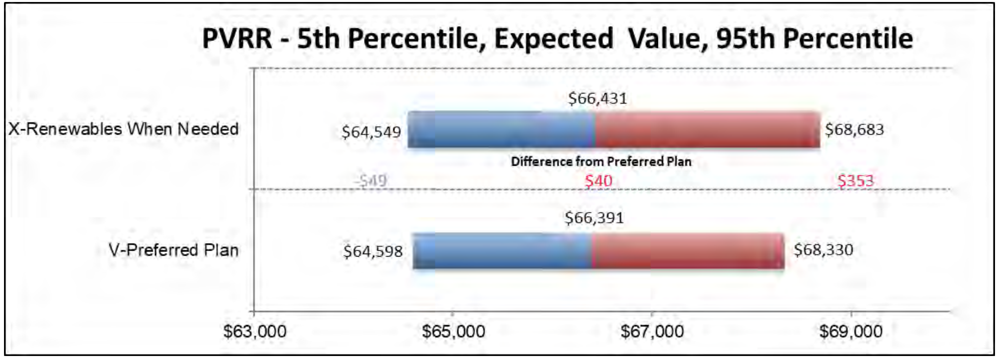

- Our preferred plan results in less variability in customer costs (PVRR) across our expected range of power market prices, providing market risk mitigation while also addressing key implementation risks.
- The analysis depicted above represents our assumed probable range for carbon prices. Carbon prices greater than those represented in our “High Carbon Price” case would result in greater market price risk mitigation.

Schedule MM-S28

Shareholder Risk – Investment Returns

- Shareholder risk is best considered in terms of risks to earning expected rates of return
- A number of factors related to renewable expansion can affect shareholder returns, but can be considered in a few categories
  - Project Management Risk – the risk of mismanagement of project execution resulting in disallowances from rate recovery
  - Retail Sales Risk – the risk that retail sales through which investment returns are realized do not materialize as expected
  - Regulatory Risk – the risk that inefficiencies in the regulatory and ratemaking processes will prevent full realization of expected and/or allowed rates of return (e.g., regulatory lag)
- This risk can be quantified in general by considering the capital revenue requirments associated with the investments
  - The PVRR for the investment component of our planned renewable transition is ~$5 billion
  - A recovery loss of 2-5% of this revenue requirement would be $100-250 million
- Shareholders would also be exposed to 5% of differences in associated margins from those included in base rates between rate reviews, assuming continuation of the existing FAC.

2022 IRP Preferred Plan Change

July 13, 2022

Schedule MM-S29

Agenda

- Overview of filing
  - Key changes since 2020 IRP
  - New preferred plan
  - Reliability analysis
  - Transition risk analysis
  - PVRR analysis
  - Implementation Plan
- Q&A

Key Changes Since 2020 IRP

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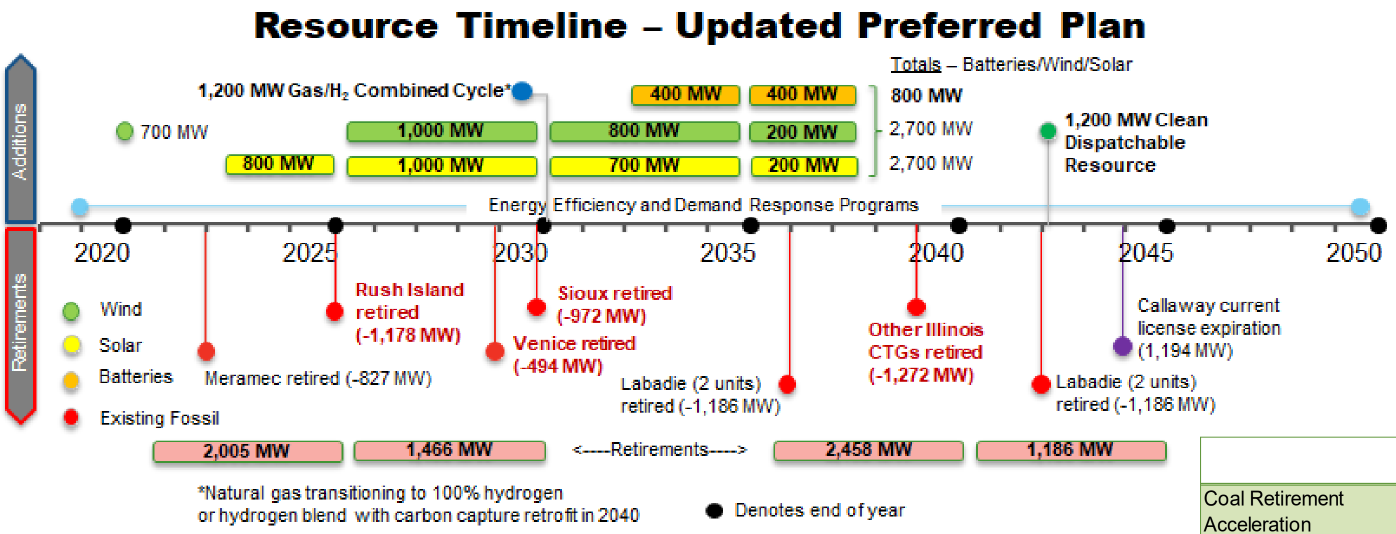
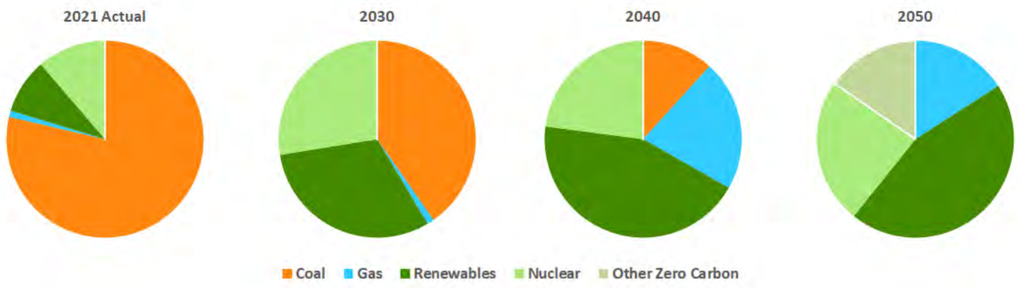
- Rush Island NSR result and retirement decision (~1,200 MW)
- Illinois legislation requiring accelerated retirement of Ameren Missouri gas-fired units in Illinois (~1,800 MW)
- MISO seasonal capacity construct proposal to FERC
- Change in power prices due to changes in key drivers:
  - Increase in expected CO_2 prices (see Appendix)
  - Increase in expected natural gas prices (see Appendix)
- Updated costs for renewable generation technologies (see Appendix)
- Supply chain risks
- Reliability analysis (Astrape' Consulting)
- Renewable transition risk analysis (Roland Berger Consulting)
- Preliminary insights from EPRI's Low Carbon Resources Initiative (LCRI) project

New Preferred Plan





- Updated CO_2 reduction goals
  - 60% by 2030
  - 85% by 2040
  - Net Zero by 2045
- Relative to 2005 Levels
- Contingent on technology developement

	2022 Preferred Plan	2020 IRP Preferred Plan
Coal Retirement Acceleration	**3,000 MW by 2030** 5,400 MW by 2042	1,800 MW by 2030 5,400 MW by 2042
Natural Gas Retirement Acceleration	**500 MW by 2030** **1,800 MW by 2040**	None
Renewable Additions	**3,500 MW by 2030** **5,000 MW by 2035** 5,400 MW by 2040	3,100 MW by 2030 4,300 MW by 2035 5,400 MW by 2040
Battery Storage Additions	**400 MW by 2035** **800 MW by 2040**	None
Carbon Emission Reduction (CO_2e)	**60% by 2030** 85% by 2040 **Net Zero by 2045**	50% by 2030 85% by 2040 Net Zero by 2050
Natural Gas Additions	**1,200 MW (2031)**	None
Other Clean Dispatchable Additions	**1,200 MW (2043)**	800 MW (2043)

Schedule MM-S29

Reliability Analysis

Year	2022	2025	2025	2030	2030	2035	2040	2040	2040	2040	2040
Case	*0*	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*
Rush Island	-	-1,178	-1,178	-1,178	-1,178	-1,178	-1,178	-1,178	-1,178	-1,178	-1,178
Sioux	-	-	-	-974	-	-974	-974	-974	-974	-974	-974
Battery Storage	-	-	-	-	-	-	354	354	354	354	1,540
CCGT	-	-	-	1,200	-	1,200	1,200	1,800	2,400	3,000	1,200
Labadie	-	-	-	-	-	-	-1,186	-1,186	-2,372	-2,372	-2,372
CT Gas	-	-	-	-491	-491	-1,765	-1,765	-1,765	-1,765	-1,765	-1,765
Solar	-	1,205	5	1,605	1,605	2,000	2,700	2,700	2,700	2,700	2,700
Wind	-	700	700	1,499	1,499	2,200	2,700	2,700	2,700	2,700	2,700
LOLE	**0.1**	0.7	1.2	0.3	1.3	0.7	1.5	0.4	1.0	0.2	2.1
Deficit Found	-	696	858	346	999	488	907	417	709	196	817
4-Hr Battery Equivalent	-	766	963	346	1,195	488	1,458	488	1,178	196	N/A

Transition Risk Analysis

Risk Variable	Description	Change in PVRR
Financing Costs	Fossil-heavy generation portfolios likely to have higher financing costs than cleaner and less carbon-intensive portfolios	$ 292 million
Land availability	Continued renewable build out will make "good land" scarcer over time, limiting capacity factors for wind	$ 247 million
Wind equipment Cost	Wind equipment cost declines and performance improvements may be less pronounced than NREL ATB assumes	$ 122 million
Solar equipment cost	Onshoring of solar PV equipment manufacturing as consequence of trade relations with China may result in higher costs	$ 59 million
Tax Credits	Extension of ITC and PTC per the proposal in the Build Back Better plan done through separate congressional action	$ 339 million

Note: Positive PVRR change indicates that the Capacity Need Plan gets relatively more expensive than the Renewable Transition Plan over study period.

PVRR Analysis

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Alternative Plans Analyzed

A. 2020 IRP Preferred Plan
B. Renewable Transition with Sioux retired at the end of 2028 and 1,200 MW NGCC generation in service at the beginning of 2029
C. Renewable Transition with Sioux retired at the end of 2030 and 1,200 MW NGCC generation in service at the beginning of 2031
D. Renewable Transition with Sioux retired at the end of 2033 and 1,200 MW NGCC generation in service at the beginning of 2034
E. Renewables for Capacity Need with Sioux retired at the end of 2030 and 1,200 MW NGCC generation in service at the beginning of 2031
F. Renewable Transition with Maximum Achievable Potential ("MAP") demand side management ("DSM"), Sioux retired at the end of 2030 and 1,200 MW NGCC generation in service at the beginning of 2031

	PVRR and PVRR Differences ($MM)	0%	50%	50%	<<<Probabilities
		No CO_2 Price	Low CO_2 Price	High CO_2 Price	Prob. Wtd.
A	2020 IRP Preferred Plan	75,361	76,594	78,946	77,770
B	Renewable Transition - Sioux 2028	77,277	78,172	79,934	79,053
C	Renewable Transition - Sioux 2030	77,181	78,116	79,933	79,024
D	Renewable Transition - Sioux 2033	77,092	78,085	79,973	79,029
E	Renewables for Capacity Need	77,307	78,502	80,811	79,656
F	Renewable Transition - Sioux 2028 - MAP	78,302	79,157	80,804	79,981
	Difference (Plan C vs. Plan E)	(126)	(386)	(878)	(632)

Key Implementation Steps

- CCN applications for solar generation projects
- Renewable Solutions program application
- Issue RFP to identify additional wind and solar project opportunities
- Finalize plans for the retirement of Rush Island Energy Center
- Adjust depreciation expense for Sioux Energy Center
- Securitization application for costs for Rush Island Energy Center
- Conduct preliminary work for the development of new NGCC generation
- Continuing to provide energy efficiency and demand response programs, including any approved modifications to the Company's programs and budgets through 2024

APPENDIX

Scenario Variables – CO_2 and Natural Gas Prices

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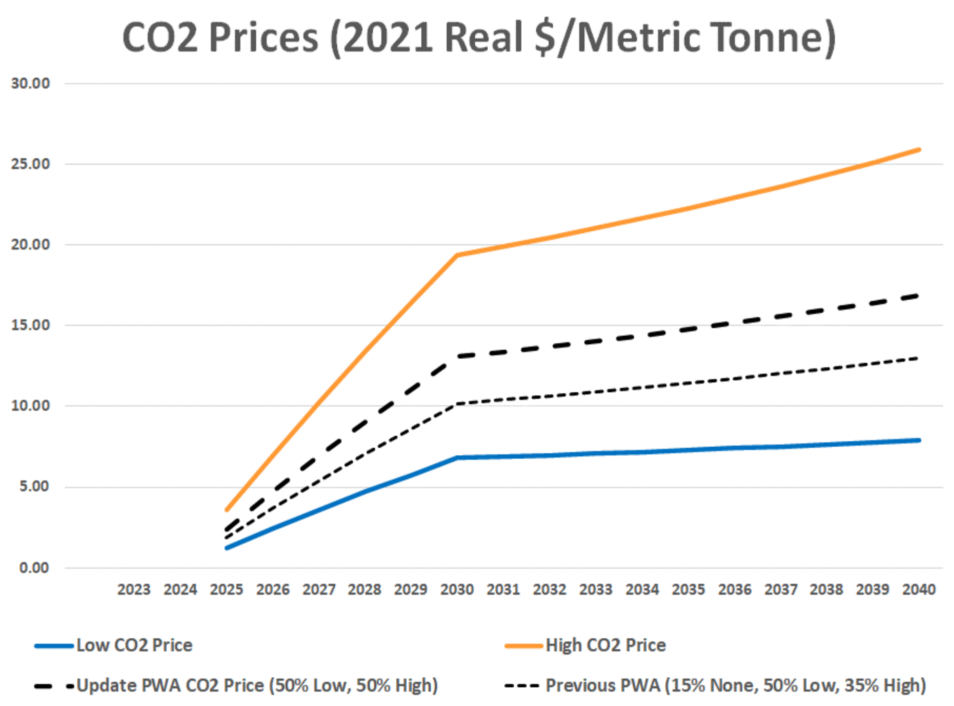
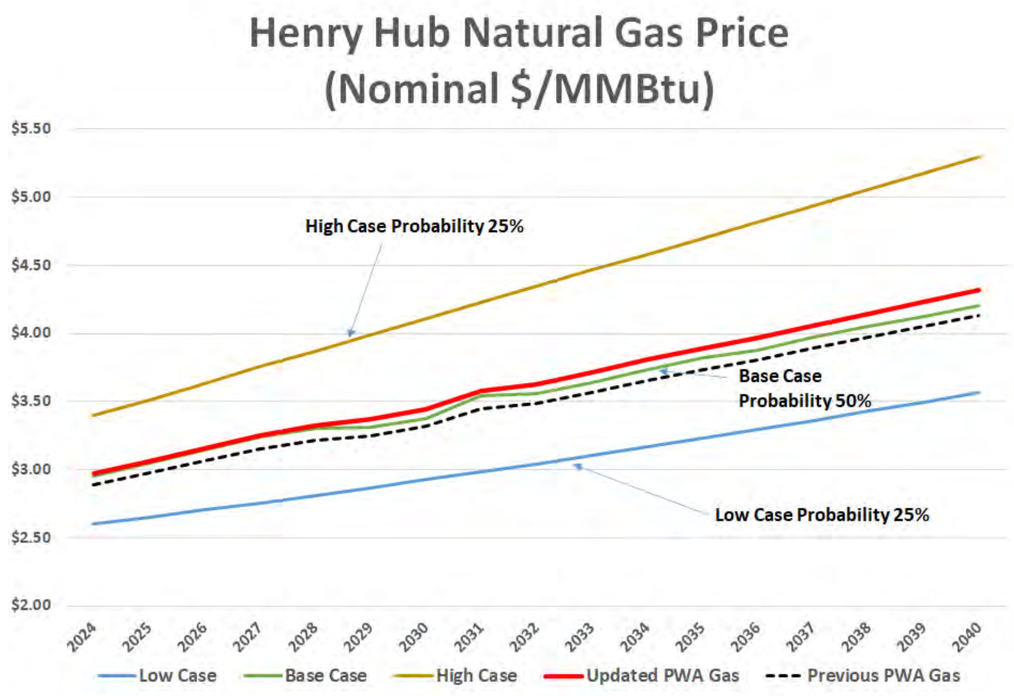
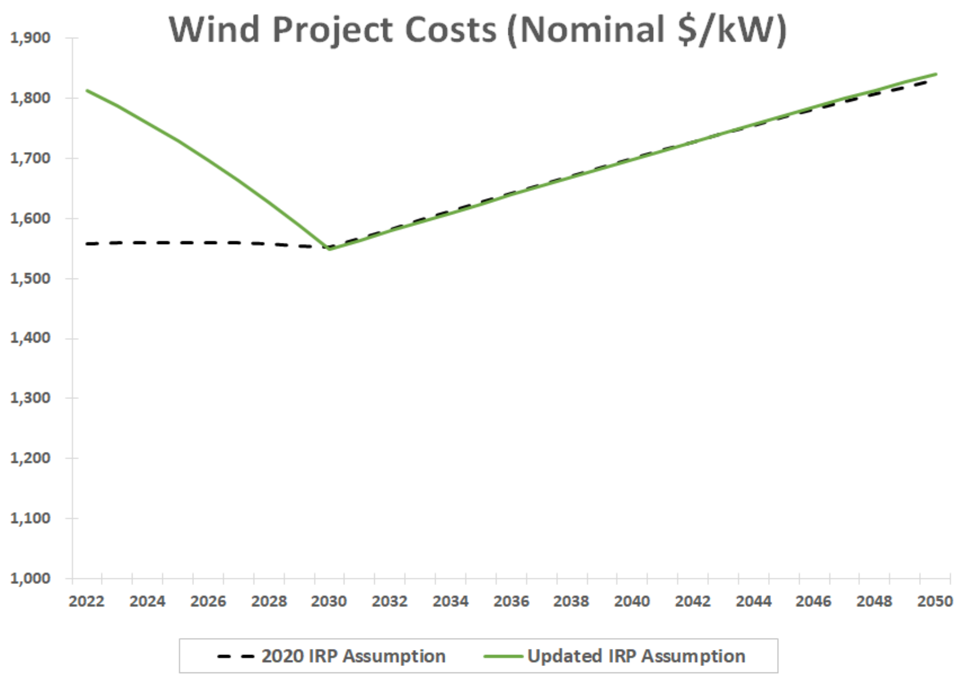
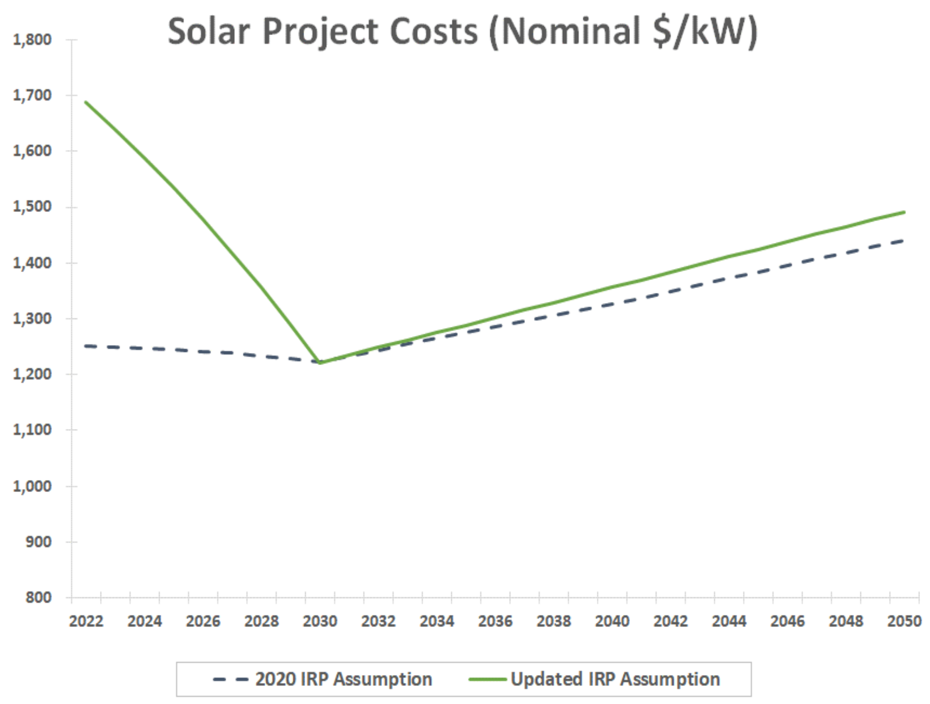




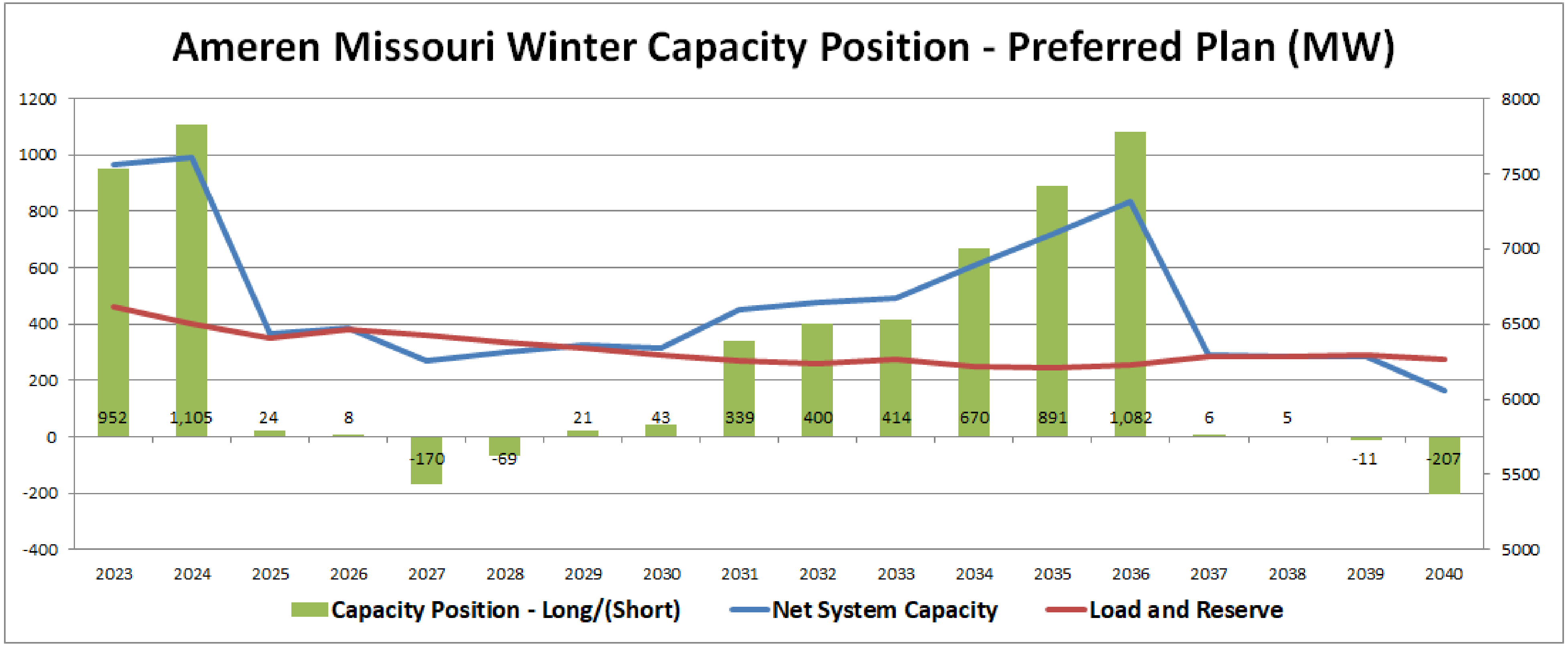
Schedule MM-S29

Wind and Solar Project Costs





Winter Capacity Position – Preferred Plan



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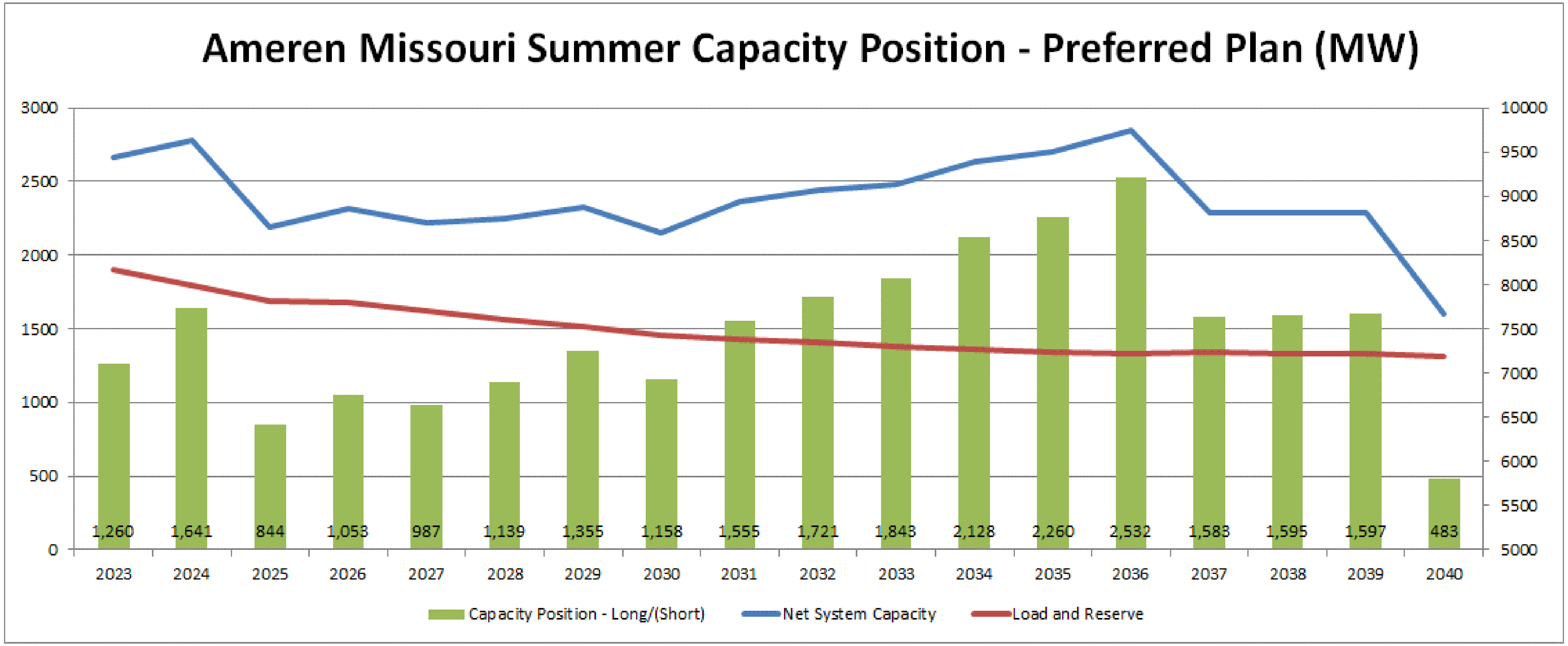
Summer Capacity Position – Preferred Plan



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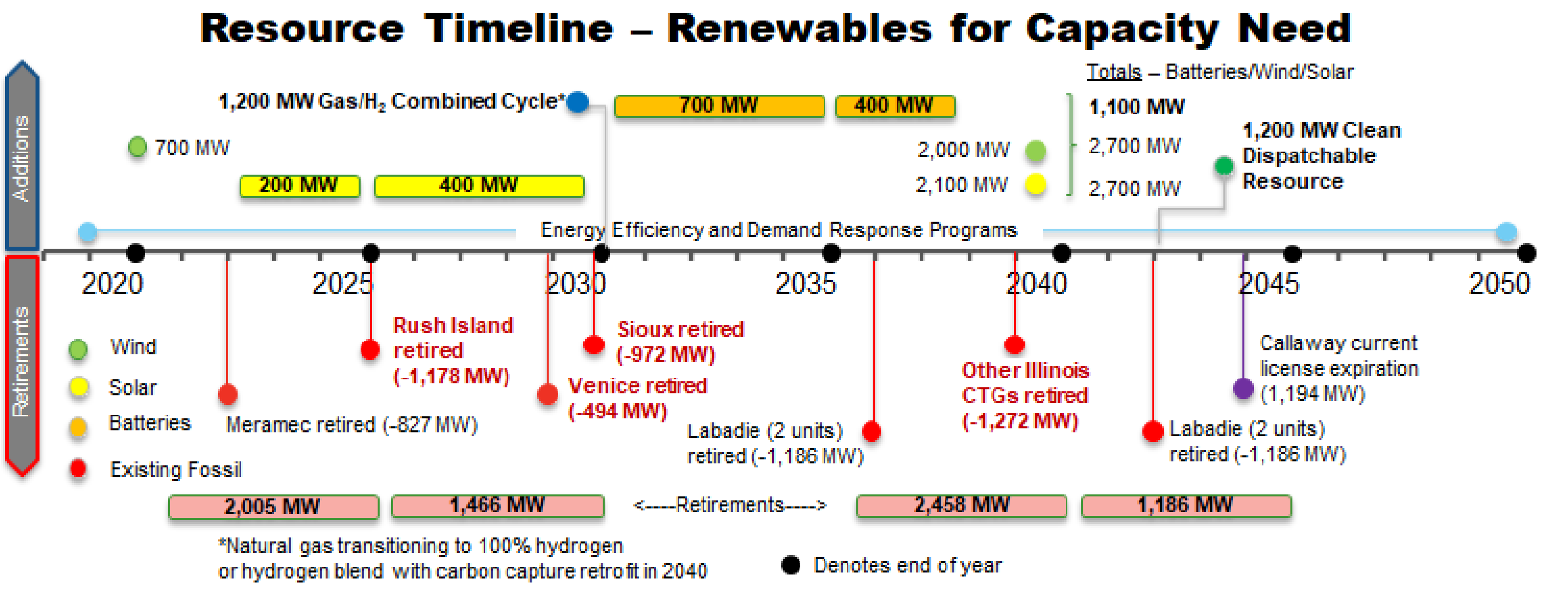
Renewables for Capacity Need Plan



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Energy Position – Capacity Need Plan vs. Renewable Transition

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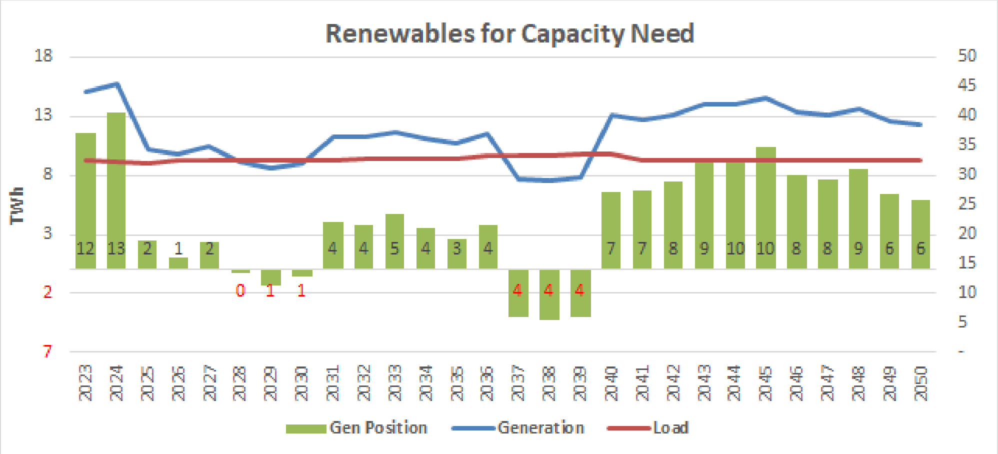
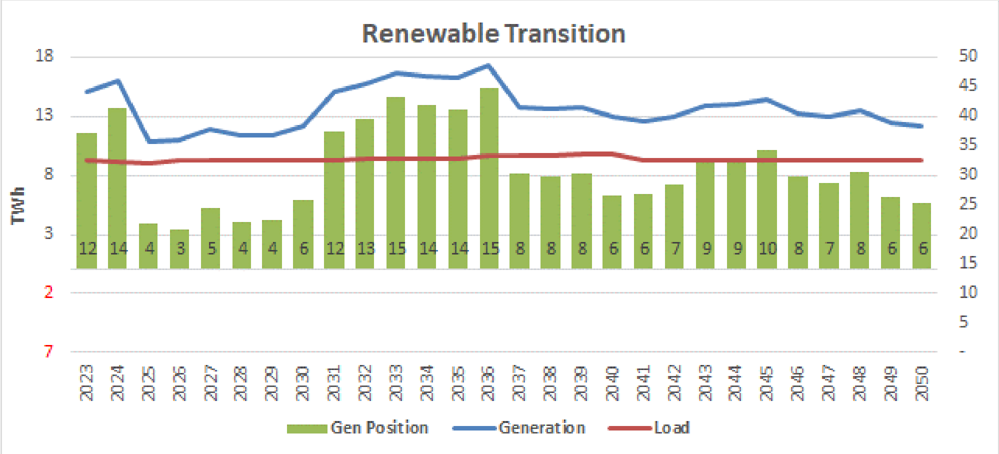
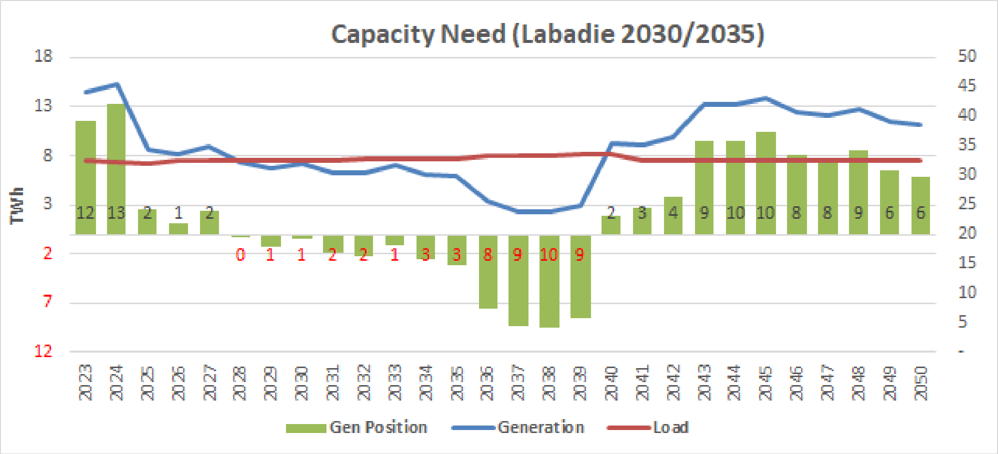
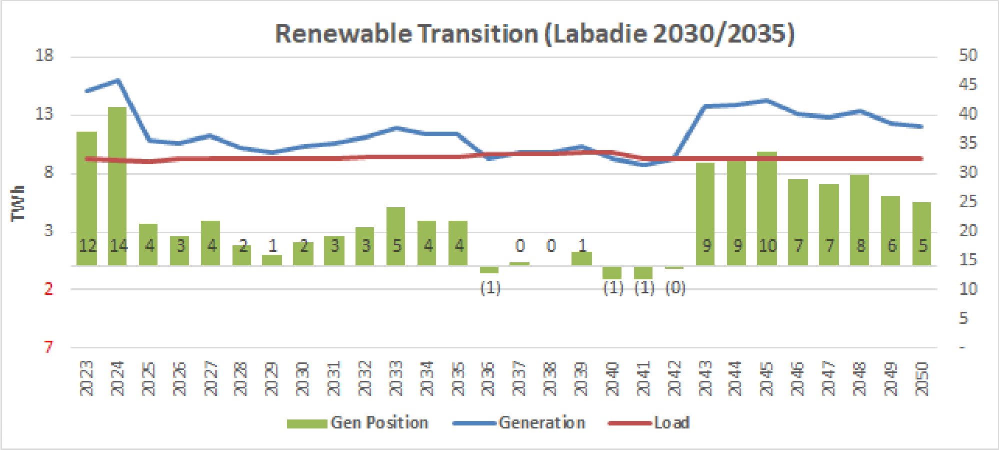


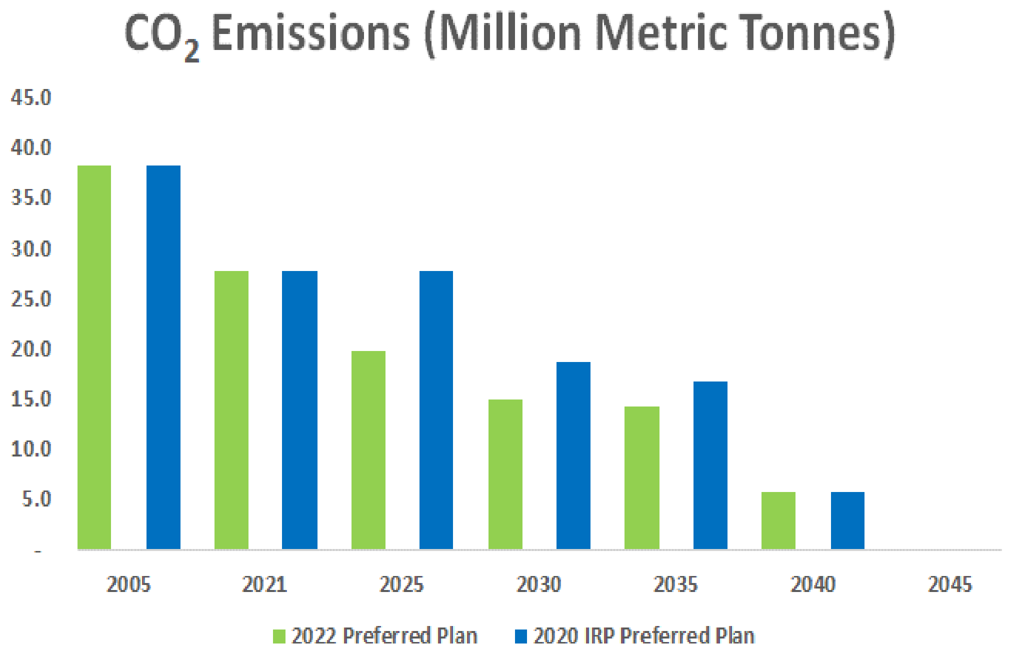


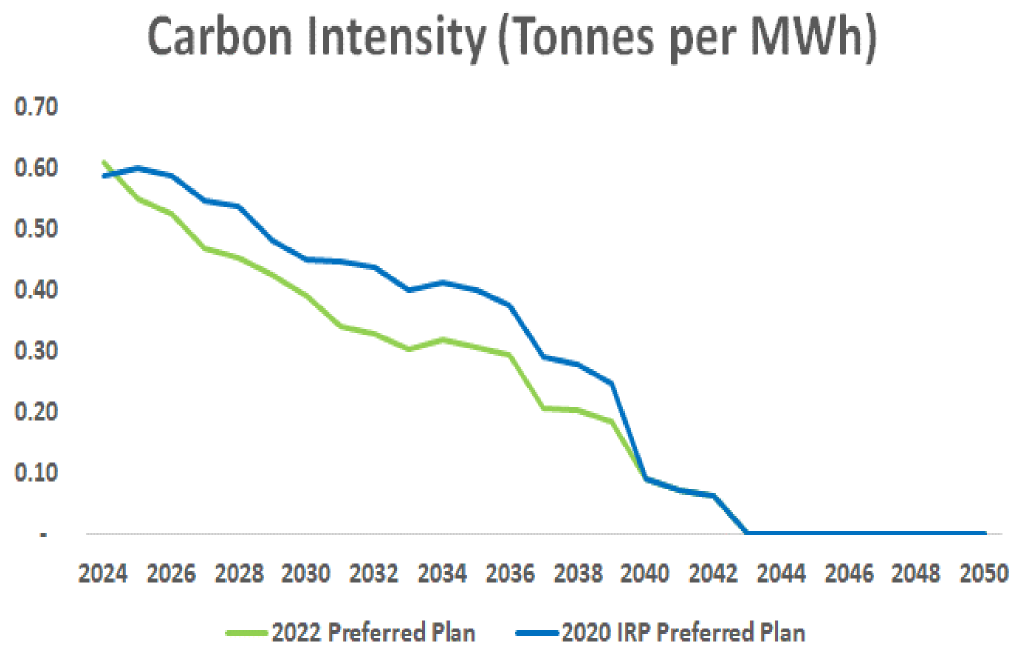




Schedule MM-S29

CO2 Emissions and Intensity





Schedule MM-S29

Performance Metric Changes and EVBI Analysis

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Performance Measures (2023-2050)	Prior Preferred Plan 2020 IRP	New Preferred Plan 2022 Update	Change	% Change
PVRR, $MM	$77,770	$79,024	$1,254	1.6%
Levelized Annual Rates, $/kWh	$18.66	$18.96	$0	1.6%
PV of Free Cash Flow, $MM	$6,638	$6,356	-$281	-4.2%
Cumulative CO_2 Emissions, Million Metric Tons	342	285	-57	-16.8%
PV of Probable Environmental Costs, $MM	$2,594	$2,524	-$70	-2.7%
Energy Savings, GWh	95,296	95,296	0	0.0%
Direct Jobs, FTE-Years	34,356	40,284	5,928	17.3%

Alternative Resource Plans		PVRR Without Better Info	Carbon Price		Natural Gas Price			Load Growth			DSM		
			Base	High	Low	Base	High	Low	Base	High	Low	Base	High
A	2020 IRP Plan	77,770	76,594	78,946	77,682	77,755	77,887	76,532	77,908	78,595	77,473	77,750	78,227
B	Renewable Transition-Sioux 2028	79,053	78,172	79,934	78,784	79,013	79,402	77,815	79,191	79,878	78,756	79,033	79,510
C	Renewable Transition-Sioux 2030	79,024	78,116	79,933	78,779	78,988	79,343	77,786	79,162	79,849	78,728	79,004	79,481
D	Renewable Transition-Sioux 2033	79,029	78,085	79,973	78,814	78,996	79,309	77,791	79,167	79,854	78,732	79,009	79,485
E	Renewables for Capacity Need	79,656	78,502	80,811	79,234	79,604	80,183	78,418	79,794	80,481	79,359	79,636	80,113
F	Renewable Transition-MAP	79,981	79,157	80,804	79,803	79,952	80,216	78,743	80,119	80,806	79,368	79,905	81,201
Minimum PVRR among plans			78,085	79,933	78,779	78,988	79,309	77,786	79,162	79,849	78,728	79,004	79,481
Plan with Minimum PVRR			D	C	C	C	D	C	C	C	C	C	C
Subjective Probability			50%	50%	25%	50%	25%	20%	60%	20%	10%	80%	10%
Expected Value of Better Info			31	0	0	0	34	0	0	0	0	0	0

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Reliability Analysis – LOLE by Month and Hour (2020)

Ameren

Month

2020	1	2	3	4	5	6	7	8	9	10	11	12
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

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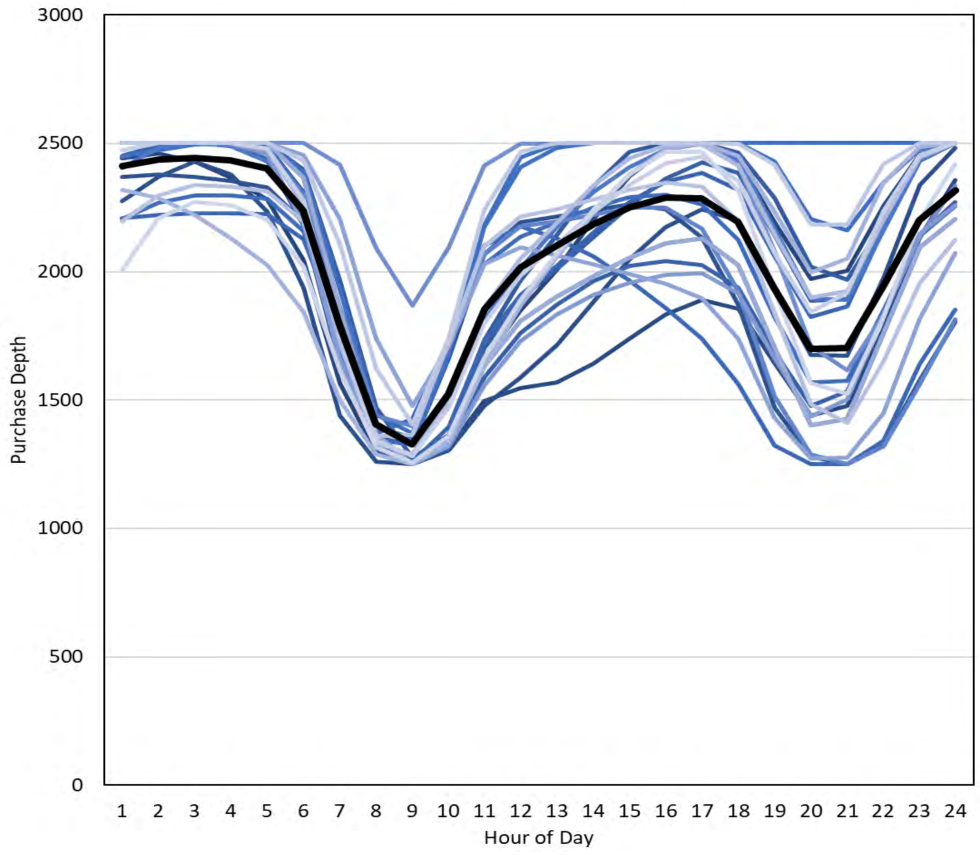
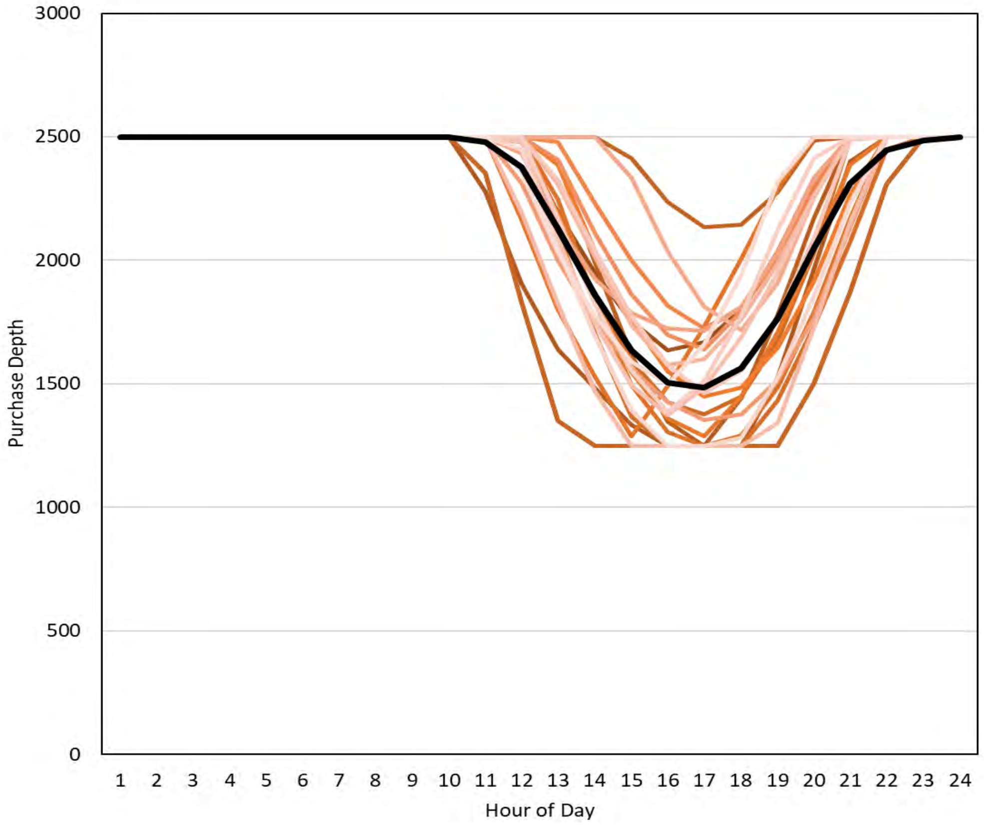
Reliability Analysis – Winter and Summer Market Support





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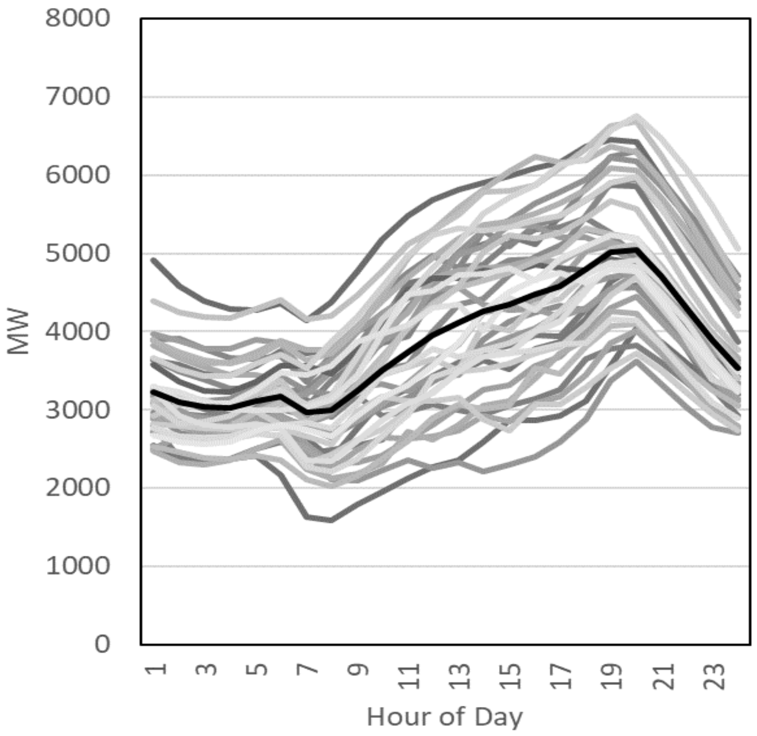
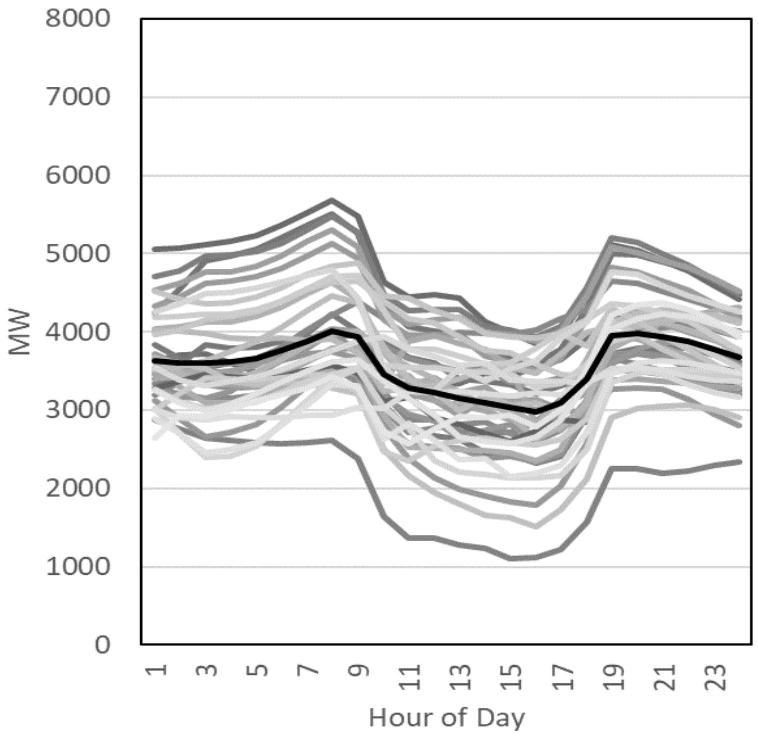
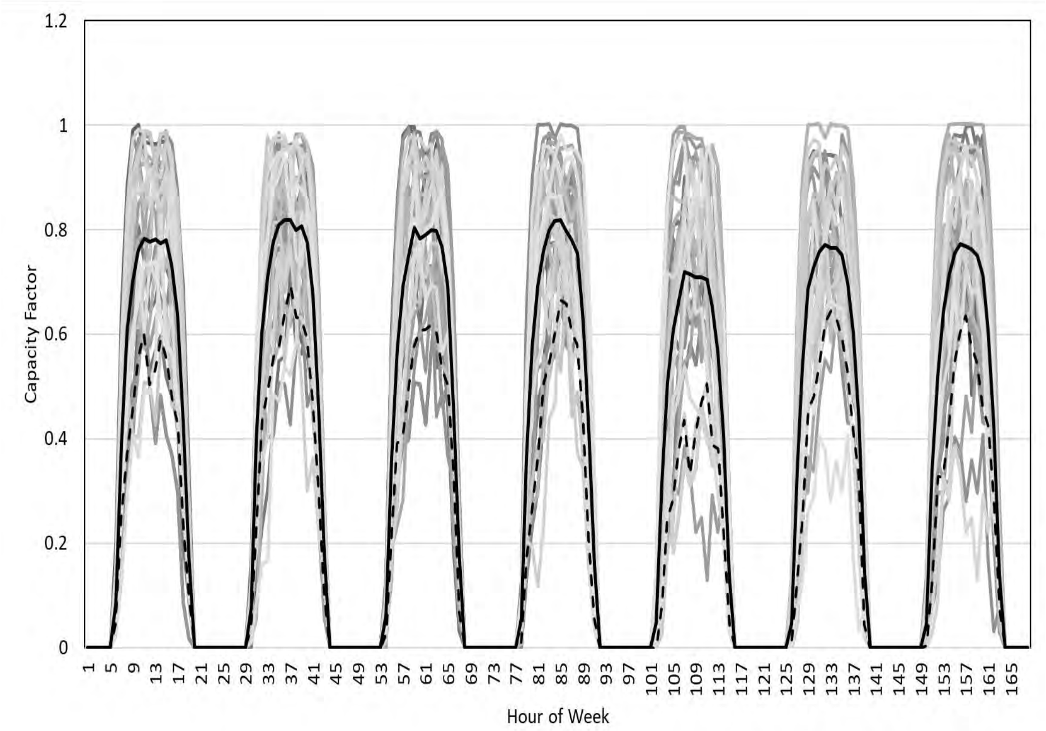
Reliability Analysis – Summer and Winter Net Load (2030)

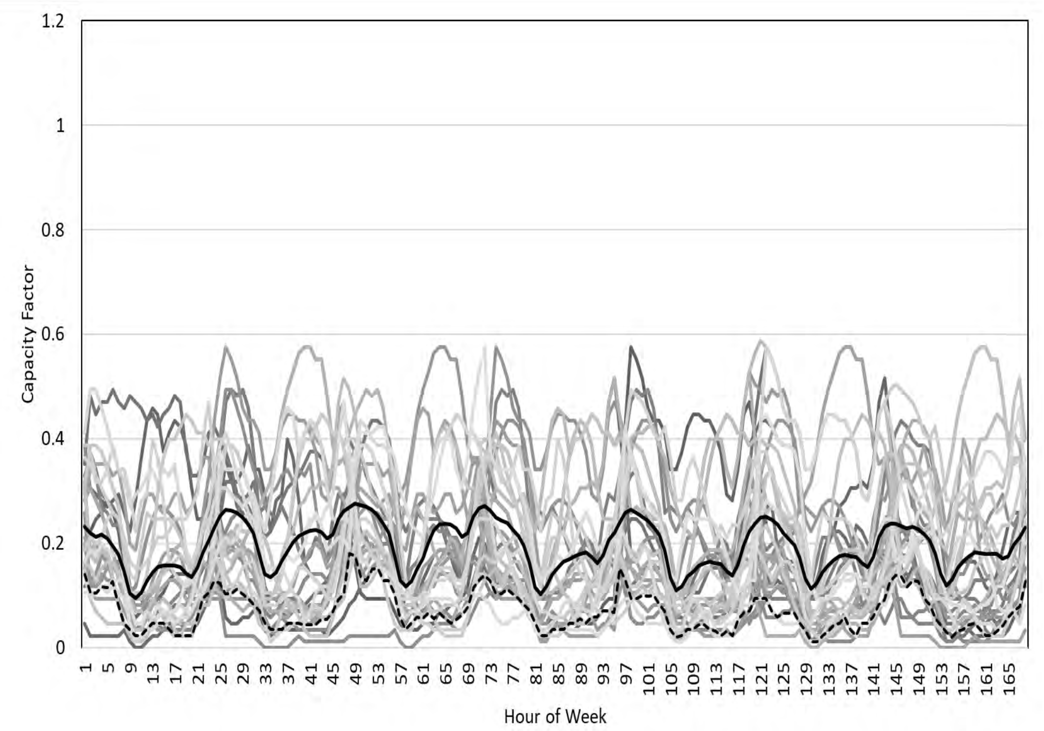




Reliability Analysis – Solar and Wind Profiles (first week of August)

Ameren





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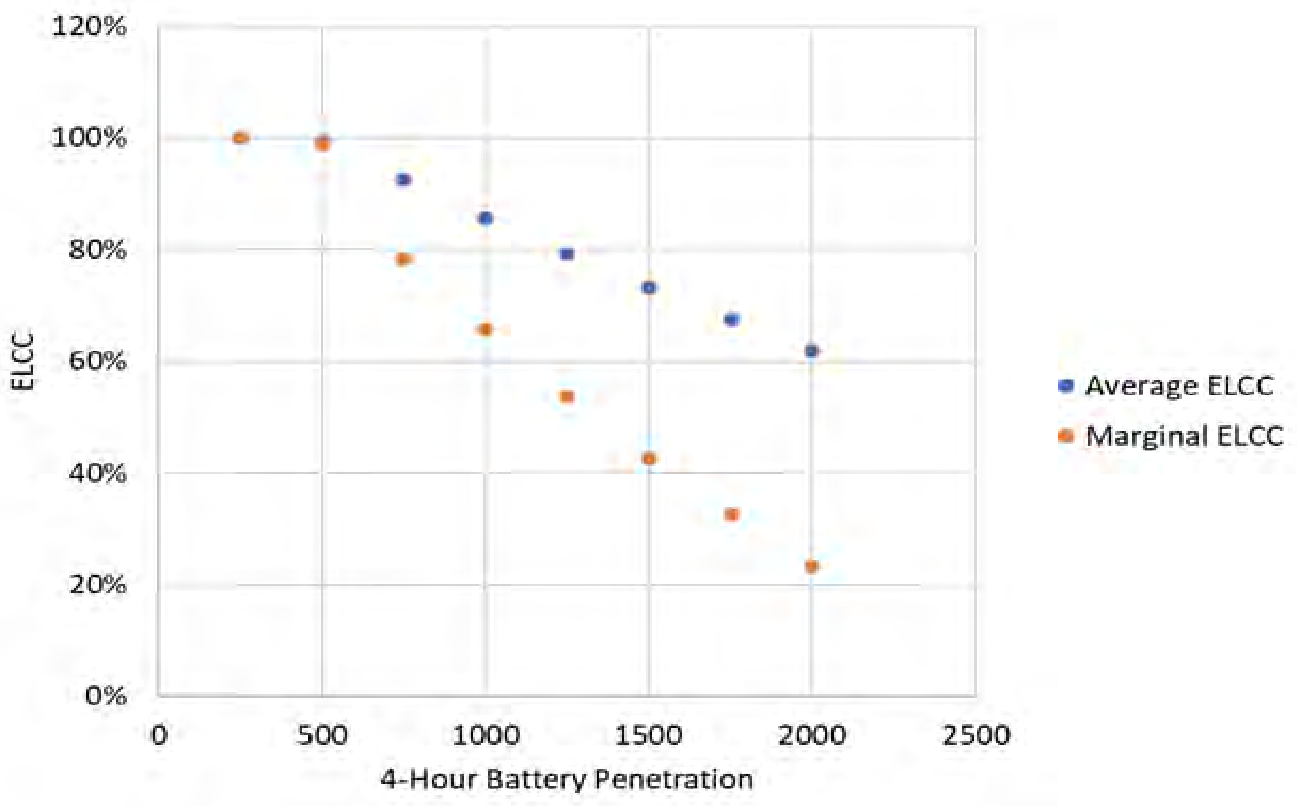
Reliability Analysis – Battery Storage ELCC



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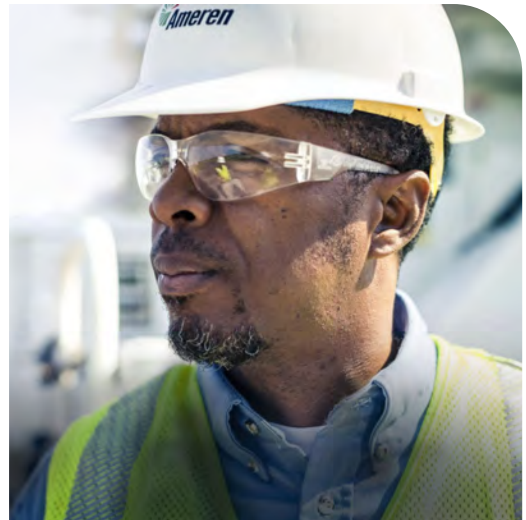

2023 Integrated Resource Plan

Ameren
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1. Executive Summary

Ensuring a Reliable and Affordable Transformation

Last year, Ameren Missouri announced our plan to accelerate the transformation of our generation portfolio to one with cleaner and more diverse energy resources. The 2022 Preferred Resource Plan included the addition of renewable resources to eventually reach 5,400 megawatts (MW) total, consisting of 2,700MW each of new wind and solar generation, along with 800 MW of new battery storage, the accelerated retirement of coal and gas-fired generation, and the addition of 1,200 MW of new and efficient natural gas-fired generation. As the Company has continued to execute on that plan, we have also continued to update our planning to include changes in the planning environment. These include changes in policy, such as the Inflation Reduction Act (IRA) passed by Congress in 2022, which provides increased incentives for the deployment of clean energy sources. They also include changes in the utility industry and power markets. Over the last year, we have seen increasing concerns regarding reliability and the sufficiency of resources to meet customer needs, especially during extreme weather events. We have also seen changes in the costs of different resource options, which are a key consideration that can affect the nature and cost of our portfolio transition.

In light of these changes, Ameren Missouri has further refined its plan to transition its portfolio in a responsible fashion and ensure reliability and affordability during that transition. Our new plan includes additional on-demand resources to ensure that we can meet our customers' energy needs in all hours, even during extreme weather events. At the same time, we have accelerated planned investments in renewable resources and energy storage resources to take advantage of tax incentives in the IRA that reduce costs to customers while also providing greater energy diversity and availability. Our plan ensures a reliable and affordable transition that results in reductions in CO_2 emissions of 60% by 2030 and 85% by 2040, both based on 2005 levels, and net zero emissions by 2045, based on expected development of viable clean dispatchable generation technologies (e.g., hydrogen, carbon capture and sequestration, advanced nuclear, and long-duration energy storage) and does so at the lowest cost to customers. In doing so, we will also support the decarbonization of our region's economy through efficient electrification of transportation and other sectors that currently require fossil fuels. The timeline on page 2 highlights the key elements of our plan.[1]

[1] In-service dates are approximate and could change based on a number of factors. Assumes the addition of 1,200 MW of unspecified carbon-free generation in each of 2040 and 2043 and extension of Callaway operating license.

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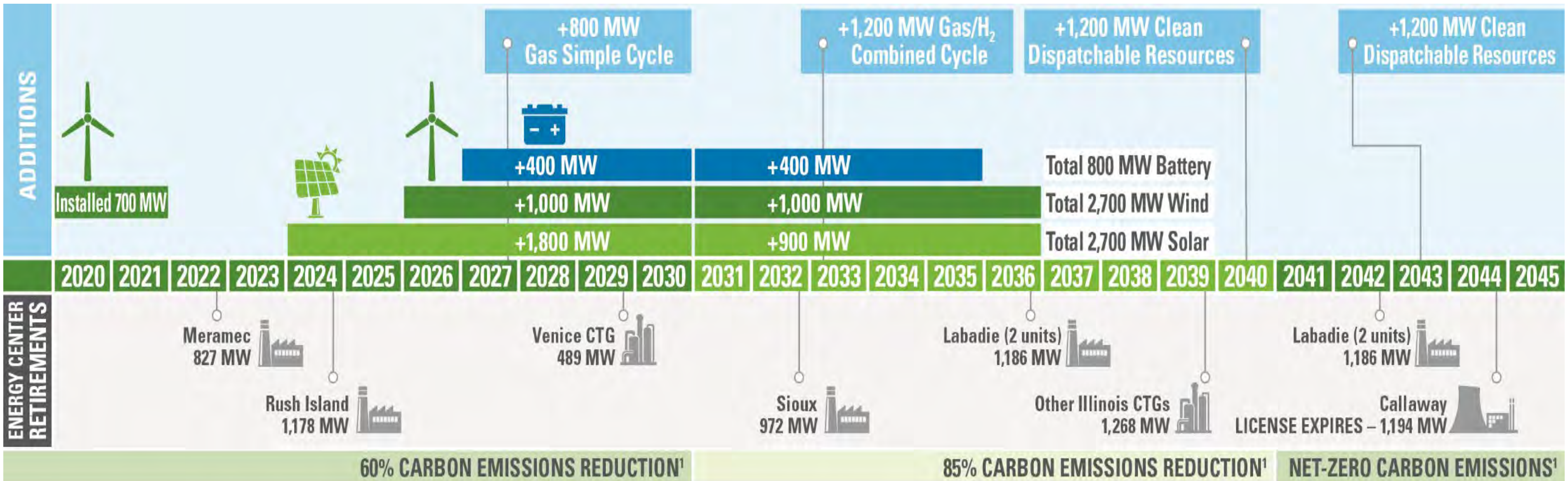
Ameren Missouri's Generation Transformation Timeline



NOTE: Final timing of Rush Island retirement is dependent on a revised order from the U.S. District Court. The company continues to evaluate the potential for additional energy efficiency and demand response programs. Reductions are presented as of the end of the period indicated and based off 2005 levels. Wind and solar additions, energy center retirements by end of indicated year.

1. Ameren's goals encompass both Scope 1 and 2 emissions including other greenhouse gas emissions of methane, nitrous oxide and sulfur hexafluoride. This goal is dependent on a variety of factors including cost-effective advancements in innovative clean energy technologies as well as constructive federal and state energy and economic policies.

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Our plan reflects a carefully considered balance of customer affordability, reliability, and environmental stewardship. It relies on the significant investments we are making to modernize our electric grid through our Smart Energy Plan to enhance reliability and unlock opportunities for customer energy efficiency, as well as greater levels of renewable energy and other distributed energy resources. Our goal of achieving net-zero CO_2 emissions by 2045 also means that we will continue to actively support public and private investment in research and development of new energy technologies, such as hydrogen fuel, carbon capture, and improved battery technologies, as well as constructive energy policies that support investment and allow us to continue to appropriately balance affordability, reliability, and environmental stewardship. Our plan will allow us to meet our customers' long-term energy needs in a way that is consistent with the objectives of the Paris Agreement to limit global temperature rise to 1.5 degrees Celsius, and do so at the least cost to customers. Aside from achieving environmental stewardship, another benefit of the plan is the critical risk mitigation it provides against ever-more-stringent environmental regulation. Providing that mitigation is extremely important given the significant reliability risk to our customers such regulation poses absent a significant shift away from our current heavy reliance on coal-fired generation to meet customers' energy needs.

Continuing this transformation now is particularly important. Not only does it further advance our ability to provide customers with replacement energy from cleaner generation sources as our existing aging fossil generation reaches end of life, as noted, it also mitigates risks associated with the kinds of clean energy policies that continue to be a focal point at the national level. At the same time, our plan allows us to maximize the value of our existing generating assets and ensure reliable service and resiliency of energy supply to our customers. Our current fleet of low-cost coal, gas, hydroelectric, and nuclear generators continues to be foundational to our ability to provide reliable and affordable energy as we add greater levels of renewable generation resources to our portfolio, with coal serving as a bridge to cleaner energy sources. The addition of new gas-fired resources further ensures a reliable transition by partnering with new renewables and existing resources in our fleet to ensure customers have the energy they need in all hours throughout the year. Through our investments in grid modernization, clean renewable energy, and the focused management of our existing generation portfolio, our plan delivers cleaner energy to our customers while ensuring continued reliability, and it does so at the least cost to our customers.

The transformation of our generation portfolio will be achieved not only through actions Ameren Missouri takes, but through actions our customers take as well. Customers and communities have increasingly expressed interest in energy service options that allow them to manage their energy use, save money, and achieve their own clean energy goals. The approval of our Renewable Solutions Program earlier this year allows customers and communities to do just that. We will also continue to offer and expand on the popular energy efficiency programs that our customers have been using for years to save money and better manage their energy needs while enjoying the comfort and convenience they desire.

Integrated Resource Plan Highlights

- Ameren Missouri is continuing to transform its generation fleet to a cleaner and more diverse portfolio in a responsible fashion, with a plan that best balances affordability, reliability, and environmental stewardship while addressing future risks.
- By 2030, Ameren Missouri plans to add 2,800 MW of new wind and solar generation, representing an investment of approximately $5-6 billion.[2] Wind and solar generation additions called for by the plan adopted in this IRP after 2030 would bring that total to 5,400 MW of operating solar and wind energy centers. These renewable resources will replace production from fossil-fueled generation even as our own efficient and low-cost fleet of existing and planned dispatchable generation is partnered with these renewable resources to continue to provide reliable and affordable energy.
- The 2023 IRP includes the planned retirement of all of Ameren Missouri's coal-fired generating capacity by 2042. This includes retirement of the Rush Island Energy Center by the end of 2024, the Sioux Energy Center by the end of 2032, two units at the Labadie Energy Center by the end of 2036, and the remaining two units at the Labadie Energy Center by the end of 2042. The collective result of these retirements is a methodical drawdown of fossil fueled generation that, along with the addition of new dispatchble resources, ensures a stable transition to a cleaner energy future.
- New dispatchable generation resources will be added over the next 20 years to partner with our expanding portfolio of renewable resources and continued operation of existing resources to ensure reliability in all hours and under all weather conditions, including the kinds of extreme heat in summer and extreme cold in winter that we have seen in recent years. New dispatchable resources include 800 MW of simple cycle gas-fired combustion turbine generators by 2027, 1,200 MW of efficient gas-fired combined cycle generation by 2032, and 1,200 MW of as-yet-unspecified clean dispatchable generation in each of 2040 and 2043.
- The plan reflects our assumption that the operating license for our Callaway nuclear facility is extended, ensuring its ability to continue providing carbon-free electric energy around the clock.

[2] 2,450 MW in addition to the solar capacity approved by the Commission earlier this year.

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- Based on detailed modeling of our plan, Ameren Missouri is expecting reductions in CO_2 emissions of at least 60 percent by 2030 and 85 percent by 2040 (based on 2005 levels), with a goal of achieving net-zero CO_2 emission by 2045. Even as we achieve these significant reductions in carbon emissions across our own fleet, our planned renewable resource additions will result in significant additional carbon emission reductions across the region.
- Ameren Missouri believes the cleanest and cheapest form of energy is the energy you do not have to produce in the first place.This is why the plan continues to include robust and cost-effective customer energy efficiency and demand response programs to help customers better control consumption and reduce their electric bills. By 2043, these programs are expected to result in nearly 1,700 MW of peak demand savings in addition to peak demand savings achieved by programs implemented to date.
- Ameren Missouri has also included in its plan electrification of transportation and other sectors. This is expected to result in significant reductions in CO_2 emissions in transportation and other sectors of our region's economy in addition to the emission reductions we will achieve with the transformation of our generation fleet.
- The plan provides for the continued replacement of aging distribution infrastructure and the development and deployment of smart grid, communications, and other advanced technologies on our distribution system, along with investments in transmission infrastructure, to enhance grid reliability and resiliency, enable new products and services, and achieve greater operational efficiencies and greater access to cleaner sources of energy.
- The plan drives the creation of thousands of clean energy jobs in our region.

Key changes to our preferred resource plan since the one we announced in June 2022 are highlighted in the table below. Ameren Missouri will continue to ensure that customers' long-term electric energy needs are met in a safe, reliable, affordable, and environmentally responsible manner. The company's IRP, filed every three years with the Missouri Public Service Commission, provides an assessment of the future electric energy needs of customers for the coming 20 years and the preferred plan for meeting those needs. Ameren Missouri's 2023 IRP represents a further refinement of our 2022 preferred resource plan, focusing on ensuring reliable energy for customers, in all hours and under all conditions, as we execute the transformation of our generation fleet to a cleaner and more fuel diverse portfolio in a responsible fashion, supporting customers' wants and needs.

	2023 Preferred Plan	2022 Preferred Plan
Coal Retirements	**2,000 MW by 2030** 3,000 MW by 2035 5,400 MW by 2042	3,000 MW by 2030 3,000 MW by 2035 5,400 MW by 2042
Natural Gas Retirements	500 MW by 2030 1,800 MW by 2040	500 MW by 2030 1,800 MW by 2040
Natural Gas Additions	**1,200 MW (2033)**	1,200 MW (2031)
Dispatchable Peaking (Gas/Oil) Generation Addition	**800 MW (2027)**	None
Renewable Additions	2,800 MW by 2030 **4,700 MW by 2036**	2,800 MW by 2030 4,300 MW by 2035 4,700 MW by 2040
Battery Storage Additions	**400 MW by 2030** **800 MW by 2035**	400 MW by 2035 800 MW by 2040
Other Clean Dispatchable Additions	**1,200 MW (2040)** 1,200 MW (2043)	1,200 MW (2043)
Carbon Emission Reduction (CO_2e)	60% by 2030 85% by 2040 Net Zero by 2045	60% by 2030 85% by 2040 Net Zero by 2045

Transformation Benefits

We have created this transformation plan through careful consideration of several key objectives we want to achieve on behalf of our customers, communities, investors, and the environment. These objectives guide our selection of resources to ensure reliable energy service for customers in all hours and under all conditions, including extreme weather. Specifically, we evaluate each of a number of alternative resource plans based on:

- **Minimizing Long-term Customer Costs** – We measure the long-term costs to customers based on the present value of revenue requirements (PVRR), or the costs to be included in determining customer rates in the future expressed in today's dollars. Focusing on long-term costs helps us to ensure long-term affordability for customers.
- **Ensuring Customer Satisfaction** – This includes a number of factors such as rates, reliability, availability of energy efficiency programs, and access to cleaner energy sources.
- **Spurring Economic Development** – We assess economic development benefits based on the direct impact of our resource decisions on jobs in our region. To be sure, these are not the only benefits of our plan to economic development –

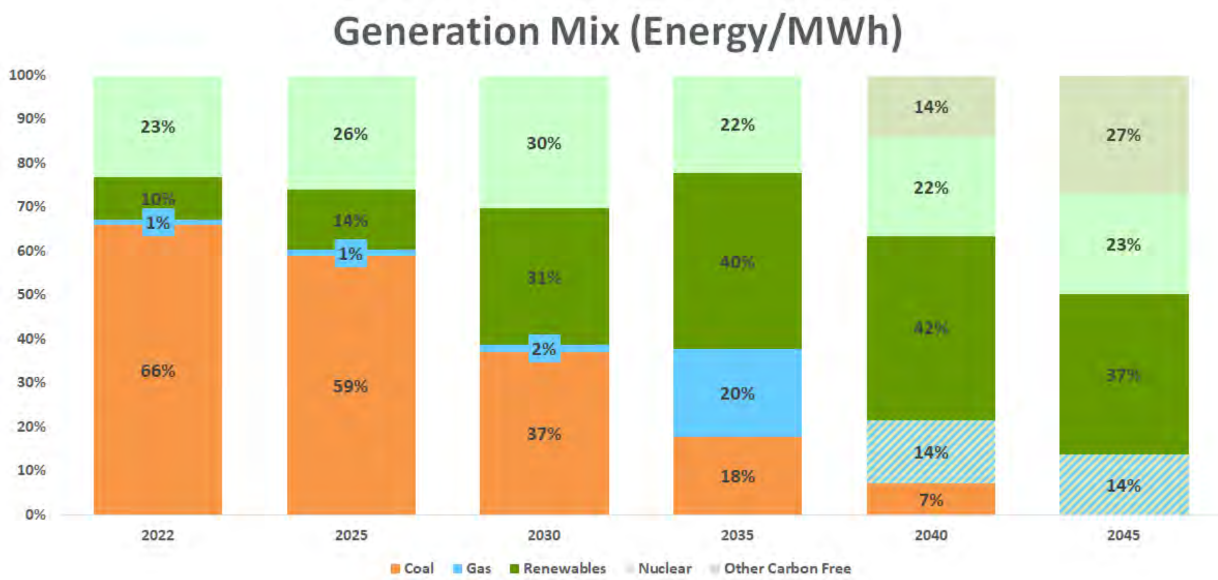
thousands of indirect jobs are expected to be created as well – but they provide a strong indication of the relative benefits of our various alternatives.

- **Addressing Financial and Regulatory Risks** – Our ability to deliver benefits to customers is dependent in large measure on our access to low-cost sources of capital for investment. Therefore, we assess potential risks to our ability to access low-cost sources of capital.
- **Driving Portfolio Transition** – Assessing the relative benefits to our environment as we transition our generation portfolio includes consideration of air emissions, deployment of clean energy sources such as wind and solar, and other environmental factors.

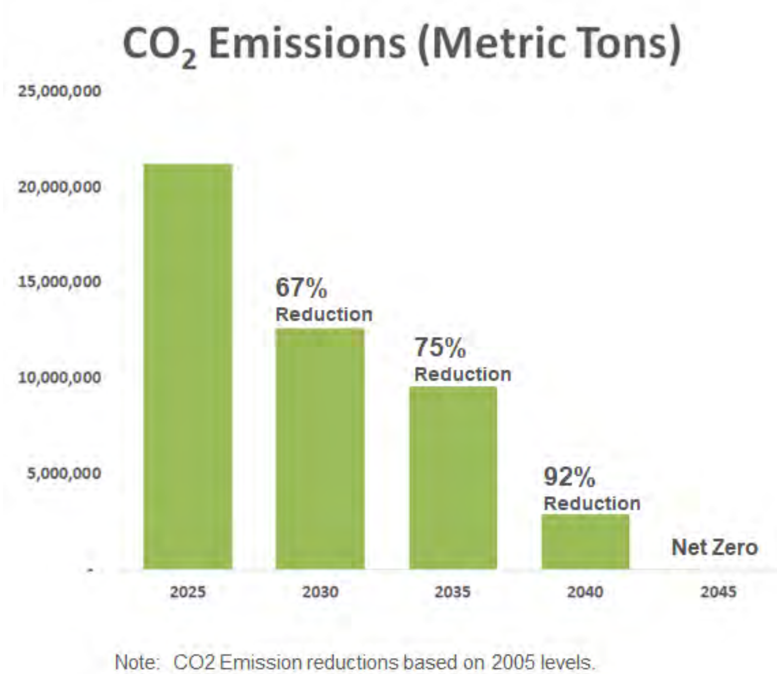
As one might imagine, achieving such objectives requires careful balancing. Ameren Missouri uses a scorecard approach in selecting its preferred resource plan, evaluating each option based on its expected performance in achieving these objectives. Our transformation plan ensures reliable and affordable energy for our customers today, tomorrow and for decades to come.

The deployment of new wind and solar resources allows us to take advantage of the efficiencies of these zero emission technologies. We are also able to take advantage of the availability of significant federal tax credits, which were extended and expanded by the IRA. At the same time, our existing fleet of generation resources continues to provide affordable energy to customers and, along with the addition of new dispatchable resources, ensure reliable energy is available around the clock as we add the renewable resources that will satisfy more and more of our customers' energy needs. Events in California, Texas, North Carolina, and the Tennessee Valley, where extreme weather conditions and a shortage of reliable on-demand generation resulted in disruptions of service to customers, serve to highlight the need to be thoughtful about how we ensure the reliability of our generation fleet for our customers as we execute on our transformation plan. This is especially important during extreme weather events, such as the extreme cold we experienced in February 2021 and December 2022 and the extreme heat we experienced during the summer of 2023. While an integrated resource plan typically focuses on the next twenty years, we are looking beyond that to ensure the plans we pursue will support our goal of achieving net-zero emissions by 2045. The figure below illustrates the transition through 2045, with over half the energy we generate coming from zero carbon sources (renewables and nuclear) by 2030.

As the figure below illustrates, we are executing on a transformation that will steadily replace fossil fuels with cleaner sources of energy. Beyond the obvious benefits to our environment, this also allows us to manage the costs and risks associated with expected future climate policy.



Climate policy may take any number of forms, whether it be through any or some combination of: more stringent EPA regulations, federal clean energy standards, caps on CO_2 emissions, or a price on CO_2 emissions (e.g., a "carbon tax). We expect that some forms of climate policy will continue to be considered during the coming years. While we cannot know the exact timing or form of such a policy today, our transformation plan positions us to address potential costs and risks associated with potential policies that may be enacted. The figure below shows the reductions in CO_2 emissions achieved by our plan compared to actual emissions in 2022.



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It is important to recognize that even as we manage the drawdown of coal-fired generators in our portfolio, these very assets, along with planned gas generation and battery storage additions and existing gas, hydroelectric and nuclear generation, provide the foundation of reliable energy supply that allows us to expand our portfolio of renewable wind and solar generation. In that respect, our coal-fired generators and new gas-fired generation serve as a bridge to the other technologies we will depend on in the future to ensure reliable and affordable energy supply.

Near-term Implementation

As mentioned previously, the transformation of our portfolio will involve actions taken by Ameren Missouri and its customers. For example, Ameren Missouri has already secured certificates of convencience and necessity (CCN) for two solar projects and applied for CCNs for another four solar projects. Together, these six projects total 900 MW of the 1,800 MW we plan to add to our portfolio by 2030. We continue to pursue additional solar projects to meet our customers energy needs. We also expect to issue another RFP for wind resources in the near term to identify projects that will fulfill our planned addition of 1,000 MW of wind resources by 2030.

In addition, Ameren Missouri has received approval to extend its current energy efficiency and demand response programs through 2024. That extension continues many existing programs for residential and business customers, while also offering business demand response customers the option to opt-out. Programs will retain continuity through 2024 while allowing for the DSM planning team to account for various factors, such as the Inflation Reduction Act, as the next MEEIA cycle is under discussion.

As Ameren Missouri's coal-fired energy centers approach the end of their useful lives, a key step in retiring the units is the assessment of resultant transmission infrastructure needs and the construction of that infrastructure. Our Rush Island Energy Center will be retired by the end of 2024, and the process of putting new transmission system infrastructure in place to support grid reliability needs is underway. With the retirement of our Sioux Energy Center by the end of 2032, we have initiated a similar process to support its retirement. Continued expansion of transmission infrastructure will also be key to integrating renewable wind and solar generation as we transform our portfolio over the next twenty years.

We have also started to take steps for the implementation of the gas-fired simple cycle (800 MW by 2027) and combined cycle (1,200 MW by 2032) generation we are adding to our portfolio to partner with renewable resources and our existing fleet to ensure reliable energy service. Implementation steps over the next three years include design, engineering, procurement, permitting, and securing interconnection rights in MISO as well as efforts to ensure staffing continuity as coal units are retired and gas generators are added.

As we implement these key steps in our portfolio transformation, we will also continue to monitor conditions that may affect our longer-term plans. This includes continually assessing the power market conditions that affect the economics of our planned generation portfolio, such as prices for coal, natural gas, nuclear fuel, and electric power. Similarly, it also includes monitoring expected customer demand and the adequacy and reliability of our portfolio resources to meet our customers' needs. It also includes advocating for constructive energy and economic policies, including those that address investment in energy infrastructure, climate change, incentives for clean energy technologies, and environmental regulations. New technologies will be critical to achieving our goal of net-zero CO_2 emission by 2045, so we will be continuing to actively participate in efforts to help advance the development of emerging technologies such as carbon capture and sequestration (CCS), the use of hydrogen fuel for electric production and energy storage, next generation nuclear, and large-scale long-duration battery energy storage.

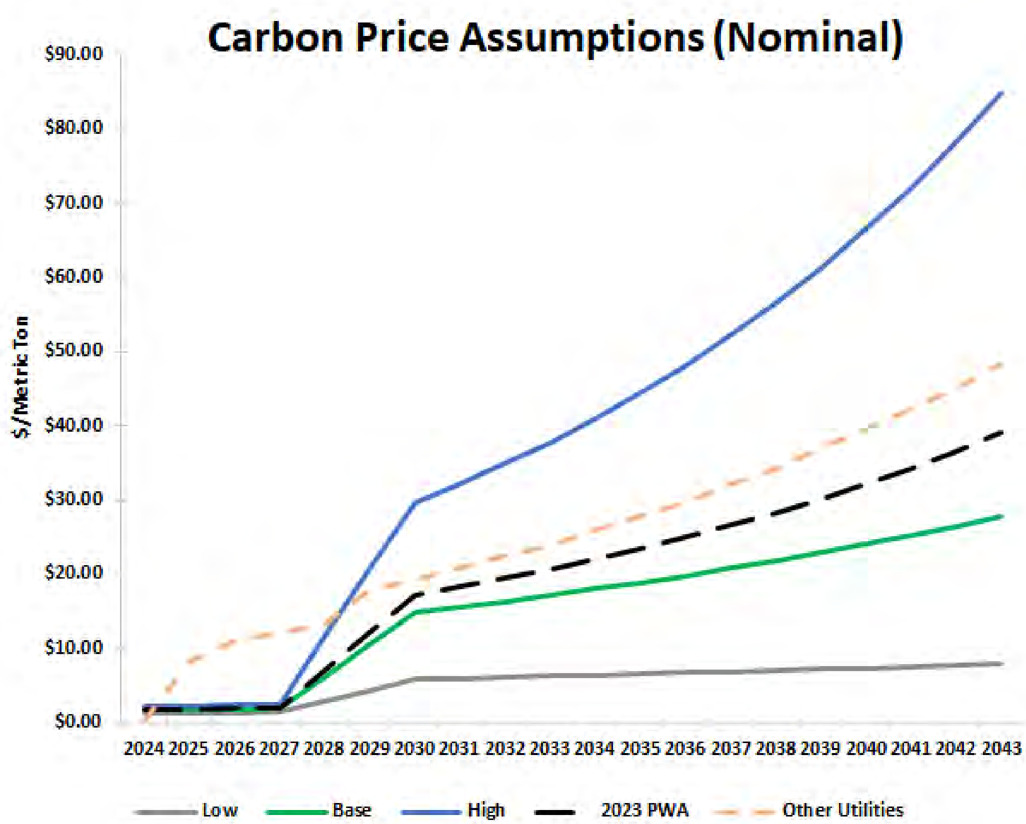
Key Considerations That Influence Our Planning

The development and evolution of our transformation plan was influenced by a host of factors and other considerations, with significant input from a broad and diverse group of stakeholders representing our customers, industry, and advocates for environmental justice, among others. Customer and investor interest in cleaner energy sources and reductions in CO_2 emission has continued to increase. Current and potential future customers have expressed interest in cleaner energy options, with some seeking to achieve their own clean energy targets, and Ameren Missouri has responded by offering customers the opportunity to do just that through our Renewable Solutions and Community Solar programs.

An increasing focus on cleaner energy also extends to sectors outside the power sector. Clean electrification continues to transform the transportation sector, with more and more electric vehicle models to choose from and conversions of industrial forklifts and other off-road vehicles to electric options. Uses of fossil fuel in other sectors of the economy will see the potential for electrification as well, including cooking, space heating, and industrial processes. The electric utility industry will play an indispensable role in the decarbonization of a number of sectors of the economy through electrification and electric customers will benefit from a larger base of sales to support current and future investments needed to serve our customers for the next twenty years and beyond.

Cleaner energy technologies will clearly play a pivotal role in supporting these trends in customer and investor needs. The IRA provides significant tax incentives for the deployment of wind, solar and battery storage resources, as well as incentivizing the development of domestic production for these resources. While battery storage technologies are still relatively costly today, the significant IRA tax benefits make them affordable, and we expect they will increasingly play a role in the integration of intermittent renewable energy resources as wind and solar are added to the grid and older fossil-fired generation is retired.

Trends in customer demand will continue to drive our outlook for the need for generation resources. This includes the electrification trends mentioned earlier along with continuing improvements in energy efficiency. While underlying general economic trends are expected to produce modest increases in demand, we also expect to see further economic development in our service territory, including the potential for adding clean energy manufacturing, in part as a result of the incentives in the IRA.



In addition to the trends in customer and investor attitudes and preferences, we must also consider the potential for changes in energy policy. One of the areas of great potential impact related to energy policy is that of addressing the risks of climate change. For example, the US EPA announced proposed rules in May 2023 that could require billions of dollars in investments in new emission controls. While we do not know what form climate policy will take over the next twenty years, we can represent the expected economic impacts using a price on CO_2 emissions. The CO_2 prices shown in the chart above are those we have utilized in our planning analysis to represent the effects of

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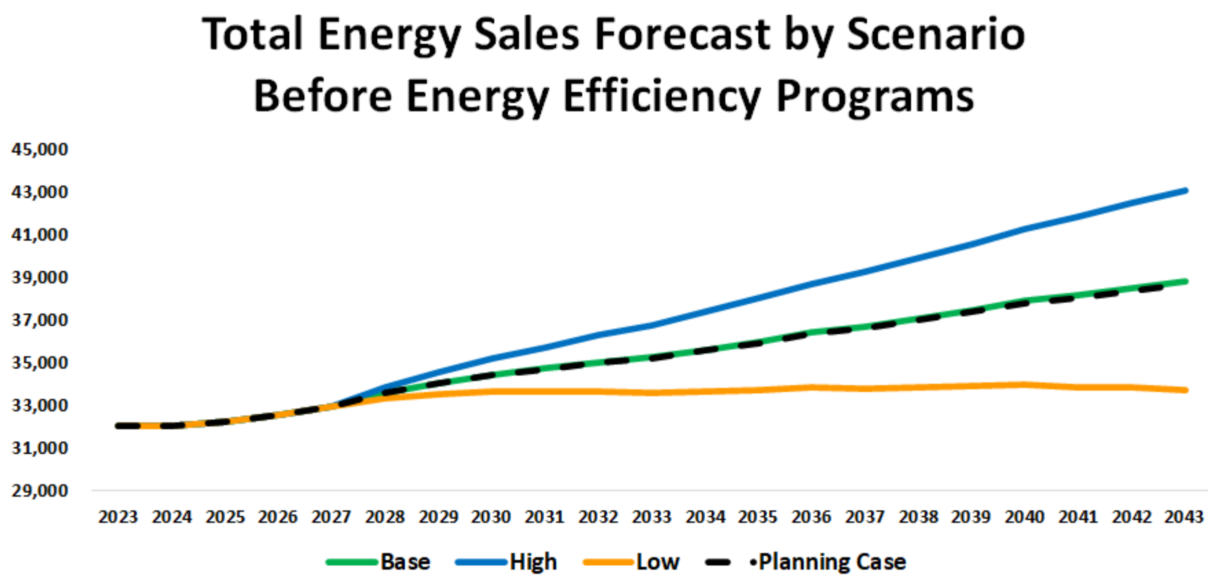
potential future climate policy, including our assumption for the probability of each of three price scenarios and the probability-weighted average (PWA) price represented by the black dashed line. For comparison, we also show a composite price trajectory used by industry peers (the yellow dashed line).

Other policies that could affect our planning include more stringent regulation of hydraulic fracking used to extract natural gas and policies promoting electrification of transportation and other uses of fossil fuels. They also include other potential changes in regulation of power plant emissions, water use and waste handling. We also consider potential changes to Missouri's renewable energy standard (RES), which was passed in 2008 and called for utilties to generate or acquire renewable energy equal to 15% of its customer usage by 2021.

A number of future market conditions also have an influence on our planning, and we have examined ranges of possibilities for such factors to test their potential to impact our planning decisions. These factors include prices for natural gas, electric power, and the cost for debt and equity capital to fund necessary electric infrastructure investments. The cost and reliability of our existing fleet of generation resources is also important as we consider the specific actions necessary to implement our transformation. We will also continue to evaluate the potential need for, and cost of, transmission infrastructure necessary to deliver greater amounts of renewable energy to, and ensure reliability for, our customers.

Our Customers' Future Energy Needs

We expect base customer demand to grow over the next twenty years at an annual growth rate of 0.3 percent to 1 percent, before the inclusion of future savings from our energy efficiency programs. This includes consideration of customer-owned distributed energy resources (DER) like rooftop solar, growth in electric vehicles, and other efficient electrification. We have examined future demand under three different scenarios representing different assumptions for economic conditions, electrification, and customer adoption of DER. The chart below shows the range of customer demand we have analyzed in assessing future resource needs and costs.



To ensure reliability, we must have sufficient resource capacity to meet our customers' highest possible peak demand, generally on the hottest day of the year for summer and the coldest day of the year for winter, plus a reserve margin to account for uncertainty. Ameren Missouri's planning standard is to ensure that we have the resources to provide energy for our customers in all hours and under all conditions, including during extreme weather events. The figures below show our planned generation capacity, peak demand, and reserve margin requirement for the summer and winter seasons, in which we see the greatest demand, under normally expected load conditions.[3] It includes peak demand savings from energy efficiency and demand response programs. Our capacity buffer provides us with significant and important flexibility to ensure reliability during extreme weather conditions and respond to emerging trends, changes in market conditions and changes in energy policy. This flexibility allows us to carefully consider all options and execute on those that are most beneficial to our customers. Without that flexibility, our options at any given time will be more limited. Note that in the near term, we expect to see a slight shortfall in capacity in the winter, resulting in greater temporary exposure to the market until new renewable and dispatchable resources are added.

[3] For each chart, the right vertical scale corresponds to the total load+reserve and total generation, and the left vertical scale corresponds to the capacity position (i.e., total generation less total load+reserve). See Chapter 10 for a full discussion of capacity needs under both normal and extreme weather conditions.

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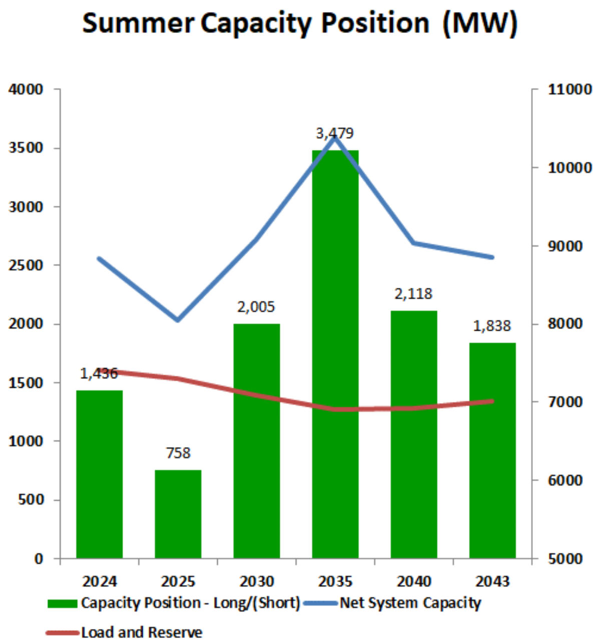
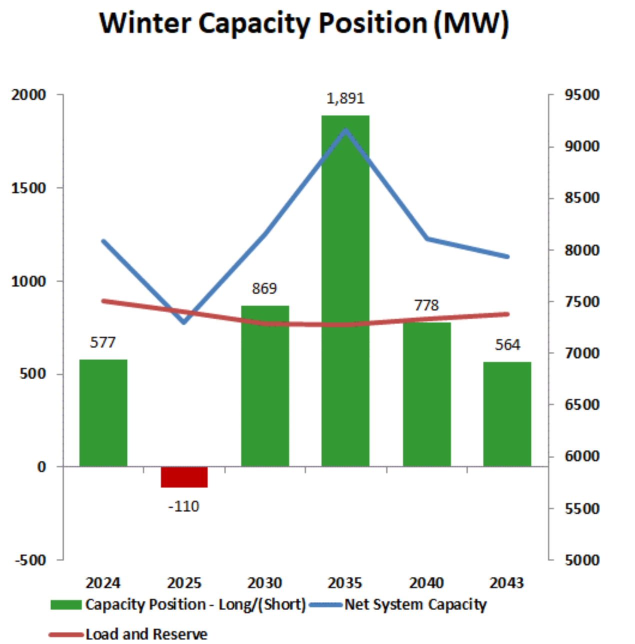
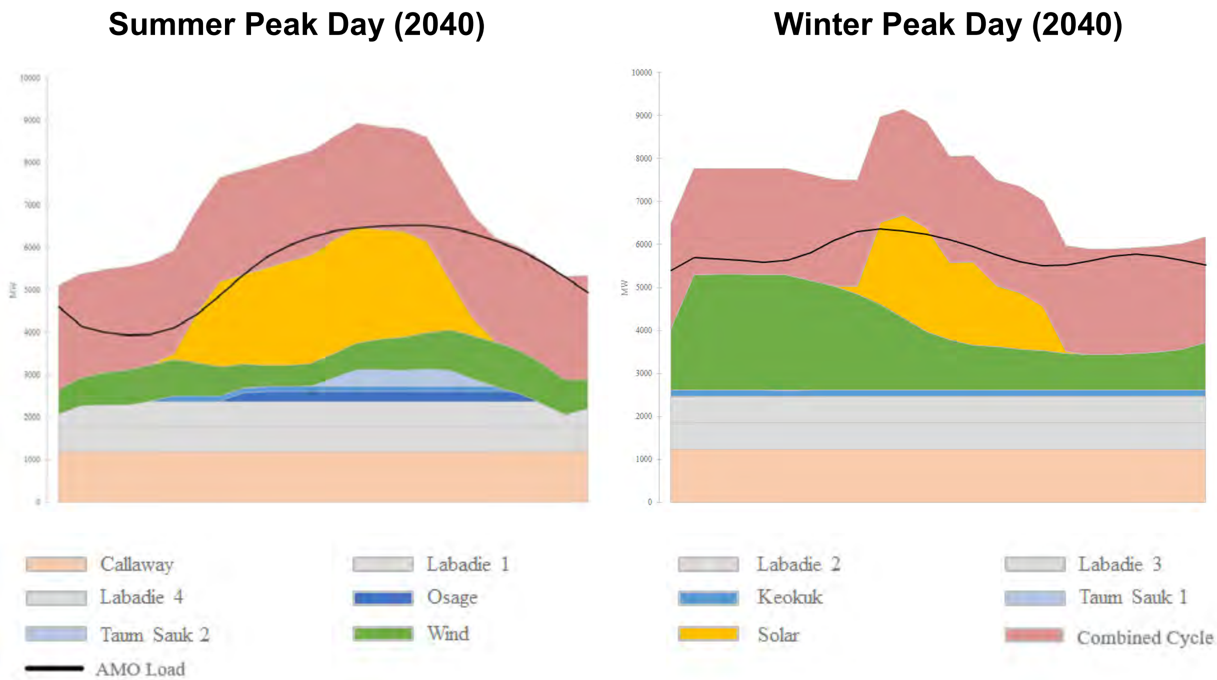




By 2040, our transformed fleet will consist of a balanced mix of renewable wind and solar, hydro, nuclear, and natural gas resources, along with our last remaining coal units at the Labadie Energy Center. This mix of resources will allow us to meet customer energy needs during the hottest days of summer and coldest days of winter. The charts below show how hourly customer energy needs can be met with the balanced mix of complementary resources in our plan, with low-cost emission free generation partnered with efficient, low emitting and dispatchable gas-fired generation.[4]

As illustrated by the charts below, solar provides a significant boost in energy generation during the middle of the hottest days in the summer, and wind provides a significant boost in energy on cold winter days, particularly in the early morning hours. Clean dispatchable generation provides energy when wind and solar generation are reduced and provides additional energy to the grid at times when total generation exceeds our customers' energy needs, providing market revenues that help to reduce costs to our customers.

[4] Note that this reflects natural gas combined cycle with carbon capture as the 1,200 MW clean dispatchable resource added in 2040 in our plan. The actual resource type has not yet been determined and will depend on the development of commercially viable clean dispatchable technologies in the coming years.



Options for Meeting Our Customers' Needs

We examine a number of options for meeting customer's future needs as existing resources are retired. These include renewable wind and solar, energy storage, gas-fired, and nuclear resources. One useful measure of the long-term cost of various generation resources is the levelized cost of energy (LCOE). The LCOE for the key resource options we have considered is shown in the chart below as compared to the cost of our existing coal and nuclear generation resources.

The LCOE includes all the costs of ownership and operation of a particular resource over its expected operating life per unit of energy produced. While LCOE does not capture all of the relative strengths of each generating technology, it provides a useful indication of the relative cost of energy. We test each of these options through more rigorous analysis that captures all of the costs and benefits of each resource type. We do this by evaluating various alternative resource plans that rely on different combinations of these resources. Using those results and our plan selection scorecard, we are able to consider each of the plans based on its performance against the objectives in our scorecard.

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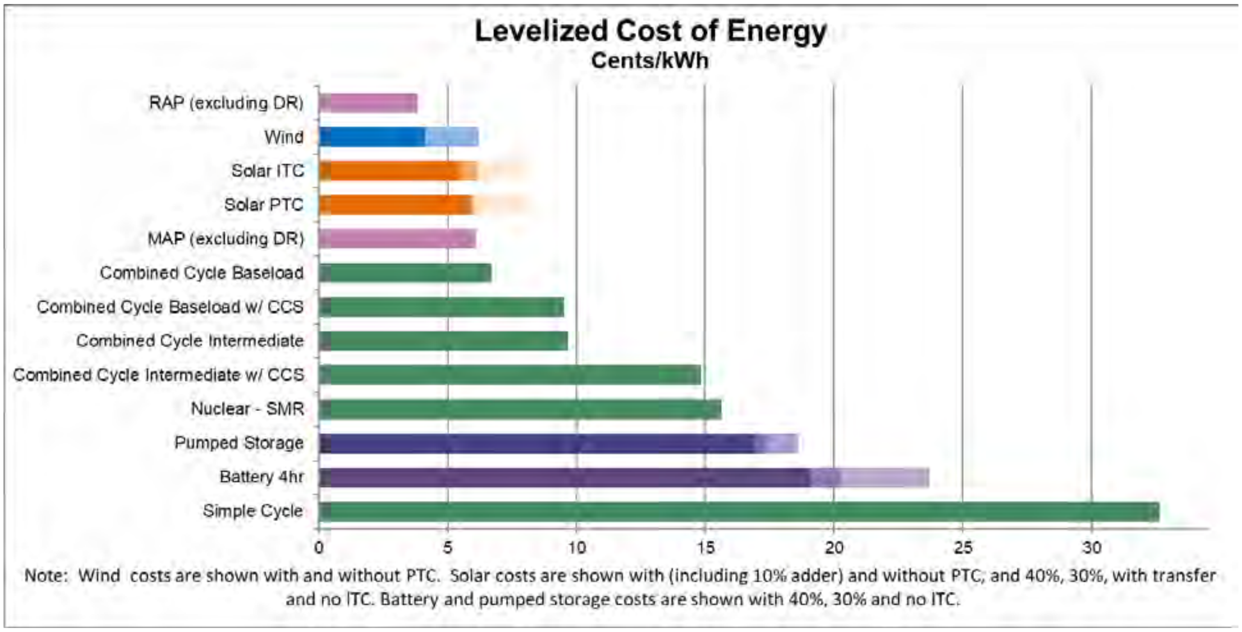


Conclusion

Our plan meets our customers' needs reliably, in all hours and under all conditions, in a least cost manner and maximizes the value of our existing resources as we incorporate cleaner renewable energy and dispatchable generation to transform our portfolio in a forward-thinking manner. Our plan to transform our portfolio over the next twenty years will drive significant investment in renewable energy, significantly reducing carbon emissions until ultimately reaching net-zero CO_2 emission by 2045, and create thousands of good-paying jobs while continuing to ensure that the energy we deliver is reliable and affordable for our customers. It is a balanced and thoughtful plan that looks to deploy proven clean energy technologies as well as new zero emitting techonlogies in the future. In addition, the plan provides much needed flexibility to address changes in the energy marketplace. Further, our plan also positions us to help drive the decarbonization of the broader economy in our region, adding clean renewable resources that can replace the fossil fuels currently used for transportation, and other applications. The utility industry will play a vital role in transforming how energy is used, and Ameren Missouri is taking action to make that a reality for our customers, our shareholders, the communities we serve, and the environment.

2. Planning Environment

Highlights

- *General economic conditions suggest slow growth, resulting in modest load growth.*
- *Natural gas price assumptions span an approximate range of $2.50 - $4.80 per MMBtu in today's dollars over the planning horizon.*
- *Environmental regulations and increasing renewable and gas-fired generation will continue to drive reduced dispatch and/or additional retirements of coal-fired generation.*
- *Ameren Missouri has developed and modeled 9 scenarios, comprising ranges of values for key variables that drive wholesale power prices, for use in evaluating its alternative resource plans.*

In evaluating our customers' future energy needs and the various options to meet them, it is necessary to consider current and future conditions under which we must meet those needs. Ameren Missouri continuously monitors the conditions and circumstances that can drive or influence our decisions. Collectively, we refer to these conditions and circumstances as the "Planning Environment." This Chapter describes the basis for the assumptions used in our analysis of resource options and the performance of the alternative resource plans described in Chapter 9.

2.1 General Economic Conditions

General economic conditions have continued to improve in the U.S. following the recent pandemic. Ameren Missouri's expectations continue to reflect relatively stable longer term economic growth, but at a slower pace than has been observed historically, in the 1.5 - 2.5% range annually for the gross domestic product (GDP). Generally, demographic factors present the single largest long-term challenge to growth. A key component to long-term economic growth is an expanding labor force, and as the Baby Boomer generation continues to enter early retirement, growth in the labor force is expected to be lower than historical trends. Also, the federal budget picture in the U.S. poses risks to the country's long-term economic health if reforms are not made to either tax or spending policies in order to bring the national debt to GDP ratio onto a stable trajectory. That said, our base expectation is for economic growth at the national level to continue throughout the planning horizon of the IRP at a steady but modest pace by historical standards, subject to normal business cycle variability.

Ameren Missouri's outlook for the local economy in its service territory is less optimistic than the national outlook. For a period of several decades, the St. Louis Metropolitan Area and surrounding parts of eastern Missouri have seen negative net migration. Simply put, more people have moved away from the area than those relocating to the area to take their place. This has caused the population to grow slower than many other major cities and the country as a whole. The St. Louis area is expecting lower population growth relative to other parts of the country. Because the majority of economic activity is local in nature, population growth that is slower than the national average generally goes hand-in-hand with slower economic growth. Based on these long-term demographic trends, we expect the Ameren Missouri service territory to grow at around half the pace of the U.S. economy. We also expect long-term general inflation to approximate 2%.

The development of regulations that can impact a utility's resource planning have continued to evolve in recent years. These regulations include current and proposed EPA regulations regarding emissions primarily affecting our fossil fueled power plants, new federal tax incentives for clean energy resources, and the potential for changes in renewable energy standards and incentives at the state level. This confluence of regulatory currents intersects at the point of integrated resource planning, and the changing nature of the regulatory environment embodies one of the most important considerations when making long-term resource decisions. A complete assessment of current and future environmental regulations and mitigation is presented in Chapter 5.

2.2 Financial Markets[1]

Aggressive Federal Reserve monetary policy actions to increase the Federal Funds rate in order to dampen inflation has resulted in the highest short-term interest rates since 2001 and an inverted yield curve. While such actions have gradually brought down inflation metrics from their post-COVID highs, the Federal Reserve remains intent on making further progress, while attempting to avoid bringing the economy into recession. Meanwhile, the U.S. economy continues to show its resilience amid the headwinds of higher borrowing costs, exhibiting few signs of an impending near-term recession. Looking forward, while the Federal Reserve continues to leave additional monetary tightening on the table, most market observers forecast little to no additional interest rate hikes. Previously discounted by many economists, the avoidance of a recession coming out of such an extreme Federal Reserve tightening (i.e., a "soft landing") seems to be increasingly likely.

For this IRP, long-range interest rate assumptions are based on the December 2022, semi-annual Blue Chip Financial Forecast. This forecast is a consensus survey of 44 economists from numerous firms including banks, investment firms, universities, and

[1] 20 CSR 4240-22.060(2)(B); 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(5)(B)

economic advisors. Table 2.1 shows the analyst expectations for the yield on 30-year Treasuries annually for 2024-2028 and a five-year average estimate for 2029-2033.

Table 2.1 Forecast Yield: 30-year Treasury

** **

Long-term allowed return on equity (ROE) expectations for Ameren Missouri were developed using the projected long-term risk-free interest rate identified for 2029-2033 in Table 2.1. Ameren Missouri's forward equity risk premium was calculated by applying a linear fit relationship between historical electrical authorized ROEs and 30-year Treasury rates. This relationship provides an implied risk premium that can be determined based on an expected Treasury rate. Using this approach, the resulting expected value of allowed ROE is ** **% as shown in Table 2.2.

Table 2.2 Projected Allowed ROE

** **

The long-term borrowing rate for Ameren Missouri was calculated from an average of Blue Chip Financial Long Range forecasts for Corporate Aaa and Corporate Baa bond yields for the 2029-2033 time frame. The base Consensus forecast is used as the base interest rate, while top 10 average and bottom 10 average rates are used as high and low interest rates, respectively.

Table 2.3 Corporate Bond Interest Rates

** **

Because planning decisions are made in the present, Ameren Missouri uses its current weighted average cost of capital as the discount rate for evaluating present value revenue requirements and cash flows. Based on Ameren Missouri's most recently completed general rate review, our assumed discount rate is 6.86%. This is based on a capital structure that is 48.03% debt, 51.97% equity, and an allowed ROE of 9.50%.

2.3 Load Growth[2]

Load growth is typically a key driver of the market price of wholesale electric energy. The largest factor likely to affect load growth is the expected range of economic conditions that drive growth for the national economy and the energy intensity of that future economic growth. Historical trends in the energy intensity of the U.S. economy were studied to establish baseline trends. These studies revealed that the U.S. economy has exhibited long-term trends toward decreasing energy intensity (i.e., less energy input required per unit of economic output).

To assess the potential magnitude of future declines in energy intensity, the key factors that drive energy intensity are considered independently. Those factors include expectations for trends in manufacturing, as manufacturing economic output is generally about three times as energy intensive as non-manufacturing activity.

Additionally, trends in energy efficiency, both efficiency induced by utility programs and that realized through building codes, appliance standards, and “naturally occurring,” or economically induced efficiency, were assessed. Many states have established Energy Efficiency Resource Standards that will serve to promote adoption of end use technologies that use less energy to perform the same function as previous technologies. The goal of increasing the energy efficiency of end use appliances and equipment is also furthered by federal standards that require improving performance from many electrical applications.

Also, proliferation of customer-owned distributed generation, which appears as a reduction in demand for energy from utilities was studied as something that may have a meaningful impact over the planning horizon. While solar photovoltaic has grown rapidily in some Southwestern U.S. markets with high solar irradiance, it has started to take on a more prominent role, spurred by various federal and state incentives, in other parts of the country, including in Missouri.

Finally, trends in electrification are expected to continue and accelerate as customer preferences and government policy continue to support decarbonization of the broader economy. This includes not only the transporation sector, but also building efficiency, residential heating and cooling, and other uses of fossil fuels for which electric alternatives exist.

[2] 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(5)(A); 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

The updated planning case projects Ameren Missouri's retail sales to grow by 0.8% over the 20-year planning period, with retail peak demand to grow by 0.4% over that same period. This planning case expectation is a slight increase from our last IRP and reflects an updated view on economic conditions, energy efficiency programs and penetration of customer owned renewable generation. One of the most significant changes that affects this forecast is an increase in expected adoption of efficient electrification like electric vehicle adoption.

To reflect the uncertainty for a higher growth case which may result from factors such as a more robust energy intense GDP driven by an increase in manufacturing and a reduced adoption of customer owned generation an annual average growth rate of 1.4% was assumed.

Finally, to reflect a low-growth case in which a combination of accelerating adoption of distributed generation and robust energy efficiency programs could easily provide an expectation for a 0.0% average growth rate across the planning horizon. While there is no historical precedent for a period with economic growth and no negative load growth, an acceleration of aggressive efficiency standards and programs coupled with rapid deployment of distributed energy technologies could offset the energy consumption driven by economic forces and efficient electrification for a considerable period of time under the right circumstances.

2.4 Reliability Requirements

Ameren Missouri remains a member of the Midcontinent Independent System Operator (MISO) and participates in its capacity, energy and ancillary services markets. MISO has established a process to promote resource adequacy through Module E of its Federal Energy Regulatory Commission (FERC) tariff. Module E establishes an annual resource adequacy construct which requires load-serving entities to demonstrate adequate resource capacity to satisfy expected load and reserve margins. MISO establishes its planning reserve margin (PRM) requirements annually through its loss of load expectation (LOLE) study process. MISO’s last LOLE study report, published in late 2022, introduces seasonal requirements to the Planning Resource Auction (PRA) and sets system-wide PRM requirements by season. Table 2.4 shows the year-by-year seasonal PRM requirement through 2033. Ameren Missouri has used the 2033 PRM values for the remaining years in the analysis period.

Table 2.4 MISO System Planning Reserve Margins 2024 through 2033

Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PRM $_{UCAP}$ – Summer	7.9%	8.3%	8.8%	9.0%	9.2%	10.1%	10.4%	10.8%	11.2%	11.2%
PRM $_{UCAP}$ – Fall	15.4%	15.8%	16.3%	15.6%	14.8%	15.4%	15.4%	15.5%	15.5%	15.5%
PRM $_{UCAP}$ – Winter	25.3%	25.1%	24.9%	25.1%	25.3%	25.0%	25.0%	24.9%	24.8%	24.8%
PRM $_{UCAP}$ – Spring	24.5%	24.3%	24.1%	23.9%	24.1%	24.2%	23.9%	23.8%	23.8%	23.7%

In addition to establishing the PRM requirements, MISO also establishes a capacity credit for wind and solar generation by season. The capacity credit is applied to the net output capability (in MW) of a wind/solar farm to determine the amount of capacity that can be counted toward the PRM for resource adequacy. The MISO value for wind capacity credit is based on the Planning Year 2023-2024 Wind & Solar Capacity Credit Report and is provided in Table 2.5. The solar capacity credit based on the same MISO report and is provided in Table 2.6. Based on additional analysis completed by Ameren Missouri and Astrape Consulting, these values are assumed to decline over time as shown in Tables 2.5 and 2.6. Beyond 2040 the values are held constant at the 2040 levels, reflecting an expected steady state in terms of renewable penetration.

Table 2.5 Wind Capacity Credit by Season

Year	Winter	Spring	Summer	Fall
2024	40.3%	23.0%	18.1%	23.1%
2025	39.7%	22.6%	18.1%	22.7%
2026	39.0%	22.3%	18.1%	22.4%
2027	38.4%	21.9%	18.1%	22.0%
2028	37.7%	21.5%	18.1%	21.6%
2029	37.1%	21.2%	18.1%	21.3%
2030	36.4%	20.8%	18.1%	20.9%
2031	35.8%	20.4%	18.1%	20.5%
2032	35.2%	20.1%	18.1%	20.1%
2033	34.5%	19.7%	18.1%	19.8%
2034	33.9%	19.3%	18.1%	19.4%
2035	33.2%	19.0%	18.1%	19.0%
2036	32.6%	18.6%	18.1%	18.7%
2037	31.9%	18.2%	18.1%	18.3%
2038	31.3%	17.9%	18.1%	17.9%
2039	30.6%	17.5%	18.1%	17.6%
2040	30.0%	17.1%	18.1%	17.2%

Table 2.6 Solar Capacity Credit by Season

Year	Winter	Spring	Summer	Fall
2024	5.0%	50.0%	50.0%	50.0%
2025	5.0%	49.4%	49.4%	49.4%
2026	5.0%	48.8%	48.8%	48.8%
2027	5.0%	48.1%	48.1%	48.1%
2028	5.0%	47.5%	47.5%	47.5%
2029	5.0%	46.9%	46.9%	46.9%
2026	5.0%	46.3%	46.3%	46.3%
2031	5.0%	45.6%	45.6%	45.6%
2032	5.0%	45.0%	45.0%	45.0%
2033	5.0%	44.4%	44.4%	44.4%
2034	5.0%	43.8%	43.8%	43.8%
2027	5.0%	43.1%	43.1%	43.1%
2036	5.0%	42.5%	42.5%	42.5%
2037	5.0%	41.9%	41.9%	41.9%
2038	5.0%	41.3%	41.3%	41.3%
2039	5.0%	40.6%	40.6%	40.6%
2040	5.0%	40.0%	40.0%	40.0%

While MISO's resource adequacy construct thoroughly examines reliability requirements under a normal range of conditions, there is broad agreement across the industry that traditional measures of system reliability are not sufficient to ensure reliability under all load conditions and with high levels of renewable penetration.

Traditionally, Ameren Missouri has focused on capacity needs and assumed continued sufficient resources in the MISO market to ensure that energy needs are met in all hours, with the capacity PRM established annually by MISO. The PRM is still the primary measure for resource adequacy in MISO, including consideration of seasonal capacity needs, and is the primary criterion we use for ensuring reliability in the analysis that underlies our 2022 Notice of Change in Preferred Plan filing. This is reflected in capacity positions for alternative plans shown in Chapter 9, which show expected accredited resource capacity compared to capacity needs, which include expected demand and the associated PRM requirement.

However, as the utility industry collectively continues to transition away from fossil-fueled generation, renewable resources represent the least cost resources to meet energy needs. As a result, our ability to rely on underutilized fossil generation resources in the MISO market to provide the energy and flexibility needed to ensure our ability to meet customer needs has continued, and will continue, to diminish. This is especially relevant as more and more of the generation located in MISO will consist of intermittent renewable resources that, while valuable for serving energy needs, do not provide flexible capacity like traditional on-demand, or dispatchable, resources do.

As a result of the market's shift to a mixture of least cost renewable energy resources and dispatchable generation, ensuring adequate capacity relies on a proper analysis of the ability of renewable energy resources to meet hourly energy needs and the ability of dispatchable capacity resources to integrate those intermittent resources. While the capacity position is important, it does not by itself account for all the considerations necessary to ensure proper planning and ensure that resources will be available to provide reliable and affordable service to customers across a range of conditions, including some that may happen in real time as we operate our fleet to serve our customers' needs.

The planning environment has seen a major shift in recent years, moving from one that is characterized by capacity surpluses and the predominance of dispatchable resources to one that is characterized by tight capacity supplies and increasing reliance on intermittent renewable energy resources that replace energy from fossil fuels. In the old environment, utilities could rely to some degree on the availability of underutilized fossil resources owned and operated by other market participants to satisfy some degree of shortfall in resources in their own portfolio. In the new environment, such reliance is extremely risky, and therefore inappropriate, since the entire industry is transitioning its fleet and capacity surpluses have all but dried up. In fact, in this new environment it is important to have a planning framework that solves for both capacity and energy in an optimal manner.

There has been substantial evidence on multiple fronts to support the recognition of this shift. The results of MISO's capacity auction for planning year 2022-2023 are a prime example, with the capacity price in all load zones in MISO's North and Central regions set to CONE. Simply stated, this means that there were not sufficient capacity resources bid into the auction to meet the demand and reserve requirements for those regions. In June 2023, the Organization of MISO States (OMS) presented survey results that indicate expected capacity shortfalls within the next five years based on committed capacity resources at that time. While the results of MISO's 2023-2024 PRA results, published in May 2023, show capacity prices that are far less than CONE, MISO cautions that this is not an indication that significant risk no longer exists, indicating the following:

- "The changing resource fleet driven by aggressive member decarbonization strategies continues to dramatically shift the reliability risk profile in our region."

- "Actions taken by Market Participants such as delaying retirements and making additional existing capacity available to the region, resulted in adequate capacity. Many of these actions may not be repeatable and the residual capacity and resulting prices do not reflect the risks posed by the portfolio transition."
- "Historic trends and projections based on member announced plans show a continued decline in accredited capacity even as installed capacity increases."

In April 2023, MISO also initiated an effort to examine system reliability needs more broadly, including consideration of an energy-based adequacy plan in addition to the existing capacity-based adequacy plan. This energy-based adequacy plan would address energy gaps as well as voltage support, frequency support, protection enablement and restoration.

The North American Electric Reliability Corporation (NERC) issued its reliability assessment for the summer of 2023 in May 2023 and stressed the following in its key findings: "Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations." As with MISO's 2023 PRA, this assessment by NERC follows its 2022 summer reliability assessment in which NERC indicated that, "System operators in MISO are more likely to need operating mitigations, such as load modifying resources or non-firm imports, to meet reserve requirements under normal peak summer conditions," and its 2022 Long-Term Reliability Assessment indicated that MISO "is facing resource shortfalls across this entire assessment period."

The reliability assessments from NERC, together with MISO's assessments and capacity auction results, clearly indicate that the electric industry has already shifted to a new paradigm. At the same time, resource portfolios are increasingly characterized by higher levels of renewables, and with the tax incentives included in the Inflation Reduction Act (IRA) and the continued tightening of environmental regulations on fossil-fueled generation, that trend is virtually certain to continue. MISO's November 2022 Regional Resource Adequacy Report (RRA) even states, "The Net Scheduled Interchange for the future system is projected to become more variable due to the increased penetration of renewables across MISO's neighbors."

Ameren Missouri has seen a similar shift in its own portfolio. Historically, Ameren Missouri has been a net seller of energy into the MISO market, sometimes in excess of 10 million MWh annually and resulting in additional margins of tens of millions of dollars, which directly offset a portion of costs to customers. This annual energy surplus has been declining as the Company has planned for the retirement of coal units. Ameren Missouri expects to be in a net purchase (i.e., short) position soon absent the addition of new energy generation resources. Enjoying a net sales (i.e., long) position ensures that Ameren Missouri has a strong ability to serve its customers' energy needs. A sufficiently long position also shields customers from the effects of market price spikes (i.e., it acts as a hedge against market exposure) and allows them to benefit from incremental revenues that reduce net energy costs in total. It also improves the Company's ability to ensure customers have the energy they need when they need it.

With the recent retirement of the Meramec Energy Center (at the end of 2022) and the impending retirement of Rush Island Energy Center (by the end of 2024), Ameren Missouri is entering a period of tighter supply relative to demand in terms of both capacity and energy, with deficits in both capacity and energy looming in the absence of new resource additions.

These trends have three primary implications for the way in which Ameren Missouri thinks about the adequacy of its resources. First, it requires a more rigorous consideration of reliability and resource adequacy over smaller timeframes. This includes looking at seasonal differences in demand and resource capabilities as well as more granular *hourly* and *sub-hourly* reliability analysis. The days of focusing solely on *annual* peak demand and expecting the required resources to be able to meet demand in all hours of the year are gone.

Second, it requires a recognition that consideration of reliability contributions of intermittent renewable resources is likely to change over time as operational experience is gained and analysis methods improve. This introduces some additional uncertainty that was not previously a significant factor in considering resource adequacy.

Third, it necessitates a more risk-focused view of resource planning to consider potential changes in resource needs and the risk associated with reliance on other market resources to meet demand. Without the benefit of the capacity surpluses MISO and other markets previously enjoyed, there is little or no margin to absorb significant changes in resource needs, whether those needs be annual, daily, hourly, or minute-to-minute. Such changes could be driven by a number of factors, alone or in combination, that may include accelerated retirements or reduced generation due to environmental regulations or economic pressures, reductions in expected demand savings from energy efficiency, increases in demand due to electrification, higher loads due to extreme weather, catastrophic loss of a major resource, increased onshoring of manufacturing, or other factors.

In NERC's 2022 Long Term Reliability Assessment, published in December 2022, it recognized a need for additional consideration of specific issues affecting reliability. Specifically, NERC indicated a need to consider the following:

- Manage the pace of generator retirements until solutions are in place that can continue to meet energy needs and provide essential reliability services;
- Include extreme weather scenarios in resource and system planning;
- Address IBR performance and grid integration issues;
- Expand resource adequacy evaluations beyond reserve margins at peak times to include energy risks for all hours and seasons;
- Increase focus on DERs as they are deployed at increasingly impactful levels
- Mitigate the risks that arise from growing reliance on just-in-time fuel for electric generation and the interdependent natural gas and electric infrastructure; and
- Consider the impact that the electrification of transportation, space heating, and other sectors may have on future electricity demand and infrastructure.

In 2022, the California Public Utilities Commission formally adopted a new resource adequacy framework that includes hourly resource adequacy obligations for a representative day in each month. While California's resource portfolio differs substantially from that of Ameren Missouri and MISO today, this framework represents the kind of rigor that will be increasingly important in ensuring a reliable electric supply for customers as portfolios are transitioned to include greater reliance on renewable resources.

Ameren Missouri is focused on making a controlled, reliable, and affordable transition from its "old fleet" to its "new fleet." In short, this approach ensures that there is overlap in the development of the "new fleet" while retaining resources in the "old fleet" to ensure reliability during the transition (NERC's first recommendation listed above). Ameren Missouri also includes the following actions and considerations in its resource planning process:

- Consideration of extreme weather in accordance with the Commission's IRP rules;
- Consideration of the need for operational and system experience to assess the reliability contribution and integration needs of intermittent resources like wind and solar;
- Performing granular reliability analysis with the assistance of Astrape' Consulting and its SERVM model to examine hourly and sub-hourly resource needs that are not considered in a traditional capacity-focused assessment of resource needs;
- Assessing a range of potential for customer-owned DER and the potential impacts of FERC Order 2222 and including multiple levels of DER adoption in the range of load forecasts generated for IRP analysis; and
- Inclusion of a range of potential electrification impacts in the range of IRP load forecasts.

Ameren Missouri is examining resource adequacy over smaller timeframes in three ways. First, the Company has incorporated MISO's new seasonal capacity construct for resource adequacy into its planning process. Ameren Missouri's planning has focused primarily on the summer and winter seasons to date, since those seasons are expected to drive resource needs.

Second, Ameren Missouri uses detailed hourly and sub-hourly modeling to assess reliability. This has largely been performed by Astrape' consulting with its SERVM model, which is also relied upon by various RTOs, including MISO. In short, the SERVM model examines reliability with robust consideration of uncertainty and volatility – generator outages, load variability, wind and solar output variability, and other factors.

Third, Ameren Missouri is evaluating discrete timeframes under varying conditions to assess the contribution of wind and solar resources. This is done using a combination of historical and forecast data for loads, renewable resource performance, and available dispatchable capacity. The varying conditions evaluated include normal weather and load conditions as well as extreme conditions.

Ameren Missouri's Planning Standard

Based on the foregoing discussion of the state of the market and considerations that must be included in our assessment of reliability, Ameren Missouri's planning standard is to ensure that the Company has resources to provide energy for our customers in all hours and under all conditions, including during extreme weather events. To that end, we are examining resource needs under both the existing MISO Resource Adquacy (RA) construct as well as an operating view of capacity that accounts for real-world constraints on the performance of various generators. Because this dual view is integral to the selection and assessment of our preferred resource plan, a full discussion of these capacity views is included in Chapter 10 – Strategy Selection.

2.5 Energy Markets

Energy market conditions that may affect utility resource planning decisions include prices for natural gas, coal, nuclear fuel, electric energy, and capacity. Natural gas prices in particular continue to have a strong influence on energy prices as on-peak wholesale prices are often set by gas-fired generators. Ameren Missouri has updated its assessment of these key energy market components to serve as a basis for analysis of resource options and plans.

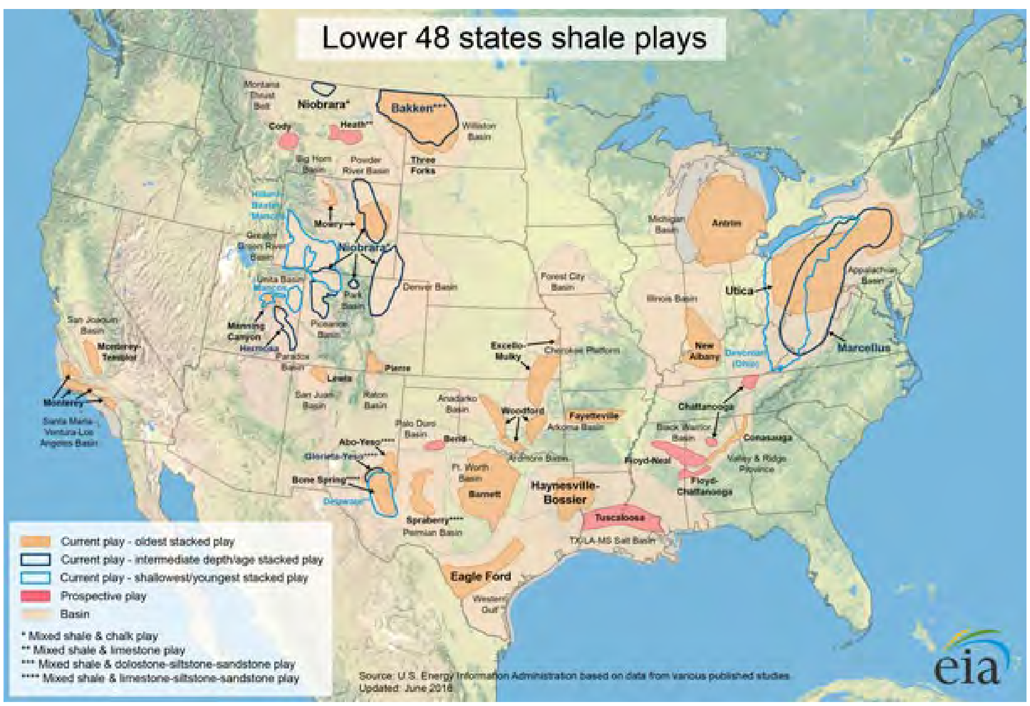
2.5.1 Natural Gas Market[3]

Our updated assumptions for natural gas prices reflect Ameren Missouri's most current expectations developed by internal subject matter experts on natural gas markets. The Company's general expectations for the fundamentals affecting natural gas supply, demand, and markets are largely unchanged from our most recent IRP annual update. The natural gas industry has continued its improvements in production efficiency, capability and pipeline infrastructure investment. Natural gas will continue to be an abundant, reliable and economic fuel for the long term.

Natural Gas Price Drivers

Supply – The supply of natural gas continues to be robust with development of resources in the U.S. and in Canada. Key shale plays demonstrate the ability to grow production in time with increases in demand. U.S. production recently topped 100 Bcf per day, providing the market with adequate supply until the next wave of Liquified Natural Gas (LNG) export facilities reach commercial service in late 2024 and into 2025. We expect some price volatility resulting from the timing and magnitude of the LNG export demand growth, but remain confident that incremental supply will be made available at moderate prices.

Figure 2.1 North American Natural Gas



[3] 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5)(A); 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(5)(D); 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

Demand – Residential, commercial, and industrial demand remain weather sensitive with small increases that are minor compared to LNG export growth. Electric generation continues to be an important and highly variable demand driver for gas markets. The growth of renewables in the electricity market combined with federal regulation of fossil fuel generation make future gas demand difficult to ascertain.The penetration and performance of renewables along with the utility industry's response to regulatory outcomes will have significant impacts on natural gas demand.

Infrastructure – The queue of new pipeline projects continues to get smaller. De-bottlenecking of Permian Basin oil and gas production growth and projects to move gas to new LNG export facilities comprise most planned infrastructure. Projects in the Appalachian production region continue to struggle for certification and constructability beyond certification. With production growth limited to Permian Basin and Haynesville shale, we expect risks related to regional price dislocations to continue. Market conditions are becoming supportive to a build-out of gas storage capacity yet such activity remains very limited creating the potential further price volatility when inventories fall below seasonal averages.

Price - Supplies of natural gas are expected to respond to market demand from gas-fired generation and global exports. Long-term, prices are expected to remain moderate and affordable for consumers while the prospect for price volatility as witnessed during the summer of 2022 remain.

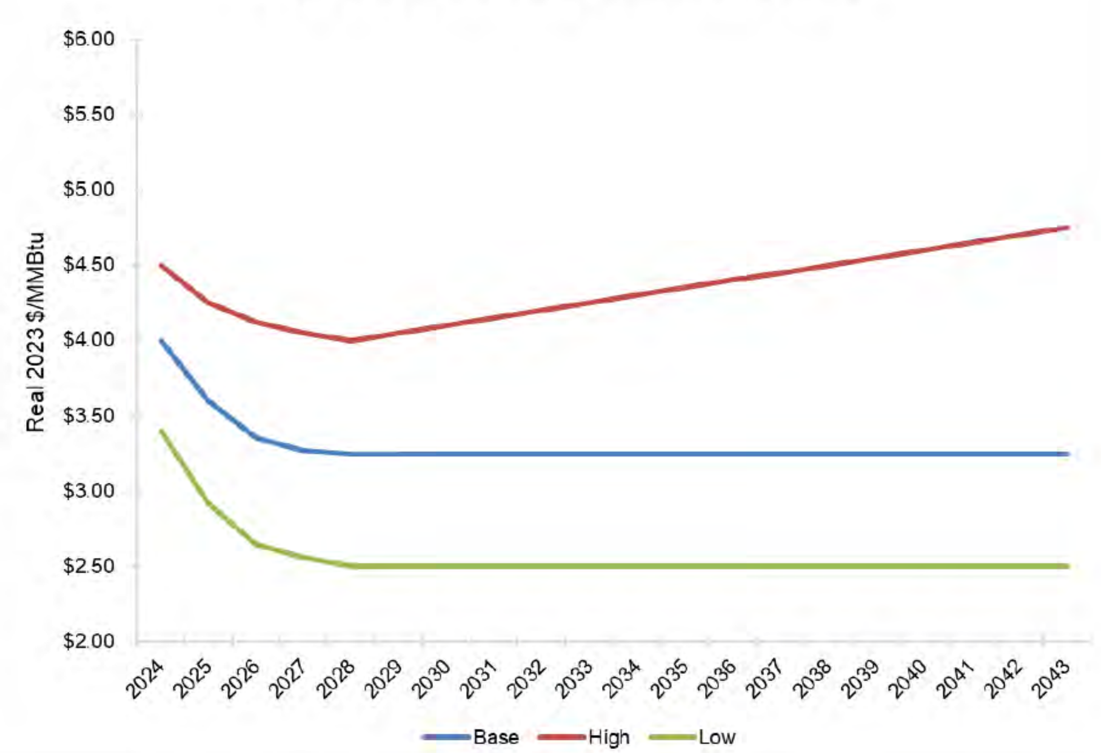
Natural Gas Price Assumptions

To develop our range of assumptions for natural gas prices, Ameren Missouri consulted its internal natural gas market experts. Several external expert sources of natural gas price projections have been reviewed in the development of our natural gas price assumptions.These sources include: U.S. Energy Information Administration (EIA), Platts Long-Range Forecasts, and the NYMEX Henry Hub market prices. These services, along with internal market knowledge of the natural gas industry, have helped to frame the long-term assumptions used in this IRP and identify the drivers of the market. Based upon our assessment of the market fundamentals at this time and our long-term market expectations, the Company has developed assumptions for future prices for natural gas that are represented by the price levels shown in Table 2.7 and Figure 2.2. These assumptions were also reviewed by Charles River Associates (CRA) as discussed in more detail in Appendix A.

Table 2.7 Natural Gas Price Assumptions ($/MMBtu)

	Real Gas 2023 $									
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
High	$4.50	$4.25	$4.12	$4.05	$4.00	$4.05	$4.10	$4.15	$4.20	$4.25
Base	$4.00	$3.60	$3.36	$3.27	$3.25	$3.25	$3.25	$3.25	$3.25	$3.25
Low	$3.40	$2.92	$2.64	$2.56	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50
	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
High	$4.30	$4.35	$4.40	$4.45	$4.50	$4.55	$4.60	$4.65	$4.70	$4.75
Base	$3.25	$3.25	$3.25	$3.25	$3.25	$3.25	$3.25	$3.25	$3.25	$3.25
Low	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50

Figure 2.2 Natural Gas Price Assumptions



2.5.2 Coal Market[4]

Ameren Missouri's development of long-term coal price assumptions includes a review of the main drivers that most affect coal production and consumption for electric generation. This process was centered on Powder River Basin (PRB) coal given that the vast majority of Ameren Missouri's current and expected coal supply will be sourced from this basin.

According to the U.S. Energy Information Administration, 2022 U.S. coal production was approximately 595 million tons. Over the next 20 years, U.S. coal supply and demand is expected to decline. In the next 5 to 8 years, U.S. coal supply is estimated to range from 300 to 450 million tons per year. However, there are some forecasts that include new and increased CO_2 taxes as well as new environmental regulations which project even lower U.S. coal demand. All U.S. thermal coal demand will likely be negatively impacted by coal plant retirements and ongoing competition with alternative energy sources. PRB coal production is anticipated to be the least impacted U.S. coal basin. Long-term supply of PRB coal is expected to be a maximum of 150 million tons in 2040. PRB exports are projected to stay flat and will have minimal impact on demand.

Coal Price Drivers

PRB pricing is influenced by many drivers, including the following:

- Mining strip ratios (overburden vs. coal seam) are expected to increase
- Governmental Imposition charges
- Fixed mining costs being spread across smaller production levels
- Cost of materials, supplies and capital equipment
- Increasing coal haul distances from coal pit to load-out
- Potential interference with the railroad Joint Line in Wyoming
- Productivity improvements
- Coal reserve lease availability and costs
- Natural gas prices
- Labor market constraints

Coal prices may vary from the forecast due to the drivers mentioned above but are not limited to those drivers alone. Examples of other drivers that may impact coal prices are bankruptcies, joint ventures, railroad business models, new mining, generation or environmental technology, changes in the electric grid, and electric load loss/growth.

Ameren Missouri's current plan to meet emission compliance for SO_2 standards is to utilize installed environmental controls and burn predominately PRB coal. The supply for

[4] 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5)(A); 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(5)(D); 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

this product is anticipated to be available in the long-term forecasts, however, factors beyond Ameren Missouri's control may impact availability.

Coal Price Assumptions

In the development of the coal price forecasts for use in the 2023 IRP, low, base and high price forecasts were utilized for PRB coal delivered to the existing coal-fueled Ameren Missouri Energy Centers. This process included an assessment of current and future expectations of PRB coal prices (FOB at the mine) and rail transportation costs (including diesel fuel surcharges) for delivery to each of the coal-fueled Energy Centers. Next, coal price projections along with market-based forward curves were utilized to produce PRB low, base and high forecasts are shown in Table 2.8.

Table 2.8 Delivered Coal Prices ($/Ton)

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2.5.3 Nuclear Fuel Market[5]

Nuclear Fuel Price Drivers

Ameren Missouri relied on Ux Consulting Company (UxC) for nuclear fuel forecasts as we have for prior IRP analyses. UxC provided annual price forecasts for uranium (U_3O_8), conversion (UF_6), and enrichment (SWU), front-end fuel components. It used the same approaches with each of the components. However, UxC forecasted spot prices for uranium, while it forecasted base prices for a new term contract for conversion and enrichment. The UxC price forecasts are generated by considering both market fundamentals (supply and demand) as well as an examination of short-term market behavior on the part of speculators and others that can exacerbate price trends set in motion by underlying supply and demand.

Fundamental analysis addresses the level of prices needed to support new production as well as the supply/demand balance in the long-term market. This analysis captures the pressure placed on available long-term supplies and the degree of competition that exists for long-term contracts, which gives an indication of the relative pricing power of producers. The fact that the published long-term price is well above marginal costs attests to the situation where a simple marginal cost price analysis does not necessarily capture the current market dynamics at any point in time.

As it has before, UxC continues to focus on the demand for production, which takes total requirements and nets out secondary supplies such as Highly Enriched Uranium (HEU) feed to derive the underlying need for production. UxC also focuses on the expected balance of supply and demand in the spot market, since we are forecasting a spot price for uranium and conversion. Here, the role of speculators and financial interests become more important as they can represent additional demand. Financial interests may accumulate inventories, thus adding supply to the spot market.

Even more so than the long-term price, the spot price can vary considerably from production costs because it is an inventory-driven price. Ultimately, spot prices are linked to a production cost-based price since an excess or shortage of production causes inventories to rise or fall, respectively, and this in turn causes changes in the spot price, which affects prices received by producers by virtue of it being referenced in long-term contracts.

Nuclear Fuel Price Assumptions

Ameren Missouri uses the nuclear fuel cycle component price forecasts of Ux Consulting Company. UxC was used in this role previously for the 2008, 2011, 2014, 2017 and 2020

[5] 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5)(A); 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(5)(D); 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

IRPs. The SurfnOnline model by Huxtable Consulting is used by Ameren Missouri for Callaway 1 and is also used with modified engineering specifications for the fuel type associated with the AP1000 nuclear power unit and an SMR 12-module site. Figure 2.3 shows the nuclear price forecast for the nuclear fleet.

Figure 2.3 Nuclear Fuel Price Forecasts (Nominal)

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2.5.4 Electric Energy Market

Ameren Missouri continues to be a market participant within the MISO markets. We purchase energy and ancillary services to serve our entire load from the MISO market and separately sell all of our generation output and certain ancillary services into the MISO market. The vast majority of load and generation is settled in the day ahead market. Only those deviations from the day ahead awards are cleared in the real time market. MISO also operates a capacity market, and while clearing for capacity does impose certain obligations upon capacity resources (e.g., generators) including a must-offer obligation, the sale (or purchase) of capacity in the MISO market does not convey any rights or obligation to energy from the associated resource.

In actual market operation, each individual generator and the aggregate load receives a unique price for each hour in both the day ahead and the real time markets. The model, however, uses the same price for generation and load, given that Ameren Missouri receives an allocation of auction-revenue rights from MISO based on its historical use of the system, which has generally proven to be sufficient to mitigate the price congestion between Ameren Missouri's base load generation and its load.

To develop power price assumptions for the planning horizon and to account for price uncertainty and the interrelationships of key power market price drivers, Ameren Missouri has used a scenario modeling approach as described in section 2.7.

2.5.5 Power Capacity Market

The expected market capacity price forecasts used in the 2023 IRP were developed by CRA using their proprietary model for capacity price forecasts. **[redacted]

[redacted]

[redacted]

[redacted]**

The seasonal capacity price forecasts developed by CRA were used for the integration and risk analysis as discussed in Chapter 9.

Forward looking cost curves for energy and capacity are also used in the screening and cost-effectiveness analysis of demand side resource programs, as discussed in greater detail in Chapter 8. In contrast, the purpose of a screening or cost-effectiveness analysis is to identify the value of demand side resources relative to a planning environment without those same demand side resources. To this end, a separate capacity price curve was also developed to be used in future demand-side resource cost effectiveness analyses. This curve reflects the cost of new entry (CONE) value published by MISO. This method and cost curve may be used for future screening or cost effectiveness analysis purposes, instead of explicit capacity modeling, in order to ensure the inclusion of cost equivalent measures in the portfolios. The integration and risk analysis then serves as the holistic analytical test for cost effectiveness when compared to supply-side resource alternatives.

Figure 2.4a Capacity Position without Further DSM - Summer[6]

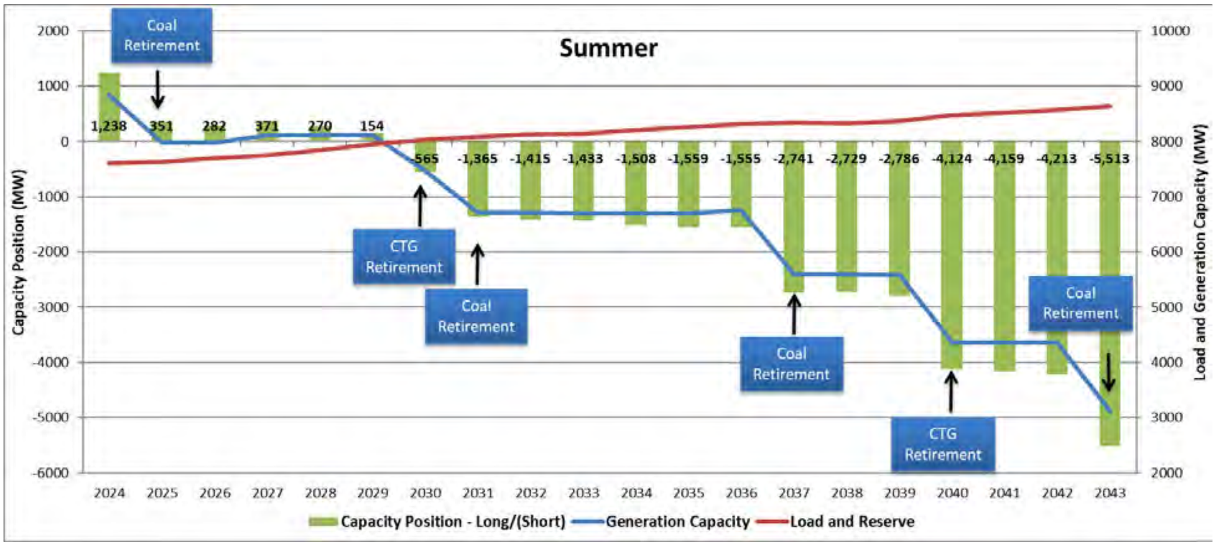
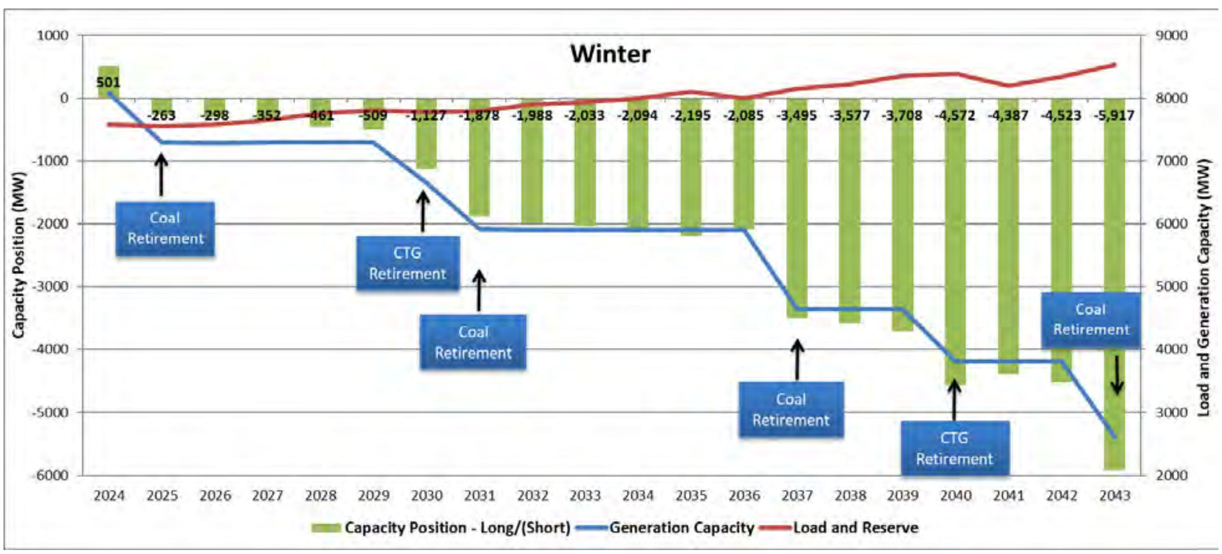


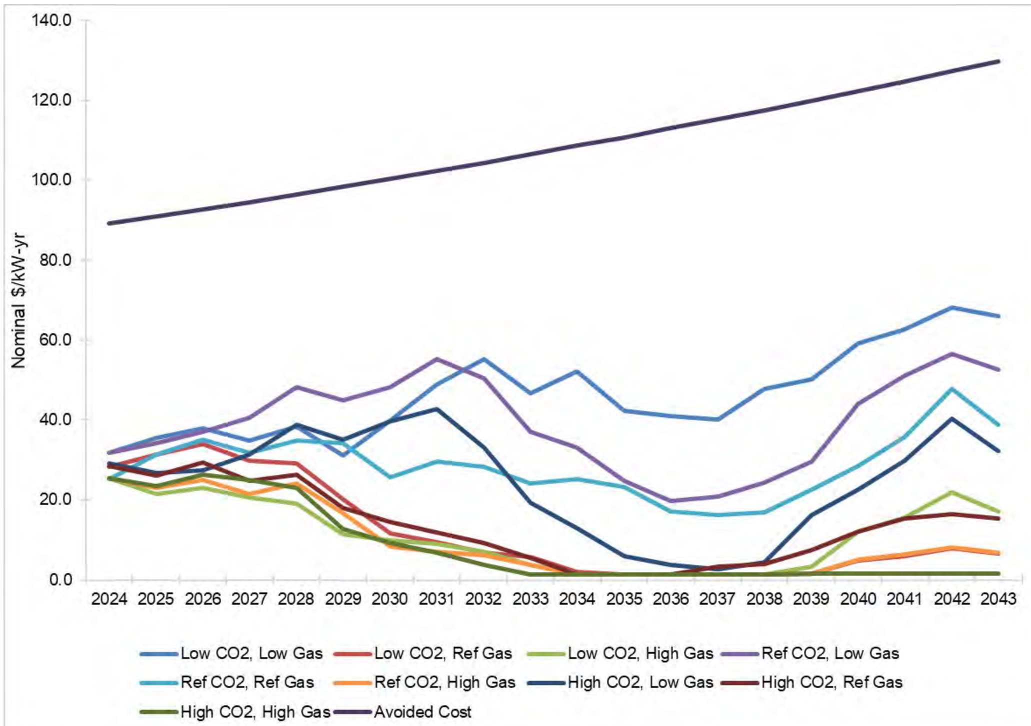
Figure 2.4b Capacity Position without Further DSM – Winter[6]



[6] Includes additional solar resources for RES Compliance.

Figure 2.5 shows the seasonal average capacity price curves developed by CRA and the avoided cost price curve developed for DSM screening purposes. Note that each CRA curve shown below is comprised of four separate seasonal curves. For additional details on the capacity prices developed by CRA, please see Appendix A.

Figure 2.5 Capacity Price Assumptions



2.5.6 Renewable Energy Standard

One of the considerations in developing alternative resource plans for Ameren Missouri is the need to comply with the Missouri Renewable Energy Standard (RES), which was passed into law by a voter initiative in November 2008. This standard requires all investor-owned regulated Missouri utilities to supply an increasing level of energy from renewable energy resources or acquire the equivalent renewable energy credits (RECs) while subject to a rate impact limitation of 1% as determined by rules set by the Missouri Public Service Commission. The target levels of renewable energy, determined by applying increasing percentage to total retail sales, are:

- 2% in 2011-2013
- 5% in 2014-2017
- 10% in 2018-2020
- 15% starting in 2021

Additionally, a solar carve-out provision is included in the standard and requires that at least 2% of renewable energy be sourced from solar generation. This provision can also be met with the purchase of solar RECs or SRECs. Our analysis of RES compliance is presented in Chapter 9.

2.6 Environmental Regulations

With increasingly stringent regulation of coal-fired power plants, including continuing efforts to regulate greenhouse gas (GHG) emissions, the effects of these regulations on the electric energy market must be considered in assessing potential resource options and portfolios.

A detailed discussion of enviromental regulations can be found in Chapter 5. In addition to the regulations discussed in Chapter 5, the potential continues for new and evolving laws and regulation to create a changing landscape for investment decisions over the planning horizon. Therefore, we must also consider potential actions with respect to climate policy and regulation of GHG emissions beyond the regulations that have been finalized by the EPA. To help frame the ongoing possibilities for carbon policy and regulation of GHG emissions, we examined a variety of sources and considered numerous policy pathways through which carbon prices could be implemented. Through this process an updated set of assumptions was developed to reflect environmental policy through the timing, magnitude and probability of an explicit price on carbon dioxide emissions.

Carbon Dioxide Emissions Prices[7]

Updated expectations for an explicit carbon price and timing were reviewed and revised for this IRP. The development of an assumed range of carbon prices included a review of several viewpoints on a carbon price including the 2022 EIA AEO, a variety of literature on the Social Cost of Carbon, Federal climate policy proposals, and various recent utility IRPs including those filed by Xcel, Entergy, CMS, AEP, and Pacificorp. Table 2.9 shows the values used in the current IRP analysis. These price assumptions were reviewed by CRA, a discussion of which is included in Appendix A.

[7] 20 CSR 4240-22.040(2)(B); 20 CSR 4240-22.040(5); 20 CSR 4240-22.040(5)(D); 20 CSR 4240-22.060(5); 20 CSR 4240-22.060(5)(C); 20 CSR 4240-22.060(5)(H); 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

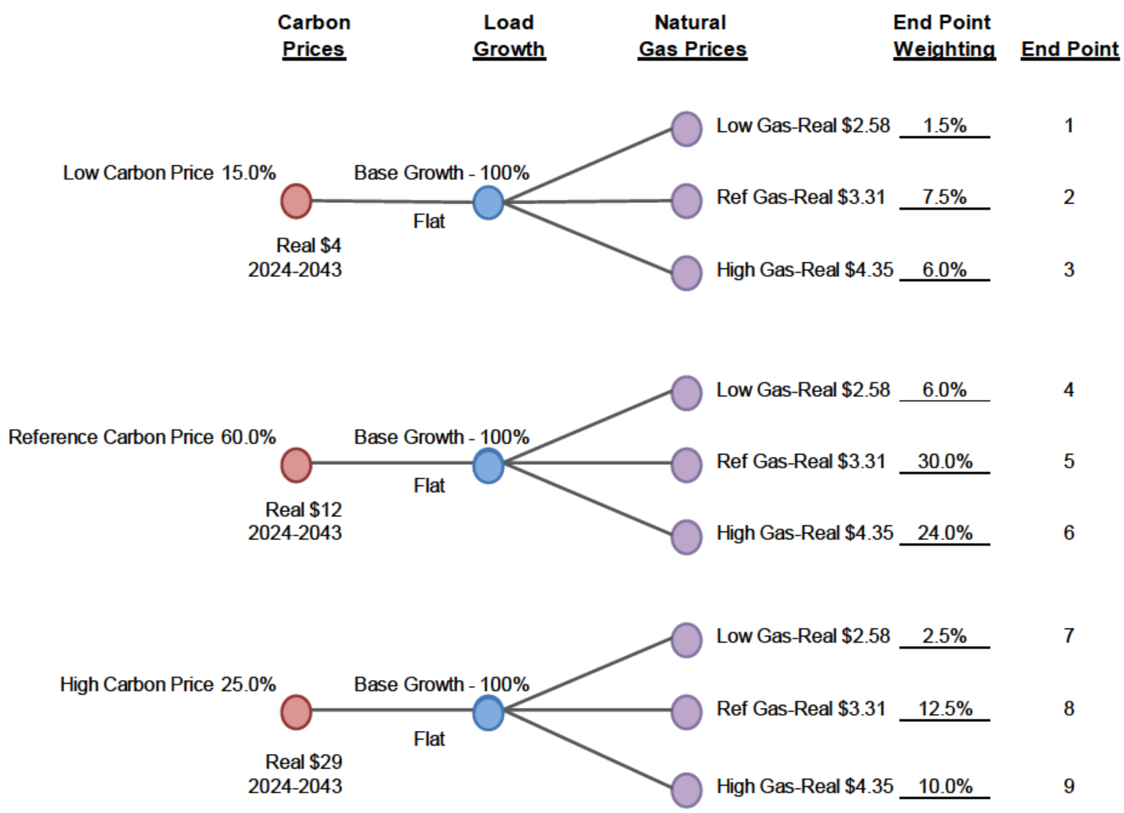
Table 2.9 Carbon Dioxide Emissions Price Assumptions

	Real 2023 $/metric ton			Nominal $/metric ton		
	Low Case	Mid Case	High Case	Low Case	Mid Case	High Case
2024	$1.29	$1.62	$2.05	$1.33	$1.67	$2.11
2025	$1.30	$1.65	$2.14	$1.37	$1.73	$2.25
2026	$1.30	$1.68	$2.23	$1.40	$1.80	$2.39
2027	$1.31	$1.71	$2.33	$1.43	$1.88	$2.55
2028	$2.60	$5.57	$10.40	$2.90	$6.22	$11.61
2029	$3.83	$9.28	$18.15	$4.36	$10.56	$20.66
2030	$5.02	$12.83	$25.60	$5.82	$14.90	$29.72
2031	$5.04	$13.20	$27.19	$5.96	$15.63	$32.20
2032	$5.05	$13.57	$28.89	$6.11	$16.39	$34.90
2033	$5.07	$13.95	$30.69	$6.25	$17.19	$37.82
2034	$5.10	$14.35	$32.61	$6.40	$18.03	$40.99
2035	$5.12	$14.76	$34.65	$6.56	$18.92	$44.42
2036	$5.14	$15.18	$36.83	$6.72	$19.84	$48.15
2037	$5.16	$15.61	$39.14	$6.88	$20.81	$52.20
2038	$5.18	$16.05	$41.60	$7.04	$21.83	$56.59
2039	$5.20	$16.50	$44.22	$7.21	$22.90	$61.36
2040	$5.22	$16.97	$47.01	$7.39	$24.02	$66.53
2041	$5.24	$17.46	$49.97	$7.57	$25.20	$72.14
2042	$5.26	$17.95	$53.13	$7.75	$26.43	$78.24
2043	$5.29	$18.46	$56.49	$7.94	$27.73	$84.85

2.7 Price Scenarios

Power prices are influenced primarily by electric demand, the mix of available generation resources, and natural gas prices. Using our assumptions for carbon prices and natural gas prices, we developed scenarios based on combinations of these assumptions. The development of scenario modeling is best represented by a probability tree diagram and the associated probability of each branch of the tree. Each branch of the tree is used to represent a combination of dependent input variables that can have an impact on plan selection. In order to focus on those combinations with the greatest influence on alternative resource plan performance, potential branches that would be characterized by a significantly low probability of occurrence are collapsed to provide a simplified yet still robust set of possible branches. This process provides for a wide range of potential future combinations with which we can analyze alternative resource plan performance and risk. Figure 2.6 shows the final scenario tree.

Figure 2.6 Final Scenario Tree



Electric Power Prices[8]

To support our analysis of alternative resource plans, as described in Chapter 9, we engaged CRA to develop forward price forecasts for MISO Zone 5 using the industry-leading modeling software "Aurora." Appendix A provides a detailed overview of how CRA utilized Aurora to develop updated forward prices for Ameren Missouri. To ensure that a range of possible future power prices was incorporated, those inputs determined to be uncertain and impactful enough to warrant the need for a range of possible inputs were varied. These inputs were:

- Natural gas prices
- An explicit price on carbon dioxide emissions

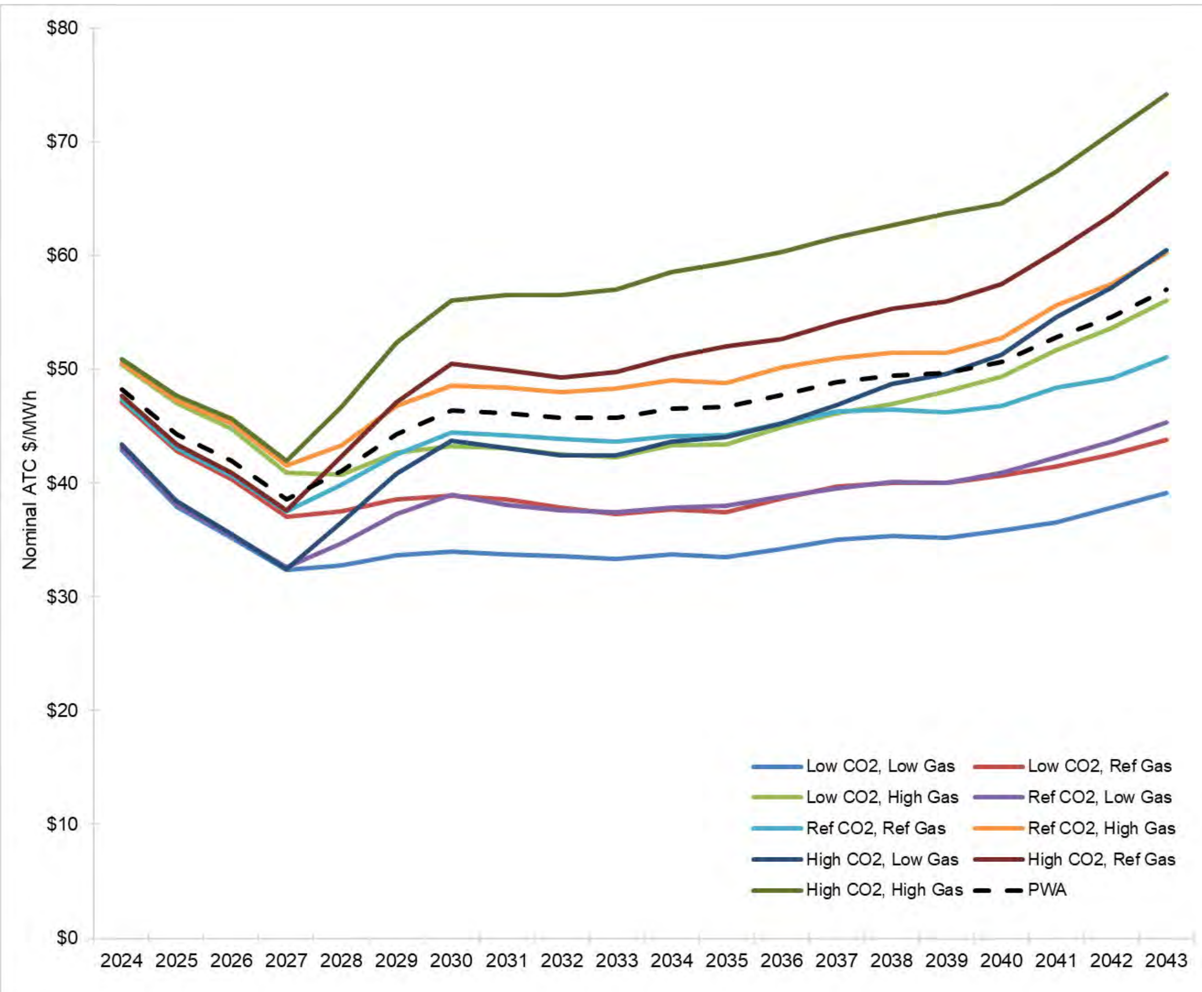
These inputs were varied within the model, and audited by CRA to ensure they were reasonable and comprehensive. This process produced values based on the probability

[8] 20 CSR 4240-22.060(5)(G); 20 CSR 4240-22.060(7)(C)1A; 20 CSR 4240-22.060(7)(C)1B

tree shown in Figure 2.6. The results of this modeling for each branch yield different power price futures, which are shown in Figure 2.7.

These power prices were used in the analysis of alternative resource plans described in Chapter 9.

Figure 2.7 Scenario Power Prices



2.8 Compliance References

10. Strategy Selection

Highlights

- *Ameren Missouri is continuing the transformation of its generation portfolio over the next twenty years while also considering portfolio implications through 2050.*
  - *Our plan includes continued expansion of renewable wind and solar generation, bringing us to over 3,500 MW of wind and solar by the end of 2030 and over 5,400 MW by 2036. This allows us to replace energy no longer generated from coal-fired resources with the lowest cost alternative, clean, emission free renewable energy, while mitigating significant risks associated with changes in energy policy, including policies that establish a price on carbon dioxide (CO_2) emissions.*
  - *Our plan also includes continued customer energy efficiency and demand response program offerings, customer programs for renewable energy, and retirement of nearly three-fourths of our remaining coal-fired generating capacity by 2040, which will be reaching the end of its useful life.*
  - *Our plan results in reductions in CO_2 emissions of at least 60% by 2030 from 2005 levels and 85% by 2040, with a goal of achieving Net Zero CO_2 emissions by 2045.*
- *Our implementation plan for the next three years includes steps necessary to add an additional 1,800 MW of solar generation and 1,000 MW of wind generation to our portfolio by the end of 2030, approval and implementation of energy efficiency and demand response programs beyond our current plan, steps to implement new simple cycle gas-fired generation by the end of 2027 and new combined cycle gas generation by the end of 2032, and actions to preserve contingency resource options and enable us to quickly respond to changing needs and conditions while continuing to ensure safe, reliable and cost-effective service to our customers.*
- *Ameren Missouri will continue to monitor critical uncertain factors to assess their potential impacts on our preferred plan, contingency plans and implementation. These include prices for CO_2 and natural gas and costs for new renewable and dispatchable generating resources.*
- *We will also continue to monitor prices for coal, needs for transmission network infrastructure, and development of carbon-free resources such as large-scale long-cycle battery energy storage, hydrogen-based generation and storage, new nuclear technologies, and generation with carbon capture and sequestration.*

Ameren Missouri has selected its preferred resource plan and contingency options in accordance with its planning objectives and practical considerations that inform our decision making. Our selection process consists of several key elements:

- ✓ Establishing planning objectives and associated performance measures to develop and assess alternative resource plans
- ✓ Creating a scorecard based on our planning objectives and performance measures to evaluate the degree to which various alternative resource plans would satisfy our planning objectives
- ✓ Critically analyzing the most promising alternative resource plans to ensure that we select a plan that best balances competing objectives

We have established an implementation plan for 2024-2026 that allows us to begin implementing the resource decisions embodied in our preferred resource plan and to preserve contingency options to allow us to effectively respond to changing needs and conditions while continuing to ensure safe, reliable, and cost-effective electric service to our customers.

10.1 Planning Objectives

The fundamental objective of the resource planning process in Missouri is to ensure delivery of electric service to customers that is safe, reliable and efficient, at just and reasonable rates in a manner that serves the public interest. This includes compliance with state and federal laws and consistency with state energy policies.[1] Ameren Missouri considers several factors, or planning objectives, that are critical to meeting this fundamental objective. Planning objectives provide guidance to our decision-making process and ensure that resource decisions are consistent with business planning and strategic objectives that drive our long-term ability to satisfy the fundamental objective of resource planning. Following are the planning objectives, established in the development of our 2011 IRP, that continue to inform our resource planning decisions today.

Cost (to Customers): Ameren Missouri is mindful of the impact that its future energy choices will have on cost to its customers. Therefore, minimization of present value of revenue requirements (PVRR) is our primary selection criterion.[2]

Costs alone do not and should not dictate resource decisions. Our other planning objectives are discussed below.

[1] 20 CSR 4240-22.010(2); 20 CSR 4240-22.010(2)(A)
[2] 20 CSR 4240-22.010(2)(B)

Customer Satisfaction: Ameren Missouri is dedicated to continuing to improve customer satisfaction. While there are many factors that can be measured, for practical reasons Ameren Missouri focused primarily on measures that can be significantly impacted by resource decisions: 1) rate impacts – levelized average rates, 2) supply and service reliability, 3) customer preferences for renewable energy sources and demand-side programs that provide customers with options to manage their usage and costs, 4) availability of programs that allow customers to source more of their energy needs from renewable resources, and 5) reductions in energy center emissions.

Portfolio Transition: While Ameren Missouri has retired and will soon retire additional coal-fired generating resources, coal currently produces the majority of the energy it generates. Ameren Missouri continues to be focused on transitioning its generation fleet to a cleaner and more fuel diverse portfolio. We therefore evaluate alternative resource plans based on the degree and pace of the transition from fossil generation sources to cleaner sources of energy, including reductions in energy consumption resulting from customer energy efficiency programs.

Financial/Regulatory: The continued financial health of Ameren Missouri is crucial to ensuring safe, reliable and cost-effective service for customers in the future. Ameren Missouri will continue to need the ability to access large amounts of capital for investments needed to comply with renewable energy standards and environmental regulations, invest in demand and/or supply side resources to meet customer demand, provide reliable service, and execute our portfolio transition. Measures of expected financial performance and creditworthiness are evaluated along with potential risks.

Economic Development: Ameren Missouri is committed to supporting the communities it serves beyond providing reliable and affordable energy. Ameren Missouri assesses the economic development opportunities, for its service territory and for the state of Missouri, associated with our resource choices. We do this by examining the potential for direct job growth for both construction and operation of resources, which in turn promotes additional economic activity.

Table 10.1 summarizes our planning objectives, the primary measures used to assess our ability to achieve these objectives with our alternative resource plans, and the weighting applied to each objective for scoring the alternative resource plans.

Table 10.1 Planning Objectives and Measures[3]

Planning Objective Categories	Measures	Weighting
Cost	Present Value of Revenue Requirements	30%
Customer Satisfaction	Customer Preferences, Levelized Rates	20%
Portfolio Transition	Resource Diversity, CO_2 Emissions, Probable Environmental Costs	20%
Financial/Regulatory	Free Cash Flow, Financial Ratios, Stranded Cost Risk, Transaction Risk, Cost Recovery Risk	20%
Economic Development	Direct Job Growth (FTE-years)	10%

These planning objectives are consistent with Ameren's overall sustainability efforts. In early May 2023, Ameren Corporation released its corporate sustainability report – Powering a Smart, Sustainable Tomorrow. The report details Ameren's commitment to sustainability and environmental stewardship and offers a comprehensive view of the actions taken on key matters. In the report, Ameren addresses the following key topics:

- ✓ Environmental Stewardship
  - Accelerating the transition to a cleaner and more diverse generation portfolio
  - Significant transmission investment supporting cleaner energy
  - Decade-long investment in gas infrastructure to reduce leaks
- ✓ Social Impact
  - Delivered value to customers in 2022 while focused on safety
  - Socially responsible and economically impactful financial support
  - Supporting core value of DE&I both inside Ameren and in our communities
- ✓ Governance
  - Diverse board of directors focused on strong oversight
  - Board oversight aligned with ESG matters
  - Executive compensation supports sustainable, long-term performance
- ✓ Sustainable Growth
  - Constructive frameworks for investment in all jurisdictions

[3] 20 CSR 4240-22.060(2); 20 CSR 4240-22.060(2)(A)1 through 7

- o Strong long-term infrastructure investment pipeline
- o Expect future dividend growth to be in line with long-term EPS growth expectations

10.2 Assessment of Alternative Resource Plans

Ameren Missouri uses a scorecard to evaluate the performance of alternative resource plans with respect to our planning objectives and measures described above. The scorecard and measures include both objective and subjective elements that together represent the trade-offs Ameren Missouri's management considers in balancing these competing objectives. It is important to keep in mind that the scorecard is a tool for decision makers and does not, in and of itself, determine the preferred resource plan. The selection of the preferred resource plan is informed by the scorecard and by a more critical analysis of the relative merits of alternative resource plans, including an assessment of any risks or other constraints.

10.2.1 Preliminary Scoring of Alternative Resource Plans[4]

To score each of the alternative resource plans, we employed a standard approach to scoring for each planning objective on a 5-point scale and determined a composite score by applying the weightings shown in Table 10.1 to each planning objective. As Cost is the primary selection criterion, it was given the greatest weight – 30% -- just as it was in the scoring performed for all of our IRP filings since 2011.[5] The scoring approach for each planning objective is as follows:

Cost – The 23 alternative resource plans were separated into five groups according to probability weighted average PVRR results from the risk analysis discussed in Chapter 9. The lowest cost group of plans were given a score of 5, the next lowest cost group a score of 4, and so on, with the highest cost group of plans receiving a score of 1.

Customer Satisfaction – Alternative resource plans were evaluated based on levelized annual average rates for a portion of the score. As was done with the PVRR results, the alternative resource plans were separated into five groups according to the probability-weighted average levelized annual average rate results produced from our risk analysis. The plans resulting in the lowest rates were given a score of 5, the next lowest rate group a score of 4, and so on, with the highest rate group of plans receiving a score of 1. Plans that yielded a score greater than 3 for rates were given 2 points in the overall scoring for

[4] 20 CSR 4240-22.010(2)(C); 20 CSR 4240-22.010(2)(C)1; 20 CSR 4240-22.010(2)(C)2; 20 CSR 4240-22.010(2)(C)3; 20 CSR 4240-22.070(1); 20 CSR 4240-22.070(1)(A) through (D)

[5] 20 CSR 4240-22.010(2)(B)

Customer Satisfaction. Plans that yielded a score of 3 were given 1 point. Plans were given one additional point for each of the following:

- ✓ Inclusion of demand-side programs
- ✓ Early retirement of coal generation
- ✓ Addition of significant renewables (beyond those needed to comply with legal mandates)

Portfolio Transition – Alternative resource plans were awarded points for each plan attribute contributing to greater resource diversity and/or environmental impact in terms of emission reductions. Plans were awarded one point for each of the following:

- ✓ Inclusion of demand-side programs
- ✓ Addition of nuclear generation
- ✓ Early retirement of coal-fired generation (1 point per 2 large units)
- ✓ Addition of significant renewables (beyond those needed to comply with legal mandates)
- ✓ Displacement of fossil resources with additional storage and/or renewables
- ✓ Addition of low-emission efficient gas generation

Financial/Regulatory – Scoring for Financial/Regulatory is based on a default score of 5 with deductions for risks and financial impacts that may detrimentally affect Ameren Missouri's ability to continue to access lower cost sources of capital. Plans that would result in relatively lower free cash flow (i.e., less than 3 out of 5 points) were reduced by one point. Plan scores were also reduced by one point each for potential risks associated with:

- ✓ Lack of any DSM programs beyond currently approved programs
- ✓ Nuclear construction, financing, and operating risks
- ✓ Risks associated with a heavy concentration of gas-fired generation
- ✓ Risks associated with recovery of coal-fired generation investment (including those resulting from potential changes in environmental and climate policies and regulations)

Economic Development – Alternative plans were scored based on direct job creation, including construction and ongoing operation. Construction and operating jobs were translated into full-time equivalent years (FTE-years). Alternative plans were ranked based on FTE-years and divided into five groups based on relative rank. The group of plans resulting in the highest FTE-year values were given a score of 5 points each, the next highest FTE-year group a score of 4, and so on, with the lowest FTE-year group of plans receiving a score of 1.

Table 10.2 Alternative Resource Plan Preliminary Scoring Results[6]

Plan	Description	Composite Score
O	Labadie 2039	4.40
L	Pumped Hydro w/ MAP LF	4.30
B	Sioux Retired 2028	4.20
M	SC	4.00
P	Labadie 2036	3.90
A	Sioux Retired 2030	3.80
C	RAP - Renewable Expansion	3.80
R	RAP LF	3.80
H	MAP LF-RES Compliance	3.70
T	All Renewables	3.70
Q	Labadie 2031	3.70
D	Labadie SCR	3.50
U	SC instead of First CC	3.50
K	Renewables for Capacity Need	3.30
V	CCS on 1st CC	3.30
E	MAP	3.20
S	MAP LF	3.20
W	RAP 80%	2.80
N	SMR w/ RAP LF	2.60
F	RAP-RES Compliance	2.30
G	MAP-RES Compliance	2.30
I	No Additional DSM	1.70
J	No Additional DSM-RES Compliance	1.40

[6] Plans include RAP-level DSM and Renewable Expansion portfolio unless otherwise noted.

Table 10.2 shows the composite scores for each of the 23 alternative resource plans. The full scorecard with scores for each planning objective for each alternative resource plan is shown in Appendix A. Based on the scoring results, the alternative resource plans were separated into three tiers – Top, Mid, and Bottom. Plans with scores greater than 3.7 were placed in the Top Tier. Plans with scores between 3.3 and 3.7 were placed in the Mid-Tier. Plans with scores below 3.3 were placed in the Bottom Tier. All Top Tier plans include energy efficiency and demand response at the realistic achievable potential (RAP) level and the Renewable Expansion portfolio discussed in Chapter 9.

10.2.2 Renewable Resource Expansion

One of the key conclusions from our evaluation of alternative resource plans is that the inclusion of a sustained long-term expansion of renewable energy resources is beneficial across all of our planning objectives. It steadily transforms our portfolio to one that is cleaner and more diverse while enhancing customer affordability and providing much needed clean energy jobs for our communities and the state of Missouri. It also does something to help ensure our ability to accomplish these goals – it mitigates risks inherent in our existing portfolio as we manage the transition away from fossil fuels while relying on the reliability and economic benefits they continue to provide and supplementing them with new dispatchable resources to partner with renewable resources to provide reliable and sustainable energy services at a reasonable cost.

Resource planning has traditionally focused on the balance of generating capacity with customer demand and reserve margin requirements. While that remains important, transforming our generation portfolio requires that we carefully consider all the implications of how we effectuate that transformation. This includes the following considerations, which are discussed in more detail in this section:

1. **Aging Coal Fleet –** Ameren Missouri will need energy as well as capacity resources to meet customer demand and reserve margin requirements as its coal-fired generators are retired at the end of their useful lives. That need is also driven by the risk of reduced output from coal-fired generation due to existing or proposed environmental requirements or other causes even before the coal units retire. Due primarily to recent and expected coal unit retirements and these other risks, Ameren Missouri has a clear, present, and ongoing need to add energy resources to its generation portfolio to address the dramatic shift in the Company's energy position that will occur over the next several years and continue over the next twenty years. Ameren Missouri expects to experience an energy shortage as early as 2029 assuming normal loads and generation, a dramatic change from the approximately 15-20% energy buffer from which customers have typically benefited, although at times that buffer has been a high as approximately 10 million

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MWhs. Such a shift could expose our customers to reliability challenges and high market price risk.

2. **Low Cost, Emission-Free Energy –** Renewable resources represent the lowest cost, and emission-free, sources of replacement energy, as shown in Chapter 6.

3. **Increasing Environmental Regulations –** The large-scale expansion of renewable resources provides significant risk mitigation to Ameren Missouri's portfolio, particularly with respect to additional environmental regulations that could become law, other changes in climate policy and carbon dioxide (CO_2) prices, and other factors that may significantly affect the operating costs and benefits of its existing coal-fired resources. The industry is actually seeing these risks come to fruition now with the effectiveness of new rules regulating emissions of nitrous oxides (NO_x), plus additional proposed regulations targeted specifically at CO_2, among others.

4. **Reliability and Resilience –** Ameren Missouri's addition of diverse new renewable resources during continued operation of its existing fleet, and addition of new dispatchable resources, is a prudent approach and ensures reliable, resilient, and affordable energy for our customers under varying scenarios during the transition.

5. **The Risk of Inaction –** Delaying the inevitable shift to renewables creates significant implementation risk. The transition will require a very large-scale expansion of renewable generation at the same time that other utilities and states are pursuing the same. A task of this magnitude must be implemented over time to be successful. This is the case since each renewable energy project takes 5 to 8 years to develop and construct, requires geographical diversity of projects for reliability, and requires navigating several implementation risks, such as delays in the development or completion of projects, lost opportunities for more viable projects, and the potential for financing constraints and increases in financing costs.

6. **Availability of Significant Tax Credits -** Initiating renewable resource builds in the nearer term provides the ability to realize significant tax incentives for customers and thus lower the overall cost of adding needed renewables, making addition of these necessary resources more affordable for all customers. Because federal law and policy can change, taking advantage of such incentives sooner and while the better projects are available provides greater certainty of benefits to customers.

Ameren Missouri's Need for Energy Resources

Ameren Missouri's existing generation fleet has a total net capability of 9,986 MW. Of this, 45% is coal, 12% is nuclear, 15% is hydroelectric and other renewables, and 28% is gas or oil-fired peaking generation. In contrast, coal currently provides approximately 66% of the energy produced by our fleet, with nuclear providing roughly 23% and renewables providing another 10%. Gas and oil-fired resources provide approximately 1% of the energy produced by our existing fleet. As coal-fired resources are retired or as their level of production decreases as a result of changes in operating efficiencies, CO_2 prices, other market conditions, regulatory constraints, or other factors, new energy resources will be needed to supplement the remaining generation. While the peaking generation will continue to provide capacity to meet peak demand and reserve margin needs, it will not be able to make up for the loss of coal-fired energy on its own. In fact, it is likely the production levels from current coal-fired energy assets will remain relatively low in the future as they are dispatched in the Midcontinent Independent System Operator (MISO) market and as they are operated in compliance with environmental permit constraints. The continued availability of these affordable coal-fired energy assets, along with new dispatchable resources, does allow Ameren Missouri to maintain reliability as increasing amounts of renewable energy is integrated into the system to meet customer needs.

Figure 10.1 Energy Position With and Without Renewable Transition – Low CO_2 Price

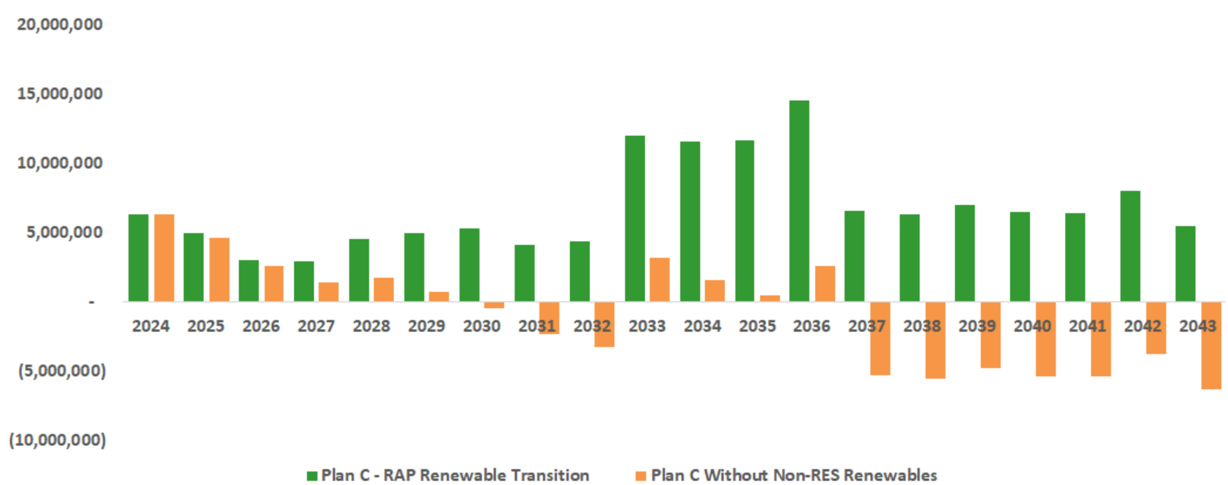

Figure 10.1 shows a comparison of the Company's expected energy position (generation minus sales) with and without renewable transition under our Low CO_2 price scenario. Figure 10.2 shows a similar comparison of energy production for several alternative plans under our High CO_2 price scenario, which results in reduced levels of generation from coal resources (and also gas to a lesser extent) compared to the levels of production under the Low CO_2 price scenario. The chart shows that for Plan C (RAP – Renewable Transition) without renewable resources beyond those needed for renewable energy

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standard (RES) compliance, Ameren Missouri would be generating less energy than its customers use by 2028 and that this shortfall would grow to over one-third of total load by 2038. Any acceleration of coal energy center retirements would further exacerbate this issue. This is also true if retail sales are higher, as shown in Figure 10.3.

Taken together, the charts in Figures 10.1, 10.2, and 10.3 highlight a key consideration in the approach to our renewable resource expansion. There is significant uncertainty regarding the level of production from our existing fleet of resources. Differences in future CO_2 prices is only one source of this uncertainty, but it helps to highlight the broader issue. Other sources of uncertainty include natural gas prices, power prices, environmental regulation, and potential changes in climate policy. All of these factors and perhaps others could impact coal-fired resources and result in a much earlier need for new energy generation. Waiting until such needs are certain may result in suboptimal solutions and potential higher costs to customers. It could also result in an unintended but necessary increase in reliance on fossil-fueled generation like natural gas combined cycle, and potentially deferring or displacing some renewable resource additions.

Figure 10.2 Energy Position With and Without Renewable Transition – High CO_2 Price

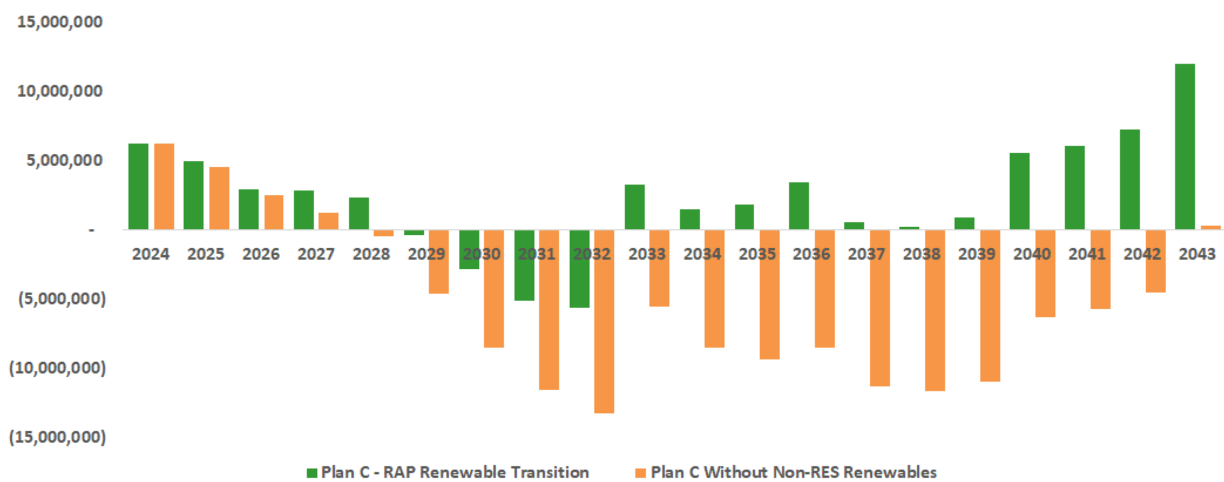

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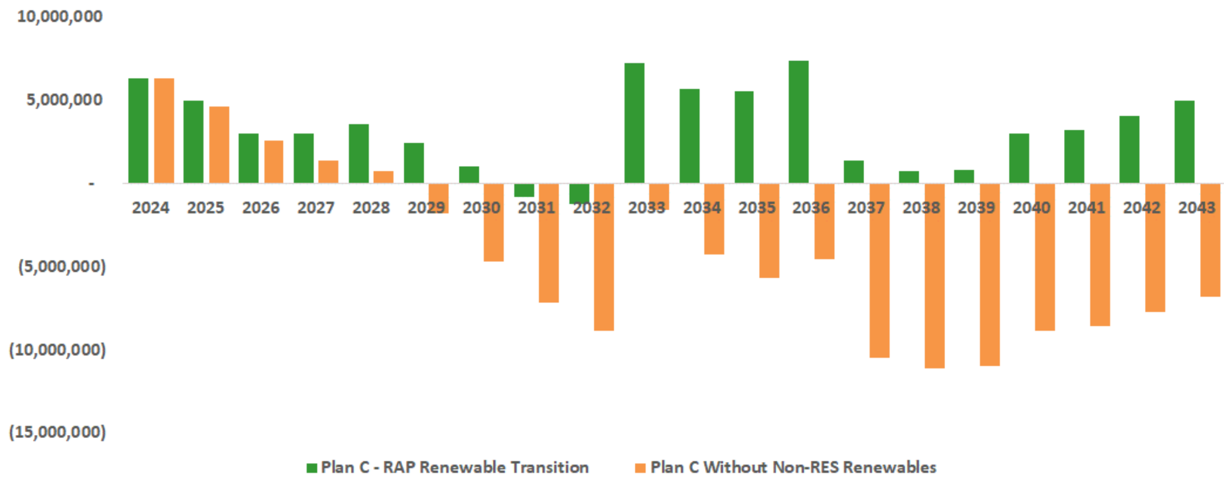
Figure 10.3 Energy Position With and Without Renewable Transition – High Load



The energy position charts in Figures 10.1-10.3 represent "economic" energy, or energy generated based on economic dispatch in the MISO market. This is important because it does not represent a constraint to the ability for units to generate at any given time, which means there is some flexibility to operate at higher levels if needed.[7] At the same time, Ameren Missouri's fleet is increasingly subject to constraints in its ability to operate units across seasons or across the year. This mainly affects the Company's remaining fleet of coal-fired generation at the Sioux and Labadie Energy Centers. In addition to assumed prices on CO_2 emissions, our modeling assumes allowance prices for NO_x emissions consistent with US EPA's Good Neighbor Rule, described in Chapter 5. As a result, forecast coal generation declines beginning in the latter part of this decade and continues to decline until units are retired. In addition, the natural gas combined cycle generators included in the PRP are forecast to run at high-capacity factors (80% or more). When added to our portfolio of high capacity factor nuclear generation and weather-dependent hydro, wind and solar generation, the ability to generate significantly more energy is somewhat limited. This further highlights the importance of the energy position analysis presented above and the vital role of new renewable additions in ensuring sufficient energy to meet customer needs. While assumptions for key variables, like CO_2 price and customer load, and constraints of further environmental regulation may change, and almost certainly will, planning to meet energy needs under such assumptions is vital to ensure reliable energy supply under a range of potential future conditions.

Risk Mitigation Benefits of Renewable Expansion

Our analysis shows that higher CO_2 prices have a beneficial impact on the economics of renewable resources and a detrimental effect on the economics of coal-fired resources,

[7] Ameren Missouri would expect to be compensated by the market in such instances.

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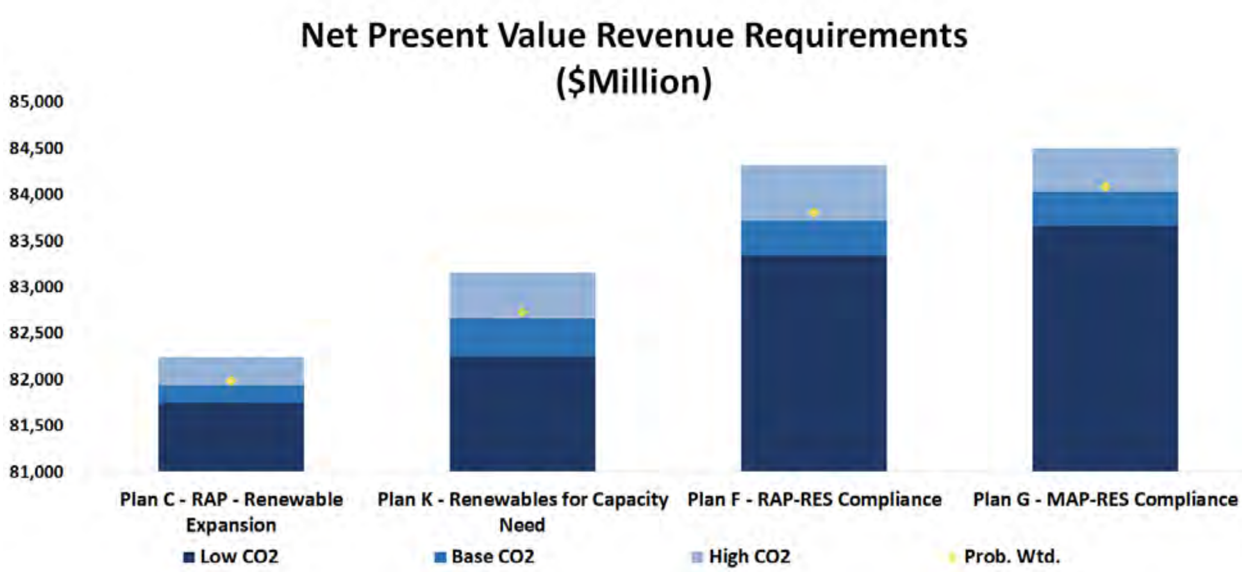
a decidedly unsurprising result. The impact on coal is somewhat obvious in that the CO_2 prices impose a cost directly on the energy production from coal generators. It is this cost imposed on coal and gas generators that also manifests itself in power market prices, as illustrated in Chapter 2. The higher the CO_2 price, the higher the power price. Wind and solar generation, along with other non-carbon-emitting generating sources like hydro and nuclear, therefore see a benefit from CO_2 prices through the revenue they receive in the market. In contrast, the absence of a CO_2 price results in maximal benefits to coal-fired generation and minimal benefits to renewables, nuclear and hydro.

By expanding the share of renewable resources in our portfolio, we improve the balance of resources that from an economic perspective perform better as CO_2 prices rise and resources whose performance diminishes as CO_2 prices rise. This is not unlike the diversification of personal investments like those many hold in retirement funds like a 401(k) plan. By investing in a variety of resources, each of which perform well under different conditions, the overall risk of the portfolio can be mitigated. To illustrate this effect in the context of resource planning, we can simply examine how various alternative resource plans perform under different levels of CO_2 price. Figure 10.4 shows the PVRR results for several plans with different levels and timing of renewable energy resources under the three different scenarios for CO_2 price used in our risk analysis.

Figure 10.4 PVRR Results for Selected Plans by CO_2 Price Scenario



As the chart in Figure 10.4 shows, the steady addition of wind and solar resources represented by Plan C provides not only the lowest PVRR among the plans, but also provides risk mitigation around the range of CO_2 prices used for risk analysis, with the range of costs to customers across the different CO_2 price scenarios being significantly narrower than for those without the steady buildout. In fact, PVRR for Plan C under all scenarios for CO_2 price is lower than the lowest cost to customers for any of the other

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plans shown. This CO_2 price risk mitigation is in addition to the risk mitigation highlighted by the discussion of energy needs above. Specifically, the steady addition of renewable resources mitigates risk with respect to numerous factors that could impact the production of coal-fired resources, including market prices for energy, environmental regulations, and other energy policies.

Customers continue to express an increasing preference for energy supplied by renewable resources. One way to meet this growing demand is to offer programs that allow customers to increase the share of their energy needs that is supplied by renewable resources. Ameren Missouri has done just this with the implementation of its Renewable Solutions Program, approved by the Missouri Public Service Commission (MPSC) in April 2023, which will provide 150 MW of solar generation to some of the Company's largest customers. The Company also has completed projects to support its Neighborhood Solar and Community Solar programs, as described in Chapter 4. In addition to such programs, there has also been a growing sentiment that greater levels of renewable generation should be available to all customers. This is the sentiment that drove the adoption of Missouri's RES in 2008. Ameren Missouri continues to implement the resources necessary to comply with the full requirement of the RES, having received MPSC approval for the planned 200 MW Huck Finn solar project, which follows the Company's acquisition of 700 MW of wind generation projects in Missouri in 2020 and 2021. The passage of the Inflation Reduction Act (IRA) in 2022 has also provided unprecedented incentives to enhance customer affordability for both the deployment of renewable resources and the development of domestic industry to support that deployment. While the advancement of further policies supporting renewable energy development remains uncertain, the trend in recent years has been one of greater and greater support for the use of renewable energy resources.[8]

Reliability and Resiliency Benefits of Renewables

The Company's plan to transition to a "new fleet," featuring renewable and low-carbon resources, reflects some meaningful operating overlap with the "old fleet" resources, comprised of primarily coal-fired resources. The term "old fleet" refers to Ameren Missouri's existing (and legacy) coal-fired generation resources. These resources have served as the backbone of Ameren Missouri's generation fleet for several decades but are now approaching the end of their useful lives, with increasing maintenance challenges for key equipment (such as energy piping, boilers, and turbines) and increasing pressure from existing and new environmental regulations. Three of the Company's four coal-fired energy centers will be retired within the next ten years: the Meramec Energy Center in 2022, the Rush Island Energy Center by 2025 and the Sioux Energy Center by 2032.

[8] File No. EO-2023-0099 1.C; File No. EO-2023-0099 1.E

These retirements will result in a dramatic swing in the Company's energy position over the next few years, from its historically abundantly long position (as many as 10 million MWhs annually) to having a shortage of energy starting in 2029, assuming normal generation and load, absent the addition of new energy resources. The shortage grows steadily thereafter. A significant shift in the Company's energy position is already underway with the recent retirement of the Meramec Energy Center, and it will continue to shift when the Rush Island Energy Center is retired. The term "new fleet" refers to the Company's planned future resource portfolio, which includes a diverse mix of zero or low-carbon resources, primarily renewable resources like solar, wind and hydroelectric, along with zero-carbon nuclear and supported by dispatchable energy storage and natural gas resources.

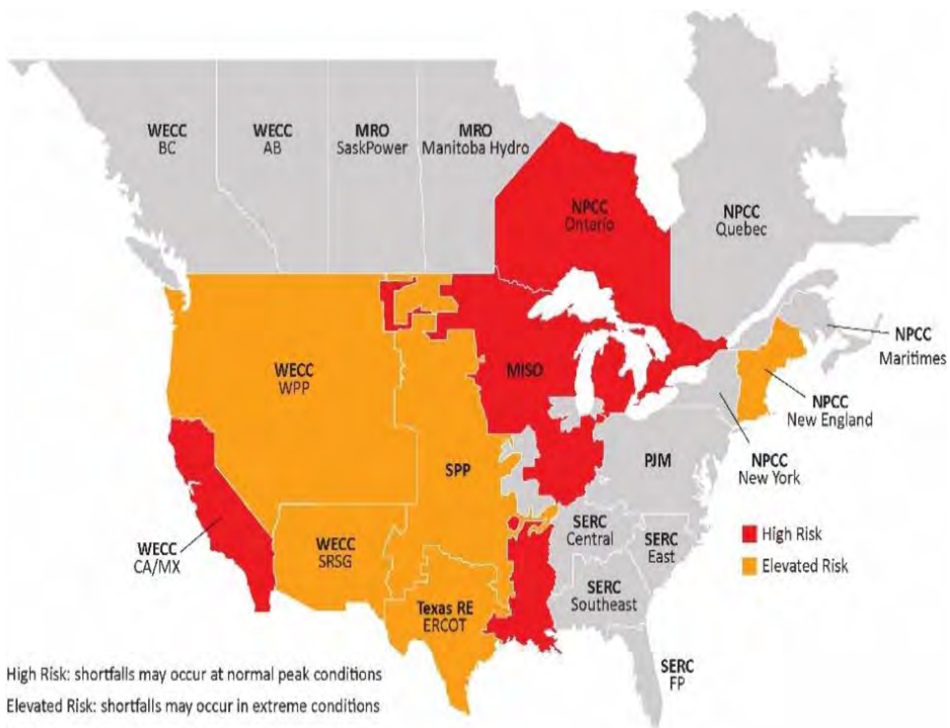
The overlap between the old fleet and the new fleet is necessary to address reliability risks during the transition period between the old fleet coming offline, and the new fleet being fully implemented. These risks are driven by myriad planning uncertainties, such as:

- Uncertainty in system load, including as industry and transportation electrify, and also driven by the potential for more frequent and intense severe weather;
- Uncertainty in the energy or demand savings, or both, from planned energy efficiency and demand-response programs;
- Uncertainty in whether and to what extent Ameren Missouri can expect to (or should) rely on the MISO market to meet customers' reliability needs;
- Uncertainty in the reliability contribution of new renewable resources;
- Ever increasing environmental regulations for existing fossil generation;
- Unplanned generation outages or other unanticipated events; and
- Material variances between our optimized generation forecasts or weather-normalized loads used for planning purposes and what happens in reality.

Taken as a whole, it is unwise to wait until some predetermined amount of capacity of coal-fired generation retires to add corresponding capacity of renewables to plug the capacity gap, or to wait until that coal capacity can no longer provide significant energy. Over the last five years, the Company's customers have benefited from an annual energy buffer of approximately 5 million MWhs. This energy buffer has mitigated the risk that the Company's customers face from reliability related emergency conditions resulting in energy shortages on the electric system. The buffer over the past roughly 5 years translates to an energy position approximately 15-20% above our retail customers' needs, which mitigates customers from the risk of adverse MISO reliability and market conditions as well as price spikes (price risk), while generating meaningful excess market revenues for the benefit of customers.

Likewise, it would not be prudent to rely on the MISO market more heavily for near-term energy needs. Just like Ameren Missouri, the entire MISO footprint is undergoing a transition from dispatchable fossil resources to a much greater reliance on renewable resources; in fact, MISO's modeling indicates that MISO as a whole is expected to move at a faster pace than Ameren Missouri. Therefore, it has become riskier to rely on the MISO market in moments of system stress than it has been in the past.

Figure 10.5 NERC Risk Area Summary, 2023-2027



As detailed in the North American Reliability Corporation's (NERC's) 2022 Long-Term Reliability Assessment, MISO's anticipated capacity reserves are alarmingly low and energy risks are expected to increase starting in 2024, especially in June through August when MISO's demand peaks. The NERC report lists MISO as a "high risk" region of the country in terms of resource adequacy, defined as an area that does not meet resource adequacy criteria, such as the 1-day-in-10-year load loss metric, during periods of the assessment horizon. Figure 10.5 highlights the regions considered high or elevated risk. MISO's "high risk" status indicates that without a concerted effort to begin and sustain our

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plan to add replacement energy resources, Ameren Missouri and MISO will both be "skating on the edge" from an energy and capacity perspective, putting customer reliability and affordability at risk. As discussed above, although MISO's 2023-2024 Planning Resource Auction results indicate that the North/Central region is expected to have adequate capacity to meet the Planning Reserve Margin during the current planning year, those results do not reflect a "fix" for all long-term capacity concerns. And similarly, NERC's 2023 Summer Reliability Assessment suggested that although the risk of meeting load in MISO was reduced for summer 2023 as compared to 2022, MISO was "at risk of operating reserve shortfalls during periods of high demand or low resource output."

Adding new renewable generation while the Company's coal-fired resources are still online is the ideal approach to ensure continued system reliability during the transition to cleaner energy resources while still enabling the Company to gain critically needed experience with renewable resources. Without that experience, Ameren Missouri risks being unable to reliably manage and operate its renewable generation fleet, and unable to fully understand the backup resource needs that may be required to ensure a reliable supply. Transitioning to renewable energy while more of our coal-fired generation and gas-fired peaking capacity is still in operation will allow us to gain this necessary experience with minimal risk of continuing to provide reliable service to our customers.

By continuing to add new renewable energy in a staged and continuous manner while a significant portion of Ameren Missouri's existing generation fleet remains online, the Company will gain invaluable experience in two areas:

1) The ability to assess when and to what extent renewable energy is truly available over a wide range of weather conditions, which is dependent in large part on the location of the renewable resource, and

2) An understanding of how the existing Ameren Missouri generation fleet may need to be dispatched differently than historical dispatch patterns to provide critical back-up generation during hours that intermittent renewable generation is not available.

By understanding the operational aspects of a significant portfolio of renewable energy resources under different weather conditions over a long period, the Company can also determine the optimal amount of renewable capacity needed to ensure a secure energy supply, ensuring we are not adding too much or too little new renewable energy generation. The Company may also learn how to increase generation through planned and preventative maintenance approaches, and how to optimize equipment selection based on project site characteristics. In addition, the Company can determine the amount of dispatchable generation and battery storage to maintain the reliability of least cost renewable energy. Said simply, by adding significant new renewable generation resources while the Company's coal-fired generation is still operational, Ameren Missouri can learn how to optimally plan and operate its generation fleet in a high renewables future without putting system reliability at risk.

Another important factor to ensure long-term system reliability and resiliency is to pursue a geographically diverse portfolio of renewable energy resources to ensure energy is always available to meet our customers' needs, even during peak energy time periods. Since solar and wind generation are dependent on weather conditions which vary by geographical location, a regionally diverse renewable resource portfolio will be more reliable under varying weather conditions. Over time, as ideal project sites are developed and land availability declines, it will become more challenging to achieve a regionally diverse portfolio of projects. This is another key reason the Company needs to continue to transition to clean energy now and sustain it.

The Risk of Inaction

It is one thing to set forth a plan to meet customer energy needs for the next twenty years. It is quite another thing to execute plans and construct the renewable energy resources to serve those needs. So while we have some time to continue to build out the entire renewable resource portfolio, there are practical considerations that must be taken into account when embarking on the kind of portfolio transformation that Ameren Missouri believes is necessary to best meet our customers' future energy needs, and there are significant risks of inaction or delays in implementation. Renewable energy development is a difficult, lengthy process with successful projects taking five to eight years to reach commercial operation. With each stage of the project lifecycle there is a risk that the project can be delayed, and at times cancelled altogether. The most significant implementation risks are likely to emerge in siting the project location, completing extensive transmission studies, evaluating transmission upgrade costs and completion schedules, completing environmental studies, conservation plans, and compliance requirements, acquiring real estate, obtaining local county permits and community support, qualifying for federal tax credits, evaluating technology options, obtaining financing, receiving regulatory approvals, procuring key equipment in a timely manner, and designing, engineering, and finally constructing, commissioning, and testing of the new renewable energy center. A challenge, delay, or misguided decision can delay and potentially terminate the project. Given the number of renewable energy projects that are needed for a successful transition combined with the length and potential risks within the full lifecycle, it would be impractical, and frankly, irresponsible for the Company to continue to take a "capacity when needed" approach – as there is never a guarantee that each renewable energy project being pursued will come to fruition. We must start and sustain the transition to account for any potential delays. The key project implementation risks include the following:

- Land (i.e., renewable site) availability
- Project permitting and construction
- Supply chain constraints
- Transmission interconnection
- Technology costs
- Financing costs
- Financing constraints

One of the most critical reasons for Ameren Missouri to pursue a controlled but sustained transition that starts immediately is to ensure the Company can acquire the best available project sites in our region. The lengthy development, permitting, regulatory approval and construction cycle challenges described above, along with the myriad of development risks involved to successfully develop a good renewable energy project site, means that the best renewable energy sites are the first to be developed. Ameren Missouri is now also in competition with large technology firms from outside its service territory who are purchasing renewable energy projects in and around Missouri and Illinois for their announced sustainability goals and are equally as eager to find the best available project sites. An ideal project site will feature good renewable resource, favorable topography, good community relations, access to a favorable transmission interconnection point, and minimal environmental risk. This means that as the availability of suitable land declines, both the cost of the planned facility and the risks of not being able to obtain necessary permissions or not being able to construct the project at all are likely to increase.

Placing a renewable energy project into service requires a series of preceding permits – these include but are not limited to environmental, construction, county, state, federal and other governmental permits. These activities require a great deal of lead time and if not obtained, could delay project construction, or even terminate a project. For example, to obtain the appropriate environmental permits, we must first complete several environmental studies to determine and mitigate any potential adverse impacts to the environment (e.g., water, land, natural habitat, etc.). These studies can take years to complete as they require extensive data collection and analysis. In some cases, the studies might indicate a fatal flaw in the project site. A fatal flaw would result in a change in project site – making it important to pursue a pipeline of potentially suitable projects simultaneously to pivot to a more suitable project site from an environmental permitting perspective.

Prior to starting construction, local and county permits might be required. If there is a delay in receiving these permits, the construction schedule can be put at risk. A delay in schedule can jeopardize the in-service date, ultimately impacting the Company's ability to receive federal tax incentives or at times, preventing project implementation altogether.

Building community support and engaging with key stakeholders early in the project development lifecycle will allow the Company to quickly identify potential delays and adjust accordingly. But navigating these permitting issues takes a great deal of time, and navigating them simultaneously with the large number of projects that would be needed all at once if we wait to add renewable capacity when the capacity need is here would be extremely difficult, if not completely impractical.

Once all necessary environmental and local government permits have been received, projects must be designed, engineered, and then constructed in a manner to provide at least 30 years of reliable energy. The design and engineering phase typically takes about a year. While recently performing due diligence on a solar project in an advanced stage of development (land acquisition, permitting and environmental assessment were all completed), Ameren Missouri discovered that the project was sited on land above a historical mine that potentially may be unsuitable for construction. Ameren Missouri had to place the project on hold until suitable geotechnical due diligence could be completed to ensure that the project can be constructed and operated in a reliable manner.

The construction phase itself for solar and wind projects can take one to two years to complete. During this time there is heavy construction traffic on smaller local county roads that can be subject to weather delays. The supply chain for solar and wind generation is global and there are numerous opportunities for delays in manufacturing, shipment, and delivery. As with any large construction projects, actual construction may face challenges from an electric and mechanical component perspective, and therefore testing of the final project after completion of construction is critical. For the High Prairie and Atchison Renewable Energy Centers, the Company experienced several months of delay before achieving successful testing and commissioning and ultimately bringing the projects online.

Supply chain constraints can occur due to labor shortages, political upheaval (globally or otherwise), commodity supply and price changes, transportation challenges, or quality control issues. Challenges in the supply chain can lead to project delays, cost increases, or ultimately an inability to construct a project at all. Since supply chain problems can meaningfully disrupt the timing and costs of renewable energy projects, it is important to have a long implementation timeframe to maintain flexibility in the generation transition. By developing long-term strategic partnerships with key renewable equipment manufacturers as well as established renewable energy developers, we ensure a greater certainty of supply of key renewable project equipment. But to develop such strategic partnerships, we need a long-term and defined transition plan with a known stream of projects for which equipment can be acquired in a timely manner. The same dynamic exists when we have ongoing relationships with national renewable energy developers for new projects, so they can plan ahead for completing projects in a timely manner. Given the 5- to 8-year life cycle for successful renewable energy project development, such partnerships are much more difficult to develop if a transition plan is not defined at least 10 years in advance to ensure certainty of equipment supply.

Transmission interconnection and upgrade costs remain one of the most important and, it is fair to say, challenging aspects of renewable energy development. This includes the challenge of navigating MISO's Generator Interconnection Queue. The larger utility scale renewable energy projects must go through a transmission interconnection queue to determine the timing and cost of transmission upgrades that may be required for interconnection. This is not only challenging, but time-consuming. In MISO, generator interconnection at the transmission level is a three-phase process that can generally take up to three years to complete. The transmission upgrade costs are a function of the number of projects in the queue, and the location and size of the projects. Generally, projects that are earlier in a queue can interconnect at a lower cost. It is also important to note that after Phase 2, a non-refundable 20% payment is due for expected transmission upgrades for a renewable energy project. As such, only the best projects with the most favorable locations and queue positions make it to the final Phase 3. Other projects are rejected due to high transmission costs in Phase 2, or at times even in Phase 3, as cost estimates can change throughout the process until it is clear which projects will proceed to construction.

At any point in the process, projects that the Company may be relying on could be terminated due to exorbitant interconnection costs, forcing the Company to start the 3-year cycle once again. Over the last ten years, generally less than a third of the projects that enter the MISO Generator Interconnection Queue make it to start of construction. Ameren Missouri has first-hand experience with projects in which a great deal of time and effort was expended only to see the project fail due to no fault of the Company. The Brickyard Hills wind project, for which the Commission granted Ameren Missouri a CCN in 2019 and which had likely been under development for approximately 10 years, ultimately had to be terminated due to unacceptably high transmission costs. As future queues get more and more constrained with new renewable energy projects, new transmission buildout will be needed. However, building new transmission lines to interconnect new renewable energy projects is generally a 6- to 10-year endeavor, if not longer. Although ideally transmission buildout will keep pace with renewable energy project buildout, projects later in the queue may have significantly higher transmission interconnection costs or may not be able to operate at full output. This poses a real risk caused by delay because the energy from the generation we will ultimately place in service may be more costly or less reliable.

The Company can best manage transmission interconnection risks, first and foremost, by continuing to proceed with the planned renewable transition now and sustaining it. Second, we must act on good projects when they are available, including smaller utility-scale projects like the Vandalia and Bowling Green Projects currently before the MPSC, which were not required to navigate the difficult and lengthy MISO generation interconnection queue since they will connect to the distribution system. Third, we must be flexible regarding the best renewable project acquisition approach for each specific project – whether we use a build-transfer, development-transfer, or self-development approach. The Company needs to maintain a renewable project pipeline with at least twice the number of projects needed for the inevitable transition to renewable energy and use the most appropriate acquisition approach for each project. To have a pipeline of twice the number of projects needed for our generation transition, we need to constantly be looking for – and acting on – good renewable projects in Missouri and surrounding states. Without a large pipeline and a phased approach, we are likely to face delays in project interconnection to the grid, significantly higher costs, or both, thus rendering our generation transition less reliable and more costly than it would have been had we obtained good project earlier in the transition process.

Although Ameren Missouri hopes that renewable technology costs will ultimately decline, the last several years served as a reminder that cost declines are far from a guarantee. It is tempting to point to some possible declining cost curve forecasts for wind and solar and recommend the Company wait until such declines materialize before proceeding with renewable development. But it is critical to remember that declines that are forecasted by some are not certain. Waiting for costs to decline is also a risky approach, because if those declines do not materialize customers could be exposed to higher costs for less ideal sites later. By adding investments steadily over time, we engage in a form of "dollar cost averaging" similar to that used in financial investing, while continuing to progress towards a prudent energy buffer.

Financing costs are also a key risk. Investors are increasingly focused on concerted efforts by utility companies to transition their portfolios to cleaner and more sustainable resources as they make decisions about which companies to invest in and what kind of return on investment they expect based on their assessment of risk. This increased focus is expected to result in differences in cost of capital between those utilities that are making concerted and consistent efforts to transition their portfolios and those that are not. Deferring implementation of renewable resources may require that Ameren Missouri invest huge amounts of capital in a short period of time, risking substantial deterioration to our credit metrics and impairment of our ability to cost-effectively and timely finance investments in the renewable generation we need when we need it. Staging the transition with a steady stream of additions over several years therefore reduces the expected financing costs associated with the renewable resources the Company needs to add.

Capturing the Value of Available Tax Credits

In 2022, Congress passed the IRA. Among its many impacts, the IRA extensively modifies provisions of the tax code for renewable energy projects. The IRA extends both the investment tax credit (ITC) and production tax credit (PTC), creates additional wage and apprenticeship requirements that projects must meet to qualify for the full ITC or PTC value, and adds additional bonus credit amounts for domestic content and project location. The IRA enables solar projects to utilize the PTC or the ITC (previously solar projects could only elect the ITC) and allows taxpayers the ability to transfer tax credits to unrelated parties for cash. Certain projects may be eligible for bonus tax credits, such as the energy community bonus incentive, which increases the value of the ITC from 30% to 40% or increases the PTC credit value in a given year by 1.1 times. Projects that are located in a community with a retired coal mine or coal generating facility are eligible.

While the benefits of the IRA are significant and expected under the law to apply for projects completed into the next decade, it is important to avoid complacency with regard to securing these benefits for customers. Although the IRA extends available tax incentives for renewable resources into the early 2030s, they are still not expected to be available forever. If the Company were to wait to add renewable resources, these new and enhanced tax benefits could be unavailable. Moreover, there is no guarantee that Congress may not change the law in such a way that the tax credits under the IRA become unavailable earlier than 2032. Implementing a sustained and planned transition to renewable resources enables the Company to capture the IRA incentives and pass them back to customers, helping maintain customer affordability while transitioning to a cleaner generating fleet.

Weighing the Considerations Together

In accounting for the foregoing considerations and in conjunction with our rigorous risk analysis of alternative resource plans, we conclude that a continued buildout of renewable wind and solar resources throughout the planning horizon yields significant real and potential benefits for our customers with limited downside. It provides us with valuable risk mitigation regarding CO_2 prices and other factors, and valuable flexibility in managing the transformation of our generation portfolio.

10.2.3 Reliability Needs and New Dispatchable Generation

While renewable wind and solar resources are vitally important to meet customers' energy needs, we also need dispatchable resources that are available on demand to partner with those renewable resources and ensure reliable and affordable service, both now and as we continue to transition our resource portfolio. As explained in Chapter 2, the nature of resource planning has changed from one in which we plan for meeting the annual peak demand (typically in the summer) with dispatchable resources that can meet energy needs in any hour to one that is far more complex. Resource planning must account for the need to blend non-dispatchable, intermittent energy resources like wind and solar with the need for dispatchable capacity to ensure reliability in all hours, and it must do so for all seasons and under the most extreme weather conditions. The need for energy resources is discussed in section 10.2.2.

To assess capacity needs, we must account for both the expected operation of resources in the real world and also how those resources will be compensated in MISO's capacity market. MISO's seasonal resource adequacy (RA) construct aims to promote reliability and ensure fair value for resources that are available when they are needed to meet load. In doing so, MISO has designed a process for capacity accreditation that accounts for each generator's historical performance in each season, including the degree to which each generator was available at time when it was needed most to ensure reliability. MISO establishes planning reserve margin (PRM) requirements for each season that accounts for generator performance as well as load forecast uncertainty under normal conditions. While this framework is necessary and important for promoting reliability and fair value for resources across the MISO footprint, it is not by itself sufficient for examining resource adequacy needs at the utility level over all timeframes.

Capacity Positions – Operating View

To examine resource adequacy needs more rigorously, Ameren Missouri has used what it has learned about reliability needs from its work with Astrapé Consulting, from trends in the industry, and from the operation of its own units in MISO under real operating constraints such as those imposed by the Climate and Equitable Jobs Act (CEJA) in Illinois. We have done this by also examining capacity needs under what we call an "Operating View." This view accounts for the real-world constraints like those of CEJA and is defined by the following characteristics:

- Most Illinois CTGs are limited to a short period of operation (rolling 12 months) and/or emergencies; unit capacity is therefore set to zero – Units in this category are Pinckneyville Units 5-8, Venice Units 2-4, and all units at the Goose Creek, Racoon Creek, and Kinmundy Energy Centers.
- All gas-only CTGs are subject to fuel availability constraints during cold weather, including at time of normal winter peak demand; gas-only CTG unit capacity is therefore set to zero for winter capacity position – Units in this category are Pinckneyville 1-4, Venice Unit 5, and all units at the Audrain Energy Center.
- Wind, solar and storage set to ELCC values (current MISO transitioning to calculated ELCC)[9]
- All other units set to full unit capability by season based on Ameren Missouri's most recent assessment of monthly unit capabilities.[10]

[9] See discussion of wind and solar capacity credits in Chapter 2.
[10] Monthly unit capabilities are reviewed and revised annually based on unit testing and operation.

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- Planning reserve margin requirement set to output of largest unit (Callaway) – Approximately 1,200 MW, which corresponds to ~17% of summer peak demand and ~20% of winter peak demand.

It should be noted that MISO's new seasonal construct, which took effect with the 2023-2024 planning year, results in an interdependent set of unit accreditations and planning reserve margins. As a result, the planning reserve margins determined by MISO for use in its seasonal capacity construct cannot be applied in the Operating View described here. As a reasonableness check, it is useful to compare the planning reserve margin requirements for the Operating View describes above with historical planning reserve margin requirements based on an installed capacity (ICAP) view, which similarly uses unit capabilities unadjusted for availability. The ICAP-based planning reserve margin requirements used by Ameren Missouri, and previously set by MISO under its annual RA construct, were typically in the range of 15-20%. The planning reserve margin requirements for the Operating View are comparable to this historical range.

Using the Operating View described above, Ameren Missouri has examined the capacity position for its PRP as well as variations from the PRP to assess the contribution of certain resource additions. These variations include the following and correspond to the subsequent figures as noted:

- Winter operating view capacity position with no new simple cycle generation, batteries or non-RES renewables – Figure 10.6
- Winter operating view capacity position for the PRP – Figure 10.7
- Summer operating view capacity position with no new solar resources beyond those for which the Company has received a CCN (i.e., the Boomtown and Huck Finn projects) – Figure 10.8
- Summer operating view capacity positions for the PRP – Figure 10.9

Figure 10.6 Winter Operating View Capacity Position Without New Simple Cycle, Batteries, or Non-RES Renewables

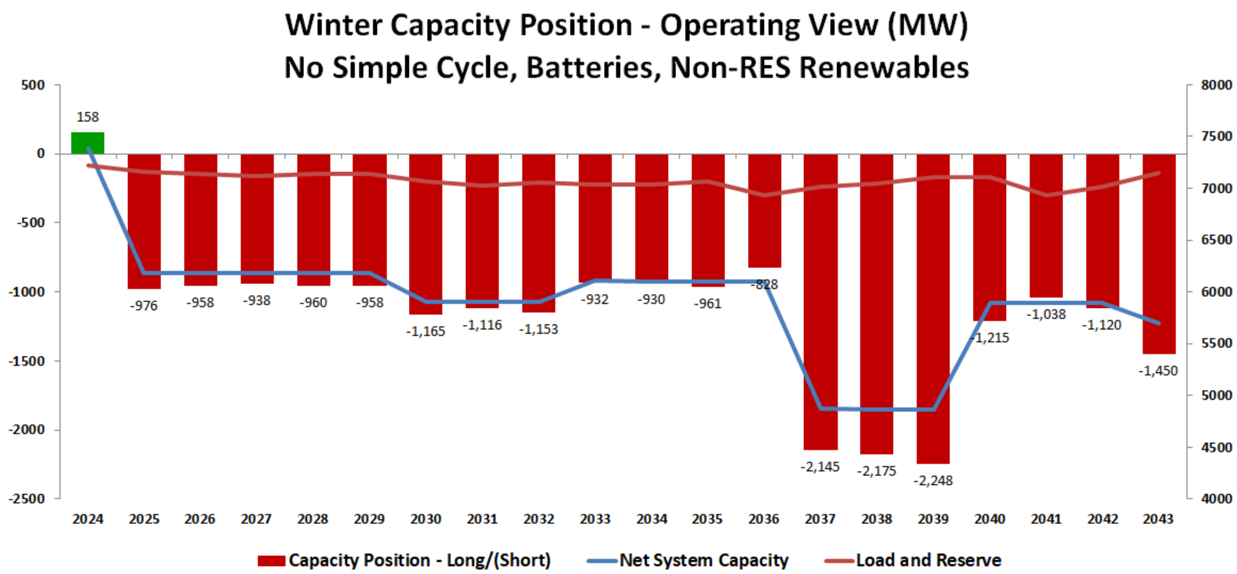

Figure 10.7 Winter Operating View Capacity Position – Preferred Resource Plan

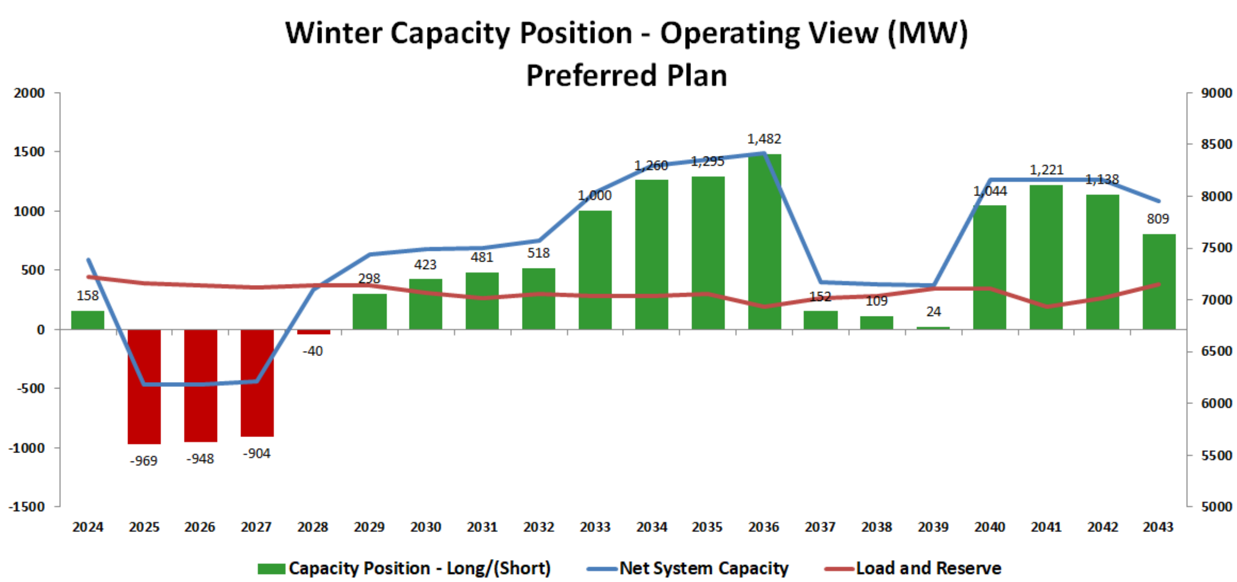

Figure 10.6 shows that without new simple cycle generation, batteries and non-RES renewables, Ameren Missouri would be roughly 1,000 MW short of its PRM in most years and roughly 2,000 MW short for the three years following the retirement of the first two units at Labadie Energy Center. Including the simple cycle generator, batteries, and planned wind and solar resources in the PRP results in Ameren Missouri achieving its PRM in all years starting in 2029, with only a slight shortfall in 2028 following the addition

of the new simple cycle generation. For the years 2025-2027, Ameren Missouri expects to be dependent on MISO to meet demand and/or the ability to operate CTG units in Illinois under emergency conditions.

Figure 10.8 shows Ameren Missouri's summer capacity position without new solar resources beyond those for which it has received a CCN, and Figure 10.9 shows Ameren Missouri's summer capacity position with additional new solar resources. Figure 10.9 shows how near-term capacity needs are reduced with the addition of additional new solar projects, such as those for which the Company is currently seeking CCNs, particularly in 2027. As with the winter capacity position shown in Figure 10.7, Ameren Missouri expects to be dependent on MISO to meet some of its near term needs and/or the ability to operate CTG units in Illinois under emergency conditions.

Figure 10.8 Summer Operating View Capacity Position With No Additional Solar

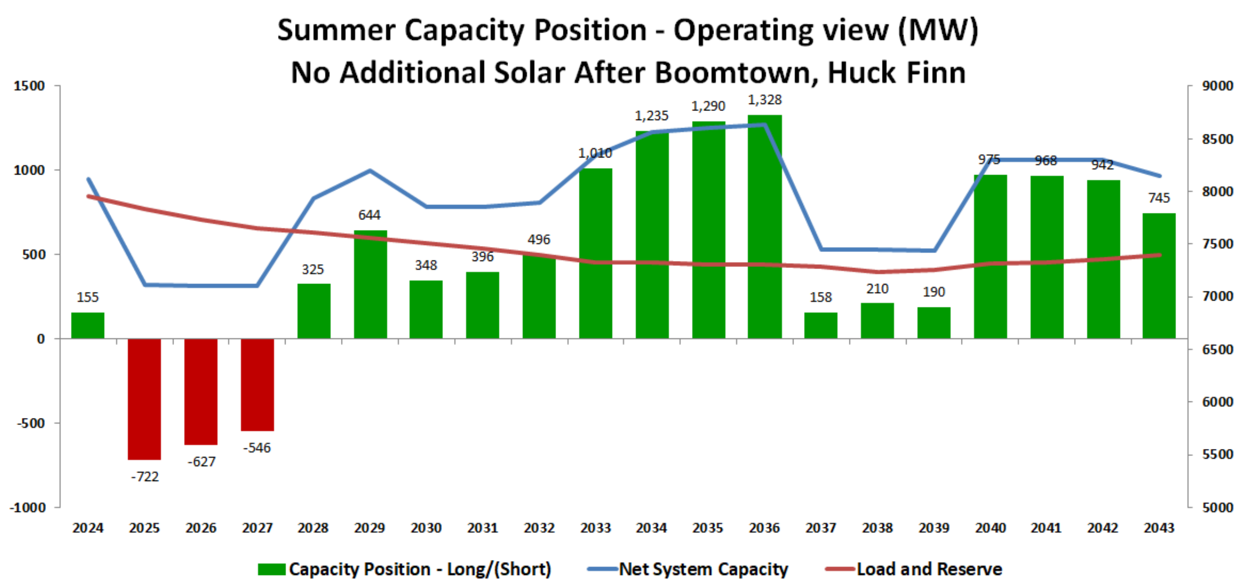

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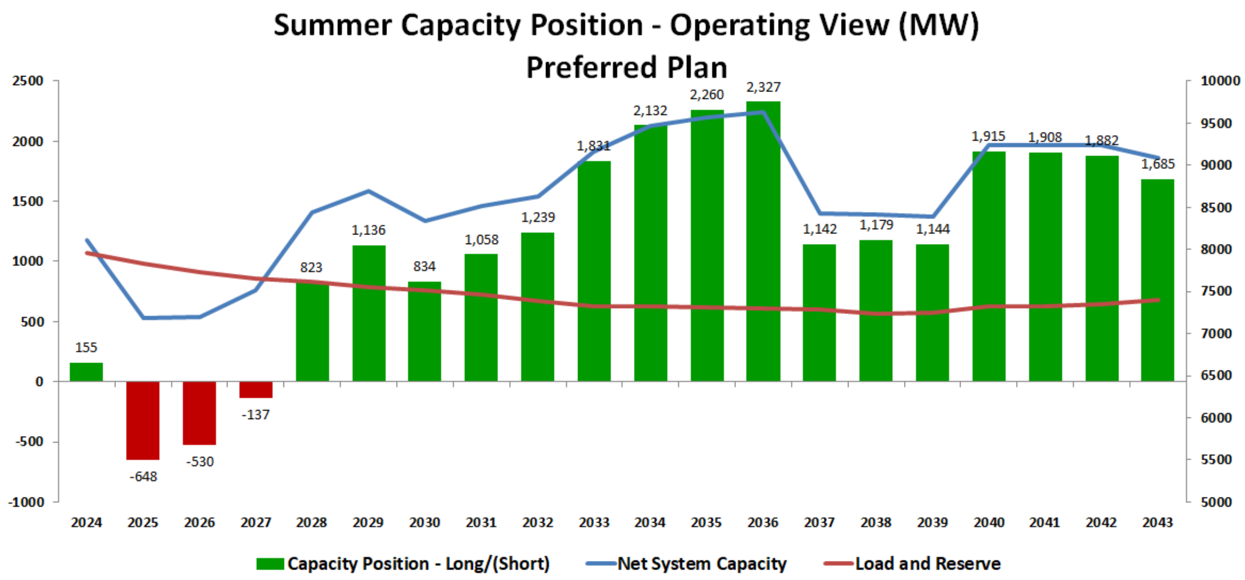
Figure 10.9 Summer Operating View Capacity Position – Preferred Resource Plan



Capacity Positions – MISO Resource Adequacy View with Extreme Weather[11]

In addition to the Operating View capacity positions shown above, Ameren Missouri has also examined its capacity position under MISO's seasonal construct and under extreme weather conditions. For convenience, and to distinguish this view from the Operating View, we refer to this as the "MISO RA View." The MISO RA View is characterized by the following:

- All units reflected at MISO seasonal accredited capacity (SAC) values
- Planning reserve margins set to MISO seasonal values[12]
- Assessment with extreme weather assumes limited use units (i.e., Illinois CTGs) are available for emergencies only
- Extreme weather reflects incremental peak demand of 600 MW in winter and 800 MW in summer based on recent extreme weather events[13]

Using the MISO RA View described above, Ameren Missouri has examined the capacity position for its PRP as well as variations from the PRP to assess the contribution of certain

[11] 20 CSR 4240-22.070(1)(D); 20 CSR 4240-22.030(8)(B)
[12] See Chapter 2 for a full discussion of seasonal PRM requirements.
[13] Summer peak load addition of 800 MW based on approximate midpoint of values calculated and presented in the extreme weather sensitivity analysis in Chapter 3. Winter peak load addition of 600 MW based on approximate increase in peak demand above normal peak experienced during winter storm Elliott in December 2022.

resource additions. These variations include the following and correspond to the subsequent figures as noted:

- Winter capacity position with no new simple cycle generation, batteries or non-RES renewables – Figure 10.10
- Winter capacity position for the PRP – Figure 10.11
- Summer capacity position with no new solar resources beyond those for which the Company has received a CCN (i.e., the Boomtown and Huck Finn projects) – Figure 10.12
- Summer capacity positions for the PRP – Figure 10.13

Figure 10.10 Winter MISO RA View Capacity Position Without New Simple Cycle, Batteries, or Non-RES Renewables

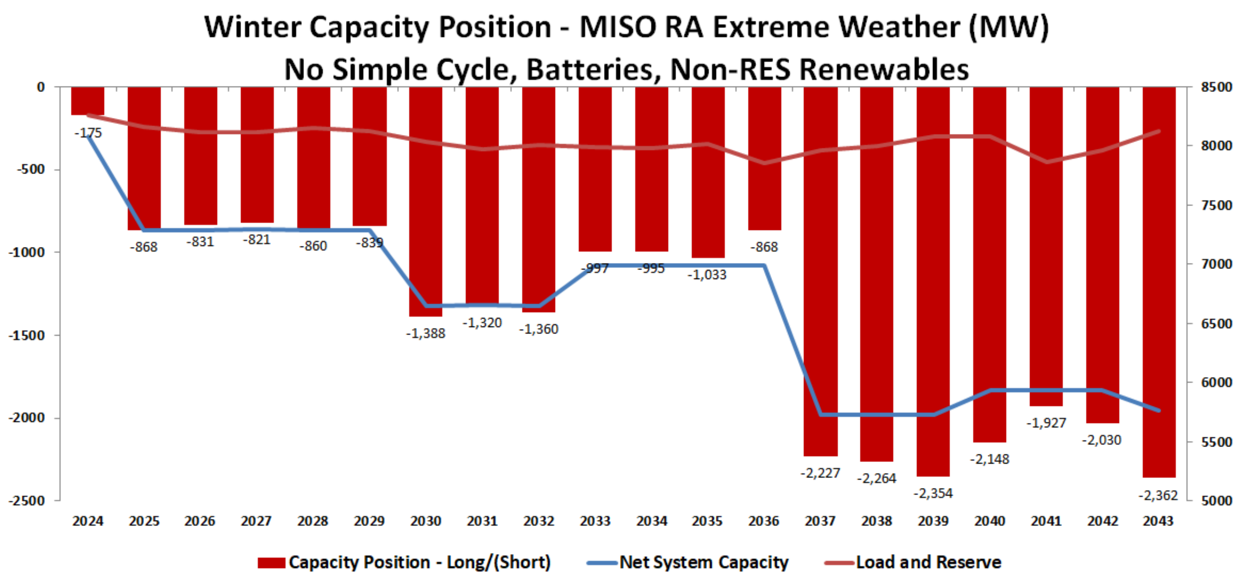


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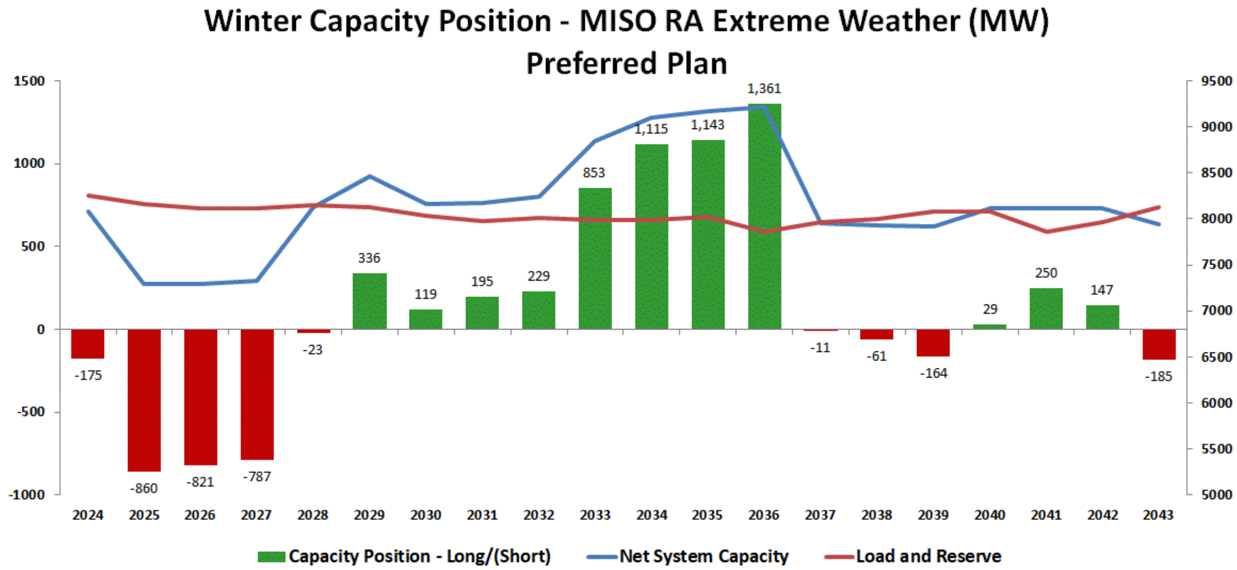
Figure 10.11 Winter MISO RA View Capacity Position – Preferred Resource Plan



Under extreme weather conditions, the MISO RA view for winter shows a capacity shortfall in all years absent the simple cycle generation, batteries and non-RES renewable additions included in the PRP, as shown in Figure 10.10. With those resources, as shown in Figure 10.11, Ameren Missouri expects to have sufficient resources in most years beginning in 2029, with a slight deficit in 2028 and relatively small deficits beyond 2036, following the retirement of the first two units at the Labadie Energy Center. Ameren Missouri could be dependent on MISO for capacity under extreme weather conditions between now and 2027.

Figure 10.12 shows that Ameren Missouri expects a relatively small capacity deficit in the summer under extreme weather conditions in 2024 and 2026 in the absence of additional solar resources. Figure 10.13 shows that this near-term deficit is resolved by the inclusion of additional solar resources, including those for which the Company is currently seeking CCNs.

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Figure 10.12 Summer MISO RA View Capacity Position With No Additional Solar

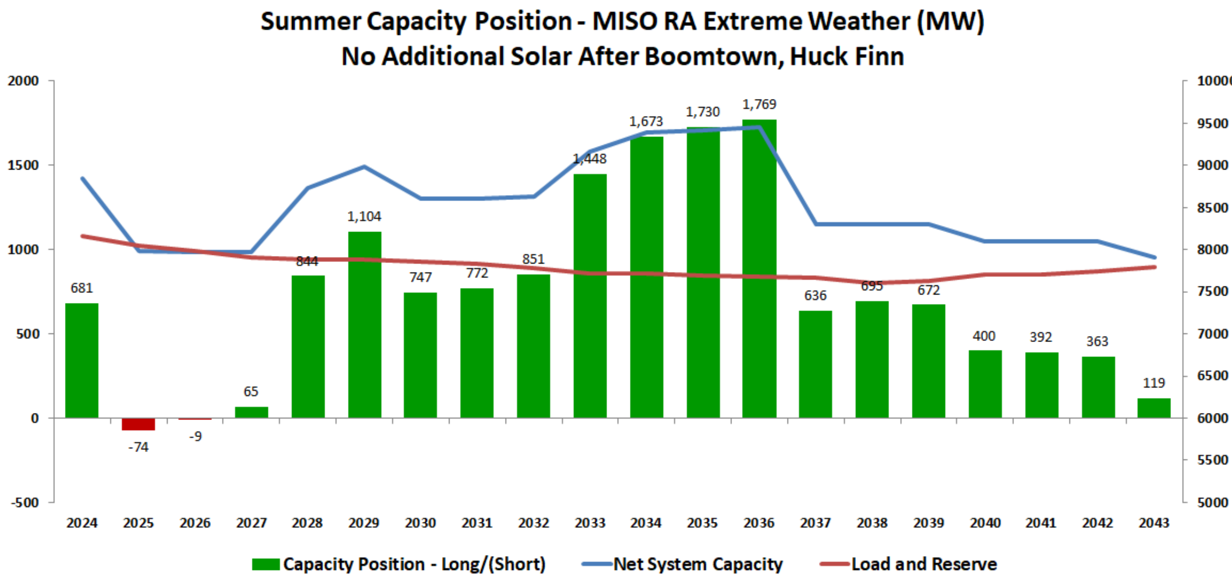
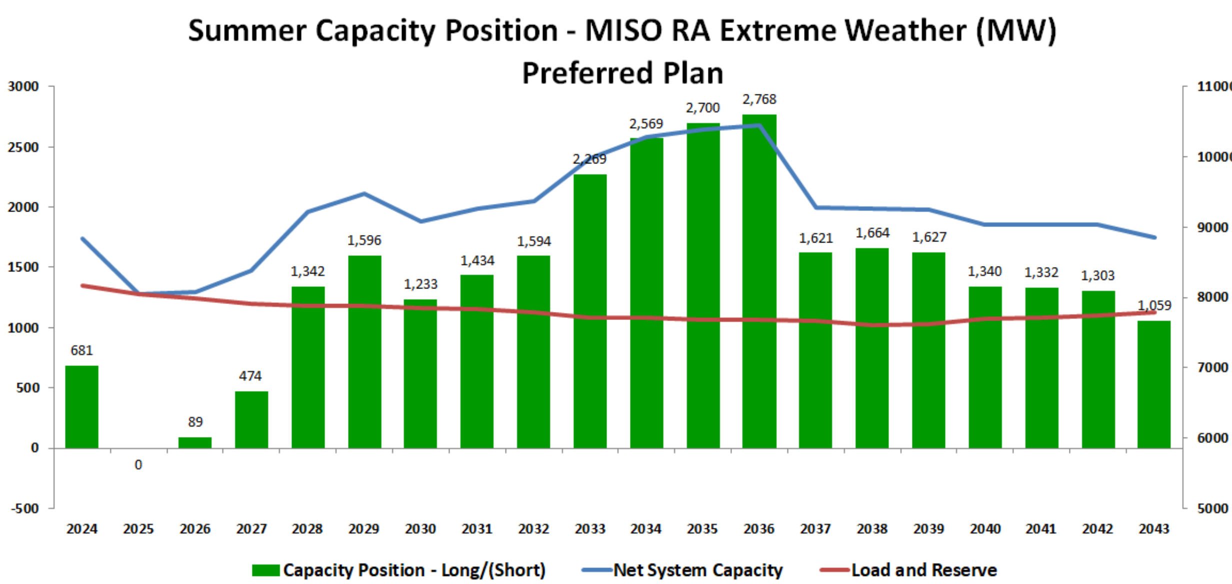


Figure 10.13 Summer MISO RA View Capacity Position – Preferred Resource Plan



Additional Reliability Analysis

As discussed previously, Ameren Missouri will need new dispatchable resources that can produce at any hour to partner with new renewable resources and other dispatchable resources in Ameren Missouri's fleet to ensure reliable energy for customer. Wind and solar resources are not dispatchable. Batteries can provide dispatchability over short periods, but they need to be charged, and therefore their value on the grid is determined by finding an optimal charging and discharging cycle over time. Gas-fired resources, on the other hand, can generate on demand in any given hour and ensure reliability of the overall portfolio in a way that renewables and storage alone cannot.

To illustrate this, the Company used Astrapé Consulting to analyze three different portfolios at or near the end of the Company's 20-year planning horizon. In each of these portfolios, all of Ameren Missouri's existing coal-fired resources are assumed to have been retired. One portfolio (marked as Case 2 in Table 10.3 below) reflects renewable resources included in the Company's PRP. Case 1 shows an alternative portfolio in which no further renewables (or battery storage) are added beyond the Company's existing and approved wind and solar resources (including the Huck Finn and Boomtown solar projects). That portfolio shows the need for 1,800 MW of additional natural gas-fired generation to achieve the same level of reliability, shown in terms of the Loss of Load Expectation (LOLE) – 0.04 in both cases. Case 3 shows an alternative portfolio in which no new gas resources are added. Case 3 includes a combination of wind (7,400 MW), solar (6,500 MW), and battery storage (4,000 MW) to attempt to achieve the same LOLE as Case 2. As the table shows, this still falls short from a reliability perspective, with an LOLE of 0.14. Further increments of wind, solar, and storage could be added to achieve the 0.04 LOLE achieved by Cases 1 and 2 but would simply result in even higher (and more unrealistic) levels of such resources. As discussed previously in this chapter, there are significant, but not insurmountable, challenges to implementing the renewable resources in the Company's PRP. To attempt to pursue the levels of renewable resources and battery storage shown in Case 3 would simply not be realistic, and even if they were available, it would require a much quicker pace of implementation in the near term than what the Company is currently seeking to execute.

Cases 4-7 show portfolios with and without further renewable resources under the PRP in 2026 and 2031, which each follow the retirement of significant coal-fired generation – Rush Island by 2025 and Sioux by 2030.[14] Cases 4 and 6 shown years 2026 and 2031, respectively, including the renewable additions in the PRP, and cases 5 and 7 show those same years, respectively, without renewable additions beyond those already approved. Differences from the PRP are highlighted in green.

[14] Note that this analysis was completed prior to the final selection of the Company's PRP.

Table 10.3 Astrapé Reliability Analysis Results

Year	2043	2043	2043	2026	2026	2031	2031
Case	*1*	*2*	*3*	*4*	*5*	*6*	*7*
Rush Island	-	-	-	-	-	-	-
Sioux	-	-	-	974	974	-	-
Battery Storage	-	800	4000	-	-	-	-
CCGT	4200	2400	-	-	-	1200	1200
Labadie	-	-	-	2372	2372	2372	2372
CT Gas	788	788	-	2711	2711	2058	2058
DR	704	704	704	704	704	704	704
Hydro	370	370	370	370	370	370	370
Nuclear	1236	1236	1236	1236	1236	1236	1236
PSH	440	440	440	440	440	440	440
Purchases	2200	2200	2200	2200	2200	2200	2200
Solar	350	2700	6500	900	350	1800	350
Wind	400	2400	7400	400	400	1400	400
LOLE	0.04	0.04	0.14	0.09	0.13	0.01	0.08

For 2026, the addition of 550 MW of solar resources, which is the total combined capacity of the solar projects currently before the MPSC, results in an improvement in LOLE from 0.13 (Case 5) to 0.09 (Case 4). For 2031, the addition of 1,450 MW of solar and 1,000 MW of wind resources results in an improvement in LOLE from 0.08 (Case 7) to 0.01 (Case 6). While renewable resources are intermittent and alone cannot provide all the necessary capacity to ensure a reliable system, they are integral to meeting reliability needs throughout the near, intermediate, and long term in partnership with existing and new dispatchable resources in the Company's fleet.

Hourly Energy Contribution of Renewable Resources

In addition to the annual energy analysis described previously in this chapter, Ameren Missouri has analyzed hourly energy needs and expected generation during key times of the year, which highlights the value of the Company's renewable additions in meeting customer energy needs.[15] This was done by taking the Company's 2023 IRP load forecasts and showing an explicit build-up of energy resources compared to the load.

[15] More granular hourly and sub-hourly analysis is among the recommendations made by NERC in its 2022 Long-term Reliability Assessment, as discussed in Chapter 2.

Specific time periods were evaluated, including summer and winter peak conditions, for several key timeframes during the 20-year planning horizon.

The hourly analysis shows that renewable resources are expected to contribute significantly to meeting customer energy needs in the short-, intermediate- and long-term and that the Company's planned solar projects in particular are valuable in meeting customer energy needs in the near term, especially during the summer. The importance of the value provided by the solar projects in the near term is further heightened by the CSAPR rule changes affecting coal generation during the summer months and proposed rules regulating CO_2 emissions.

Figure 10.14 shows peak day energy resources and load for July 5, 2026. The solar resources, shown in yellow on the chart, are contributing energy production primarily during the peak period, while wind resources, shown in green generate primarily in the off-peak period. Figure 10.15 shows a similar view for December 23, 2026. This shows much higher production from wind resources in winter than in summer, and primarily in the early morning hours, while solar resource still generate during the middle of the day. Note that in both summer and winter, there is still a need for other energy to meet load, as is the case in the annual energy positions discussed previously. This could be met by a combination of resources, including peaking resources in the Company's fleet and other available resources within MISO and the broader market.

Figure 10.14 Summer Peak Day Energy – PRP 2026

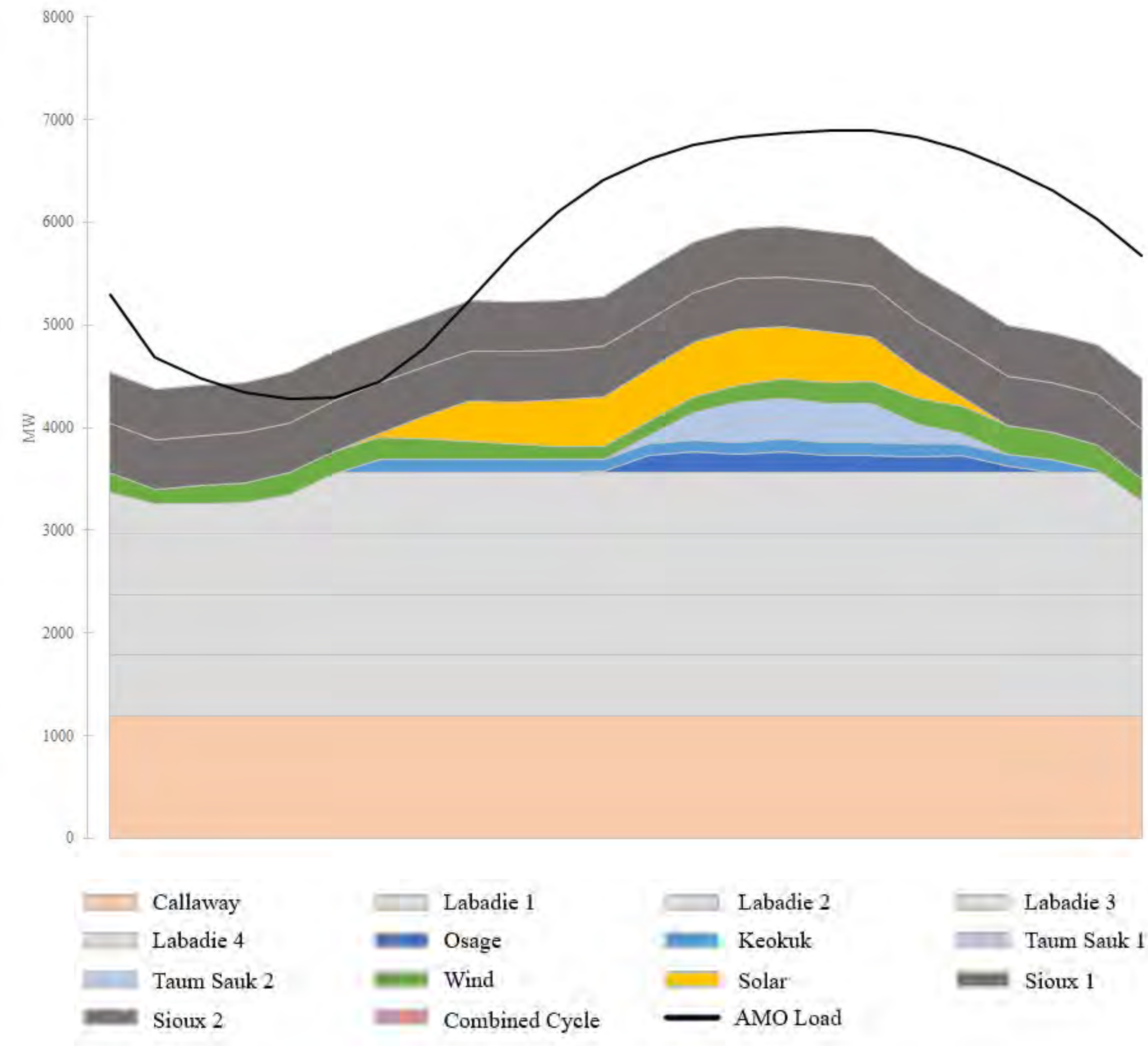
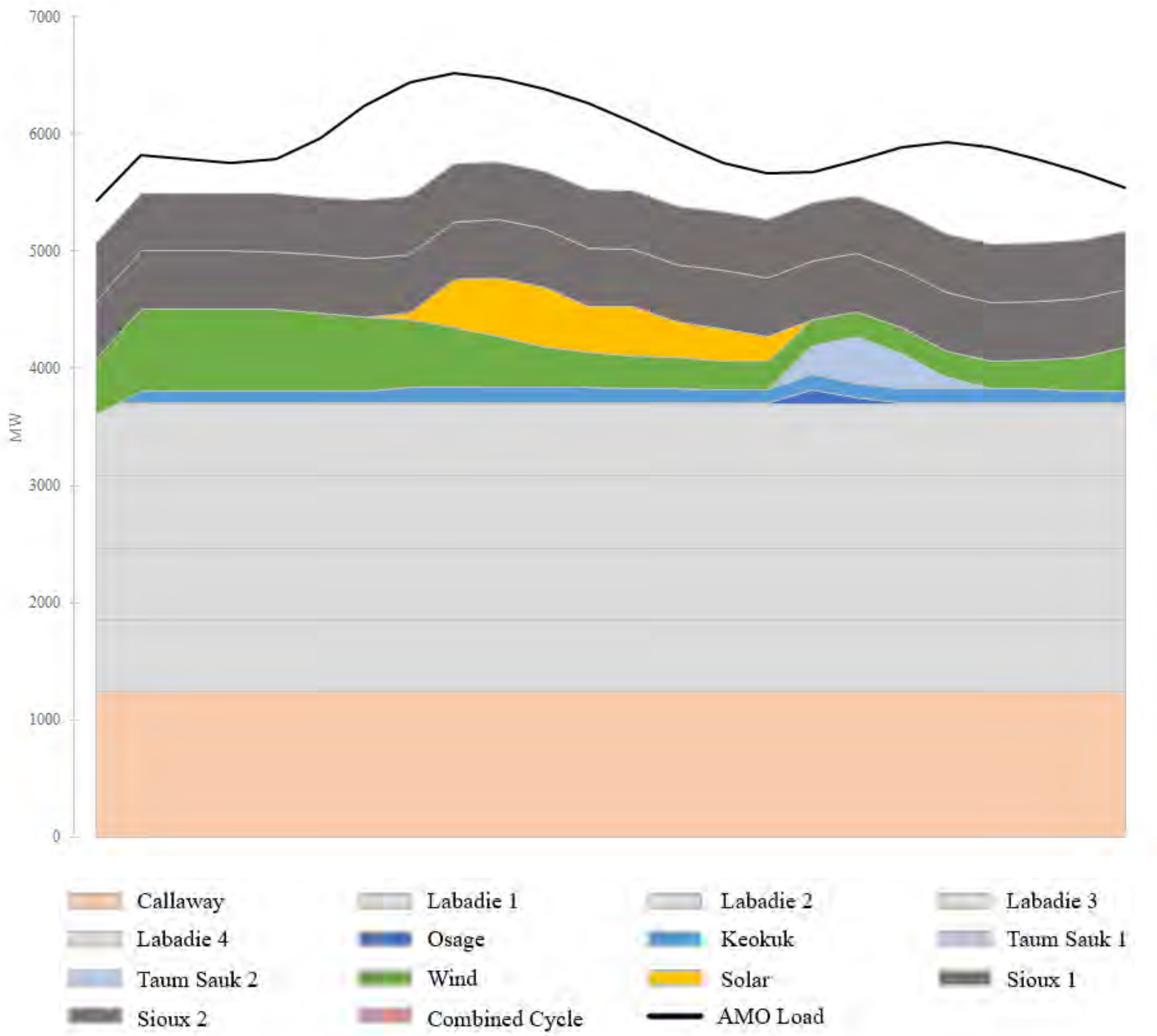


Figure 10.15 Winter Peak Day Energy – PRP 2026



Figures 10.16 and 10.17 similarly show the summer and winter, respectively, energy production and load for the same days in 2033, following the retirement of Sioux Energy Center, the addition of 1,200 MW of combined cycle gas generation and renewable additions that bring total wind generating capacity to 2,100 MW and total solar generating capacity to 2,200 MW. These charts show the higher contribution of solar during the summer and wind during the winter, while also showing that both provide generation during both seasons. The charts also demonstrate the important role of new dispatchable generation in meeting customer energy needs when total wind and solar generation are lower.

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Figure 10.16 Summer Peak Day Energy – PRP 2033

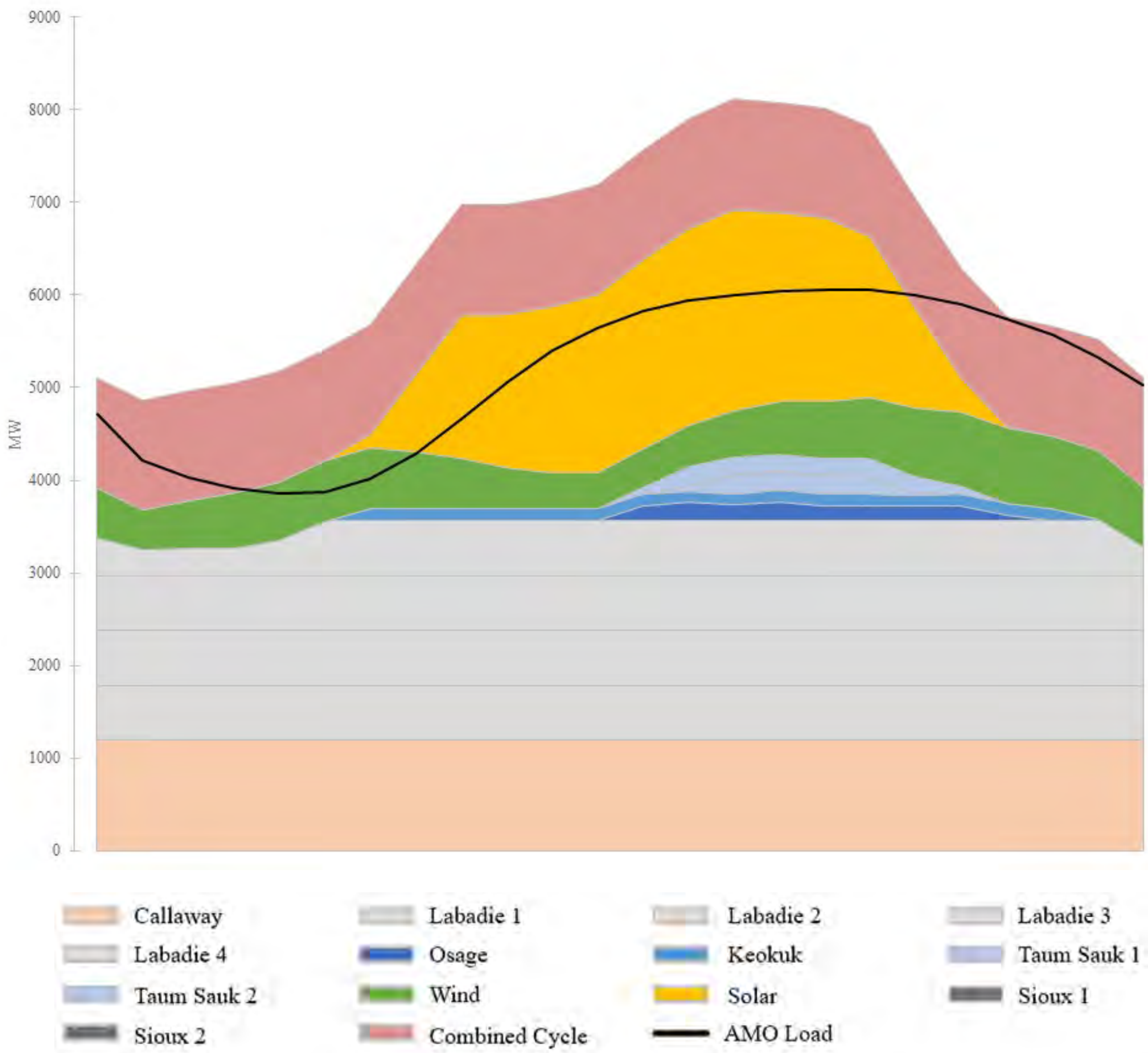
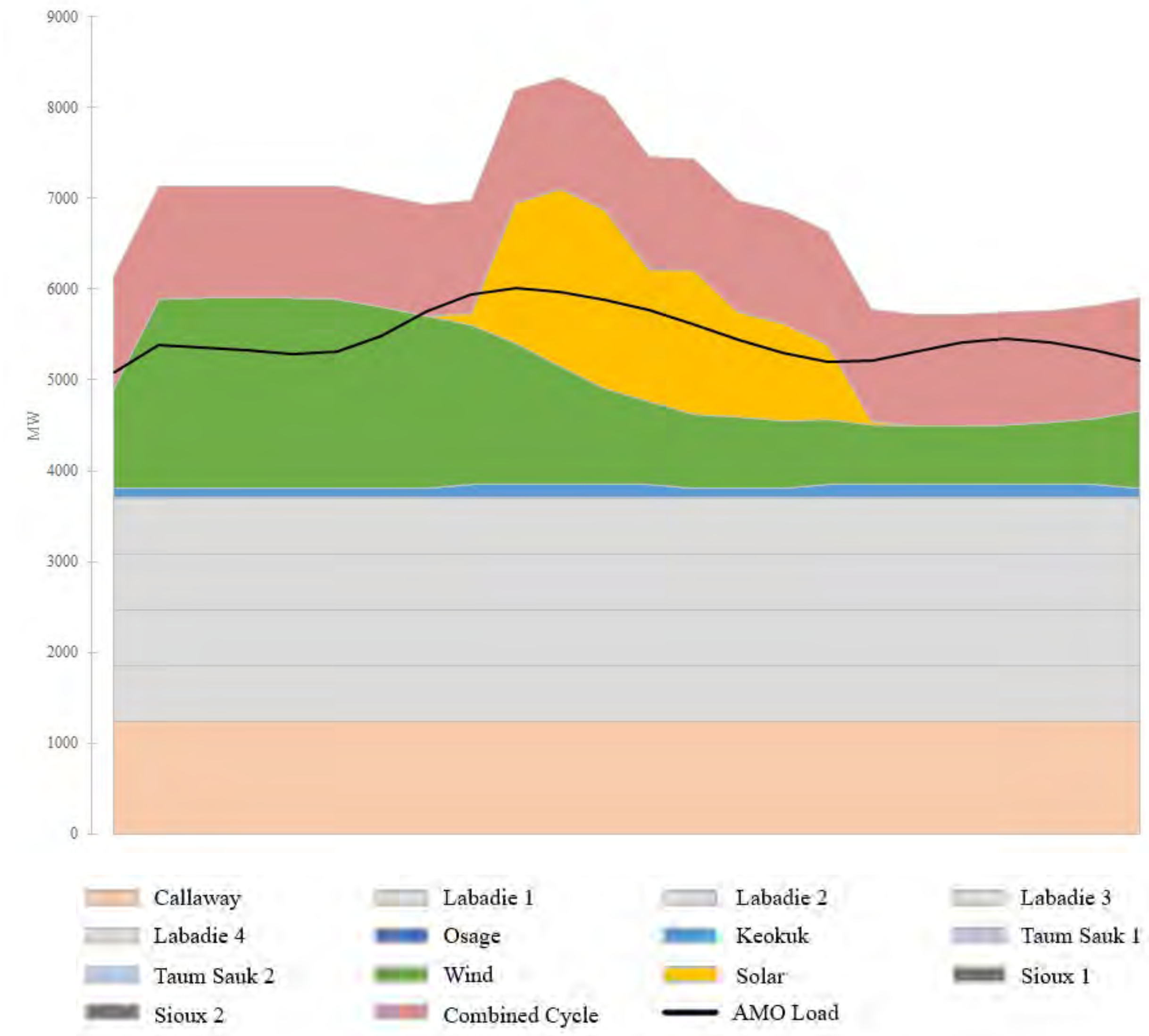


Figure 10.17 Winter Peak Day Energy – PRP 2033



Following the retirement of two Labadie units in 2036, renewable additions bring total wind and solar generating capacity to 5,400 MW. The charts in Figures 10.18 and 10.19 again show summer and winter peak days, respectively, and the generation needed to serve load in 2040, following the addition of 1,200 MW of clean dispatchable generation.[16] Once again, these charts show the important role of renewable resources in producing energy to meet load and the role of dispatchable resources to partner with renewables and ensure reliability in all hours.

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[16] For analysis purposes, the clean dispatchable resource is modeled as combined cycle gas. However, the Company plans to make the decision in the future as to exactly what type of clean dispatchable generation is ultimately deployed.

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Figure 10.18 Summer Peak Day Energy – PRP 2040

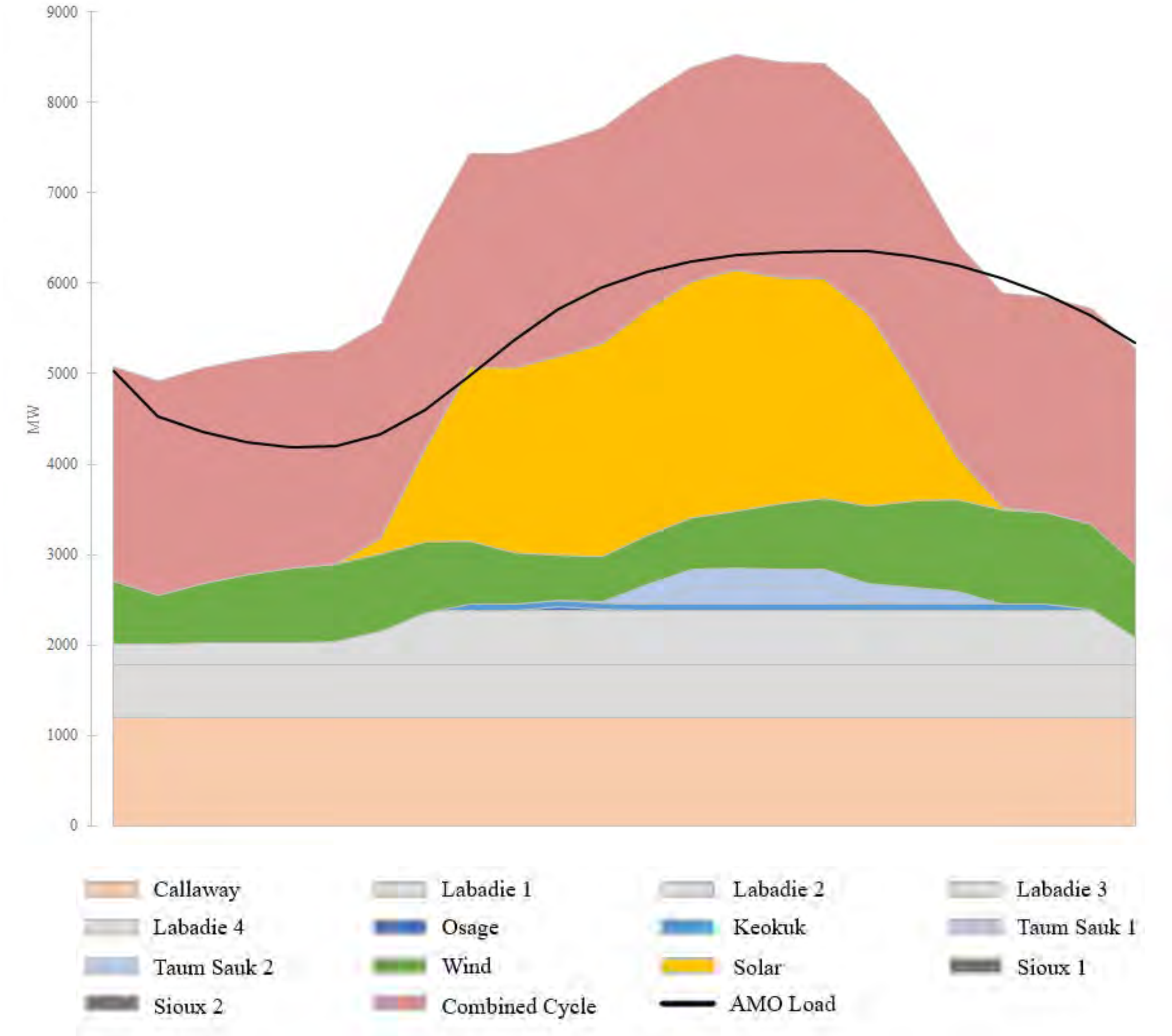
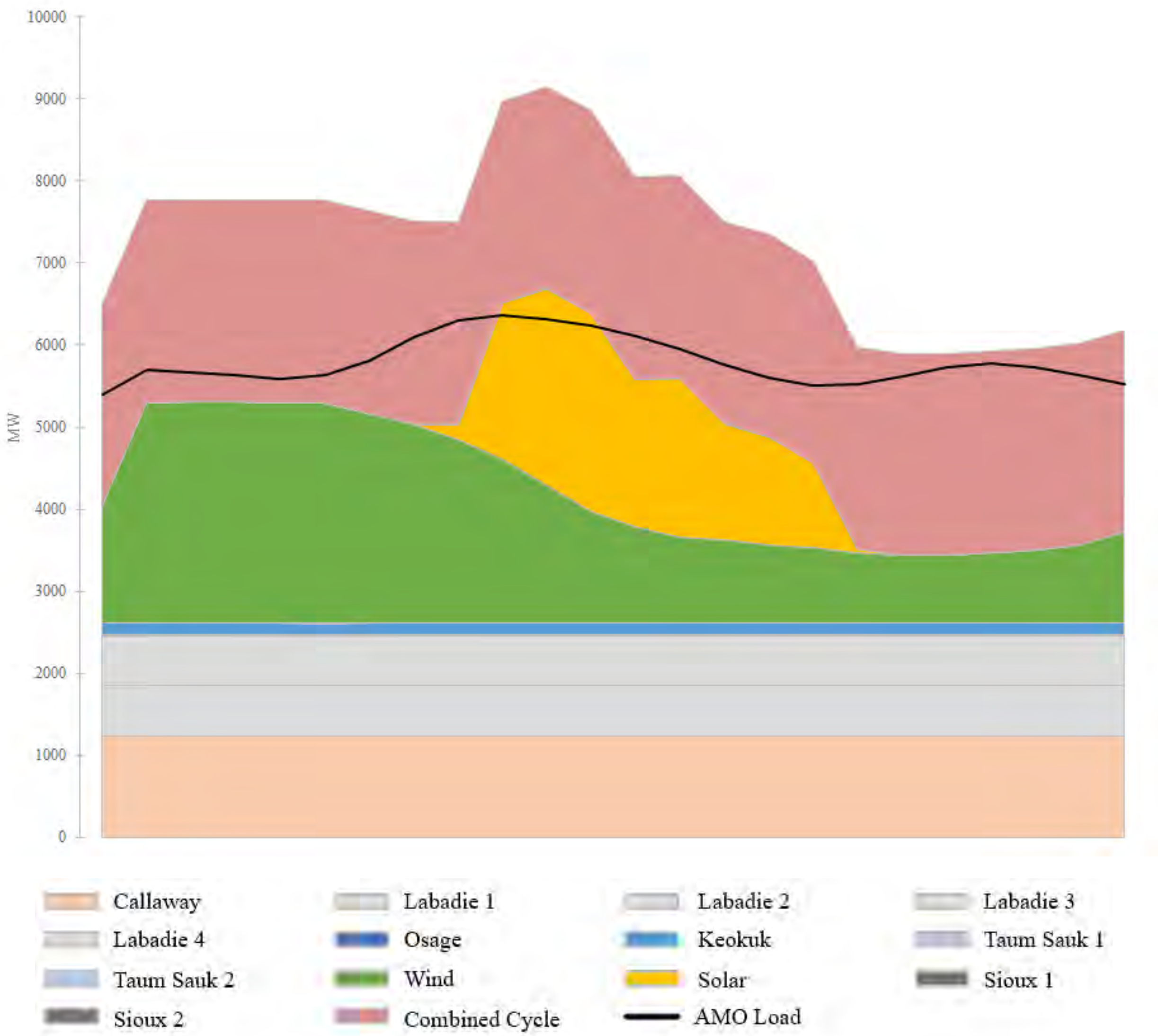


Figure 10.19 Winter Peak Day Energy – PRP 2040



10.2.4 DSM Portfolio Considerations

The continued transition from our old fleet to our new fleet has placed an even greater emphasis on the potential role of demand-side resources, which compete directly with supply-side resources in the alternative plans described and analyzed in Chapter 9. We have seen the gap between the costs of the RAP and MAP portfolios increase in terms of the cost per kWh saved. As a result, the incremental cost of the MAP portfolio does not result in savings from the deferral of supply side resources that justify this cost, as evidenced by our PVRR analysis. At the same time, achievement of energy savings at levels less than that reflected in the RAP portfolio give rise to the need for more supply side resource additions, also resulting in higher costs for customers. For these reasons, the Company believes it is appropriate to continue to target energy and demand savings based on the RAP portfolio.

In addition to its traditional evaluation of demand side programs, the Company also evaluated the potential for additional load flexibility, as described in Chapter 8. While inclusion of this potential (see Plan R in Chapter 9) results in higher PVRR, it may still prove to be a useful contingency option for meeting reliability needs, particularly in the winter. The Company will continue to evaluate the potential for additional load flexibility.

Pursuing the Policy Goal of MEEIA

The stated goal of MEEIA is to achieve all cost-effective demand-side savings by aligning utility incentives with helping customers to use energy more efficiently. Ameren Missouri has demonstrated its commitment to pursuing this goal by implementing the largest utility energy efficiency program in Missouri history. And while we believe this is a goal worth pursuing, it cannot be quantified with any degree of accuracy for the next twenty years. Rather, it is a goal that will constantly be shaped and reshaped through continuous implementation, evaluation, research, testing and readjustment.

As noted in Chapter 8, Ameren Missouri has conducted a DSM Potential Study, prepared by a nationally recognized independent contractor team. The primary objective of the study was to assess and understand the long-term technical, economic, and achievable potential for all Ameren Missouri customer segments. Assuming regulatory treatment that reflects the requirements of MEEIA, RAP represents all cost-effective energy efficiency because, by definition, it represents a forecast of likely customer behavior under realistic program design and implementation.

10.3 Preferred Plan Selection[17]

In selecting its Preferred Resource Plan, Ameren Missouri decision makers[18] relied on the planning objectives discussed earlier in this chapter and the considerations reflected in the scoring and comparison of alternative plans highlighted in the previous sections. As was noted previously, the Top Tier plans identified through scoring include the RAP DSM portfolio, a significant expansion of renewable and storage resources, and the addition of dispatchable resources in the selection of the preferred resource plan.

[17] 20 CSR 4240-22.010(2)(C); 20 CSR 4240-22.010(2)(C)1; 20 CSR 4240-22.010(2)(C)2 20 CSR 4240-22.010(2)(C)3; 20 CSR 4240-22.060(3)(A)5; 20 CSR 4240-22.070(1); 20 CSR 4240-22.070(1)(A) through (D)

[18] Names, titles and roles of decision makers are provided in Appendix B.

Figure 10.20 Comparison of Top Tier Plans

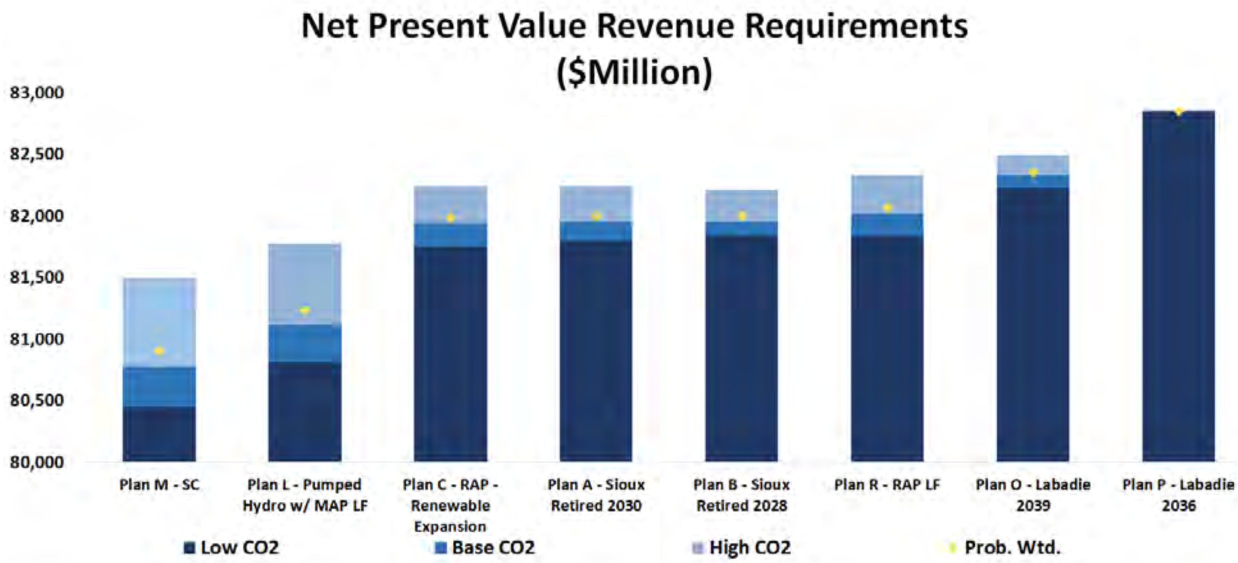
Performance Objectives	Customer Cost (PVRR) (30%)	Customer Sat. (incl. Reliability) (20%)	Financial and Regulatory (20%)	Resource Diversity (20%)	Econ. Dev. (Direct Jobs) (10%)
Plan C – Sioux Retired 2032; Clean Dispatchable (CC-CCS) 2040/2043	No Relative Advantage/Disadvantage	No Relative Advantage/Disadvantage	Relative Advantage	Relative Advantage	No Relative Advantage/Disadvantage
Plan A – Sioux Retired 2030; Clean Dispatchable (CC-CCS) 2040/2043	No Relative Advantage/Disadvantage	No Relative Advantage/Disadvantage	Relative Disadvantage	Relative Advantage	No Relative Advantage/Disadvantage
Plan B – Sioux Retired 2028; Clean Dispatchable (CC-CCS) 2040/2043	No Relative Advantage/Disadvantage	Relative Disadvantage	Relative Disadvantage	Relative Advantage	Relative Disadvantage
Plan R – Sioux Retired 2032; Clean Dispatchable 2040/2043; Additional Load Flexibility	No Relative Advantage/Disadvantage	No Relative Advantage/Disadvantage	Relative Advantage	Relative Advantage	No Relative Advantage/Disadvantage
Plan M – Sioux Retired 2032; Simple Cycle 2040; Clean Dispatchable 2043	Relative Advantage	No Relative Advantage/Disadvantage	Relative Advantage	No Relative Advantage/Disadvantage	Relative Disadvantage
Plan L – Sioux Retired 2032; Pumped Hydro 2040; Clean Dispatchable 2043	Relative Advantage	No Relative Advantage/Disadvantage	No Relative Advantage/Disadvantage	No Relative Advantage/Disadvantage	Relative Advantage
Plan O – Sioux Retired 2032; Labadie Retired 2039; Clean Dispatchable 2040x2	Relative Disadvantage	No Relative Advantage/Disadvantage	No Relative Advantage/Disadvantage	Relative Advantage	Relative Disadvantage
Plan P – Sioux Retired 2032; Labadie Retired 2036; Clean Dispatchable 2037/2039	Relative Disadvantage	Relative Disadvantage	Relative Disadvantage	Relative Advantage	Relative Disadvantage

Relative Advantage | No Relative Advantage/Disadvantage | Relative Disadvantage

To facilitate the selection of the preferred plan, an additional assessment was made of the top tier resource plans. Figure 10.20 presents the comparison of the top tier plans based on further assessment of Ameren Missouri's planning objectives. By isolating the top tier plans, we can assess their relative advantages with more specificity. This also means that the ratings applied in the scorecard in Table 10.2 do not constrain this comparison. Following is a description of the consideration of each planning objective for the top tier plans.

PVRR – Figure 10.21 summarizes the PVRR results for the top tier plans by CO_2 price scenario and for the probability weighted average. Based on these results, Plans M and L were rated as having a relative advantage compared to the other plans. Plans O and P were rated as having a relative disadvantage. All other plans were rated as having no relative advantage or disadvantage.

Figure 10.21 Results for Top Tier Plans[19]



Customer Satisfaction – Plans B and P were judged to have a relative disadvantage due to risks to the accelerated need for gas-fired generation and risks to reliability if new generation is delayed. Plan P also reduces flexibility to take advantage of new clean resource technology development. The other plans were judged to have no relative advantage or disadvantage. While Plan A also results in a slight acceleration of coal generation retirement (i.e., Sioux Energy Center), the risks to reliability are not elevated as with Plan B.

Financial and Regulatory – Plans A, B, and P were judged to have a relative disadvantage given the acceleration of retirement for coal-fired energy centers and the resultant accelerated need for gas-fired generation. The potential implications of EPA's proposed rule for greenhouse gas emissions under Section 111 of the Clean Air Act weighs significantly in the consideration of regulatory risk since they affect not only coal-fired generation, but also new gas-fired generation. Should the proposed rule take effect in a form other than that proposed, or not take effect at all, this risk would be reconsidered. Plan O was judged to have no relative advantage or disadvantage. While Plan O carries regulatory risk associated with the licensing and permitting of new pumped hydro generation, the risk is far enough in the future as to not constitute a relative disadvantage. Should policy changes reduce the regulatory risk associated with licensing and permitting new pumped hydro generation, this risk would be reconsidered. Plan L was judged to have no relative advantage or disadvantage. Like Plans A, B, and P, Plan L carries some risk associated with accelerating gas-fired generation. However, this risk is far enough in

19 Plans include RAP-level DSM unless otherwise noted.

the future so as not to constitute a relative disadvantage. All other plans were judged to have no relative advantage or disadvantage.

Portfolio Transition – Plans L and M were judged to have no relative advantage or disadvantage since the alternative resources that differentiate them – simple cycle gas and pumped hydro – would not be expected to provide replacement energy for retiring coal. This could also result in the need to retain remaining coal-fired generation and/or operating coal and gas-fired generation at higher levels to meet energy needs. Because this risk is far in the future, this did not result in a finding that they exhibited a relative disadvantage. All other plans were judged to have a relative advantage in that they result in significant energy transition. It should be noted that changes in technology and other factors may diminish the relative advantages of various resources in the period 2040 and beyond. Ameren Missouri will continue to monitor such developments as part of its ongoing planning process.

Economic Development – Plan L was judged to have a relative advantage based on the jobs associated with pumped hydro resource construction. Plans B, O and P were judged to have a relative disadvantage based on the earlier elimination of jobs at coal-fired energy centers. Plan M was also judged to have a relative disadvantage due to the reduced labor intensity of simple cycle gas. All other plans were judged to have no relative advantage or disadvantage.

Along with these objectives, we have considered the costs and benefits of the specific components that define an integrated resource plan. These include consideration of DSM programs, the addition of renewable energy resources, and the retirement of existing generation resources, particularly coal-fired generation. These components define the transformation of our portfolio that we believe best achieves and balances the objectives discussed above.

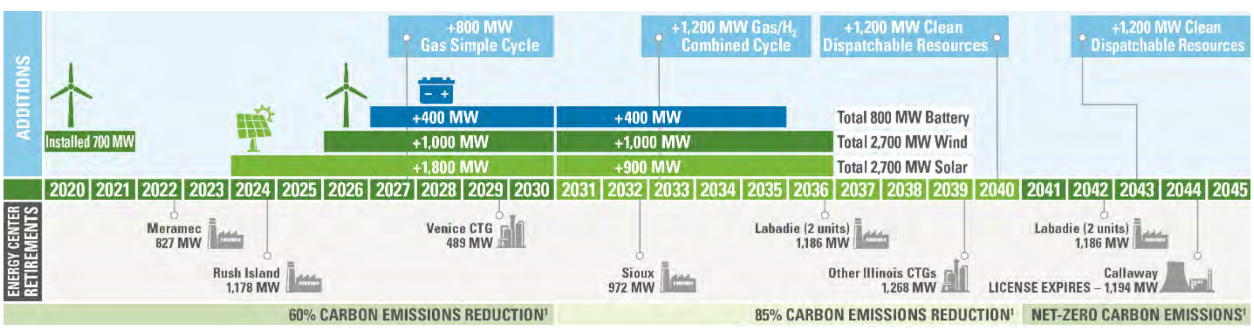
DSM Portfolio – Including energy efficiency and demand response based on RAP DSM potential in our preferred resource plan allows us to continue to offer highly cost-effective programs to customers at a reasonably aggressive level of annual spending while also allowing the potential for increased savings if our experience and expectations indicate they could be achieved in a cost-effective manner. Identifying such opportunities will depend on the results of program implementation and periodic updates of our market research.

Renewable Resources – One of Ameren Missouri's planning objectives is to transition our generation portfolio to one that is cleaner and more fuel diverse in a responsible fashion. For the reasons set forth in this chapter, we believe that the appropriate course of action is to continue the transition to greater levels of renewable energy today in a sustained and controlled manner. Doing so will address both near-term and long-term risks and ensure flexibility in the face of uncertainty and changing conditions. These could include changes in environmental regulations, coal generation economics, and changes in policy that require or can be satisfied by the addition of renewable energy resources.

Coal Retirements and Replacements – We evaluated various alternatives for earlier retirement of coal-fired generation as well as a delay of the retirement of Sioux Energy Center. Delaying the retirement of Sioux Energy Center to 2032 yields benefits in terms of customer costs while also addressing risks associated with potential policy changes and changes in market conditions that affect not only coal generation economics but also the economics and risk associated with replacement gas-fired generation. In particular, EPA's proposed GHG rule introduces risks associated with new gas fired generation, particularly non-peaking gas-fired generation. Making these changes now will ensure we can address recovery of the cost of these investments in way that is consistent with our objective to ensure affordability.

Based on our consideration of all these objectives and factors and consideration of the results of our thorough analysis of a wide range of options, we have selected Plan C as our preferred resource plan. Figure 10.22 shows the major resource additions and retirements defined by Plan C.

Figure 10.22 Preferred Resource Plan



10.4 Contingency Planning[20]

Because any assumptions about the future are subject to change, we must be prepared for changing circumstances by evaluating such potential circumstances and options for providing safe, reliable, cost-effective and environmentally responsible service to our customers. We have identified several cases which could significantly impact the performance of our preferred resource plan.

10.4.1 DSM Cost Recovery and Incentives

As stated previously, MEEIA provides for cost recovery and incentives for utility-sponsored demand-side programs to align utility incentives with helping customers to use

[20] 20 CSR 4240-22.070(4)

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energy more efficiently. In September 2023, the MPSC approved the third one-year extension of our third cycle of MEEIA programs and supporting cost recovery, and incentives. Our preferred resource plan is based on the expectation that supporting cost recovery and incentives will continue to be approved in the future. If such alignment is not achieved, it may be necessary for Ameren Missouri to change its preferred resource plan. We have therefore included a contingency plan, Plan W, for this circumstance.

Ameren Missouri expects to file an amended multi-year MEEIA 4 application with the MPSC for approval of a new portfolio of demand-side programs that would become effective starting in 2025. Costs are expected to be recovered through our Rider Energy Efficiency Investment Charge (Rider EEIC). In our request, we will also seek recovery of costs associated with the so-called “throughput disincentive.”

In addition to recovery of program costs and addressing the throughput disincentive, MEEIA also mandates that utilities be provided with timely earnings opportunities that serve to make investments in demand-side resources equivalent to investments in supply-side resources. Ameren Missouri will seek such incentives in its upcoming MEEIA filing.

10.4.2 Renewable Subscription Program

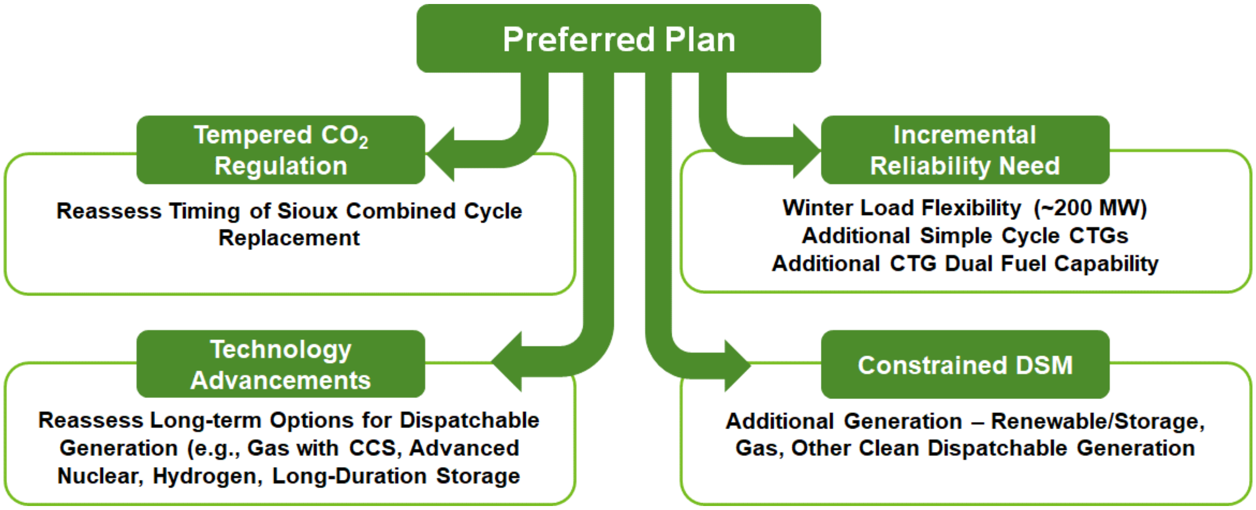
Our preferred plan includes our Renewable Solutions Program to offer commercial and industrial customers and communities the means by which they can source more of their electric energy needs from renewable resources. While further resources have not been designated for this program, some planned resources may be designated for the program in the future depending on customer demand and project economics.

10.5 Resource Acquisition Strategy[21]

Our resource acquisition strategy has three main components. First is the Preferred Resource Plan, which is discussed in more detail in Section 10.5.1. The second component of the resource acquisition strategy is contingency planning. Figure 10.23 shows the contingency options the Company has considered and the events that could lead to a change in our preferred plan. The final component of the resource acquisition strategy is the implementation plan, which includes details of major actions over the next three years, 2024-2026.

[21] 20 CSR 4240-22.070(1); 20 CSR 4240-22.070(1)(A) through (D); 20 CSR 4240-22.070(2); 20 CSR 4240-22.070(4); 20 CSR 4240-22.070(4)(A) through (C); 20 CSR 4240-22.070(7); 20 CSR 4240-22.070(7)(A) through (C)

Figure 10.23 Contingency Options



10.5.1 Preferred Plan

As discussed in Section 10.3, our Preferred Resource Plan includes energy efficiency programs based on the RAP portfolio potential discussed in Chapter 8, 4,700 MW of wind and solar generation by 2036, 800 MW of battery storage by 2035, retirement of the Fairgrounds, Mexico, Moberly, Moreau and Venice Energy Centers by the end of 2029, retirement of Rush Island Energy Center by the end of 2024, retirement of Sioux Energy Center by the end of 2032, retirement of two of the four units at Labadie Energy Center by the end of 2036, retirement of the remaining CTG energy centers in Illinois by the end of 2039, and retirement of the remaining two units at Labadie Energy Center at the end of 2042. It also includes the addition of 800 MW of simple cycle gas generation by the end of 2027, 1,200 MW of combined cycle gas generation by the end of 2032, and 1,200 MW of clean dispatchable resources in each of 2040 and 2043.

Demand-Side Resources

The preferred plan includes energy efficiency and demand response programs based on the RAP portfolio potential discussed in Chapter 8. Program spending for the 20-year planning horizon (after the current cycle of MEEIA programs) is approximately $2.5 billion. Cumulative peak demand reductions approaching 1,600 MW by 2043 (not including planning reserve margin), and cumulative annual energy savings (at the customer meter) over 4.1 million MWh.

Renewables and Storage

We are continuing a transformation of our generation portfolio, and one of the key components of that transition is the continued significant expansion of renewable wind and solar generation resources, with a total of 4,700 MW of new wind and solar generation by 2036 and 2,800MW by 2030, and the addition of 400 MW of battery storage by 2030 and another 400 MW by 2034. As discussed earlier in this chapter, these renewable

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energy resources will be necessary to ensure the energy supply that our customers need and do so in a way that is environmentally responsible and ensures affordability for our customers. Battery storage resources, along with other dispatchable resources in our fleet, will partner with these renewable resources to ensure reliable energy supply during and after the transition of our portfolio.

Supply-Side Resources

The Preferred Resource Plan calls for the retirement of Rush Island by the end of 2024, retirement of Sioux Energy Center by the end of 2032, retirement of two of the four units at Labadie Energy Center by the end of 2036, and retirement of the remaining units at Labadie Energy Center by the end of 2042. It also calls for the retirement of four older oil-fired CTGs and the gas-fired Venice Energy Center by the end of 2029 and the remaining Illinois gas-fired units at the Goose Creek, Racoon Creek, Pinckneyville and Kinmundy Energy Centers by the end of 2039. To ensure sufficient dispatchable resources to partner with the above-mentioned renewable and storage resources, we also plan to add 800 MW of gas-fired simple cycle combustion turbine generation by the end of 2027, 1,200 MW of gas-fired combined cycle generation by the end of 2032, and 1,200 MW of additional clean dispatchable generation in each of 2040 and 2043.

10.5.2 Contingency Plans[22]

Figure 10.5 presents our key contingency options. In the event that Ameren Missouri's interests are not aligned with helping customers use energy more efficiently, as required by MEEIA, we have included a contingency option that reflects a discontinuation of demand side programs after our current MEEIA cycle programs expire. The contingency option therefore also includes the installation of an additional 1,200 MW of combined cycle gas generation in 2028 and another 1,200 MW of clean dispatchable generation in 2043. Should the EPA's current proposed regulation of CO_2 take effect in a different form or not take effect at all, the Company may reevaluate the timing of the retirement of its Sioux Energy Center and the planned addition of combined cycle gas replacement generation. Should the development of clean dispatchable resource technologies advance more quickly or result in resource options that provide a more favorable combination of reliability and affordability, Ameren Missouri will reevaluate its planned generation additions. This could also include further consideration of simple cycle gas generation and/or pumped hydro energy storage resource, which scored well in our assessment of alternative plans. Should additional resources be needed for ensuring reliability, the Company will reassess the role of additional load flexibility resources.

[22] 20 CSR 4240-22.070(4)

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10.5.3 Expected Value of Better Information

After selecting the preferred plan, Ameren Missouri conducted an expected value of better information (EVBI) analysis to assess the performance of its preferred resource plan under the range of values defined for the critical uncertain factors and to inform its on-going research and implementation activities. Table 10.4 displays the results of the EVBI analysis as measured by PVRR. Under most critical uncertain factor values, the preferred plan results in the lowest PVRR. Plan M results in the lowest PVRR under certain values for critical uncertain factors – low CO_2 prices, low or base gas prices, and high project costs. Because the difference between the preferred plan and Plan M is the addition of simple cycle gas in 2040 instead of the placeholder clean dispatchable resource, incurring additional expenditures for the better information needed is not expected to resolve that choice. Instead, we have time to monitor conditions and engage in continued planning analysis until a decision must be made. For all other values of critical uncertain factors, Plan T results in the lowest PVRR. For the reasons discussed in Section 10.3, Plan T is not considered to be a feasible or desirable path. As a result, procuring better information, regardless of the cost, would not bear on plan selection.

Table 10.4 EVBI Analysis Results

Alternative Resource Plans		PVRR Without Better Info	Carbon Price			Natural Gas Price			Load Growth			Project Cost		
			Low	Base	High	Low	Base	High	Low	Base	High	Low	Base	High
A	Sioux Retired 2030	82,002	81,799	81,953	82,241	81,358	81,821	82,388	80,603	82,040	83,286	80,434	81,922	84,209
B	Sioux Retired 2028	82,003	81,839	81,955	82,215	81,341	81,810	82,409	80,604	82,041	83,287	80,416	81,923	84,226
C	RAP - Renewable Expansion	81,985	81,748	81,937	82,243	81,353	81,814	82,356	80,586	82,023	83,269	80,434	81,905	84,178
D	Labadie SCR	82,668	82,426	82,619	82,931	82,041	82,499	83,037	81,269	82,707	83,953	81,008	82,581	85,025
E	MAP	82,680	82,541	82,633	82,879	82,027	82,512	83,054	81,281	82,719	83,965	81,129	82,600	84,873
F	RAP-RES Compliance	83,807	83,344	83,711	84,314	82,537	83,439	84,583	82,407	83,845	85,091	82,129	83,724	86,147
G	MAP-RES Compliance	84,087	83,657	84,023	84,499	82,861	83,750	84,815	82,688	84,125	85,371	82,514	83,991	86,429
H	MAP LF-RES Compliance	82,080	81,352	81,933	82,870	80,960	81,791	82,721	80,681	82,118	83,364	80,814	82,012	83,891
I	No Additional DSM	86,656	86,718	86,690	86,537	85,707	86,344	87,283	85,257	86,694	87,940	84,487	86,543	89,725
J	No Additional DSM-RES Compliance	87,002	86,618	86,972	87,305	85,573	86,554	87,919	85,603	87,041	88,286	84,961	86,891	89,932
K	Renewables for Capacity Need	82,721	82,248	82,658	83,157	81,894	82,516	83,184	81,322	82,759	84,005	81,178	82,634	84,964
L	Pumped Hydro w/ MAP LF	81,238	80,819	81,118	81,778	80,648	81,100	81,559	79,839	81,277	82,522	79,803	81,181	83,135
M	SC	80,907	80,448	80,777	81,493	80,296	80,756	81,248	79,508	80,945	82,191	79,507	80,849	82,768
N	SMR w/ RAP LF	84,840	84,584	84,775	85,148	84,442	84,762	85,037	83,440	84,878	86,124	82,784	84,714	87,903
O	Labadie 2039	82,356	82,226	82,331	82,495	81,693	82,167	82,759	80,957	82,394	83,640	80,759	82,271	84,634
P	Labadie 2036	82,848	82,853	82,852	82,837	82,137	82,633	83,294	81,449	82,886	84,132	81,199	82,757	85,226
Q	Labadie 2031	83,758	83,985	83,767	83,599	82,923	83,468	84,330	82,359	83,796	85,042	81,978	83,689	86,093
R	RAP LF	82,067	81,834	82,016	82,331	81,421	81,894	82,445	80,668	82,106	83,352	80,516	81,987	84,260
S	MAP LF	82,813	82,679	82,760	83,020	82,136	82,641	83,197	81,414	82,851	84,097	81,262	82,733	85,006
T	All Renewables	80,808	80,816	80,767	80,901	80,945	80,953	80,592	79,409	80,846	82,092	78,895	80,708	83,516
U	SC instead of First CC	82,020	81,507	81,892	82,635	81,404	81,887	82,341	80,621	82,058	83,304	80,367	81,907	84,576
V	CCS on 1st CC	82,963	82,725	82,916	83,219	82,336	82,794	83,331	81,564	83,001	84,247	81,254	82,869	85,430
W	RAP 80%	83,749	83,680	83,756	83,773	83,008	83,534	84,202	82,350	83,787	85,033	81,967	83,648	86,340
Minimum PVRR among plans			80,448	80,767	80,901	80,296	80,756	80,592	79,409	80,846	82,092	78,895	80,708	82,768
Plan with Minimum PVRR			M	T	T	M	M	T	T	T	T	T	T	M
Subjective Probability			15%	60%	25%	10%	50%	40%	20%	60%	20%	10%	80%	10%
Expected Value of Better Info			1,300	1,170	1,342	1,057	1,059	1,764	1,177	1,177	1,177	1,539	1,196	1,410

10.5.4 Implementation Plan[23]

As mentioned earlier, the implementation plan outlines the major activities to be completed during the next three years, 2024-2026. Below is a description of those major activities.

Demand-Side Resources Implementation

Ameren Missouri continues to implement its third cycle of approved MEEIA programs, which run through 2024. Ameren Missouri expects to file an updated multi-year MEEIA 4 application with the MPSC in the first quarter 2024 for approval of demand-side programs and associated cost recovery and incentive mechanisms to be implemented beginning in 2025. Such a proposal will be consistent with the preferred resource plan which includes the RAP portfolio.

Renewables

Our preferred resource plan includes the addition of 2,800 MW of new wind and solar generation by the end of 2030. Ameren Missouri will be engaging in activities during the implementation period to support the development of the new wind and solar generation, including bid solicitation, contractor selection, applying for certificates of convenience and necessity, and construction. A new request for proposal process for wind resources will be initiated by the first quarter of 2024. CCN applications are currently before the MPSC for four solar projects totaling 550 MW. Additional solar project CCN applications are expected to be filed with the MPSC in the second quarter of 2024. Concurrently, Ameren Missouri continues with implementation of the Huck Finn solar project to satisfy RES requirements and the Boomtown solar project to support the Company's Renewable Solutions program, with each resource also contributing to meeting the Company's energy and capacity needs apart from the RES or the Renewable Solutions Program. Both projects were granted CCNs by the MPSC earlier in 2023, and the Renewable Solutions program was approved in that same timeframe.

New Simple Cycle Gas Generation

Our preferred resource plan includes the addition of 800 MW of simple cycle CTG generation with dual fuel (natural gas and oil) capability by the end of 2027 to provide periodic generation during times of peak demand or when wind and solar generation are diminished. The Company will be taking steps to implement this new dispatchable resource starting in 2023 and over the next few years. These include site selection, permitting, engineering, and procurement, as well as steps to secure interconnection within MISO. The Company expects to seek approval by the MPSC for a CCN for this resource sometime in 2024.

[23] 20 CSR 4240-22.070(6); 20 CSR 4240-22.070(6)(A) through (D)

New Combined Cycle Gas Generation

Our preferred resource plan also includes the addition of 1,200 MW of natural gas-fired combined cycle generation by the end of 2032 to replace the existing coal-fired generation at the Sioux Energy Center. The Company will begin taking steps to implement this new dispatchable resource over the next few years. These include site selection, permitting, engineering, and procurement, as well as steps to secure interconnection within MISO.

Rush Island and Sioux

Ameren Missouri will be taking steps to retire the units at Rush Island Energy Center by the end of 2024, including construction of new transmission facilities to ensure grid reliability. Ameren Missouri continues to operate the units at Rush Island pursuant to an SSR agreement with MISO until the units are retired. While the retirement of Sioux Energy Center has been delayed to 2032, the Company will continue to prepare for its retirement and thereby maintain flexibility to further revised retirement plans in the event conditions warrant a review of the current plans and Ameren Missouri management decides it is appropriate to make a change.

Competitive Procurement Policies[24]

Ameren Missouri assigns a Project Manager to lead the activities necessary to ensure the successful completion of its acquisition and development of supply-side resources. In general, a project team comprised of a Project Manager and various lead engineers will identify all items to be procured and will coordinate with the Strategic Sourcing and Purchasing departments within Ameren to ensure proper contract structures are considered and used for each procurement activity. A Contract Development Team (CDT) is assembled and assists in collecting material and labor estimates based on the overall project design. Strategic Sourcing, CDT and the project team work to set up a number of components as Ameren stock items that are the basis for ordering materials. A detailed procurement matrix is developed to identify the major purchases that are anticipated to be required as part of the project. Projects make use of stock items where appropriate. Where material has not been established as a stock item, the CDT determines potential vendors, collects quotes, and scores the potential vendor to make the best selection. Ameren Missouri will be following Ameren’s Project Oversight Process, which is provided in Appendix C, for monitoring the progress of projects that fulfill its Preferred Resource Plan.[25]

[24] 20 CSR 4240-22.070(6)(E)
[25] 20 CSR 4240-22.070(6)(G)

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10.5.5 Monitoring Critical Uncertain Factors[26]

Ameren Missouri will be monitoring the critical uncertain factors that would help determine whether the Preferred Resource Plan is still appropriate and whether contingency options should be pursued. Below is a description of how Company decision makers will be monitoring the factors most relevant to future resource decisions.

Climate Policy

Ameren Missouri senior management and its Environmental Services organization will continue to monitor and evaluate developments on efforts to regulate greenhouse gas emissions, including EPA's current proposed rule, as well as state and industry efforts aimed at reducing greenhouse gas emissions. The Company reviews its assumptions for climate policy and CO_2 prices as part of its IRP annual update process.

Natural Gas Prices

Ameren Missouri evaluates natural gas prices at least annually, and a review of natural gas price assumptions is included as part of its IRP annual update process.

Generation Project Costs

Ameren Missouri will continue to monitor project pricing for various resources through industry sources and through its own resource acquisition activities, such as RFPs and competitive bidding. This includes wind, solar, storage, and natural gas-fired resources (both simple cycle and combined cycle) as well as environmental controls such as SCRs, and carbon capture and sequestration. Evaluation of project costs will continue to be included as part of the Company's IRP annual update process.

[26] 20 CSR 4240-22.070(6)(F)

10.6 Compliance References

2023 OMS-MISO Survey Results

Furthering our joint commitment to regional resource adequacy, OMS and MISO are pleased to announce the results of the 2023 OMS-MISO Survey

July 14, 2023

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Results of the 2023 OMS-MISO survey reinforce the need for continued reforms to MISO's resource adequacy construct to reliably manage portfolio transition

- Survey responses reflect market actions such as delayed retirements and capacity additions resulting in 1.5 GW of residual capacity for Planning Year (PY) 2024/25.
- Without continuation of such actions, a capacity deficit of 2.1 GW is projected for the summer of 2025/26 which grows in subsequent years.
- Non-summer seasons indicate sufficient, yet declining capacity over the survey horizon.
- The North/Central subregion shows potential capacity deficits starting in summer of PY 2025/26, while the South subregion shows increasing tightness and a potential deficit starting in winter 2027/28.
- Demand growth is projected to continue for five years across all four seasons at 0.8 GW or 0.68% per year on average.

All presentation references to capacity indicate seasonal accredited capacity (SAC)

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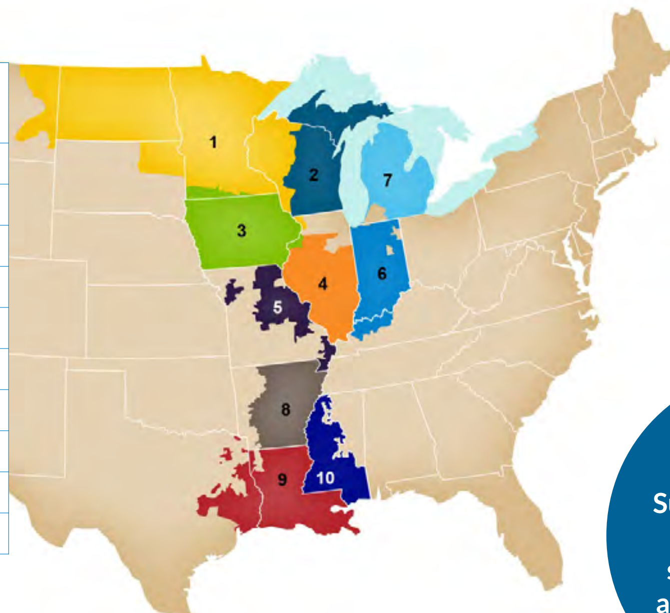
The OMS-MISO Survey provides a resource adequacy view over a five-year horizon based on currently available information

Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME



2023 OMS-MISO Survey incorporates MISO's new seasonal resource adequacy construct

Schedule MM-S33

The survey uses different categories to characterize relative levels of resource certainty

Committed Capacity

- Consists of installed generation resources and projects with interconnection agreements with commercial operation dates expected during survey horizon.*
- Survey assumes that these resources will be used to meet the Planning Reserve Margin Requirement (PRMR) in the zone and region they are physically located.

Signed GIA Capacity- Alternative estimate

- Consists of projects with signed interconnection agreements with commercial operation dates expected during survey horizon.
- Cumulative capacity added from signed GIA projects assumed to be 2.5 GW/year based on historical trend of 2-3 GW energized annually.

Potentially Unavailable Resources

- Consists of installed generation resources with unclear commitment to MISO.
- Survey assumes that these resources will NOT be used to meet the PRMR.

Potential New Capacity

- Consists of projects in MISO's generation interconnection queue that do not have a GIA, with capacity weighted to reflect progress through the queue*

* Descriptions of Resource Categories and Queue Treatment provided on slides 18-19

External factors can impact projected deficits or surpluses that are observed in the survey

Upside Possibilities

- Lower than expected load growth
- Sustained market responses from 2022 Planning Resource Auction (PRA)
  - Deferred retirements and return to service of suspended resources
  - Additional External Resources
  - Additional LMR registrations
- Higher accreditation due to improved availability and performance in times of need
- Continued queue improvements
- Easing of supply chain bottlenecks enabling substantial new capacity
- Lower planning reserve margins than currently projected

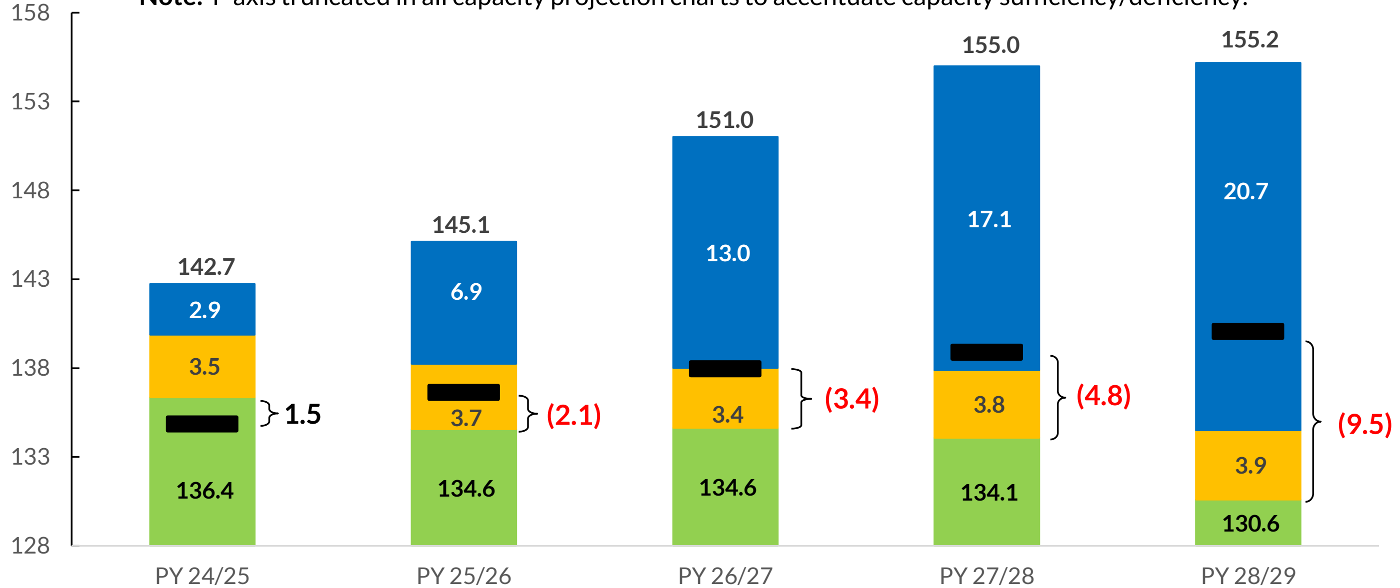
Schedule MM-S33

Committed Capacity shows declines over survey window with potential resource deficits starting in PY 2025/26

Summer Seasonal Accredited Capacity Projections (GW)

2023 OMS-MISO Survey

Note: Y-axis truncated in all capacity projection charts to accentuate capacity sufficiency/deficiency.



Projected Planning Reserve Margin (PRM)

- Committed Capacity
- Potentially Unavailable Resources
- Potential New Capacity
- Projected PRMR

Bracketed values indicate difference between Committed Capacity and projected PRMR.
Committed Capacity includes signed GIA projects shown on slide 19.
Capacity accreditation values and PRM projections based on current practices.
Timing/GW of potential New Capacity projected per methodology noted in Oct 2022 RASC.
Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

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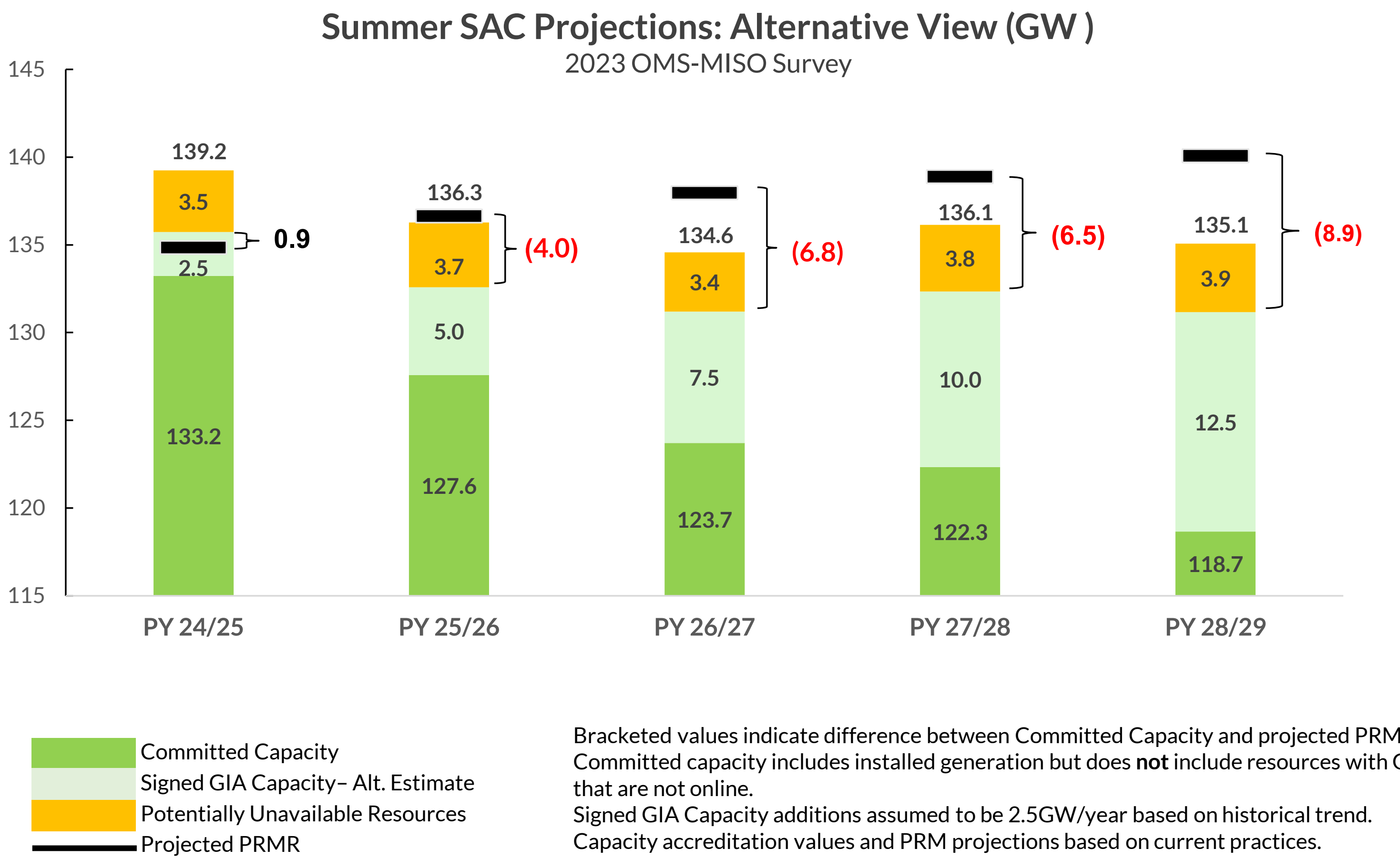
Schedule MM-S33

Alternative capacity projections based on historical additions of 2.5 GW/year indicate higher resource adequacy risk from PY 2025/26

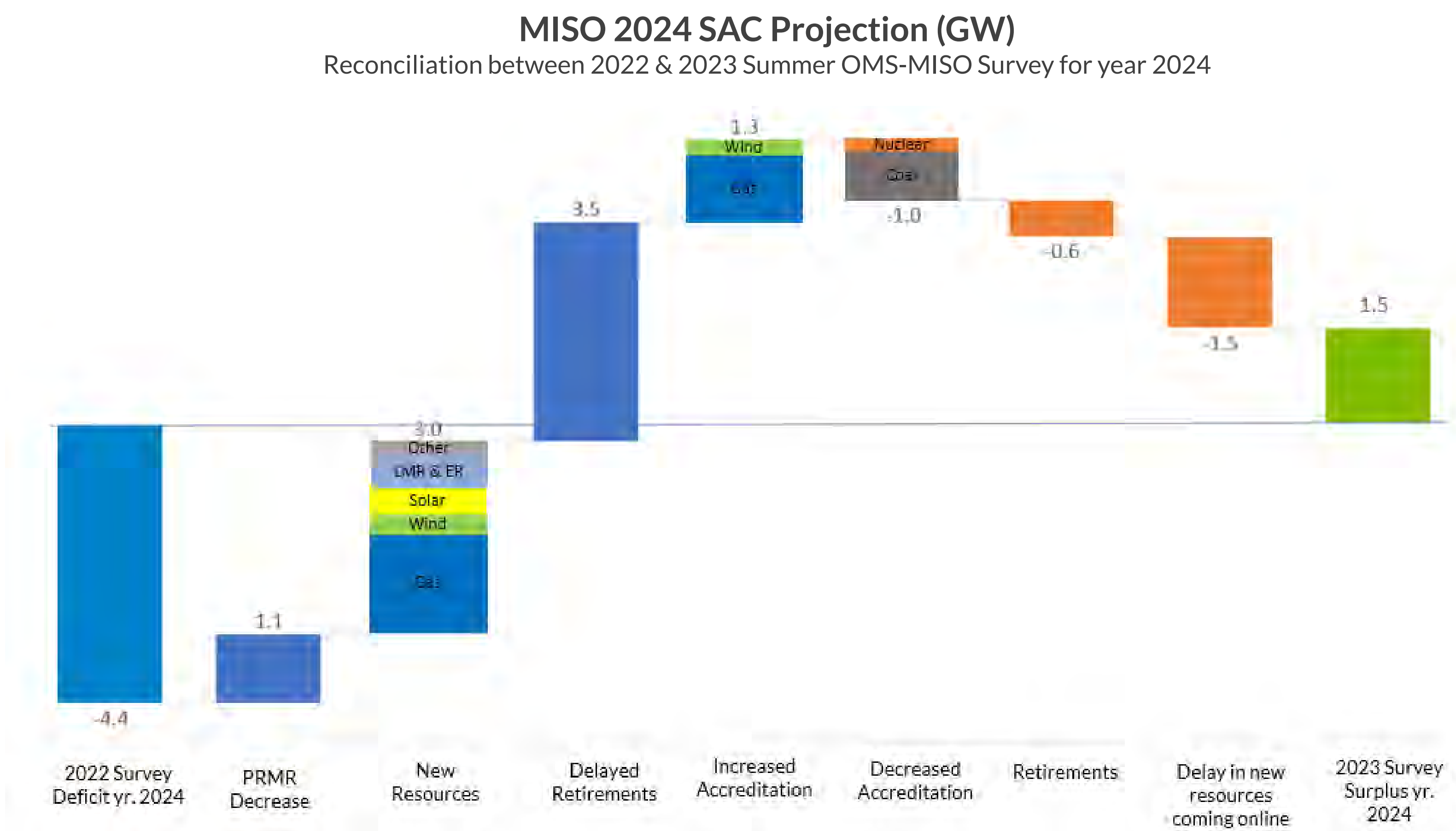


Bracketed values indicate difference between Committed Capacity and projected PRMR.
Committed capacity includes installed generation but does **not** include resources with GIA that are not online.
Signed GIA Capacity additions assumed to be 2.5GW/year based on historical trend.
Capacity accreditation values and PRM projections based on current practices.

PRM - Planning Reserve Margin (%); PRMR – Planning Reserve Margin Requirement (GW)
RDT limit of 1900 MW is reflected in this chart

Schedule MM-S33

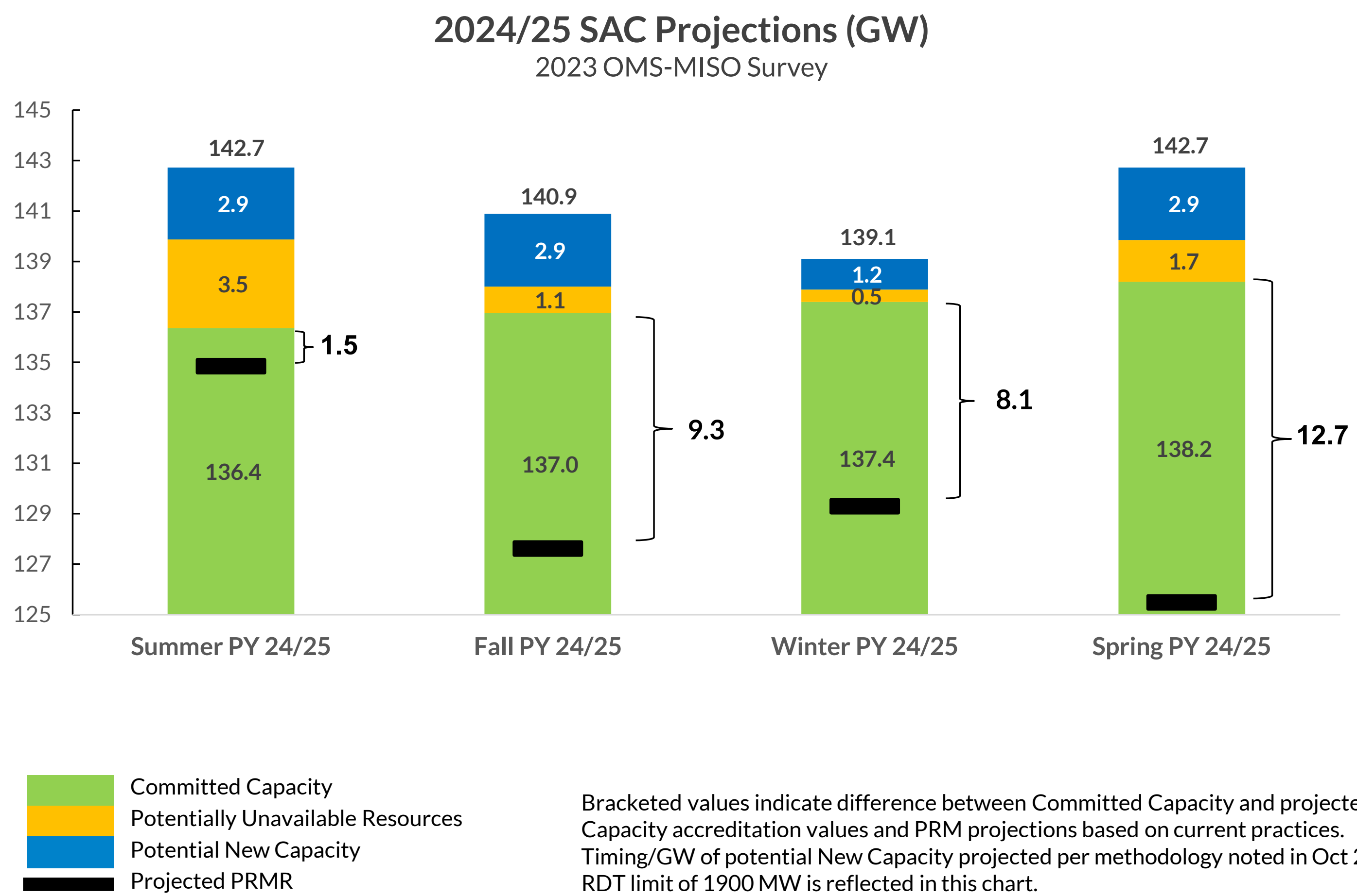
Year-over-year survey results for 2024 show a change from deficit to adequate supply due to delayed retirements, new resources and lower load forecast



Lower load forecast noted under 'PRMR decrease'

Schedule MM-S33

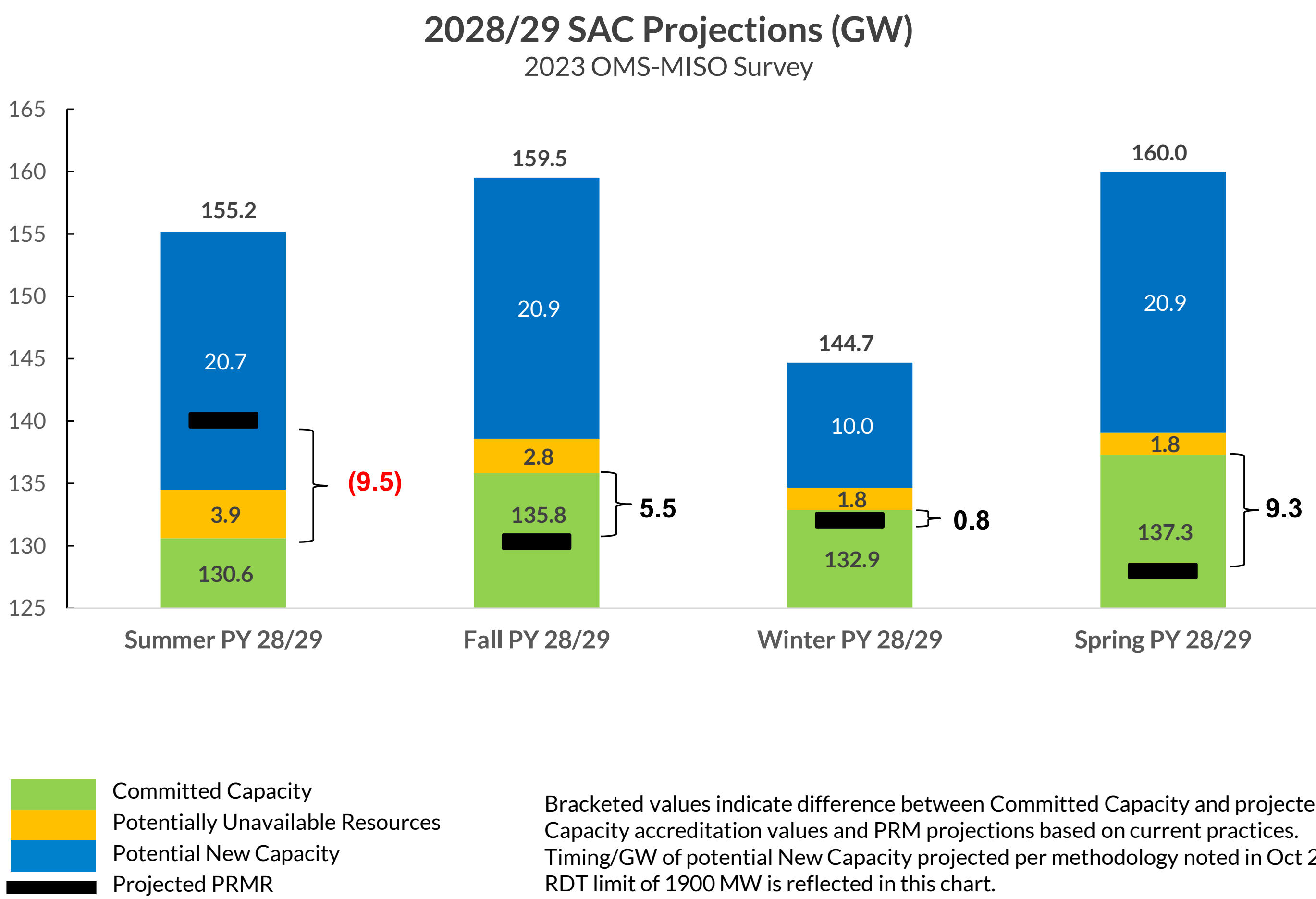
2024/2025 seasonal projections show adequate margins with summer having the tightest margins



Bracketed values indicate difference between Committed Capacity and projected PRMR.
Capacity accreditation values and PRM projections based on current practices.
Timing/GW of potential New Capacity projected per methodology noted in Oct 2022 RASC.
RDT limit of 1900 MW is reflected in this chart.

Schedule MM-S33

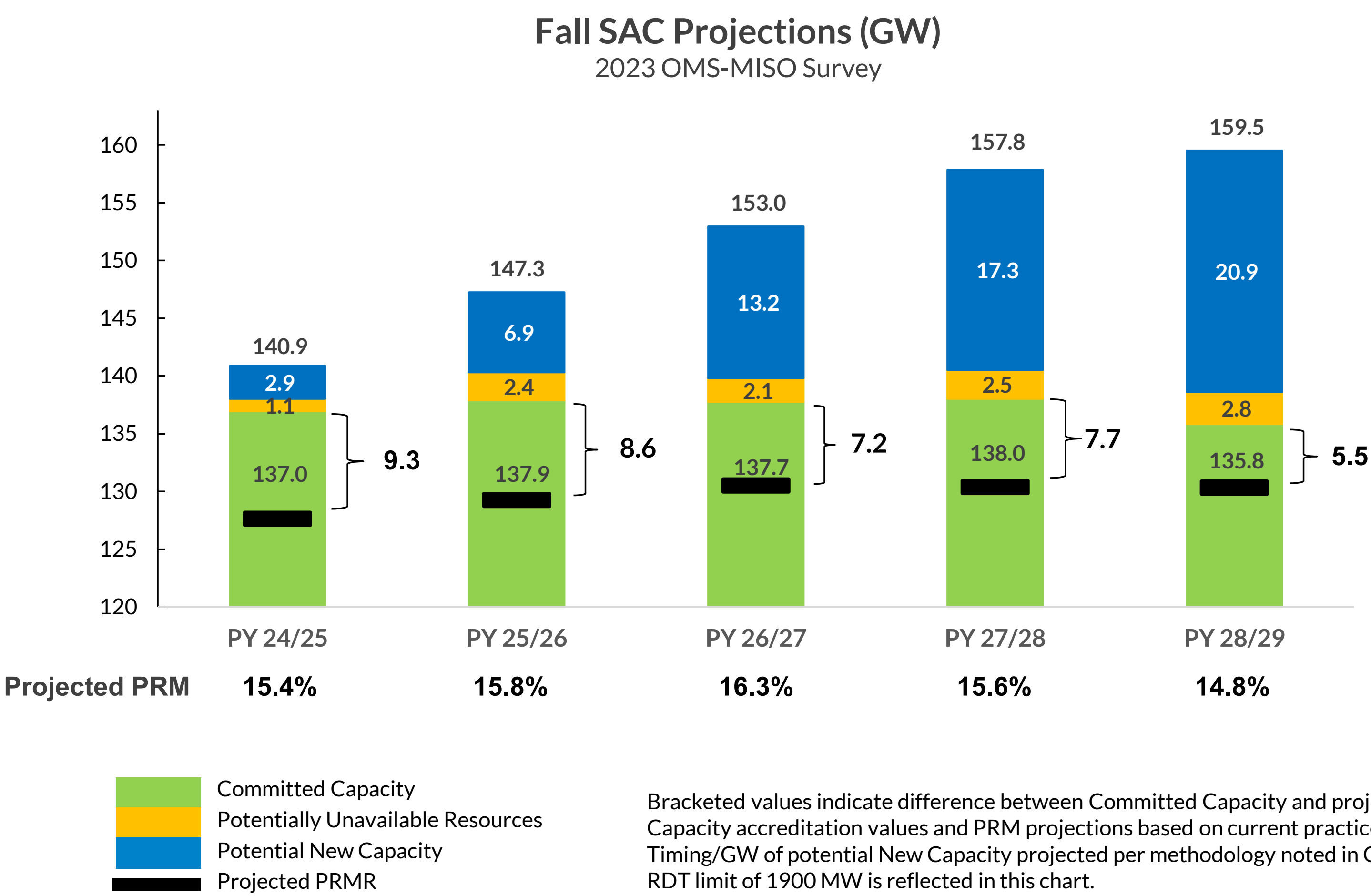
2028/2029 projections show tighter conditions and increased reliance on new resources to meet PRMR



Bracketed values indicate difference between Committed Capacity and projected PRMR.
Capacity accreditation values and PRM projections based on current practices.
Timing/GW of potential New Capacity projected per methodology noted in Oct 2022 RASC.
RDT limit of 1900 MW is reflected in this chart.

Schedule MM-S33

Fall season projections indicate sufficient capacity but show decrease in committed capacity in future years



Bracketed values indicate difference between Committed Capacity and projected PRMR.
Capacity accreditation values and PRM projections based on current practices.
Timing/GW of potential New Capacity projected per methodology noted in Oct 2022 RASC.
RDT limit of 1900 MW is reflected in this chart.

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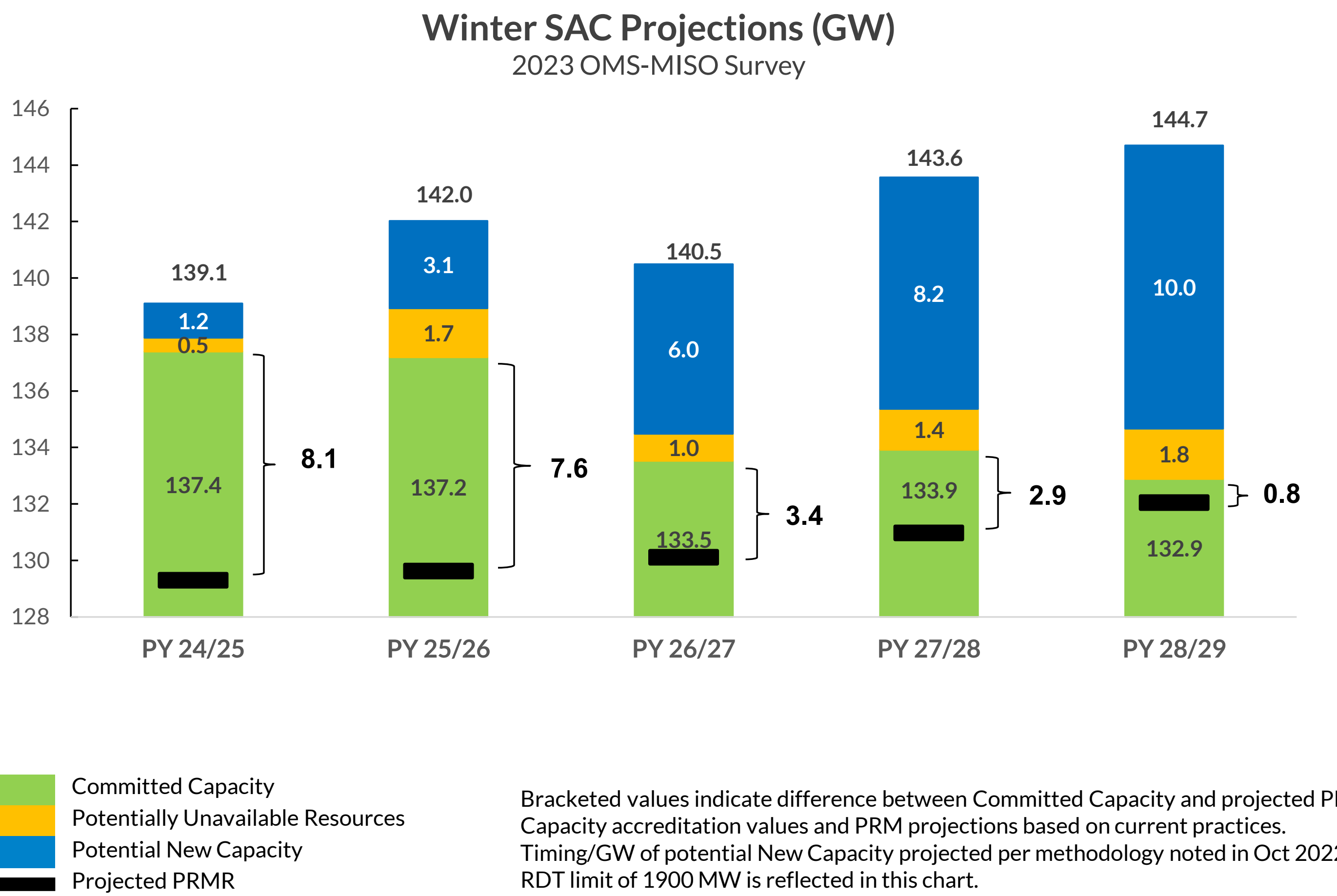
Winter season projections indicate sufficient capacity in the near term but tight conditions by PY2028/29



Bracketed values indicate difference between Committed Capacity and projected PRMR.
Capacity accreditation values and PRM projections based on current practices.
Timing/GW of potential New Capacity projected per methodology noted in Oct 2022 RASC.
RDT limit of 1900 MW is reflected in this chart.

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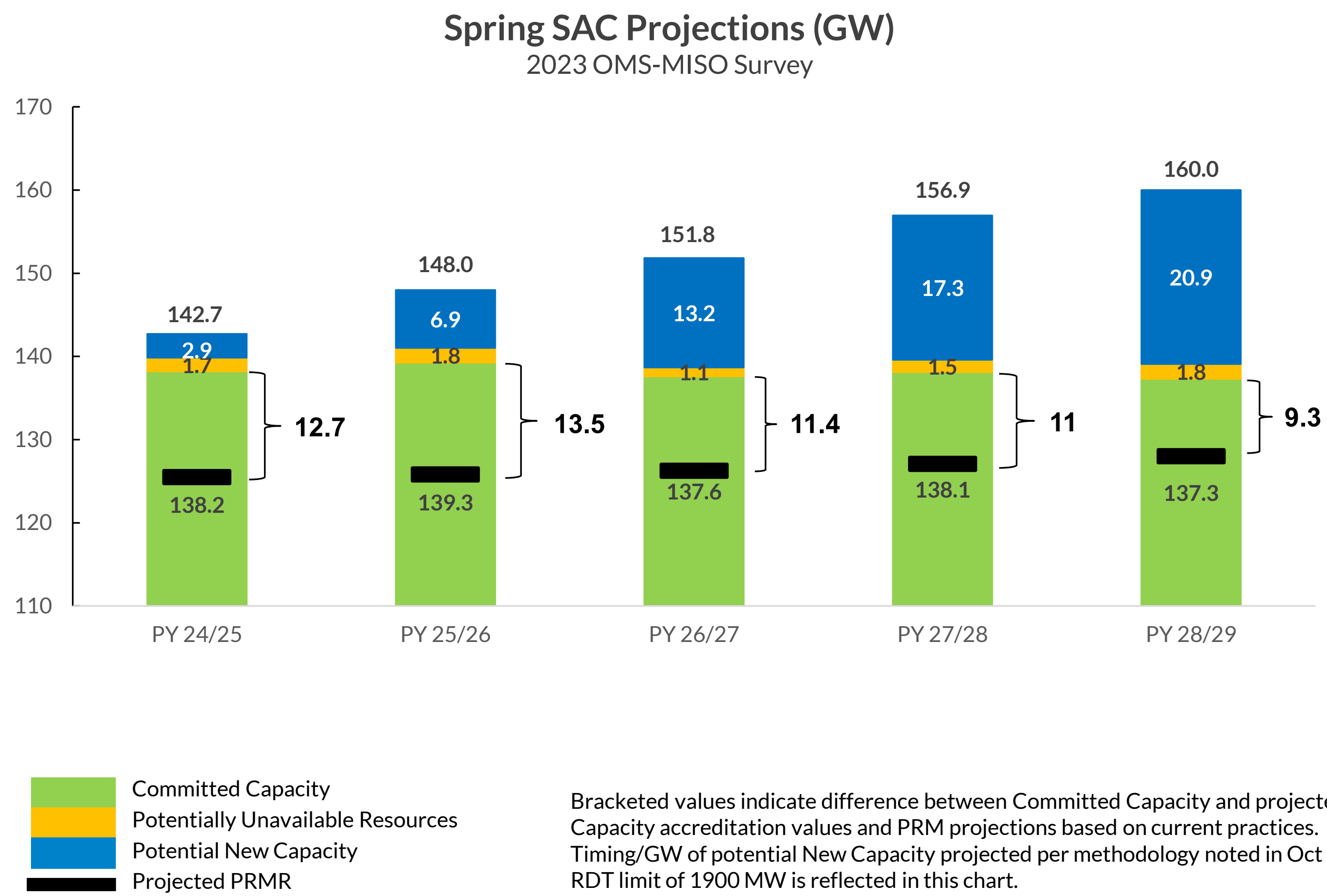
Schedule MM-S33

Spring season projections indicate sufficient capacity over the survey horizon

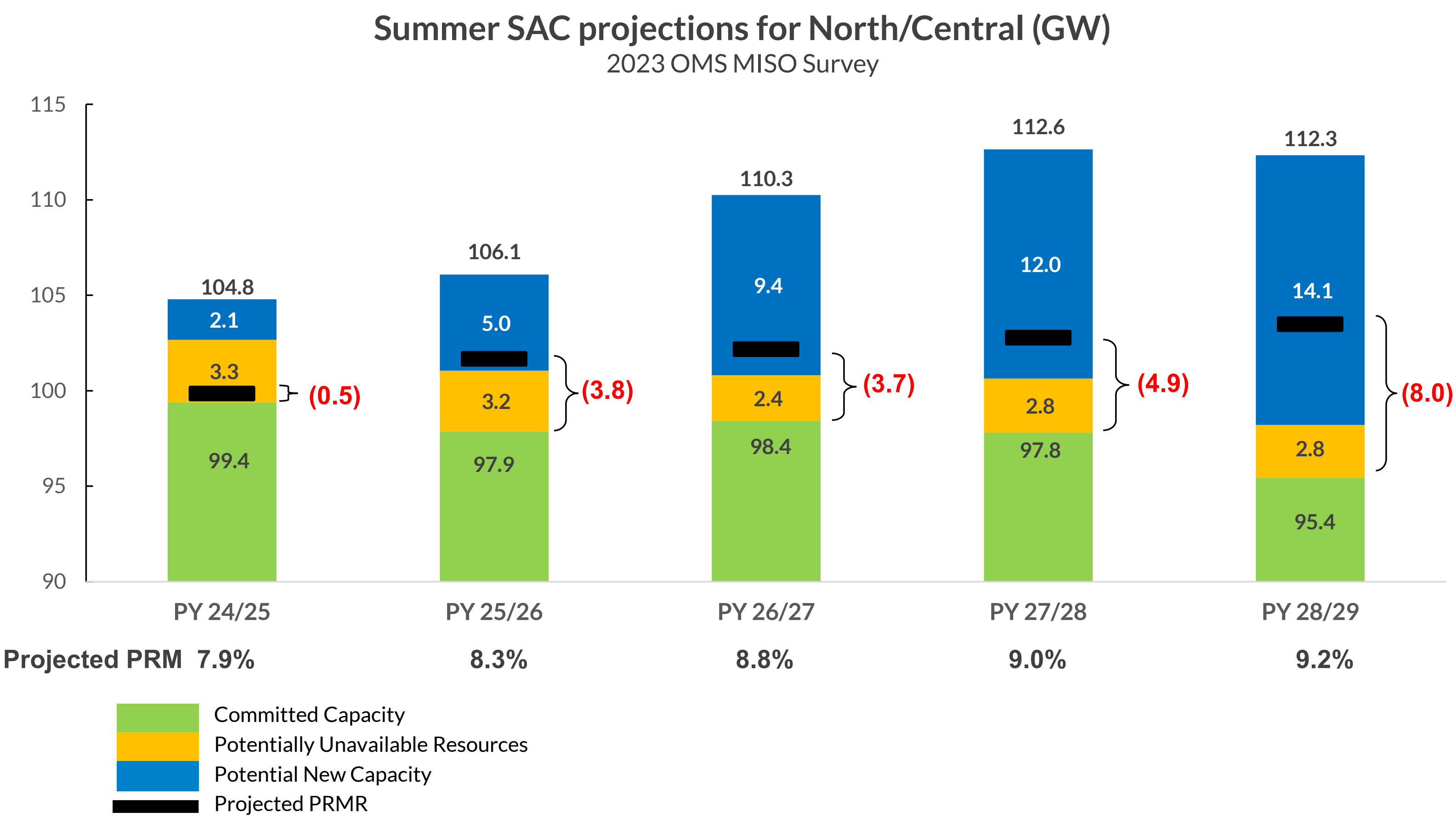


Bracketed values indicate difference between Committed Capacity and projected PRMR.
Capacity accreditation values and PRM projections based on current practices.
Timing/GW of potential New Capacity projected per methodology noted in Oct 2022 RASC.
RDT limit of 1900 MW is reflected in this chart.

Spring demand and therefore PRMR is calculated by using Winter demand forecast percent change seen year over year since out year NCPF is not submitted for out years for Fall and Spring.

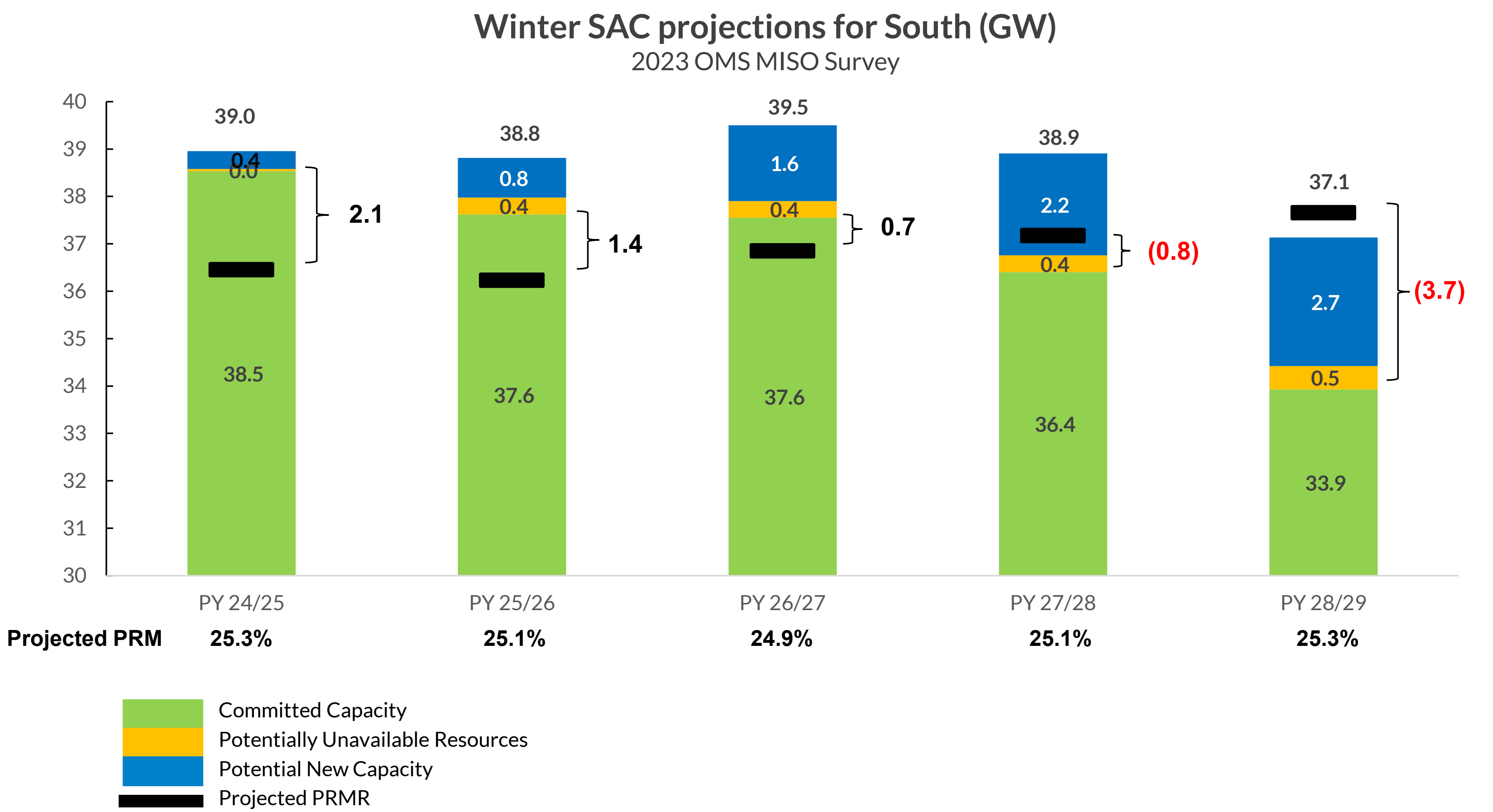
Schedule MM-S33

Sub-regional projections show an increasing gap in summer in North/Central and…



Schedule MM-S33

… a similar outcome in Winter for South



Schedule MM-S33

Appendix

Understanding Resource Categories

- **Committed Capacity** - resources committed to serving MISO load
  - Resources within MISO utilities' rate base
  - External resources with firm contracts to MISO load
  - Non-rate base units without announced retirements or commitments to non-MISO load
  - New generators with signed interconnection agreements not yet in service
- **Potentially Unavailable Resources** - resources that may be available to serve MISO load but may not have firm commitments to do so
  - Indicated as Low Certainty in survey results by Market Participants
  - Includes potential retirements or suspensions
- **Potential New Capacity** – New projects in the MISO Generator Interconnection Queue accredited at the current (2022) new resource capacity credit levels and adjusted for projected queue certainty factors
- **Unavailable resources** are not included in the survey totals
  - Resources with firm commitments to non-MISO load
  - Resources with finalized retirements or suspensions
  - Potential new generation which are not currently in the MISO Generator Interconnection Queue

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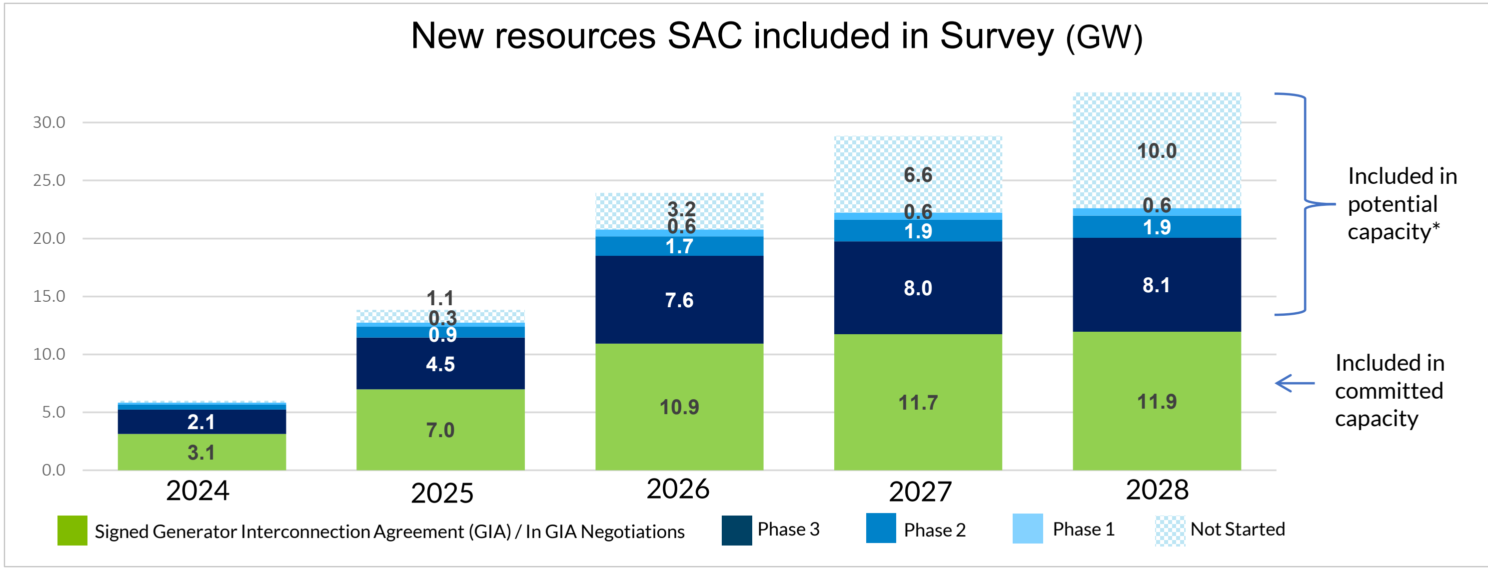
2023 OMS-MISO Survey Queue Treatment

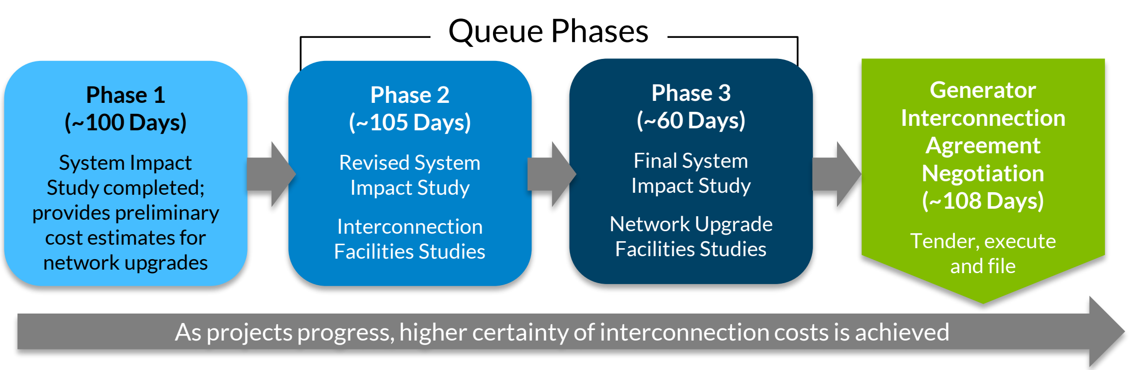
Apply Capacity Credit	Apply DPP Study Phase Weighting	Capacity Assumptions for Pre-GIA Projects*	Capacity Assumptions for Post-GIA Projects*
Wind: Summer 18.1% Fall 23.1 Winter 40.3% Spring 23%	Not Started and Phase 1= 10%	30% in COD + 1 year	80% in COD + 1 year
Solar: Winter 5% All other seasons 50%	Phase 2 = 75% Non-Intermittent, 50% Intermittent	30% in COD + 2 years	15% in COD + 2 years
Hybrid : Winter 15% All other seasons 60%	GIA in Progress and Phase 3 = 90%	40% in COD + 3 years	5% in COD + 3 years
ESR: 95% for all seasons			
All other 100%			

*Assumptions were discussed at the October 2022 RASC and are repeated here for reference.

Schedule MM-S33

Future summer resource ranges will shift as planned generation interconnections are firmed up

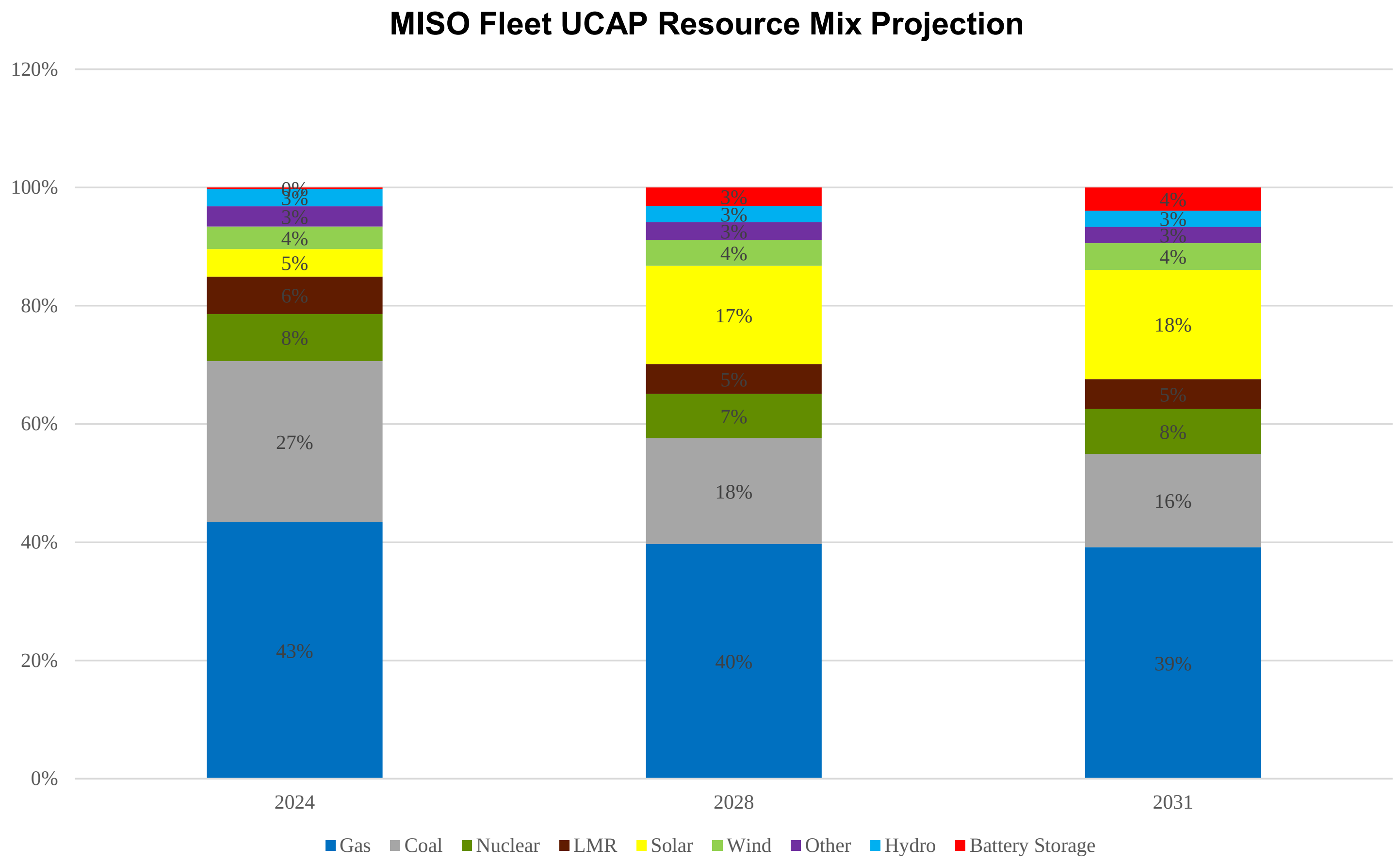




"Potential capacity" values shown here do not factor in RDT limitations.

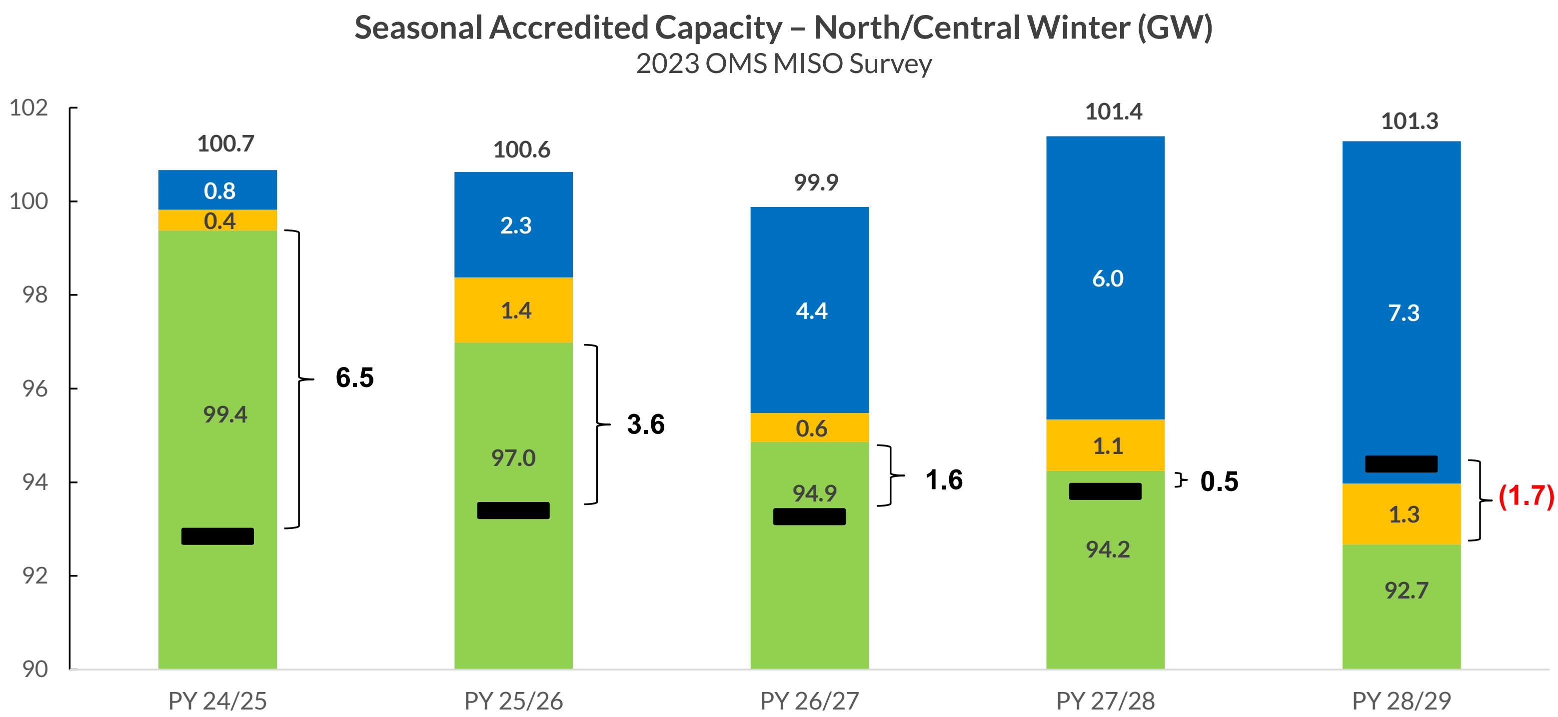
Schedule MM-S33

Interconnection Queue shows a significant increase in solar penetration



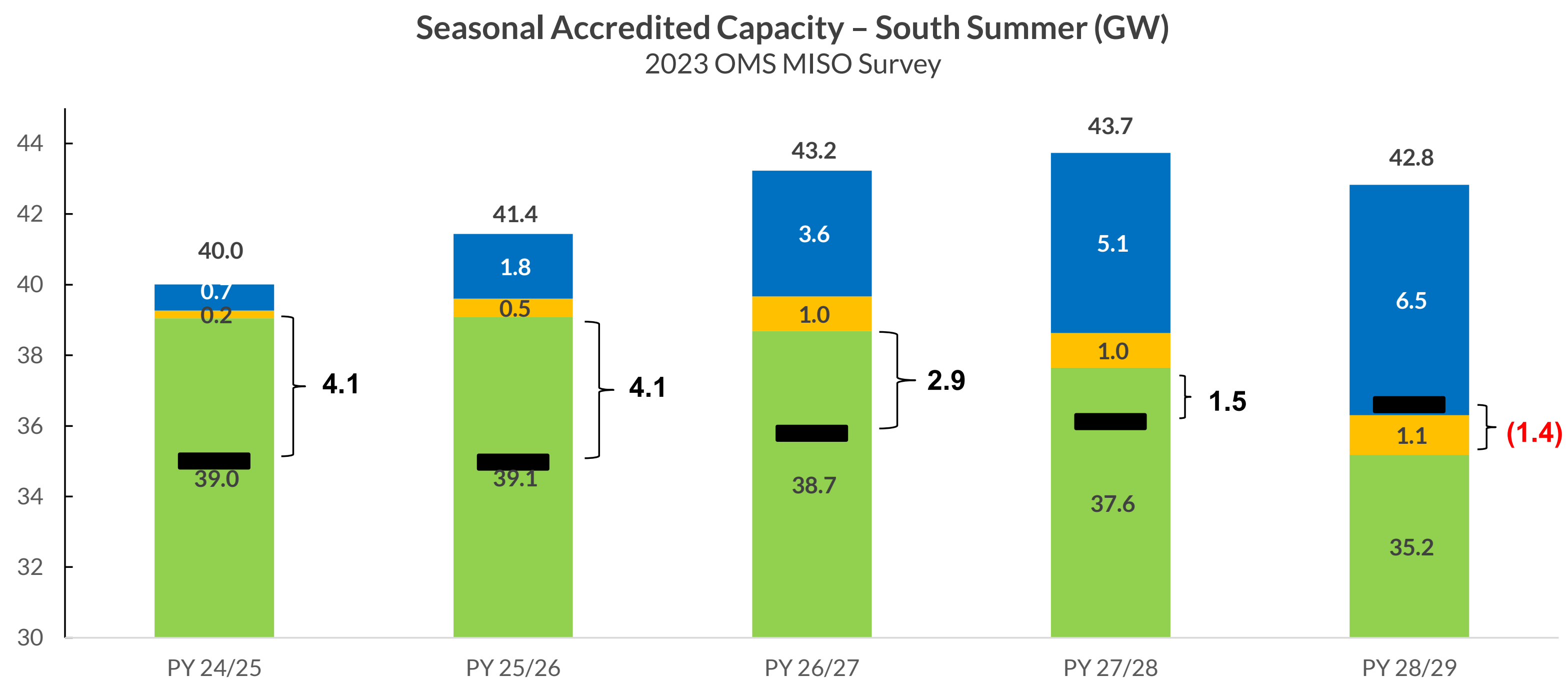
Schedule MM-S33

For Winter, North/Central increasingly trends towards reduced surpluses over five years, with 2028/29 winter showing a deficit



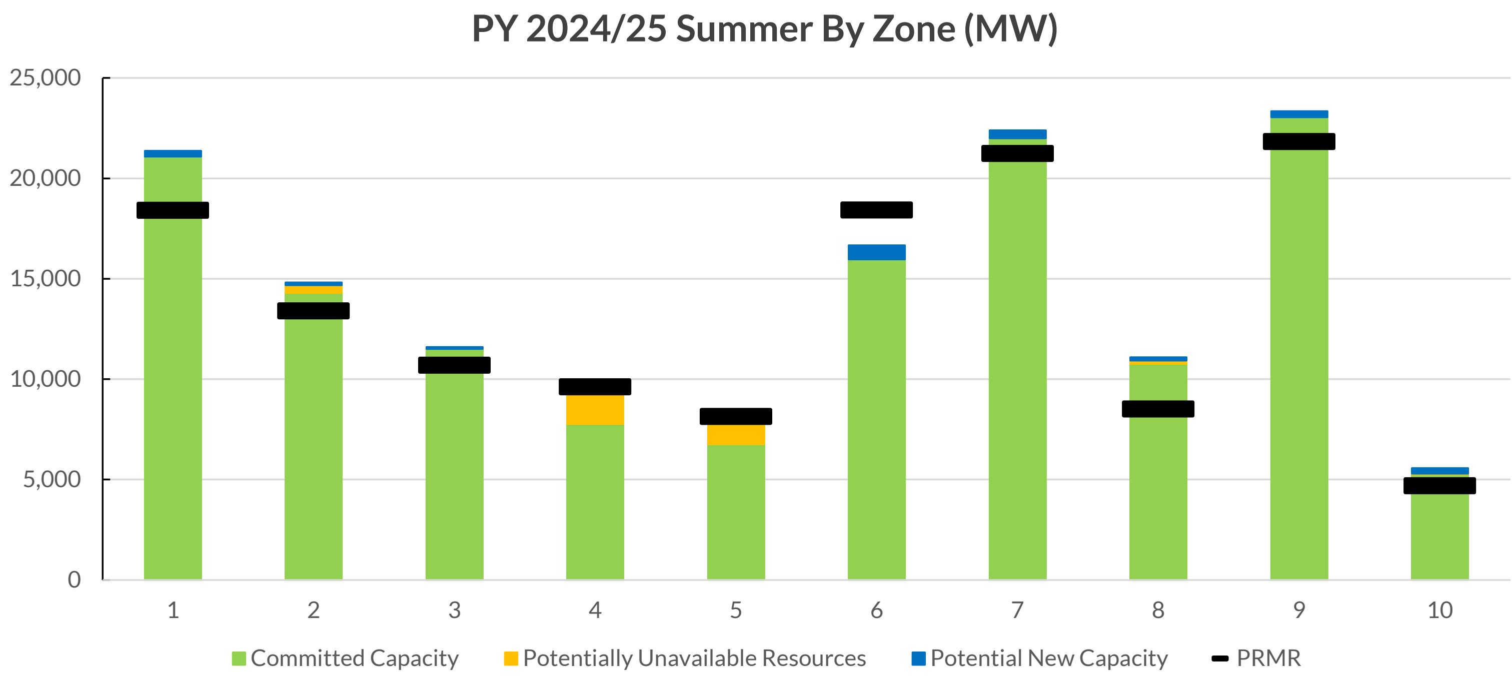
Schedule MM-S33

For Summer, South does not show a deficit until PY 2028/29



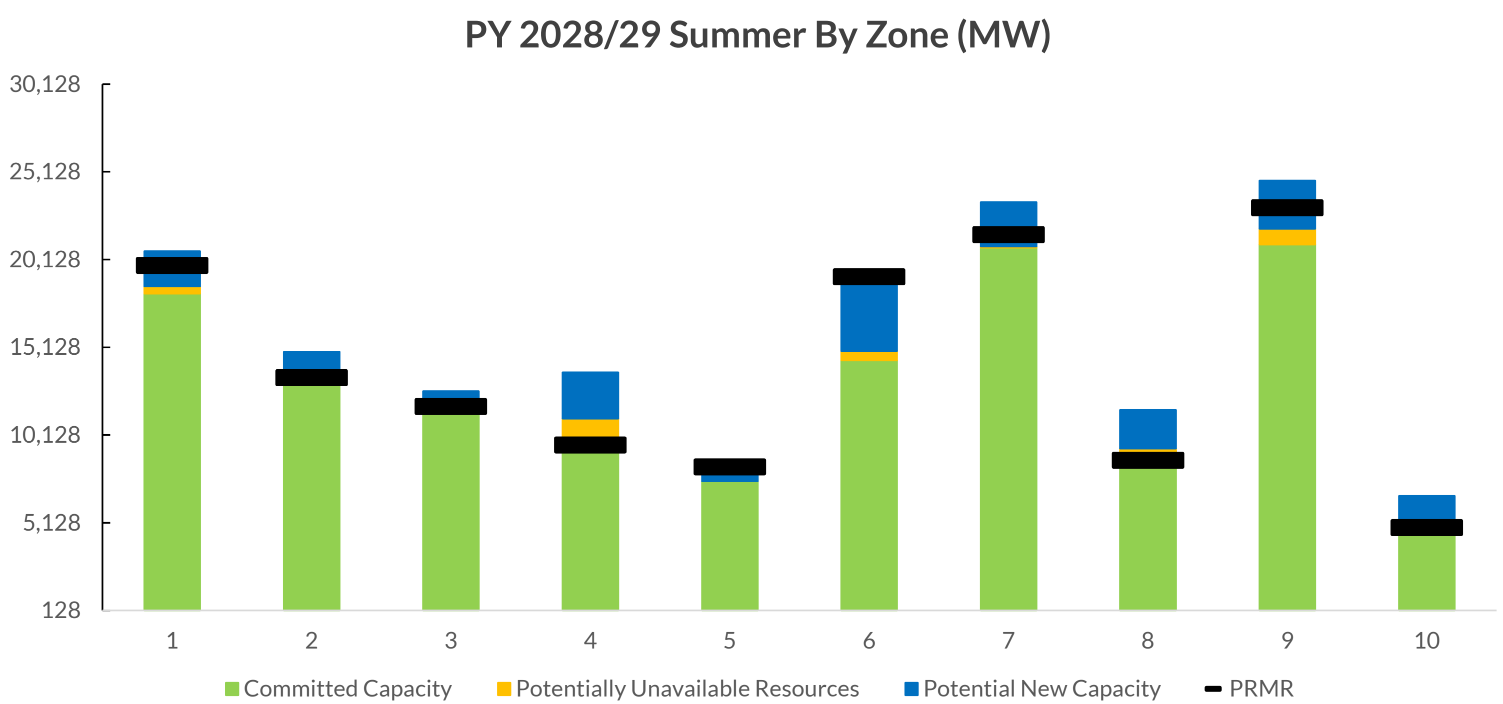
Schedule MM-S33

Zonal view for Summer 2024/25 shows that most zonal PRMRs can be met with resources located within respective zones



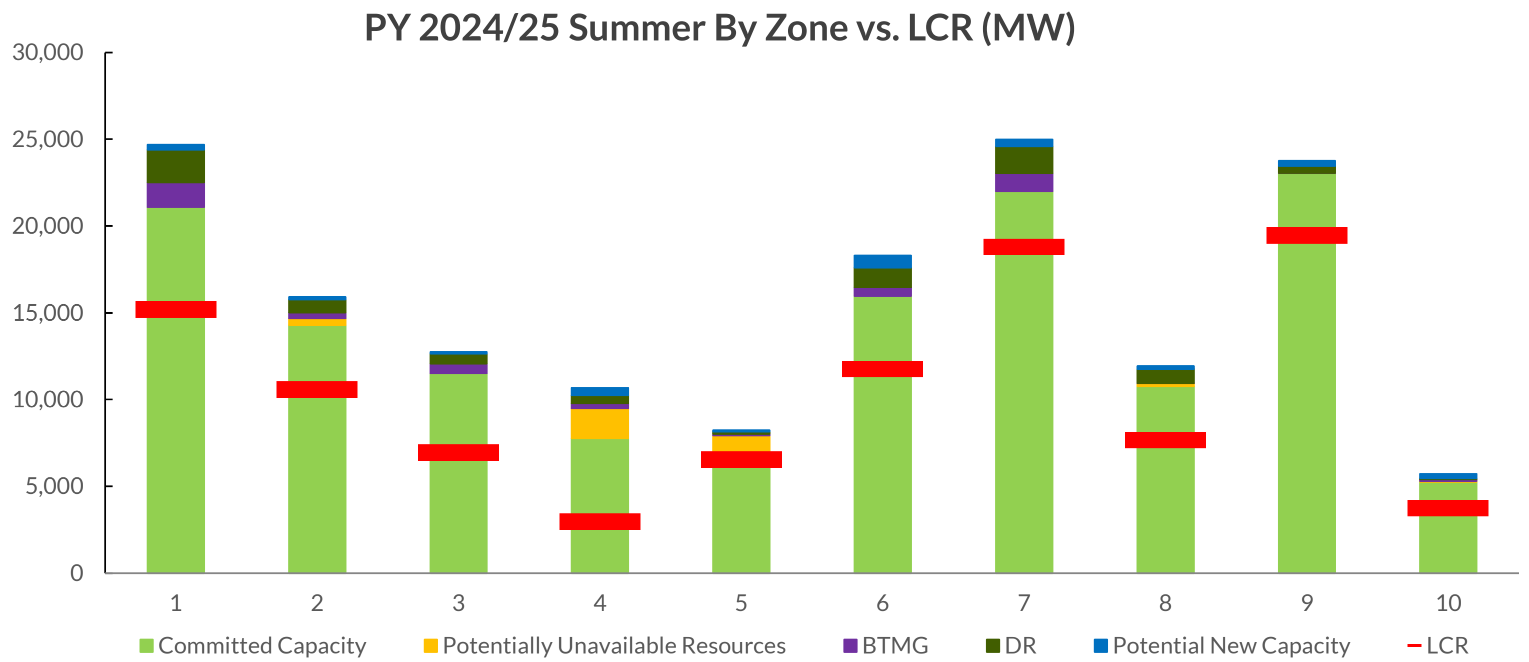
Schedule MM-S33

Looking out, 2028/29 zonal view shows the necessity of new capacity to meet PRMRs



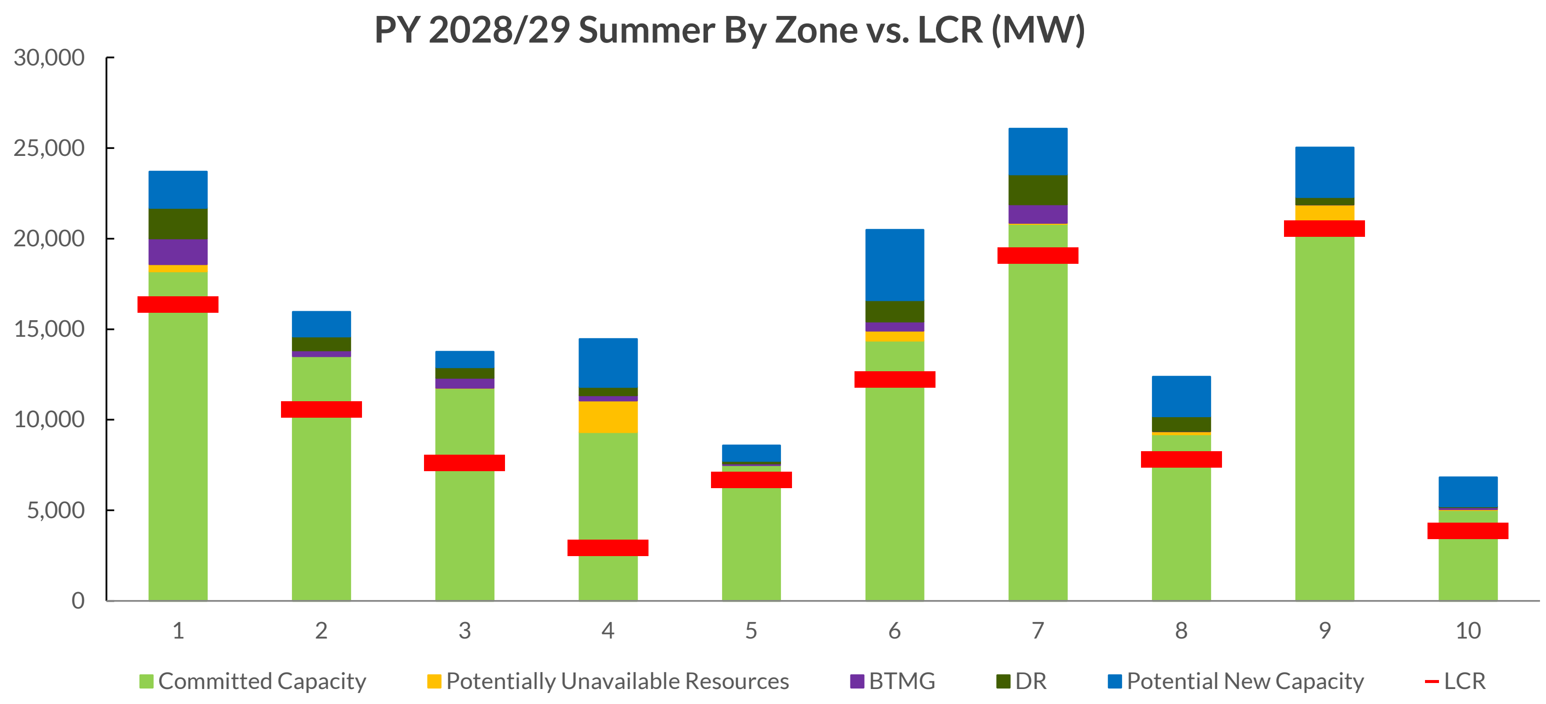
Schedule MM-S33

For Summer 2024/25, there is adequate capacity to meet Local Clearing Requirements (LCRs)



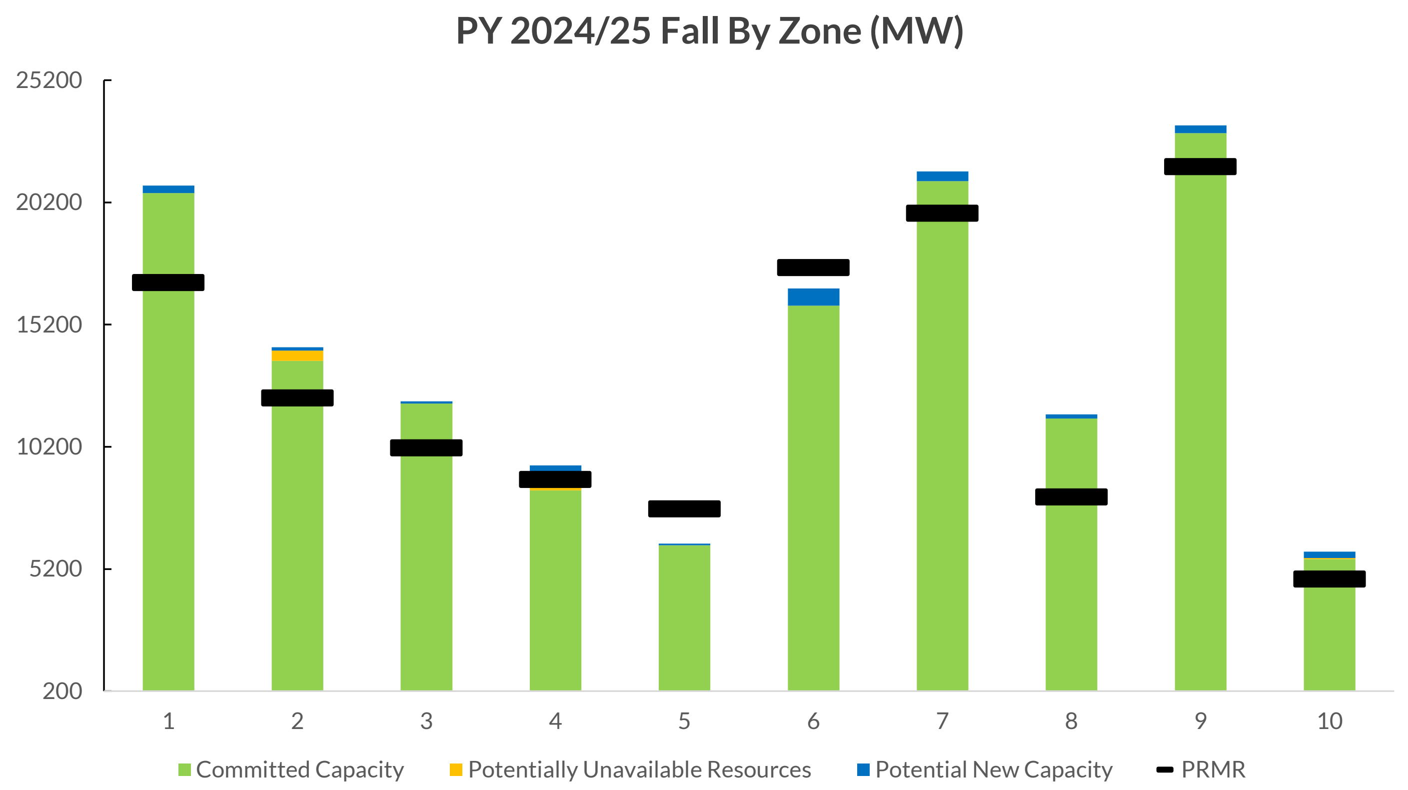
Schedule MM-S33

For Summer 2028/29, some zones show reduced residual capacity to meet LCRs



Schedule MM-S33

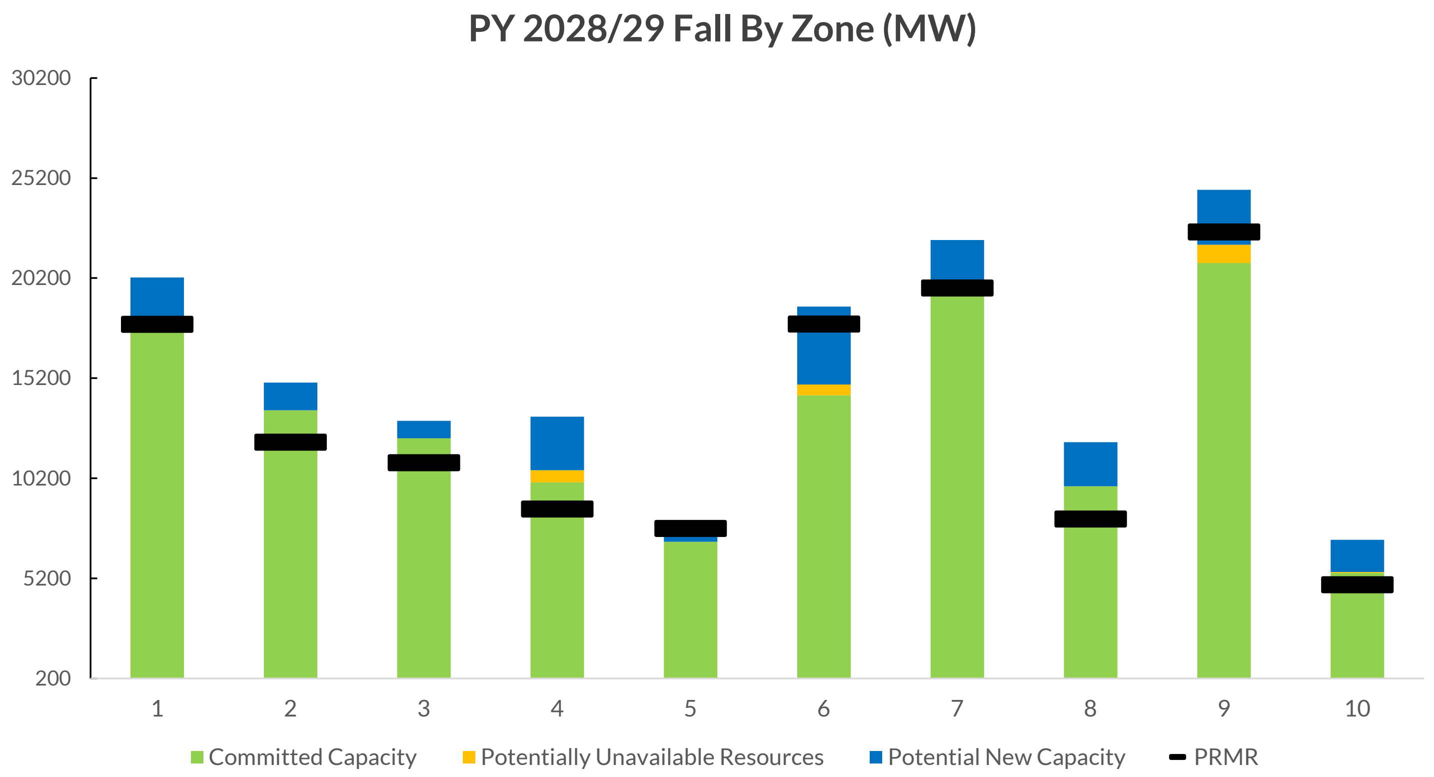
Zonal view for Fall 2024/25 shows that most zonal PRMRs can be met with resources located within respective zones



Note: Survey assumes that only resources physically located within the zone will be used to meet the zonal PRMR.

Schedule MM-S33

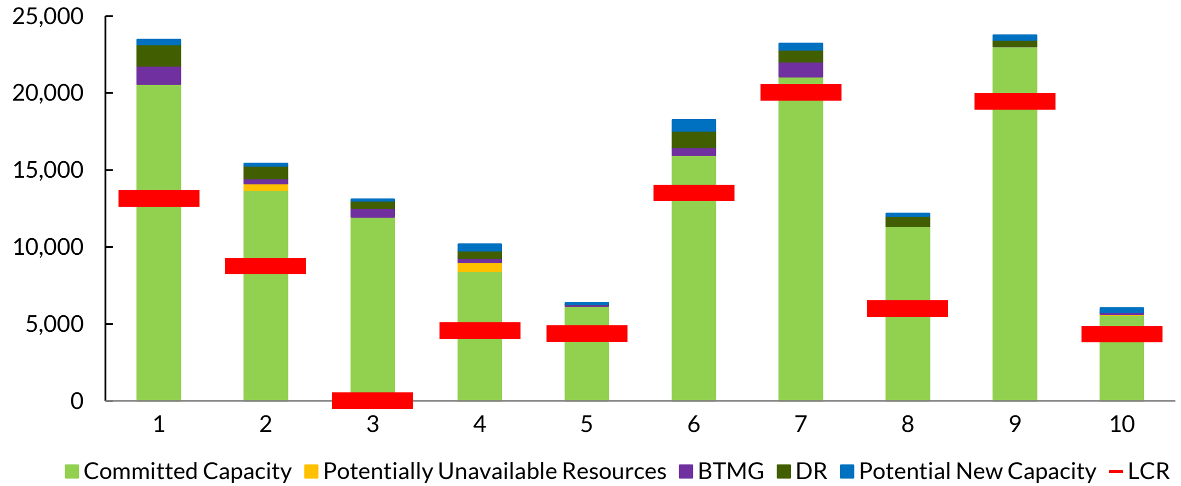
Looking out to Fall season for PY 2028/29, multiple zones rely on potential new capacity



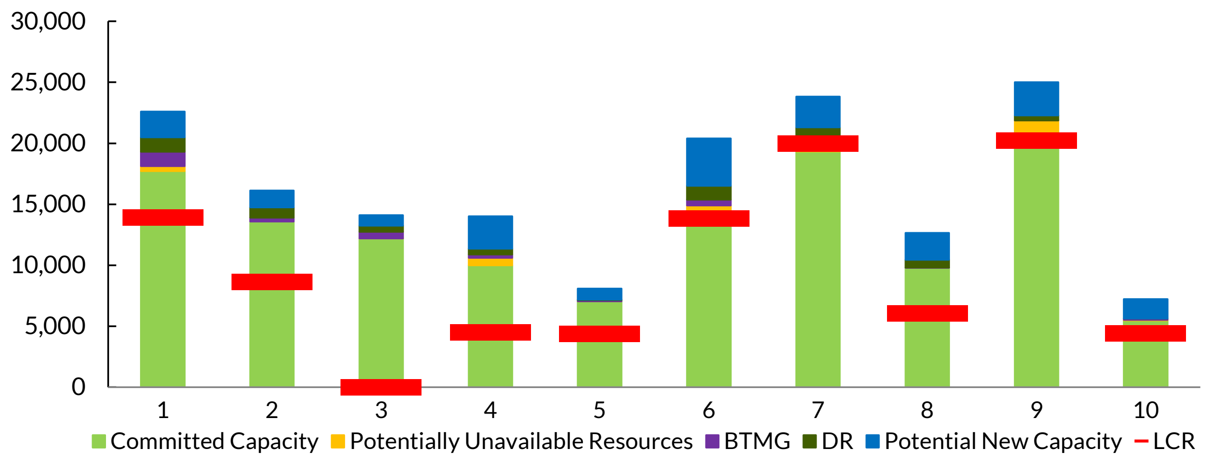
Schedule MM-S33

Fall is sufficient in the near-term, but PY 2028/29 may require new capacity addition to meet LCRs

PY 2024/25 Fall
By Zone vs. LCR (MW)

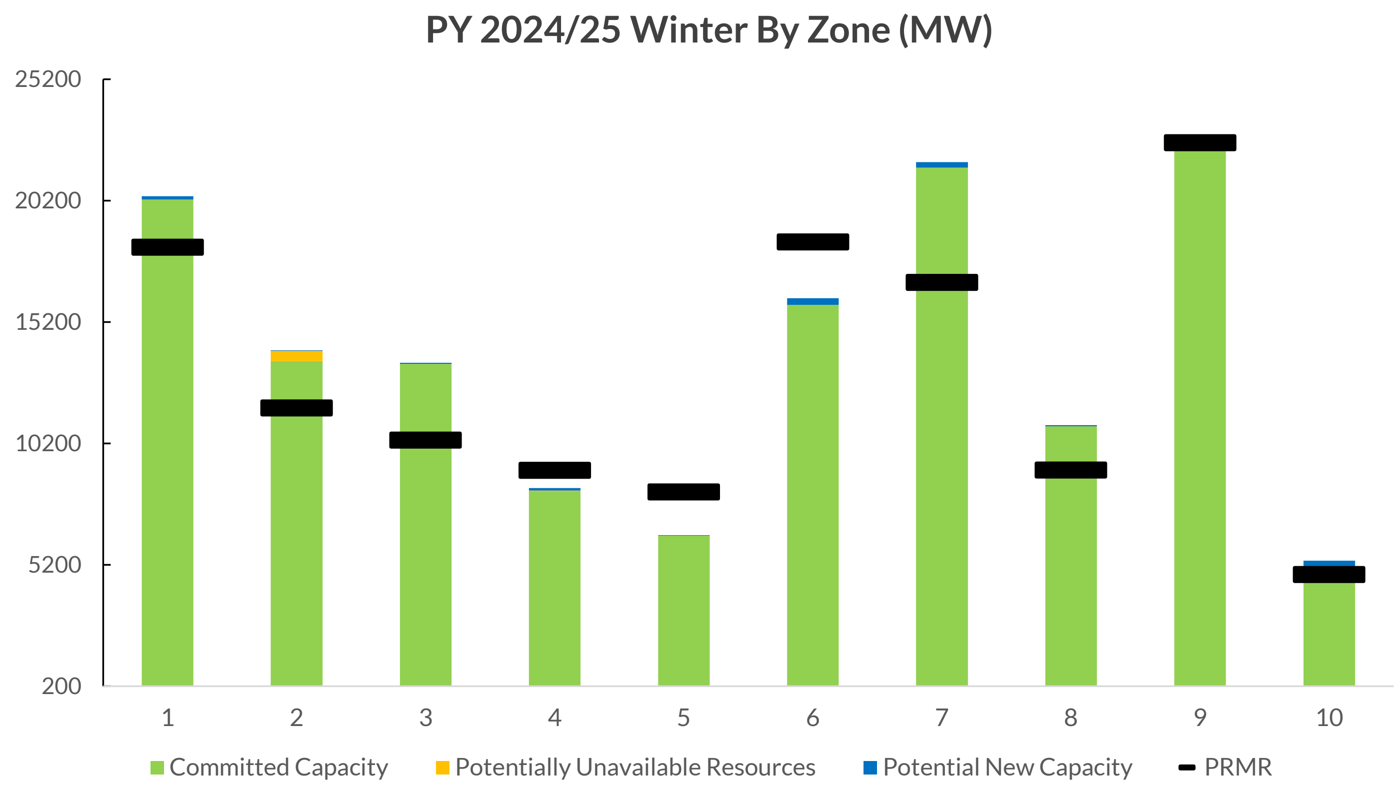


PY 2028/29 Fall
By Zone vs. LCR (MW)



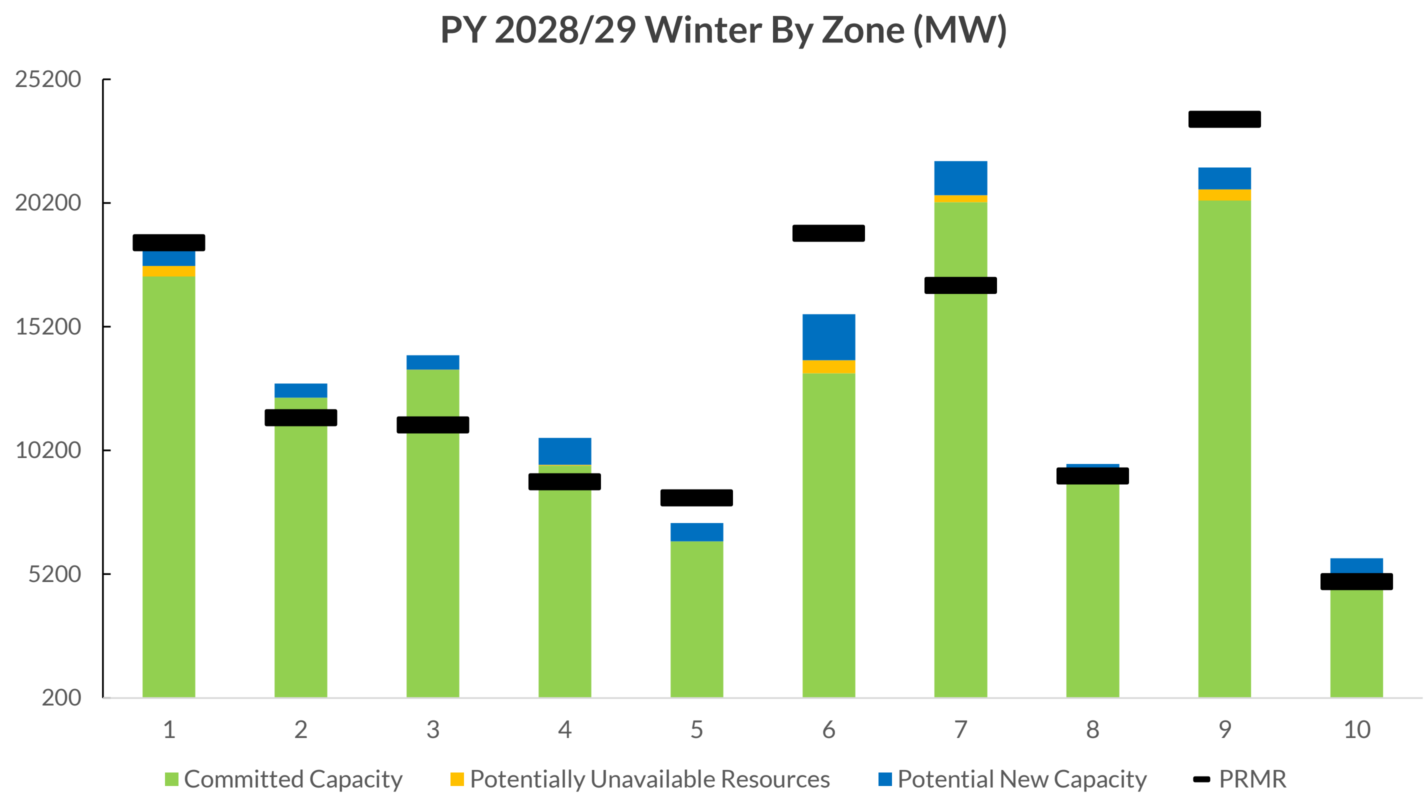
Schedule MM-S33

Zonal view for Winter 2024/25 shows that some zonal PRMRs cannot be met with resources located within respective zones



Schedule MM-S33

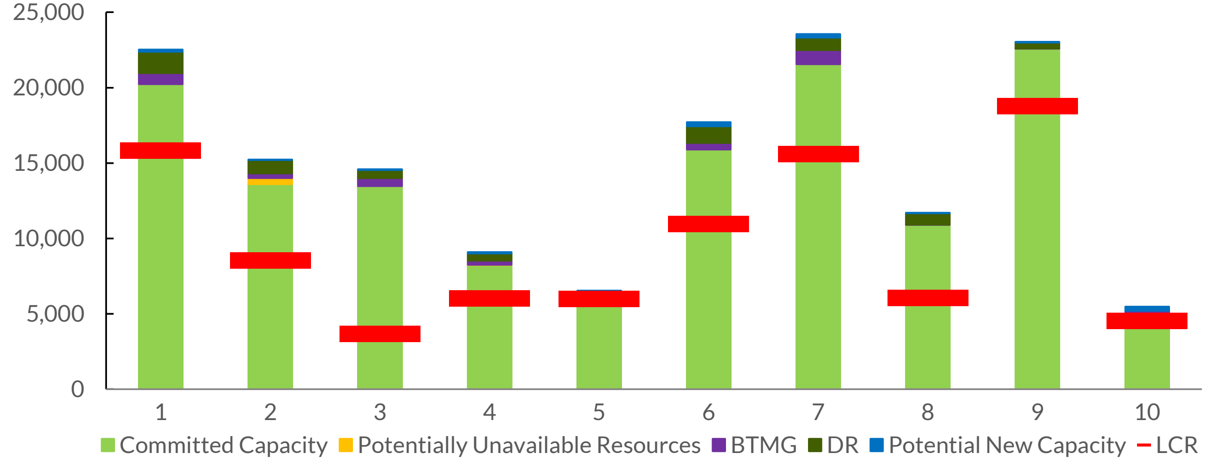
Looking out, Winter 2028/29 zonal view shows the necessity of new capacity to meet PRMRs



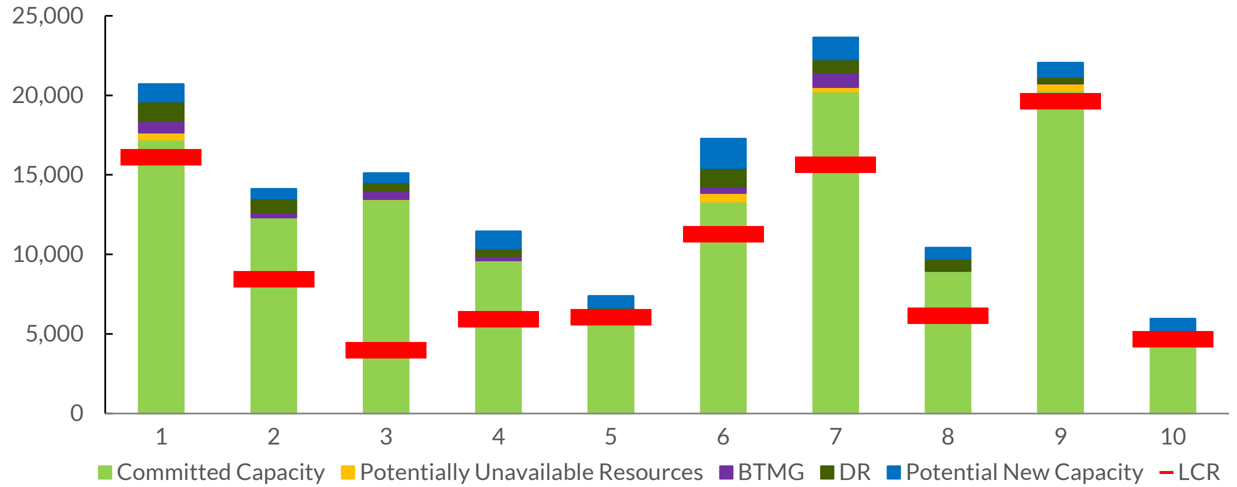
Schedule MM-S33

Winter is sufficient in the near-term, but some zones may require capacity additions by 2028/29 to meet LCRs

PY 2024/25 Winter By Zone vs. LCR (MW)

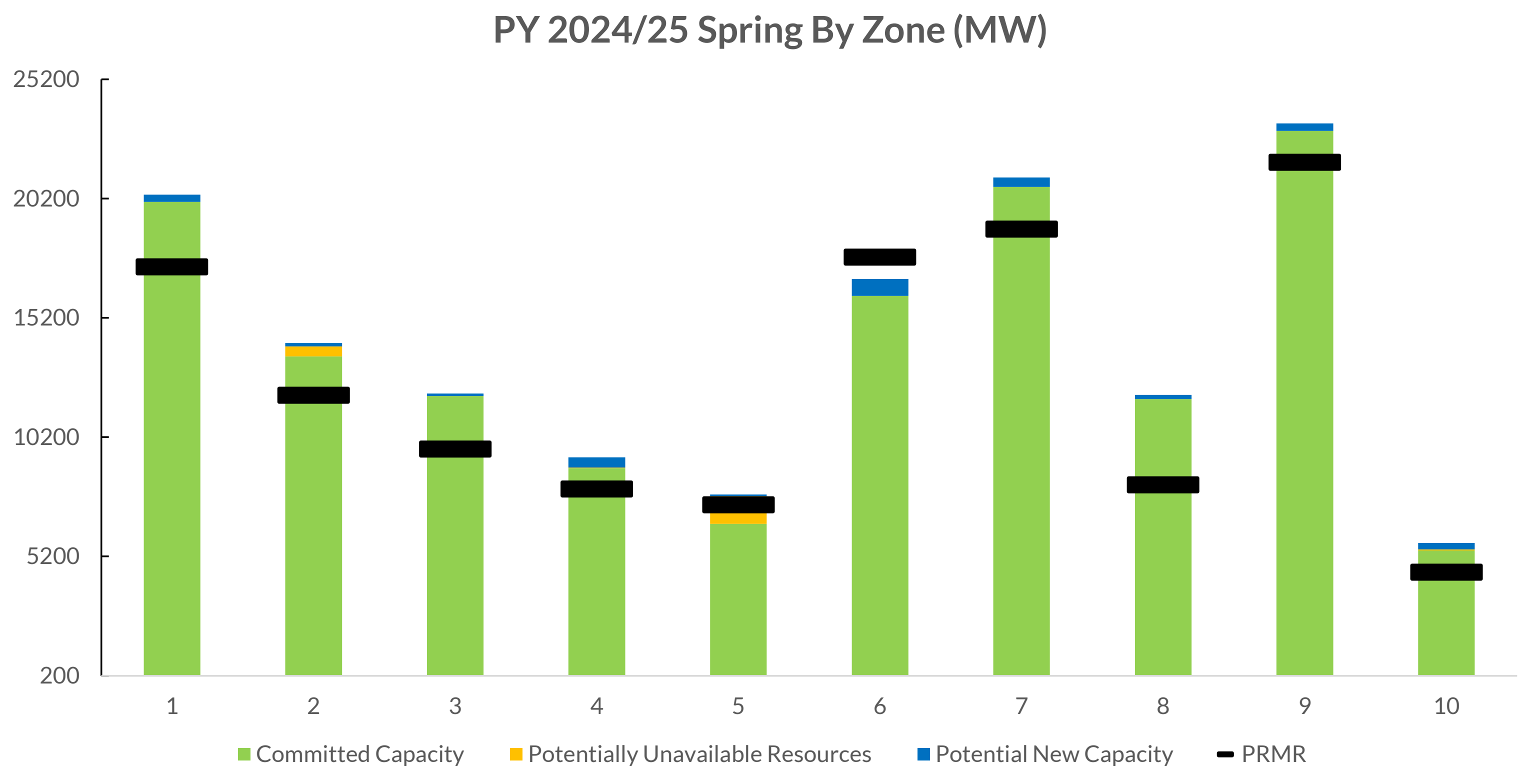


PY 2028/29 Winter By Zone vs. LCR (MW)



Schedule MM-S33

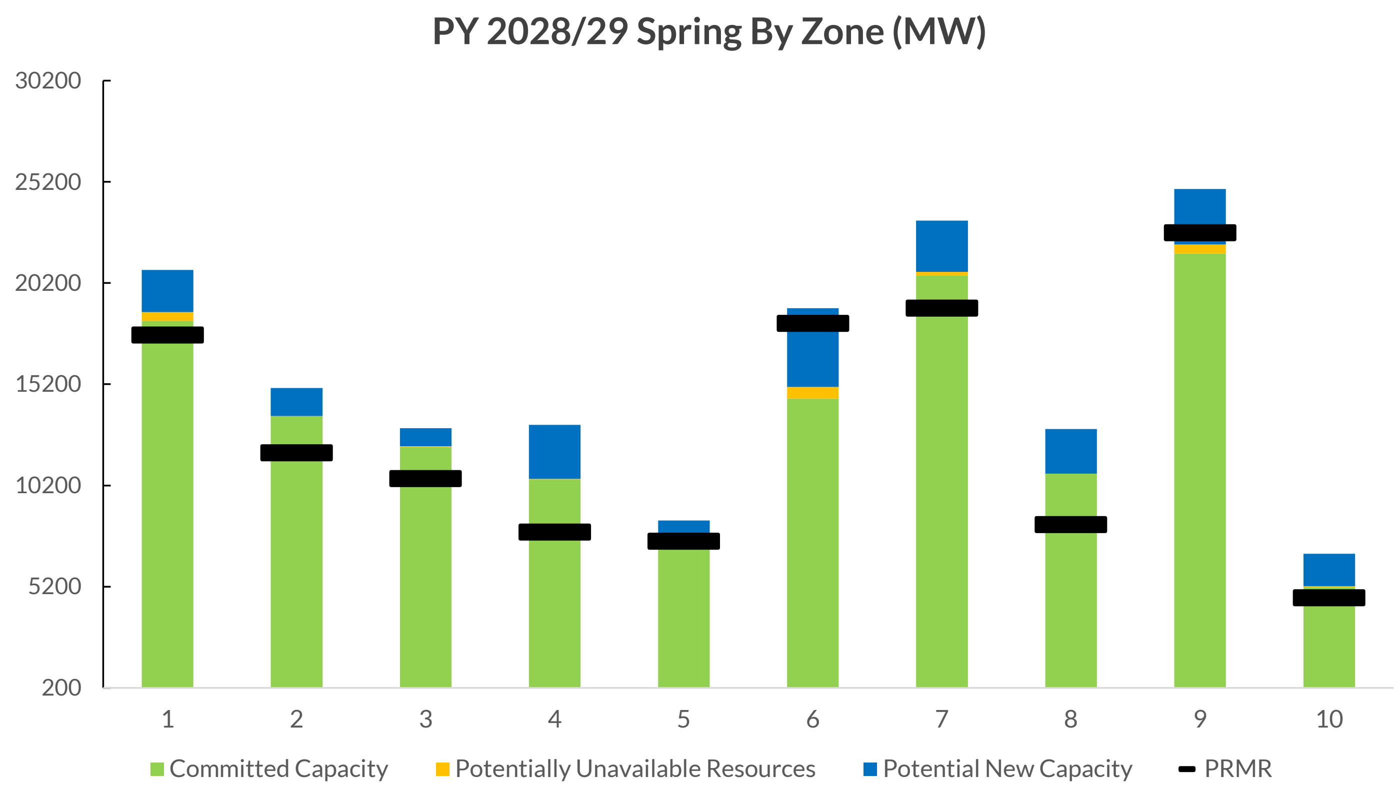
Zonal view for Spring 2024/25 shows that most zonal PRMRs can be met with resources located within respective zones



Note: Survey assumes that only resources physically located within the zone will be used to meet the zonal PRMR.

Schedule MM-S33

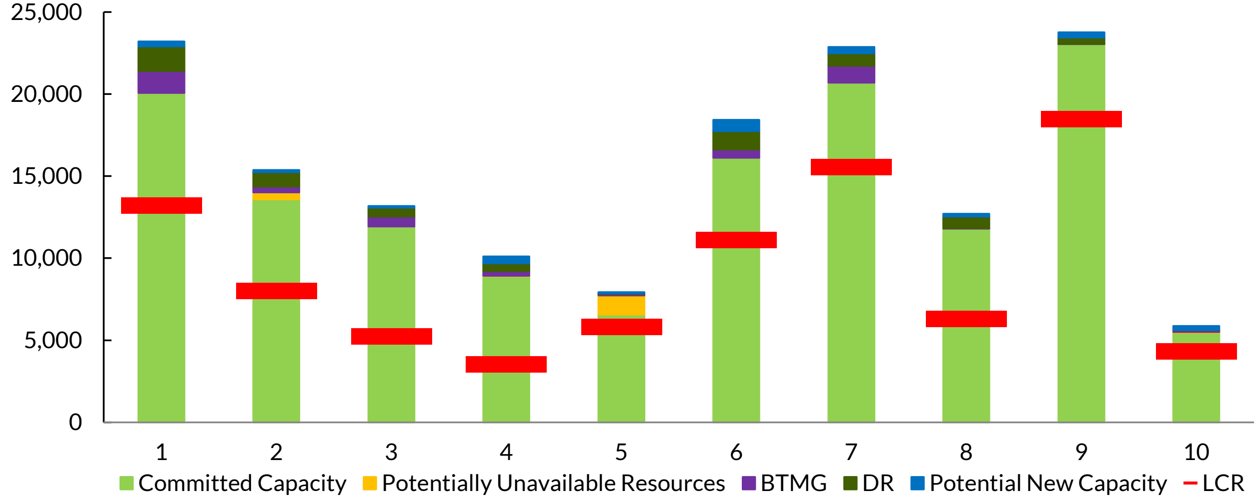
Looking out to Spring season for PY 2028/29, some zones rely on potential new capacity



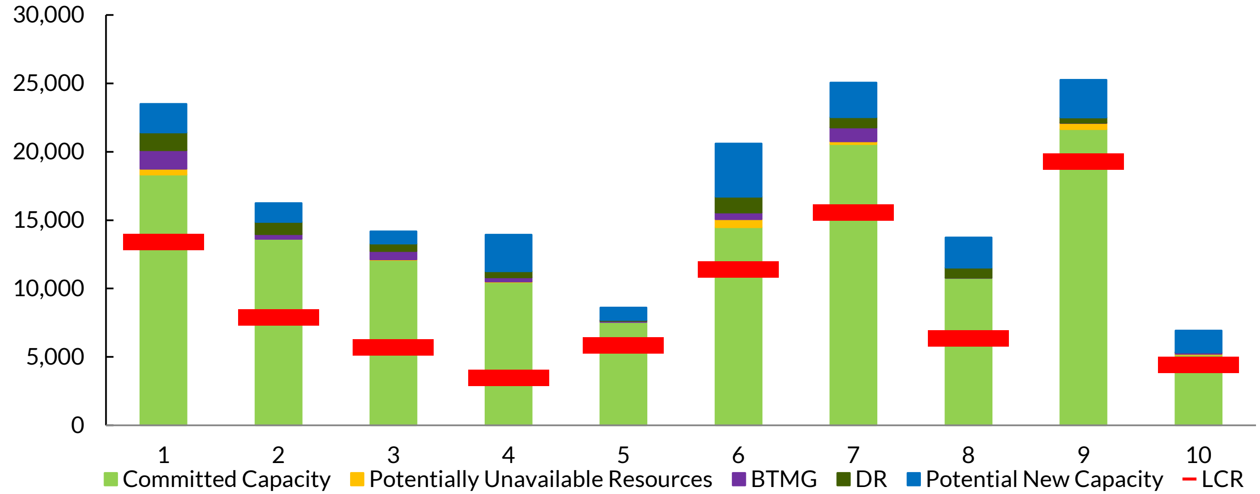
Schedule MM-S33

Spring is sufficient over the survey horizon, however there is increased tightness by 2028/29 to meet LCRs

PY 2024/25 Spring
By Zone vs. LCR (MW)
2023 OMS MISO Survey

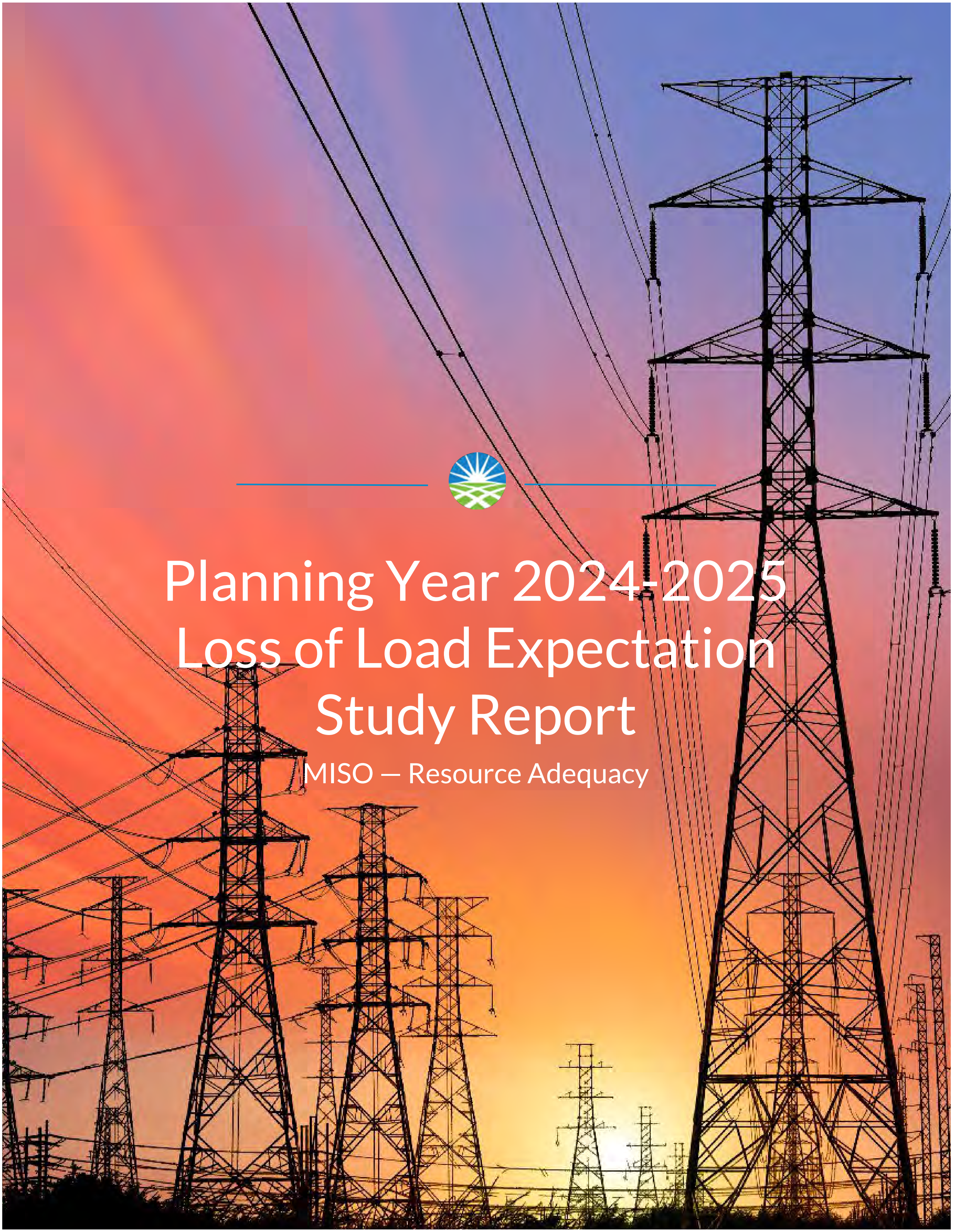


PY 2028/29 Spring
By Zone vs. LCR (MW)
2023 OMS MISO Survey



OMS MISO

Schedule MM-S33



Planning Year 2024-2025 Loss of Load Expectation Study Report

MISO – Resource Adequacy

Schedule MM-S34

Contents

Schedule MM-S34

Schedule MM-S34

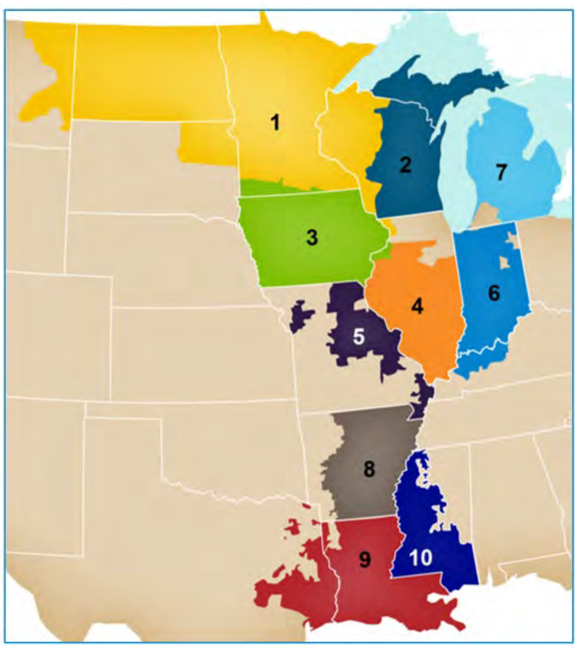
Executive Summary

In preparation for the annual Planning Resource Auction, MISO conducts an annual Loss of Load Expectation (LOLE) study to determine Resource Adequacy Requirements for the upcoming Planning Year 2024-2025. These requirements are identified on a seasonal basis for each Local Resource Zone within MISO.

Planning Reserve Margin (PRM) determined through this year's study are:

Season	PRM UCAP %
Summer 2024	9.0%
Fall 2024	14.2%
Winter 2024-2025	27.4%
Spring 2025	26.7%

MISO is divided into ten Local Resource Zones (LRZs) as shown in the figure below.



Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, GLH, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, HMPL, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

The report also determines zonal Local Reliability Requirements (LRRs). Additionally, initial values for zonal Capacity Import Limits (CIL), Capacity Export Limits (CEL), Zonal Import Ability (ZIA), and Zonal Export Ability (ZEA) for each season are also determined. These quantities are described in section 2.3.

Tables ES-1 through ES-4 below show results for each season.

Schedule MM-S34

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Summer 2024 PRM UCAP	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%
LRR UCAP per-unit of LRZ Peak Demand	1.132	1.113	1.278	1.291	1.331	1.190	1.161	1.392	1.135	1.518
Capacity Import Limit (CIL) (MW)	6,462	4,506	5,009	10,790	3,208	7,463	4,500	3,536	5,613	3,564
Capacity Export Limit (CEL) (MW)	4,537	3,971	5,450	2,730	4,644	5,637	5,709	6,171	2,359	1,840
Zonal Import Ability (ZIA) (MW)	6,460	4,506	4,911	9,857	3,208	7,197	4,490	3,444	4,794	3,564
Zonal Export Ability (ZEA) (MW)	4,539	3,971	5,548	3,663	4,644	5,903	5,719	6,263	3,178	1,840

Table ES-1: Initial Planning Resource Auction Deliverables — Summer 2024

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Fall 2023 PRM UCAP	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%
LRR UCAP per-unit of LRZ Peak Demand	1.235	1.199	1.345	1.323	1.441	1.257	1.311	1.496	1.190	1.667
Capacity Import Limit (CIL) (MW)	6,502	5,719	6,789	6,637	3,786	8,954	4,400	5,040	6,435	4,736
Capacity Export Limit (CEL) (MW)	5,711	4,512	6,913	3,863	5,402	3,519	5,381	4,212	3,602	2,889
Zonal Import Ability (ZIA) (MW)	6,500	5,719	6,684	5,699	3,786	8,661	4,390	4,942	5,608	4,736
Zonal Export Ability (ZEA) (MW)	5,713	4,512	7,018	4,801	5,402	3,812	5,391	4,310	4,429	2,889

Table ES-2: Initial Planning Resource Auction Deliverables — Fall 2024

Schedule MM-S34

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Winter 24-25 PRM UCAP	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%
LRR UCAP per-unit of LRZ Peak Demand	1.442	1.363	2.006	1.338	1.285	1.227	1.607	1.560	1.328	1.864
Capacity Import Limit (CIL) (MW)	4,693	5,523	5,704	6,731	4,477	8,526	4,666	4,336	5,420	3,219
Capacity Export Limit (CEL) (MW)	5,174	4,772	8,975	4,650	6,229	1,407	5,743	5,808	2,103	2,993
Zonal Import Ability (ZIA) (MW)	4,691	5,523	5,600	5,811	4,477	8,286	4,656	4,262	4,623	3,219
Zonal Export Ability (ZEA) (MW)	5,176	4,772	9,079	5,570	6,229	1,647	5,753	5,882	2,900	2,993

Table ES-3: Initial Planning Resource Auction Deliverables — Winter 2024-2025

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Spring 2024 PRM UCAP	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%
LRR UCAP per-unit of LRZ Peak Demand	1.329	1.363	1.531	1.662	1.618	1.371	1.322	1.610	1.334	1.878
Capacity Import Limit (CIL) (MW)	4,943	5,034	6,626	6,003	3,892	8,015	4,893	6,124	6,417	4,628
Capacity Export Limit (CEL) (MW)	6,318	4,601	5,761	5,081	4,984	3,444	5,591	4,936	3,994	2,740
Zonal Import Ability (ZIA) (MW)	4,941	5,034	6,514	5,083	3,892	7,730	4,883	6,030	5,598	4,628
Zonal Export Ability (ZEA) (MW)	6,320	4,601	5,873	6,001	4,984	3,729	5,601	5,030	4,813	2,740

Table ES-4: Initial Planning Resource Auction Deliverables — Spring 2025

The stakeholder review process played an integral role in this study. MISO would like to thank the Loss of Load Expectation Working Group (LOLEWG) and the Resource Adequacy Subcommittee (RASC) for its assistance and input.

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1 LOLE Study Process Overview

In compliance with Module E-1 of the MISO Tariff, MISO performed its annual LOLE Study to determine, for each season of Planning Year 2024-2025, the system unforced capacity (UCAP) Planning Reserve Margin (PRM) and the per-unit Local Reliability Requirements (LRR) of Local Resource Zone (LRZ) Peak Demand.

In addition to the LOLE analysis, MISO performed seasonal transfer analyses to determine seasonal Zonal Import Ability (ZIA), Zonal Export Ability (ZEA), Capacity Import Limits (CIL) and Capacity Export Limits (CEL). CIL, CEL, and ZIA are used, in conjunction with the LOLE analysis results, in the Planning Resource Auction (PRA). ZEA is informational and not used in the PRA.

The PY 2024-2025 per-unit seasonal LRR UCAP multiplied by the updated LRZ seasonal Peak Demand forecasts submitted for the 2024-2025 PRA determines each LRZ's seasonal LRR. Once the seasonal LRR is determined, the ZIA values and non-pseudo tied exports are subtracted from the seasonal LRR to determine each LRZ's seasonal Local Clearing Requirement (LCR) consistent with Section 68A.6 of Module E-1[1]. An example LCR calculation pursuant to Section 68A.6 of the current effective Module E-1 shows how these values are reached (Table 1-1).

Local Resource Zone (LRZ) EXAMPLE	Example LRZ	Formula Key
Installed Capacity (ICAP)	17,442	[A]
Unforced Capacity (UCAP)	16,326	[B]
Adjustment to UCAP (1d in 10yr)	50	[C]
Local Reliability Requirement (LRR) (UCAP)	16,376	[D]=[B]+[C]
LRZ Peak Demand	14,270	[E]
LRR UCAP per-unit of LRZ Peak Demand	114.8%	[F]=[D]/[E]
Zonal Import Ability (ZIA)	3,469	[G]
Zonal Export Ability (ZEA)	2,317	[H]
Local Clearing Requirement (LCR) EXAMPLE	**Example LRZ**	**Formula Key**
Non-Pseudo Tied Exports (UCAP)	150	[J]
Local Reliability Requirement (LRR) (UCAP)	16,376	[K]=[F]*[E]
Local Clearing Requirement (LCR)	12,757	[L]=[K]-[G]-[J]

Table 1-1: Example Local Clearing Requirement Calculation

The actual effective PRM Requirement (PRMR) for each season of Planning Year 2024-2025 will be determined after the updated LRZ Seasonal Peak Demand forecasts are submitted by November 1, 2023, for the 2024-2025 PRA. The ZIA, ZEA, CIL and CEL values are subject to updates in March 2024 based on changes to exports of MISO resources to non-MISO load, changes to pseudo tied commitments, and updates to facility ratings following the completion of the LOLE Study.

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[1] https://www.misoenergy.org/legal/tariff
Effective Date: September 1, 2022

Finally, the Simultaneous Feasibility Test (SFT) is performed as part of the PRA where the deliverability of cleared generation is validated through transfer analysis modeling to ensure transmission reliability. If constraints arise, they are mitigated by adjusting CIL and CEL values as needed.

1.1 Study Improvements

The Planning Year 2024-2025 LOLE Study incorporated additional study improvements, building on those incorporated in the prior studies. Improvements for the PY 2023-2024 LOLE Study included modeling of 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. Details for these changes can be found in PY 2023-2024 LOLE Study Report.

PY 2024-2025 study included the following improvements:

- **Enhanced modeling of battery storage resources:** Previously, battery storage was modeled as a must-run resource that is always available at nameplate capacity, unless on a forced outage (assumed to be a rate of 5% for every season). Now, battery storage is modeled as use-limited with a duration of 4 hours.
- **Realistic commercial operation dates for future resources**: PY 2024-2025 study considered more realistic anticipated commercial operation dates (CODs) for future resource additions with executed generation interconnection agreements (GIAs), factoring in macroeconomic and regulatory realities. Interconnection customers have indicated to MISO that factors such as supply-chain issues, regulatory approvals, contractor availability, and other economic factors such as PPAs, are requiring GIA projects to delay commercial operations. Correspondingly, declared anticipated CODs were adjusted based on GIA projects in the queue per customer feedback.
- **Improved cold-weather related outages**: Accounting of additional forced outages during extreme cold temperatures in the Winter season was updated in the PRM and LRR calculations. For context, the LOLE model has historically utilized a 5-year average EFORd based on historic GADS data. These resource-specific forced outage rates were annualized under the prior annual construct and were seasonalized in last year's LOLE Study, which better captured the seasonal availability of resources as observed in operations.

  Additional thermal forced outages are added to the model during times of extreme cold temperatures to better capture the magnitude of observed correlated outages. The magnitude of forced outages added increases as temperatures decrease based on the relationship between outages and temperature determined from historic GADS and weather data. The modeling of additional forced outages in the Winter season due to the adder induces a higher volume of forced outages in the model beyond just the average Winter EFORd. Each LRZ has a unique outage/temperature profile based on actual historical forced outages. The incremental cold weather outages are not assigned to a particular resource but instead represent the aggregate impact on the system for coal and gas resources.

  What has changed for this year's study was the reduction of the available Winter unforced capacity in the PRM and LRR calculations as a result of these cold weather outages. A comparative probabilistic analysis with and without the cold weather outage adder was performed to quantify the impact of modeling the cold weather outage adder profiles on the system-wide requirements. This impact was distributed pro-rata to the zonal level based on the average magnitude of the zonal cold weather outage adder profiles used in the LRR calculations.

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2 Transfer Analysis

2.1 Calculation Methodology and Process Description

Transfer analyses determined CIL and CEL values for LRZs in each season for Planning Year 2024-2025. Annual adjustments are made for Border External Resources and Coordinating Owner Resources to determine the ZIA and ZEA in each season. Further adjustments are made for exports to non-MISO loads to arrive at the CIL and CEL values. The objective of the transfer analyses is to determine constraints caused by the transfer of capacity between zones and the associated transfer capability. Multiple factors impacted the analysis when compared to previous studies, including:

- Approximately 800 MW of retirements and/or suspensions
- New intermittent resources
- Base model dispatch in MISO and seams

2.1.1 Generation Pools

To determine an LRZ's import or export limit, a transfer is modeled by ramping generation up in a source subsystem and ramping generation down in a sink subsystem. The source and sink definitions depend on the limit being tested. The LRZ studied for import limits is the sink subsystem and the adjacent MISO LBAs are the source subsystem. The LRZ studied for export limits is the source subsystem and the rest of MISO is the sink subsystem. These are the same in all seasons for the upcoming Planning Year.

Transfers can cause potential issues, which are addressed through the study assumptions. First, an abundantly large source pool spreads the impact of the transfer widely which can cause differences in studied zones' transfer capabilities and the identified constraints. Second, ramping up generation from remote areas could cause electrically distant constraints for any given LRZ, which should not determine a zone's limit. For example, export constraints due to dispatch of LRZ 1 generation in the northwest portion of the footprint should not limit the import capability of LRZ 10, which covers the MISO portion of Mississippi.

To address these potential issues, the transfer studies limit the source pool for the import studies to the Tier 1 and Tier 2 adjacent LBAs to the study zone. Since the generation that is ramped up in export studies are contained in the study LRZ, these issues only apply to import studies. Generation within the zone studied for an export limit is ramped up and constraints are expected to be near or in the study zone.

2.1.2 Redispatch

Limited redispatch is applied after performing transfer analyses to mitigate constraints. Redispatch ensures constraints are not caused by the base dispatch and aligns with potential actions that can be implemented for the constraint by MISO control room operators. Redispatch scenarios can be designed to address multiple constraints, as required, and may be used for constraints that are electrically close to each other or to further optimize transfer limits for several constraints requiring only minor redispatch. The redispatch assumptions include:

- The use of no more than 10 conventional fuel plants or intermittent resources
- Redispatch limit at 2,000 MW total (1,000 MW up and 1,000 MW down)
- No adjustments to nuclear units
- No adjustments to the portions of pseudo-tied units committed to non-MISO load

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2.1.3 Sensitivity

New to the transfer analyses this year is the ability for Transmission Owners in a specific zone to request a sensitivity be included in the generation-to-generation transfer to allow for the True Transfer Limit to be identified. The sensitivity would allow excluded units to be included in the generation-to-generation transfer for a zone's CIL. Excluded units mainly include nuclear units and units not to be used in zonal transfers from the latest MTEP model. This sensitivity can only be requested for a CIL study. A sensitivity would only be accepted for a particular zone if they are in the situation portrayed below by the chart in Figure 2-1.

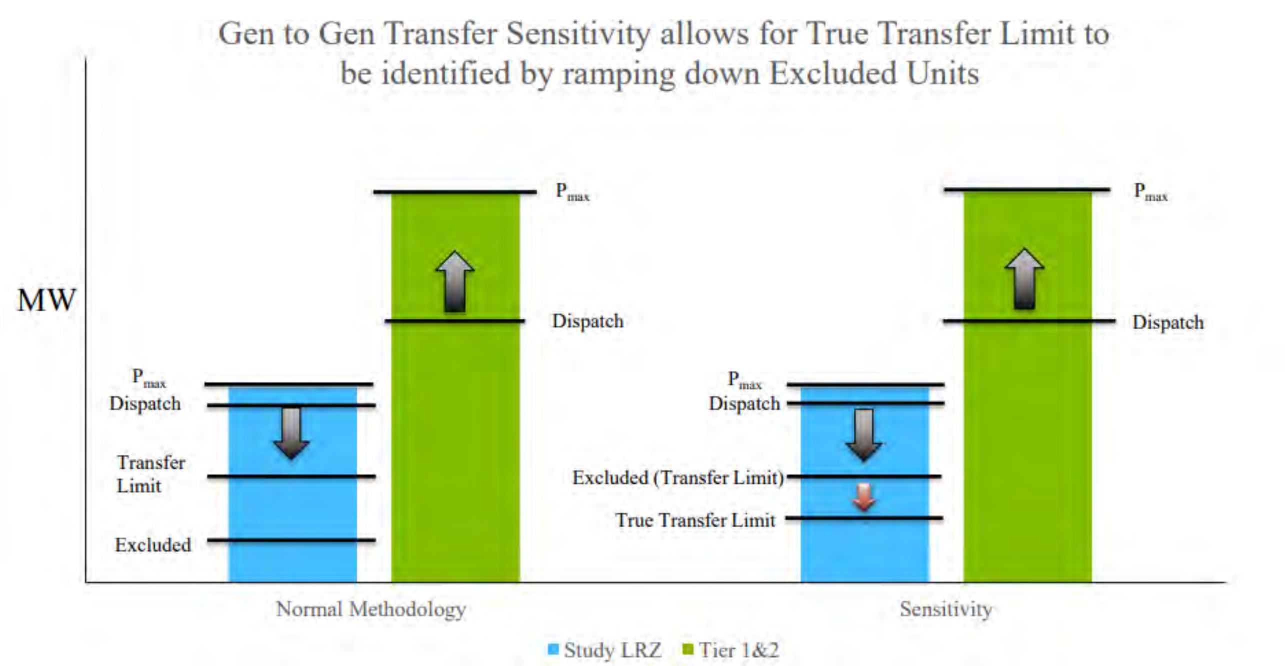

Figure 2-1: Generation-to-Generation Transfer Sensitivity

The two bars shown for the Normal Methodology would not allow for a sensitivity to be requested by a Transmission Owner. In this situation, since the transfer limit is already identified before hitting the excluded units, a request for a generation-to-generation transfer sensitivity would not be accepted. The two bars shown for the Sensitivity identify a situation where a request for a generation-to-generation transfer sensitivity would be accepted. When ramping down generation, the excluded units are hit before the True Transfer Limit, but since the rest of the units are excluded, the transfer limit would be identified as the point where the generation-to-generation stops at the excluded units. With a sensitivity in place, the generation-to-generation transfer would continue into the excluded units and the True Transfer Limit would be identified.

LRZ 10 was the only Local Resource Zone to utilize a generation-to-generation transfer sensitivity and have the results of which included in their Capacity Import Limit for Planning Year 2024-2025.

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2.1.4 Generation Limited Transfer for CIL/CEL and ZIA/ZEA

When conducting transfer analysis to determine import or export limits, the source subsystem might run out of generation to dispatch before identifying a valid constraint caused by a transmission limit. MISO developed a Generation Limited Transfer (GLT) process to identify transmission constraints in these situations, when possible, for both imports and exports.

After running the First Contingency Incremental Transfer Capability (FCITC) analysis to determine limits for each LRZ, MISO will determine whether a zone is experiencing a GLT (e.g. whether the first constraint would occur only after all the generation is dispatched at its maximum amount). If the LRZ experiences a GLT, MISO will adjust the base model depending on whether it is an import or export analysis and re-run the transfer analysis.

For an export study, when a transmission constraint has not been identified after all generation has been dispatched within the exporting system (LRZ under study), MISO will decrease load and generation dispatch in the study zone. The adjustment creates additional capacity to export from the zone. After the adjustments are complete, MISO will re-run the transfer analysis. If a GLT reappears, MISO will make further adjustments to the load and generation of the study zone.

For an import study, when a transmission constraint has not been identified after all generation has been dispatched within the source subsystem, MISO will decrease load and generation in the source subsystem. This increases the export capacity of the adjacent LBAs for the study zone. After the adjustments are complete, MISO will run the transfer analysis again. If a GLT reappears, MISO will make further adjustments to the model's load and generation in the source subsystem.

FCITC could indicate the transmission system can support larger thermal transfers than would be available based on installed generation for some zones—however, large variations in load and generation for any zone may lead to unreliable limits and constraints. Therefore, MISO limits load scaling for both import and export studies to 50 percent of the zone's load. In a GLT, redispatch, or GLT plus redispatch scenario, the FCITC of the most limiting constraint might exceed Zonal Export/Import Capability. If the GLT does not produce a limit for a zone, either due to a valid constraint not being identified or due to other considerations as listed in the prior paragraph, MISO shall report that LRZ as having no limit and ensure that the limit will not bind in the first iteration of the Simultaneous Feasibility Test (SFT).

2.1.5 Voltage Limited Transfer for CIL/CEL and ZIA/ZEA

Zonal imports may be limited by voltage constraints due to a decrease in the generation in the study zone. Voltage constraints might occur at lower transfer levels than thermal limits determined by linear FCITC. As such, LOLE studies may evaluate power-voltage curves for LRZs with known voltage-based transfer limitations identified through existing MISO or Transmission Owner studies. Such evaluation may also occur if an LRZ's import reaches a level where the majority of the zone's load would be served using imports from resources outside of the zone. MISO will coordinate with stakeholders as it encounters these scenarios. For Planning Year 2024-2025, only Local Resource Zones 1, 4, and 7 import analyses included voltage screening and study. No studies identified a voltage limit with lower transfer capability than the thermal limit for Planning Year 2024-2025.

2.2 Powerflow Models and Assumptions

2.2.1 Tools Used

MISO used the Siemens PTI Power System Simulator for Engineering (PSS/E) and PowerGEM Transmission Adequacy and Reliability Assessment (TARA) tools.

2.2.2 Inputs Required

Thermal transfer analysis requires powerflow models and related input files. MISO used contingency files from MTEP[2] reliability assessment studies. Single-element contingencies in MISO and seam areas were also evaluated.

MISO developed a subsystem file to monitor its footprint and seam areas which was used for all seasons. LRZ definitions were developed as sources and sinks in the study. See Appendix C for tables containing adjacent area definitions (Tiers 1 and 2) used for this study. The monitored file includes all facilities under MISO functional control and single elements in the seam areas of 100 kV and above.

2.2.3 Powerflow Modeling

The MTEP23 models were built using MISO's Model on Demand (MOD) model data repository, with the following base assumptions (Table 2-1).

Scenario	Effective Date	Projects Applied	External Modeling	Load and Generation Profile	Wind %	Solar %
Summer 2024	July 15th	MTEP Appendix A and Target A	ERAG MMWG 2022 Series 2024 Summer Peak Load Model	Summer Peak	18%	50%
Fall 2024	October 15th	MTEP Appendix A and Target A	ERAG MMWG 2022 Series 2024 Spring Light Load Model	Fall Peak	28.5%	0%
Winter 2024-2025	January 15th	MTEP Appendix A and Target A	ERAG MMWG 2022 Series 2024 Winter Peak Load Model	Winter Peak	67%	0%
Spring 2025	April 15th	MTEP Appendix A and Target A	ERAG MMWG 2022 Series 2024 Spring Light Load Model	Spring Peak	28.5%	0%

Table 2-1: Model Assumptions

MISO excluded several types of units from the transfer analysis dispatch—these units' base dispatch remained fixed.

- Nuclear dispatch does not change for any transfer without a sensitivity
- Wind and solar resources can be ramped down, but not up
- Pseudo-tied resources were modeled at their expected commitments to non-MISO load, although portions of these units committed to MISO could participate in transfer analyses

System conditions such as load, dispatch, topology, and interchange have an impact on transfer capability. The model was reviewed as part of the base model built for MTEP23 analyses, with study files made available on MISO ShareFile.

[2] Refer to the Transmission Planning BPM (BPM-20) for more information regarding MTEP input files. https://www.misoenergy.org/legal/business-practice-manuals/

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MISO worked closely with Transmission Owners and stakeholders to model the transmission system accurately, as well as to validate constraints and redispatch. Like other planning studies, transmission outage schedules were not included in the analyses. This is driven partly by limited availability of outage information as well as current transmission planning standards. Although no outage schedules were evaluated, single element contingencies were evaluated. This includes Bulk Electric System lines, transformers, and generators.

Contingency coverage covers most of category P1 and some of category P2 outlined in Table 1 of NERC Reliability Standard TPL-001.

2.2.4 General Assumptions

MISO uses TARA to process the powerflow model and associated input files to determine the seasonal import and export limits of each LRZ by determining the transfer capability. Transfer capability measures the ability of interconnected power systems to reliably transfer power from one area to another under specified system conditions. The incremental amount of power that can be transferred is determined through FCITC analysis. FCITC analysis and base power transfers provide the information required to calculate the First Contingency Total Transfer Capability (FCTTC), which indicates the total amount of transferrable power before a constraint is identified. FCTTC is the base power transfer plus the incremental transfer capability (Equation 2-1). All published limits are based on the zone's FCTTC and may be adjusted for capacity exports.

$$First\ Contingency\ Total\ Transfer\ Capability\ (FCTTC) = Base\ Power\ Transfer + \ FCITC$$

Equation 2-1: Total Transfer Capability

FCITC constraints are identified under base case situations in each season or under P1 contingencies provided through the MTEP process. Linear FCITC analysis identifies the limiting constraints using a minimum transfer Distribution Factor (DF) cutoff of 3 percent, meaning the transfer must increase the loading on the overloaded element, under system intact or contingency conditions, by 3 percent or more.

A pro-rata dispatch is used, which ensures all available generators will reach their maximum dispatch level at the same time. The pro-rata dispatch is based on the MW reserve available for each unit and the cumulative MW reserve available in the subsystem. The MW reserve is found by subtracting a unit's base model generation dispatch from its maximum dispatch, which reflects the available capacity of the unit.

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Table 2-2 and Equation 2-2 show an example of how one unit's dispatch is set, given all machine data for the source subsystem.

Machine	Base Model Unit Dispatch (MW)	Minimum Unit Dispatch (MW)	Maximum Unit Dispatch (MW)	Reserve MW (Unit Dispatch Max – Unit Dispatch Min)
1	20	20	100	80
2	50	10	150	100
3	20	20	100	80
4	450	0	500	50
5	500	100	500	0
			Total Reserve	**310**

Table 2-2: Example Subsystem

$$\boldsymbol{Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch} = \frac{\boldsymbol{Machine\ 1\ Reserve\ MW}}{\boldsymbol{Source\ Subsystem\ Reserve\ MW}} \times \boldsymbol{Transfer\ Level\ MW}$$

$$Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = \frac{80}{310} \times 100 = 25.8$$

$$Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = 25.8$$

Equation 2-2: Machine 1 Dispatch Calculation for 100 MW Transfer

2.3 Results for CIL/CEL and ZIA/ZEA

Study constraints and associated ZIA, ZEA, CIL, and CEL for each LRZ for each season were presented and reviewed through the LOLEWG with final results for Planning Year 2024-2025 presented at the October 17th, 2023 meeting. Table 2-3 below shows the Planning Year 2024-2025 CIL and ZIA with corresponding constraint, GLT, and redispatch (RDS) information.

All zones had an identified ZIA this year. If there is no valid constraint identified, the following equation will be used where the FCITC will be replaced by the Tier 1 and Tier 2 capacity.

$$\boldsymbol{ZIA = FCITC + Area\ Interchange - Border\ External\ Resources\ and\ Coordinating\ Owners}$$

Equation 2-3: Zonal Import Ability (ZIA) Calculation

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LRZ1	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2024	Wien - T Corners 115 kV	Arpin - Eau Claire 345 kV	10%	826MWx2	6460	6462
Fall 2024	Mitchell County - Adams 345 kV	Sherburne Country Generator	None	977MWx2	6500	6502
Winter 2024/25	Pleasant Valley - Byron 161 kV	Byron - Pleasant Valley 345 kV	None	670MWx2	4691	4693
Spring 2025	Coal Creek CR4 - Coal Creek TP4 230 kV	Coal Creek - Stanton 230 kV	None	1000MWx2	4941	4943
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Paddock 345/138 kV Transformer	Riverside Generator	None	586MWx2	4506	4506
Fall 2024	Arpin - Sigel 138 kV	Pow STG20 Generator	None	1000MWx2	5719	5719
Winter 2024/25	Rockdale - Lakehead Cambridge Tap 138 kV	Cambridge Tap - Rockdale 138 kV	None	614MWx2	5523	5523
Spring 2025	Arpin - Sigel 138 kV	Arpin - Rocky Run 345kV	None	1000MWx2	5034	5034
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Ottumwa 345/161 kV Transformer	Ottumwa Generator	None	617MWx2	4911	5009
Fall 2024	Ottumwa 345/161 kV Transformer	Ottumwa Generator	None	365MWx2	6684	6789
Winter 2024/25	Sub 3458 (Nebraska City) - Sub 3456 345 kV	Sub 3455 - Sub 3740 345 kV	None	440MWx2	5600	5704
Spring 2025	Ottumwa 345/161 kV Transformer	Ottumwa Generator	None	527MWx2	6514	6626
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	None	None	20%	None	9857	10790
Fall 2024	Palmyra - Marblehead North 161 kV	Herleman - Palmyra Tap 345 kV	10%	533MWx2	5699	6637
Winter 2024/25	Palmyra 345/161 kV Transformer	Herleman - Palmyra Tap 345 kV	None	1000MWx2	5811	6731
Spring 2025	Palmyra - Marblehead North 161 kV	Herleman - Palmyra Tap 345 kV	None	1000MWx2	5083	6003
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Moro - Miles 138 kV	Roxford - Moro 345 kV	None	1000MWx2	3208	3208
Fall 2024	Moro - Miles 138 kV	Roxford - Moro 345 kV	None	202MWx2	3786	3786
Winter 2024/25	Moro - Miles 138 kV	Roxford - Moro 345 kV	None	1000MWx2	4477	4477
Spring 2025	Moro - Miles 138 kV	Roxford - Moro 345 kV	None	356MWx2	3892	3892
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Cayuga Sub- Cayuga 345 kV	Kansas West - Sugar Creek 345 kV	5%	712MWx2	7197	7463
Fall 2024	Cayuga Sub - Cayuga 345 kV	Kansas West - Sugar Creek 345 kV	None	282MWx2	8661	8954
Winter 2024/25	Sullivan - Petersburg 345 kV	Rockport - Jefferson 765 kV	None	890MWx2	8286	8526
Spring 2025	Lawrenceville South - Vincennes 138 kV	Albion South - Gibson 345 kV	None	294MWx2	7730	8015
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Monroe 1&2 - Brownstown (Superior) 345kV	Monroe 1&2 - Wayne 345 kV	None	1000MWx2	4490	4500
Fall 2024	Verona - J758 138 kV	J758 - Verona West 138 kV	None	373MWx2	4390	4400
Winter 2024/25	Argenta - Tompkins 345 kV	Argenta - Battle Creek 345 kV	None	1000MWx2	4656	4666
Spring 2025	Stillwell - Dumont 345 kV	Wilton Center - Dumont 765 kV	None	927MWx2	4883	4893
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Winnfield 230/115 kV Transformer	Montgomery - Clarence 230 kV	None	1000MWx2	3444	3536
Fall 2024	Mount Olive - Vienna 115 kV	Mount Olive - Eldorado 500 kV	None	1000MWx2	4942	5040
Winter 2024/25	Little Gypsy - Fairview 230 kV	Michoud - Front Street 230 kV	None	1000MWx2	4262	4336
Spring 2025	Winnfield 230/115 kV Transformer	Mount Olive - Layfield 500 kV	10%	1000MWx2	6030	6124
LRZ9	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Danville - Dodson 115 kV	Mount Olive - Layfield 500 kV	None	1000MWx2	4794	5613
Fall 2024	Daniel - Daniel Intermediate 1 230 kV	Daniel - Daniel Intermediate 2 230 kV	None	1000MWx2	5608	6435
Winter 2024/25	Bogalusa 500/230 kV Transformer	Mcknight - Franklin 500 kV	None	1000MWx2	4623	5420
Spring 2025	Bogalusa 500/230 kV Transformer	Mcknight - Franklin 500 kV	None	1000MWx2	5598	6417
LRZ10	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Perryville - Baxter Wilson 500 kV	Grand Gulf Generator	None	1000MWx2	3564	3564
Fall 2024	Mcknight - Franklin 500 kV	Baxter Willson - Perryville 500 kV	21%	929MWx2	4736	4736
Winter 2024/25	Perryville - Baxter Wilson 500 kV	Grand Gulf Generator	None	1000MWx2	3219	3219
Spring 2025	Mcknight - Franklin 500 kV	Baxter Willson - Perryville 500 kV	34%	284MWx2	4628	4628

Table 2-3: Planning Year 2024–2025 Import Limits

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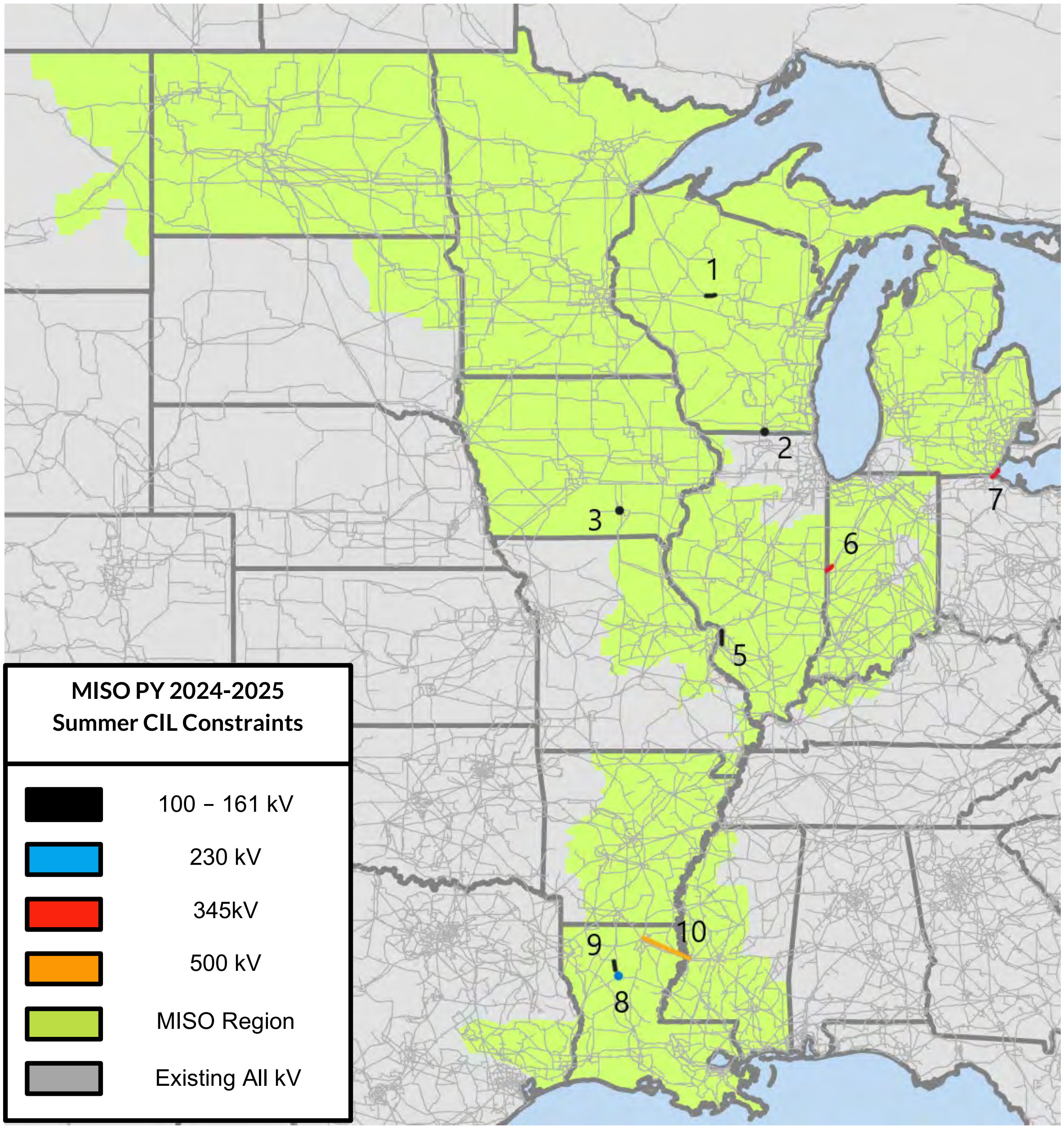

Figure 2-2: Planning Year 2024-2025 Summer Capacity Import Constraints Map

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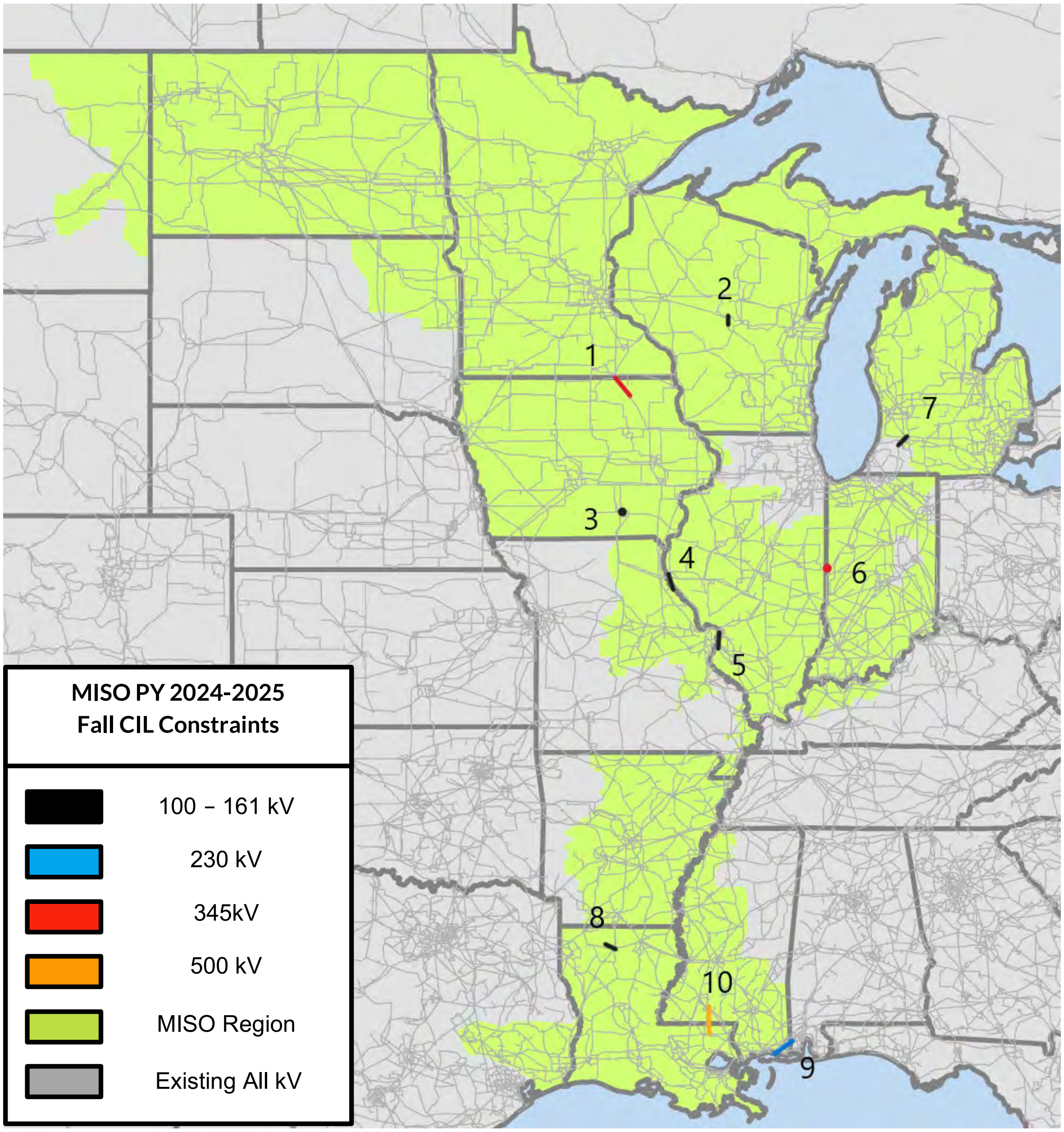

Figure 2-3: Planning Year 2024-2025 Fall Capacity Import Constraints Map

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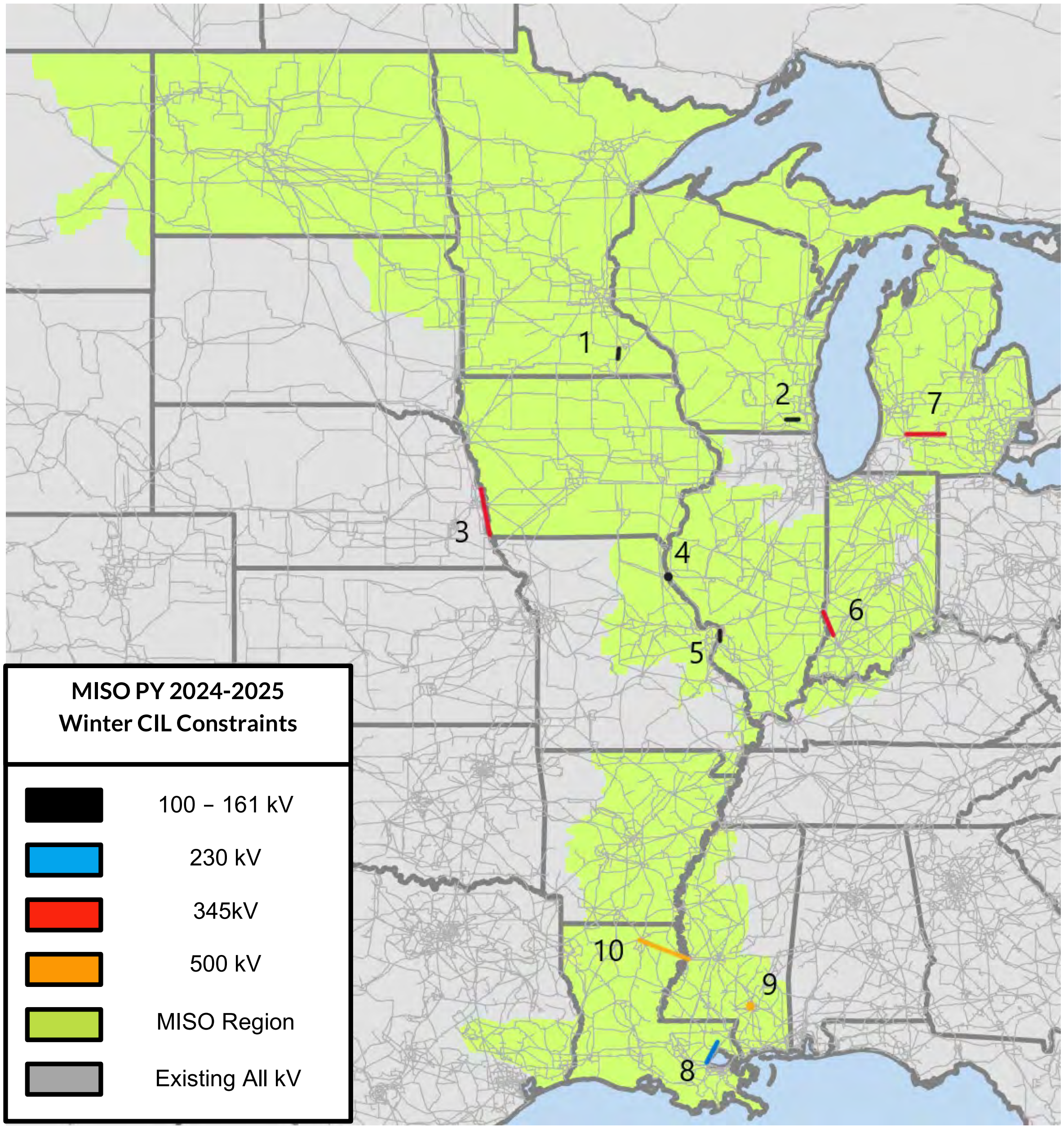

Figure 2-4: Planning Year 2024-2025 Winter Capacity Import Constraints Map

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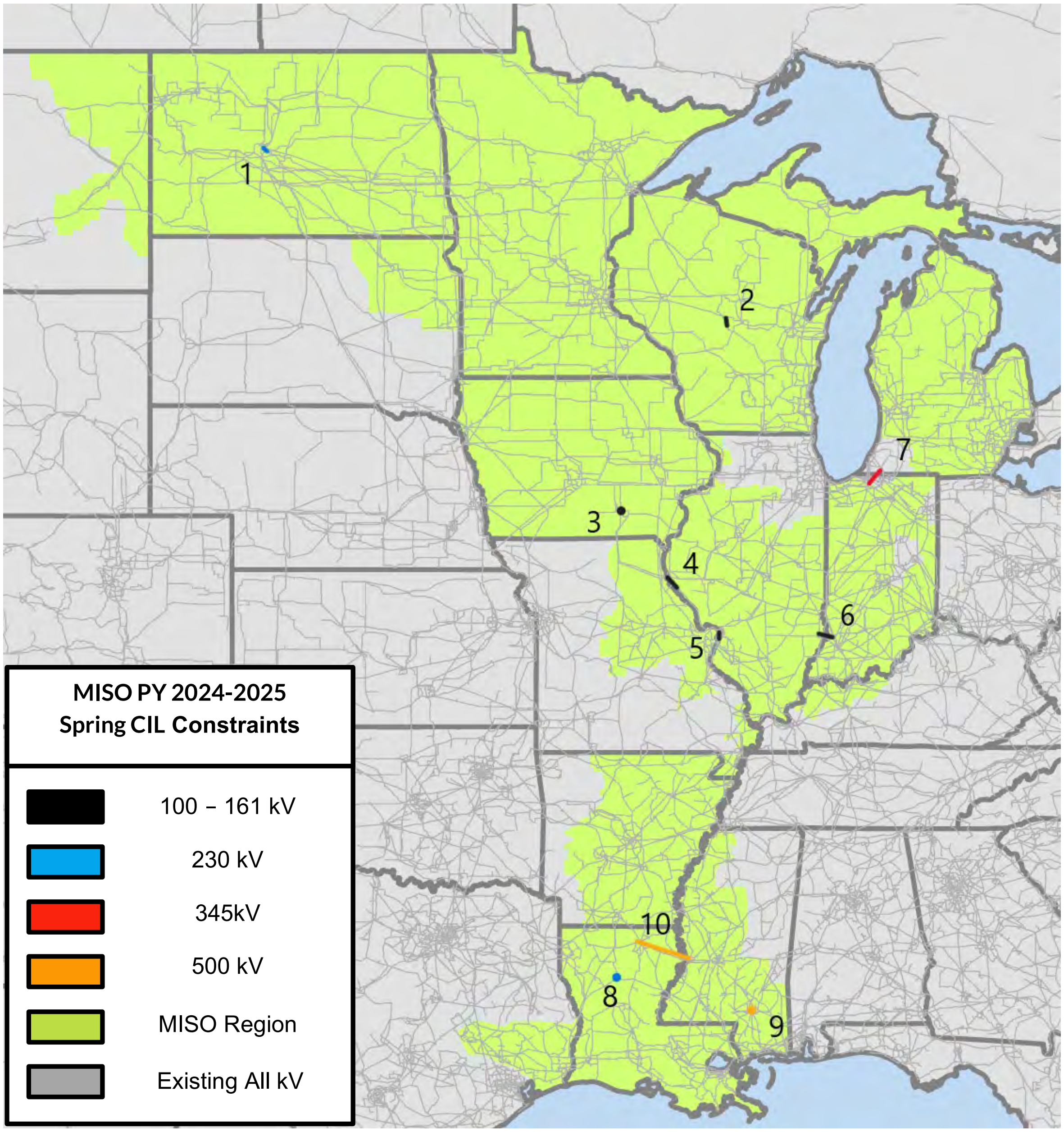

Figure 2-5: Planning Year 2024-2025 Spring Capacity Import Constraints Map

Capacity Exports Limits are found by increasing generation in the study zone and decreasing generation in the rest of the MISO footprint to create a transfer. Table 2-4 below shows the Planning Year 2024-2025 CEL and ZEA with corresponding constraint, GLT, and redispatch information.

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LRZ1	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2024	Split Rock - Sioux Falls 230 kV	Split Rock - Sioux City 345 kV	10%	1000MWx2	4539	4537
Fall 2024	Arpin - Sigel 138 kV	Arpin - Rocky Run 345kV	None	302MWx2	5713	5711
Winter 2024/25	Split Rock - Sioux Falls 230 kV	Split Rock - Sioux City 345 kV	None	847MWx2	5176	5174
Spring 2025	Split Rock - Sioux Falls 230 kV	Split Rock - Sioux City 345 kV	None	194MWx2	6320	6318
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	Pleasant Prairie - Zion 345 kV	Pleasant Prairie - Zion EC 345 kV	40%	295MWx2	3971	3971
Fall 2024	Pleasant Prairie - Zion 345 kV	Pleasant Prairie - Zion EC 345 kV	None	936MWx2	4512	4512
Winter 2024/25	Pleasant Prairie - Zion EC 345 kV	Pleasant Prairie - Zion 345 kV	30%	1000MWx2	4772	4772
Spring 2025	Pleasant Prairie - Zion EC 345 kV	Pleasant Prairie - Zion 345 kV	None	1000MWx2	4601	4601
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	None	None	50%	None	5548	5450
Fall 2024	Sandburg 161/138 kV Transformer	Galesburg - Oak Grove 345 kV	40%	515MWx2	7018	6913
Winter 2024/25	Wapello County - Appanoose County 161 kV	Zachary - Hughes 345kV	None	1000MWx2	9079	8975
Spring 2025	Sandburg 161/138 kV Transformer	Galesburg - Oak Grove 345 kV	50%	285MWx2	5873	5761
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	None	None	50%	None	3663	2730
Fall 2024	None	None	50%	None	4801	3863
Winter 2024/25	None	None	50%	None	5570	4650
Spring 2025	None	None	50%	None	6001	5081
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	None	None	40%	None	4644	4644
Fall 2024	Mass 345/161 kV Transformer	Mass - Joppa 345 kV	None	360MWx2	5402	5402
Winter 2024/25	None	None	50%	None	6229	6229
Spring 2025	Mass 345/161 kV Transformer	Shawnee - Mass 345 kV	None	1000MWx2	4984	4984
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	BR Tap - Paradise 161 kV	Paradise - Paradise CC Units 3-4 161 kV	35%	93MWx2	5903	5637
Fall 2024	South - Southeast 138 kV	Hanna - Franklin Township 138 kV	None	624MWx2	3812	3519
Winter 2024/25	Grandview - Newtonville 138 kV	Daviess - Coleman EHV Substation 345 kV	None	388MWx2	1647	1407
Spring 2025	South - Southeast 138 kV	Hanna - Franklin Township 138 kV	None	575MWx2	3729	3444
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	Lallendorf - Fostoria Central 345 kV	Lemoyne - Fostoria Central 345 kV	30%	921MWx2	5719	5709
Fall 2024	Monroe 1&2 - Lallendorf 345 kV	Morocco - Allen Jct 345 kV	None	1000MWx2	5391	5381
Winter 2024/25	Morocco - Allen Jct 345 kV	Lallendorf - Monroe 345 kV	None	1000MWx2	5753	5743
Spring 2025	Monroe 1&2 - Lallendorf 345 kV	Morocco - Allen Jct 345 kV	None	564MWx2	5601	5591
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	Perryville - Baxter Wilson 500 kV	Grand Gulf Generator	30%	1000MWx2	6263	6171
Fall 2024	Independence - Moorefield 161 kV	Independence - Power Line Road EHV 500 kV	None	35MWx2	4310	4212
Winter 2024/25	Arklahoma - Hot Springs East 115 kV	Hot Springs West - Arklahoma 115 kV	50%	155MWx2	5882	5808
Spring 2025	Cash - Jonesboro 161 kV	Independence - Power Line Road EHV 500 kV	None	177MWx2	5030	4936
LRZ9	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	PPG - Verdine 230 kV	PPG - Manena 230 kV	None	1000MWx2	3178	2359
Fall 2024	White Bluff - Keo 500 kV	Sheridan - Mabelvale 500 kV	None	1000MWx2	4429	3602
Winter 2024/25	Adams Creek - Angie 230 kV	French Branch - Slidell 230 kV	None	1000MWx2	2900	2103
Spring 2025	Michoud - Front Street 230 kV	Mcknight - Franklin 500 kV	None	1000MWx2	4813	3994
LRZ10	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	Clarksdale - Lyon 115 kV	MEPS Clarkesdale - Moon Lake 230kV	None	377MWx2	1840	1840
Fall 2024	Clarksdale - Lyon 115 kV	MEPS Clarkesdale - Moon Lake 230kV	None	535MWx2	2889	2889
Winter 2024/25	Clarksdale - Lyon 115 kV	MEPS Clarkesdale - Moon Lake 230kV	None	284MWx2	2993	2993
Spring 2025	Clarksdale - Lyon 115 kV	MEPS Clarkesdale - Moon Lake 230kV	None	535MWx2	2740	2740

Table 2-4: Planning Year 2024–2025 Export Limits

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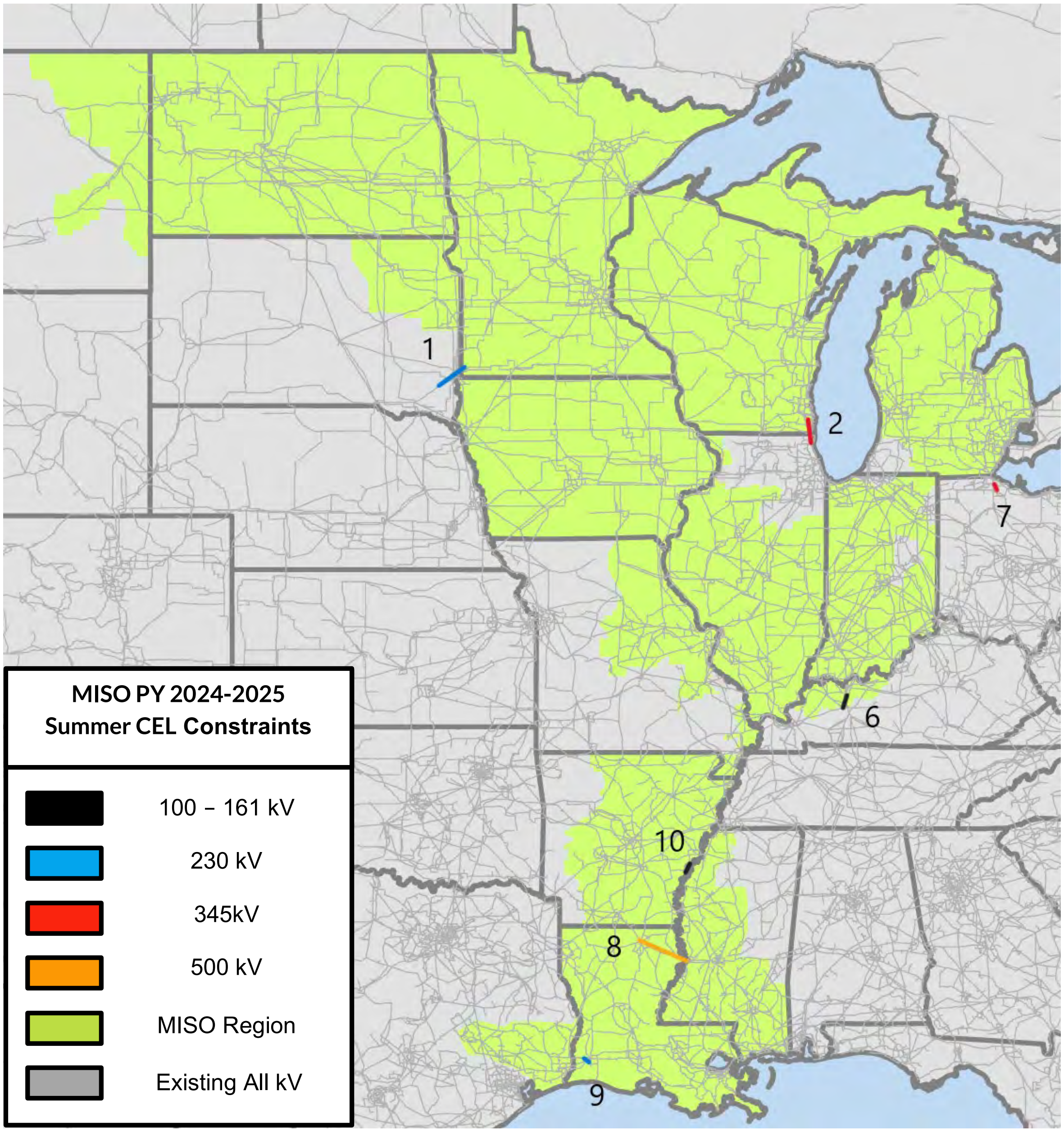

Figure 2-6: Planning Year 2024-2025 Summer Export Constraint Map

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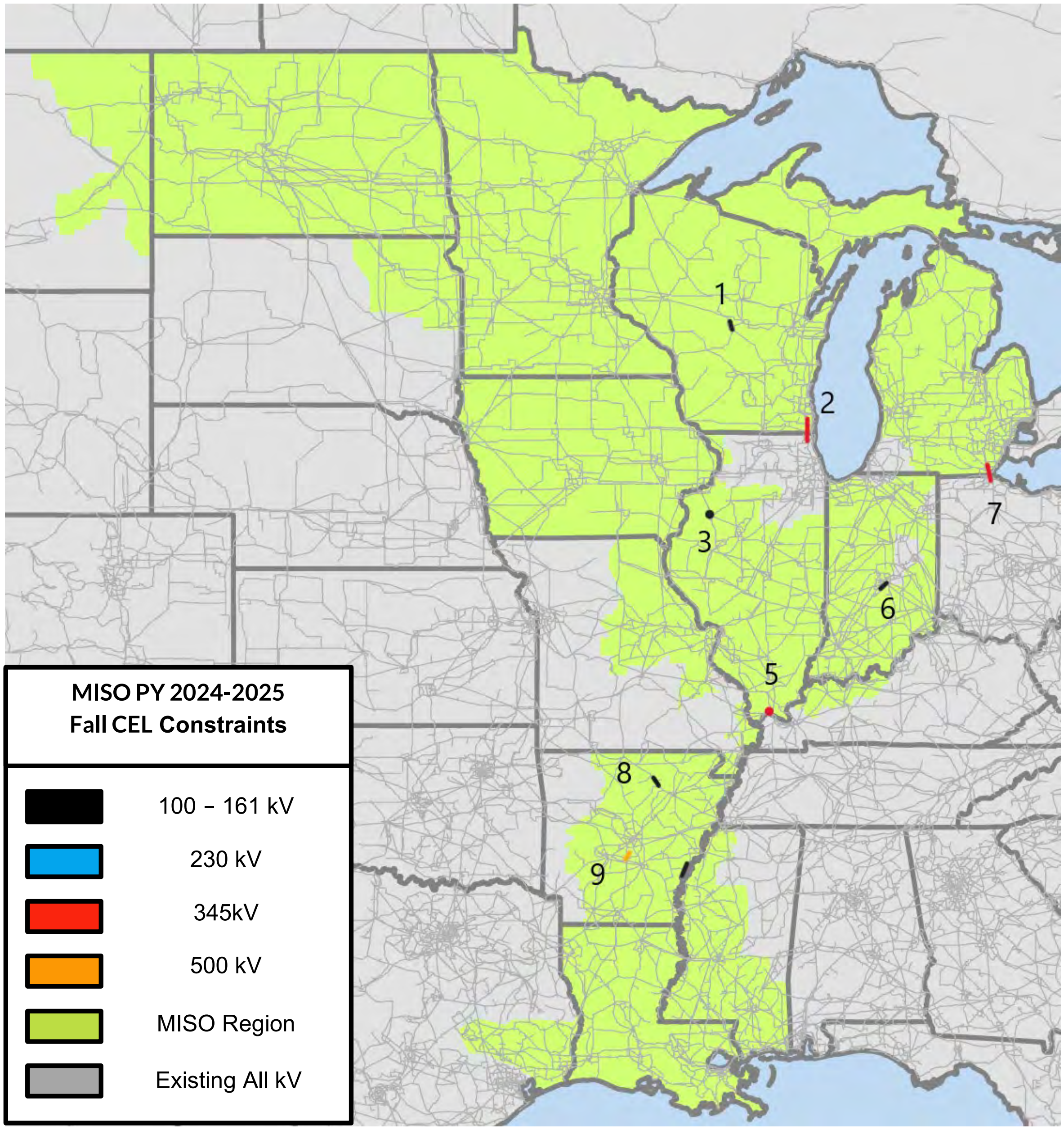

Figure 2-7: Planning Year 2024-2025 Fall Export Constraint Map

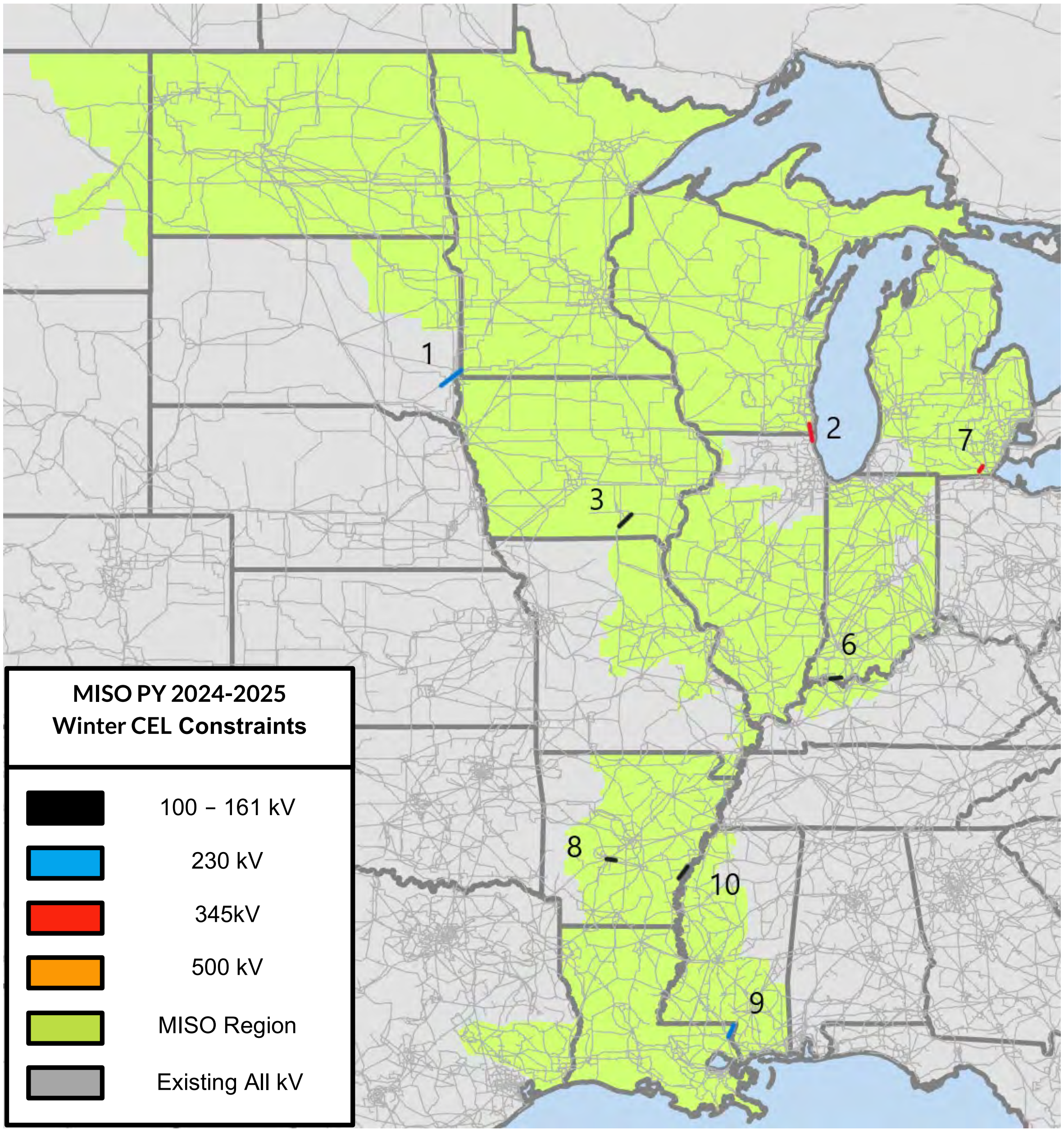

Figure 2-8: Planning Year 2024-2025 Winter Export Constraint Map

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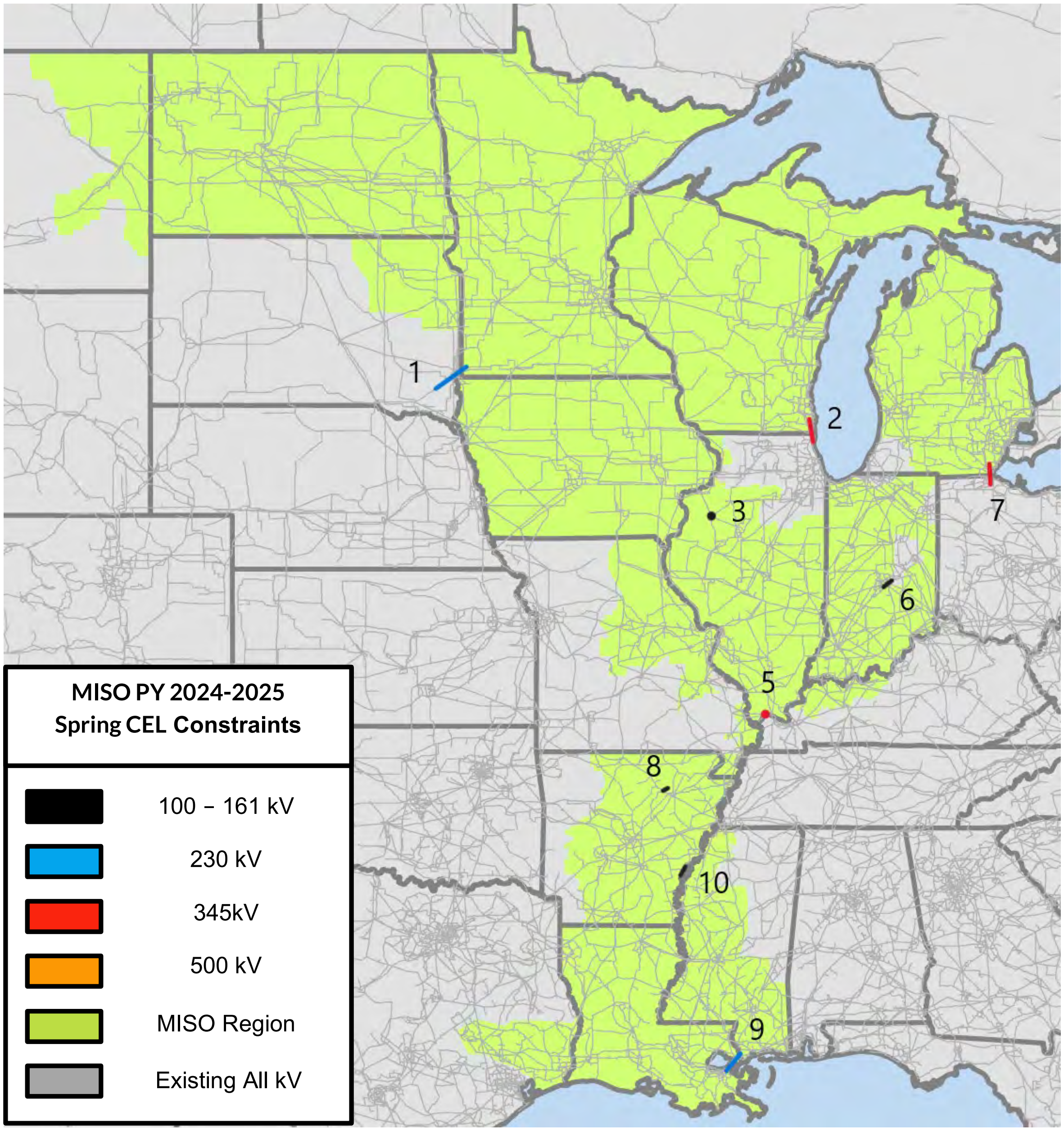

Figure 2-9: Planning Year 2024-2025 Spring Export Constraint Map

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3 Loss of Load Expectation Analysis

3.1 LOLE Modeling Input Data and Assumptions

MISO uses a program developed and maintained by Astrapé Consulting called Strategic Energy & Risk Valuation Model (SERVM) to calculate LOLE for the applicable Planning Year. SERVM uses a sequential Monte Carlo simulation to model a generation system and to assess the system's reliability, based on any number of interconnected areas. SERVM calculates LOLE for the MISO system and for each LRZ by stepping through the year chronologically and taking into account generation, load, load modifying and energy efficiency resources, equipment forced outages, planned and maintenance outages, weather and economic uncertainty, and external support.

Building the SERVM model is the most time-consuming task of the LOLE Study. Several sensitivities are built in order to determine how specific inputs and variables impact the results. The base case models determine the seasonal MISO PRM Installed Capacity (ICAP), PRM Unforced Capacity (UCAP), and the Local Reliability Requirements (LRRs) for each LRZ for future Planning Years one, four, and six.

3.2 MISO Generation

3.2.1 Thermal Units

The Planning Year 2024-2025 LOLE Study used the 2023-2024 PRA converted capacity as a starting point for which resources to include in the study. This ensured that only resources eligible as Planning Resources were included in the LOLE Study. An exception was made to include resources with a signed and executed GIA that have an anticipated in-service date (adjusted for average GI delays) for PY 2024-2025. All internal Planning Resources were modeled in the LRZ in which they are physically located. Additionally, Coordinating Owner External Resources and Border External Resources were modeled as being internal to the LRZ in which they are committed to serving load.

Seasonal forced outage rates and annualized planned maintenance outage rates were calculated over a five-year period (January 2016 to December 2022) for each resource. Some resources did not have five years of historical data in MISO's Generator Availability Data System (PowerGADS)—however, if they had at least 3 consecutive months of outage data, resource-specific information was used to calculate their seasonal forced and planned maintenance outage rates. Resources with fewer than 3 consecutive months of resource-specific outage data were assigned the corresponding MISO seasonal class average forced outage rate and annualized planned maintenance outage rate based on their resource type. The overall MISO ICAP-weighted seasonal class average forced outage rates and annualized planned maintenance outage rate were applied in lieu of class averages for classes with fewer than 30 resources reporting 12 or more months of data.

Each nuclear unit has a fixed maintenance schedule, which was pulled from publicly available information and was modeled for each of the study years.

The historical class average outage rates as well as the MISO system-wide weighted average forced outage rate are provided in Table 3-1 to show the year-over-year trends, as well as in Table 3-2 on a seasonal basis.

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Pooled EFORd GADS Years	2018-2022 (%)	2017-2021 (%)	2016-2020 (%)	2015-2019 (%)	2014-2018 (%)	2013-2017 (%)
LOLE Study Planning Year	**PY 2024-2025 LOLE Study** Summer	**PY 2023-2024 LOLE Study** Summer	**PY 2022-2023 LOLE Study** Annualized	**PY 2021-2022 LOLE Study** Annualized	**PY 2020-2021 LOLE Study** Annualized	**PY 2019-2020 LOLE Study** Annualized
Combined Cycle	5.92	5.54	5.85	5.52	5.70	5.37
Combustion Turbine (0-20 MW)	24.42	23.40	35.20	36.38	40.39	23.18
Combustion Turbine (20-50 MW)	6.54	6.30	13.65	14.20	15.29	15.76
Combustion Turbine (50+ MW)	4.88	4.07	4.36	4.76	4.65	5.18
Diesel Engines	17.14	12.79	7.25	10.05	23.53	10.26
Fluidized Bed Combustion	*	*	*	*	*	*
Hydro (0-30 MW)	*	*	*	*	*	*
Hydro (30+ MW)	*	*	*	*	*	*
Nuclear	*	*	*	*	*	*
Pumped Storage	*	*	*	*	*	*
Steam – Coal (0-100 MW)	*	*	*	*	5.33	4.60
Steam - Coal (100-200 MW)	*	*	*	*	*	*
Steam - Coal (200-400 MW)	*	*	*	10.47	10.16	9.82
Steam - Coal (400-600 MW)	*	*	*	*	*	*
Steam - Coal (600-800 MW)	*	*	*	*	*	8.22
Steam - Coal (800-1000 MW)	*	*	*	*	*	*
Steam - Gas	14.04	11.26	11.84	12.91	12.54	11.56

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Pooled EFORd GADS Years	2018-2022 (%)	2017-2021 (%)	2016-2020 (%)	2015-2019 (%)	2014-2018 (%)	2013-2017 (%)
LOLE Study Planning Year	**PY 2024-2025 LOLE Study** Summer	**PY 2023-2024 LOLE Study** Summer	**PY 2022-2023 LOLE Study** Annualized	**PY 2021-2022 LOLE Study** Annualized	**PY 2020-2021 LOLE Study** Annualized	**PY 2019-2020 LOLE Study** Annualized
Steam - Oil	*	*	*	*	*	*
Steam - Waste Heat	*	*	*	*	*	*
Steam - Wood	*	*	*	*	*	*
MISO Weighted System-wide	8.24	8.23	9.04	9.36	9.24	9.28

**MISO weighted system-wide forced outage rate used in place of class data for classes with less than 30 resources reporting 12 or more months of data*

Table 3-1: Historical Class Average Forced Outage Rates

Pooled EFORd GADS Years	2018-2022 (%)	2018-2022 (%)	2018-2022 (%)	2018-2022 (%)
LOLE Study Planning Year 2024-2025	**Summer 2024**	**Fall 2024**	**Winter 2024-2025**	**Spring 2025**
Combined Cycle	5.92	7.43	5.38	6.55
Combustion Turbine (0-20 MW)	24.42	24.17	46.17	51.36
Combustion Turbine (20-50 MW)	6.54	18.59	50.59	34.26
Combustion Turbine (50+ MW)	4.88	7.23	10.53	5.15
Diesel Engines	17.14	14.26	24.94	8.89
Fluidized Bed Combustion	*	*	*	*
Hydro (0-30 MW)	*	*	*	*
Hydro (30+ MW)	*	*	*	*
Nuclear	*	*	*	*

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Pooled EFORd GADS Years	2018-2022 (%)	2018-2022 (%)	2018-2022 (%)	2018-2022 (%)
LOLE Study Planning Year 2024-2025	**Summer 2024**	**Fall 2024**	**Winter 2024-2025**	**Spring 2025**
Pumped Storage	*	*	*	*
Steam – Coal (0-100 MW)	*	*	*	*
Steam - Coal (100-200 MW)	*	*	*	*
Steam - Coal (200-400 MW)	*	*	*	*
Steam - Coal (400-600 MW)	*	*	*	*
Steam - Coal (600-800 MW)	*	*	*	*
Steam - Coal (800-1000 MW)	*	*	*	*
Steam - Gas	14.04	13.26	11.11	12.07
Steam - Oil	*	*	*	*
Steam - Waste Heat	*	*	*	*
Steam - Wood	*	*	*	*
MISO Weighted System-wide	8.24	9.15	11.23	10.33

**MISO weighted system-wide forced outage rate used in place of class data for classes with less than 30 resources reporting 12 or more months of data*

Table 3-2: Planning Year 2024-2025 Seasonal Class Average Forced Outage Rates

3.2.2 Behind-the-Meter Generation

Behind-the-Meter Generation data came from the Module E Capacity Tracking (MECT) tool. Behind-the-Meter Generation backed by thermal resources were explicitly modeled just as any other thermal generator with a monthly capability and forced outage rate. Behind-the-Meter Generation backed by intermittent resources were modeled at their expected seasonal availability.

3.2.3 Attachment Y

MISO obtained information on generating resources with approved suspensions or retirements (as of June 1, 2023) through MISO's Attachment Y process. Any resource with an approved retirement or suspension in Planning Year

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2024-2025 was excluded from the year-one analysis during the months the resource has been approved to be out of service for. This same methodology is used for the four- and six-year analyses.

3.2.4 Future Generation

The LOLE model included resources with a signed and executed Generator Interconnection Agreement (as of June 1, 2022). These future resources were assigned seasonal class average forced outage rates and planned maintenance outage rates based on their resource class. Future thermal generation and upgrades were added to the LOLE model based on resource information in the MISO Generator Interconnection Queue. Resources with a planned upgrade during the study period reflect the megawatt increase for each month, beginning the month the upgrade is expected to be completed. The LOLE analysis includes future wind and solar generation, tied to the same hourly wind and solar profiles used for existing wind and solar resources in the model.

3.2.5 Intermittent Resources

Intermittent resources include solar, wind, biomass, battery storage, and run-of-river hydro. Most intermittent resources submit historical output data during seasonal peak hours, defined as hours ending 15, 16, & 17 EST for Summer, Fall, and Spring, and hours ending 8, 9, 19, & 20 for Winter. Non-CPNode wind and battery storage resources are exceptions to this and only submit historical output data for the top 8 seasonal coincident peaks for the last 3 Planning Years for which data is available. This data is averaged at the seasonal level and modeled in the LOLE analysis as seasonal effective capacity for all months within a given season. Each individual resource is modeled in the LRZ corresponding to its load obligation.

Using historical wind operational data from 253 front-of-meter wind resources from 2013 to 2022, normalized hourly capacity profiles were developed and aggregated at the LRZ level to represent hourly wind capability in the model. As a result of the LOLE analysis being based on 30 weather years (1993 – 2022), synthetic shapes were developed by Astrapé for the 1992 – 2013 period based on historical wind performance and temperatures. Once the weather and wind performance matching has been performed, the data is analyzed as a function of load to ensure the variability around the load profiles is reasonable.

Solar profiles were also developed by Astrapé using historical solar irradiance data from the NREL National Solar Radiation Database (NSRDB) from 1998 – 2022.

For more details on profile development methodology, refer to the supporting documentation Astrapé provided stakeholders at the LOLEWG detailing the development of the wind and solar profiles:
MISO Seasonal Inputs for the 2022 LOLE Study

3.2.6 Demand Response

Demand response programs and their corresponding capabilities came from the MECT tool. These resources were explicitly modeled as dispatch-limited resources. Each demand response program was modeled individually with a monthly capacity, limited by duration and the number of times each program can be called upon for each season.

3.3 MISO Load Data

The Planning Year 2024-2025 LOLE analysis used a load training process with neural net software to establish a correlated relationship in the trained and predicted load shapes between historical weather and load data. This relationship was then applied to 30 years of hourly historical load data to create 30 different load shapes for each LRZ to capture both load diversity and seasonal variations. The Zonal Coincident Peak Forecasts provided by the Load

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Serving Entities were used to develop zonal- and monthly-specific load forecast scaling factors which scale the average of the 30 load shapes based on provided forecasts. The results of this process are shown as the MISO System Peak Demand (Table 4-1) and LRZ Peak Demands (Table 5-1, Table 5-2, Table 5-3, & Table5-4).

Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. Demand response is dispatched in the LOLE model to avoid load shed during simulation when all other available generation has been exhausted.

3.3.1 Weather Uncertainty

MISO has adopted a six-step load training process in order to capture the weather uncertainty associated with the most recent 50/50 load forecasts submitted by the Load Serving Entities for the development of the 30 years of hourly zonal correlated load and weather shapes in the LOLE model.

The first step of the load training process is to collect the most recent year of historical hourly net load data, as well as any hourly load reductions. Since Load Modifying Resources are modeled in the LOLE Study, the hourly load reductions are added to the net load data. MISO also collects historical temperature data from a zonal-specific weather station for the most recent weather year included in the study. Both the hourly LMR deployment and load data are taken from historical MISO energy market data for each LBA, while the historical weather data is collected from the National Oceanic and Atmospheric Administration (NOAA) for each LRZ. After collecting the data, the hourly gross load for each LRZ is calculated using the most recent five years of historical data.

The second step of the process is to normalize the five years of load data to consistent economics. This process involves zonal load growth adjustments by comparing the most recent 5 years of historical load at extreme temperatures and shifting the shapes up or down if they do not reasonably overlay on top of each other. Regression analysis is then performed at the zonal level, focusing on summer and winter peak periods in order to compensate for the fact that the neural net training software can occasionally over- or under-predict results for extremely high or extremely low temperatures.

The third step of the process utilizes neural net software to establish functional relationships between the most recent five years of historical weather and load data. After the load growth adjustments and regressions have been performed, the treated historical load and weather data are input into the neural net software. MISO utilizes the NeuroShell Predictor software which performs neural net training and predicting using a genetic algorithm. The neural net trains each month of zonal data individually to predict a total of 120 datasets.

In the fourth step of the process and after the neural net has finished, we check the results of the neural net at extreme temperatures to smooth out any over- or under-predicted loads by comparing against the entire 30 years of historical correlated load and weather years. MISO looks for hours where the load is plus or minus 30% different than the previous hour and corrects those hours.

In the fifth step of the load training process, MISO undertakes extreme temperature verification on the 30 years of load shapes to ensure that the hourly load data is reasonably accurate at extremely hot or cold temperatures. This is required since there are fewer data points available at the temperature extremes when determining the neural net functional relationships. This lack of data at the extremes can result in inaccurate predictions when creating load shapes, which will need to be corrected before moving forward.

The sixth and final step of the load training process is to average the monthly peak loads of the predicted load shapes and adjust them to match each LRZ's monthly Zonal Coincident Peak Forecast provided by the Load Serving Entities

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for each of the study years. To calculate this adjustment, the ratio of the first year's Non-Coincident Peak Forecast to the Zonal Coincident Peak Forecast is applied to future outyears' Non-Coincident Peak Forecasts.

By adopting this methodology for capturing weather uncertainty, MISO can model multiple load shapes based on a functional relationship with weather. This modeling approach provides diversity in the load shapes, as well as in the peak loads observed within each load shape. This approach also provides the ability to capture the frequency and duration of historical severe weather patterns.

3.3.2 Economic Load Uncertainty

To account for economic load uncertainty in the Planning Year 2024-2025 LOLE model, MISO utilized a normal distribution of electric utility forecast error accounting for projected and actual Gross Domestic Product (GDP), as well as electricity usage. The historic projections for GDP growth were taken from the Congressional Budget Office (CBO), the actual GDP growth was taken from the Bureau of Economic Analysis (BEA), and the electricity usage was taken from the U.S. Energy Information Administration (EIA). Due to a lack of state-wide projected GDP data, MISO relied on aggregated United States data when calculating economic uncertainty.

To calculate the electric utility forecast error, MISO first calculated the forecast error of GDP between historical projections and actual values. The resulting GDP forecast error was then translated into electric utility forecast error by multiplying by the rate at which electric load grows in comparison to GDP. Finally, a standard deviation is calculated from the electric utility forecast error and used to create a normal distribution representing the probabilities of the load forecast errors (LFE) as shown in Table 3-3.

	LFE Levels				
	-2.0%	-1.0%	0.0%	1.0%	2.0%
Standard Deviation in LFE	Probability assigned to each LFE				
0.90%	4.8%	24.1%	42.1%	24.1%	4.8%

Table 3-3: Economic Uncertainty

3.4 External System

Firm imports from external areas to MISO are modeled at the individual resource level. The specific firm external resources were modeled with their Installed Capacity amount and their corresponding seasonal forced outage rates, or at the contracted capacity from their corresponding Power Purchase Agreement (PPA). These resources are only modeled within the system-wide MISO PRM analysis and are not modeled when calculating the zonal LRRs, as the determination of the Local Reliability Requirements is an island-type analysis. Border External Resources and Coordinating Owner External Resources are modeled as internal MISO units and are included in the PRM and LRR analyses. The external resources included as firm imports in the LOLE Study were based on the amount of capacity that was either part of a Fixed Resource Adequacy Plan (FRAP) or that offered and cleared in the Planning Year 2023-2024 Planning Resource Auction (PRA).

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The LOLE analyses incorporate firm exports from MISO internal units to neighboring regions, where information was available. For units with capacity sold off-system, their monthly capacities were reduced by the megawatt amount exported. These values came from PJM's Reliability Pricing Model (RPM) as well as information on exports to other external areas taken from the Independent Market Monitor (IMM) exclusion list.

Firm exports from MISO to external areas were modeled the same as in previous years. Capacity ineligible as MISO capacity due to transactions with external areas was removed from the model. Table 3-4 shows the amount of firm imports and exports in this year's study. MISO went from being a net firm exporter to a net firm importer in the most recent PRA.

Contracts	Summer ICAP (MW)	Summer UCAP (MW)	Fall ICAP (MW)	Fall UCAP (MW)	Winter ICAP (MW)	Winter UCAP (MW)	Spring ICAP (MW)	Spring UCAP (MW)
Imports (MW)	3,217	3,052	2,865	2,758	3,771	3,613	3,247	3,105
Exports (MW)	1,142	1,086	1,160	1,124	1,125	1,062	1,159	1,094
Net	**2,075**	**1,966**	**1,705**	**1,634**	**2,646**	**2,552**	**2,088**	**2,010**

Table 3-4: Planning Year 2023-2024 Firm Imports and Exports

Non-firm imports in the Planning Year 2024-2025 LOLE Study were modeled as a probabilistic distribution of capacity value. These distributions were developed using historic seasonal NSI data which accounted for imports into MISO during emergency pricing hours. Firm imports cleared in the PRA for each Planning Year were subtracted from the NSI data to isolate the non-firm values. An additional region was included in SERVM which contained 12,000 MW of perfect generation connected to the MISO system. A distribution of the region's export capability was modeled to the upper and lower bounds. As SERVM steps through the hourly simulation, random draws on the export limits of the external region were used to represent the amount of capacity MISO could import to meet peak demand. The probability distribution of non-firm external imports used in the LOLE model has been provided in Table 3-5.

	Summer	Fall	Winter	Spring
p5	1,138	525	9	1,384
p10	1,440	903	288	1,626
p25	2,959	1,749	1,223	2,283
p50	4,260	2,601	3,292	3,717
p75	5,198	3,632	5,785	4,987
p90	5,921	4,935	8,097	6,221
p95	6,520	5,748	9,197	6,497

Table 3-5: Non-Firm External Import Distribution During Emergency Pricing Hours (MW)

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3.5 Loss of Load Expectation Analysis and Metric Calculations

Upon completion of the annual LOLE Study model refresh, MISO performed probabilistic analyses to determine the seasonal PRM ICAP and PRM UCAP for Planning Year 2024-2025 as well as the seasonal Local Reliability Requirement for each of the ten Local Resource Zones. These metrics were derived through probabilistic modeling of the system, first solving to the industry standard annual LOLE risk target of 1 day in 10 years, or 0.1 day per year, and then solving to the minimum seasonal LOLE criteria of 0.01 LOLE for seasons demonstrating minimal risk.

3.5.1 Seasonal LOLE Distribution

To determine the seasonal LOLE distribution that will be used to calculate the PRM and LRRs, MISO followed the process described in Section 68A.2.1 of Module E-1 of the MISO Tariff. This process involves first solving the LOLE model to an annual value of 0.1 and then checking the seasonal distribution of the annual LOLE of 0.1. If a season had a LOLE value of at least 0.01, then it met the minimum seasonal LOLE criteria and would be set to that LOLE. If a season had less than 0.01 LOLE, additional simulations were performed until the minimum seasonal LOLE criteria of 0.01 was met.

Example: Assume the model is solved to an annual LOLE of 0.1 with 0.05 occurring in both Summer and Winter while Fall and Spring had LOLE values of 0 from this simulation. In this case, the Summer and Winter seasons would not need additional analysis since both had at least 0.01 LOLE naturally when the model was solved to an annual value of 0.1. Since Fall and Spring had 0 LOLE, they would be assigned the minimum seasonal LOLE criteria of 0.01 and additional LOLE simulations would be performed until the minimum seasonal LOLE criteria was met.

The annual distribution of LOLE across the four seasons at the industry standard of 1 day in 10 years, or 0.1 day per year, determined through the Planning Year 2024-2025 LOLE Study are shown in Table 3-6. The MISO-wide distribution results from the PRM analysis and the zonal distributions result from the LRR analyses.

Region	Summer	Fall	Winter	Spring
MISO-wide	0.1	0.01	0.01	0.01
LRZ 1	0.094	0.01	0.01	0.01
LRZ 2	0.099	0.01	0.01	0.01
LRZ 3	0.091	0.01	0.01	0.01
LRZ 4	0.022	0.01	0.075	0.01
LRZ 5	0.01	0.01	0.083	0.01
LRZ 6	0.085	0.01	0.015	0.01
LRZ 7	0.037	0.061	0.01	0.01
LRZ 8	0.014	0.01	0.078	0.01
LRZ 9	0.042	0.036	0.014	0.01
LRZ 10	0.058	0.019	0.015	0.01

Table 3-6: Planning Year 2024-2025 Seasonal LOLE Distribution

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3.5.2 MISO-Wide LOLE Analysis and PRM Calculation

MISO determines the appropriate PRM for each season of the applicable Planning Year based upon probabilistic analysis of reliably serving expected demand. The probabilistic analysis will utilize a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations.

To determine the PRM, the LOLE model will initially be run with no adjustments to the capacity. If the LOLE is less than the minimum seasonal LOLE criteria, a negative output unit with no outage rates will be added until the LOLE reaches the minimum seasonal LOLE criteria. This is comparable to adding load to the model. If the LOLE is greater than the minimum seasonal LOLE criteria, proxy units based on a typical combustion turbine unit of 160 MW with class average seasonal forced outage rates will be added to the model until the LOLE reaches the minimum seasonal LOLE criteria.

MISO's annual LOLE Study will calculate the seasonal PRMs based on the LOLE criteria identified in the previous section. The minimum seasonal PRM requirement will be determined using the LOLE analysis by either adding a perfectly available negative output unit or by adding proxy units until a minimum LOLE of 0.01 day per season is reached.

The formulas for the PRM values for the MISO system are:

PRM ICAP % = (Installed Capacity + Firm External Support ICAP + ICAP Adjustment to meet LOLE target – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

PRM UCAP % = (Unforced Capacity + Firm External Support UCAP + UCAP Adjustment to meet LOLE target – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

Where Unforced Capacity (UCAP) = Installed Capacity (ICAP) x (1 – XEFORd)

3.5.3 LRZ LOLE Analysis and Local Reliability Requirement Calculation

For the Local Resource Zone analysis, each zone included only the generating units within the LRZ (including Coordinating Owner External Resources and Border External Resources) and was modeled without consideration of the benefit of the LRZ's import capability. Similar to the MISO PRM analysis, Unforced Capacity is either added or removed in each LRZ such that an LOLE of 0.1 day per year is achieved when solving for the annual target and a minimum LOLE at least 0.01 day per season when solving for the minimum seasonal LOLE criteria. The minimum amount of Unforced Capacity above each LRZ's seasonal peak demand that was required to meet the reliability criteria was used to establish each LRZ's LRR.

The Planning Year 2024-2025 seasonal LRRs were determined using the LOLE analysis by first either adding or removing capacity until the annual LOLE reaches 0.1 day per year for the LRZ. If the LOLE is less than 0.1 day per year, a perfectly available negative output unit with no outage rates will be added until the LOLE reaches 0.1 day per year. If the LOLE is greater than 0.1 day per year, proxy units based on a typical combustion turbine unit of 160 MW with class average seasonal forced outage rates will be added to the model until the LOLE reaches 0.1 day per year.

After solving each LRZ for to the annual LOLE target of 0.1 day per year, MISO will calculate each seasonal LRR such that the summation of seasonal LOLE across the year in each zone is 1 day in 10 years, or 0.1 day per year. A minimum seasonal LOLE criteria of 0.01 will be used to calculate the LRR in seasons with less than 0.01 LOLE risk under the annual case. The seasonal Local Reliability Requirement will be determined using the LOLE analysis by either adding a perfectly available negative output unit or by adding proxy combustion turbine units until a minimum LOLE of 0.01 day per season is reached. When needed, a fraction of the marginal proxy unit was added to achieve the exact minimum seasonal LOLE criteria for the LRZ.

LRR UCAP % = (Unforced Capacity + UCAP Adjustment to meet LOLE target – Zonal Coincident Peak Demand)/Zonal Coincident Peak Demand

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4 MISO System Planning Reserve Margin

4.1 Planning Year 2024-2025 MISO Planning Reserve Margin Results

For Planning Year 2024-2025, the ratio of MISO capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin ICAP of 17.7 percent and a Planning Reserve Margin UCAP of 9.0 percent for the Summer season. Numerous values and calculations went into determining the MISO system PRM ICAP and PRM UCAP (Table 4-1).

MISO Planning Reserve Margins (PRM)	PY 2024-2025 Summer	PY 2024-2025 Fall	PY 2024-2025 Winter	PY 2024-2025 Spring	Formula Key
MISO System Peak Demand (MW)	124,669	112,232	104,303	99,496	[A]
Installed Capacity (ICAP) (MW)	150,187	148,755	165,924	152,092	[B]
Unforced Capacity (UCAP) (MW)	139,444	136,572	143,201	138,251	[C]
Firm External Support (ICAP) (MW)	3,217	2,865	3,771	3,247	[D]
Firm External Support (UCAP) (MW)	3,052	2,758	3,613	3,105	[E]
Adjustment to ICAP (MW)	-6,650	-11,145	-13,890	-15,275	[F]
Adjustment to UCAP (MW)	-6,650	-11,145	-13,890	-15,275	[G]
ICAP PRM Requirement (PRMR) (MW)	146,754	140,475	155,805	140,064	[H]=[B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	135,846	128,185	132,925	126,081	[I]=[C]+[E]+[G]
MISO PRM ICAP	**17.7%**	**25.2%**	**49.4%**	**40.8%**	[J]=([H]-[A])/[A]
MISO PRM UCAP	**9.0%**	**14.2%**	**27.4%**	**26.7%**	[K]=([I]-[A])/[A]

Table 4-1: Planning Year 2024-2025 MISO System Planning Reserve Margins

4.1.1 Additional Risk Metric Statistics

In addition to the LOLE results, SERVM has the ability to calculate several other probabilistic metrics, shown below in Table 4-2. The values for Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) are calculated at the point where the annual LOLE is at 1 day in 10 years, or 0.1 LOLE. Loss of Load Hours is defined as the number of hours during a given time period where system demand will exceed the generating capacity. Expected Unserved Energy is energy-centric and analyzes all hours of a particular Planning Year. Results are calculated in megawatt-hours (MWh). EUE is the summation of the expected number of MWh of load that will not be served in a given Planning Year as a result of demand exceeding the available generation across all deficient hours.

MISO LOLE Statistics	
Loss of Load Expectation (LOLE) [days/year]	0.100
Loss of Load Hours (LOLH) [hours/year]	0.289
Expected Unserved Energy (EUE) [megawatt-hours/year]	989.451

Table 4-2: Additional Risk Metric Statistics

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4.2 Comparison of PRM Targets Across 10 Years

Figure 4-1 compares the PRM UCAP values over the last 10 Planning Years. The last two data points show the Summer PRM UCAP values following FERC acceptance of MISO's seasonal capacity construct, while the prior data points are indicative of the PRM UCAP under the annual capacity construct.

Figure 4-1: Comparison of PRM Targets Across 10 Years

4.3 Future Years 2023 through 2032 Planning Reserve Margins

Beyond the Planning Year 2024-2025 LOLE Study analysis, LOLE analysis will be performed for the four-year-out Planning Year of 2027-2028, as well as for the six-year-out Planning Year of 2029-2030. All other future Planning Years in scope will be derived from interpolation and extrapolation of the three modeled Planning Years.

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5 Local Resource Zone Analysis – LRR Results

5.1 Planning Year 2024-2025 Local Resource Zone Analysis

MISO calculated the per-unit LRR of LRZ seasonal peak demand for Planning Year 2024-2025 on a seasonal basis (Table 5-1, Table 5-2, Table 5-3, & Table 5-4). The UCAP values in the seasonal LRR tables reflect the assumed seasonal UCAP within each LRZ, including Coordinating Owner External Resources and Border External Resources. The adjustments to UCAP values are the megawatt adjustments needed in each LRZ so that the seasonal LOLE criteria is met. The LRR is the summation of the zone's UCAP and adjustment to UCAP megawatts. The LRR is then divided by each LRZ's seasonal peak demand to determine the per-unit LRR UCAP. The Planning Year 2024-2025 per-unit LRR UCAP values will be multiplied by the updated seasonal peak demand forecasts submitted for the 2024-2025 PRA to determine each LRZ's LRR. Zonal peak demand timestamps for all 30 weather years modeled in SERVM are shown in Table 5-5. These peak demand timestamps are the result of the SERVM load training process and are not necessarily the actual peaks for each year.

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Local Resource Zone (LRZ)	**LRZ-1 MN/ND**	**LRZ-2 WI**	**LRZ-3 IA**	**LRZ-4 IL**	**LRZ-5 MO**	**LRZ-6 IN**	**LRZ-7 MI**	**LRZ-8 AR**	**LRZ-9 LA/TX**	**LRZ-10 MS**	**Formula Key**
PY 2024-2025 Local Reliability Requirements – Summer 2024											
Installed Capacity (ICAP) (MW)	22,031	14,680	12,032	9,635	7,942	17,184	25,178	11,749	24,009	5,748	[A]
Unforced Capacity (UCAP) (MW)	20,970	13,866	11,487	8,745	7,361	15,348	23,578	10,915	22,113	5,061	[B]
Adjustment to UCAP (MW)	380	590	1,503	3,245	3,044	5,209	980	692	2,502	2,093	[C]
LRR (UCAP) (MW)	21,351	14,456	12,990	11,990	10,405	20,557	24,558	11,607	24,615	7,153	[D]=[B]+[C]
Peak Demand (MW)	18,854	12,990	10,165	9,288	7,814	17,279	21,160	8,336	21,689	4,712	[E]
LRR UCAP per-unit of LRZ Peak Demand	**113.2%**	**111.3%**	**127.8%**	**129.1%**	**133.1%**	**119.0%**	**116.1%**	**139.2%**	**113.5%**	**151.8%**	[F]=[D]/[E]

Table 5-1: Planning Year 2024-2025 LRZ Local Reliability Requirements for Summer 2024

Local Resource Zone (LRZ)	**LRZ-1 MN/ND**	**LRZ-2 WI**	**LRZ-3 IA**	**LRZ-4 IL**	**LRZ-5 MO**	**LRZ-6 IN**	**LRZ-7 MI**	**LRZ-8 AR**	**LRZ-9 LA/TX**	**LRZ-10 MS**	**Formula Key**
PY 2024-2025 Local Reliability Requirements – Fall 2024											
Installed Capacity (ICAP) (MW)	21,604	14,808	11,765	9,543	8,092	17,140	24,487	11,568	23,995	5,753	[A]
Unforced Capacity (UCAP) (MW)	20,167	13,723	11,151	8,300	7,428	15,491	22,832	10,923	21,477	5,081	[B]
Adjustment to UCAP (MW)	-847	-402	1,007	2,303	2,486	4,040	956	427	2,440	2,041	[C]
LRR (UCAP) (MW)	19,320	13,321	12,157	10,604	9,914	19,531	23,787	11,349	23,917	7,122	[D]=[B]+[C]
Peak Demand (MW)	15,645	11,113	9,037	8,014	6,880	15,537	18,142	7,585	20,095	4,272	[E]
LRR UCAP per-unit of LRZ Peak Demand	**123.5%**	**119.9%**	**134.5%**	**132.3%**	**144.1%**	**125.7%**	**131.1%**	**149.6%**	**119.0%**	**166.7%**	[F]=[D]/[E]

Table 5-2: Planning Year 2024-2025 LRZ Local Reliability Requirements for Fall 2024

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Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2024-2025 Local Reliability Requirements – Winter 2024-2025											
Installed Capacity (ICAP) (MW)	24,143	15,861	16,846	11,141	8,737	18,366	26,118	12,347	26,054	6,312	[A]
Unforced Capacity (UCAP) (MW)	21,941	13,894	15,443	7,142	6,199	14,464	23,949	11,108	23,558	5,504	[B]
Adjustment to UCAP (MW)	143	-500	1,432	3,053	2,936	4,899	-1,153	651	2,353	1,968	[C]
LRR (UCAP) (MW)	22,084	13,394	16,874	10,195	9,136	19,363	22,796	11,760	25,911	7,472	[D]=[B]+[C]
Peak Demand (MW)	15,312	9,830	8,413	7,622	7,110	15,779	14,186	7,539	19,513	4,009	[E]
LRR UCAP per-unit of LRZ Peak Demand	**144.2%**	**136.3%**	**200.6%**	**133.8%**	**128.5%**	**122.7%**	**160.7%**	**156.0%**	**132.8%**	**186.4%**	[F]=[D]/[E]

Table 5-3: Planning Year 2024-2025 LRZ Local Reliability Requirements for Winter 2024-2025

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2024-2025 Local Reliability Requirements – Spring 2025											
Installed Capacity (ICAP) (MW)	21,887	15,164	12,479	10,301	8,322	17,448	24,391	11,755	24,434	5,911	[A]
Unforced Capacity (UCAP) (MW)	20,576	14,079	11,568	8,579	7,082	15,812	22,221	10,549	22,516	5,269	[B]
Adjustment to UCAP (MW)	-1,500	-260	730	2,652	2,957	4,098	-920	292	2,491	2,077	[C]
LRR (UCAP) (MW)	19,076	13,819	12,298	11,231	10,040	19,909	21,301	10,841	25,007	7,346	[D]=[B]+[C]
Peak Demand (MW)	14,356	10,137	8,034	6,756	6,206	14,523	16,109	6,733	18,746	3,911	[E]
LRR UCAP per-unit of LRZ Peak Demand	**132.9%**	**136.3%**	**153.1%**	**166.2%**	**161.8%**	**137.1%**	**132.2%**	**161.0%**	**133.4%**	**187.8%**	[F]=[D]/[E]

Table 5-4: Planning Year 2024-2025 LRZ Local Reliability Requirements for Spring 2025

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Weather Year Time of Peak Demand (ESTHE)	MISO	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS
1993	7/27/93 17:00	8/11/93 17:00	8/27/93 14:00	8/22/93 19:00	7/17/93 17:00	7/27/93 16:00	7/25/93 16:00	7/9/93 15:00	7/31/93 17:00	8/14/93 16:00	7/31/93 18:00
1994	7/6/94 15:00	6/14/94 17:00	6/15/94 17:00	7/19/94 17:00	7/5/94 17:00	7/19/94 18:00	1/19/94 6:00	6/18/94 17:00	6/29/94 18:00	8/14/94 17:00	7/5/94 17:00
1995	7/13/95 17:00	7/13/95 18:00	7/13/95 16:00	7/14/95 17:00	7/14/95 17:00	7/13/95 16:00	7/13/95 17:00	7/13/95 17:00	8/17/95 14:00	7/27/95 17:00	7/12/95 15:00
1996	6/29/96 17:00	8/6/96 17:00	6/29/96 17:00	7/18/96 17:00	7/18/96 18:00	7/18/96 17:00	7/19/96 17:00	8/7/96 15:00	7/20/96 15:00	2/5/96 7:00	7/3/96 18:00
1997	7/26/97 16:00	7/16/97 16:00	7/16/97 17:00	7/25/97 18:00	7/18/97 16:00	7/26/97 17:00	7/26/97 16:00	7/16/97 16:00	7/25/97 18:00	8/16/97 16:00	7/25/97 18:00
1998	7/20/98 16:00	7/13/98 16:00	6/25/98 18:00	7/20/98 18:00	7/20/98 18:00	7/19/98 16:00	7/19/98 17:00	6/25/98 18:00	7/6/98 17:00	8/28/98 18:00	8/27/98 15:00
1999	7/30/99 14:00	7/25/99 15:00	7/13/95 16:00	7/30/99 18:00	7/18/99 22:00	7/30/99 17:00	7/26/97 16:00	7/30/99 14:00	7/25/99 17:00	8/14/99 18:00	8/20/99 18:00
2000	8/31/00 16:00	6/8/00 19:00	9/1/00 17:00	8/31/00 16:00	9/1/00 15:00	8/17/00 16:00	9/1/00 15:00	9/1/00 14:00	7/19/00 17:00	8/30/00 16:00	8/30/00 17:00
2001	8/8/01 16:00	8/7/01 16:00	8/9/01 16:00	7/31/01 16:00	7/23/01 17:00	7/23/01 17:00	8/7/01 17:00	8/8/01 16:00	7/11/01 16:00	7/10/01 16:00	7/20/01 17:00
2002	7/3/02 16:00	7/6/02 18:00	8/1/02 15:00	7/20/02 18:00	7/5/02 17:00	8/1/02 16:00	8/3/02 16:00	7/3/02 16:00	7/9/02 17:00	8/2/02 19:00	10/4/02 15:00
2003	8/21/03 16:00	8/24/03 17:00	8/21/03 16:00	7/26/03 18:00	8/21/03 16:00	8/21/03 18:00	8/27/03 17:00	8/21/03 17:00	7/18/03 14:00	8/10/03 16:00	7/17/03 17:00
2004	7/22/04 16:00	6/7/04 17:00	7/22/04 16:00	7/20/04 17:00	7/13/04 17:00	7/13/04 16:00	1/31/04 9:00	7/22/04 16:00	7/14/04 17:00	7/24/04 17:00	7/25/04 15:00
2005	7/24/05 17:00	7/17/05 17:00	7/24/05 16:00	7/25/05 17:00	7/24/05 16:00	7/24/05 18:00	7/25/05 17:00	7/24/05 18:00	8/21/05 18:00	7/25/05 16:00	8/21/05 15:00
2006	7/31/06 17:00	7/31/06 17:00	8/1/06 17:00	7/19/06 18:00	7/31/06 18:00	7/31/06 16:00	7/31/06 16:00	7/31/06 16:00	7/31/93 17:00	8/15/06 18:00	7/16/06 15:00
2007	8/1/07 17:00	7/26/07 15:00	8/2/07 15:00	7/17/07 17:00	8/15/07 18:00	8/15/07 18:00	8/29/07 17:00	7/31/07 18:00	8/17/95 14:00	8/14/07 15:00	8/14/07 15:00
2008	7/16/08 17:00	7/11/08 18:00	7/17/08 17:00	8/3/08 17:00	7/20/08 17:00	7/20/08 16:00	8/23/08 16:00	8/24/08 12:00	8/17/95 14:00	7/20/08 17:00	7/27/08 16:00
2009	6/25/09 16:00	6/22/09 19:00	7/28/09 16:00	7/24/09 18:00	8/9/09 16:00	8/9/09 16:00	1/16/09 8:00	6/25/09 16:00	6/22/09 16:00	7/2/09 16:00	7/2/09 18:00

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Weather Year Time of Peak Demand (ESTHE)	MISO	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS
2010	8/10/10 17:00	8/8/10 18:00	8/20/10 14:00	7/17/10 19:00	7/15/10 15:00	8/3/10 16:00	8/2/91 18:00	9/1/10 17:00	8/17/95 14:00	8/1/10 17:00	8/2/10 17:00
2011	7/20/11 18:00	6/7/11 19:00	7/13/95 16:00	7/20/11 16:00	9/1/11 16:00	8/31/11 16:00	7/26/97 16:00	7/20/11 19:00	7/31/93 17:00	7/2/11 17:00	7/10/11 18:00
2012	7/6/12 17:00	7/6/12 18:00	7/13/95 16:00	7/7/12 16:00	7/7/12 17:00	7/25/12 18:00	7/26/97 16:00	7/6/12 17:00	7/30/12 17:00	6/26/12 16:00	7/3/12 15:00
2013	7/19/13 16:00	7/18/13 19:00	8/27/13 16:00	8/30/13 16:00	9/11/13 16:00	8/31/13 17:00	8/31/13 15:00	7/19/13 14:00	6/27/13 18:00	8/7/13 16:00	8/8/13 17:00
2014	7/22/14 16:00	7/22/14 17:00	7/22/14 16:00	7/22/14 16:00	9/5/14 16:00	7/26/14 15:00	2/7/14 9:00	7/22/14 17:00	7/27/14 17:00	8/23/14 16:00	7/26/14 17:00
2015	7/29/15 16:00	8/14/15 15:00	8/14/15 17:00	7/13/15 15:00	9/3/15 16:00	7/13/15 16:00	7/18/15 17:00	8/2/15 16:00	8/7/15 18:00	8/10/15 16:00	7/30/15 16:00
2016	7/20/16 15:00	7/21/16 17:00	8/10/16 17:00	7/22/16 16:00	9/22/16 16:00	7/23/16 17:00	6/11/16 14:00	8/10/16 14:00	7/20/16 13:00	9/1/16 16:00	7/20/16 15:00
2017	7/20/17 16:00	7/6/17 17:00	6/12/17 14:00	7/21/17 17:00	9/26/17 15:00	7/12/17 15:00	9/26/17 16:00	6/12/17 14:00	7/21/17 15:00	8/19/17 15:00	7/20/17 15:00
2018	6/29/18 15:00	6/29/18 15:00	6/29/18 15:00	5/28/18 14:00	9/5/18 15:00	8/6/18 16:00	9/5/18 16:00	9/5/18 15:00	1/17/18 6:00	1/17/18 6:00	9/19/18 16:00
2019	7/19/19 14:00	7/19/19 18:00	7/19/19 16:00	7/19/19 14:00	9/12/19 16:00	10/1/19 15:00	9/13/19 16:00	7/19/19 13:00	8/13/19 14:00	10/4/19 15:00	10/2/19 16:00
2020	7/9/20 15:00	7/2/20 17:00	8/27/20 14:00	7/8/20 14:00	7/8/20 15:00	7/11/20 15:00	8/25/20 15:00	7/9/20 15:00	7/12/20 15:00	7/11/20 15:00	9/4/20 16:00
2021	8/24/21 15:00	7/27/21 16:00	8/10/21 15:00	7/28/21 16:00	8/27/21 15:00	8/25/21 16:00	8/24/21 16:00	8/24/21 15:00	8/10/21 14:00	8/23/21 16:00	7/29/21 14:00
2022	7/19/22 17:00	7/19/22 18:00	6/15/22 16:00	7/23/22 16:00	8/13/22 18:00	7/23/22 15:00	7/11/22 17:00	6/21/22 17:00	7/8/22 16:00	9/21/22 17:00	8/15/22 17:00

Table 5-5: Modeled Peak Demand Days/Hours by Local Resource Zone

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6 Appendix A: Comparison of Planning Year 2023-2024 to Planning Year 2024-2025

Multiple study sensitivity analyses were performed to compute changes in the PRM target on a UCAP basis for each season, from Planning Year 2023-2024 to Planning Year 2024-2025. These sensitivities included one-off incremental changes of input parameters to quantify how each change affected the PRM result independently. Note the impact of the incremental PRM changes from Planning Year 2023-2024 to Planning Year 2024-2025 in the waterfall charts below (Figure A-1, Figure A-2, Figure A-3, & Figure A-4). The following subsections provide more details around each of the sensitivities.

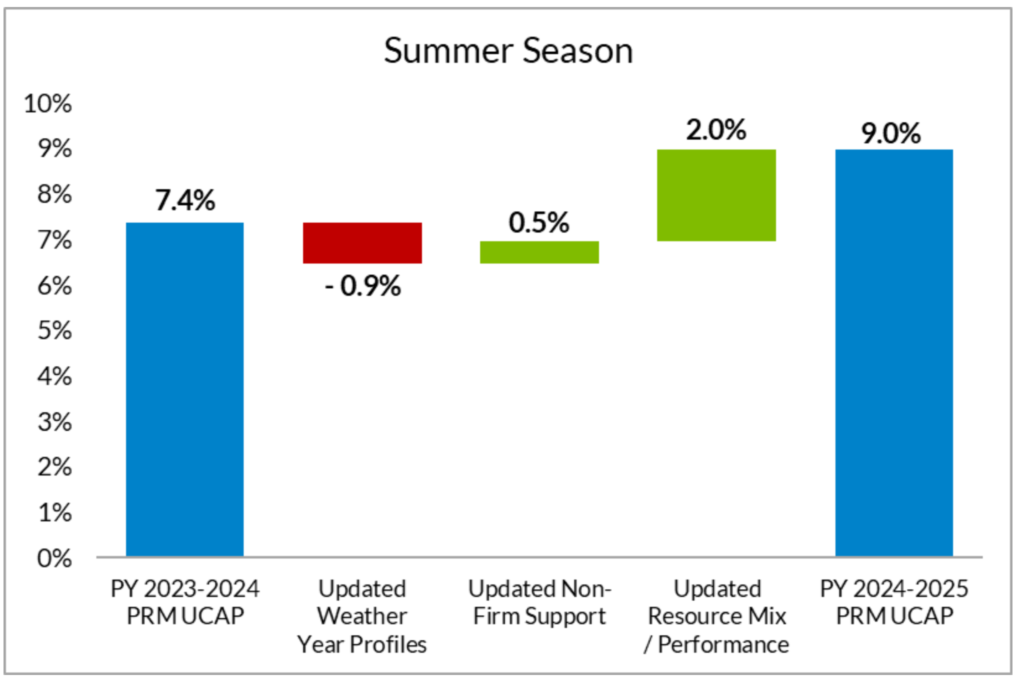

Figure A-1: Waterfall Chart of Summer PRM UCAP from PY 2023-2024 to PY 2024-2025

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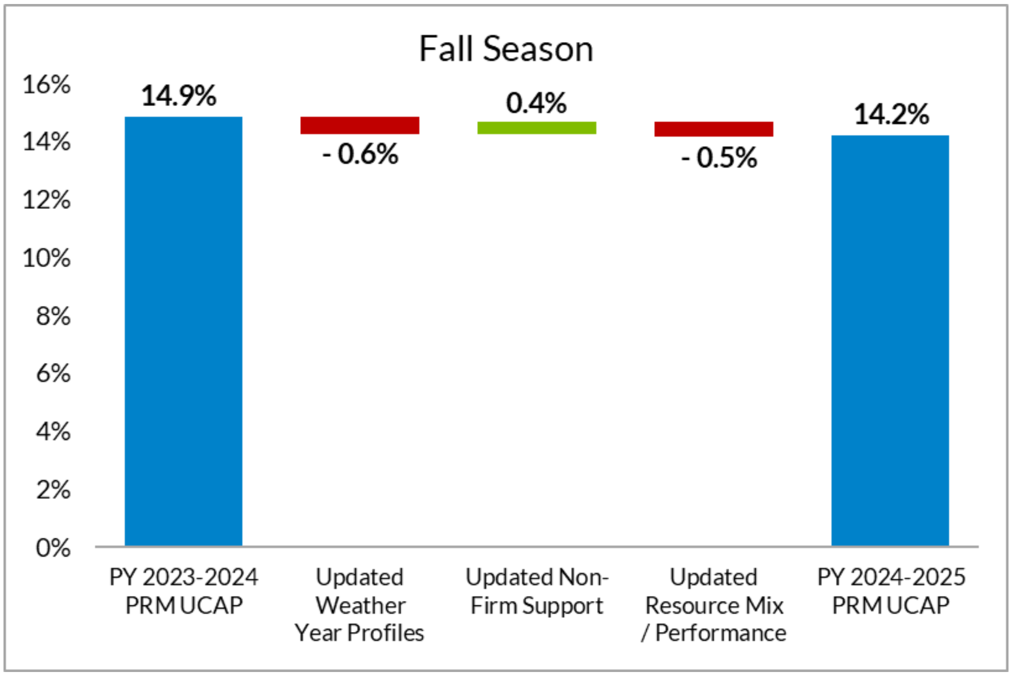

Figure A-2: Waterfall Chart of Fall PRM UCAP from PY 2023-2024 to PY 2024-2025

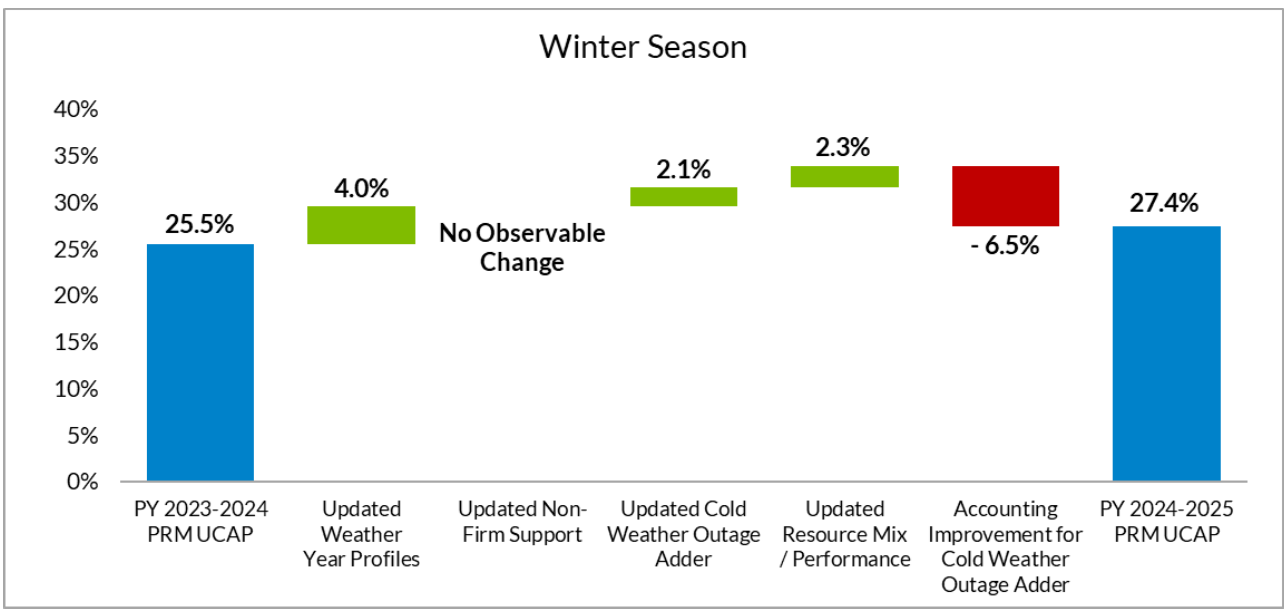

Figure A-3: Waterfall Chart of Winter PRM UCAP from PY 2023-2024 to PY 2024-2025

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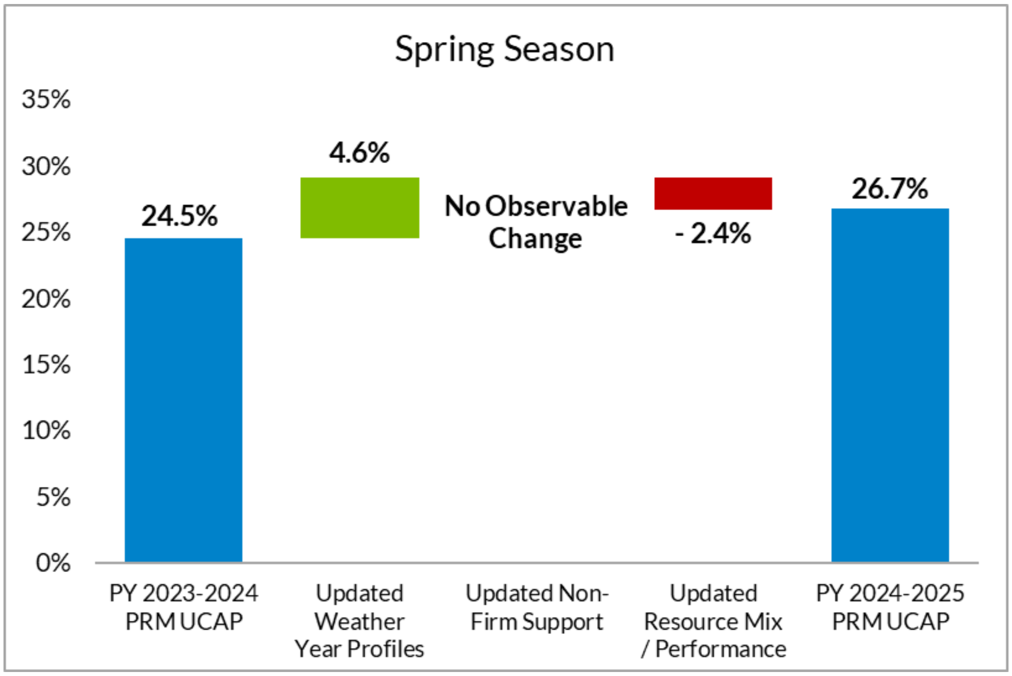

Figure A-4: Waterfall Chart of Spring PRM UCAP from PY 2023-2024 to PY 2024-2025

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6.1 Waterfall Chart Details

6.1.1 Updated Weather Year Profiles

With the annual refresh to the LOLE model, the oldest weather year is dropped off and a new weather year is added. Previously, only load shapes were tied to the weather years. Now, with the addition to the model of hourly profiles for renewables and the cold weather outage adder, it is no longer possible to isolate just the updated load profiles as stakeholders may be used to seeing in prior reports.

6.1.2 Updated Non-Firm Support

The probabilistic distribution of seasonal non-firm support is not tied to any specific weather years and is the next input dataset to be replaced in the LOLE model.

6.1.3 Updated Resource Mix / Performance

Changes in resource capability from Planning Year 2023-2024 are primarily driven by a methodology change in the Planning Resource Auction (PRA) to request from generation owners seasonally corrected Generation Verification Test Capacity (GVTC). Other drivers include updated seasonal forced outage rates, updated annualized planned maintenance outage rates, new units, retirements, suspensions, and changes in the resource mix. There was also a modeling improvement to make battery storage use-limited in the model that would also be a driver for change.

6.1.4 Updated Cold Weather Outage Adder (Winter only)

The isolated impact on the system-wide PRM requirement of modeling outage adder during extreme cold temperatures was found to be 6,710 MW. When compared to the cold weather outage adder from the prior year study, this represents an approximately 2.2 GW impact increase year-over-year.

6.1.5 Accounting Improvement for Cold Weather Outage Adder (Winter only)

The modeling of additional forced outages in the Winter season due to the adder induces a more elevated volume of forced outages in the model beyond the average Winter forced outage rates, but this was previously not reflected in the PRM and LRR accounting. ELCC-type analysis was performed to quantify the system-wide impact of modeling the cold weather outage adder profiles. Including these additional Winter forced outages in the numerator of the requirement calculations as a reduction in total Unforced Capacity lowers Winter requirements.

7 Appendix B: Increased Winter Thermal Capability Sensitivity

As requested by stakeholders at the LOLEWG, MISO performed a sensitivity for the Winter season to better understand the impact of including increased Winter capabilities of certain thermal resources to the Winter Planning Reserve Margin Requirement. For this sensitivity, MISO utilized generation owners' seasonal GVTC values for the Planning Year 2023-2024 Planning Resource Auction and scaled the thermal winter capabilities by, approximately, an additional 20% to see how the adjustment to capacity in the model changed to maintain the same LOLE criteria. This sensitivity demonstrated that there are diminishing returns for the ability to reduce risk in the model when there is a saturated increase in resource capability. Increased capability across the same set of resources may not translate to increased availability, as non-risk hours that already had excess generation may see no benefit whereas risk hours may be exacerbated, or more risk hours may emerge, from an elevated volume of outages when forced and planned maintenance outage rates are applied to a higher thermal capability.

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8 Appendix C: Capacity Import Limit Tier 1 & 2 Source Subsystem Definitions

MISO Local Resource Zone 1

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
XEL / 600	ITCM / 627	WEC / 295
MP / 608	ALTE / 694	MIUP / 296
SMMPA / 613	WPS / 696	AMMO / 356
GRE / 615	MGE / 697	AMIL / 357
OTP / 620		MPW / 633
MDU / 661		MEC / 635
BEPC-MISO / 663		
DPC / 680		

MISO Local Resource Zone 2

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
WEC / 295	METC / 218	NIPS / 217	OTP / 620
MIUP / 296	XEL / 600	ITCT / 219	MPW / 633
ALTE / 694	MP / 608	AMMO / 356	MEC / 635
WPS / 696	ITCM / 627	AMIL / 357	
MGE / 697	DPC / 680	SMMPA / 613	
UPPC / 698		GRE / 615	

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MISO Local Resource Zone 3

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
ITCM / 627	AMMO / 356	DEI / 208	MP / 608
MPW / 633	AMIL / 357	NIPS / 217	GRE / 615
MEC / 635	XEL / 600	WEC / 295	OTP / 620
	SMMPA / 613	CWLP / 360	WPS / 696
	DPC / 680	SIPC/ 361	MGE / 697
	ALTE / 694	GLHB / 362	

MISO Local Resource Zone 4

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
AMIL / 357	DEI / 208	HE / 207	SMMPA / 613
CWLP / 360	NIPS / 217	SIGE / 210	MPW / 633
SIPC / 361	BREC / 314	IPL / 216	DPC / 680
GLHB / 362	AMMO / 356	METC / 218	ALTE / 694
GLH / 373	ITCM / 627	HMPL / 315	
	MEC / 635	XEL / 600	

MISO Local Resource Zone 5

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
CWLD / 333	AMIL / 357	DEI / 208	SMMPA / 613
AMMO / 356	GLHB / 362	NIPS / 217	MPW / 633
	ITCM / 627	CWLP / 360	DPC / 680
	MEC / 635	SIPC / 361	ALTE / 694
		XEL / 600	

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MISO Local Resource Zone 6

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
HE / 207	METC / 218	ITCT / 219
DEI / 208	AMIL / 357	MIUP / 296
SIGE / 210	SIPC / 361	AMMO / 356
IPL / 216		CWLP / 360
NIPS / 217		GLHB / 362
BREC / 314		ITCM / 627
HMPL / 315		MEC / 635

MISO Local Resource Zone 7

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
METC / 218	NIPS / 217	DEI / 208
ITCT / 219	MIUP / 296	WEC / 295
		AMIL / 356
		WPS / 696
		UPPC / 698

MISO Local Resource Zone 8

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
EES-EAI / 327	EES-EMI / 326	LAGN / 332
	EES / 351	Cooperative Energy / 349
		CLEC / 502
		LAFA / 503

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MISO Local Resource Zone 9

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
LAGN / 332	EES-EMI / 326	Cooperative Energy / 349
EES / 351	EES-EAI / 327	
CLEC / 502		
LAFA / 503		
LEPA / 504		

MISO Local Resource Zone 10

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
EES-EMI / 326	EES-EAI / 327	LAGN / 332
Cooperative Energy / 349	EES / 351	CLEC / 502
		LAFA / 503

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9 Appendix D: Compliance Conformance Table

Requirements under: Standard BAL-502-RF-03	Response
R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall:	The Planning Year 2024-2025 LOLE Study Report is the annual Resource Adequacy Analysis for the peak season of June 2024 through May 2025 and beyond. Analysis of Planning Year 2024-2025 is in Sections 0 and 0. Analysis of Future Years 2025-2034 will be included in Appendix F as an addendum to the study report in early 2024.
R1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).	Section 0 of this report outlines the utilization of LOLE in the reserve margin determination. "These metrics were derived through probabilistic modeling of the system, first solving to the industry standard annual LOLE risk target of 1 day in 10 years, or 0.1 day per year, and then solving to the minimum seasonal LOLE criteria of 0.01 LOLE for seasons demonstrating minimal risk."
R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.	Section 3.3 of this report. "Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. Demand response is dispatched in the LOLE model to avoid load shed during simulation when all other available generation has been exhausted."
R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median forecast peak Net Internal Demand (planning reserve margin).	Section 4.1 of this report. "…the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin…"
R1.2 Be performed or verified separately for each of the following planning years.	Covered in the segmented R1.2 responses below.
R1.2.1 Perform an analysis for Year One.	In Sections 0 and 0, a full analysis was performed for Planning Year 2024-2025.
R1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.	Analysis of Planning Years 2027-2028 and 2029-2030 will be included in Appendix F as an addendum to the study report in early 2024.

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Requirements under: Standard BAL-502-RF-03	Response
R1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.	Analysis was performed.
R1.3 Include the following subject matter and documentation of its use:	Covered in the segmented R1.3 responses below.
R1.3.1 Load forecast characteristics: • Median (50:50) forecast peak load • Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts). • Load diversity. • Seasonal Load variations. • Daily demand modeling assumptions (firm, interruptible). • Contractual arrangements concerning curtailable/Interruptible Demand.	Median forecasted load – In Section 0.1 of this report: "The sixth and final step of the load training process is to average the monthly peak loads of the predicted load shapes and adjust them to match each LRZ's monthly Zonal Coincident Peak Forecast provided by the Load Serving Entities for each of the study years." Load Forecast Uncertainty – A detailed explanation of the weather and economic uncertainties is given in Section 3.3. Load Diversity / Seasonal Load Variations — In Section 0 of this report: "MISO has adopted a six-step load training process in order to capture the weather uncertainty associated with the most recent 50/50 load forecasts submitted by the Load Serving Entities for the development of the 30 years of hourly zonal correlated load and weather shapes in the LOLE model… The third step of the process utilizes neural net software to establish functional relationships between the most recent five years of historical weather and load data." Demand Modeling Assumptions / Curtailable and Interruptible Demand — All Load Modifying Resources must first meet registration requirements through Module E. As stated in Section 3.2.6: "Each demand response program was modeled individually with a monthly capacity, limited by duration and the number of times each program can be called upon for each season."

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Requirements under: Standard BAL-502-RF-03	Response
R1.3.2 Resource characteristics: • Historic resource performance and any projected changes. • Seasonal resource ratings • Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area. • Resource planned outage schedules, deratings, and retirements. • Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration. • Criteria for including planned resource additions in the analysis.	Section 0 details how historic performance data and seasonal ratings are gathered, and includes discussion of future units and the modeling assumptions for intermittent capacity resources. A more detailed explanation of firm capacity purchases and sales is in Section 3.4.
R1.3.3 Transmission limitations that prevent the delivery of generation reserves	Annual MTEP deliverability analysis identifies transmission limitations preventing delivery of generation reserves. Additionally, Section 0 of this report details the transfer analysis to capture transmission constraints limiting capacity transfers.
R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis	Inclusion of the planned transmission addition assumptions is detailed in Section 2.2.3.
R1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.	Section 3.4 provides the analysis on the treatment of external support assistance and limitations.

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Requirements under: Standard BAL-502-RF-03	Response
R1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included: • Availability and deliverability of fuel. • Common mode outages that affect resource availability. • Environmental or regulatory restrictions of resource availability. • Any other demand (Load) response programs not included in R1.3.1. • Sensitivity to resource outage rates. • Impacts of extreme weather/drought conditions that affect unit availability. • Modeling assumptions for emergency operation procedures used to make reserves available. • Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.	Fuel availability, environmental restrictions, common mode outage and extreme weather conditions are all part of the historical availability performance data that goes into the unit's EFORd statistic. The use of the EFORd values is covered in Section 0.1. The use of demand response programs is mentioned in Section 0.6. The effects of resource outage characteristics on the reserve margin are outlined in Section 3.7.1 by examining the difference between PRM ICAP and PRM UCAP values.
R1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included	Transmission maintenance schedules were not included in the analysis of the transmission system due to the limited availability of reliable long-term maintenance schedules and minimal impact to the results of the analysis. However, Section 0 treats worst-case theoretical outages by Perform First Contingency Total Transfer Capability (FCTTC) analysis for each LRZ, by modeling NERC Category P0 (system intact) and Category P1 (N-1) contingencies.
R1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis	MISO internal resources are among the quantities documented in the tables provided in Sections 0 and 0.
R1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis	MISO load is among the quantities documented in the tables provided in Sections 0 and 0.
R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis.	In Sections 0 and 0, the peak load and estimated amount of resources for Planning Year 2024-2025 are shown. This includes the detail for each transmission constrained sub-area.
R2.1 This documentation shall cover each of the years in year one through ten.	Appendix F will cover the future Planning Years when the report is amended in early 2024 after the outyear analyses have been completed.

Requirements under: **Standard BAL-502-RF-03**	**Response**
R2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.	The prompt Planning Year seasonal PRM values are covered in Sections 4.1. The outyear Planning Years 4 (2027-2028) and 6 (2029-2030) will be covered in Appendix F when the report is amended in early 2024 after the outyear analyses have been completed.
R2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.	The final PY 2024-2025 LOLE Study Report will be posted publicly in December 2023, several months prior to the start of the applicable Planning Year.
R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2.	In Sections 0 and 0 is shown the differences between the needed amount and the projected planning reserves for Planning Year 2024-2025. The needed amount of planning reserves for the outyear Planning Years 4 (2027-2028) and 6 (2029-2030) will be covered in Appendix F when the report is amended in early 2024 after the outyear analyses have been completed.

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10 Appendix E: Acronyms List Table

CEL	Capacity Export Limit
CIL	Capacity Import Limit
CPNode	Commercial Pricing Node
DF	Distribution Factor
EFORd	Equivalent Forced Outage Rate demand
ELCC	Effective Load Carrying Capability
ERZ	External Resource Zone
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FCITC	First Contingency Incremental Transfer Capability
FCTTC	First Contingency Total Transfer Capability
GADS	Generator Availability Data System
GLT	Generation Limited Transfer
GVTC	Generation Verification Test Capacity
ICAP	Installed Capacity
LBA	Local Balancing Authority
LCR	Local Clearing Requirement
LFE	Load Forecast Error
LFU	Load Forecast Uncertainty
LOLE	Loss of Load Expectation
LOLEWG	Loss of Load Expectation Working Group
LRR	Local Reliability Requirement
LRZ	Local Resource Zones
LSE	Load Serving Entity
MARS	Multi-Area Reliability Simulation
MECT	Module E Capacity Tracking
MISO	Midcontinent Independent System Operator
MOD	Model on Demand
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt hours
NERC	North American Electric Reliability Corporation

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PRA	Planning Resource Auction
PRM	Planning Reserve Margin
PRM ICAP	PRM Installed Capacity
PRM UCAP	PRM Unforced Capacity
PRMR	Planning Reserve Margin Requirement
PSS E	Power System Simulator for Engineering
RCF	Reciprocal Coordinating Flowgate
RDS	Redispatch
RPM	Reliability Pricing Model
SERVM	Strategic Energy & Risk Valuation Model
SPS	Special Protection Scheme
TARA	Transmission Adequacy and Reliability Assessment
UCAP	Unforced Capacity
XEFORd	Equivalent forced outage rate demand with adjustment to exclude events outside management control
ZIA	Zonal Import Ability
ZEA	Zonal Export Ability

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11 Appendix F: Outyear PRM and LRR Results

Outyear PRM and LRR results for the future Plannings Years 2027-2028 and 2029-2030 will be published as an addendum to this report in early 2024 once the supporting probabilistic simulations and analyses have been completed.

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Planning Year 2024-25 Planning Reserve Margin (PRM) and Local Reliability Requirement (LRR) Results

LOLEWG

October 17, 2023

Schedule MM-S35

Purpose & Key Takeaways

Purpose:

Review seasonal results of MISO Planning Year (PY) 2024-25 Planning Reserve Margins (PRM) and Local Reliability Requirements (LRR)

Key Takeaways:

- The PY 2024-25 seasonal LOLE study results in a:
  - 9.0% PRM UCAP for Summer, a 1.6 percentage point increase from the PY 2023-24 Summer PRM UCAP of 7.4%
  - 33.9% PRM UCAP for Winter, an 8.4 percentage point increase from the PY 2023-24 Winter PRM UCAP of 25.5%
  - 14.2% PRM UCAP for Fall, representing a 0.7 percentage point decrease
  - 26.7% PRM UCAP for Spring, representing a 2.2 percentage point increase
- The changes in PRMs and LRRs are largely driven by seasonal thermal capabilities, resource mix and performance, load factors, and a modeling enhancement for battery storage
- The prompt year results will be published by November 1
  - MISO will publish the LOLE study report before the end of November

MISO experienced numerous delays to the Seasonal Planning Reserve Margin analysis

- Challenges encountered with new technology infrastructure
  - Performing the probabilistic modeling on the new infrastructure resulted in increased simulation solve time
  - Decision made to use same servers and version of SERVM as last year
  - Upgrade postponed to next year

- Understanding drivers for some seasons required additional time for analysis
  - Worked extensively with Astrapé to analyze and validate model input and resulting behavior

PRMs vary across seasons largely driven by different resource mix/performance and load levels across seasons

MISO Planning Reserve Margin (PRM)	Summer 2024	Fall 2024	Winter 2024-2025	Spring 2025	Formula Key
MISO System Peak Demand (MW)	124,669	112,232	104,303	99,496	[A]
Installed Capacity (ICAP) (MW)	150,187	148,755	165,924	152,092	[B]
Unforced Capacity (UCAP) (MW)	139,444	136,572	149,911	138,251	[C]
Firm External Support ICAP (MW)	3,217	2,865	3,771	3,247	[D]
Firm External Support UCAP (MW)	3,052	2,758	3,613	3,105	[E]
Adjustment to ICAP [1d in 10yr] (MW)	(6,650)	(11,145)	(13,890)	(15,275)	[F]
Adjustment to UCAP [1d in 10yr] (MW)	(6,650)	(11,145)	(13,890)	(15,275)	[G]
ICAP PRM Requirement (PRMR) (MW)	146,754	140,475	155,805	140,064	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	135,846	128,185	139,635	126,081	[I] = [C]+[E]+[G]
MISO PRM ICAP	17.7%	25.2%	49.4%	40.8%	[J]=([H]-[A])/[A]
MISO PRM UCAP	9.0%	14.2%	33.9%	26.7%	[K]=([I]-[A])/[A]
LOLE Criteria (days/year)	0.1	0.01	0.01	0.01	

If a season had an LOLE value of at least 0.01, then its criteria would be the LOLE that naturally occurred from the annual distribution of 0.1 LOLE. If a season had less than 0.01 LOLE, capacity in the model was removed until the minimum seasonal criteria of 0.01 LOLE was met.

MISO

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Compared to last year's winter PRM UCAP of 25.5%, this year's increased winter PRM UCAP of 33.9% were driven by a combination of factors

- Significant increase in winter GVTC for Schedule 53 resources
  - Seasonally-corrected winter capabilities are collectively greater than the annual GVTC from the year prior by more than 10 GW
  - Leads to a higher UCAP/ISAC ratio for Schedule 53 resources which will likely increase the accredited capacity for the 2024-25 Planning Resource Auction
  - Results in a higher volume of outages scheduled in winter
- Increase in Wind ELCC for winter
  - 53.1% this year vs. 40.3% last year
- Improved modeling of battery storage
  - Use-limited with 4-hour duration vs. 5% forced outage rate assumption last year
- Increase in cold weather outage adder
  - 2.6 GW increase to winter PRM UCAP this year vs. 1.9 GW increase last year

The zonal LRRs vary across seasons largely driven by seasonality of resource mix/performance and load levels

LRZ	Summer 2024		Fall 2024		Winter 2024-2025		Spring 2025	
	LRR % (UCAP)	LRR UCAP	LRR % (UCAP)	LRR UCAP	LRR % (UCAP)	LRR UCAP	LRR % (UCAP)	LRR UCAP
1	113.2%	21,351 MW	123.5%	19,320 MW	148.2%	22,694 MW	132.9%	19,076 MW
2	111.3%	14,456 MW	119.9%	13,321 MW	140.9%	13,850 MW	136.3%	13,819 MW
3	127.8%	12,990 MW	134.5%	12,157 MW	207.2%	17,436 MW	153.1%	12,298 MW
4	129.1%	11,990 MW	132.3%	10,604 MW	151.1%	11,519 MW	166.2%	11,231 MW
5	133.1%	10,405 MW	144.1%	9,914 MW	143.0%	10,163 MW	161.8%	10,040 MW
6	119.0%	20,557 MW	125.7%	19,531 MW	134.1%	21,157 MW	137.1%	19,909 MW
7	116.1%	24,558 MW	131.1%	23,787 MW	163.6%	23,205 MW	132.2%	21,301 MW
8	139.2%	11,607 MW	149.6%	11,349 MW	158.3%	11,936 MW	161.0%	10,841 MW
9	113.5%	24,615 MW	119.0%	23,917 MW	134.6%	26,262 MW	133.4%	25,007 MW
10	151.8%	7,153 MW	166.7%	7,122 MW	186.4%	7,472 MW	187.8%	7,346 MW

Seasonal zonal requirements on a MW basis were calculated by applying each zone's LRR % to its cumulative zonal coincident peak forecast submitted by the LSEs.

MISO

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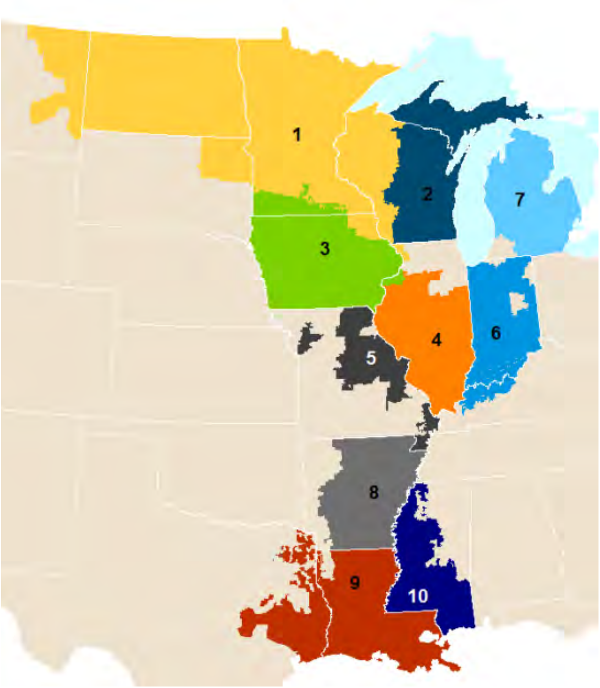
The zonal Local Reliability Requirements (LRR) for Summer season have changed due to similar factors as the PRM

LRZ	Summer 2023	Summer 2024	Delta	Major Driver(s) for Change
1	113.9%	113.2%	-0.7%	Renewable profiles, increased peak demand
2	112.0%	111.3%	-0.7%	Increased peak demand
3	129.9%	127.8%	-2.1%	Improved outage rates, renewable profiles
4	121.2%	129.1%	7.9%	Increased capacity
5	133.3%	133.1%	-0.2%	Increased peak demand
6	117.2%	119.0%	1.8%	Worsened outage rates, decreased peak demand
7	117.1%	116.1%	-1.0%	Increased peak demand
8	147.3%	139.2%	-8.1%	Increased peak demand
9	115.7%	113.5%	-2.2%	Improved outage rates
10	153.8%	151.8%	-2.0%	Increased peak demand, improved outage rates

Local Resource Zones



MISO

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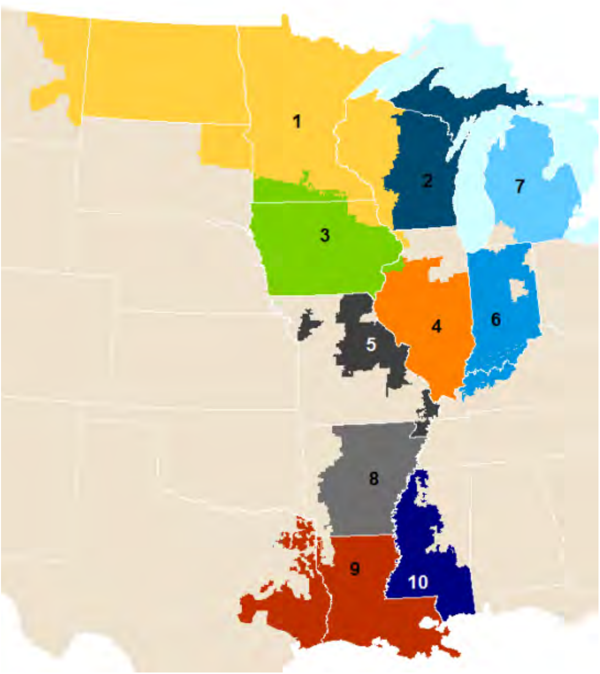
The zonal Local Reliability Requirements (LRR) for Fall season have changed due to similar factors as the PRM

LRZ	Fall 2023	Fall 2024	Delta	Major Driver(s) for Change
1	127.4%	123.5%	-3.9%	Increased peak demand, decreased capacity
2	121.8%	119.9%	-1.9%	Increased peak demand
3	140.8%	134.5%	-6.3%	Renewable profiles, improved outage rates
4	125.4%	132.3%	6.9%	Worsened outage rates, decreased peak demand, increased capacity
5	145.2%	144.1%	-1.1%	Improved outage rates, increased peak demand
6	124.7%	125.7%	1.0%	Worsened outage rates, decreased peak demand
7	134.5%	131.1%	-3.4%	Increased peak demand
8	149.0%	149.6%	0.6%	Increased capacity
9	127.8%	119.0%	-8.8%	Increased peak demand, decreased capacity
10	161.9%	166.7%	4.8%	Smallest zone, sensitive to capacity fluctuations

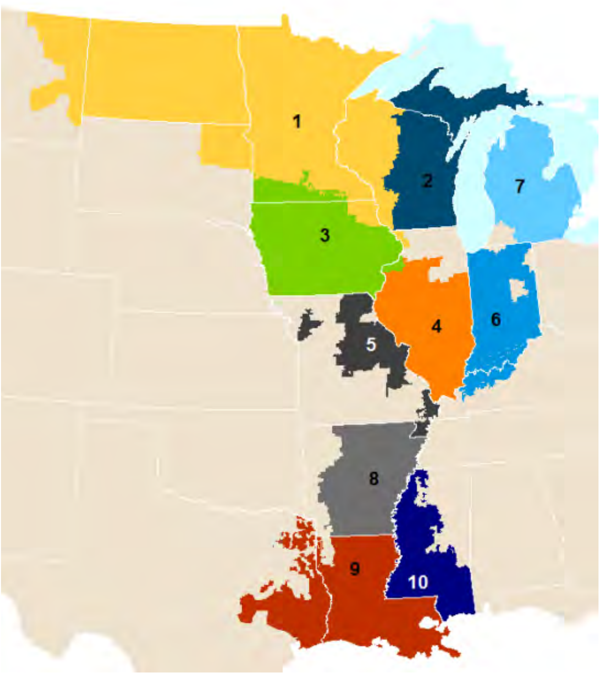
Local Resource Zones



The zonal Local Reliability Requirements (LRR) for Winter season have changed due to similar factors as the PRM

LRZ	Winter 2023-24	Winter 2024-25	Delta	Major Driver(s) for Change
1	140.3%	148.2%	7.9%	Renewable profiles, increased capacity
2	142.2%	140.9%	-1.3%	Increased peak demand
3	185.0%	207.2%	22.3%	Renewable profiles, increased capacity
4	136.5%	151.1%	14.6%	Worsened outage rates, increased capacity
5	147.4%	143.0%	-4.4%	Increased peak demand, improved outage rates
6	130.1%	134.1%	4.0%	Decreased peak demand, worsened outage rates
7	157.3%	163.6%	6.3%	Decreased peak demand, increased capacity
8	150.3%	158.3%	8.0%	Increased capacity
9	132.3%	134.6%	2.3%	Increased capacity
10	177.7%	186.4%	8.7%	Increased capacity

Local Resource Zones



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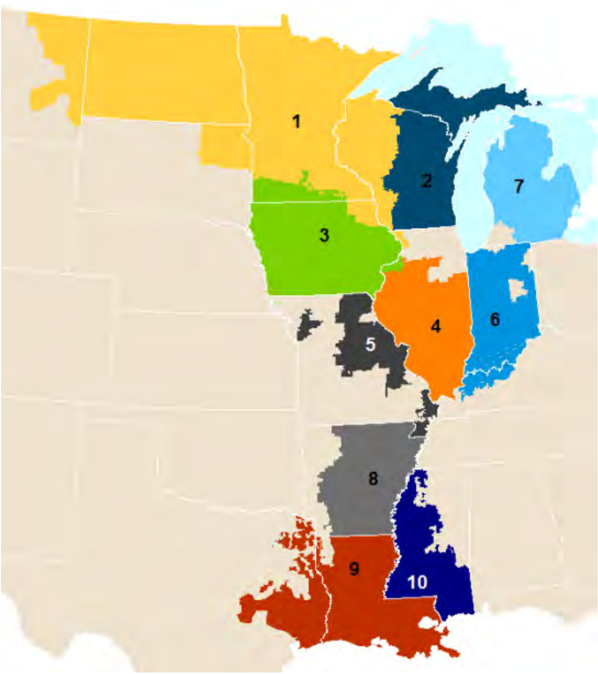
The zonal Local Reliability Requirements (LRR) for Spring season have changed due to similar factors as the PRM

LRZ	Spring 2024	Spring 2025	Delta	Major Driver(s) for Change
1	137.5%	132.9%	-4.6%	Increased peak demand, improved outage rates
2	126.7%	136.3%	9.6%	Increased capacity
3	162.3%	153.1%	-9.2%	Improved outage rates
4	145.4%	166.2%	20.8%	Increased capacity, decreased peak demand
5	161.0%	161.8%	0.8%	Worsened outage rates
6	132.0%	137.1%	5.1%	Increased capacity
7	132.9%	132.2%	-0.7%	Renewable profiles
8	162.7%	161.0%	-1.7%	Increased peak demand, improved outage rates
9	131.5%	133.4%	1.9%	Increased capacity
10	174.7%	187.8%	13.1%	Worsened outage rates, smallest zone, sensitive to capacity fluctuations

Local Resource Zones



MISO

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Seasonal LRR LOLE Criteria

LRZ	Summer 2024	Fall 2024	Winter 2024-25	Spring 2024
LRR LOLE Criteria by Zone/Season				
1	0.094	0.01	0.01	0.01
2	0.099	0.01	0.01	0.01
3	0.091	0.01	0.01	0.01
4	0.022	0.01	0.075	0.01
5	0.01	0.01	0.083	0.01
6	0.085	0.01	0.015	0.01
7	0.037	0.061	0.01	0.01
8	0.014	0.01	0.078	0.01
9	0.042	0.036	0.014	0.01
10	0.058	0.019	0.015	0.01

If a season had an LOLE value of at least 0.01, then its criteria would be the LOLE that naturally occurred from the annual distribution of 0.1 LOLE. If a season had less than 0.01 LOLE, capacity in the model was removed until the minimum seasonal criteria of 0.01 LOLE was met.

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Effective Load Carrying Capability (ELCC) for Wind and Solar

MISO performed seasonal Effective Load Carrying Capability (ELCC) analyses for wind and for solar used in the PY 2024-25 LOLE study, represented in the model as 30-year hourly capacity factor profiles, to determine season-wide capacity values for use in the seasonal Planning Reserve Margin (PRM) and Local Reliability Requirement (LRR) calculations. The table below shows the ELCC percentages resulting from the analyses.

	Wind ELCC %	Solar ELCC %
Summer	18.1%	46.4%
Fall	15.6%	37.6%
Winter	53.1%	12.8%
Spring	18.0%	33.8%

Next Steps

- Final seasonal PRM and LRR values will be published to the MISO public website under the Resource Adequacy page on November 1

- LOLE study results and findings will be published in the LOLE study report in November
  - A notice will be sent out to stakeholders once the draft LOLE study report has been posted to the MISO public website under the Resource Adequacy page
  - Stakeholders are encouraged to review the draft report and provide feedback

- Outyear PRM and LRR analyses will be published in the LOLE study report as an addendum in Q1 2024

Contact Information

- Please submit questions and/or requests for information to the MISO Help Center

Appendix

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Recent Modeling Enhancements

Model Input	Current Method	Prior Method
Forced Outage Rates	5-year seasonal average EFORd calculated from historic GADS data	5-year annual average EFORd calculated from historic GADS data
Cold Weather Outages	Increased outages correlated with extreme cold temperatures	Not modeled
Wind & Solar Output	30-year hourly profiles for wind and solar based on historic output	Wind: Constant output at monthly ELCC values Solar: Constant output at annual capacity credit
Non-Firm Support	Probabilistic distribution of non-firm imports based on historic NSI	Fixed adjustment to PRM outside of the model
Use-Limited Battery Storage	Use-limited with 4-hour duration	Modeled at nameplate with 5% forced outage rate assumption for all seasons

Local Reliability Requirements – PY 2024-25

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
Summer 2024											
Unforced Capacity (UCAP) (MW)	20,970	13,866	11,487	8,745	7,361	15,348	23,578	10,915	22,113	5,061	[A]
Adjustment to UCAP (MW)	380	590	1,503	3,245	3,044	5,209	980	692	2,502	2,093	[B]
Local Reliability Requirement UCAP (MW)	21,351	14,456	12,990	11,990	10,405	20,557	24,558	11,607	24,615	7,153	[C] = [A] + [B]
Peak Demand (MW)	18,854	12,990	10,165	9,288	7,814	17,279	21,160	8,336	21,689	4,712	[D]
LRR UCAP per-unit of LRZ Peak Demand	**113.2%**	**111.3%**	**127.8%**	**129.1%**	**133.1%**	**119.0%**	**116.1%**	**139.2%**	**113.5%**	**151.8%**	[E] = [C] / [D]
Fall 2024											
Unforced Capacity (UCAP) (MW)	20,167	13,723	11,151	8,300	7,428	15,491	22,832	10,923	21,477	5,081	[A]
Adjustment to UCAP (MW)	-847	-402	1,007	2,303	2,486	4,040	956	427	2,440	2,041	[B]
Local Reliability Requirement UCAP (MW)	19,320	13,321	12,157	10,604	9,914	19,531	23,787	11,349	23,917	7,122	[C] = [A] + [B]
Peak Demand (MW)	15,645	11,113	9,037	8,014	6,880	15,537	18,142	7,585	20,095	4,272	[D]
LRR UCAP per-unit of LRZ Peak Demand	**123.5%**	**119.9%**	**134.5%**	**132.3%**	**144.1%**	**125.7%**	**131.1%**	**149.6%**	**119.0%**	**166.7%**	[E] = [C] / [D]
Winter 2024-25											
Unforced Capacity (UCAP) (MW)	22,551	14,350	16,004	8,466	7,227	16,257	24,358	11,285	23,909	5,504	[A]
Adjustment to UCAP (MW)	143	-500	1,432	3,053	2,936	4,899	-1,153	651	2,353	1,968	[B]
Local Reliability Requirement UCAP (MW)	22,694	13,850	17,436	11,519	10,163	21,157	23,205	11,936	26,262	7,472	[C] = [A] + [B]
Peak Demand (MW)	15,312	9,830	8,413	7,622	7,110	15,779	14,186	7,539	19,513	4,009	[D]
LRR UCAP per-unit of LRZ Peak Demand	**148.2%**	**140.9%**	**207.2%**	**151.1%**	**143.0%**	**134.1%**	**163.6%**	**158.3%**	**134.6%**	**186.4%**	[E] = [C] / [D]
Spring 2025											
Unforced Capacity (UCAP) (MW)	20,576	14,079	11,568	8,579	7,082	15,812	22,221	10,549	22,516	5,269	[A]
Adjustment to UCAP (MW)	-1,500	-260	730	2,652	2,957	4,098	-920	292	2,491	2,077	[B]
Local Reliability Requirement UCAP (MW)	19,076	13,819	12,298	11,231	10,040	19,909	21,301	10,841	25,007	7,346	[C] = [A] + [B]
Peak Demand (MW)	14,356	10,137	8,034	6,756	6,206	14,523	16,109	6,733	18,746	3,911	[D]
LRR UCAP per-unit of LRZ Peak Demand	**132.9%**	**136.3%**	**153.1%**	**166.2%**	**161.8%**	**137.1%**	**132.2%**	**161.0%**	**133.4%**	**187.8%**	[E] = [C] / [D]

MISO

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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2023 Long-Term Reliability Assessment

December 2023

Infographic | Video

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Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities (LSE) participate in one Regional Entity while associated Transmission Owners/Operators participate in another.

MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Assessment

NERC is a not-for-profit international regulatory authority with the mission to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC, also known as the Commission) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the North American BPS and serves more than 334 million people. Section 39.11(b) of FERC's regulations provides that "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

Development Process

This assessment was developed based on data and narrative information NERC collected from the six Regional Entities (see **Preface**) on an assessment area basis (see **Regional Assessments Dashboards**) to independently evaluate the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period. The Reliability Assessment Subcommittee (RAS), at the direction of NERC's Reliability and Security Technical Committee (RSTC), supported the development of this assessment through a comprehensive and transparent peer review process that leverages the knowledge and experience of system planners, Reliability Assessment Subcommittee members, NERC staff, and other subject matter experts; this peer review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the RSTC, and the NERC Board of Trustees subsequently accepted this assessment and endorsed the key findings.

NERC develops the Long-Term Reliability Assessment (LTRA) annually in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations,[3] this is also required by Section 215(g) of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

Considerations

Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2023 about known system changes with updates incorporated prior to publication. This *2023 LTRA* assessment period includes projections for 2024–2033; however, some figures and tables examine data and information for the 2023 year. This assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.[5] NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in the **Demand Assumptions and Resource Categories** section of this report. Reliability impacts related to cyber and physical security risks are not specifically addressed in this assessment; this assessment is primarily focused on resource adequacy and operating reliability. NERC leads a multi-faceted approach through NERC's Electricity-Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information-sharing efforts with the electric industry.

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and system energy needs, demand response (DR), resource capacity, and transmission projects. Data from each Regional Entity is also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and a portion of Baja California, Mexico. NERC's reliability assessments are developed to inform industry, policy makers, and regulators as well as to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

[1] NERC Rules of Procedure - Section 803

[2] Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[3] Title 18, § 39.11 of the Code of Federal Regulations

[4] BPS reliability, as defined in the **How NERC Defines BPS Reliability** section of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.

[5] ERO Reliability Assessment Process Document

Assumptions

In this *2023 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:[6]

- Supply and demand projections are based on industry forecasts submitted and validated in July 2023. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame have been included where appropriate.
- Peak demand is based on average peak weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Regional Entity's self-assessment.
- Generation and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in service as planned, planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

Reading this Report

This report is compiled into two major parts:

- A reliability assessment of the North American BPS with the following goals:
  - Evaluate industry preparations that are in place to meet projections and maintain reliability
  - Identify trends in demand, supply, and reserve margins
  - Identify emerging reliability issues
  - Focus the industry, policy makers, and the general public's attention on BPS reliability issues
  - Make recommendations based on an independent NERC reliability assessment process
- A regional reliability assessment that contains the following:
  - 10-year data dashboard
  - Summary assessments for each assessment area
  - Focus on specific issues identified through industry data and emerging issues
  - Identify regional planning processes and methods used to ensure reliability

[6] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

Executive Summary

The North American BPS is on the cusp of large-scale growth, bringing reliability challenges and opportunities to a grid that was already amid unprecedented change.[7] Key measures of transmission development and future electricity peak demand and energy needs, which NERC tracks and reports annually in the LTRA, are rising faster than at any time in the past five or more years. New resource projects continue to enter the interconnection planning process at a faster rate than existing projects are concluded; this increases the backlog of resource additions and prompts some Regional Transmission Organizations (RTO) and Independent System Operators (ISO) to adapt their processes to manage expansion. Industry faces mounting pressures to keep pace with accelerating electricity demand, energy needs, and transmission system adequacy as the resource mix transitions.

This *2023 LTRA* is the ERO's independent assessment and comprehensive report on the adequacy of planned BPS resources to reliably meet the electricity demand across North America over the next ten year; it also identifies reliability trends, emerging issues, and potential risks that could impact the long-term reliability, resilience, and security of the BPS. The findings presented here are vitally important to understanding the reliability risks to the North American BPS as it is currently planned and being influenced by government policies, regulations, consumer preferences, and economic factors.

Capacity and Energy Risk Assessment

The **Capacity and Energy Risk Assessment** section of this report identifies potential future electricity supply shortfalls under normal as well as extreme conditions; it is a forward-looking snapshot of resource adequacy that is tied to industry forecasts of electricity supplies, demand, and transmission development. NERC's assessment makes use of the latest demand forecasts, resource levels, and area transfer commitments along with collected information on expected generator retirements, resource additions, and demand-side resources.

This assessment provides clear evidence of growing resource adequacy concerns over the next 10 years (**Figure 1**). Capacity deficits are projected in areas where future generator retirements are expected before enough replacement resources are in service to meet rising demand forecasts. Energy risks are projected in areas where the future resource mix could fail to deliver the necessary supply of electricity under energy-constrained conditions. For example, subfreezing temperatures can create energy-limiting conditions by disrupting the natural gas fuel supplies to generators, leading to fuel-related derates or outages and potentially insufficient electricity supply. Furthermore, disruptions in electricity supplies can further exacerbate the availability of natural gas, which is dependent on the delivery of this electrical energy. Periods of low wind are another example of potentially energy-constrained conditions if the resource mix is not sufficiently balanced with dispatchable resources to prevent electricity shortfalls. While the outlook is improving for some assessment areas where resource additions and delayed generator retirements are alleviating previously identified near-term supply shortfalls, a growing number of areas in North American face resource capacity or energy risks over this assessment period. See **Risk Categories** for a general overview of each of the three categories.

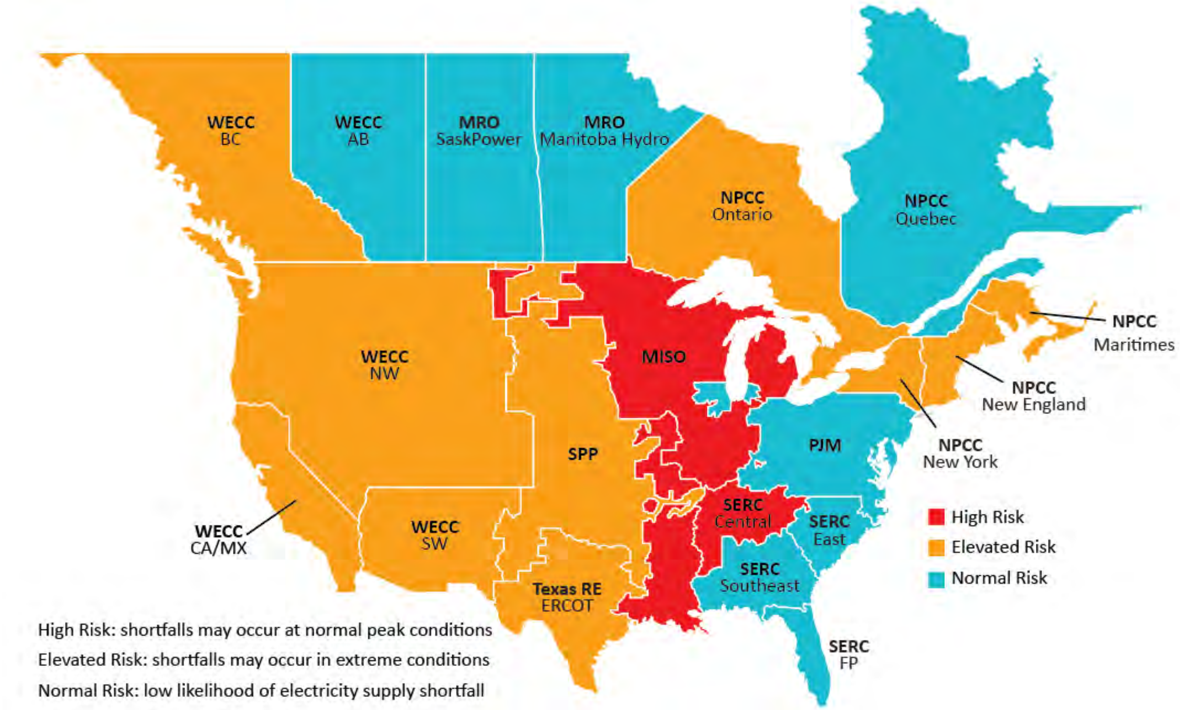

Figure 1: Risk Area Summary 2024–2028[8]

The following pages will provide overviews of each of the risk areas (i.e., high, elevated, and normal).

[7] As discussed throughout this report and in other NERC reliability assessments and reports, the North American BPS is undergoing a rapidly changing resource mix and the introduction of new technologies affecting how the system is planned and operated. NERC reliability assessments and the ERO Reliability Risk Priorities Report can be found at these locations: Reliability Assessments and Reliability Issues Steering Committee

[8] The Capacity and Energy Risk Assessment is focused on the first five years of the assessment period. Capacity, demand, and reserve margin information covering the entire assessment period can be found in the **Regional Assessments Dashboards** pages.

High Risk Areas[9]

Most areas are projected to have adequate electricity supply resources to meet demand forecasts associated with normal weather; however, areas that are red (high risk) in **Figure 1** do not meet resource adequacy criteria, such as the 1-day-in-10-year load-loss metric during periods of this assessment period. This indicates that the supply of electricity for these areas is more likely to be insufficient in the forecast period and that more firm resources are needed. See **High Risk Area Details** for additional information. The following are details on the two high risk areas:

- **Midcontinent Independent System Operator (MISO):** Market responses to higher capacity prices in 2022 and new resource additions have overcome the planning reserve deficits that were projected to occur in 2023 and reported in the *2022 LTRA*. In this *2023 LTRA*, MISO's summer anticipated reserve margin (ARM) is projected to be above Reference Margin Levels (RML) established by MISO for reliability through the 2027 summer. However, beginning in 2028, MISO is projected to have a 4.7 GW shortfall if expected generator retirements occur despite the addition of new resources that total over 12 GW. See **MISO** dashboard pages for more information.

- **SERC-Central:** There is a potential shortfall in planned reserves over the 2025–2027 period as demand forecasts increase faster than the transitioning resource mix grows. This assessment area will add over 7 GW of natural gas generation and retire over 5 GW of coal generation over the period. Nearly 4 GW of Bulk Electric System (BES)-connected solar projects are expected in the next 10 years. The period of projected shortfall is occurring in a mid-point of the assessment period from generator retirements that are currently slated to take place before new resources are added. SERC-Central was not identified as a risk area in the *2022 LTRA*. See **SERC-Central** dashboard pages for more information.

Elevated Risk Areas[10]

Extreme temperatures and prolonged severe weather conditions are increasingly impacting the BPS. Extreme heat and subfreezing temperatures can impact the BPS by increasing electricity demand and threatening electricity supplies by forcing vulnerable generation offline and simultaneously disrupting the flow of the natural gas fuel supply to generators. While a given area (see **Figure 1**) may have sufficient capacity to meet resource adequacy requirements, it may not have sufficient availability and energy from resources during extreme and prolonged weather events and abnormal atmospheric conditions (i.e., smoke, smog, and wind extremes that affect output from solar and wind resources). Therefore, long-duration extreme weather events increase the risk of electricity supply shortfalls. See **Elevated Risk Area Details** for additional information.

As forecasted peak electricity demand rises across the BPS, many areas are also experiencing increasing complexity in load models that adds to operating risk. Extreme heat and cold temperatures and irregular weather patterns can cause demand for electricity to deviate significantly from historical forecasts. Electrification of the heating sector is increasing temperature-sensitive load components while increasing levels of variable-output solar photovoltaic (PV) distributed energy resources (DER) add to the load forecast uncertainty. Underestimating electricity demand prior to the arrival of extreme temperatures can lead to ineffective operations planning and insufficient resources being scheduled. Generator performance and fuel issues are more likely to occur when generators are called upon with short notice; this can expose Balancing Authorities (BA) to potential resource shortfalls. Electrification and DER trends can be expected to further contribute to demand growth and sensitivity to weather patterns.

Electricity supplies can decline in extreme weather for many reasons:

- Generators that are not designed or prepared for severe cold or heat can be forced off-line in increasing amounts.
- Wide area weather events can also impact multiple balancing and transmission operations simultaneously that limit the availability of transfers.

[9] An assessment area is deemed to be "high risk" when it fails to meet the established resource adequacy target or requirement. The established resource adequacy target is not established by NERC, but instead by the prevailing regulatory authority or market operator. Generally, these targets/requirements are based on a 1-day/event load-loss in a 10-year planning requirement. High risk areas have a probability of load shed greater than the requirement/target. Simply said, high risk areas do not meet resource adequacy requirements.

[10] An assessment area is deemed to be "elevated risk" when it meets the established resource adequacy target or requirement, but the resources fail to meet demand and reserve requirements under the probabilistic or deterministic scenario analysis. The established resource adequacy target is not established by NERC, but instead the prevailing regulatory authority or market operator. Simply put, elevated risk areas meet resource adequacy requirements, but they may face challenges meeting load under extreme conditions.

- Fuel production or transportation disruptions could limit the amount of natural gas or other fuels available for electricity generation.
- Wind, solar, and other variable energy resource (VER) generators are dependent on the weather.

Areas in orange (elevated risk) in **Figure 1** meet resource adequacy criteria and have sufficient energy and capacity for normal forecasted conditions, but they are at risk of shortfall in extreme conditions:

- **NPCC-Maritimes**: Since the *2022 LTRA*, winter peak demand forecasts for this assessment area have risen. As a result, ARMs are currently projected to fall below the RML of 20% beginning in 2026. The small projected shortfall in planning reserves (120 MW or less over the five-year period) can be managed through supply procurements to reach resource adequacy targets. However, supply shortfalls are more likely to occur in the Maritimes province during wide-area heat events and extreme winter storms; this stresses demand and internal resources and puts external transfer assistance at risk of curtailment. NPCC-Maritimes was not identified as a risk area in the *2022 LTRA*. See the **NPCC-Maritimes** dashboard pages for more information.

- **NPCC-New England**: As reported in prior LTRAs and Winter Reliability Assessments (WRA), a persistent concern is whether there will be sufficient fuel available to satisfy electrical energy and operating reserve demands during an extended cold spell, or a series of cold spells, given the existing resource mix and regional fuel delivery infrastructure. ISO-New England's (ISO-NE) latest projections for winter peak demand show the highest growth rates in North America (3.46% compound-annual growth rate (CAGR) over this assessment period), heightening concerns for potential winter supply shortfalls toward the later part of this assessment period. Electrification of the transportation and heating sectors are primary drivers of the increase in demand forecast. New resources in ISO-NE's interconnection request queue do not generally offer the same reliability benefits in winter as the generation resources that are retiring (e.g., dispatchability, stored fuels). See the **NPCC-New England** dashboard pages for more information.

- **NPCC New York:** Reliability studies performed by the New York Independent System Operator (NYISO) have identified potential shortfalls starting in 2025 in New York City, prompting NYISO to solicit for market-based and regulated backstop solutions (i.e., generation, DR, or transmission, or combinations). The need is primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation types in New York City that are affected by a state law to reduce nitrogen oxide emissions. The deficiency could be significantly greater during a summer heatwave. NPCC New York was not identified as a risk area in the *2022 LTRA*. See the **NPCC-New York** dashboard pages for more information.

- **NPCC-Ontario:** Planned and contracted resource additions have improved the resource adequacy outlook since the *2022 LTRA.* At that time, NERC projected that shortfalls could occur beginning in 2025. In this *2023 LTRA*, reserve margins are projected to remain above Ontario's RMLs throughout the first five years. The improved outlook is the result of 1,600 MW of upgrades and expansions to natural-gas-fired generators and new BESS projects as well as a recent memorandum of understanding with Québec for 600 MW of firm summer capacity beginning in 2025. NPCC-Ontario meets resource adequacy criteria but with as little as 300 MW of surplus summer capacity starting in summer 2028. Extreme conditions that cause peak demand to exceed forecasts or above normal outages to occur could expose the area to risks of capacity shortfall. Additional capacity from the Independent Electricity System Operator's (IESO) future annual capacity auctions and ongoing procurements will continue to reduce these risks. See the **NPCC-Ontario** dashboard pages for more information.

- **Southwest Power Pool (SPP):** Since the *2022 LTRA*, projected reserve margins for the assessment period have declined while the RML of reserves needed for maintaining reliability has risen at the same time. Consequently, SPP's surplus capacity over the next five years will fall sharply. Lower reserve margins are driven by generation retirements (1,500 MW since the *2022 LTRA)* and rising peak demand forecasts. SPP raised the RML from 16% to 19% in 2023, LSEs in the RTO area to procure more resource capacity for the same amount of load. Energy shortfalls can occur in SPP when high demand coincides with low wind or above-normal generator outages. See the **SPP** dashboard pages for more information.

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Texas RE-ERCOT: Generation resources, primarily solar PV, continue to be added to the grid in large quantities, increasing ARM but also elevating concerns of energy risks. With demand forecast to rise steadily, the future resource mix is likely to have the lowest reserve levels during off-peak periods when solar PV resource output is diminished. These include hot summer evenings as well as fall and spring months when dispatchable thermal generation is performing scheduled maintenance. Extreme winter weather, such as Winter Storm Uri in February 2021, remains a serious concern that warrants continued efforts to ensure that generators and fuel supplies are available and capable of performing in severe conditions. Without provisions for electric grid reliability, new and proposed Environmental Protection Agency (EPA) rules could heighten the risk of thermal unit retirements before solutions to resource adequacy and system planning issues are in place. See the **Texas RE-ERCOT** dashboard pages for more information.

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British Columbia (WECC-BC): Forecasted peak demand growth is causing a decline in reserve margins and reduced surplus capacity for managing periods of above-normal demand. Energy shortfall risks in the WECC-BC assessment area are associated with extreme weather conditions that cause periods of above-normal demand to coincide with lower-than-normal resource output. Probabilistic assessment (ProbA) results show little energy risk in 2024; however, load-loss and unserved energy risks increase in 2026 as forecasted demand increases and natural-gas-fired generation retires. WECC-BC was not identified as a risk area in the *2022 LTRA*. See the **WECC-BC** dashboard pages for more information.

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WECC U.S. Assessment Areas: Throughout this area, both demand and resource variability are projected to continue increasing as the resource mix transitions and more DERs connect to the distribution system. In normal conditions, the expected demand and resource variability is balanced across the area as excess supply from one part of the system is delivered through the transmission network to places in need. However, more extreme summer temperatures that stress large portions of the Interconnection reduce the availability of excess supply for transfer while also reducing the transmission network's transfer capability:

  - 
  California/Mexico (WECC-CA/MX): Resource additions, generator uprating, and service extensions have helped alleviate near-term capacity risks and lower the area's reliance on imports to meet high demand. Since the *2022 LTRA*, WECC's probabilistic analysis indicates that risks of unserved energy and load loss in 2024 have fallen to negligible levels. However, loss-of-load and unserved energy risks emerge in 2026 concentrated in the July–September period and are primarily associated with extreme weather conditions. ARMs continue to rise from levels reported in NERC's previous LTRAs as new resources are added, primarily solar PV, hybrid-solar PV, and BESS resources. See the **WECC-CA/MX** dashboard pages for more information.

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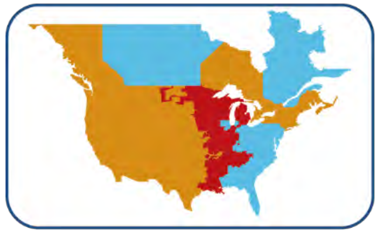
  Northwest (WECC-NW) and **Southwest (WECC-SW):** Like WECC-CA/MX, WECC-NW and WECC-SW are projected to be at risk of resource shortfalls during extreme summer weather conditions after 2024. Although the assessment areas are projected to have sufficient capacity to meet forecasted peak demand throughout this assessment period, dispatchable generation declines as generators retire starting in 2026. The resulting resource mix is more variable and has a risk of supply shortfalls during extreme summer conditions emerge in WECC's probabilistic analysis. See the **WECC-NW** and **WECC-SW** dashboard pages for more information.

Normal Risk Areas

Normal risk areas are shown in blue (see **Figure 1**). In these areas, resource adequacy criteria are met, and it is unlikely for electricity supply shortfalls to occur even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance). See **Normal Risk Area Details** for additional information.

Changing Resource Mix and Reliability Implications

Wind, solar PV, and hybrid generation are projected to be the primary additions to the resource mix over the 10-year assessment period; this leads the continued energy transition as older thermal generators retire. Maintaining a reliable BPS throughout the transition requires unwavering attention to ensure the resource mix satisfies capacity, energy, and essential reliability service (ERS) needs under designed conditions. It will also require significant planning and development of the interconnected transmission system to have a deliverable electricity supply from new resources to changing types of loads and the ability to withstand system contingencies.



In this LTRA, NERC accounted for over 83 GW of fossil-fired and nuclear generator retirements that are currently anticipated through 2033. An additional 30 GW of fossil-fired generators have announced plans to retire over the decade but have yet to enter deactivation processing with the planning authorities. These additional retirements can exacerbate energy, capacity, or ERS issues in high risk (red) and elevate risk (orange) areas and potentially affect the projected sufficiency of resources in normal risk (blue) areas (**Figure 1**). Environmental regulations and energy policies that are overly rigid and lack provisions for electric grid reliability have the potential to influence generators to seek deactivation despite a projected resource adequacy or operating reliability risk; this can potentially jeopardizing the orderly transition of the resource mix.[11] For this reason, regulators and policymakers need to consider effects on the electric grid in their rules and policies and design provisions that safeguard grid reliability.

Trends and Reliability Implications

Demand and transmission trends affect long-term reliability and the sufficiency of electricity supplies.

Demand Trends

Electricity peak demand and energy growth forecasts over the 10-year assessment period are higher than at any point in the past decade. Electrification and projections for growth in electric vehicles (EV) over this assessment period are a component of the demand and energy estimates provided by each assessment area. Since the *2022 LTRA*, peak season CAGR has risen in nearly all assessment areas, contributing to an overall trend to lower reserve margins. Some of the sharpest peak demand forecast increases and growth rates can be seen in winter seasons as heating system and transportation electrification influence forecasts. Dual-peaking or changing from summer to winter peaking is anticipated in several areas, requiring resource and system planners to shift the focus of adequacy planning. Concentrated growth and the emergence of new types of loads are occurring in many areas. These growth trends bring additional challenges for resource and transmission adequacy. Planners and operators can prepare by considering robust demand and energy scenarios, carefully monitoring and refining demand forecasts, and developing operational tools for peak load management.

Transmission Trends

The amount of BPS transmission projects reported to NERC as under construction or in planning for construction over the next 10 years has increased, indicating an overall increase in transmission development. New transmission projects are being driven to support new generation and enhance reliability. Siting and permitting challenges continue to inflict delays in transmission expansion planning. Regional transmission planning processes are adapting to manage the energy transition, but impediments to transmission development remain.

Conclusions and Recommendations

The energy and capacity risks identified in this *2023 LTRA* underscore the need for reliability to be a top priority for energy policymakers, regulators, and industry. Growing the reliable BPS will involve doing the following four things, numbered only for identification:

1. **Add new resources with needed reliability attributes and make existing resources more dependable.** As BPS resources grow to meet rising demand and the resource mix changes, IBR performance issues as well as generator and fuel vulnerabilities to extreme temperatures must be addressed to have a reliable electricity supply:
    - New wind and solar PV resources use inverters to convert their output power onto the grid, and the vast majority of resource inverters are susceptible to tripping or power disruption during normal grid fault conditions; this makes the future grid less reliable when more resources are inverter-based.
    - Natural-gas-fired generators are essential for meeting demand; they are dispatchable at any hour and provide a consistent rated output under a wide range of conditions. However, sufficient natural gas fuel supplies cannot be assured without better reliability measures and the effective coordination between the operators and planners of both electricity and natural gas infrastructures.
    - Reducing risks to electricity supplies in extreme hot and cold temperatures requires generating resources that are up to the task. However, natural-gas-fired generators, natural gas fuel supplies, and wind resources (which are becoming increasingly common)

[11] The EPA is implementing, has finalized, or has proposed six rules that impact the fossil-fired generators: Coal Combustion Residuals (being implemented), revised Effluent Limitations Guidelines (proposed), revised Mercury and Air Toxics Standards (proposed), Good Neighbor Rule (finalized), Carbon Rule (proposed), and Regional Haze (being implemented).

have proven vulnerable and unable to meet demand during winter storms over the past decade.

- Additionally, to reliably grow the BPS, generator retirements over the 10-year assessment period of this *2023 LTRA* need to be carefully evaluated. State and provincial resource adequacy stakeholders and policymakers need to ensure that resource plans account for growing electricity demand and load profiles as well as the future resource portfolio's capabilities to provide essential grid reliability services. They must have effective measures that can be implemented to prevent loss of resources that are needed for resource and energy adequacy, grid reliability, and system restoration.

2. **Expand the transmission network to deliver supplies from new resources and locations to serve changing loads.** A strong, flexible transmission system that is capable of coping with a wide variety of system conditions is key for the reliable supply and delivery of electricity. The rapidly changing resource mix requires access and deliverability of new resources—including transmission availability—to maintain reliability:
   - Transmission development is needed to connect resources to load and to adapt to a future system demand profile that will be influenced by EV charging, electrification in heating, large industrial loads and data centers, and the behavior of large flexible loads. The capability for electricity supplies to be transferred between areas may play a significant part in overall energy adequacy when the system may have highly variable electricity supply resources and more weather-sensitive demand.
   - Additionally, introducing new resource types into the system and ensuring that the planned system can be operated within reliability criteria requires engineering analysis that will be increasingly complex. Transmission planning processes are adapting to overcome challenges and the speed of development; however, backlogs remain.
3. **Adapt BPS planning, operations, and resource procurement markets and processes to the realities of a more complex power system.** The addition of variable resources (primarily wind and solar PV) and the retirement of conventional generation are fundamentally changing how the BPS is planned and operated. With electricity supplies coming increasingly from VERs and natural-gas-fired generators, there is a growing risk that supplies can fall short of demand during some periods. To ensure energy shortfall risks are identified and addressed, resource contributions to serving load must be accurately represented in resource planning and operating models as well as in the design of wholesale electricity market designs:
   - Resource and system planners must have robust tools and capabilities for assessing energy needs, extreme weather scenarios, and grid stability. Planning Reserve Margins can fail to identify energy risks that stem from low VER output or generator fuel supply issues, making them unsuitable as a sole basis of resource adequacy. Resource planners and wholesale markets must use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. NERC and the industry should also use wide-area assessments capable of accurately modeling interregional transfers to improve resource adequacy and energy risk assessments.
   - Geographically diverse wind and solar resources and loads can help reduce energy risks but require robust transmission networks, comprehensive energy and transfer capability analysis, and effective operating procedures and market mechanisms.
   - Natural gas supply infrastructure and the BPS form an interconnected energy system that requires a high degree of coordination and integration. The operation of this interconnected energy system can be disrupted when natural gas fuel supplies are not available for electricity generation as well as when electricity is not available to operate electricity-driven compressors and other critical infrastructure components in the natural gas supply chain. The potential for extreme cold temperatures to have wider impact because of the interconnected nature of the electric and natural gas systems makes integrated planning and effective coordination imperative.
   - Explosive growth in rooftop solar PV and other resources on distribution networks add complexity to planning and operating models and market designs that require visibility and coordination across distribution and BPS jurisdictions. Large flexible loads and demand-side management programs offer reliability benefits by providing operators with another resource for managing peak loads; however, operating models and mechanisms for control must be in place.
4. **Strengthen relationships among reliability stakeholders and policymakers.** Making informed policies and decisions in matters that have the potential to affect electric grid reliability requires a high level of awareness as future electricity resource reserves shrink in the face of demand growth and the interconnected nature of the electric and natural gas systems are more pronounced:
   - Initiatives like the North American Energy Standards Board Gas Electric Harmonization Forum—which is comprised of a broad cross section of natural gas and electricity stakeholders and experts; this forum was assembled to address weaknesses identified in 2021's Winter Storm Uri and 2022's Winter Storm Elliott. The NAESB put forward several recommendations that, if implemented today, would enable BPS operators to have a more reliable and fuel-secure generation mix and be in a better position to maintain the integrity of the BPS during extreme weather events, such as Winter Storm Elliott.

Initiatives like this are essential to come up with structural solutions to risks that arise from critical interdependencies.

- The Memorandum of Understanding between the U.S. Department of Energy (DOE) and the U.S. EPA to foster interagency cooperation and consultation to support electric grid reliability is an encouraging acknowledgement of the need for environmental policies to carefully consider electric grid reliability and provides a path for flexibility provisions to be addressed.[12]
- There is a need for dialogue among a broad group of stakeholders when policies and regulations have the potential to affect future electricity supplies, demand, and the development of electricity and natural gas resources and infrastructure. Regulations that have the potential to accelerate generator retirements or restrict operations must have sufficient flexibility and provisions to support grid reliability. The need for close coordination is further reinforced by the expanding interdependencies with other critical infrastructure sectors (i.e., communications, water and wastewater, transportation, critical manufacturing, and finance).[13]

Specific and actionable recommendations are contained in the **Recommendations: Details** section of this report with the same numbers to identify them. A summary of ERO ongoing activities and resources that address applicable recommendations is included in the **ERO Actions Summary** section.

[12] DOE-EPA Electric Reliability MOU
[13] 2023 ERO Reliability Risk Priorities Report

Recommendations: Details

The following numbered recommendations are additional details for the Executive Summary **Conclusions and Recommendations** with the same identifying numbers.

1. Add new resources with needed reliability attributes and make existing resources more dependable:

   - **Address performance deficiencies with existing and future inverter-based resources:** Reliably integrating IBRs onto the grid is paramount, and evidence indicates that the risk of grid vulnerabilities from interconnection practices and IBR performance issues are growing. IBRs include most solar and wind generation as well as new BESS or hybrid generation and account for over 70% of the new generation in development for connecting to the BPS. IBRs respond to disturbances and dynamic conditions based on programmed logic and inverter controls. The tripping of BPS-connected solar PV generating units and other control system behavior during grid faults has caused sudden loss of generation resources (over wide areas in some cases). Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California and similar events have occurred in new geographic areas as recently as the summer of 2023.[14] A common thread with these events is the lack of IBR ride-through capability that causes a minor system disturbance to become a major disturbance. Based on the findings of a recent NERC alert, more ride-through and ERS capabilities can be enabled within existing solar PV resources to improve performance and support the reliable operation of the BPS.[15] Industry adoption of the recommended practices set forth in NERC reliability guidelines and the NERC alert will reduce risks from IBR performance issues to the grid as NERC also develops mandatory Reliability Standards based on those reliability guidelines. It is also critically important for interconnection processes to include accurate modeling and studies requirements.[16] Guided by NERC's comprehensive Inverter-Based Resources Strategy and in response to FERC Order No. 991, the ERO and industry should take additional steps to ensure that IBRs operate reliably and that the system is planned with due consideration for their characteristics.[17,18]

   - **Improve the performance of the generating fleet in extreme weather:** The ERO and industry need to prioritize the development of Reliability Standard requirements to address reliability related findings from the FERC, NERC, and Regional Entity joint staff inquiry into the February 2021 cold weather grid outages.[19] Findings of the inquiry into Winter Storm Elliott (December 2022) reinforce the urgency of this effort.[20]

   - **Mitigate fuel-related risks to electricity generation (fuel assurance)**: In addition to serving as base and intermediate-load plants, natural-gas-fired generation has become a necessary balancing resource that enables reliable integration of VERs into the dispatch. As a result, the BES has never been more dependent upon the round-the-clock continuity of just-in-time natural gas delivery. The past two winters have seen interruptions of natural gas delivery to generators that resulted in energy deficiencies. NERC strongly endorses actions to establish reliability rules for the natural gas infrastructure necessary to support the grid as recommended in the Winter Storm Elliott report. Additionally, as part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electricity reliability. The NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System,* provides planning guidance.[21]

   - **Carefully manage generator deactivations:** State and provincial regulators and ISOs/RTOs need to have mechanisms they can employ to extend the service of generators seeking to retire when they are needed for reliability, including the management of energy shortfall risks. Regulatory and policy-setting organizations must use their full suite of tools to manage the pace of retirements and ensure that replacement infrastructure can be timely developed and placed in service. If needed, the DOE should use its 202(c) authority in support of electric system operators.

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[14] See the ERO's extensive IBR event reporting here: NERC Major Event Reports
[15] The NERC Level 2 alert to gather data from solar PV resource owners and issue recommendations can be found here: *Industry Recommendation: Inverter-Based Resource Performance Issues*.
[16] NERC's comprehensive initiatives to reduce IBR risks are detailed here: IBR Quick Reference Guide
[17] NERC IBR Activities
[18] FERC Order No. 901 - Final Rule Reliability Standards to Address Inverter-Based Resources
[19] *The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report*
[20] Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott
[21] Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised Guideline also identifies as fuel risks requiring evaluation many of the scenarios industry has encountered during recent periods of extreme cold weather and high demand for natural gas. The revised guideline is under review with the Reliability and Security Technical Committee. The approved and revised draft guideline can be found on the RSTC website: NERC Reliability and Security Guidelines

2. Expand the transmission network to deliver supplies from new resources and locations to serve changing loads:

- **Develop the transmission network:** ISOs/RTOs should continue looking for opportunities to streamline transmission planning processes and reduce the time required for transmission development. However, addressing the siting and permitting challenges that are the most common cause for delayed transmission projects will require regulators and policymakers at the federal, state, and provincial levels to focus attention and provide support.

- **Assess interregional transfer capabilities and their contribution to BPS reliability.** Studies of interregional transfers and transfer capability under a range of scenarios can provide insight into potential benefits of transmission development on grid reliability. It is important for NERC and the industry to complete the interregional transfer capability study directed in the Fiscal Responsibility Act of 2023 and share the results with legislators, regulators, and policymakers.[22] NERC should also incorporate insights and study approaches from the interregional transfer capability study to better account for interregional transfers in energy and capacity risk assessments.

3. Adapt BPS planning, operations, and resource procurement markets and processes to the realities of a more complex power system:

- **Resource contributions must be accurately represented in resource planning, wholesale electricity markets, and operating models.** Resource planners and wholesale market designers are developing new processes for assigning the contribution of resources to meeting demand in most areas with growing wind and solar PV resources. Earlier this year, MISO implemented seasonal resource adequacy auctions (spring, summer, fall, winter) based on reserve requirements and resource performance that are tailored to each season. Other ISOs and RTOs are exploring similar initiatives. Some assessment areas are implementing effective load-carrying capacity (ELCC) methods that involve probabilistic study to assign the capacity contribution of resources. These ELCC methods must address the risks and shortcomings in the present modeling described in this *2023 LTRA.* Specifically, the statistical representation of capacity that has variable and uncertain fuel can be problematic when combined in a reserve margin evaluation with capacity that has firm fuel and is highly reliable. Planners and operators must continue updating processes, tools, and techniques to keep pace with the changing resource mix. Among the changes needed is the consideration of the energy contributions that each resource type is expected to provide in order to identify periods of potential energy shortfalls. The explosive growth of BESS and hybrid resources seen in most areas requires additional details to be incorporated into operating and planning models, such as state of charge, BESS duration, and BESS operating mode.

- **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** Planning Reserve Margins are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Industry and research partners should focus on developing tools, models, and methods for including a wide-area view of energy transfers in resource adequacy studies. Additionally, the ERO must develop and implement analytical approaches to incorporate natural-gas fuel supply risks in NERC reliability assessments.

- **Maintain sufficient amounts of flexible resources**: To maintain load-and-supply balance in real-time with higher penetrations of variable supply and less-predictable demand, dispatchable generators must be available and capable of following changing electricity demand. Retirements of fossil-fired generators are reducing the amounts of dispatchable generation in many areas. As more solar PV and wind generation is added, additional flexible resources are needed to offset these resources' variability, such as supporting solar down ramps when the Sun goes down and complementing wind pattern changes. Natural-gas-fired generators and hydro generators have traditionally provided this ERS. Battery resources can provide flexibility during short durations, while new wind and solar PV have minimal assured flexibility. Maintaining ERSs is critically important. Resource planners and wholesale electricity market operators should ensure resources are procured and made available in the long-range resource portfolio as part of the planning process; markets and other mechanisms need to be in place to deliver weather-ready resources with sufficient energy and ERS capabilities to the operators.[23]

- **Develop tools for assessing extreme weather risks:** Planners are finding it necessary to have improved tools and methods to study wide-area, long duration extreme weather risks and other low-likelihood, extreme events. Scenario planning is needed to ensure appropriate evaluation of likelihood, consequence, and potential mitigations to enhance reliability and resilience of the BPS. Traditional resource adequacy models and approaches rooted in a loss-of-load expectation (LOLE) of 1 day-in-10-years do not account for the essential role that electricity plays in modern society, and normal demand

[22] Fiscal Responsibility Act of 2023
[23] NERC ERS Measure 6 Forward Tech Brief

distributions appear to be ill-suited for describing the extremes of changing weather patterns. NERC, industry, and research partners should collaborate to develop models and approaches for studying the risks to electricity supplies, including natural gas fuel availability, from wide-area and long-duration extreme weather conditions. Such capabilities for rigorously studying the impact of extreme weather will enable a more accurate assessment of the risks and provide for the development of effective measures for resilience.

- **Include extreme weather scenarios in resource and system planning:** Industry and regulators need to conduct all-hours analyses for evaluating and establishing resource adequacy and include extreme conditions in integrated resource planning and wholesale market designs. While more sophisticated capabilities for assessing extreme event risk are being developed, scenario planning can be more readily incorporated in resource and system planning. Scenarios should consider the potential effects of wide-area, long-duration extreme weather events, including the impact they can have on natural gas fuel supplies and on the interconnected energy system.

- **Accommodate the growth of DERs:** Preparing the grid to operate with increasing levels of distribution resources must also be a priority in many areas. Growth of DERs promise both opportunities and risks for reliability. Increased DER penetrations can improve local resilience at the cost of reduced operator visibility into loads and resource availability. Data sharing, models, and information protocols are needed to support BPS planners and operators. Industry must continue to evaluate potential reliability concerns associated with increasing DER penetration and DER performance and, when necessary, develop reliability standards requirements to address identified gaps. DER aggregators will also play an increasingly important role for BPS reliability in the coming years. ISOs/RTOs must consider how the implementation of DER aggregators in the wholesale market will affect BPS planning and operations.[24]

4. Strengthen relationships among reliability stakeholders and policymakers:

   - **The ERO and industry partners need to expand strategic engagements with federal, state, and provincial regulators and policymakers:** These officials have jurisdictional authority to make key decisions that affect reliability, resource adequacy, and infrastructure development.

   - **The ERO, regulators, and industry partners need to work together:** Special emphasis needs to be placed on mechanisms to ensure the reliable delivery of natural gas fuel supplies for electricity generation as well as to act on the recommendations in *The FERC-NERC-Regional Entity Staff Report: Inquiry into Bulk Power System Operations December 2022 Winter Storm Elliott*.

[24] A comprehensive guide to ERO activities on DERs can be found here: DER Activities

Capacity and Energy Assessment

Conditions for tighter resource adequacy—characterized by less surplus capacity relative to forecasted demand—have emerged generally across the BPS over the past decade. **Figure 2** shows summer peak resource capacity (top) and forecasted peak demand (bottom) aggregated for all NERC assessment areas at the beginning and the end of the 2012–2032 period. While summer forecasted peak demand increased by 3% since 2012, current on-peak BPS resource capacity decreased by 4%. Furthermore, summer peak demand is forecast to increase another 10% by 2032 while resources are expected to grow modestly by 4%. Lower reserves by this broad and retrospective measure are a coarse indicator that signals a need for stakeholders to pay careful attention to more specific and granular resource adequacy measures and input assumptions.

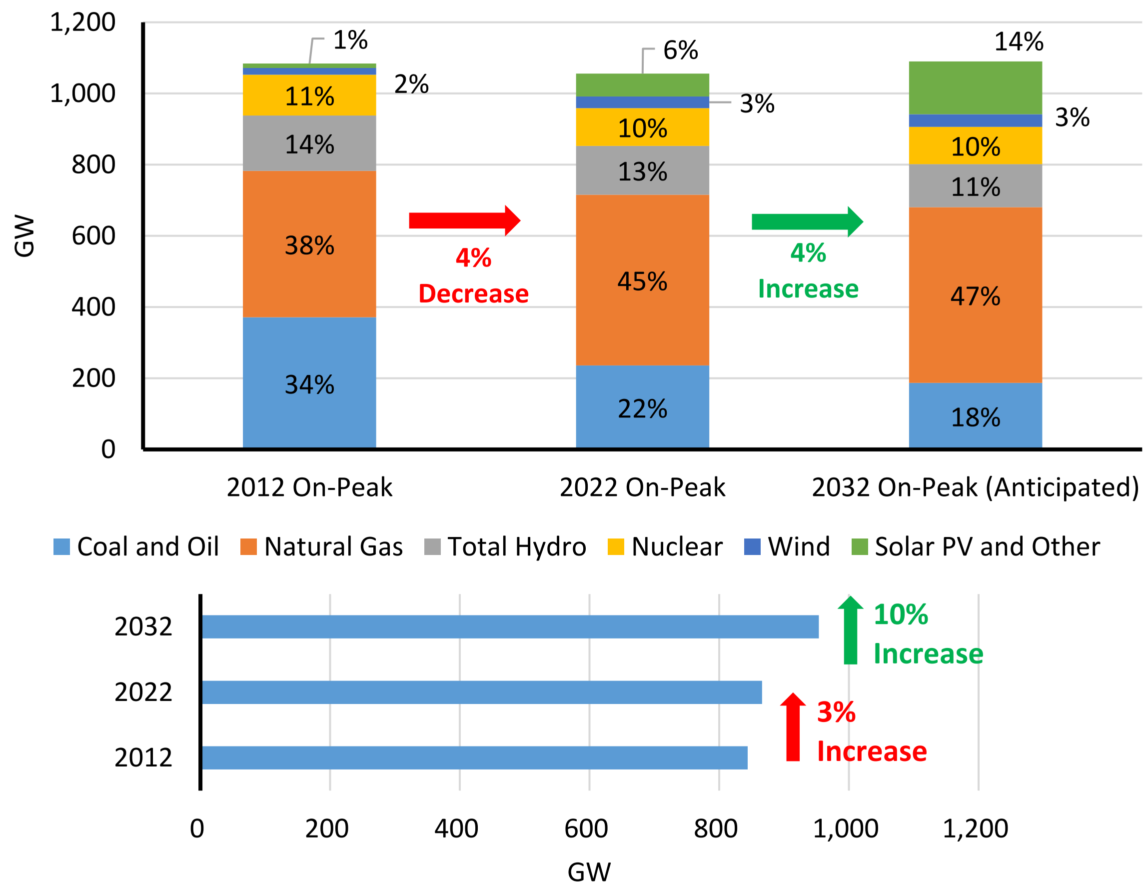


Figure 2: Change in Summer Peak Capacity and Demand Forecast 2012–2032

Assessment Approach

NERC is using two approaches in this *LTRA* to assess future resource capacity and energy risk; both are forward-looking snapshots of resource adequacy that are tied to industry forecasts of electricity supplies, demand, and transmission development:

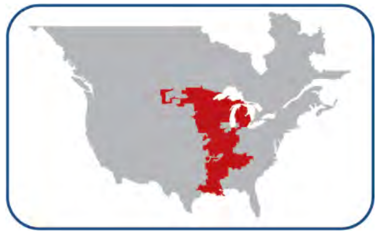
- Comparing the margin between projected resources and peak net demand, or reserve margin, to an RML that represents the accepted level of risk based on a probability-based loss-of-load analysis.
- Assessing load-loss metrics determined from probability-based simulation of projected demand and resource availability over all hours to identify high risk periods and potential energy constraints resulting in load loss events. Loss-of-load hours (LOLH) and expected unserved energy (EUE) from NERC's biennial ProbA are used to identify risk levels. The ProbA was completed in 2022 and published in the *2022 LTRA*. Subsequently, NERC published the *2022 Probabilistic Assessment Regional Risk Scenarios Report* to analyze more extreme area-specific reliability risks and uncertainties with probabilistic methods.[25] This *LTRA* considers both results and updated projections to determine energy risk trends.

See the **Demand Assumptions and Resource Categories** for further details on these approaches. Assessment area dashboards (see **Regional Assessments Dashboards**) provide resource capacity and energy risk assessment results for all areas.

Finding: This *2023 LTRA* Capacity and Energy Assessment section highlights both progress and growing resource adequacy concerns as the resource mix transition continues. Delayed generator retirements and resource additions are alleviating some previously identified near-term capacity shortfalls. However, a growing number of areas in North American face resource capacity or energy risks over the assessment period. Capacity deficits, where they are projected, are largely the result of generator retirements that have yet to be replaced. While some areas have sufficient capacity resources, energy limitations and unavailable generation during certain conditions (e.g., low wind, extreme and prolonged cold weather) can result in the inability to serve all firm demand.

[25] 2022 ProbA Regional Risk Scenarios Report

Risk Categories



An assessment area is high risk (see **Figure 1**) when established resource adequacy targets or requirements are not met during this assessment period. NERC does not establish resource adequacy targets; these are set by regulatory authorities or market operator and are typically based on a 1-day/event load-loss in a 10-year planning requirement. High risk areas have a probability of load shed greater than the requirement/target.

An assessment area is considered an elevated risk when it meets the established resource adequacy target or requirement, but the resources fail to meet demand and reserve requirements under probabilistic or deterministic analysis of conditions that are plausible but more extreme than normal seasonal peaks. More extreme conditions can include temperatures that result in above normal demand levels, low resource output or availability, and/or disruption of normal electricity transfers. Simply put, elevated risk areas meet resource adequacy requirements, but they may face challenges meeting load under extreme conditions.

NERC assesses areas as normal risk when resource adequacy criteria are met and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance). Although areas categorized as Normal Risk are expected to have sufficient resources for plausible extreme conditions, they are not immune to the effects of exceedingly rare severe weather events that simultaneously affect demand and generation or other high-impact, low frequency events.

High Risk Area Details

Most areas are projected to have adequate electricity supply resources to meet demand forecasts associated with normal weather. However, the following two areas (listed in order of appearance on the **Regional Assessments Dashboards)** do not meet resource adequacy criteria, such as the 1-day-in-10-year load-loss metric during periods of the assessment period. This indicates that the supply of electricity for these areas is more likely to be insufficient in the forecast period and that more firm resources are needed. See **High Risk Areas** in a previous section for additional information.

MISO

In 2023, MISO transitioned to its first year of seasonal capacity auctions (summer, fall, winter, spring). Market responses to higher capacity prices in 2022 and new resource additions have overcome planning reserve deficits reported in the *2022 LTRA*, and now MISO's summer ARM is projected to be above the RMLs through the 2031 summer (**Figure 3**). Beginning in 2028, MISO is projected to have a 4.7 GW shortfall if expected generator retirements occur and over 12 GW of new resources are added.

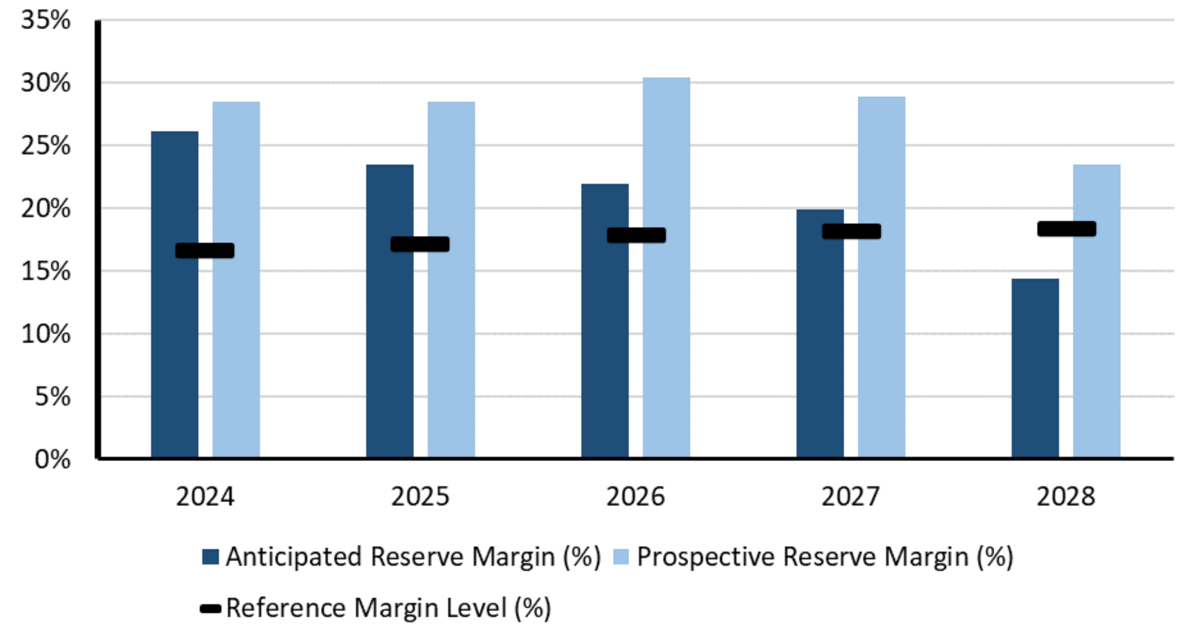


Figure 3: MISO Five-Year Planning Reserve Margin—Summer

MISO's switch to seasonal resource adequacy construct now more effectively identifies risk across the entire year as it makes use of seasonal resource accreditation and seasonal resource adequacy requirements. Resource performance in winter may differ from other seasons (e.g., seasonal wind patterns effect wind generating fleet; thermal generator outage rates vary by season; and solar resources typically have less or no output at times of highest demand in winter). Similarly, demand profiles are different by season. A seasonal RML accounts for these and other factors. Beginning in 2028, MISO's winter ARM is expected to fall below the area's winter RML (1,300 MW shortfall). **Figure 4** shows the steady decline of winter ARMs in MISO and the winter RML. The contrast between the increasing summer ARMs and declining winter ARMs is the result of the changing resource mix. Retiring generators, primarily thermal, are being replaced with solar PV (which has very small capacity contributions in winter) and some wind.

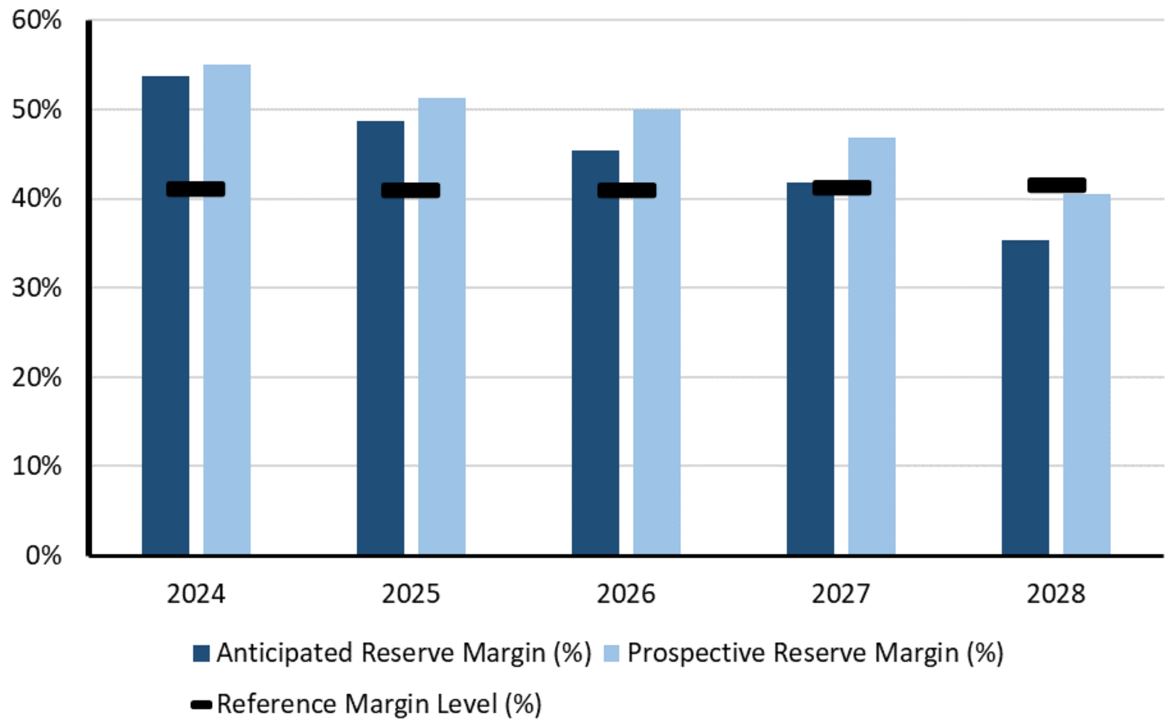


Figure 4: MISO Five-Year Planning Reserve Margin–Winter

Like MISO, other ISO/RTO areas and integrated resource planners are considering or developing seasonal resource adequacy approaches to better respond to anticipated challenges.

SERC-Central

The SERC-Central assessment area faces a potential shortfall in planned reserves over the 2025–2027 period as demand forecasts increase faster than the transitioning resource mix grows (**Figure 5**). The assessment area will add 7,251 MW of natural gas generation and retire 5,159 MW of coal generation over the period. A total of 3,937 MW of BES-connected Tier 1 solar PV projects are expected in the next 10 years. The period of projected shortfall is occurring in a mid-point of this assessment period from generator retirements that are currently slated to take place before new resources are added. Overall, there will be 2,762 MW of net additions and retirements within the next 10 years.

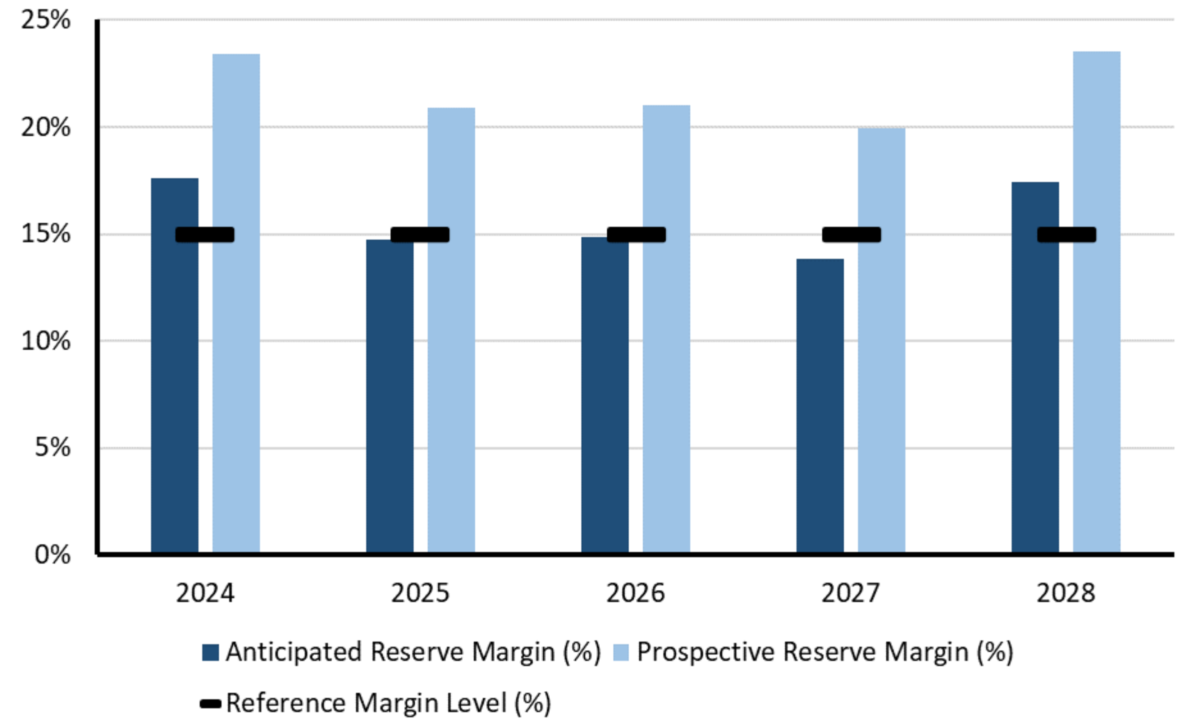


Figure 5: SERC-C Five-Year Planning Reserve Margin

NERC's 2022 ProbA revealed some LOLH (<0.1 hours/year) concentrated in winter. With rising demand projections and relatively unchanged resources, the risk is increasing over this assessment period.

Elevated Risk Area Details

The below areas are projected to meet resource adequacy criteria and have sufficient energy and capacity for normal forecasted conditions but are at risk of supply shortfall in assessed extreme conditions. Areas are listed in order of appearance on the **Regional Assessments Dashboards** section. See **Elevated Risk Areas** in a previous section for additional information.

NPCC-Maritimes

Since the *2022 LTRA*, winter peak demand forecasts for the assessment area have risen. As a result, Anticipated Reserve Margins (ARM) are currently projected to fall below the RML of 20% beginning in 2026 (**Figure 6**). The small projected shortfall in planning reserves (120 MW or less over the five-year period) can be managed through supply procurements to reach resource adequacy targets. However, supply shortfalls are more likely to occur in Maritimes during wide-area heat events and extreme winter storms transfers that stress demand and internal resources and put external transfer assistance at risk of curtailment.

NERC's 2022 ProbA revealed some LOLH (<0.1 hours/year) concentrated in winter. With rising demand projections and relatively unchanged resources, the risk is increasing over this assessment period.

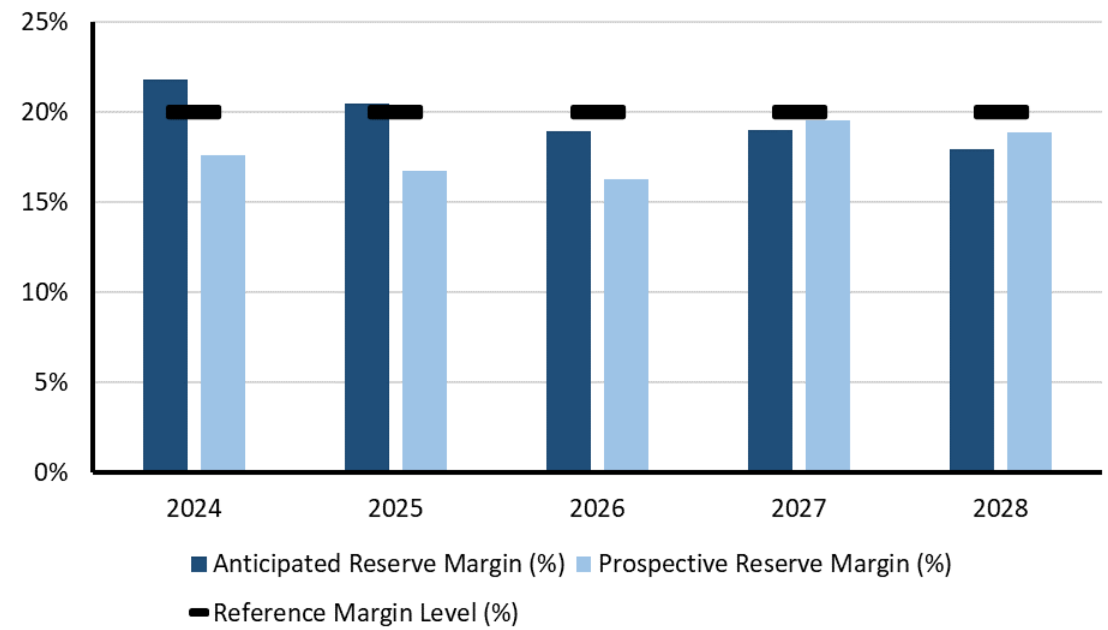
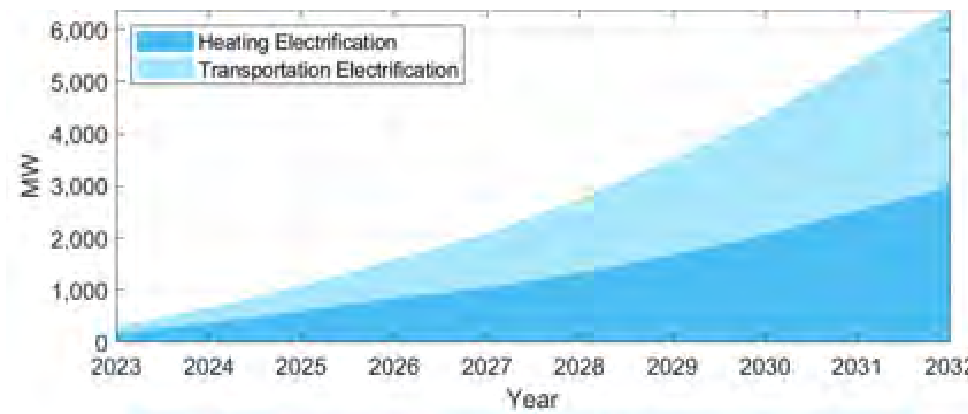


Figure 6: NPCC-Maritimes Five-Year Planning Reserve Margin

NPCC-New England

As reported in prior LTRAs and WRAs, a persistent concern for New England is whether there will be sufficient fuel available to satisfy electrical energy and operating reserve demands during an extended cold spell or a series of cold spells given the existing resource mix and regional fuel delivery infrastructure. ISO-NE's latest projections for winter peak demand show the highest growth rates in North America (3.46% CAGR over this assessment period), heightening concerns for potential winter supply shortfalls toward the later part of this assessment period. Electrification of the transportation and heating sectors are primary drivers of the increase in demand forecast (See **Figure 7**).



	Transportation Electrification				Heating Electrification		
Year	CELT 2022 (MW)	CELT 2023 (MW)	Change (MW)		CELT 2022 (MW)	CELT 2023 (MW)	Change (MW)
2023	50	116	66		75	175	100
2024	133	271	138		179	370	192
2025	244	473	229		311	601	290
2026	382	726	344		473	848	374
2027	549	1,042	493		668	1,040	372
2028	743	1,404	661		895	1,333	438
2029	967	1,822	855		1,158	1,673	515
2030	1,221	2,293	1,072		1,476	2,063	588
2031	1,497	2,820	1,323		1,831	2,521	691
2032		3,420				2,965	

Figure 7: Electrification Component of Winter Peak Demand Projections (Source: ISO-NE CELT Report 2023)

New resources in ISO-NE's interconnection request queue do not offer the same reliability benefits in general during winter as the generation resources that are retiring or at risk of retiring over this assessment period. Thermal generation with stored fuel is at risk of retirement without fuel-assured replacements. The generation interconnection queue includes over 35 GW capacity; however, it is primarily VERs. More dispatchable, fuel-assured, or long-duration stored energy resources will be required to provide for reliable winter operations as electrification continues in the area.

NPCC New York

ARMs exceed a RML of 15% over the near-term; however, reserve surplus is near zero in 2025 (see **Figure 8**).[26] This leaves little reserve to meet above-normal levels of summer demand or manage high generator outages or loss of imports that can occur during extreme weather events.

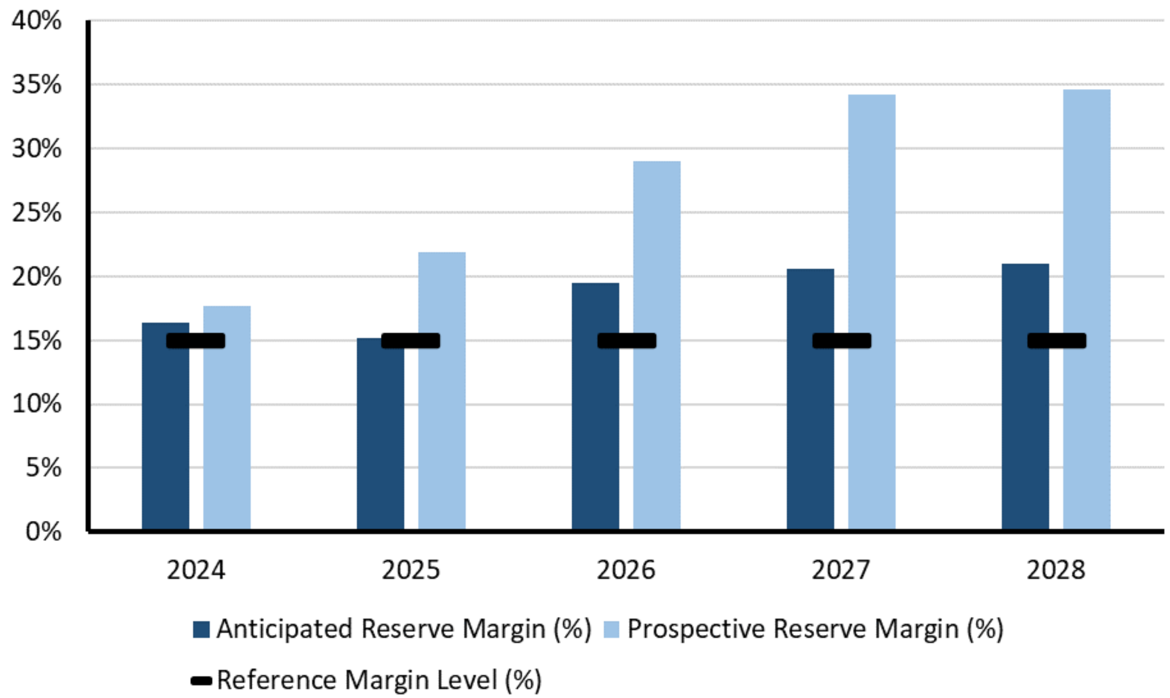


Figure 8: NPCC New York Five-Year Planning Reserve Margin

NYISO reliability studies identified a reliability need that would start in 2025 in New York City, resulting in NYISO evaluating proposed solutions. The need is primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City that is affected by a state law to reduce nitrogen oxide emissions. The deficiency will be significantly greater if a heatwave occurs.

The transition to a cleaner grid in New York is leading to an electric system that is increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation. Reliability margins are shrinking as generators needed for ERSs are planning to retire. Delays in the construction of new supply and transmission, higher than expected demand, and extreme weather could threaten reliability and resilience in the future.

NPCC Ontario

Since the *2022 LTRA,* planned and contracted resource additions have improved the province's resource adequacy outlook. The ARMs in NPCC-Ontario are projected to remain above Ontario's current RMLs throughout the first five years of this assessment period (see **Figure 9**). The improved outlook is the result of 1,600 MW of upgrades and on-site expansions to natural-gas-fired generators and new BESS projects. In addition, a recent memorandum of understanding with neighboring province Québec adds 600 MW of firm summer capacity beginning in 2025. NPCC-Ontario meets resource adequacy criteria but with as little as 300 MW of surplus summer capacity in 2028 and later. Extreme conditions that cause peak demand to exceed forecasts or that cause above normal outages to occur could expose the area to risks of capacity shortfall. However, the risks can be mitigated with additional capacity from IESO's future annual capacity auctions and ongoing procurements.

[26] NERC uses a RML of 15% in the *2023 LTRA* Capacity and Energy Risk Assessment for NPCC New York in absence of an established Planning Reserve Margin requirement. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. New York requires LSEs to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2023–2024 IRM at 20%. All values in the IRM calculation are based upon full Installed Capacity MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year. Additionally, NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 event-days/year.

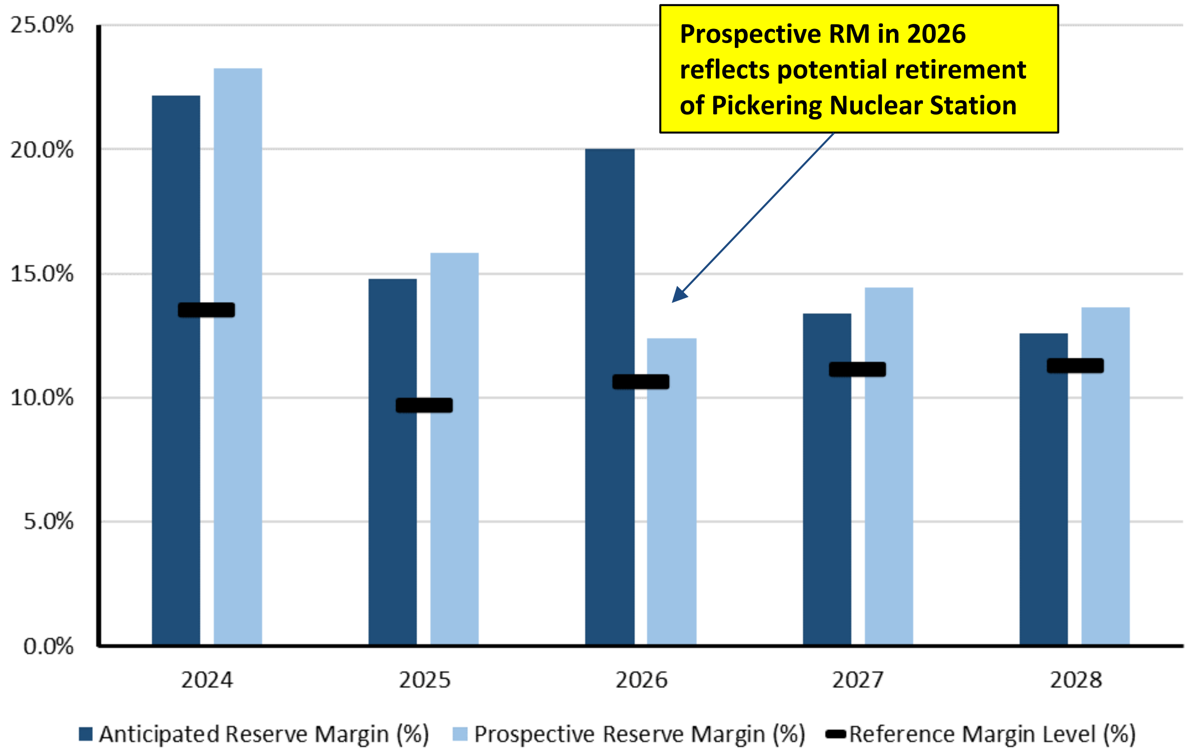


Figure 9: NPCC-Ontario Five-Year Planning Reserve Margin

As reported in the two prior *LTRAs*, the main drivers for Ontario's projected decline in capacity are planned retirements and lengthy outages for nuclear units undergoing refurbishment. In September 2022, Ontario's Ministry of Energy announced that it was supporting a plan by Ontario Power Generation to extend operation of Pickering Nuclear Generating Station beyond its planned retirement in 2025 through September 2026.

Recently, the Canadian federal government released a draft of clean electricity regulations; IESO is undertaking analysis to help inform the final draft.

SPP

Since the *2022 LTRA*, SPP's projected reserve margins for this assessment period have declined while the RMLs needed for maintaining reliability have risen. Consequently, SPP's surplus capacity over the next five years has fallen sharply. See **Figure 10**.

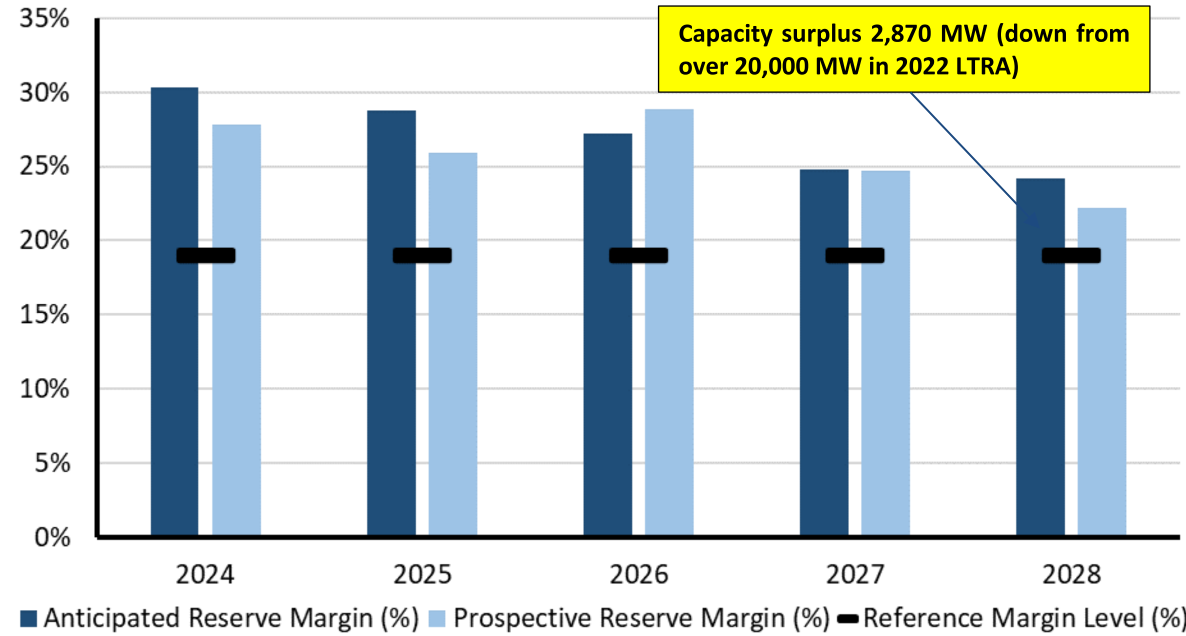


Figure 10: SPP Five-Year Planning Reserve Margin

Lower reserve margins are driven by generation retirements (1,500 MW since the *2022 LTRA*) and rising peak demand forecasts. Winter forecasted peak demand growth is outpacing summer (winter CAGR 1.24% vs. summer CAGR 1.12%). SPP raised the RML from 16% to 19% beginning in 2023 based on its most recent biennial LOLE study. The previous RML was not sufficient to meet 0.1 day/year LOLE. LSEs in SPP must procure resources to cover a higher RML.

SPP's sizeable but diminishing reserve margins do not account for planned, forced, or maintenance generator outages. Instead, they reflect the full availability of accredited capacity. Additionally, anticipated resources do not reflect derates based on real-time operational impacts. Capacity and energy shortfalls can occur in SPP when high demand coincides with low-wind or above-normal generator outages.

Texas RE-ERCOT

Generation resources, primarily solar PV, continue to be added to the grid in Texas in large quantities, increasing ARMs but also elevating concerns of energy risks that result from the variability of these resources and the potential for delays in implementation. Rising demand forecasts adds to energy risks as the risk of shortfalls increases during warm season evening hours when demand remains high while solar output is diminished. Sufficient levels of dispatchable generation and demand-side resources are needed. New and proposed EPA rules heighten the risk of thermal unit retirements before solutions are in place for reliability (e.g., transmission, resource adequacy).

Extreme winter weather (e.g., Winter Storm Uri in February 2021) remains a serious concern, warranting continued efforts ensure adequate resources are available and capable of performing in severe conditions to meet extreme demand. Market reforms and reliability initiatives that have been instituted are expected to reduce risks in extreme weather. These include the performance credit mechanism (PCM) incentives to generators for commitments to produce during tight grid conditions and to the firm fuel supply service (FFSS), which provides resources that are supported by on-site fuel or have off-site natural gas storage that meets qualification criteria.

U.S. Western Interconnection (WECC-CA/MX, WECC-NW, WECC-SW)

Throughout the U.S. assessment areas in WECC, both demand and resource variability are projected to continue as the resource mix transitions and DERs grow. In normal conditions, the expected demand and resource variability is balanced across the area as excess supply from one part of the system is delivered through the transmission network to places where demand is higher than supply. However, more extreme summer temperatures that stress large portions of the Interconnection reduce the availability of excess supply for transfer while also reducing the transmission network's ability to transfer the excess.

Energy Risks in WECC-CA/MX

Resource additions, generator uprating, and service extensions in WECC-CA/MX have helped alleviate near-term capacity risks and lower the area's reliance on imports to meet high demand. ARMs continue to rise from levels reported in NERC's previous LTRAs as new resources (primarily solar PV), hybrid-solar PV, and BESS are added (see **Figure 11**). Anticipated resources are sufficient to meet forecasted peak demand throughout this assessment period.

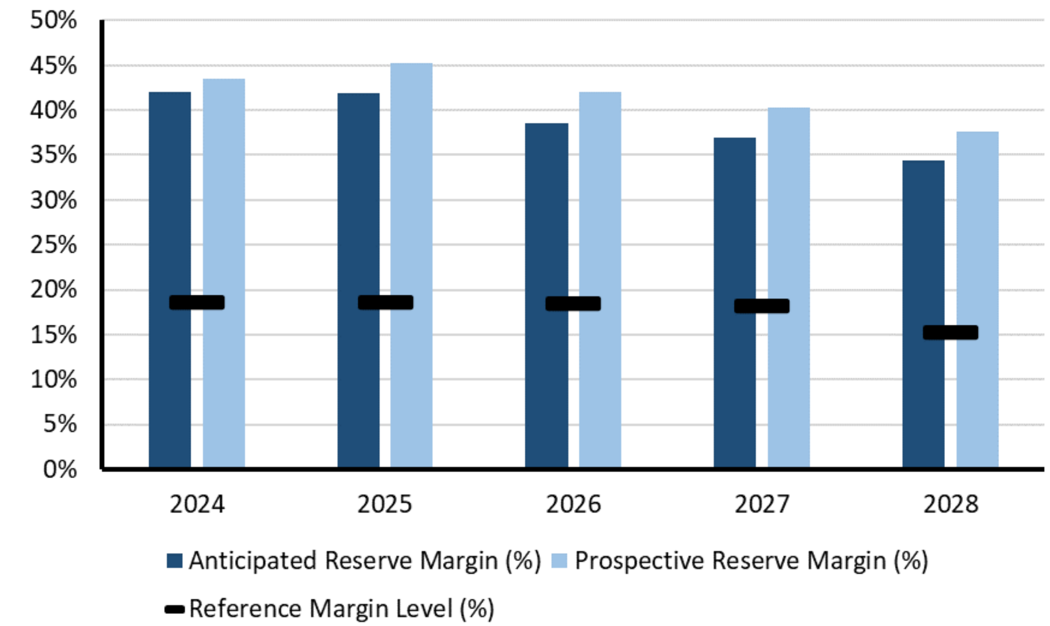


Figure 11: WECC-CA/MX Five-Year Planning Reserve Margin

Despite the on-peak capacity surplus, energy risks persist and are projected to increase after 2024 as additional thermal generators are planned for retirement. **Table 1** provides the results of probabilistic analysis performed by WECC that identify the risks of unserved energy and load-loss. Comparing the results of WECC's probabilistic analysis performed in 2022 with the current results indicates that risks of unserved energy and load loss in 2024 have fallen to negligible levels. However, loss-of-load and unserved energy risks emerge in the July–September period of 2026 and are primarily associated with extreme weather conditions.

Table 1: CA/MX ProbA Base Case Summary of Results

	2024*	2024	2026
EUE (MWh)	37,305	-	11,731
EUE (PPM)	136	-	43
LOLH (hours per Year)	0.721	-	0.227
Operable On-Peak Margin	30.3%	30.7%	27.5%

** Results from the 2022 ProbA are provided for comparison and are trending with the current results.*

WECC-CA/MX remains dependent on electricity imports to manage periods of extreme electricity demand or low resource output. Energy shortfall risks are associated with periods of above-normal demand that coincide with lower-than-normal resource output that is most pronounced during summer late-afternoon and evening periods when solar PV output is lower (see **Figure 12**). Heat events that span a wide area and reduce the availability of electricity imports into California are likely to continue to raise concerns and increase the risk of energy shortfalls.

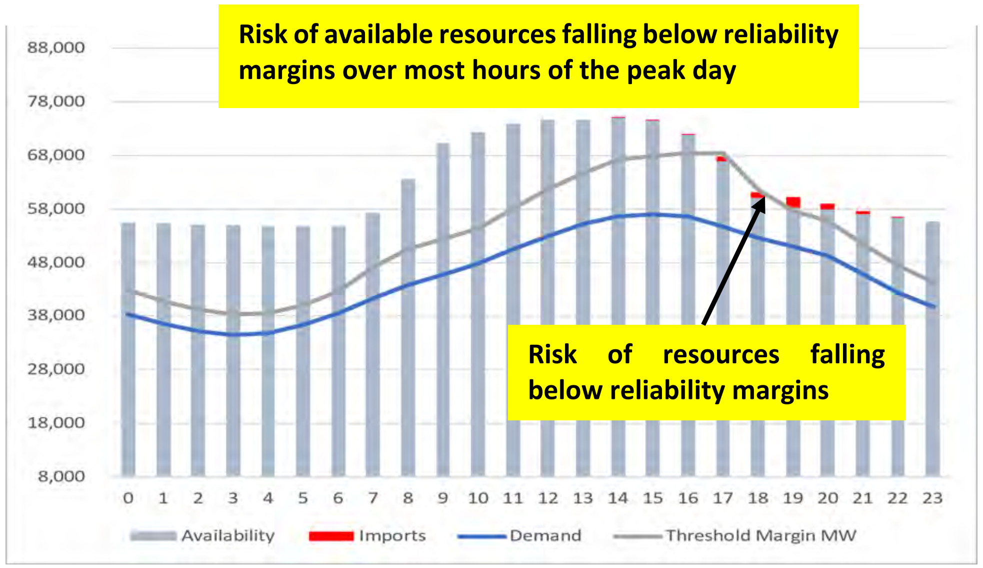


Figure 12: Hourly Resources and Demand Modeled for 2026 Summer Peak Day in WECC-CA/MX (Source: WECC)

Energy Risks in WECC-BC

Forecasted peak demand growth is causing a decline in reserve margins and reduced surplus capacity for managing periods of above-normal demand. British Columbia (WECC-BC) is a winter-peaking area that experiences peak demand typically in the early evening (6:00 p.m.) hours of December. Peak demand is forecasted to grow from 11.6 GW in 2023 to 12.9 GW in 2033. Anticipated resources are sufficient to meet forecasted peak demand throughout this assessment period. See **Figure 13**.

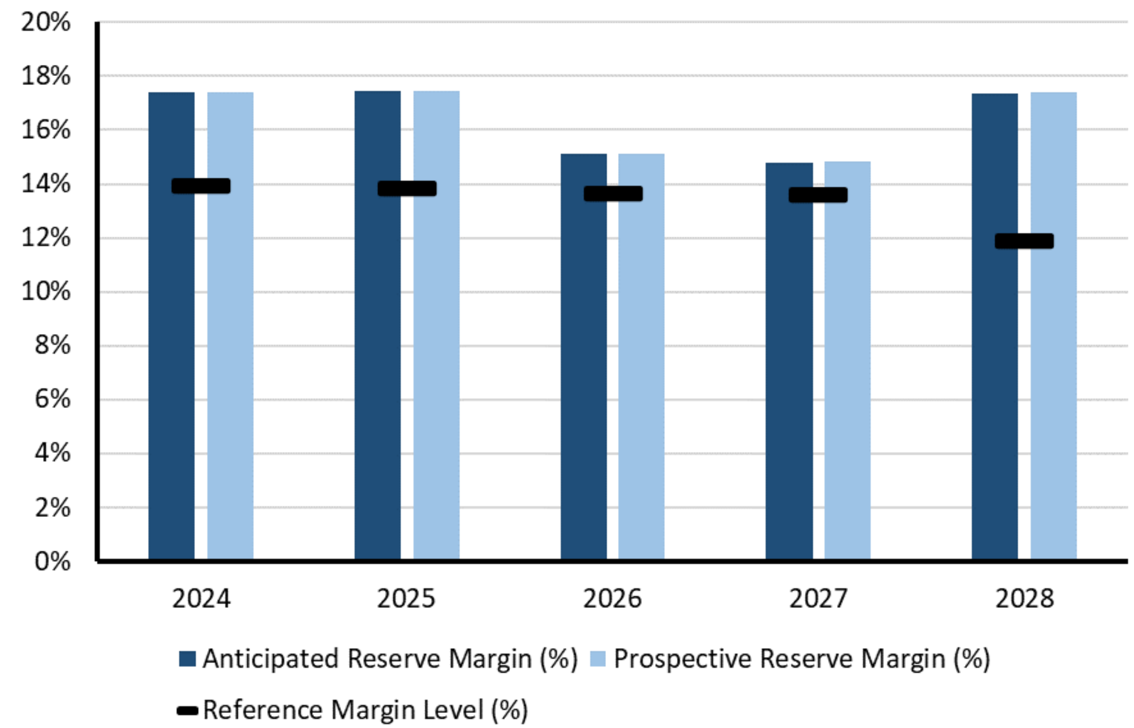


Figure 13: WECC-BC Five-Year Planning Reserve Margin

Energy shortfall risks in the WECC-BC assessment area are associated with extreme weather conditions that cause periods of above-normal demand to coincide with lower-than-normal resource output. **Figure 14** shows WECC's modeling of electricity supply and demand for the representative peak day in December 2026. ProbA results show little energy risk in 2024. However, load-loss and unserved energy risks increase in 2026 as forecasted demand increases and natural-gas-fired generation retires.

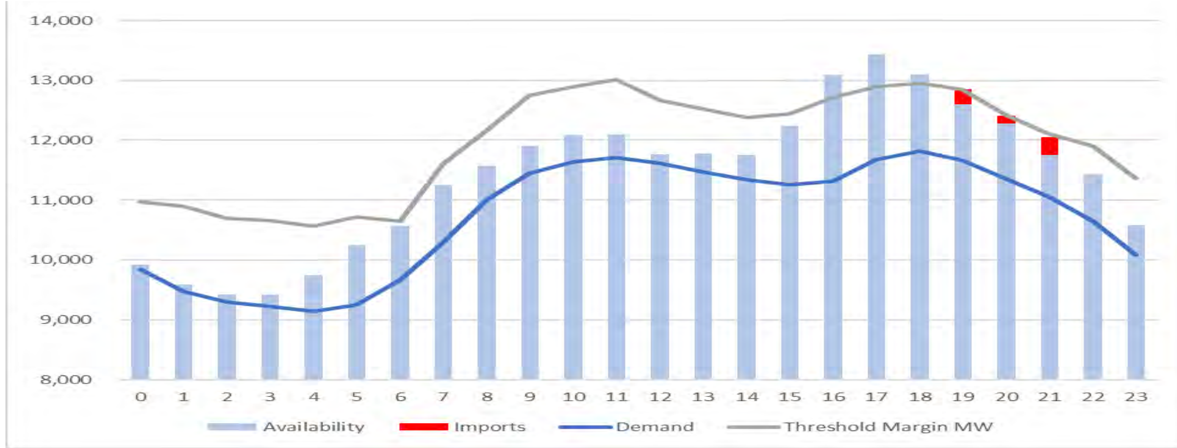


Figure 14: WECC-BC Hourly Resources and Demand Modeled 2026 Winter Peak Day (Source: WECC)

Energy Risks in WECC-NW and WECC-SW

Like WECC-CA/MX, the U.S. Northwest (WECC-NW) and U.S. Southwest (WECC-SW) are projected to be at risk of resource shortfalls during extreme summer weather conditions after 2024. Although the assessment areas are projected to have sufficient capacity to meet forecasted peak demand throughout this assessment period, dispatchable generation declines as generators retire in 2026 and later. The resulting resource mix is more variable, causing a risk of supply shortfalls during extreme summer conditions in WECC's probabilistic analysis (see **Table 2** and **Table 3**).

Table 2: WECC-NW ProbA Base Case Summary of Results			
	2024*	**2024**	**2026**
EUE (MWh)	1,722	-	8,101
EUE (PPM)	4	-	21
LOLH (hours per Year)	0.036	-	0.132
Operable On-Peak Margin	25.8%	37.6%	32.5%

**Results from the 2022 ProbA are provided for comparison and trending with current results*

Table 3: WECC-SW ProbA Base Case Summary of Results			
	2024*	**2024**	**2026**
EUE (MWh)	84	-	818
EUE (PPM)	1	-	6
LOLH (hours per Year)	0.003	-	0.031
Operable On-Peak Margin	28.1%	18.3%	18.4%

**Results from the 2022 ProbA are provided for comparison and trending with current results*

WECC-NW and WECC-SW areas' loss-of-load and unserved energy risks are associated with extreme weather events and concentrated in the late afternoon and early evening hours during the July–September period. See the **Regional Assessments Dashboards** pages for WECC's modeling of electricity supply and demand for the peak days in these areas. Modeling shows that imported electricity supplies are needed in all U.S. Western Interconnection assessment areas to meet forecasted demand during summer peak demand days, raising concerns of supplies during a wide-area heat event.

Normal Risk Area Details

All other assessment areas (see **Figure 1**) are assessed as normal risk. In these areas, resource adequacy criteria are met, and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance). See **Normal Risk Areas** for additional information.

Resource and Demand Projections

The **Capacity and Energy Risk Assessment** section in this *LTRA* is a forward-looking snapshot of resource adequacy that is tied to industry forecasts of electricity supplies, demand, and transmission development. Later sections in this report describe important trends in each of these areas. The future electricity supply will come from a resource mix that is more variable, weather dependent, and reliant on natural gas for fuel without a broad coordination and careful attention to the pace of change. Future electricity demand is being shaped by many factors that collectively influence peak demand forecast levels, peak seasons, and hourly profiles. Peak demand and energy forecasts are projected to rise during this *2023 LTRA* assessment period at their highest rates in recent years, providing another sign of acceleration in the broader energy transition. In summary and taken all together, the energy transition has growing potential to threaten resource and energy adequacy without broad coordination and careful attention to the pace of change.

Reducing Resource Capacity and Energy Risk

The risk of electricity supply shortfalls in the assessment period can be lowered through the concerted efforts of resource and system planning stakeholders. The actions taken in electricity markets and regulatory jurisdictions with the improving trends noted previously provide examples of what can work: obtaining additional firm resources to meet resource adequacy targets, delaying generation retirements when reliability needs dictate, and using capacity targets and energy risk metrics based on better resource and demand models. Specific and actionable recommendations are contained in the **Recommendations: Details** section of this report.

Resource Mix Changes

Findings: Wind, solar PV, and hybrid generation are projected to be the primary additions to the resource mix over this 10-year assessment period, leading the continued energy transition as older thermal generators retire. Maintaining a reliable BPS throughout the transition requires unwavering attention to ensure the resource mix satisfies capacity, energy, and ERS needs under designed conditions. It will also require significant planning and development of the interconnected transmission system to have a deliverable electricity supply from new resources to loads and the ability to withstand system contingencies and disturbances.

The addition of VERs (primarily wind and solar PV) and the retirement of conventional generation are fundamentally changing how the BPS is planned and operated. Planning and operating the grid must increasingly account for different characteristics and performance in electricity resources. Maintaining reliability will require industry and regulators to carefully manage the pace of change and take steps to ensure that ERSs continue to be provided as generators retire.

Generation Resource Mix in 2023 vs. 2033

The total capacity of traditional baseload generation fuel types will continue to decline as older generators retire and are replaced with new generation that has different capacity characteristics. Figure 15 shows how the current (**black)** resource mix (on-peak capacity) compares to the projection of the future on-peak capacity in 2033 (gray**)** if expected retirements occur and all projected Tier 1 resources are added. With these assumptions, the change in resource mix is gradual. Over this 10-year assessment period, Thermal generation, which consists mainly of natural-gas-fired, coal-fired, nuclear plants, and hydroelectric power are projected to continue providing 85% or more of the BPS on-peak generation capacity. As discussed below, the pace of change in the resource mix is likely to be influenced by the addition of more wind, solar PV, battery resources, and the retirement of more fossil-fired generators.

On-peak resource capacity reflects the expected capacity that the resource type will provide at the hour of peak demand. Because the electrical output of wind and solar PV VERs depends on weather and light conditions, on-peak capacity contributions are less than nameplate installed capacity. Wind on-peak capacity contribution contributions range between a low of 10% of installed capacity to over 25% in some assessment areas. Solar PV on-peak contributions are 0% in most areas during winter when the peak occurs in low light. In summer, some areas, such as ERCOT and parts of the U.S. West, can expect the solar PV contribution to reach over 80% of installed capacity at peak demand hour. High expected capacity contributions from VERs help increase Planning Reserve Margins but also increase the exposure of the system to energy risks from weather or environmental conditions that impact VER output. Supplementary tables on NERC's Reliability Assessments[27] web page provide on-peak capacity contributions of existing wind and solar PV resources in each assessment area.

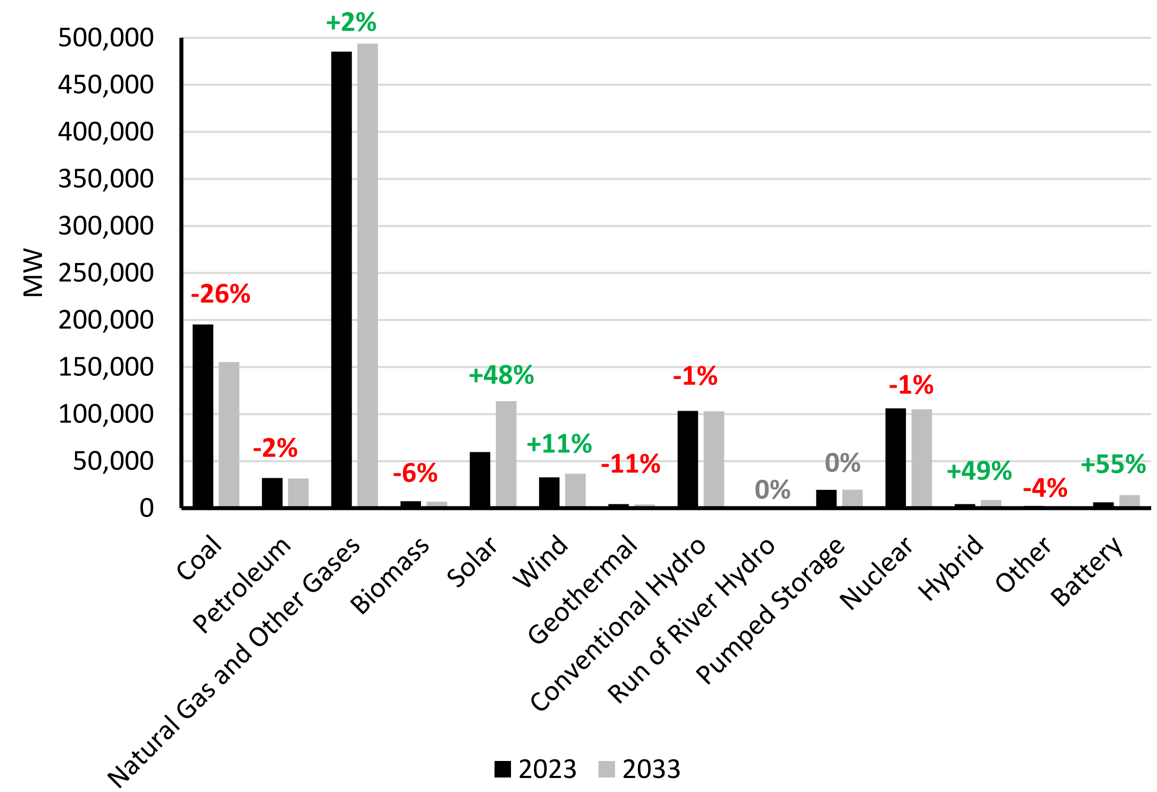


Figure 15: 2023 vs. 2033 BPS On-Peak Capacity by Fuel Type with Tier 1 Resources

[27] Reliability Assessments (nerc.com)

Capacity Additions

New generation is added to the BPS through the area interconnection planning processes. Wind, solar PV, and natural-gas-fired generation are the overwhelmingly predominant generation types planned for addition to the BPS. A summary of generation resources in the interconnection planning queues is shown in **Figure 16**. Capacity in planning has grown since the *2022 LTRA* by over 9 GW (2%).

In general, Tier 1 resources are in the final stages for connection while Tier 2 resources are further from completion. Supply chain issues, planning and siting challenges, and business or economic factors can cause projects to be delayed or withdrawn.

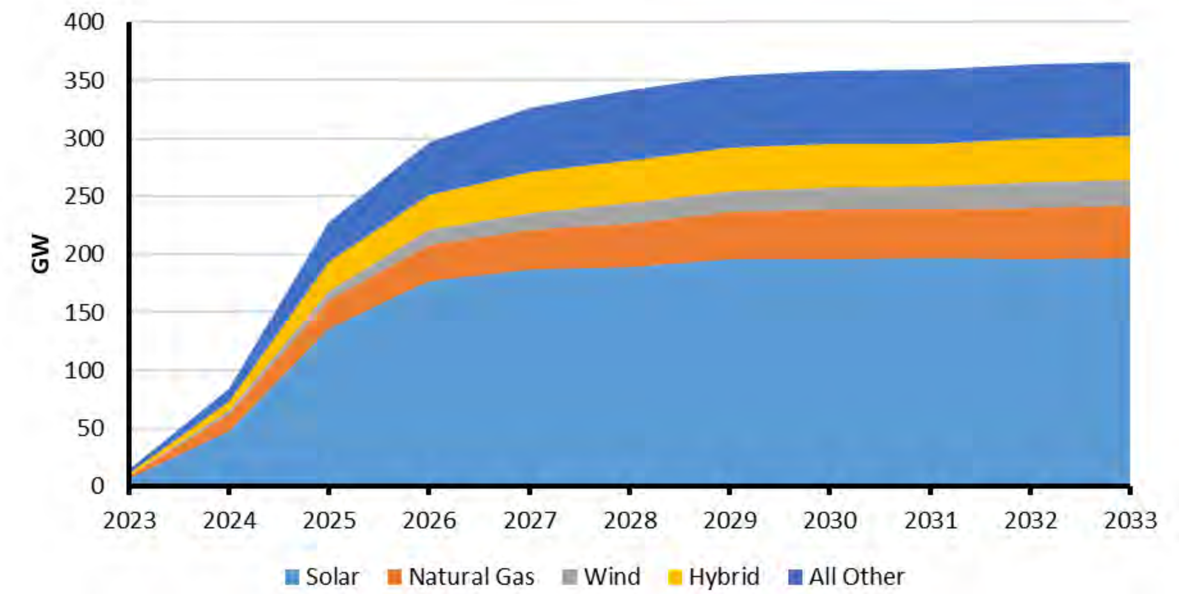


Figure 16: Tier 1 and 2 Planned Resources Projected Through 2033

Solar PV and wind capacity, both existing and planned, vary widely by area. **Figure 17** and **Figure 18** show current solar PV and wind installed capacities and the capacity in the planning process through 2033 for assessment areas with significant amounts. In addition, hybrid generation resources, which combine energy storage with a generating plant (i.e., a wind or solar farm), are connecting to the grid in parts of North America, and many more projects are in BPS planning processes.

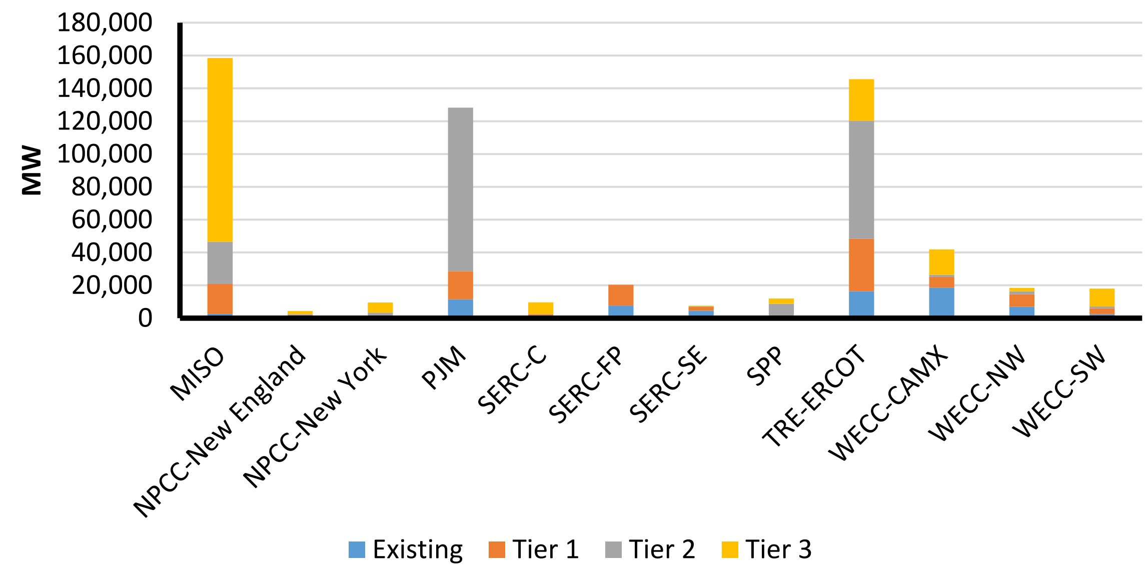


Figure 17: Solar Capacity Existing and Planned through 2033

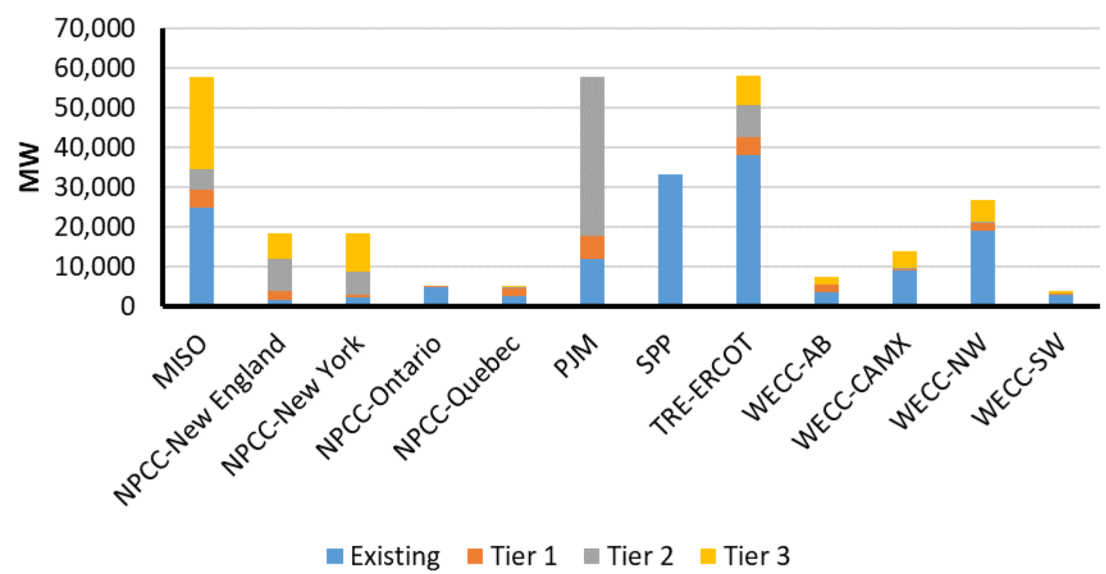


Figure 18: Wind Capacity Existing and Planned through 2033

Battery Resources

As the BPS increases the share of energy provided by VERs, the ability to provide energy by battery energy storage systems (BESS) or hybrid-solar PV and wind plants is increasingly important. While currently installed capacity totals 7,172 MW, over 260,000 MW of BESS are in planning. **Figure 19** shows the nameplate capacity of BESS resources currently in operation and in planning for connection to the BPS through 2033.

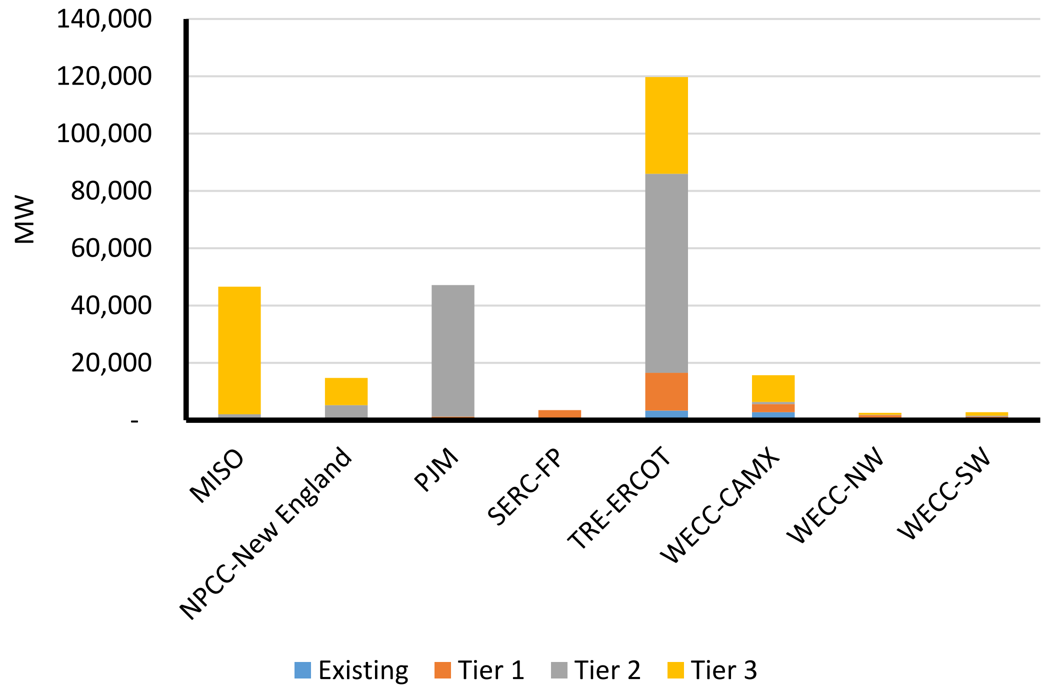


Figure 19: Battery Resource Capacity Existing and Planned through 2033

BESS have the potential to offer reliability benefits for the grid, such as helping to offset the variability and uncertainty of IBRs. BESS are, however, a relatively new type of grid resource with unique operating characteristics. The joint *NERC-WECC Staff Report:* 2022 California Battery Energy Storage System Disturbances[28] report highlights an event when a BESS, like some other IBRs, failed to properly ride through a normal system fault. This indicates that BESS must be included in the currently underway strategies to address IBR performance issues.

Planners and operators are focused on requirements to model, study, and operate the BPS with increased BESS and hybrid resources. In ERCOT and many other areas, BESS are used primarily for ancillary services, such as frequency response. In parts of the Western Interconnection with high solar PV penetration, BESS often reduce ramping requirements on other resources by discharging in late afternoon as solar PV output rapidly declines. The majority of currently installed BESS does not count towards peak hour contribution (i.e., they are not expected to discharge at peak demand). Wholesale markets, programs, and procedures are evolving to effectively integrate these new resources and realize their reliability benefits.

Solar PV Distributed Energy Resource Growth

Behind-the-meter (BTM) solar PV generators are solar PV resources connected on the distribution system, such as residential rooftop solar systems. The rapid growth of BTM solar PV continues with cumulative levels expected to reach almost 89 GW by the end of this 10-year assessment period (up from 80 GW reported in the *2022 LTRA*, an increase of 11.3%), see **Figure 20**.

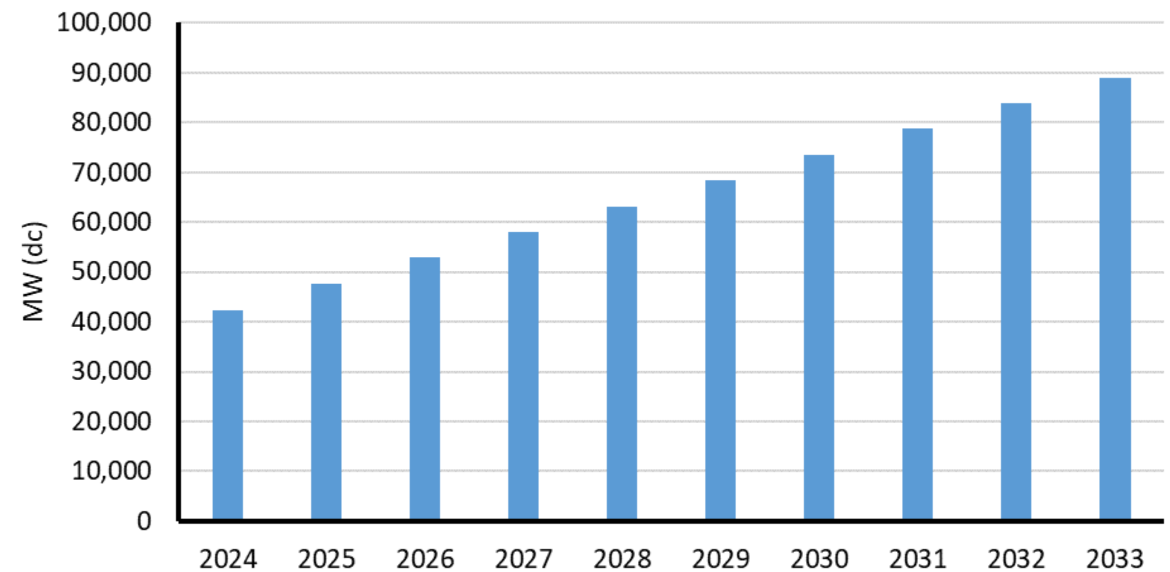


Figure 20: Cumulative Solar PV DER Capacity in All Assessment Areas

[28] NERC–WECC *2022 California Battery Energy Storage System Disturbances*

BTM solar PV generators, like grid-connected solar PV, are also VERs. In large penetrations, their predictable change in output from the time of day contributes to steep ramps in demand. As the Sun sets and output diminishes, grid resources must make up for the decrease in solar generation and increase in demand that was being served. The opposite ramp occurs during morning hours; it may be less impactful to reliability but can be challenging for grid-connected generator scheduling and dispatch. **Figure 21** shows the current and projected BTM solar PV by area through 2033.

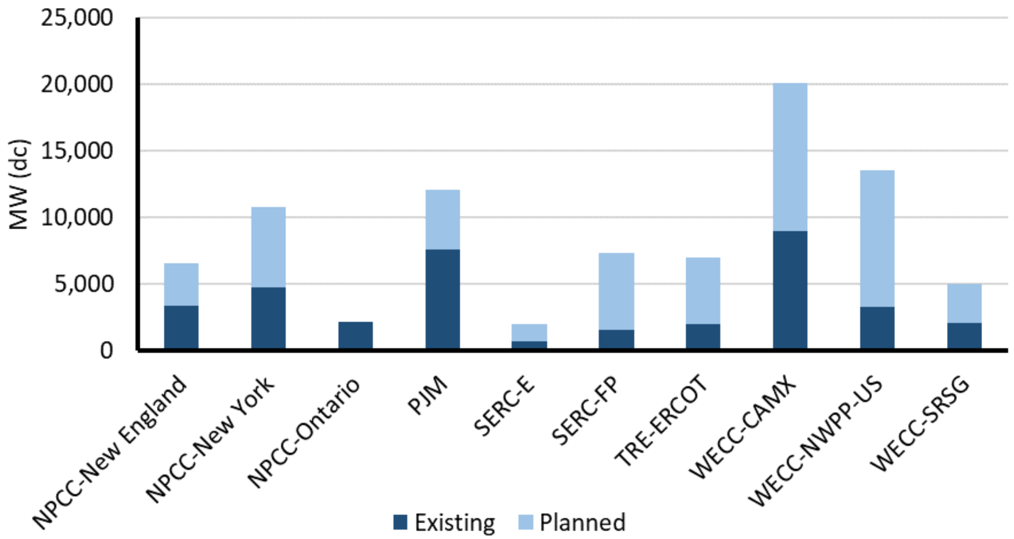


Figure 21: Solar PV DER Capacity Existing and Planned through 2033

Generation Retirements

The total capacity of traditional baseload generation fuel-types will continue to decline as older generators retire. Generators become confirmed for retirement according to various processes in place in the Interconnections, such as regional planning tariffs in the wholesale electricity market areas or the integrated resource planning process in vertically integrated states. Properly designed mechanisms can prevent generators from retiring before planners can study and address reliability issues that could occur.

Currently, over 83 GW of fossil-fired and nuclear generating capacity is retiring over this assessment period (see **Figure 22**). This capacity includes generators that are confirmed for retirement through retirement planning processes or that have indicated plans to retire to an ISO/RTO or planning coordinator.

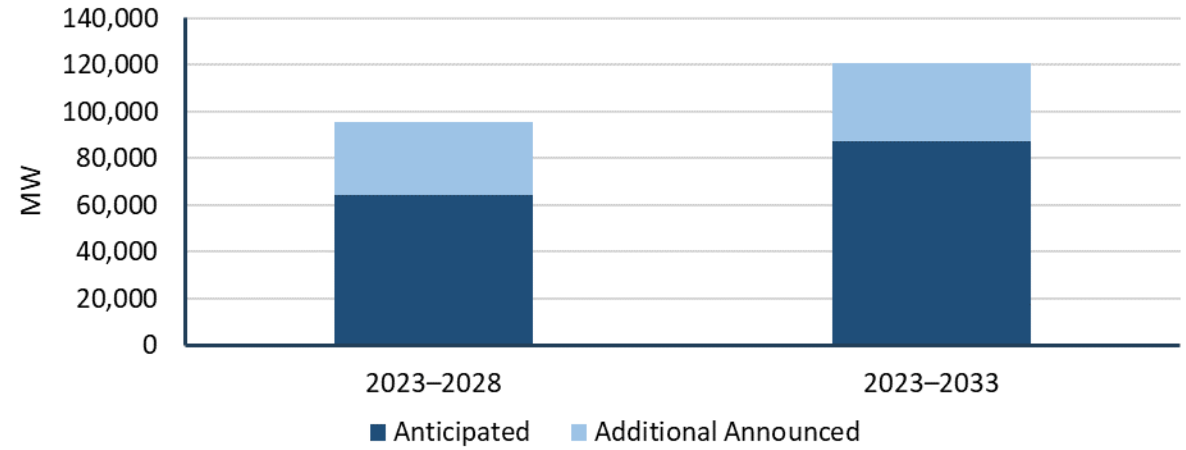


Figure 22: Projected Generation Retirement Capacity Through 2033

Additional fossil-fired generator retirements are expected, leading to a loss of existing capacity more than the reported 83 GW capacity. Generator Owners often announce plans to retire generator units before initiating the interconnection planning process, and the announced plans or timing may be subject to change before the retirement is confirmed. **Figure 23** shows the total capacity of reported retirements (i.e., reported to ISOs/RTOs and planning entities) as well as owner-announced, unconfirmed retirements of fossil-fueled and nuclear generators across the BPS over the next 10 years in each assessment area.[29]

[29] Confirmed generator retirements are reported to NERC by each assessment area in this *2023 LTRA* development process. NERC obtained data on announced, unconfirmed generator retirements from Energy Ventures Analysis, Inc. and from each assessment area. Some sources of information on announced generator retirements include EIA 860 data, trade press, and utility integrated resource plans.

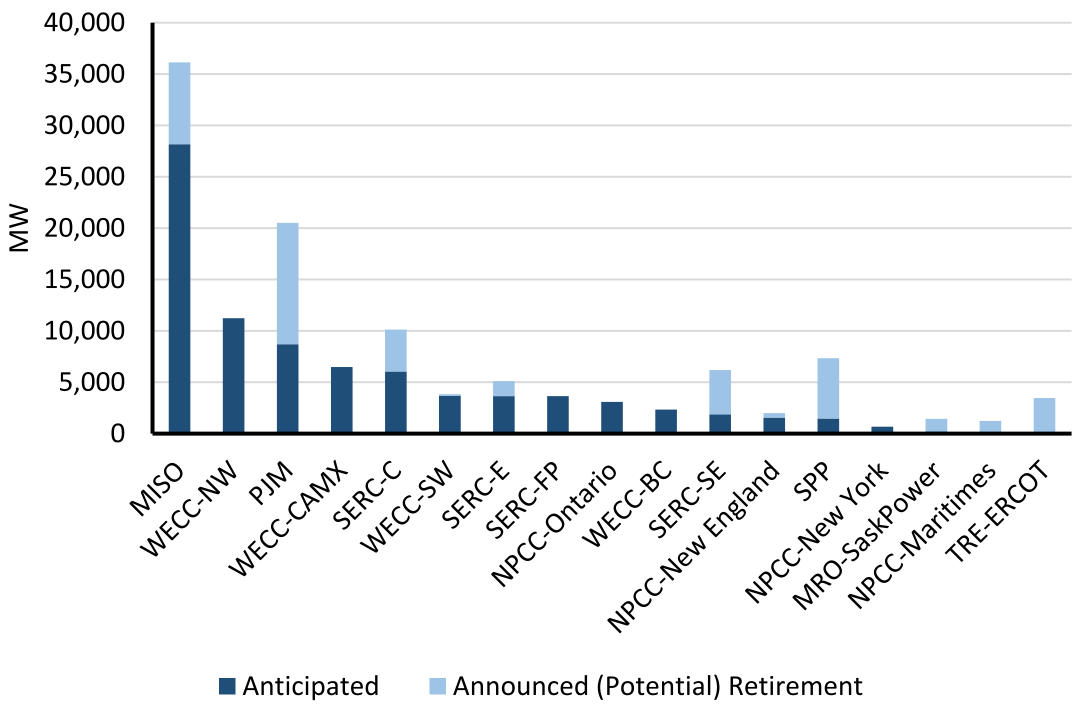


Figure 23: Projected Retiring Nuclear and Fossil Generation Capacity 2023–2033

Throughout this *2023 LTRA*, anticipated generation retirements have been removed from each assessment area's anticipated and prospective resources while unconfirmed, announced generator retirements have been removed from prospective resources only. See Page 32 for information about new policy and regulations that affect future generator retirements.

Natural Gas Fuel Reliance Trends

Natural-gas-fired generators are and will remain a critical resource for BPS reliability in many areas over the 10-year assessment period, especially during winter. **Figure 24** shows the total contribution of natural gas to the winter resource mix; in the figure, areas with more natural gas are darker blue. See **Table 4** for the specific values for each area. These generators provide many necessary reliability attributes that are exiting the system as traditional generators retire and inverter-based renewable resources take their place in the resource mix. Natural-gas-fired generators are dispatchable and provide the ERSs of inertia, frequency response, and ramping flexibility. In winter, when peak demand in most areas occurs during early morning hours, natural-gas-fired generation is at its highest contribution to the resource mix in many areas. Severe winter weather events in 2021 and 2022 provided stark evidence of the critical nature of natural gas as a generator fuel and the importance of secure supplies during times of extreme electricity demand. While more work remains, several important steps to mitigate the risks of natural gas supply interruption have been taken in the aftermath of Winter Storm Uri in February 2021.

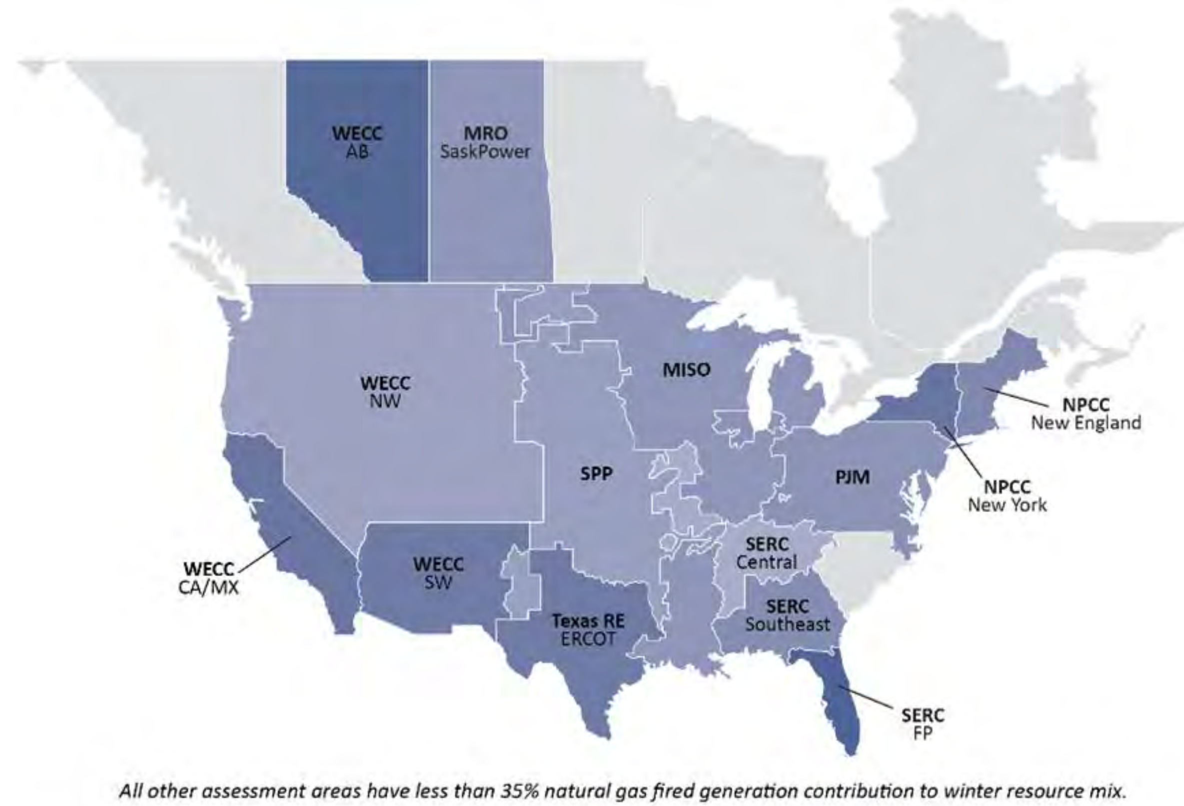


Figure 24: Natural-Gas-Fired Generation Contributions to 2023–2024 Winter Generation Mix

For example, ERCOT has developed an FFSS whereby capacity with qualifying on-site fuel or off-site natural and other gas storage can be procured by LSEs through a competitive procurement process with a single clearing price. ERCOT is also working to implement a newly adopted Public Utility Commission of Texas PCM rule that permits generation resources within ERCOT to commit to producing more energy during the tightest grid conditions of the year and sell credits to LSEs. Convened in response to Winter Storm Uri report, the North American Energy Standards Board Gas Electric Harmonization Forum has completed its work and published 20 recommendations that are directed at harmonizing across and improving coordination between natural gas supply/transport and BES operations.

Table 4: Total Natural Gas Peak Winter Capacity		
Assessment Area	**Total in GW**	**Contribution to Total Winter Resource Mix**
MISO	67.5	46%
MRO-SaskPower	2.1	46%
NPCC-New England	17.3	54%
NPCC-New York	24.5	66%
PJM	84.9	47%
SERC-Central	22.7	44%
SERC-Florida Peninsula	50.6	79%
SERC-Southeast	31.5	51%
SPP	27.4	41%
Texas RE-ERCOT	54.2	62%
WECC-AB	11.4	75%
WECC-CA/MX	39.9	65%
WECC-NW	31.0	39%
WECC-SW	18.2	62%

Supply Chain Concerns

New resource additions are critical to maintaining resource adequacy criteria and reducing energy shortfall risk under more extreme conditions. Supply chain issues have impacted resource projects over the past year. Lingering pandemic-related issues, competition for scarce resources, and geopolitical matters are likely to continue affecting generation and transmission projects. Supply chain issues are also making the following more difficult: the scheduling of maintenance outages, planning for when new resources will come online when line upgrades can be completed, and the ability to connect new customers. Grid planners and system operators need to continue accounting for uncertainties in resource availability.

Reliability Implications

The addition of variable resources, primarily wind and solar PV, and the retirement of conventional generation are fundamentally changing how the BPS is planned and operated. With electricity supplies coming increasingly from VERs and natural-gas-fired generators, there is a growing risk that supplies can fall short of demand during some periods. Geographically diverse wind and solar resources and loads can help reduce these risks, but they require robust transmission networks, comprehensive energy and transfer capability analysis, and effective operating procedures and market mechanisms. Specific and actionable recommendations are contained in the **Recommendations: Details** section of this report.

New Policy and Regulations Affecting Future Generator Retirements

Coal-fired generating capacity has declined significantly over the past decade, falling from over 280 GW in 2014 to the current level of 195 GW.[30] The U.S. Energy Information Administration models project this trend to steadily continue over the next decade and beyond (**Figure A**).[31] Furthermore, many of these modeled projections exceed the announced generator retirements as shown in **Figure 22**, heightening concerns that generation is at risk of retirement before reliability solutions are in place.

Future fossil-fired generator retirements will be influenced by a range of factors, such as environmental policies, incentives for new renewable generation, operating economics, and technology developments. The Inflation Reduction Act contains climate and energy provisions, including tax credits and expenditures that will influence the BPS resource mix by supporting renewable resources, energy storage, and nuclear generation. The Inflation Reduction Act will accelerate the energy resource transformation, including additional fossil-fired generator retirements. While subject to change in the rulemaking process, proposed EPA regulations under Clean Air Act Section 111 to address carbon emissions from fossil-fired generators would result in an increase in the rate of generator retirements.[32] Recent analysis and models that incorporate the potential effects of these new policies and proposed regulations illustrate projections for coal-fired generator retirements in excess of currently announced retirements (**Figure B**).[33] Natural-gas-fired generator retirements are also expected to increase under proposed new EPA regulations as Generator Owners face added costs of emissions-reducing technologies. Technologies for enabling generators to operate to the new standards are also being developed.

Additional generator retirements beyond currently expected levels have the potential to exacerbate energy, capacity, or ERS issues. See the **Capacity and Energy Assessment** and **Reliability Implications** in the preceding sections of this *2023 LTRA*. Close coordination will be needed among regulators, policymakers, and industry to ensure that sufficient electricity resources will be available to meet rising demand and grid reliability needs. Regulations that have the potential to accelerate generator retirements or restrict operations must have sufficient flexibility and provisions to support grid reliability.

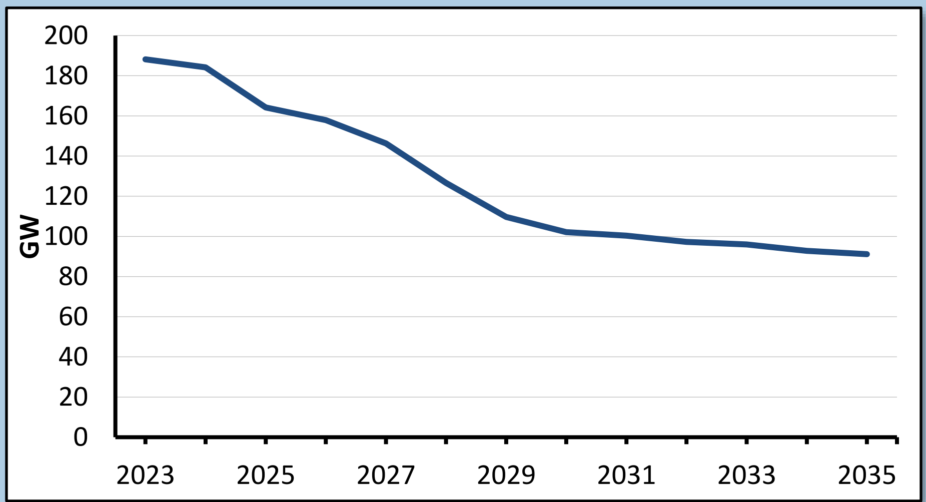


Figure A: BPS Coal-Fired Generation Capacity—United States Only

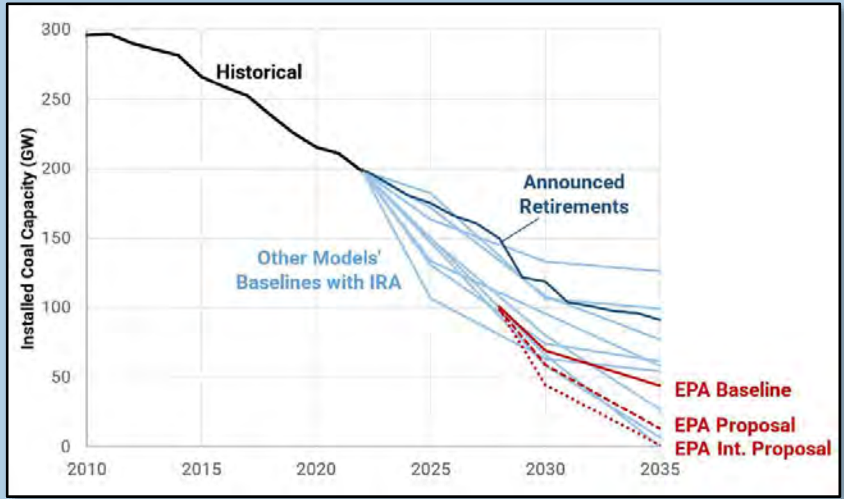


Figure B: BPS Coal-Fired Generation Capacity in Various Scenario Models—United States Only

30 NERC 2014 LTRA
31 EIA Annual Energy Outlook 2023
32 EPA Rulemaking Docket New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of Affordable Clean Energy Rule
33 *Source: Comment submitted by Electric Power Research Institute (EPRI), Docket EPA-HQ-OAR-2023-072, New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule:* EPRI Comments on U.S. EPA Rule, Docket ID EPA-HQ-OAR-2023-072

Demand Trends and Implications

Finding: Electricity peak demand and net energy growth rates in North America are increasing more rapidly than at any point in the past three decades. Concentrated growth and the emergence of new types of loads are occurring in some areas. These growth trends bring additional challenges for resource and transmission adequacy. Planners and operators can prepare by considering robust demand and energy scenarios, carefully monitoring and refining demand forecasts, and developing operational tools for peak load management.

Demand and Energy Projections

Electricity peak demand and energy growth forecasts over the 10-year assessment period are higher than at any point in the past decade. The aggregated assessment area summer peak demand forecast is expected to rise by over 79 GW, and aggregated winter peak demand forecasts are increasing by nearly 91 GW. Furthermore, the growth rates of forecasted peak demand and energy have risen sharply since the *2022 LTRA*, reversing a decades-long trend of falling or flat growth rates. See **Figure 25** for seasonal peak demand growth over the current and prior assessment periods and **Figure 26** for net energy growth. More information is available in the **Regional Assessments Dashboards** section.

Electrification and Demand Growth

Electrification and projections for EV growth over this assessment period are components of the demand and energy estimates provided by each assessment area. Since the *2022 LTRA*, peak season CAGR has risen in all assessment areas except two: (WECC-AB winter CAGR fell slightly from 0.6% to 0.56% while ERCOT's summer CAGR was unchanged at 1.01%). Rising peak demand forecasts are contributing to the lower reserve margins projected for nearly all assessment areas.

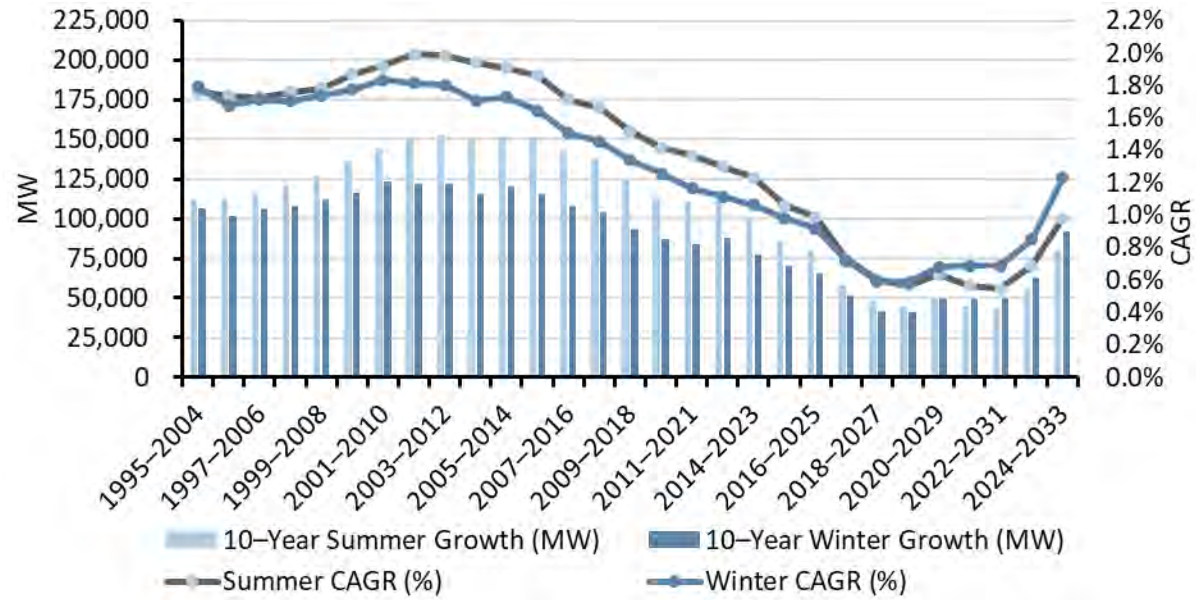


Figure 25: The 10-Year Summer and Winter Peak Demand Growth and Rate Trends

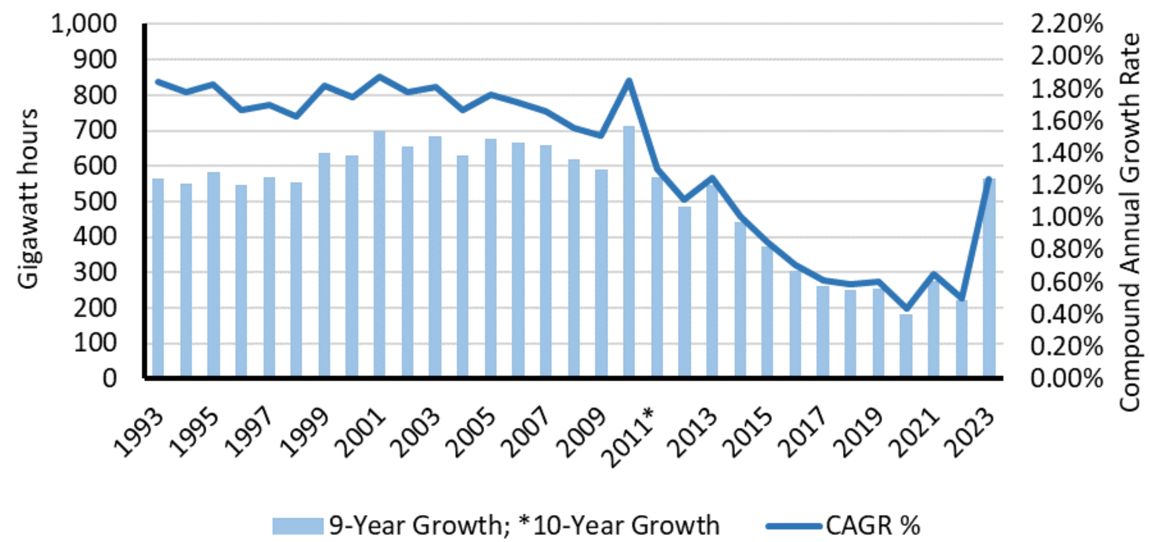


Figure 26: Net Energy for Load Growth and Rate Projection Trends

Peak Season Transition

Some of the sharpest peak demand forecast increases and growth rates can be seen in winter seasons as electrification in heating systems and transportation influence forecasts. Dual-peaking or changing from summer to winter peaking is anticipated in several areas, including the U.S. Southeast and Northeast. Electrification of heating systems and the anticipated growth of EVs (which are expected to charge overnight and coincide with periods of electricity demand for heating) are driving factors. Such changes have wide-ranging implications for how the grid and resources are planned and operated. For example, resource output can be significantly different in winter, requiring the focus of resource adequacy processes to change. The following are the areas that anticipate a change from a summer-peaking system to a winter-peaking (or dual-season peaking) system and the approximate year of the transition:

- NPCC-New England (mid 2030s)
- NPCC-New York (mid 2030s)
- NPCC-Ontario (2036)

In the U.S. Southeast, SERC-Central and SERC-East became dual-peaking systems in recent years. SERC-Southeast recently began experiencing slightly higher peak demand in winter compared to summer.

Reliability Implications

Demand and energy growth projections in this assessment period provide both challenges and opportunities for electric grid reliability. Planning for resource and transmission adequacy requires accurate long-term forecasting, but future demand and energy use will be influenced by many factors, including the economy, energy policies, technology development, weather, and consumer preferences. Changing patterns in electricity use, load behavior, and DER performance affect the accuracy of operational load forecasts that are essential to grid operators. Large flexible loads and demand-side management programs hold promise for peak load management capabilities that can reduce the risk of firm load interruption.

Anticipating electrification, EV adoption, and the impacts of energy transition programs on future demand and energy needs will require even more focus for planners and operators. Peak demand forecast changes in the past year had noticeable effect on resource adequacy for many areas. A confluence of factors (economic, energy policies, technology development, and consumer preferences) has the potential to fuel continued growth.

Transmission Development Trends and Implications

Finding: The amount of BPS transmission projects reported to NERC as under construction or in planning for construction over the next 10 years has increased, indicating an overall increase in transmission development. Siting and permitting challenges continue to inflict delays in transmission expansion planning. Regional transmission planning processes are adapting to manage energy transition, but impediments to transmission development remain.

Transmission Projects

This year's cumulative level of 18,675 miles of transmission (>100 kV) in construction or stages of development for the next 10 years (**Figure 27**) is higher than averages of the past five years of NERC's LTRA reporting on average (16,970 miles of transmission planning projects in each 10-year period published in the last five LTRAs).

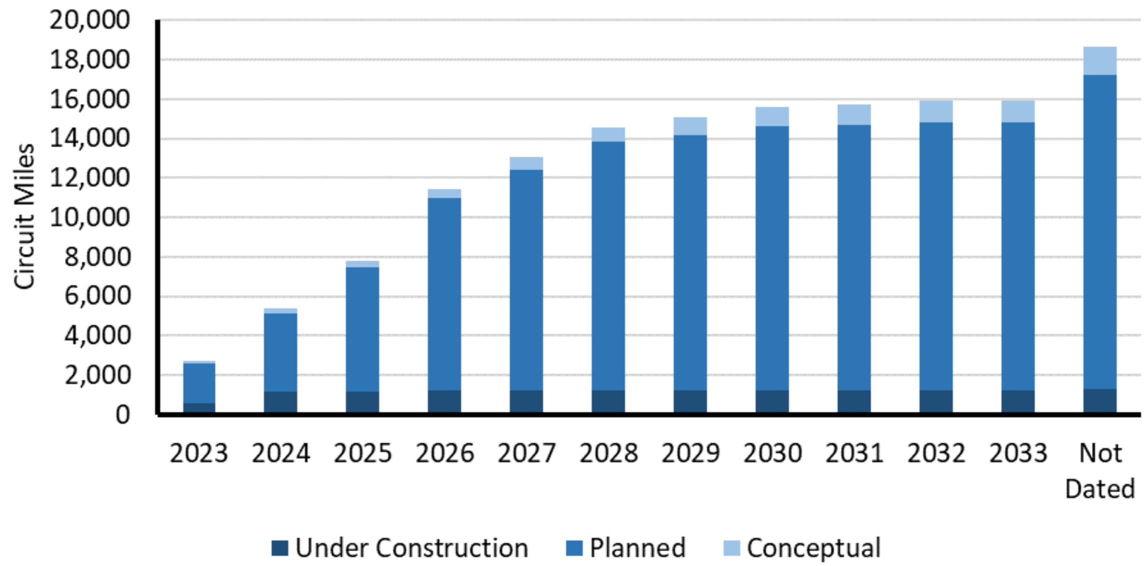


Figure 27: Future Transmission Circuit Miles >100 kV by Project Status

New transmission projects are being driven to support new generation and enhance reliability. **Figure 28** shows the percentage of future transmission circuit miles by primary driver. Most projects reported this year have been initiated for the purpose of grid reliability, which generally includes transmission projects that are needed to ensure that the BPS operates within established limits and design criteria. Some substantial new projects to integrate renewable generation are also in development or are entering planning processes. The NPCC-New York and PJM assessment areas have begun transmission planning to support interconnection of offshore wind resources. See the transmission summaries at the end of each assessment area's pages (see **Regional Assessments Dashboards)** for current transmission development details.

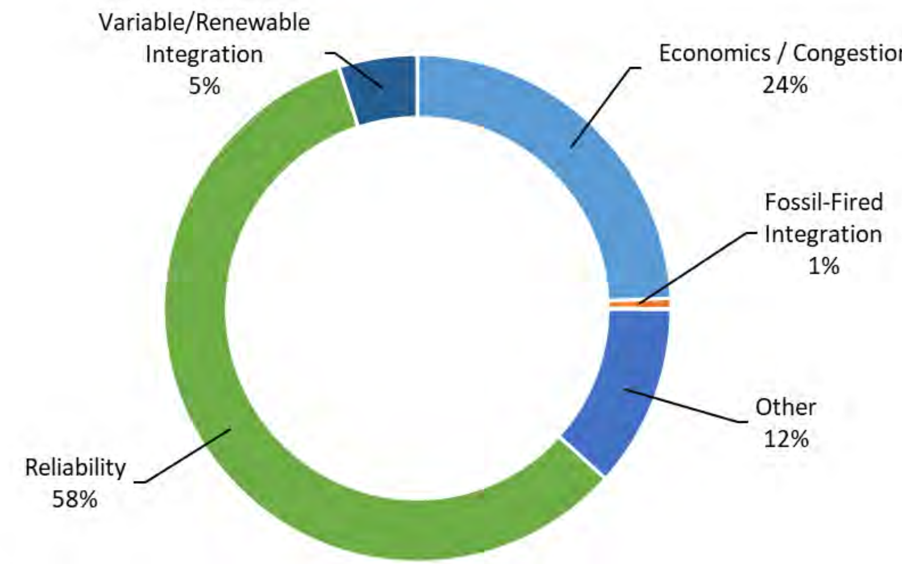


Figure 28: Future Transmission Circuit Miles by Primary Driver

Transmission development in some areas is hampered by siting and permitting challenges. Of the over 900 projects that are under construction or in planning for over the next 10 years, 87 projects are currently delayed from their expected in-service dates. Siting and permitting issues are the most common cause for delays (i.e., 46 projects for a total of 940 miles of new transmission). Other reasons for delays include economic or changing needs.

Adapting Transmission Planning Processes

Regional transmission planning and resource interconnection processes are adapting to manage the development needs of the energy transition. Across ISO/RTO organizations, long-term system planning is increasingly evaluating policy-driven projects that would support investment decisions necessary to reach state and province goals. Many are also instituting processing reforms that are aimed at reducing backlogs in generation interconnection queues. See the **Regional Assessments Dashboards** for details on changes and initiatives.

Reliability Implications

Monitoring and managing transmission planning processes is a necessary part of maintaining reliability as the resource mix evolves. Furthermore, the rapidly changing resource mix requires greater access and deliverability of resources, including transmission availability, to maintain reliability. Regional transmission planning processes are adapting to manage the energy transition, but impediments to transmission development remain.

The transmission system is being tested by an ever-evolving risk landscape. Ensuring an adequate transmission system requires system planners to consider the broad range of future resource, demand, environmental, and security conditions. Planning processes need to include analysis of an expanded set of scenarios for normal and extreme events so that owners and operators can develop proactive plans that will reduce the risk of unacceptable performance.

Emerging Issues

While developing this *LTRA*, NERC and the industry considered trends and developments that have the potential to impact the future reliability of the BPS over the next 10 years and beyond. Discussed below are emerging issues and trends not previously covered in this report that have the potential to impact future long-term projections or resource availability and operations.

Cryptocurrency Impacts on Load and Resources

Due to unique characteristics of the operations associated with cryptocurrency mining, potential growth can have a significant effect on demand and resource projections as well as system operations.

Computer operations for cryptocurrency mining are energy intensive, and mining operators can interrupt or scale operations in response to energy costs. ERCOT continues to see a large volume of interconnect requests from cryptocurrency mining: 9 GW have had planning studies approved of 41 GW that are currently requested.

This new category of large flexible loads is leading some areas to update load forecasting methods to capture the flexibility and price-responsiveness of cryptocurrency mining operations. In anticipation of further growth in large flexible loads, ERCOT and its stakeholders are assessing further operational issues that could emerge, such as the effect on system frequency of sudden changes in large flexible loads.

Blackstart Resources for Restoration in Extreme Conditions

Blackstart generation resources are a critical element of BPS resilience that enables the orderly restoration of grid sections following a blackout. System restoration plans rely on the ability of designated fossil-fuel generators to provide blackstart service.

Recent extreme winter weather has exposed vulnerabilities to generating units and fuel sources that are not adapted to cold temperatures, raising concerns for blackstart unit readiness. The changing resource mix is cause for additional awareness of blackstart capabilities. Currently, few IBRs on the system are capable of grid forming control, one of the necessary components for blackstart resources.

Industry is working to incorporate IBR grid forming technology to address system stability and performance needs, apart from blackstart capabilities. Wholesale markets and resource planners must anticipate the future needs for system restoration services and procure blackstart resources to ensure reliable operations.

Distribution Transformer Supply Chains

The electric industry reports that distribution transformers are in short supply as manufacturer production is unable to keep pace with demand; lead times often exceed two years. Low inventories of replacement distribution transformers could slow restoration efforts following hurricanes and severe storms.[34] A lack of skilled labor for manufacturing transformers is the primary cause of current backlogs. However, access to the grain-oriented electrical steel used in power transformers is the next constraint as the United States has a single producer of grain-oriented electrical steel. New efficiency standards for distribution transformers proposed by the U.S. DOE could further exacerbate the transformer supply shortages by adding requirements that manufacturers are not currently set up to handle.[35]

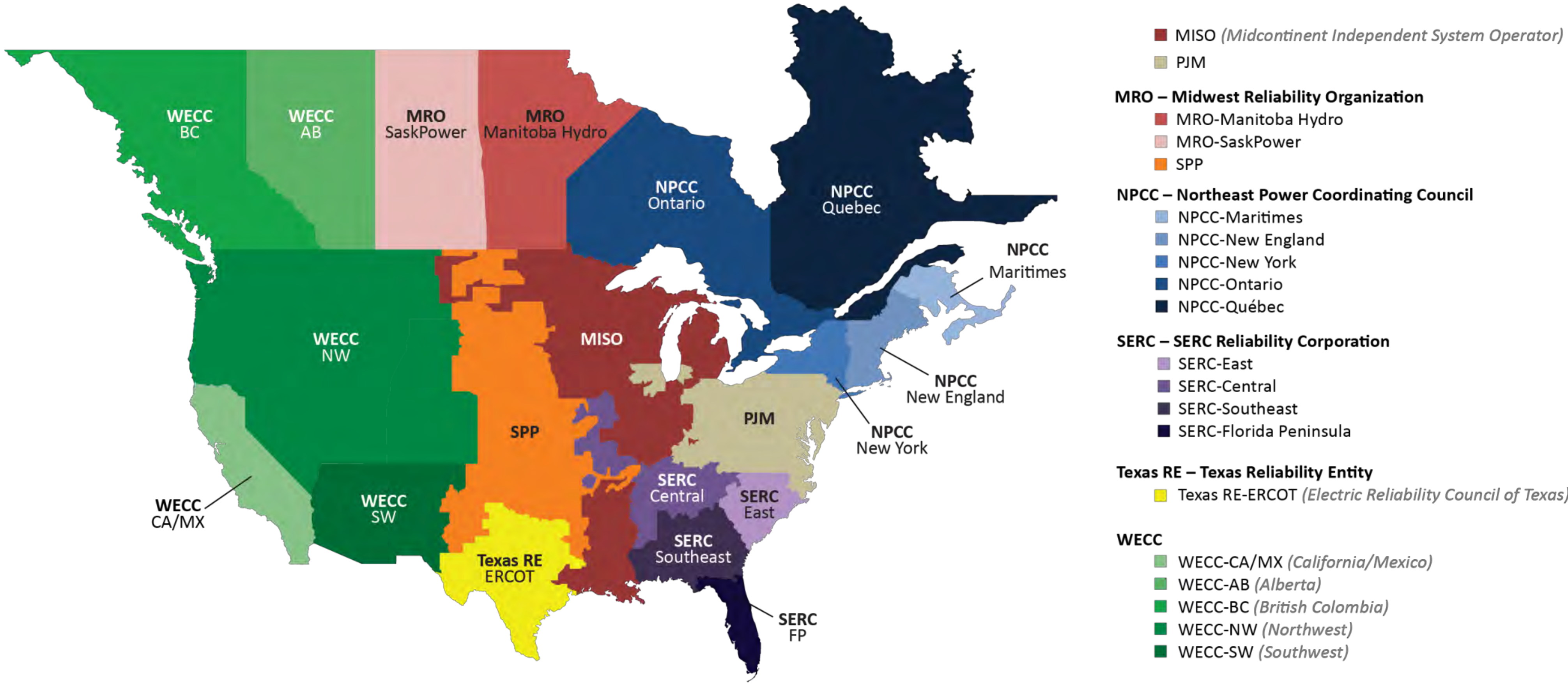
Localized Load Growth

Some areas are experiencing concentrated load growth from industrial and commercial development. Examples of large industrial loads include data centers, smelters, manufacturing centers, hydrogen electrolyzers, and future electrified mass transit or shipping charging stations. Adding large parcels of load on the system can add new uncertainties to peak and hourly load forecasting. For example, data centers have longer operating hours and require more heating and cooling than other commercial buildings. In Texas, crypto mining facilities have connected in recent years that scale their operations (and thus electricity demand) depending on electricity prices. Growth of large, concentrated loads can challenge load forecasting and localized transmission development.

[34] Public Power Article on APPA Survey
[35] Doe Proposes New Efficiency Standards for Distribution Transformers

Regional Assessments Dashboards

The following regional assessments were developed based on data and narrative information collected by NERC from the Regional Entities on an assessment area basis. The Reliability Assessment Subcommittee, at the direction of NERC's RSTC, supported the development of this assessment through a comprehensive and transparent peer review process that leveraged the knowledge and experience of system planners, Reliability Assessment Subcommittee members, NERC staff, and other subject matter experts. This peer review process promotes the accuracy and completeness of all data and information.

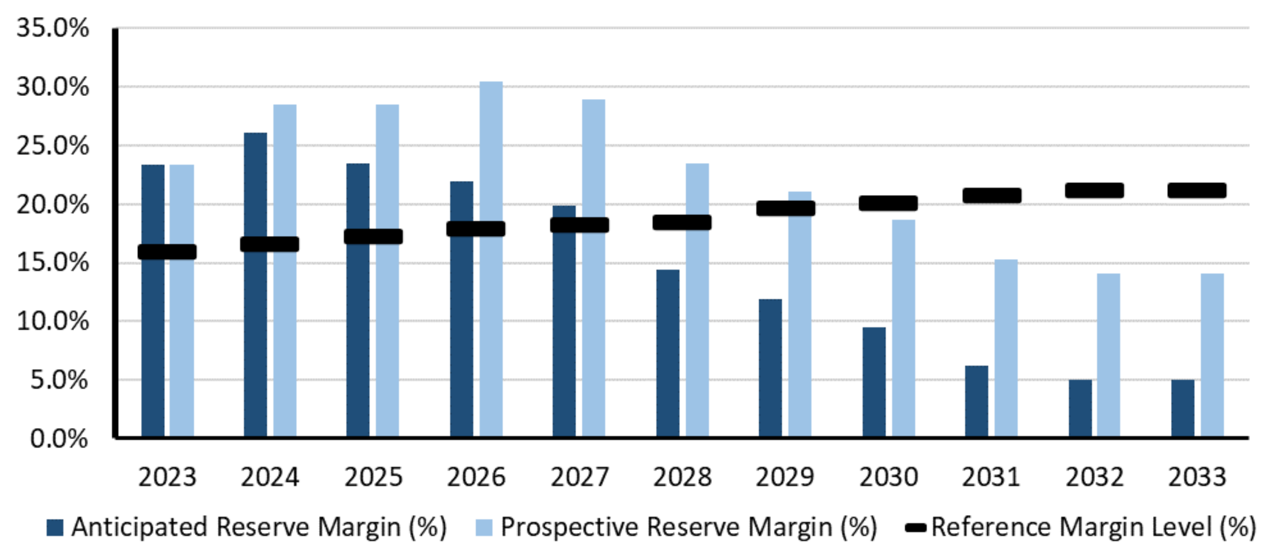


MISO

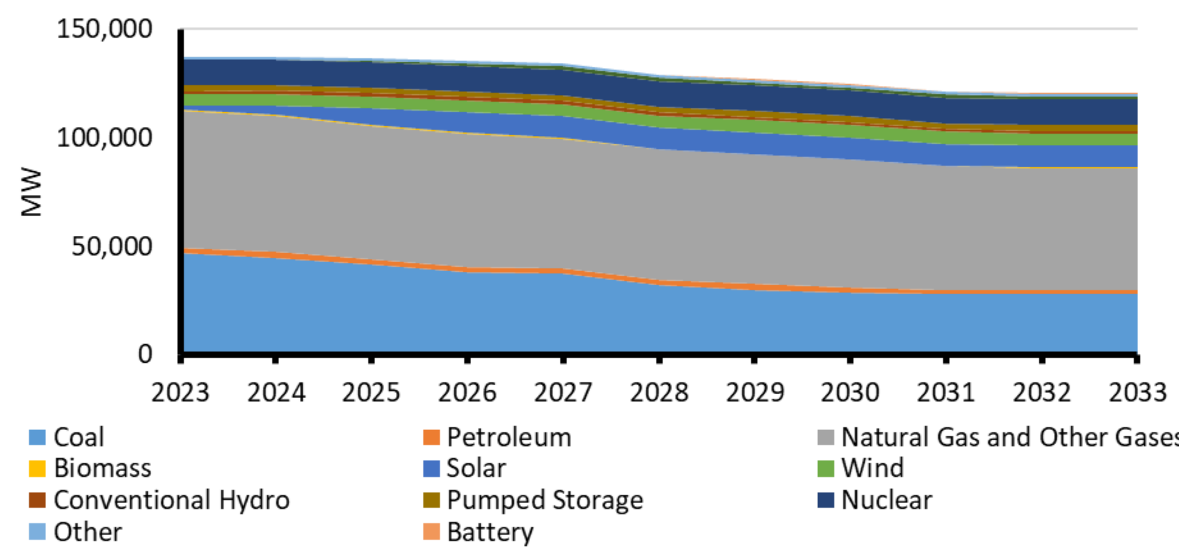
MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy and operating reserve markets that consist of 41 local BAs and over 500 market participants, serving approximately 45 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments. See **High Risk Areas** for more details.

Demand, Resources, and Reserve Margins (Summer)

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	121,933	122,726	123,315	123,888	124,659	125,140	125,591	126,135	126,593	126,593
Demand Response	7,776	7,741	7,798	7,812	7,726	7,728	7,729	7,731	7,728	7,728
Net Internal Demand	114,157	114,985	115,517	116,076	116,933	117,412	117,862	118,404	118,865	118,865
Additions: Tier 1	3,135	6,972	10,936	11,744	11,944	11,945	11,945	11,945	11,945	11,945
Additions: Tier 2	2,694	5,771	9,836	10,495	10,672	10,749	10,749	10,749	10,749	10,749
Additions: Tier 3	163	1,096	3,166	6,615	9,989	12,454	13,332	13,450	13,450	13,450
Net Firm Capacity Transfers	2,125	1,129	1,159	1,057	906	911	806	805	781	781
Existing-Certain and Net Firm Transfers	140,831	134,999	129,924	127,394	121,776	119,493	117,122	113,811	112,865	112,865
Anticipated Reserve Margin (%)	26.1%	23.5%	21.9%	19.9%	14.4%	11.9%	9.5%	6.2%	5.0%	5.0%
Prospective Reserve Margin (%)	28.5%	28.5%	30.5%	28.9%	23.5%	21.1%	18.6%	15.3%	14.0%	14.0%
Reference Margin Level (%)	16.6%	17.2%	17.9%	18.2%	18.4%	19.6%	20.1%	20.7%	21.2%	21.2%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- MISO transitioned to its first year of seasonal capacity auctions (summer, fall, winter, spring). The switch to a seasonal construct improves understanding of non-summer risk and derives seasonal resource accreditation and seasonal resource adequacy requirements. Market responses to higher capacity prices in 2022 and new resource additions have overcome the planning reserve deficits reported in the *2022 LTRA*, and now MISO's ARMs are projected to meet RMLs for the first three years of this assessment period without significant new Tier 2 and Tier 3 resource additions.
- In the past year, coal-fired and nuclear generation capacity has declined mainly due to retirements by 300 MW and 140 MW, respectively. These reductions are not as large as projected last year due to delayed retirements. New wind and wind accreditation increased 725 MW while solar PV and solar PV accreditation increased by 920 MW. The larger increases in resources since last year's LTRA are the result of new natural-gas-fired generators as well as improvements that increased the accredited output contribution from existing natural-gas-fired generators that account for more than 4 GW of added capacity.

MISO Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	44,742	41,656	38,017	37,297	32,266	30,017	28,771	27,856	27,856	27,856
Petroleum	2,719	2,545	2,545	2,545	2,535	2,535	2,310	2,310	2,239	2,239
Natural Gas	62,909	61,454	61,311	59,919	59,755	59,752	59,059	56,842	56,074	56,074
Biomass	374	374	374	339	230	230	169	169	169	169
Solar	4,367	7,446	9,532	9,964	10,054	10,054	10,054	10,054	10,054	10,054
Wind	5,191	5,534	5,622	5,634	5,566	5,541	5,534	5,520	5,516	5,516
Conventional Hydro	1,443	1,443	1,443	1,443	1,443	1,443	1,443	1,307	1,307	1,307
Pumped Storage	2,696	2,696	2,696	2,696	2,696	2,696	2,696	2,696	2,696	2,696
Nuclear	11,725	11,725	11,725	11,725	11,725	11,725	11,725	11,725	11,725	11,725
Hybrid	31	375	1,006	1,392	1,476	1,492	1,492	1,492	1,492	1,492
Other	1,299	1,243	1,243	1,243	1,243	1,243	1,243	1,238	1,238	1,238
Battery	0	27	183	213	222	222	222	222	222	222
Total MW	137,496	136,518	135,696	134,410	129,211	126,950	124,719	121,432	120,589	120,589

MISO Assessment

Planning Reserve Margins

In 2023, MISO transitioned to its first year of seasonal capacity auctions (summer, fall, winter, spring). Market responses to higher capacity prices in 2022 and new resource additions have overcome the planning reserve deficits reported in the *2022 LTRA*, and now MISO's summer and winter ARMs are projected to be above the RMLs for the first three years of this assessment period. MISO's summer ARM is projected to be above the RMLs through the 2027 summer. Beginning in 2028, MISO is projected to have a 4.7 GW shortfall if expected generator retirements occur and over 12 GW of new resources are added. It is important to note that there are 50 GW of generation with signed generation interconnection agreements that are not yet on-line and another 200+ GW of new resources within the interconnection queue that are still being evaluated.

With the transition to seasonal auctions, MISO conducted seasonal LOLE studies to identify the RML based on resource installed capacity in each season with the following results: summer 15.9%, fall 25.8%, winter 41.2%, and spring 39.3%.

Energy Assessment and Non-Peak Hour Risk

The introduction of the seasonal planning resource auction and inputs to the process provide more granularity and reliability planning for non-peak hour times during the year; in addition to this change, MISO conducts seasonal resource assessments that evaluate generation availability, outage rates, and forecasted load variation across all four seasons.

Probabilistic Assessments

NERC's most recent probabilistic assessment (2022 ProbA) Base Case results found that most of the LOLHs occur in June–August, corresponding to the typical MISO peak time frame. There are some instances of LOLHs occurring in September–October when seasonal planned outages overlap with high demand. MISO experiences a small amount LOLH in winter when cold temperatures push demand higher than normal.

Base Case Summary of Results (2022 ProbA)			
	2024*	2024	2026
EUE (MWh)	14.3	193.6	68.8
EUE (PPM)	0.02	0.304	0.108
LOLH (hours per Year)	0.085	0.808	0.393
Operable On-Peak Margin	13.7%	8.1%	13.9%

* Provides the 2020 ProbA Results for Comparison

Non-peak risk drivers tend to be unique to the season. In the fall, the risk of unseasonably high demand overlapping with seasonal planned outages increases the loss-of-load risk. Extreme cold weather, particularly in MISO South, increases demand and causes the risk of loss of load to increase.

In 2023, MISO completed a probabilistic analysis of a risk scenario that examined the effects of modeling seasonal forced outage rates as well as correlated cold weather outages rather than annual average outage rates.[36] The sensitivity analysis shows an increase in the total EUE compared to the Base Case results; these values are 201.8 MWh for EUE and 0.824 hours/year for LOLH. LOLH was relatively unchanged in the Sensitivity Case, which indicates that the duration of load-shed events was similar to the Base Case, but the magnitude of load shed was greater.

The results of MISO's 2023 probabilistic risk scenario indicate that summer remains the season with the largest EUE risk; however, resource outages in other seasons contribute to risk throughout the year. MISO's new seasonal resource adequacy construct is better equipped to identify such risks and procure sufficient capacity to avoid shortfalls.

MISO conducted an internal seasonal LOLE study for inputs in the 2023–2024 seasonal planning resource auction.[37]

Demand

The peak demand forecast for each year in this assessment period has decreased from the *2021 LTRA* forecasts by over 4 GW (3.2%) in the near term and narrowing to 1.7 GW (1.3%) by 2032. The forecast is created using inputs from LSEs in the MISO footprint; MISO does not forecast loads for resource adequacy assessments. MISO performs studies to investigate electrification and transportation industry impacts to load forecasts in its transmission expansion planning process.

[36] See 2022 ProbA Regional Risk Scenarios Report

[37] MISO LOLE Study Report

Demand-Side Management

DR programs continue to play a significant role in MISO's capacity. DR is steady at 7.5–8 GW and is projected to remain constant during this assessment period. MISO's transition to seasonal capacity auctions includes the accreditation of DR and the availability for each season (not strictly the summer peak season).

Distributed Energy Resources

BTM generation contributes about 4.2 GW of capacity in MISO of which about 1.2 GW are distributed solar PV. MISO's transition to seasonal capacity auctions accounts for the availability of DERs in each season. MISO is working with stakeholders to derive adequate methods of aggregating, reporting, and allowing DER participation in MISO markets.

Generation

In the past year, coal-fired and nuclear generation capacity has declined mainly due to retirements by 300 MW and 140 MW, respectively. These reductions are not as large as projected in the *2022 LTRA* as some previously announced retirements have been postponed. New wind and wind accreditation increased 725 MW while solar PV and solar PV accreditation increased 920 MW. The larger increases in resources since last year's LTRA are the result of new natural-gas-fired generators as well as some increases in accredited output contribution from existing natural-gas-fired generators, which account for more than 4GW of added capacity.

There are over 50 GW of generation capacity (predominantly solar PV) with signed generation interconnection agreements in MISO that are projected to come online within the next five years. Some projects have experienced delays in achieving commercial operation due to supply chain issues even as late as the post-agreement phase. MISO tariff changes and interconnection queue processes are reducing interconnection queue timelines.

Recognizing that many projects for new generation terminate the interconnection process before completion, MISO applies a factor to the Tier 2 and Tier 3 resource capacities based on the study phase and likelihood of resources coming on-line. The effect is to reduce the capacity of prospective new resources for more accuracy in long-term planning by accounting for the uncertainty and delays of new resources completing the interconnection process.

Energy Storage

MISO has significant amounts of energy storage (55+GW) currently being studied in the generation interconnection queue that are mostly reflected in Tier 3 of this *2023 LTRA*. MISO does not have information on smaller (distribution level) energy storage in its area.

Capacity Transfers and External Assistance

Net firm transfers have increased since the *2022 LTRA* but are not expected to remain at increased levels. Non-firm transfers across various areas have played a critical role in maintaining reliability during extreme weather events.

Transmission

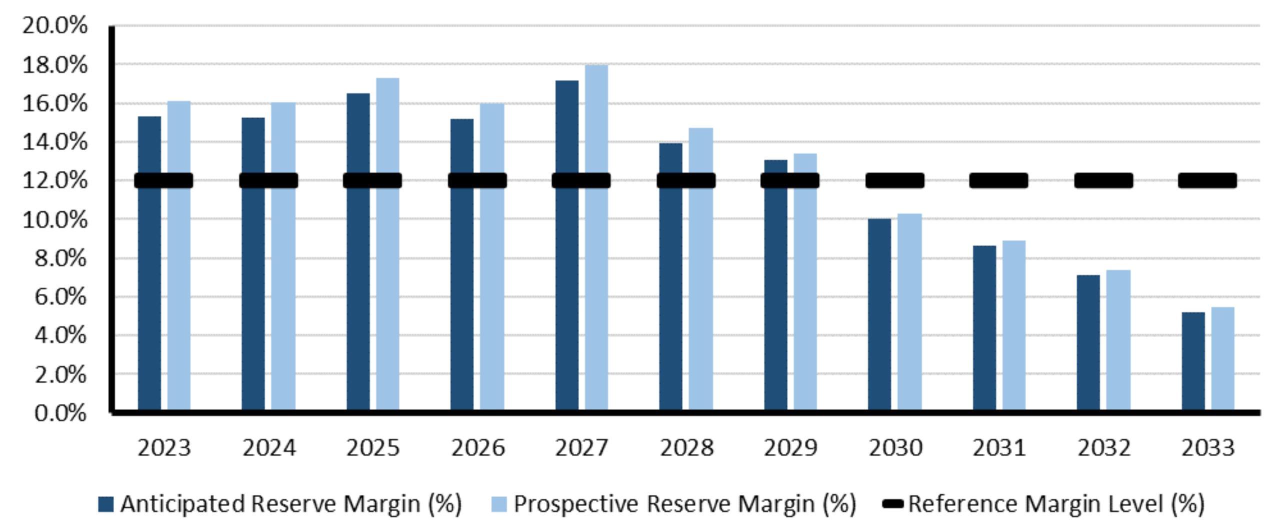
MISO continues to expand its transmission system for reliability and the integration of new resources. In the latest MISO Transmission Expansion Plan, $4.3 billion in transmission projects were approved with $550 million going towards integrating new resources, $550 million going towards baseline reliability projects, and the remainder supporting age- and condition-based needs. The latest approvals in MISO Transmission Expansion Plan (MTEP) 22 build on $10.3 billion in investment contained in MTEP 21 that provides reliability and economic benefits estimated at $23–52 billion across the MISO footprint and facilitates the integration of over 50 GW in new resources. In the *2022 LTRA*, MISO reported approximately 500 miles of new transmission across the footprint. In this *2023 LTRA*, that number has over tripled to near 1,800 miles of new transmission lines across MISO. Next year's MTEP and joint targeted interconnection queue projects with SPP will continue to provide additional transfer capacity across the Midwest and strengthen the transmission grid.

MRO-Manitoba Hydro

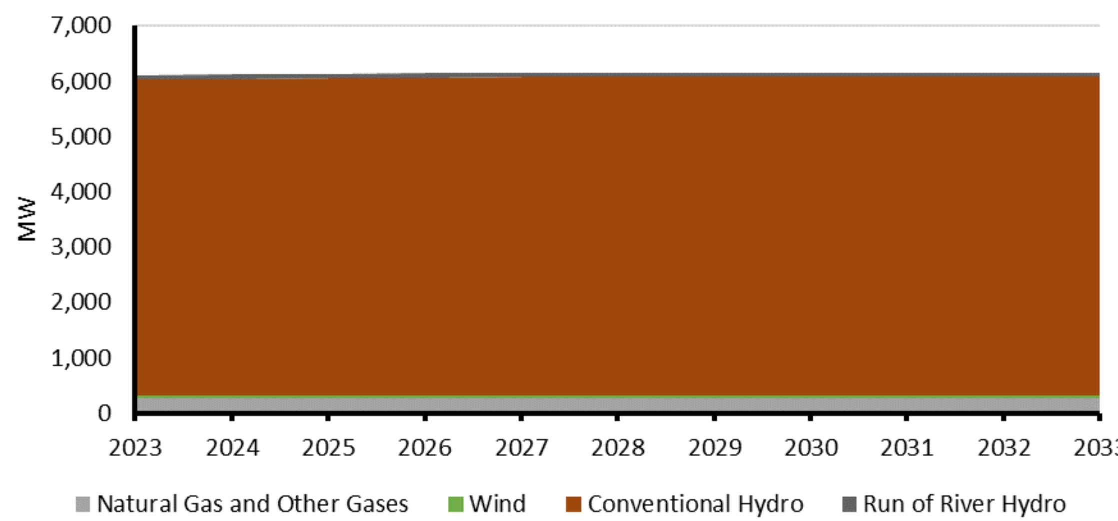
Manitoba Hydro is a provincial crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro provides electricity to approximately 608,500 electricity customers in Manitoba and provides approximately 293,000 natural gas customers in Southern Manitoba. The service area is the province of Manitoba which is 251,000 square miles. Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator and BA. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro. See **Normal Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	4,629	4,636	4,656	4,664	4,863	4,895	4,946	5,009	5,081	5,174
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	4,629	4,636	4,656	4,664	4,863	4,895	4,946	5,009	5,081	5,174
Additions: Tier 1	91	111	139	152	152	152	152	152	152	152
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-627	-563	-588	-543	-467	-472	-565	-565	-565	-565
Existing-Certain and Net Firm Transfers	5,244	5,290	5,224	5,313	5,389	5,384	5,291	5,291	5,291	5,291
Anticipated Reserve Margin (%)	15.3%	16.5%	15.2%	17.2%	14.0%	13.1%	10.0%	8.7%	7.1%	5.2%
Prospective Reserve Margin (%)	16.0%	17.3%	15.9%	17.9%	14.7%	13.4%	10.3%	8.9%	7.4%	5.4%
Reference Margin Level (%)	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Manitoba Hydro ARM is above the RML throughout the first five years of this assessment period. No resource adequacy issues are anticipated.
- The Manitoba Hydro system is not currently experiencing the large additions of wind and solar generation or thermal generation retirements as seen in some other assessment areas. The predominately hydro nature of the system is not expected to change during this assessment period.

MRO-Manitoba Hydro Fuel Composition										
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Natural Gas	278	278	278	278	278	278	278	278	278	278
Wind	52	52	31	31	31	31	31	31	31	31
Conventional Hydro	5,702	5,722	5,750	5,763	5,763	5,763	5,763	5,763	5,763	5,763
Run of River Hydro	81	81	81	81	81	81	81	81	81	81
Total MW	6,113	6,133	6,140	6,153	6,153	6,153	6,153	6,153	6,153	6,153

MRO-Manitoba Hydro Assessment

Planning Reserve Margins

The ARM for Manitoba does not fall below the RML of 12% during the first five years of this assessment period. No resource adequacy issues are anticipated for the first five years of this assessment period. Manitoba Hydro is nearing the completion of an Integrated Resource Planning process, which will inform resource additions for future assessments.

Energy Assessment and Non-Peak Hour Risk

The primary energy adequacy risk to Manitoba Hydro is severe drought. Manitoba Hydro continually monitors water levels, estimates flows where possible, and uses physically based inflow forecasts to plan its operations. A probabilistic risk evaluation of severe drought is discussed in the following section.

Manitoba Hydro has not identified any ramping issues at the present time and does not anticipate any during the next five years. The inherent flexibility of the hydro resource combined with the limited penetration of variable renewable resources have shielded Manitoba Hydro from ramping issues. In the longer term, Manitoba Hydro will monitor variable renewable penetration and changes in the load shape, including changes from EV charging, to see if ramping demands are increasing.

Probabilistic Assessments

Every two years, Manitoba Hydro prepares a probabilistic assessment for the Manitoba system, most recently in 2022. The 2022 probabilistic assessment was supportive of a 12% RML for the Manitoba system being sufficient to provide a LOLE of less than 0.1 days per year under the study assumptions.

Base Case Summary of Results (2022 ProbA)			
	2024*	2024	2026
EUE (MWh)	3.383	28.64	7.23
EUE (PPM)	0.133	1.141	0.287
LOLH (hours per Year)	0.004	0.036	0.007
Operable On-Peak Margin	N/A	13.5%	13.5%

* Provides the 2020 ProbA Results for Comparison

In 2023, Manitoba Hydro completed a probabilistic analysis of a risk scenario that examined the impact of the most significant resource adequacy factor over the long-run, variations in water conditions.[38] In this scenario, hydro resources are modeled at one-tenth percentile low-water conditions. Results indicate that LOLH and EUE values increase for both 2024 and 2026 in the low-water scenario to levels. LOLH, for example, will increase by an order of magnitude to nearly 0.6 hours/year in 2024 in comparison with the Base Case, highlighting the significant impact of low-flow conditions on the predominately hydro system. Since Manitoba Hydro is a small winter-peaking system on the northern edge of a summer peaking system, there is generally assistance available to provide energy to supplement hydro generation in low flow conditions in winter, particularly in off-peak hours. Management of energy in reservoir storage in accordance with good utility practice provides risk mitigation under low waterflow conditions.

[38] NERC 2022 ProbA Regional Risk Scenarios Report

Demand

Manitoba Hydro is projecting modest electricity load growth over the next five years. Factors considered in load growth projections include economic activity, electric vehicle adoption, and demand-side management programs in Manitoba operated by Efficiency Manitoba. EV adoption in Manitoba is being driven in part by proposed federal regulations that are expected to require that at least 20% of new vehicles sold in Canada to be zero emissions by 2026, at least 60% by 2030, and 100% by 2035.

Demand-Side Management

Manitoba Hydro’s Curtailable Rate Program has approximately 160 MW of load enrolled as resources for peak load management as well as some contingency reserves. The program permits up to 16 curtailments of 4.25 hours each.

Distributed Energy Resources

There is a potential for significant solar PV DER resources in the latter half of this assessment period, and plans are being developed to study the impacts on the Manitoba Hydro system. The potential for future solar PV DER may be dependent on solar PV subsidies and/or incentives.

Generation

All seven generating units at the new Keeyask Generating Station are operating, and their completion improves resource adequacy for the remainder of this assessment period. Keeyask Unit 6 is listed as a Tier 1 capacity resource as it is operating but awaiting official commercial operation/designated network resource status. A Tier 1 project to replace eight older and smaller hydro units is being planned for the Pointe du Bois Generating Station. The Pointe du Bois Renewable Energy Project of about approximately 50 MW replaces the original hydro units that were mothballed or retired based on economics/end-of-life after about 100 years of operation. No Tier 2 or Tier 3 resources have been assumed to come into service during this assessment period.

Manitoba is not currently experiencing the large additions of wind and solar resources being seen in other areas, so the emerging reliability issues arising from such large wind and solar resource additions are not anticipated in the next five years.

Energy Storage

Manitoba Hydro does not currently anticipate additions of energy storage resources in the next 10 years.

Capacity Transfers and External Assistance

The Manitoba Hydro system is winter peaking and is interconnected to MISO, which is summer peaking. Significant capacity transfer limitations from MISO into Manitoba may have the potential to cause reliability impacts, but only if the following conditions occur simultaneously: extreme Manitoba winter loads, unusually high forced generation/transmission outages, and a simultaneous emergency in the northern MISO footprint. Emergency operating procedures may be necessary under such conditions.

The completion of the Manitoba–Minnesota 500 kV transmission line in June 2020 increased import capability from 700 MW to 1,400 MW and firm export capability from 2,100 MW to 2,983 MW. This new 500 kV line also improved the resilience of the network in the event of transmission contingencies.

Transmission

There are several transmission projects expected to come on-line during this assessment period. Most of the projects are dictated by the need to expand the transmission system to reliably serve growing loads, transmit power to the export market, improve safety, improve import capability, increase efficiency, and connect new generation.

Reliability Issues

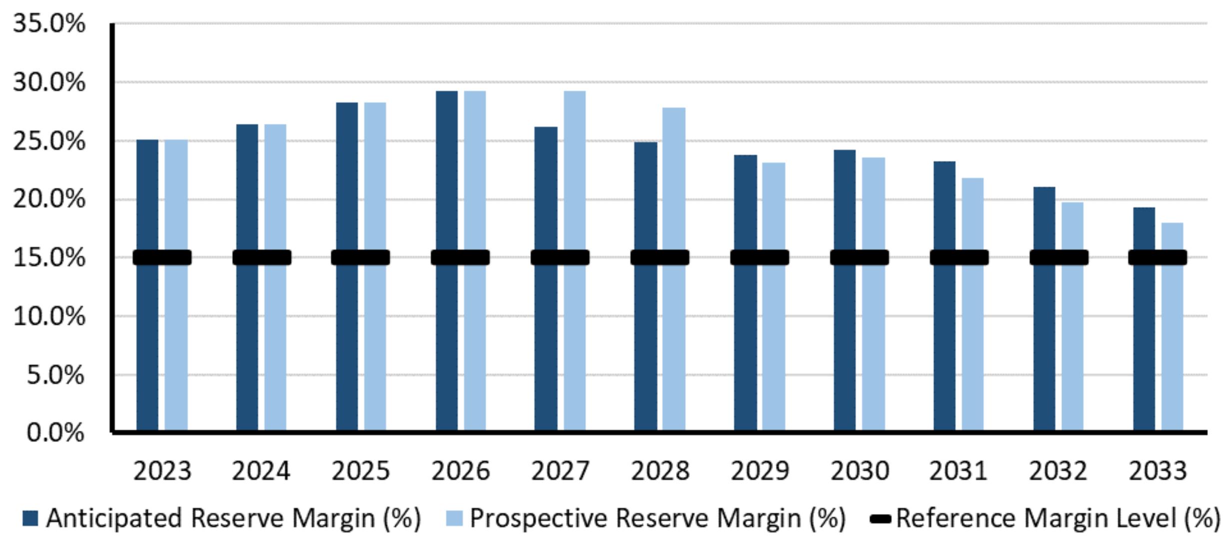
Manitoba Hydro is monitoring federal and provincial policy/strategies/regulations related to electricity/energy. The Canadian federal government is considering significant carbon emission regulation. Through Environment and Climate Change Canada, the government is taking multiple steps to develop clean electricity regulations that aim for Canadian electricity generation to achieve net zero greenhouse gas emissions by 2035. This includes requiring generating units to meet a stringent emissions intensity standard (measured in tons CO_2 equivalent per GWh) and pay a price for any remaining emissions. The proposed regulations are still in development and will not be fully implemented until 2035, so it is too early to determine any potential impacts. The province of Manitoba is developing a provincial energy strategy/policy that may be released in 2023. As details are not yet available, it is too early to determine any potential impacts.

MRO-SaskPower

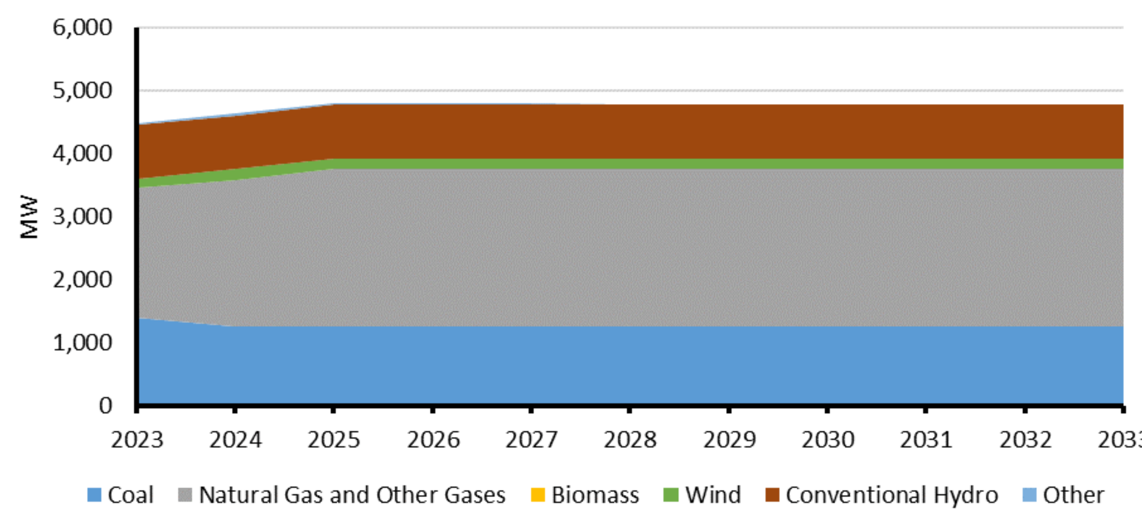
MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles), population of 1.2 million and approximately 550,000 customers. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its interconnections. See Normal Risk Areas for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	3,880	3,941	4,019	4,065	4,096	4,131	4,153	4,189	4,261	4,324
Demand Response	67	67	67	67	67	67	67	67	67	67
Net Internal Demand	3,813	3,874	3,952	3,998	4,029	4,064	4,086	4,122	4,194	4,257
Additions: Tier 1	416	506	506	506	506	506	506	506	506	506
Additions: Tier 2	0	0	0	421	421	1,173	1,173	1,173	1,173	1,173
Additions: Tier 3	0	0	0	80	80	80	80	80	80	80
Net Firm Capacity Transfers	290	315	315	315	315	315	315	315	315	315
Existing-Certain and Net Firm Transfers	4,405	4,461	4,604	4,539	4,524	4,524	4,571	4,572	4,571	4,571
Anticipated Reserve Margin (%)	26.4%	28.2%	29.3%	26.2%	24.9%	23.8%	24.3%	23.2%	21.1%	19.3%
Prospective Reserve Margin (%)	26.4%	28.2%	29.3%	29.2%	27.9%	23.1%	23.6%	21.8%	19.7%	17.9%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- SaskPower's ARM is above the RML throughout this assessment period. ARMs for winter 2024 are lower than reported in the *2022 LTRA* due to the retirement of generation (one coal-fired and one natural-gas-fired unit with combined capacity of 180 MW), scheduled refurbishment shutdown of an existing generator, and the delay of a new natural-gas-fired generator (45 MW) from December 2024 to April 2025.
- Saskatchewan is adding approximately 734 MW of generation under Tier 1 category within the next five years. This includes a 200 MW wind generation facility, a 10 MW utility-scale solar PV project, two new natural gas facilities totaling 414 MW, and the expansion of two existing natural gas facilities totaling 90 MW. The remaining capacity addition (20 MW) comes from geothermal and other projects.

MRO-Saskpower Fuel Composition

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251
Natural Gas	2,334	2,501	2,501	2,501	2,501	2,501	2,501	2,501	2,501	2,501
Biomass	3	3	3	3	3	3	3	3	3	3
Wind	164	164	164	162	162	162	162	162	162	162
Conventional Hydro	860	860	860	860	860	860	860	860	860	860
Other	22	22	17	17	1	1	1	1	1	1
Total MW	4,632	4,800	4,795	4,793	4,777	4,777	4,777	4,777	4,776	4,776

MRO-Saskpower Assessment

Planning Reserve Margins

Saskatchewan uses a criterion of 15% as the RML and has assessed its Planning Reserve Margin for the upcoming 10 years with summer and winter peak hour loads, available existing and anticipated generating resources, firm capacity transfers, and available DR for each year. Saskatchewan's ARM ranges from approximately 18–33% and does not fall below the RML.

Energy Assessment and Non-Peak Hour Risk

Saskatchewan performs energy assessments using probabilistic methods to inform the area's resource adequacy requirements. Saskatchewan is evaluating non-peak hours risks and diminishing capacity credits associated with higher penetration levels of VERs as part of the long-term planning process. It is exploring a probabilistic evaluation approach to evaluate VER capacity contribution values.

Probabilistic Assessments

NERC's most recent probabilistic assessment (2022 ProbA) Base Case results found some risk of load loss in both study years, but LOLH remained below 1-day-in-10-year criteria. The major contribution to LOLH and EUE is extended planned maintenance at some of Saskatchewan's hydroelectric units through winter peak season for life extension and upgrade. The planned maintenance on the hydro units is staggered to minimize adverse impacts on system reliability.

Base Case Summary of Results (2022 ProbA)			
	2024*	**2024**	**2026**
EUE (MWh)	26.5	169.5	117.0
EUE (PPM)	1.1	6.5	4.4
LOLH (hours per Year)	0.3	1.4	0.9
Operable On-Peak Margin	22.8%	23.1%	24.6%

* Provides the 2020 ProbA Results for Comparison

In 2023, SaskPower completed a probabilistic analysis of a risk scenario that examines the system's reliability when a coal unit approaching its planned end-of-life experiences a critical failure leading to premature unavailability. This scenario was selected to better understand the strategy for managing the coal units in Saskatchewan as they approach end of life in the next few years.[39] The results of this scenario reveal higher loss-of-load values in the first year of the assessment as compared to the Base Case. Saskatchewan is on track to add a large natural gas unit facility (377 MW) in-service by April 2024 that should enhance the system reliability for the remainder of this assessment period. SaskPower is also reviewing lay-up strategies for its existing units to support the system's reliability during peak periods.

Demand

Saskatchewan's system peak load forecast is based on econometric variables, weather normalization, and individual level forecasts for large industrial customers. Average annual summer and winter peak demand growth is expected to be approximately 1.15% throughout this assessment period.

Demand-Side Management

Saskatchewan's EE and energy conservation programs include incentives-based and education programs that focus on installed measures and products that provide verifiable, measurable, and permanent reductions in electrical energy and demand reductions during peak hours. DR consists of contracts with industrial customers for interruptible load based under conditions specified in DR programs. The first of these programs provides a curtailable load, currently up to 67 MW, with a 12-minute event response time. Other programs are in place providing access to additional curtailable load that require up to two hours notification time.

Distributed Energy Resources

Current BTM DER installed capacity in Saskatchewan is approximately 42 MW, which includes approximately 40 MW of solar PV, and approximately 2 MW of distributed wind projects. 25 MW of additional DER solar PV are expected to be added in the next five years. The estimated BTM DER installations are incorporated into the load forecast models that are used in supply and transmission planning study models.

Small power producers contribute an additional 5 MW of installed DER capacity (non-BTM) in Saskatchewan. There is currently an existing 8 MW and a potential for up to 20 MW of DERs being added in the next two years based on the currently approved Power Generation Partner programs. These projects are included as generation additions categories but currently their capacity is not considered in reliability planning.

[39] See 2022 ProbA Regional Risk Scenarios Report

Generation

Saskatchewan is adding approximately 734 MW of generation under Tier 1 category within the next five years. This includes a 200 MW wind generation facility and the expansion of two existing natural gas facilities that total 90 MW, two new natural gas facilities that total 414 MW, and the remaining capacity (30 MW) is projected to be geothermal and other projects.

Under Tier 2, over 1,279 MWs of new generation is projected in this assessment period. This includes three large (377 MW), two small (<50 MW) natural gas facilities, and a 100 MW utility-scale project. Natural gas generation is a proxy holder for any new generation needed beyond the medium-term (>5 years), but a portion of this capacity is anticipated to be covered through deploying renewables as well as carbon neutral and low emission generation projects.

Generating resources being planned as Tier 2 and Tier 3 will replace generators planned for retirement prior to deactivation. Therefore, Saskatchewan is not expecting any long-term reliability impacts due to generation retirements.

Energy Storage

SaskPower currently has its first BESS, a 20 MW/20 MWh unit, under construction. There are plans to expand this site by an additional 60 MW/60 MWh capacity.

The prevalent use for the planned energy storage is to provide regulating reserve, peak capacity and energy reduction, net demand ramping control, reactive power/voltage control, primary frequency control, and blackstart.

Capacity Transfers and External Assistance

SaskPower has three interfaces with its neighboring areas. The interface with Manitoba is currently the largest of the three interfaces and is the only interface with long term firm contracts. Capacity transfers from Manitoba would be limited in the events of prior outage of tie lines between SPC and MH as well as nearby transmission facilities supporting the interface. This could only impact reliability if it coincided with the extreme winter or summer peak demand and prior outage of one or more large generating units in Saskatchewan. Risk mitigation is in place through SaskPower's emergency operating procedure that will allow one or more measures, such as short-term imports from other available interfaces (for example Alberta or SPP), initiating DR and short-term load shedding.

Transmission

Approximately 80 km of 230 kV transmission line has been completed this summer and several other transmission projects (approximately 650 circuit km) are under the planning and conceptual phase in the 5-to-10-year assessment period. These projects are driven by load growth, new generation additions and reliability needs.

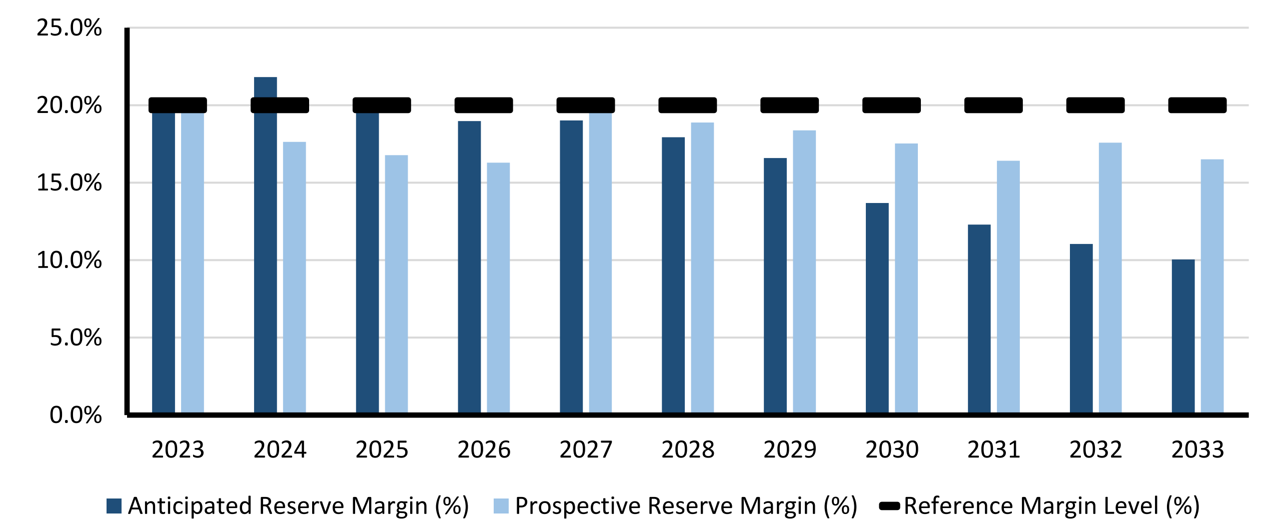
SaskPower performs transmission planning studies including the annual TPL assessment and other applicable periodic studies to meet NERC requirements, System Impact Studies for new load/generation interconnections, generation retirements, transmission service request (TSR) studies, area adequacy studies and other special studies as required to identify potential system issues. Mitigations are identified as part of these studies and included in the system development plan to ensure system performance requirements are met.

NPCC-Maritimes

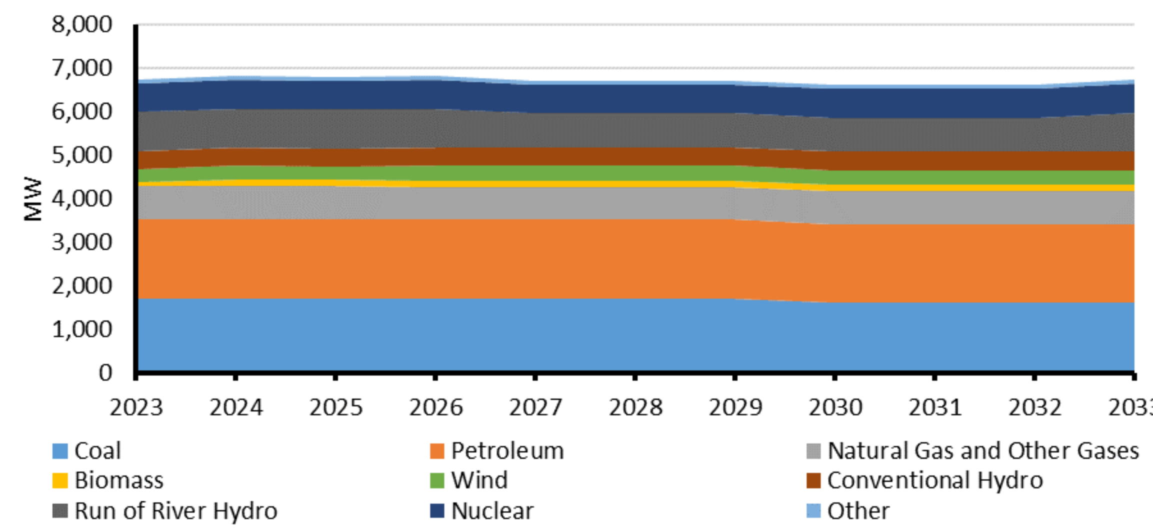
The Maritimes assessment area is a winter peaking NPCC sub-region with a single Reliability Coordinator and two BA areas (New Brunswick and Nova Scotia). It is comprised of the Canadian provinces of New Brunswick (NB), Nova Scotia (NS), and Prince Edward Island (PEI), and the northern portion of Maine (NM), which is radially connected to NB. The area covers 58,000 square miles with a total population of 2 million people. See **Elevated Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	5,911	5,951	5,999	6,052	6,105	6,171	6,240	6,314	6,381	6,451
Demand Response	266	285	290	290	289	288	288	287	287	286
Net Internal Demand	5,644	5,665	5,709	5,763	5,816	5,883	5,953	6,027	6,095	6,165
Additions: Tier 1	34	34	52	52	52	52	52	52	52	52
Additions: Tier 2	10	36	93	276	451	960	1,083	1,103	1,253	1,253
Additions: Tier 3	0	32	105	125	495	515	535	555	575	590
Net Firm Capacity Transfers	55	23	-32	145	145	145	145	145	145	145
Existing-Certain and Net Firm Transfers	6,841	6,792	6,740	6,807	6,807	6,807	6,716	6,716	6,716	6,732
Anticipated Reserve Margin (%)	21.8%	20.5%	19.0%	19.0%	17.9%	16.6%	13.7%	12.3%	11.0%	10.0%
Prospective Reserve Margin (%)	17.6%	16.8%	16.3%	19.5%	18.9%	18.4%	17.5%	16.4%	17.6%	16.5%
Reference Margin Level (%)	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Since the *2022 LTRA*, winter peak demand forecasts for this assessment area have risen. As a result, ARMs are currently projected to fall below the RML of 20% beginning in 2026.

NPCC-Maritimes Fuel Composition										
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Coal	1,695	1,695	1,695	1,695	1,695	1,695	1,604	1,604	1,604	1,604
Petroleum	1,829	1,823	1,818	1,818	1,818	1,818	1,818	1,818	1,818	1,818
Natural Gas	760	760	760	760	760	760	760	760	760	760
Biomass	148	148	148	148	148	148	148	148	148	148
Wind	322	310	328	328	328	328	328	328	328	328
Conventional Hydro	418	418	418	418	418	418	418	418	418	418
Run of River Hydro	902	902	902	792	792	792	792	792	792	902
Nuclear	663	663	671	671	671	671	671	671	671	671
Other	90	90	90	90	90	90	90	90	90	90
Total MW	6,827	6,809	6,830	6,720	6,720	6,720	6,629	6,629	6,629	6,739

NPCC-Maritimes Assessment

Planning Reserve Margins

The reference reserve margin level that is used for evaluating the New Brunswick (NB), Nova Scotia (NS), Prince Edward Island (PEI), and Northern Maine (NM) sub-areas that make up the Maritimes area is 20% of firm load. The 20% criterion is not a mandated requirement. The ARM in the first five years for Maritimes ranges between 19% to 22% during the winter period and between 73% to 83% during the summer period of this LTRA study.

Energy Assessment and Non-Peak Hour Risk

The ARM level during off-peak season for the Maritimes areas ranges between 73% to 83%. During off peak hours, Maritimes has surplus generation available to meet the area's energy needs and hence there are no constraints with converting the capacity to energy during these times.

Probabilistic Assessments

The two BAs within Maritimes, as members of NPCC, jointly prepare annual interim or comprehensive probabilistic assessment reviews that cover three- to five-year forward-looking periods for both Maritimes' transmission system and resource adequacy evaluations. In addition, the Maritimes area also supports NERC's annual seasonal probabilistic assessments, which provide an evaluation of generation resource and transmission system adequacy that will be necessary to meet projected seasonal peak demands and operating reserves.

Base Case Summary of Results (2022 ProbA)			
	2024*	2024	2026
EUE (MWh)	1.125	1.838	3.869
EUE (PPM)	0.039	0.06	0.138
LOLH (hours per Year)	0.023	0.023	0.071
Operable On-Peak Margin	16.7%	25%	22.9%

* Provides the 2020 ProbA Results for Comparison

Demand

There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes area. The peak area demand occurs in winter and is highly reliant on the forecasts of the two largest sub-areas of NB and NS, which are historically highly coincidental. Demand for the Maritimes area is determined to be the non-coincident sum of the peak loads forecasted by the individual sub-areas. The aggregated growth of both demand and energy for the combined sub-areas see an upward trend over summer and winter seasonal periods of this LTRA assessment period. The Maritimes area peak loads are expected to increase by 11.3% during summer and by 10% during winter seasons over the 10-year assessment period. This translates to compound average growth rates of 1.1% in summer and 1% in winter. The Maritimes area annual energy forecasts are expected to increase by a total of 6.2% during the 10-year assessment period for an average growth of 0.6% per year.

Demand-Side Management

Plans to develop up to 100 MW by 2030/2031 of controllable direct load control programs with smart grid technology to selectively interrupt space and/or water heater systems in residential and commercial facilities are underway, but no specific annual demand and energy saving targets currently exist. During the 10-year LTRA assessment period in the Maritimes area, annual amounts for summer peak demand reductions associated with EE and conservation programs rise from 17 MW to 162 MW while the annual amounts for winter peak demand reductions rise from 88 MW to 551 MW.[40]

Distributed Energy Resources

The DER installed capacity in NS is approximately 230 MW at present, including distribution-connected wind projects under purchase power agreements, small community wind projects under a feed-in tariff and BTM solar PV.

The LTRA wind capacity for NB, NS and PEI is de-rated between 18% and 33% with probabilistic methods to calculate equivalent perfect capacities for each sub-area excluding Northern Maine which uses seasonal capacity factors. BTM solar PV is assumed to have an ELCC of 0% during winter period. The Maritimes Area has shown embedded BTM solar PV projections of 99 MW in 2023 rising to 669 MW by 2033. These projects include distributed small-scale solar PV (mainly rooftop) that fall under the net metering program and serve as a reduction in load mainly in the residential class. The forecasted increase in solar PV installations in the coming years is a result of initiatives, including municipal and provincial incentive programs. There is no capacity contribution from solar generation due to the timing of area's system peak, which occurs either before sunrise or after sunset in the winter period.

[40] Current and projected EE effects based on actual and forecasted customer adoption of various demand-side management programs with differing levels of impact are incorporated directly into the load forecast for each of the areas but are not separately itemized in the forecasts. Since controllable space and water heaters will be interrupted via smart meters, the savings attributed to these programs will be directly and immediately measurable.

Generation

In NB, a hydro facility of 4 MW nameplate capacity shall reach its end of life and is planned to be retired at the end of 2023. NB assumes that 28 MW of diesel-fired generation will be extended starting in 2025 and that recently upgraded 290 MW of natural-gas-fueled resources will be completed in 2023. In NB, unconfirmed retirements include a 98 MW power purchase agreement contract that will come to an end in 2024–2025. An anticipated replacement power purchase agreement contract, a long-term firm energy contract from neighboring jurisdictions, and opportunities to buy in day-ahead and real-time markets will be utilized to maintain overall resource adequacy.

In Nova Scotia, Tier 1 resources include wind projects with a total nameplate capacity of 502 MW phased-in from 2024–2027 with an ELCC of 10%. Tier 2 resources in NS include a 200 MW of BESS (2026–2032), 520 MW of combustion turbines (2027–2033), a 150 MW conversion of a coal-fired unit to natural gas (2028), and 459 MW conversion of coal-fire units to oil (2030). Tier 3 resources in NS include natural gas additions (combustion turbines) of 350 MW in 2029 and new wind generation with a nameplate capacity of 1,600 MW phased in from 2026–2033. These Tier 3 resource additions are anticipated to facilitate the retirement of additional coal-fired generation by 2030. However, these retirements have not been included in the assessment due to their uncertainty.

Small amounts of new solar PV generation capacity (Tier 2) of up to 31 MW are expected to be installed in PEI in the fall of year 2023. PEI also plans to add a new 10 MW of hybrid energy storage (Tier 2) during the year 2023.

Tier 3 additions include wind projects with a total nameplate capacity of 1,840 MW starting year 2025, solar PV projects of 200 MW nameplate capacity starting year 2025 and 400 MW nameplate capacity of dual fueled combustion turbines starting year 2027.

NB de-rates its wind capacity with a calculated year-round equivalent capacity of 33%. NS and PEI de-rate wind capacity to 18% and 17%, respectively, of nameplate based on year-round calculated equivalent load carrying capabilities for their respective individual sub areas. The peak capacity contribution of grid based solar is estimated at zero since the Maritimes area peak occurs in the winter either before sunrise or after sunset.

Energy Storage

NS Power includes a 200 MW (4-hour duration) nameplate capacity standalone BESS added as a Tier 2 resource phased-in from 2026–2032. This grid-scale project will support the integration of new renewable generation, provide energy arbitrage and resiliency services, and provide firm capacity and fuel savings.

PEI includes a 10 MW nameplate capacity hybrid energy storage as a Tier 2 resource starting fall of 2023. This project will provide storage option to the output from the 10 MW solar PV facility that is planned to be coming on-line during the same time frame. This project will provide fuel savings and may provide additional reliability if a generation outage occurs.

NB Power has not included any BESS in the 2023 LTRA submission; however, the value of energy storage options is expected to increase as the technology improves and NB's smart grid network develops. NB Power issued a request for expressions of interest for new renewable generation sources, including 200 MW of wind, 15 MW of solar PV, 5 MW of tidal, and 50 MW of 4-hour duration BESS in February of 2023. Under this program, NB Power expects uptake in new energy storage projects in the coming years. Internal pilot projects and studies are underway to understand the economics, application, and performance of BESS resources. Ongoing internal analyses are conducted by NB Power to determine the cost and benefit associated with BESS options as well as dispatching these resources to reduce/shift peaks and/or balance intermittent resources, such as wind, to provide additional flexibility to the system.

Capacity Transfers and External Assistance

ProbA studies show that the Maritimes area is not reliant on inter-area capacity transfers to meet NPCC resource adequacy criteria.

Transmission

There are no new transmission projects in the Maritimes area.

Reliability Issues

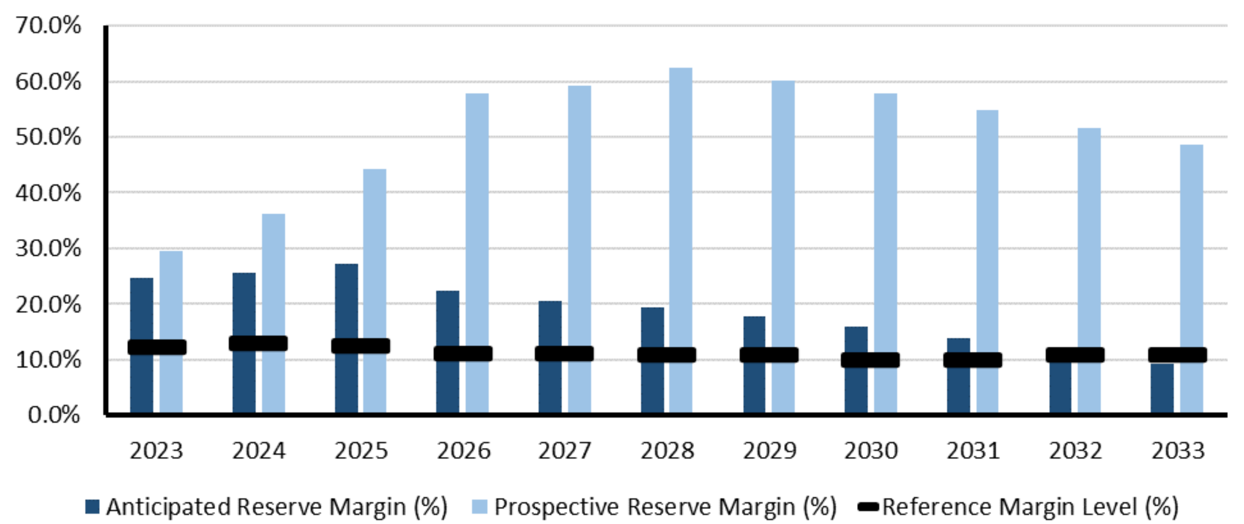
The Maritimes area has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind (de-rated), dual fuel oil/gas, tie benefits, and biomass with no one type feeding more than about 27% of the total capacity in the area. The Maritimes area does not anticipate fuel disruptions that pose significant challenges for resources during this assessment period.

NPCC-New England

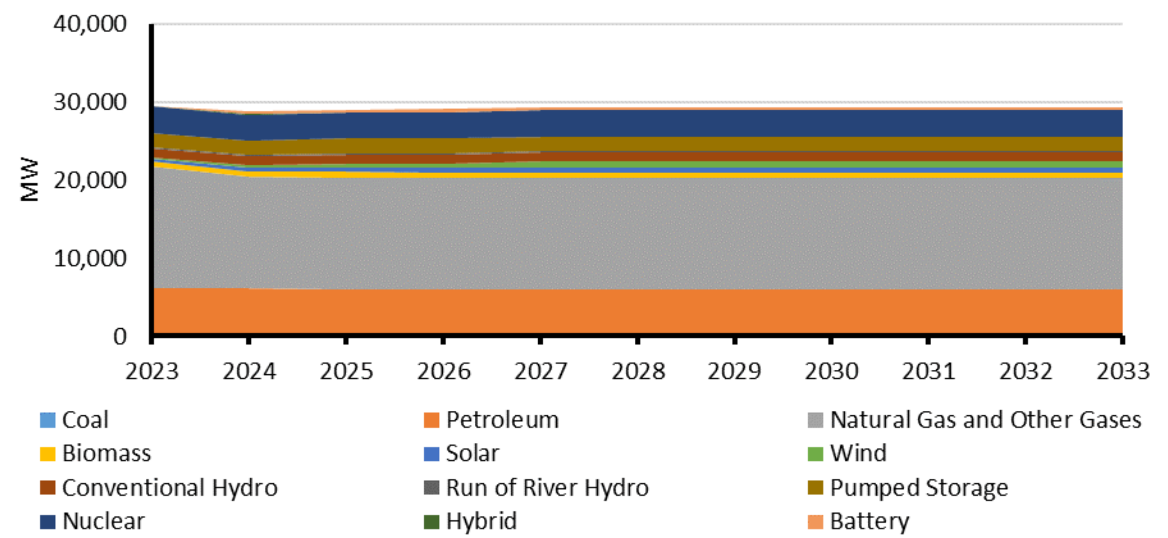
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont served by ISO-NE Inc. ISO-NE is a regional transmission organization responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS. The New England BPS serves approximately 14.5 million customers over 68,000 square miles. See **Elevated Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	24,633	24,708	24,866	25,052	25,307	25,636	26,036	26,505	27,046	27,598
Demand Response	661	669	623	623	623	623	623	623	623	623
Net Internal Demand	23,972	24,039	24,243	24,429	24,684	25,013	25,413	25,882	26,423	26,975
Additions: Tier 1	708	1,084	1,111	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Additions: Tier 2	1,376	1,836	6,338	7,181	8,392	8,392	8,392	8,392	8,392	8,392
Additions: Tier 3	1,130	2,199	3,625	9,514	11,306	11,836	12,525	12,525	12,525	12,525
Net Firm Capacity Transfers	1,297	1,504	567	84	84	84	84	84	84	84
Existing-Certain and Net Firm Transfers	29,408	29,505	28,552	28,068	28,068	28,068	28,068	28,068	28,068	28,068
Anticipated Reserve Margin (%)	25.6%	27.2%	22.4%	20.5%	19.3%	17.7%	15.9%	13.8%	11.4%	9.2%
Prospective Reserve Margin (%)	36.2%	44.2%	57.7%	59.1%	62.4%	60.2%	57.7%	54.9%	51.7%	48.6%
Reference Margin Level (%)	12.9%	12.6%	11.0%	11.0%	11.0%	11.0%	10.0%	10.0%	11.0%	11.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- New England is forecast to have the resources needed to meet consumer demand for electricity through the first nine years of the 10-year LTRA assessment period. In the last year of the assessment, in the summer of 2033, the summer ARM of 9.2% falls below the annual RML of 11.0%. However, at this time, ISO-NE does not expect the need to procure capacity additions to mitigate potential resource adequacy issues forecast for the last summer of the 10-year LTRA.
- Beyond the LTRA assessment period, additional imports of Canadian hydroelectricity, offshore wind, and new technologies, such as longer-duration energy storage, will likely continue the trend toward a cleaner, albeit more complex, power system.
- ISO-NE is addressing the issues brought on by grid transformation through a number of planning, operational, and market measures.

NPCC-New England Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	437	437	437	437	437	437	437	437	437	437
Petroleum	5,635	5,562	5,546	5,546	5,546	5,546	5,546	5,546	5,546	5,546
Natural Gas	14,311	14,328	14,328	14,328	14,328	14,328	14,328	14,328	14,328	14,328
Biomass	749	711	711	711	711	711	711	711	711	711
Solar	424	542	568	568	568	568	568	568	568	568
Wind	341	583	583	852	852	852	852	852	852	852
Conventional Hydro	1,155	1,155	1,155	1,155	1,155	1,155	1,155	1,155	1,155	1,155
Run of River Hydro	133	133	133	133	133	133	133	133	133	133
Pumped Storage	1,861	1,861	1,861	1,861	1,861	1,861	1,861	1,861	1,861	1,861
Nuclear	3,354	3,354	3,354	3,354	3,354	3,354	3,354	3,354	3,354	3,354
Hybrid	34	34	34	34	34	34	34	34	34	34
Battery	386	386	386	386	386	386	386	386	386	386
Total MW	28,820	29,086	29,095	29,364	29,364	29,364	29,364	29,364	29,364	29,364

NPCC-New England Assessment

New England is forecast to have the resources needed to meet consumer demand for electricity through the first nine years of the 10-year LTRA assessment period. In the last year of the assessment, in the summer of 2033, the summer ARM of 9.2% falls below the annual RML of 11.0%, a 1.8% (-494 MW) shortfall. If only 6% (about 500 MW) of the total Tier 2 resources (8,392 MW) materializes in the future, the summer shortfall in the final year of the assessment would be mitigated. However, at this time, ISO-NE does not expect the need to procure capacity additions to mitigate potential resource adequacy issues forecast for the last summer of the 10-year LTRA.

With the widespread development of renewable and clean energy resources, the BPS will emit lower air emissions. Beyond the LTRA assessment period, additional imports of Canadian hydroelectricity, offshore wind, and new technologies (e.g., longer duration energy storage) will likely continue the trend toward a cleaner, albeit more complex, power system. ISO-NE is addressing these issues brought on by grid transformation through a number of planning, operational, and market measures.

Planning Reserve Margins

ISO-NE's seasonal ARM is based on the capacity needed to meet the ISO-NE and NPCC 1-day-in-10 years LOLE resource planning reliability criterion. The capacity needed, referred to as the installed capacity requirement (ICR), varies from year to year depending on projected system conditions. The ICR is calculated on an annual basis, covering four years into the future. The latest calculations result in an annual RML of 12.3% in 2023, 12.9% in 2024, 12.6% in 2025, and 11.0% in 2026 and 2027. For the years beyond ISO-NE's forward capacity market (FCM) time frame, this assessment uses the annual RML associated with the representative future ICRs calculated for 2028 through 2032. ISO-NE assumes a continuation of the annual RML in 2032 for the annual RML in 2033. These annual RMLs range from a low of 10.0% in 2030 and 2031 to a high of 11.0% in 2028, 2029, 2032 and 2033.

Energy Assessment and Non-Peak Hour Risk

ISO-NE's probabilistic and deterministic study results indicate that there are sufficient capacity resources to meet forecasts of seasonal peak and energy demands for nine years out of the 10-year LTRA assessment period. However, a standing concern is whether there will be sufficient fuel available for resources to turn capacity into electricity to satisfy both demand and required operating reserves during an extended cold spell, a series of cold spells, or a long-term critical infrastructure or supply chain force majeure scenario.

ISO-NE regularly prepares outlooks for both energy demand and production. Forecasts of weather, transmission topology, resource capability, fuel inventories, known and forced outages, regional gas pipeline or liquid fuel constraints, and projected imports/exports all factor into this outlook for New England's energy production capability. If the regional supply/demand balance is negative, projected energy deficiencies can trigger energy alerts or energy emergencies that are then disseminated to market participants and federal and state regulators. This early notification of potential electricity shortages should incentivize market participants to procure the necessary fuel needed to support future ISO dispatch orders.

ISO-NE has undertaken several new projects to develop more enhanced deterministic and probabilistic energy security analyses. For instance, ISO-NE is working with the Electric Power Research Institute to conduct probabilistic energy adequacy studies for New England under extreme weather events. These studies establish a framework for risk analysis that can be updated as climate projections are refined and the resource mix evolves. The energy adequacy risk profile is dynamic and will be a function of the evolution of both supply and demand profiles. Preliminary results for 2027 winter events, 2027 summer events, 2032 summer events, and 2032 winter events reveal a range of energy shortfall risks and associated probabilities.[41] In terms of magnitude and probability, these baseline results indicate that energy shortfall risks in the near-term appear manageable over a 21-day period. Sensitivity analysis of 2032 worst-case scenarios indicates an increasing energy shortfall risk profile between 2027 and 2032.

ISO-NE and stakeholders are working on near- and long-term market improvements to expand the existing suite of energy and ancillary services that will cost-effectively address uncertainties in firm electricity production. All of these activities directly enhance overall BPS energy security.

Probabilistic Assessments

ISO-NE conducts probabilistic resource adequacy assessments annually in conjunction with NPCC to identify regional capacity resource needs and to comply with NPCC/NERC reliability requirements. In the transmission assessment domain, revisions to ISO-NE planning processes now reflect the changing resource characteristics, probabilistic study assumptions, and changes to national and regional criteria. Coordinated transmission planning activities with neighboring systems will continue and help

[41] Results of the preliminary EPRI/ISO-NE studies reveal similar energy adequacy risk both with and without the Everett Marine Terminal LNG facility in-service.

support the New England states' policy objectives of providing access to a greater diversity of clean resources to meet environmental compliance obligations.

Base Case Summary of Results (2022 ProbA)			
	2024*	2024	2026
EUE (MWh)	58.62	0.937	0.551
EUE (PPM)	0.471	0.007	0.004
LOLH (hours per Year)	0.095	0.002	0.002
Operable On-Peak Margin	9.8%	32.6%	27.8%

* Provides the 2020 ProbA Results for Comparison

As expected from the 2022 ProbA risk scenario, the EUE and LOLH remain close to zero with increased capacity, decreasing demand, and no major reported Tier 1 resources after 2024. The New England area is currently summer-peaking, and the EUE risk occurs during the summer months; however, the EUE values are negligible.

Demand

Over the 10-year planning period, the forecast net internal summer peak demand increases by 2,993 MW from 24,605 MW in 2023 to 27,598 MW in 2033. The corresponding net internal winter peak demand forecast increases by 7,183 MW from 20,269 MW in 2023–2024 to 27,452 MW in 2033–2034. Net energy for load is forecast to grow by 33,006 GWh from 120,552 GWh in 2023 to 153,558 GWh in 2033.

The forecast for summer peak load reductions due to EE and conservation is expected to increase by 436 MW from 1,969 MW in 2023 to 2,405 MW in 2033. This demand reduction is represented in the reported total internal demand of the Demand, Resources and Reserve Margins table.

Currently, New England has 981 MW (3,366 MW nameplate) of BTM-PV. BTM-PV is forecast to grow to 1,116 MW (6,553 MW nameplate) by 2033. The BTM-PV peak load reduction values are calculated as a percentage of nameplate. The percentages include the effect of diminishing PV production at time of system peak as increasing PV penetrations shift the timing of summer peaks to later in the day. As such, the BTM-PV summer peak load reduction values decrease from 29.1% of nameplate in 2023 to 17.0% in 2033. Like EE and conservation, BTM-PV is also a demand reduction represented in the reported Total Internal Demand of the Demand, Resources and Reserve Margins table on the **NPCC-New England** dashboard.

Demand-Side Management

New England currently has 564 MW of controllable and dispatchable DR resources, and that amount is projected to grow by 59 MW to 623 MW by 2033. The area also currently has over 3,253 MW of passive demand-side management resources that participate in the regional FCM. This amount is projected to decrease by 936 MW to 2,317 MW by 2032.

Distributed Energy Resources

Approximately 2,550 MW (nameplate) of settlement-only generation does not participate in ISO-NE's FCM. Of this total, approximately 2,400 MW is made up of units or stations smaller than 5 MW each.

Generation

Future capacity required to comply with NPCC's resource planning criterion is procured through ISO-NE's FCM. Studies of projected system conditions show that developing new resources near load centers, particularly in Northeast Massachusetts/Boston and Southeastern Massachusetts and Rhode Island, would provide the greatest reliability benefit. To the extent that new resources are developed to help balance supply with demand, the BPS would require fewer transmission upgrades and ancillary services and would exhibit less congestion and losses.

The continued reliance on natural-gas-fired generation still exposes New England to the reliability impacts from the fleet's lack of firm gas pipeline transportation contracting and its dependence upon uncertain liquified natural gas import deliveries. Natural gas sector infrastructure contingencies can become electric sector reliability risks during any time of the year. ISO-NE and interregional reliability organizations have identified these risks in a number of energy security studies and assessments, and ISO-NE has taken a number of remedial actions to improve the overall gas/electric interface. The development of renewable resources with energy storage, imports from neighboring areas, and fast-start and flexible ramping resources along with the continued investment in EE/conservation measures within both the electric and natural gas sectors are also part of the overall reliability solution.

Future environmental regulations, public policies, and economic considerations will all affect the operation of existing resources and the mix of new resources. As existing oil- and coal-fired generators retire, their replacements would likely be predominantly renewable sources of energy, notably wind and solar PV. Federal and state policies, such as those that promote EE, PV, and wind resources, will continue to affect the planning process. Carbon emission reduction targets will continue to be the key regional constraint on electricity production by fossil-fueled generating units.

Energy Storage

ISO-NE currently has 1,861 MW of pumped-storage hydroelectric stations, 61 MW of stand-alone BESS, and 27 MW of co-located and integrated hybrid BESS (summer ratings). These amounts are expected to grow over the 10-year LTRA assessment period. ISO-NE reports 386 MW of stand-alone BESS and 34 MW of co-located/integrated hybrid BESS for the summer of 2033.

Capacity Transfers and External Assistance

New England is interconnected with the three Bas of Québec, Maritimes, and New York. ISO-NE considers the tie benefits associated with these Bas to meet the regional resource adequacy criterion and to prevent over-reliance on such assistance. ISO-NE's FCM methodology limits the purchase of import capacity based on the interconnection transfer limits. ISO-NE's capacity imports are assumed to range from 567 MW to 1,504 MW during the 2023–2026 summer periods. There is one long-term firm import contract of 84 MW that extends through the 10-year LTRA assessment period. In addition, there are no firm exports identified over the 10-year LTRA assessment period.

As a result of updates to the permitting status of the New England Clean Energy Connect inter-area transmission line and supporting energy contract, which is scheduled for commercial operation in December of 2024 and starting in the summer of 2025, ISO-NE is reporting an expected import from Québec in the amount of 1,090 MW/hr. This contract is not reported by ISO-NE for the winter periods due to Québec's own load needs for serving its winter-peaking system.

Transmission

Transmission expansion in New England has improved the overall level of reliability and resiliency, reduced air emissions, and lowered wholesale market costs by nearly eliminating congestion. Generator retirements, off-peak system needs, the growth of DERs and VERs by using IBRs, and changes to mandatory planning criteria promulgated by NERC, NPCC, and regional stakeholders have driven the need for longer-term transmission assessments.

Future reliable and economic performance of the BPS is expected to continue to improve as a result of approximately $1.5 billion of planned transmission upgrades over the next 10 years, much of which is still under construction. Generator retirements, the integration of many DERs and VERs, the use of IBR technologies, and issues rising from minimum load assessments and high-voltage conditions are changing the needs for reliability-based transmission upgrades. In addition, transmission improvements will also be needed to support state policies to access remotely located sources of clean energy. Transmission assessments and resultant plans are being developed throughout the area to meet these future system needs.

Reliability Issues

New England's BPS is transitioning to a system with a growing number of renewables, clean energy resources, VERs and DERs. The rapid implementation of revised interconnection standards for VERs and DERs is vital to ensure overall BPS reliability and facilitate the economic development of IBRs.

As of summer 2023, constraints on global, regional, and local supply chains are affecting the procurement of new (or needed) BPS infrastructure due to the lack of raw materials, manufacturing limitations, labor shortages, and high inflation and interest rates. This has led to some previously signed long-term, off-shore wind contracts being renegotiated and/or canceled.

New England has already experienced constraints on electricity production due to a lack of natural gas for the power sector during winter. In response, ISO-NE has been a key player at the national level in promoting BPS reliability through sharing of lessons learned and best practices and now through initiating the performance of more detailed and in-depth BPS energy assessments. Additionally, to address winter energy security challenges, ISO-NE and regional stakeholders developed and put in place a two-year program to compensate certain resources that provide energy security during the winters of 2023–2024 and 2024–2025 (from December to February). ISO-NE's Inventoried Energy Program is a voluntary program designed to provide incremental, winter period compensation for participants that maintain inventoried energy for their assets during extreme cold periods when energy security is most stressed. [42]

The just-in-time delivery of a generators fuel supply, whether natural gas, wind, or solar, is creating the need for the electric sector to quickly develop ways to retain access to flexible, stored energy either through long-term energy storage solutions that can capture and store renewable power or through the use of dispatchable resources, whether these dispatchable resources are carbon emitting or not.

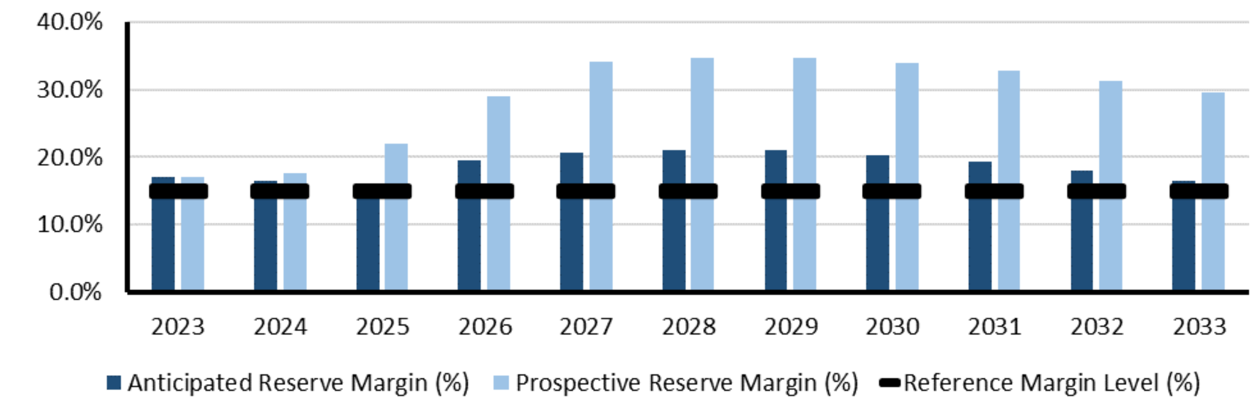
[42] Beginning September 1, 2023, only participants using the fuel types of oil, refuse, batteries, pumped storage and natural gas (with firm supply and transport) may elect to participate in IEP.

NPCC-New York

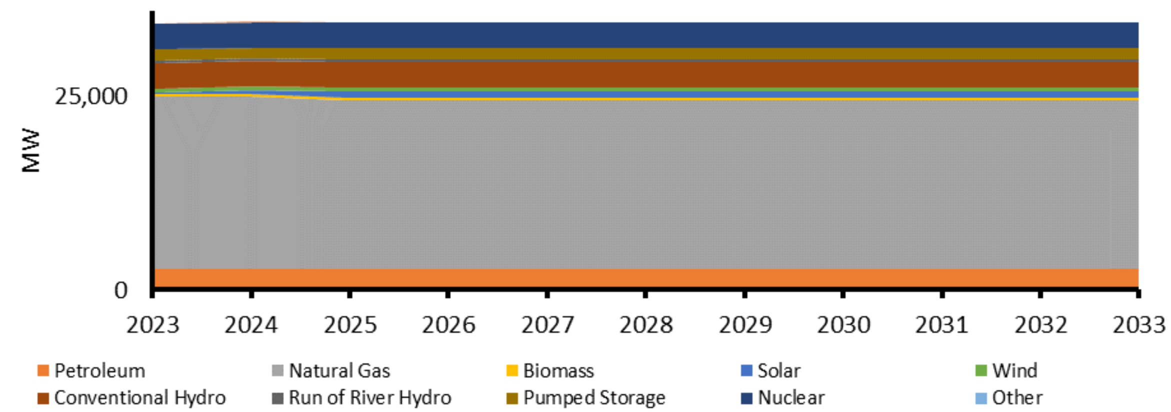
NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within New York. NYISO supports reliability primarily through three complementary markets: energy, ancillary services, and capacity. The transmission grid of New York State encompasses over 11,000 miles of transmission lines, 760 power generation units, and serves the electricity needs of 19.6 million people. New York experienced its all-time peak demand of 33,956 MW in the summer of 2013. See **Elevated Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	32,280	32,390	32,440	32,410	32,310	32,300	32,490	32,750	33,110	33,520
Demand Response	860	860	860	860	860	860	860	860	860	860
Net Internal Demand	31,420	31,530	31,580	31,550	31,450	31,440	31,630	31,890	32,250	32,660
Additions: Tier 1	410	877	888	888	888	888	888	888	888	888
Additions: Tier 2	415	2,124	3,000	4,305	4,305	4,305	4,305	4,305	4,305	4,305
Additions: Tier 3	3,796	6,124	10,171	12,204	12,204	12,204	12,204	12,204	12,204	12,204
Net Firm Capacity Transfers	1,932	1,815	3,212	3,518	3,518	3,518	3,518	3,518	3,518	3,518
Existing-Certain and Net Firm Transfers	36,152	35,445	36,842	37,148	37,148	37,148	37,148	37,148	37,148	37,148
Anticipated Reserve Margin (%)*	16.4%	15.2%	19.5%	20.6%	20.9%	21.0%	20.3%	19.3%	17.9%	16.5%
Prospective Reserve Margin (%)	17.7%	21.9%	29.0%	34.2%	34.6%	34.7%	33.9%	32.8%	31.3%	29.6%
Reference Margin Level (%)**	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

*Values are with wind derated by 82% wind, solar by 43% and run-of-river by 60% for summer capability period. Additionally, the proposed 1,250 MW Champlain-Hudson Power Express HVDC from Québec to New York City is assumed in the net transfers starting 2026.

**The NERC LTRA RML is 15% and it is used for the sole purpose of the LTRA; however, there is no Planning Reserve Margin criteria in New York. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. Additionally, NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 days/year. However, New York requires LSEs to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2023–2024 IRM at 20%. All values in the IRM calculation are based upon full installed capacity MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year.

Highlights

- Public policies, such as the 2019 Climate Leadership and Community Protection Act (CLCPA), are driving rapid changes in New York's electric system and impacting how electricity is produced, transmitted, and consumed. The transition to a cleaner grid in New York is leading to an electric system that will be increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation.
- Recent assessments reveal that reliability margins are shrinking. Electrification programs are driving demand for electricity higher, and New York is projected to become winter peaking in the future. Largely in response to public policies, fossil fuel generators are retiring at a faster pace than new renewable supply is entering service. The potential for delays in construction of new supply and transmission, higher than forecasted demand, and extreme weather could threaten grid reliability and resilience.
- NYISO's reliability studies identified actionable reliability needs starting 2025 in New York City, resulting in NYISO solicitating for market-based and regulated backstop solutions (the solutions can be generation, DR, or transmission, or combinations). The need is primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City that is affected by state legislation for emissions limits, known as The Peaker Rule.[43]
- Driven by public polices, new supply, load, and transmission projects are seeking to interconnect to the grid at record levels. NYISO's interconnection process balances developer needs with grid reliability. Efforts are underway to make this process more efficient while protecting grid reliability. New transmission is being built, but more investment is necessary to support the delivery of offshore wind energy to connect new resources upstate to downstate load centers where demand is greatest. Planning for new transmission to support offshore wind is underway.
- To achieve the mandates of the CLCPA, new emission-free supply with the necessary reliability services will be needed to replace the capabilities of today's generation. These types of resources must be significant in capacity and have attributes like the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid and steep ramping requirements. Such new emission-free supply is not yet available on a commercial scale.
- New wholesale electricity market rules are supporting the grid in transition. These markets are critical for a reliable transition. Wholesale electricity markets are open to significant investment in wind, solar, and BESS. Peak load management needs to be integrated as a measure to facilitate achievement of CLCPA targets. By lowering peak load and avoiding system buildout to serve the highest demand hour, less dispatchable emission-free resource build-out will be needed and fewer fossil fuel-fired plants will be needed to meet lower peaks during the transition.

NPCC-New York Fuel Composition										
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Petroleum	2,632	2,632	2,632	2,632	2,632	2,632	2,632	2,632	2,632	2,632
Natural Gas	22,384	21,794	21,794	21,794	21,794	21,794	21,794	21,794	21,794	21,794
Biomass	330	330	330	330	330	330	330	330	330	330
Solar	379	803	814	814	814	814	814	814	814	814
Wind	490	533	533	533	533	533	533	533	533	533
Conventional Hydro	3,305	3,305	3,305	3,305	3,305	3,305	3,305	3,305	3,305	3,305
Run of River Hydro	379	379	379	379	379	379	379	379	379	379
Pumped Storage	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407
Nuclear	3,305	3,305	3,305	3,305	3,305	3,305	3,305	3,305	3,305	3,305
Battery	20	20	20	20	20	20	20	20	20	20
Total MW	34,631	34,507	34,518	34,518	34,518	34,518	34,518	34,518	34,518	34,518

[43] New York Department of Environmental Conservation Peaker Rule

NPCC-New York Assessment

Planning Reserve Margins

The LTRA Planning Reserve Margins are above 15% throughout the 10-year assessment period; however, the system margins are narrowing. Wind, grid-connected solar, and run-of-river totals were derated for the LTRA calculation. Under its reliability planning processes, NYISO uses probabilistic assessments to evaluate the system's resource adequacy against the LOLE resource adequacy criterion of no greater than 0.1 event-days/year probability of unplanned load loss. NYISO's *2022 Reliability Needs Assessment*, completed on November 2022, identified that the New York Control Area (NYCA) LOLE is below its "one day in 10 years" criterion for the 10-year study period.

NYISO also provides support to the New York State Reliability Council (NYSRC) in conducting an annual IRM[44] study. This study determines the IRM for the upcoming capability year (May 1 through April 30). The IRM is used to quantify the capacity required to meet the NPCC and NYSRC resource adequacy criterion of "one day in 10 years." The current IRM for the 2023–2024 capability year is 20% of the forecasted NYCA peak load. All values in the IRM calculation are based upon full installed capacity values of resources. The IRM has varied historically from 15% to 20.7%. Additionally, NYISO performs an annual study to identify the locational minimum installed capacity requirements[45] for the upcoming capability year.

Energy Assessment, Including Non-Peak Hour Risk

The Climate Leadership and Community Protection Act decarbonization targets span over all major industries and are a main driver for the electric system changes. NYISO staff in system operations, planning, and markets will continue to assess the system changes to prepare for the grid's transformation.

With high penetration of renewable intermittent resources, dispatchable emission-free resources and long-duration resources are needed to balance intermittent supply with demand. These types of resources must be significant in capacity and have attributes, such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. Additionally, although new transmission is being built, more investment is necessary to support the delivery of offshore wind energy and to connect new resources upstate to downstate load centers where demand is greatest.

NYISO performs long-range energy assessments (10-year and beyond) in the is accounted for in the 8,760 hours per year simulations in the resource adequacy studies as part of the RPP and the production cost simulations as part of the system and resource outlook study.

NYISO Grid Operations performs or assists in performing energy assessments, including, but not limited to, a fuel and energy security study and ongoing assessments, a study that assesses potential impacts related to climate change, and weekly analysis based on the results of reporting by generation resources through NYISO's Generator and Fuel Emissions Reporting data portal. NYISO grid operations also performs an internal energy analysis at least weekly based on data and information reported by supply resources through NYISO Generator and Fuel Emissions Reporting system. Resources provide data and information on an annual, weekly, and as needed basis considering system operating conditions. This analysis has the capability to analyze the impact of changes in stored fuel inventory, resource outages, fuel supply disruptions, transmission constraints, and other relevant conditions that may adversely impact fuel and energy security. Additionally, the New York City and Long Island areas have a loss of gas supply dual-fuel requirement and certain combined-cycle natural gas units participate in a Minimum Oil Burn program. While oil accounts for a relatively small percentage of the total energy production in New York, it is often called upon to fuel generation during critical periods, such as when severe cold weather limits access to natural gas.

Probabilistic Assessments (NERC ProbA and other studies)

NYISO performs probabilistic assessments by using General Electric's Multi-Area Reliability Simulation (MARS) as part of its reliability planning processes as well as to determine annual Locational Minimum Installed Capacity Requirements (LCR). NYISO also pursued capacity accreditation market rules to more accurately reflect capacity market suppliers' contributions to resource adequacy. These new market rules align compensation for capacity suppliers with an individual resource's expected reliability benefit to consumers and uses the probabilistic models from the LCR process to define capacity accreditation factors for various capacity accreditation resource classes. The groundbreaking proposal was accepted by FERC in May 2022. The capacity accreditation factors will reflect the marginal reliability contribution of the installed capacity suppliers within each capacity accreditation resource class toward meeting NYSRC resource adequacy requirements for the upcoming capability year, starting with the capability year that begins in May 2024.

[44] NYSRC IRM Study
[45] LCRs

Additionally, every other year, each Regional Entity provides results for NERC's ProbA process; the results from the ProbA performed in 2022 by NPCC appear below.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	6.837	0.091	0.059
EUE (PPM)	0.046	0.001	0.00
LOLH (hours per Year)	0.029	0.00	0.00
Operable On-Peak Margin	11.3%	11.6%	16.7%

* Provides the 2022 ProbA Results for Comparison

NPCC's Directory 1 defines a compliance obligation for NYISO, as Resource Planner and Planning Coordinator, to perform a resource adequacy study evaluating a five-year planning period. NYISO delivers a report every year under this study process to verify the system against the one-day-in-ten-years LOLE criterion, usually based on NYISO's latest available reliability assessment results and assumptions. NYSRC Reliability Rules have recently included a requirement that defines NYISO's obligation to deliver a *Long-Term Resource Adequacy Assessment Report* every *Reliability Needs Assessment Report* year and an annual update in the non-RNA years.

Demand

NYISO employs a multi-stage process to develop load forecasts for each of the 11 zones within the NYCA. The impacts of net electricity consumption of energy storage resources due to charging and discharging are added to the energy forecasts while the peak-reducing impacts of BTM energy storage resources are deducted from the peak forecasts.

Currently, the NYCA summer peak typically occurs in late afternoon. The NYCA summer peak will likely shift into the evening as additional BTM solar PV is added to the system and as EV charging impacts increase during the evening hours. Because the hour of the summer peak shifts into the evening over the course of the assessment period, BTM solar PV generation becomes less coincident with the NYCA peak hour, and BTM solar PV coincident peak reductions are forecasted to decrease in later years. The forecast of solar PV-related reductions to the winter peak is zero because the system typically peaks after sunset.

Trended weather conditions from the *Climate Impact Study Phase I* report are included in NYISO's end-use models and are reflected in the baseline, policy scenario, and percentile forecasts. NYISO develops 90th and 99th percentile forecasts to account for the impacts of extreme weather on seasonal peak demand and calculates 10th percentile forecasts to represent milder seasonal peak conditions.

The ten-year annual average energy (+1.0%) and summer peak demand (+0.5%) growth rates are higher than last year's forecast. Increases in growth rates relative to the prior forecast are primarily attributed to increased large load projects and EV charging impacts, including greater coincidence with periods of peak electricity demand. Baseline energy and coincident peak demand increase significantly throughout the 30-year forecast period, largely by high load project growth in the early forecast years and electrification of space heating, non-weather sensitive appliances, and electric vehicle charging in the outer forecast years. New York is projected to become winter peaking in future decades due to space heating electrification and electric vehicle penetration.

Demand-Side Management

NYISO will develop market concepts to encourage the participation of flexible load; this will become increasingly important as the levels of weather-dependent intermittent resources on New York's grid increases in response to the state's climate and clean energy policies. Many New York utilities are piloting several load management programs (e.g., smart EV charging, home-thermostat use, and the integration of BTM storage for local peak demand modulation. As part of NYISO's annual long-term forecasting process, the impacts of these programs are discussed and significant impacts on demand are included in the load forecast.

For the *2023 LTRA Report*, the DR participation for the summer capability period has increased slightly from 1,170 MW to 1,234 MW. There are currently 307 MW of DR participating in ancillary services programs to provide either 10-minute spinning reserves or 30-minute non-synchronous reserves.

Distributed Energy Resources

NYISO is currently implementing a plan to integrate DERs, including DR resources, into the markets it administers. The DER Participation Model project aims to enhance DER participation in competitive wholesale markets. These measures closely align the bidding and performance measurements for DERs with the rules for generators. The measures establish a state-of-the-art model that is largely consistent with the market design envisioned by FERC in its Order 2222. This project, which began in 2017, will provide a single participation model for DER DR resources to provide energy, ancillary services, and installed capacity through an aggregation. The market rules for the DER and aggregation participation model were accepted by FERC in January 2020. NYISO filed additional proposed tariff revisions with FERC in June 2023 to clarify and enhance these market rules. NYISO is currently developing software associated with these tariff revisions and anticipates deploying its DER participation model in 2023.

Generation

The pace of renewable project development and existing generation retirement is unprecedented and driving a need to increase the pace of transmission, new clean dispatchable generation, and demand management programs development. In general, resource and transmission expansion take many years from development to deployment. Coordination of project additions and retirements is essential to maintaining reliability and achieving policy. Significant new resource development will be required to achieve CLCPA energy targets. The total installed generation capacity to meet policy objectives within New York is projected to range between 111 GW and 124 GW by 2040. At least 95 GW of this capacity will consist of new generation projects and/or modifications to existing plants. Even with these additions, New York still may not be sufficient to maintain the reliable electricity supply. The sheer scale of resources needed to satisfy system reliability and policy requirements within the next 20 years is unprecedented.

To achieve an emission-free grid, dispatchable emission-free resources (DEFR) must be developed and deployed throughout New York. DEFRs that provide sustained on-demand power and system stability will be essential to meeting policy objectives while maintaining a reliable electric grid. While essential to the grid of the future, such DEFR technologies are not commercially available today.

Essential reliability services usually provided for the system by synchronous fossil generation will continue to be necessary. New technology is being developed to allow for a reliable transition to a clean grid. Grid-forming inverter capabilities as well as DEFRs will likely be part of this transformation. On May 2023, the New York State Public Service Commission has initiated a process to examine the need for resources to ensure the reliability of the 2040 zero-emissions electric grid mandated by the CLCPA. Under this initiative, the Public Service Commission seeks to identify innovative technologies to ensure reliability of a zero emissions electric grid. Numerous other initiatives at both state and federal levels are in progress and will impact the grid of the future.

Additionally, NYISO's interconnection process contains a significant number of proposed projects in various stages of development with only a fraction in more advanced stages included in the reliability planning models.

Energy Storage

Storage resources can help to fill in voids created by reduced output from renewable resources; however, sustained periods of reduced renewable generation can rapidly deplete storage capabilities. NYISO has implemented its Co-located Storage Resources model to allow wind or solar resources that are interconnected with an energy storage resource the ability to participate in the markets while respecting a shared interconnection limitation. NYISO is developing a model for hybrid storage resources to allow multiple technologies at the same point of interconnection participate in the market as a single resource. Additionally, the resource adequacy simulation tools (e.g., GE's MARS) used in system planning and for setting the IRMs were enhanced to include energy limited resources models that allow for charging and discharging and also include temporal constraints (*e.g.,* hours/days or hours/month).

Capacity Transfers

The models used for NYISO reliability planning studies include firm capacity transactions (purchases and sales) with the neighboring systems as a base case assumption. Proposed projects that are in a more advanced stage are included. One such project is the 1,250 MW HVDC line from Québec into New York City, which is reflected in the LTRA summer total transfers starting in 2026. Additionally, the probabilistic model used in the RPP to assess the adequacy of resources employs a number of methods that are aimed at preventing overreliance on the external systems support (e.g., limiting emergency assistance from neighbors by modeling a total limit of 3,500 MW, modeling simultaneous peak days, modeling the long-term purchases and sales with neighboring control areas, not modeling emergency operating procedure steps for the neighbors, etc.). As the energy policies in neighboring areas evolve, New York's energy imports and exports could vary significantly due to the resulting changes in neighboring grids. New York is fortunate to have strong interconnections with neighboring areas and has enjoyed reliability and economic benefits from such connections. The availability of energy for interchange is predicted to shift fundamentally as policy achievement progresses. Balancing the need to serve demand reliably while achieving New York's emission-free target will require continuous monitoring and collaboration with neighboring states.

Transmission

Significant new transmission is being built across New York, but more investment is necessary to support, among other things, the delivery of offshore wind energy to connect new resources upstate to downstate load centers where demand is greatest. Key transmission projects under development and accounted for in the reliability models include the following:

- New York Power Authority/National Grid's Northern New York Priority Transmission Project upgrading the transmission corridors from the renewable generation pocket in the north country to central NY
- The 1,250 MW Champlain-Hudson Power Express HVDC line from Hydro Québec to New York City
- The AC Public Policy Transmission Projects: upgrading transmission corridors on central NY and lower Hudson Valley (These projects target completion of the majority of the components by December 2023.)

Additionally, there are significant transmission projects either recently selected or under study that are not yet in the reliability model, including the following:

- New York Power Authority/New York Transco project selected by NYISO's Board of Directors to meet the Long Island offshore wind export public policy transmission need.
- PSC recently declared a new Public Policy Transmission Planning Need that is intended to support the integration of 4.7 GW of wind resources in New York City.
- Con Edison's proposed Brooklyn Hub project includes a new 345 kV load serving substation that is reported to potentially serve as a point-of-interconnection for up to 1,500 megawatts (MW) of offshore wind power.

Furthermore, NYISO will also be part of the Transmission Owners' Coordinated Grid Planning Process. The NY Utilities proposal was filed with PSC on December 27, 2022. The PSC initiated a proceeding to develop an integrated planning process that identifies and constructs local transmission and distribution infrastructure solutions in coordination with any necessary bulk transmission infrastructure expansion, throughout New York to support the optimal deployment of investments.

Reliability Issues

The *2022 RNA*, completed in November 2022, identified no reliability needs for the study period 2026–2032. However, NYISO found that the system margins are very narrow in certain locations, such as New York City, for parts of the study period. The 2023 Q2 STAR was completed on July 14, 2023.[46] This assessment finds a reliability need beginning in summer 2025 in New York City that is primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City that is affected by the Peaker Rule. The reliability need is a deficiency in the transmission security margin that accounts for expected generator availability, transmission limitations, and updated demand forecasts with data published in the 2023 Gold Book. Specifically, the New York City zone is deficient by as much as 446 MW for a duration of nine hours on the peak day during expected weather conditions (95 degrees Fahrenheit) when accounting for forecasted economic growth and policy-driven increases in demand. Solutions to this need are being evaluated in accordance with the NYISO Short-Term Reliability Process.

The transition to a cleaner grid in New York is leading to an electric system that is increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation. Reliability margins are shrinking. Generators needed for ERSs are planning to retire. Delays in the construction of new supply and transmission, higher than expected demand, and extreme weather could threaten reliability and resilience in the future. A successful transition of the electric system requires replacing the reliability attributes of existing fossil-fueled generation with clean resources with similar capabilities. Such resources must be significant in capacity and have attributes like the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid and steep ramping needs. These attributes are critical to a dynamic and reliable future grid. New transmission is being built but more investment is necessary to support the delivery of offshore wind energy to connect new resources located in upstate to downstate load centers where demand is greatest. Planning for new transmission to support offshore wind is underway.

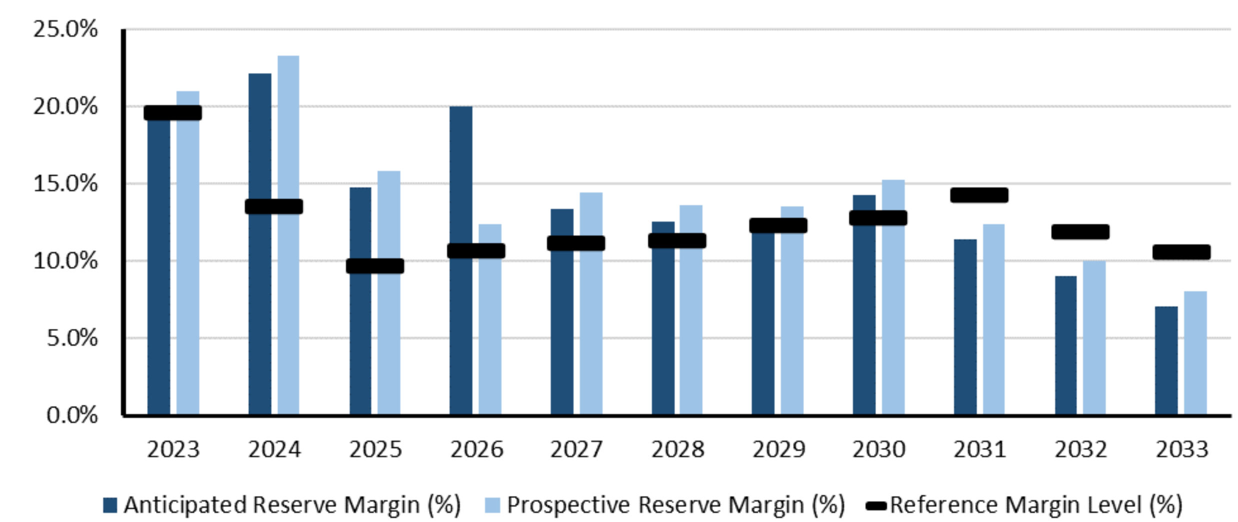
[46] 2023 Q2 STAR Report

NPCC-Ontario

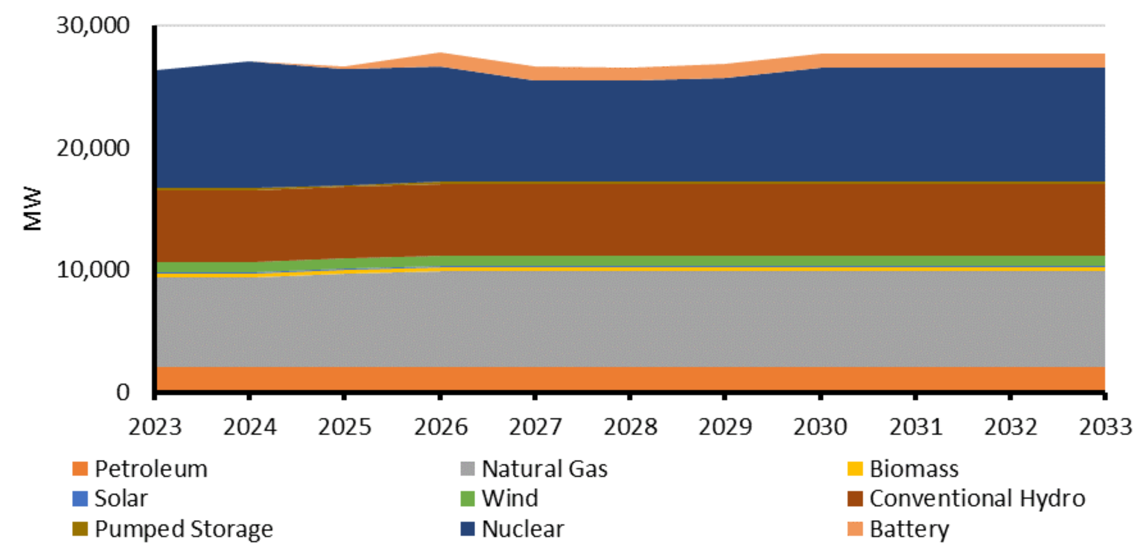
NPCC-Ontario is an assessment area in the Ontario province of Canada. IESO is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 15 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York. See **Elevated Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	23,236	24,321	24,217	24,460	24,695	24,953	25,295	25,928	25,928	26,387
Demand Response	1,022	544	544	544	544	544	544	544	544	544
Net Internal Demand	22,214	23,777	23,673	23,916	24,151	24,409	24,751	25,384	25,384	25,843
Additions: Tier 1	10	513	1,635	1,635	1,635	1,917	1,917	1,917	1,917	1,917
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	0	600	600	500	600	600	600	600	0	0
Existing-Certain and Net Firm Transfers	27,124	26,780	26,780	25,487	25,555	25,555	26,364	26,355	25,755	25,755
Anticipated Reserve Margin (%)	22.1%	14.8%	20.0%	13.4%	12.6%	12.6%	14.3%	11.4%	9.0%	7.1%
Prospective Reserve Margin (%)	23.3%	15.8%	12.4%	14.5%	13.6%	13.6%	15.3%	12.4%	10.0%	8.0%
Reference Margin Level (%)	13.5%	9.7%	10.7%	11.2%	11.3%	12.3%	12.8%	14.2%	11.9%	10.6%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The IESO is taking action to secure resources that address reserve margin shortfalls forecast for 2031 that are driven by nuclear retirements, refurbishments, and overall demand growth. The IESO is doing this in part through a mix of long-term contracts for new builds, medium-term contracts for existing resources, and an Annual Capacity Auction. In 2023, the IESO procured new storage resources and upgrades to natural-gas-fired generators and will continue this procurement cycle over the next few years by seeking long-term contracts for both energy and capacity.
- In August 2023, Ontario and Québec signed a memorandum of understanding for the swap of 600 MW of capacity for up to 10 years. Under the proposed electricity trade agreement, the IESO and Hydro-Québec will carry out an annual capacity swap of 600 MW that will help address their respective peak season demands. The agreement is expected to come into effect in winter 2024–2025.
- The IESO is also responsible for implementing new provincial policy as outlined in the Ontario government's *Powering Ontario Growth*, which includes developing new nuclear projects, transmission expansions, and expanded conservation and demand management programs.
- With the recent federal release of draft clean electricity regulations, the IESO is reviewing and will incorporate changes into future planning products, starting with revised supply assumptions in the 2023 Annual Planning Outlook.

NPCC-Ontario Fuel Composition										
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Petroleum	2,107	2,107	2,107	2,107	2,107	2,107	2,107	2,107	2,107	2,107
Natural Gas	7,337	7,617	7,856	7,856	7,856	7,856	7,856	7,856	7,856	7,856
Biomass	299	299	299	299	299	299	299	299	299	299
Solar	91	91	91	91	91	91	91	91	91	91
Wind	801	801	801	801	801	801	801	801	801	801
Conventional Hydro	5,930	5,930	5,930	5,930	5,930	5,930	5,930	5,930	5,930	5,930
Pumped Storage	118	118	118	118	118	118	118	118	118	118
Nuclear	10,450	9,506	9,506	8,313	8,280	8,562	9,372	9,363	9,363	9,363
Battery	0	223	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107
Total MW	27,133	26,693	27,815	26,622	26,590	26,872	27,681	27,673	27,673	27,673

NPCC-Ontario Assessment

Planning Reserve Margins

ARMs remain adequate for the first seven years of this assessment period. The IESO continues to actively procure resources to meet longer-term needs by using the mechanisms in the Resource Adequacy Framework.

Ongoing refurbishments at Bruce Nuclear Generating Station and Darlington Nuclear Generating Station will see between one and three reactors concurrently off-line through 2033. Refurbishments remain on or ahead of schedule, and outages continue to be managed to limit impacts to the grid. Currently, a request is before the federal nuclear regulator to construct and operate a 300 MW small modular reactor at Darlington by 2028.

The Ontario government has also announced a plan to deliver new small modular reactors and examine new large-scale nuclear generators. The release of *Powering Ontario's Growth* by the provincial government in July 2023 directed the IESO to conduct an impact assessment on potentially adding 4,800 MW of large-scale nuclear capacity to Bruce and three additional 300 MW SMRs at Darlington. While Pickering Nuclear Generation Station is scheduled for decommissioning in 2025, approval is being sought to extend operation through September 2026. The Ministry of Energy has also requested a feasibility assessment on the potential for refurbishing four units at Pickering NGS. The plant operator is conducting a comprehensive technical examination and aims to submit a final recommendation by the end of 2023.

The IESO's *2022 Annual Acquisition Report* identified a need for 4,000 MW of capacity emerging mid-decade, which the IESO is addressing through its Resource Adequacy Framework. The 2022 annual capacity auction secured 1,431 MW of summer and 1,160 MW of winter capacity. The 2022 Medium-Term Request for Proposal (RFP) secured 757 MW of supply from both existing natural gas and wind resources coming off contract; these resources will be available starting 2024–2026. Through long-term procurements, the IESO has acquired 319 MW through on-site natural gas expansions and 930 MW (3,720 MWh) of storage resources. In addition, the IESO has secured 286 MW in natural gas facility upgrades that have had their contracts extended.

Separately, Ontario has entered into an agreement with Oneida Energy Storage for a 250 MW (1,000 MWh) BESS facility expected to be in operation by summer 2026. The IESO has targeted securing 2,500 MW in capacity (1,600 NW storage and 900 MW non-storage) through its long-term RFP with expected commercial operation in 2028.

The IESO calculates the reserve margin requirement on an annual basis and publishes this in the Annual Planning Outlook.[47] The IESO calculates the reserve margin requirement for each year for net demand at the time of the annual demand peak to provide an LOLE that is at or below 0.1 days per year. The reserve margin requirement in the 2023 LTRA is derived from the capacity requirement in the 2022 *Annual Planning Outlook*[48]

Energy Assessment and Non-Peak Hour Risk

Energy adequacy assessments are conducted annually for the annual planning outlook by using a deterministic approach in the IESO's economic dispatch model. Should Pickering Nuclear Generating Station retire 2024–2025, increased adequacy risks are expected; however, an extension to 2026 would help alleviate these risks until 2027, when unserved energy is forecast to be 1.09 TWh.

The IESO now assesses capacity adequacy accounting for both peak and non-peak load hours to form a more comprehensive assessment. Generally, summer hours represent the highest probability of load loss, but actual hourly profiles change yearly. The IESO's first round of long-term procurements is securing resources that can provide energy at least four hours at a time.

Looking forward, the federal government has proposed Clean Energy Regulations to decarbonize Canada's electric system by 2035. The IESO is assessing the current role of natural gas generation as a flexible resource in the interim as it introduces new sources of non-emitting supply to the system.

Future annual planning outlooks will continue to highlight deficits in capacity and energy as Ontario works toward decarbonization targets and procurements with the regular cadence outlined in the Resource Adequacy Framework.

Probabilistic Assessments

No probabilistic assessment has been performed since 2022 but will occur later this year by both the IESO and NPCC. However, risks will have decreased compared with 2022 due to procurements, nuclear units being extended, and refurbishments coming in on time or ahead of schedule.

[47] Planning and Forecasting Annual Planning Outlook

[48] 2022 Annual Planning Outlook Data Tables

Base Case Summary of Results (2022 ProbA)			
	2024*	2024	2026
EUE (MWh)	0.049	0.00	72.164
EUE (PPM)	0.00	0.00	0.492
LOLH (hours per Year)	0.001	0.00	0.442
Operable On-Peak Margin	4.4%	7.9%	-6.7%

* Provides the 2020 ProbA Results for Comparison

Demand

Forecasted demand over the 10-year study period increased by 5% and 10% in summer and winter, respectively, after the preliminary LTRA data submission. Increased demand for electricity is being driven by population growth, economic expansion, and increased penetration of electric devices. Offsetting this growth are conservation, electricity price responsiveness, and increased output by embedded generation. Overall, demand is ramping up more quickly than in 2022 due to government policy on decarbonization. Notable increases in demand arise from growth in the greenhouse sector, use of industrial electric arc furnaces, EVs, BESS manufacturing operations, and new mines.

Ontario continues to be summer peaking through the forecast period. The IESO's Industrial Conservation Initiative acts as a critical peak-pricing program and is expected to reduce around 1,300 MW on the system peak hour of the top five system peak days and 650 MW on the second top-five days (days 6-10). It is expected to scale based on increased industrial growth in future years. Over this assessment period, the IESO projects the total internal demand growth to increase at a CAGR of 1.42% for summer and 1.59% for winter.

Demand-Side Management

Capacity auction resources consist mainly of DR followed by generation and imports. Beginning this year, the IESO is introducing a qualification process that will apply resource-specific methodologies to determine the unforced capacity for each resource is able to offer into the auction.

In 2023, the IESO implemented new programs designed to grow Ontario's DR capability, particularly during the peak summer months. The Peak Perks program is targeted at residential customers while a new industrial pilot is designed to identify events in advance that large load customers can respond to effectively to reduce their exposure to capacity charges.

The 2021–2024 Conservation and Demand Management Framework managed by the IESO continues with increased budget and additional savings. Incremental savings are included in the overall demand forecast but remain in line with 2021–2024 levels. An EE auction pilot secured peak demand reductions of 7.4 MW for winter 2022–2023 and 6.6 MW for summer 2023. Typically, EE measures persist for years.

Distributed Energy Resources

The IESO estimates that contracted DERs contributed more than 3,400 MW of capacity and 5.3 TWh of energy in 2022, more than half of which is solar PV, one-third wind and modest contributions from hydroelectric and biomass resources. While IESO has little insight into uncontracted DERs, it has observed energy contributions of approximately 2 TWh in 2022.

Generation

Recent generation procurements are provided in the Planning Reserve Margin section.

IESO has initiated implementation of new technologies, processes, and more dynamic tools to support the operation of the transforming grid with more diverse resource types and a more complex transmission system.

The IESO's 2022 *Pathways to Decarbonization* report included a limited assessment of the ability of Ontario's resource portfolios to manage a variety of conditions in real time. Further areas to explore include the sufficiency of the studies' resource mix to provide inertia and primary frequency response, operating reserve, ramping capability and reactive support, and voltage control. The IESO is also investigating implications of increased penetration of variable resources on the system.

The IESO-controlled grid will have sufficient system inertia and frequency response to ensure stable operation up to 2025. The IESO worked with the provincial regulator to amend the Distribution System Code, which was released in 2022 to include the requirements of the new IEEE 1547-2018 standard. This effort was to ensure all resources contribute, as needed, to maintain grid reliability. The IESO also acts in accordance with NERC Reliability Standards to ensure adequate warning is provided for generators coming off-contract that would adversely impact grid reliability. In such scenarios, Reliability-Must-Run contracts can be established to meet system needs.

Energy Storage

Recent storage procurements are provided in the Planning Reserve Margin section. Currently, storage resources in Ontario amount to only about 50 MW, excluding the Beck generating stations' overall capacity. Some storage provides capacity while the rest offer ancillary services. The Expedited Long-Term RFP procured 930 MW of storage for a commercial operation start date of May 1, 2026. The LT1 RFP process has targeted 1,600 MW of storage with a commercial operation date of May 1, 2028. Both procurements required storage resources to have a minimum four-hour duration.

Prevalent uses for existing storage include regulation services, reactive support and voltage control, energy market participation, and BTM peak shaving. Newly acquired energy storage facilities will be required to participate in Ontario's energy markets during peak hours. Non-committed storage is now able to participate in the annual capacity auctions and provide capacity and operating reserve. Market integration of hybrid storage-generation resources has been identified as a priority under the umbrella of projects within the enabling resources initiative, and stakeholder engagement is underway.

Capacity Transfers and External Assistance

Firm capacity imports and exports with neighboring jurisdictions are included in the IESO's planning studies, but the IESO assumes only a limited amount of imports for the purposes of its reliability assessments. The IESO also includes non-firm imports of 250 MW for summer and 240 MW for winter.

Although Ontario has been a net energy exporter for many years, exports are expected to decrease sharply with the retirement of Pickering Nuclear Generating Station and more units on outage. The area's most recent energy adequacy assessments suggest economic imports will increase, and Ontario could become a net energy importer throughout the refurbishment period.

As part of the capacity exchange agreement between Ontario and Québec, the IESO may call on a total of 500 MW of firm imports from Hydro-Québec over summer months prior to September 2030. The decision on when to call the capacity will be made in due course depending on the outcomes of the IESO's current procurement and the potential extension to Pickering Nuclear Generating Station operations.

Transmission

March 31, 2022, marked the in-service date for the expansion of the East–West Tie with the addition of a 230 kV double-circuit transmission line to provide the necessary transfer capability to meet capacity needs in the IESO's northwest area.

The IESO is reinforcing its bulk system in the province's Northeast with the development of three new transmission lines to support electrification of the steel industry as well as overall growth in the area.

A new double-circuit 230 kV transmission line from Chatham Transmission Station (TS) to Lakeshore TS will bring additional supply to the Windsor-Essex area and is expected to be completed by Q4 2025. It will also improve the ability for resources and bulk facilities to operate efficiently and maintain the existing interchange capability on the interconnection between Windsor and Detroit, Michigan. The IESO has recommended further reinforcement to support the area's medium-term needs, including an additional double-circuit 230 kV line from Lambton TS to Chatham TS, expected in-service by 2028, and a new 500 kV transmission line from Longwood TS to Lakeshore TS to be in service by 2030.

To reinforce the Peterborough area, the IESO is developing a new double-circuit 230 kV transmission line with a planned in-service date of 2029. In addition to these new lines, additional refurbishment and upgrade projects are planned across the province to maintain reliability.

Reliability Issues

Nuclear refurbishment over the next decade is a major resource risk that requires additional attention. The IESO has regular meetings with nuclear operators to assess probable delays and take appropriate mitigation actions.

For long-term planning purposes, the IESO carries an additional level of reserve to account for these risks. It provides advanced outage approvals solely when Ontario is adequate under extreme weather. Ontario's reserves were below reserve margin requirements during most of summer 2023 due to planned generator outages, including nuclear, but the IESO managed this by either rejecting planned outages during this time if extreme weather materialized or used emergency control actions.

Other factors that may contribute to IESO reliability issues include supply chain issues, conditions in neighboring jurisdictions, extreme weather, decarbonization-driven changes to supply and demand, policy and regulatory uncertainty, asset health, forced outages, and potential market exit.

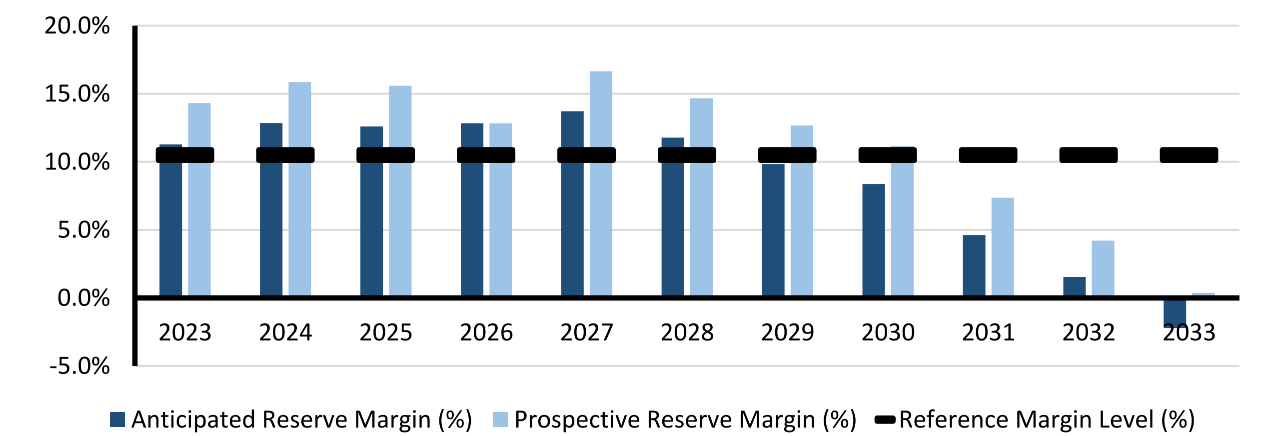
The IESO has not conducted specific assessments on critical infrastructure but does monitor performance of its natural gas facilities. More than 18% of natural-gas-fired generation has dual-fuel capability with on-site oil supply in winter for more than a day of operation. In the *2022 Annual Planning Outlook's* 20-year planning period, the risk for pipeline contingencies is low when calculating reserve margin. While the diverse supply mix helps improve resilience, the IESO will continue to monitor natural gas supply as demand leads to increased dependence on this resource, including for significant energy.

NPCC-Québec

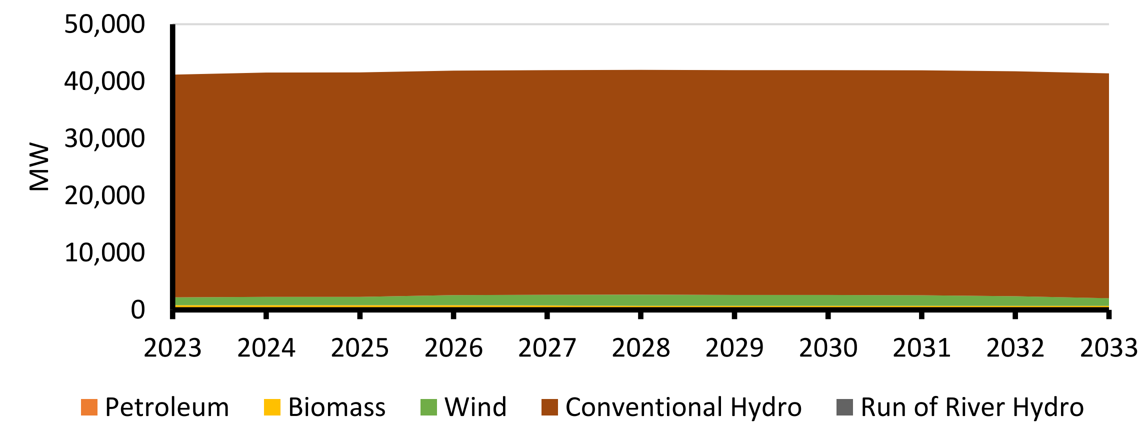
The Québec assessment area (Province of Québec) is a winter-peaking NPCC subregion that covers 595,391 square miles with a population of eight and a half million. Québec is one of the four NERC Interconnections in North America with ties to Ontario, New York, New England, and the Maritimes. These ties consist of either HVDC ties, radial generation, or load to and from neighboring systems. See **Normal Risk Areas** for more details.

Demand, Resources, and Reserve Margins[49]

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	41,036	41,488	41,946	42,468	43,377	44,062	44,776	45,569	46,627	47,820
Demand Response	4,452	4,732	4,896	5,068	5,258	5,322	5,377	5,389	5,389	5,389
Net Internal Demand	36,584	36,756	37,049	37,400	38,118	38,740	39,399	40,181	41,238	42,432
Additions: Tier 1	73	73	559	687	815	815	815	815	815	815
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-334	-245	-145	455	455	455	600	0	0	0
Existing-Certain and Net Firm Transfers	41,211	41,312	41,246	41,840	41,793	41,734	41,882	41,222	41,060	40,677
Anticipated Reserve Margin (%)	12.8%	12.6%	12.8%	13.7%	11.8%	9.8%	8.4%	4.6%	1.5%	-2.2%
Prospective Reserve Margin (%)	15.9%	15.6%	12.8%	16.7%	14.7%	12.7%	11.2%	7.4%	4.2%	0.4%
Reference Margin Level (%)	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%



Planning Reserve Margins



Existing and Tier 1 Resources

[49] The electric system in NPCC-Quebec

Highlights

- The ARM remains above the RML until 2029. However, the PRM is above the RML until 2031.
- Approximately 877 MW of capacity additions are expected over this assessment period. A total of 2,548 MW wind generation capacity (815 MW capacity value at peak time) is expected to be in service by 2029.
- The commissioning of the second Micoua-Saguenay 735 kV line is expected by the end of 2023.

NPCC- Québec Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Petroleum	429	429	429	429	429	429	429	429	429	429
Biomass	378	378	397	397	345	281	277	277	277	269
Solar	10	10	10	10	10	10	10	10	10	10
Wind	1,375	1,449	1,449	1,751	1,843	1,936	1,893	1,893	1,842	1,678
Conventional Hydro	38,975	39,269	39,275	39,280	39,317	39,354	39,354	39,354	39,362	39,362
Total MW	41,166	41,533	41,558	41,866	41,942	42,008	41,962	41,962	41,919	41,748

NPCC-Québec Assessment

Planning Reserve Margins

The ARM is based on existing and anticipated generating capacity and firm capacity transfers. It is above the area RML over this study period assessment except for the last five winter periods 2030–2034. However, the PRM remains above the RML for almost all years of this assessment. Under the Prospective scenario, a total of 1,100 MW of expected capacity supply is planned by the Québec area; this capacity could either be supplied by resources within the area or by imports. This capacity has not yet been backed by firm long-term contracts. However, based on its annual capacity needs, the Québec area proceeds with short-term capacity contracts to meet its capacity requirements.

Probabilistic Assessments

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	0.00	0.00	0.00
EUE (PPM)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
Operable On-Peak Margin	7.1%	-1.6%	-2.3%

* Provides the 2020 ProbA Results for Comparison

Demand

The requirements are obtained by adding transmission and distribution losses to the sales forecasts. The monthly peak demand is then calculated by applying load factors to each end-use and/or sector sale. The sum of these monthly end-use sector peak demands is the total monthly peak demand. The Québec area demand forecast average annual growth is 1.2% during this assessment period.

Demand-Side Management

The Québec area has various types of DR resources specifically designed for peak shaving during winter operating periods. The first type of DR resource is the interruptible load program that is mainly designed for large industrial customers; it has an impact of 2,790 MW on winter 2023–2024 peak demand. The area is also expanding its existing interruptible load program for commercial buildings that will grow from 568 MW in 2023–2024 to 889 MW by the end of this assessment period. Another similar program for residential customers is in operation and should gradually rise from 96 MW for winter 2023–2024 to 621 MW for winter 2028–2029 and continue to grow in later years.

New dynamic rate options for residential and small commercial or institutional customers will also contribute to reducing peak load during winter periods by 297 MW for winter 2023–2024and 445 MW for winter 2033–2034.

Moreover, data centers specialized in blockchain applications are required to reduce their demand during peak hours at Hydro-Québec's request. Their contribution as a resource is expected to be around 269 MW over this assessment period.

Finally, another DR resource consists in a voltage reduction scheme allowing for a 250 MW peak demand reduction.

EE and conservation programs are integrated in the assessment area's demand forecasts.

Distributed Energy Resources

Total installed BTM capacity (solar PV) is expected to increase to more than 718 MW in 2034. Solar PV is accounted for in the load forecast. Nevertheless, since Québec is a winter-peaking area, solar PV on-peak contribution ranges from 1 MW for winter 2023–2024 to 5 MW for winter 2033–2034.

Generation

Four wind generation projects are expected to be in service during this assessment period for a total of 2,548 MW of installed capacity (815 MW on-peak value). The first project, Apuiat (204 MW), is expected to be in service in 2024–2025. The second project, Des neiges (1,200 MW), is divided into three phases. The first phase (400 MW) is expected to be in service for the 2026–2027 winter period. The second and third phase with the same capacity (400 MW each) are expected to be in service for the 2027–2028 and 2028–2029 winter periods, respectively. The third and last project is the 2021 call for tenders for a total of 1,144 MW of wind, and it is expected to be in service in December 2026.

The integration of small hydro unit accounts for 41 MW new capacity during this assessment period.

Capacity Transfers and External Assistance

The governments of Québec and Ontario have signed a Memorandum of Understanding (MOU) of an Agreement that allows a seasonal capacity exchange between the two areas for the next seven years except for the year 2027 (no exchange is allowed). The technical details of the Agreement will be completed by the next Fall (2024). The agreement will start from winter 2024–2025 to winter 2030–2031. This agreement will be firm and allow the Québec area to import 600 MW from November to April. In the summer season, Québec will export 600 MW of firm capacity to Ontario from May to October.

Transmission

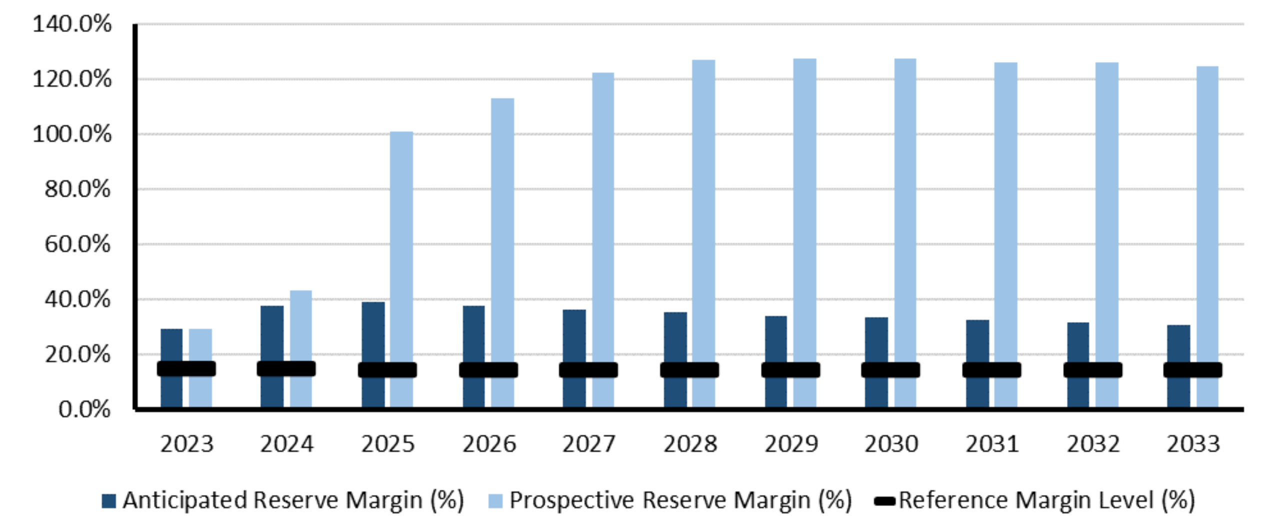
- **The Micoua-Saguenay 735-kV Line**
  Hydro-Québec has identified the need to build a new 735 kV line that extends 262 km (163 miles) between Micoua substation in the Côte-Nord region and Saguenay substation in Saguenay–Lac–Saint-Jean. The project also includes adding equipment to both substations and expanding Saguenay substation. This project is now under construction and is expected to be in service in 2023.
- **Appalaches-Maine Interconnection**
  This project to increase transfer capability between Québec and Maine by 1,200 MW is in the construction phase. The project will connect to the New England Clean Energy Connect project in Maine. It involves the construction of a ±320-kV DC transmission line about 100 km (62 miles) long from Des Appalaches 735/230-kV substation to the Canada–United States border. From the international border crossing, the dc transmission line will be extended 145 miles to a substation in Lewinston, ME, where the power will be converted from dc to ac. The project in Québec also includes the construction of an ac to dc converter at Des Appalaches substation and triggers the need of thermally upgrading two 735 kV lines in the south of the system. The first thermal upgrade was completed in 2022 and the second one is expected to be completed in 2023. The planned in-service date of the interconnection project is under review.
- **Hertel-New York Interconnection**
  This project to increase transfer capability between Québec and New York by 1,250 MW is currently in the permitting phase. It involves the construction of a ±400 kV DC underground transmission line about 60 km (37 miles) long from Hertel 735/315 kV substation just south of Montréal to the Canada–United States border. The project will connect to the Champlain Hudson Power Express project in New York State. From the international border crossing, the dc transmission line will be extended 339 miles to a substation in Astoria, NY, where the power will be converted from dc to ac. The project in Québec also includes the construction of an ac to dc converter at Hertel substation. The project is expected to be in service in May 2026.

PJM

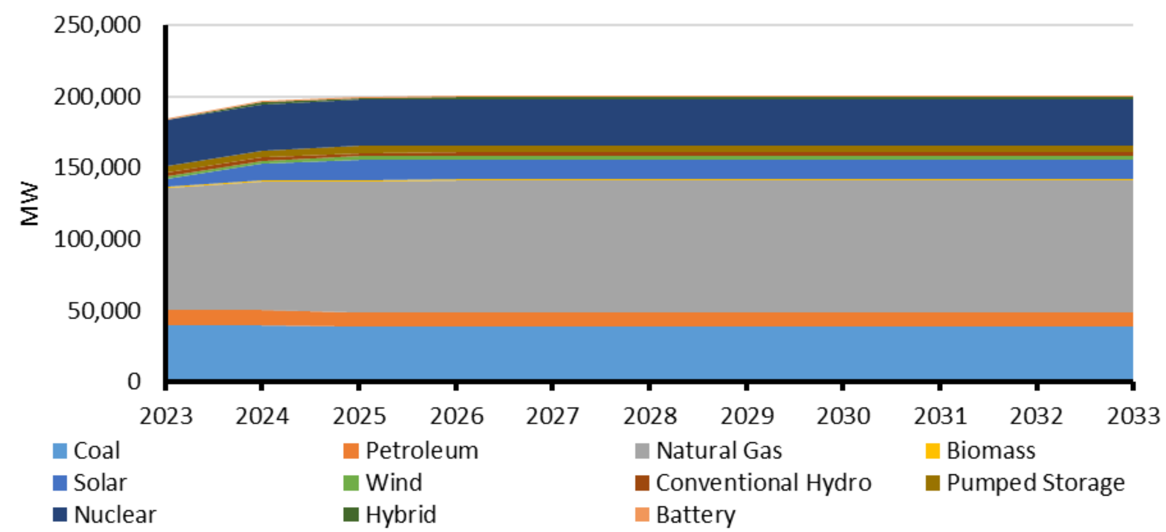
PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator. See **Normal Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	149,737	150,924	152,736	154,275	155,703	156,923	157,899	158,942	159,917	160,971
Demand Response	7,397	7,453	7,515	7,573	7,617	7,646	7,679	7,710	7,731	7,758
Net Internal Demand	142,340	143,471	145,221	146,702	148,086	149,277	150,220	151,232	152,186	153,213
Additions: Tier 1	13,090	18,234	19,715	19,706	19,706	19,706	19,706	19,706	19,706	19,706
Additions: Tier 2	7,982	88,414	109,210	126,252	135,888	139,177	141,681	141,855	144,220	144,220
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-607	-105	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	181,614	180,346	179,338	179,324	179,324	179,324	179,324	179,324	179,324	179,324
Anticipated Reserve Margin (%)	36.8%	38.4%	37.1%	35.7%	34.4%	33.3%	32.5%	31.6%	30.8%	29.9%
Prospective Reserve Margin (%)	42.4%	100.0%	112.2%	121.7%	126.1%	126.5%	126.7%	125.3%	125.5%	124.0%
Reference Margin Level (%)	14.8%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM is above the RML for each year of the assessment period.
- As in other assessment areas, there is potential for resource adequacy risks to emerge in PJM during the later years of the assessment period and beyond. In February 2023, PJM published a report of its analysis of the future energy transition in PJM based on resource retirement, replacement, and electricity demand scenarios.[50] PJM found increasing reliability risks due to the potential for the timing of generator retirements to be misaligned with load growth and the arrival of new generation on the system. Trends toward higher demand, faster generator retirements, and slower resource entry could expose PJM to decreasing Planning Reserve Margins and reliability challenges from imbalanced resource composition and resource performance characteristics. Unlike the demand forecasts and resource projections in this LTRA, the PJM report used scenarios and modeling for its analysis.

PJM Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	39,921	38,648	38,238	38,238	38,238	38,238	38,238	38,238	38,238	38,238
Petroleum	10,206	10,039	10,039	10,039	10,039	10,039	10,039	10,039	10,039	10,039
Natural Gas	89,804	91,820	93,310	93,310	93,310	93,310	93,310	93,310	93,310	93,310
Biomass	928	931	930	930	930	930	930	930	930	930
Solar	11,802	14,135	13,402	13,386	13,386	13,386	13,386	13,386	13,386	13,386
Wind	1,963	2,527	2,605	2,601	2,601	2,601	2,601	2,601	2,601	2,601
Conventional Hydro	2,523	2,439	2,429	2,426	2,426	2,426	2,426	2,426	2,426	2,426
Pumped Storage	4,798	4,801	4,786	4,786	4,786	4,786	4,786	4,786	4,786	4,786
Nuclear	32,594	32,594	32,594	32,594	32,594	32,594	32,594	32,594	32,594	32,594
Hybrid	1,212	1,035	1,006	1,006	1,006	1,006	1,006	1,006	1,006	1,006
Battery	836	992	990	990	990	990	990	990	990	990
Total MW	196,587	199,960	200,329	200,305	200,305	200,305	200,305	200,305	200,305	200,305

[50] Energy Transition in PJM: Resource Retirements, Replacements, and Risks

PJM Assessment

Planning Reserve Margins

The ARM for each year in this assessment period does not fall below the RML in PJM. PJM has a normal risk of energy shortages.

Energy Assessment and Non-Peak Hour Risk

PJM is expecting a normal risk of experiencing periods of resources falling below required operating reserves during upcoming peak periods based on the *2022 PJM Reserve Requirement Study*. As indicated in the *2022 PJM Reserve Requirement Study*, PJM is forecasting around 30% installed reserves (including expected committed demand resources), which is well above the target IRM of 14.9% necessary to meet the 1-day-in-10-years LOLE criterion. Due to the relatively low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with most loss-of-load risk remains the hour with highest forecasted demand. Notwithstanding the above, to address potential future reliability concerns due to limitations associated with the performance of limited and variable resources, PJM's ELCC methodology calculates the reliability and energy contribution of limited and variable resources.

Probabilistic Assessments

Base Case Summary of Results			
	2024*	**2024**	**2026**
EUE (MWh)	0.00	0.00	0.00
EUE (PPM)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
Operable On-Peak Margin	29.0%	29.0%	28.0%

* Provides the 2020 ProbA Results for Comparison

Demand

The PJM Interconnection produces an independent peak load forecast of total internal demand by using econometric regression models with daily load as the dependent variable and independent variables including calendar effects, weather, economics, and end-use characteristics. PJM annually reviews load forecast methodology and implements changes when improvements are identified. For the 2021 load forecast, the major changes encompassed refinements to sector models and non-weather-sensitive load, both of which were first introduced with the 2020 load forecast.

Demand-Side Management

DR resources can participate in all PJM Markets–capacity, energy, and ancillary services.

Distributed Energy Resources

PJM expects 4,865 MW of solar PV DER at the time of the peak in 2028 and 7,109 MW in 2033. The effects of solar PV DER are included in the load forecast for PJM. No effect of solar PV DER is incorporated in the winter load forecast since winter expected peak occurs after sundown.

Generation

PJM's existing installed capacity reflects a fuel mix that is comprised of approximately 47% natural gas, 24% coal, and 18% nuclear. Hydro, wind, solar PV, oil, and waste fuels constitute the remaining 11%. A diverse generation portfolio reduces the system risk associated with fuel availability and reduces dispatch price volatility. Totaling over 78,000 MW of Capacity Interconnection Rights (CIRs), renewable fuels are changing the landscape of PJM's interconnection queue. Solar PV energy comprises 66% of the generation in PJM's interconnection queue, a 10% increase over the previous year. An increase in solar PV generation interconnection requests is attributable to state policies encouraging renewable generation.

Prior to 2021, the variable resource capacity value was set at a resource's average output over a defined number of summer peak load hours. This approach has two limitations: it weights the output over all hours equally, regardless of an individual hour's actual contribution to the annual loss-of-load risk; and it fails to recognize the saturation effect as the amount of intermittent resources in PJM increases. To address these two limitations, PJM performed analysis to assess the reliability value of intermittent resources by using an ELCC method. This more robust methodology recognizes the full value of a resource's output over high-load risk hours and also accounts for resources by using an ELCC methodology and also accounts for the saturation effect.

As part of the process to implement the ELCC, a proposal was developed: PJM now requires generation owners of ELCC resources to provide specific information about their resources. This information is used by PJM as input to its resource adequacy model. Pending FERC approval, the ELCC methodology will be applied to intermittent, limited-duration and hybrid resources beginning with the 2023/2024 delivery year.

Energy Storage

Energy storage development continues to grow in PJM. As solar PV generation increases across the PJM footprint, storage growth is expected to follow, particularly as part of co-located projects. Efficient grid operations in an era of rapid renewable energy resource growth will require increased electric system flexibility. Energy storage can help grid operators maintain stable power supply under varying wind and solar power output that is driven by weather conditions and unit outages and improve utilization levels of existing transmission facilities. PJM has worked with various companies and national laboratories to study storage use and to ensure that the PJM wholesale market can permit all forms of energy storage to participate. PJM recognizes that storage paired with renewables and transmission can optimize the delivery of power. To address the limited-duration issue, some developers are pairing storage with variable renewable generation, such as solar PV or wind, to create opportunistic revenue streams. The pairing is either co-located (in which the storage facility and the generator facility are sited on the same parcel of land, but each has its own connection to the grid) or is hybrid (in which the storage facility and generator share a common connection to the grid).

Today, storage resources are made up of pumped storage hydro for a total of nearly 4,000 MW as well as BESS and flywheel energy storage for a total of 300 MW. Pumped storage can participate in the PJM capacity, energy, regulation and reserves markets. Queued storage resources total over 34,000 MW of interconnection requests for CIRs.

Capacity Transfers and External Assistance

PJM does not rely on significant transfers to meet resource adequacy requirements. Maximum transfer (total transmission interchange capability) into PJM would amount to less than 2% of PJM's internal generation capability. At no time within this assessment period does the ARM get anywhere near 2%. PJM reliability would not be negatively affected if transfers were dropped to zero.

Transmission

The $2.4 billion of baseline transmission investment approved during 2022 continues to reflect the shifting dynamics driving transmission expansion. New large-scale transmission projects (345 kV and above) have become more uncommon as RTO load growth has fallen below 1%. Aging infrastructure, grid resilience, a shifting generation mix, and more localized reliability needs are now more frequently driving new system enhancements.

Reliability Issues

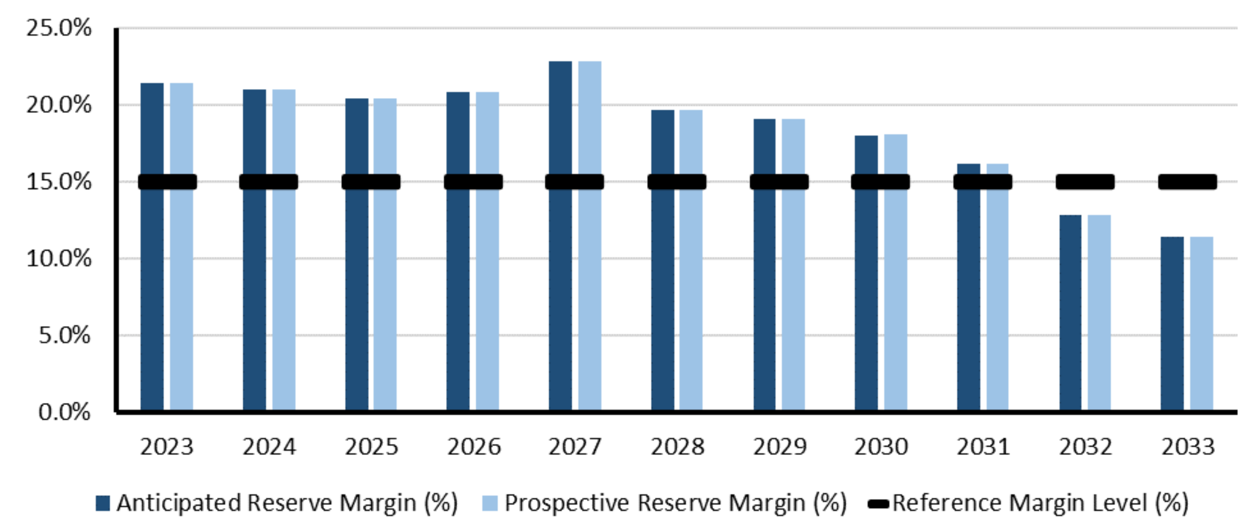
Offshore wind is emerging as a potential major source of power that is seeking grid interconnection along coastal states in the PJM area. Through September 2021, only two operational offshore wind farms in the United States have reached commercial operation: the 30 MW Block Island Wind Farm off the coast of Rhode Island and the 12 MW Coastal Virginia Offshore Wind Pilot Project near Virginia Beach. Although current operational capacity totals are low, offshore wind is expected to be a major contributor to U.S. clean energy and decarbonization initiatives over the coming decades.

SERC-East

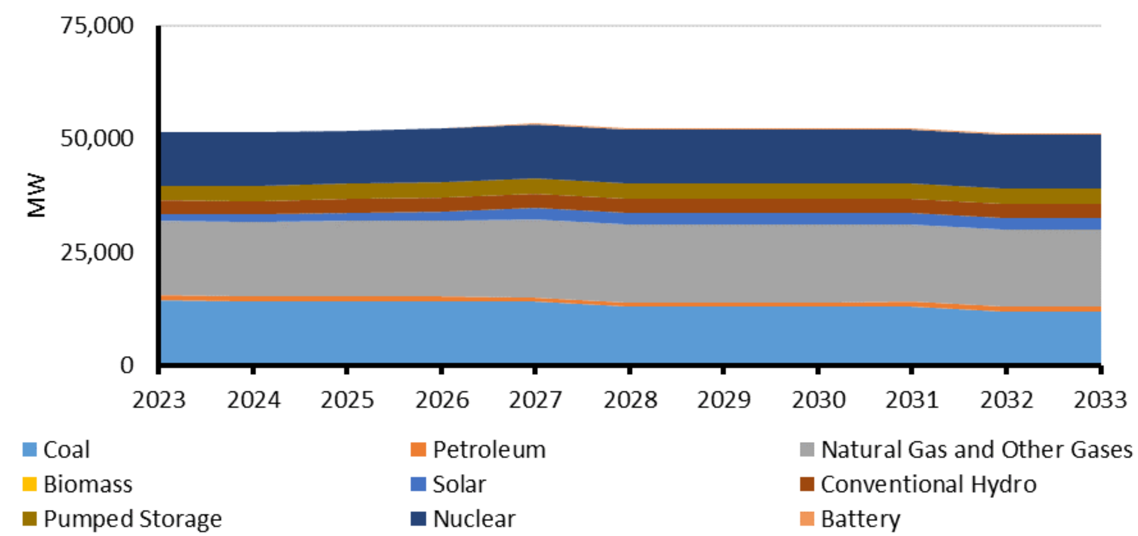
SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 34 Balancing Authorities, 27 PAs, and 7 RCs. See **Normal Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	44,014	44,590	44,789	44,993	45,220	45,425	45,831	46,583	46,985	47,580
Demand Response	983	989	996	1,003	1,006	1,007	1,008	1,009	1,010	1,011
Net Internal Demand	43,031	43,601	43,793	43,990	44,214	44,418	44,823	45,574	45,975	46,569
Additions: Tier 1	55	546	961	2,267	2,267	2,267	2,267	2,267	2,267	2,267
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	624	624	624	624	624	624	624	624	624	624
Existing-Certain and Net Firm Transfers	52,290	51,954	51,954	51,778	50,648	50,648	50,648	50,667	49,620	49,620
Anticipated Reserve Margin (%)	21.6%	20.4%	20.8%	22.9%	19.7%	19.1%	18.1%	16.1%	12.9%	11.4%
Prospective Reserve Margin (%)	21.6%	20.4%	20.8%	22.9%	19.7%	19.1%	18.1%	16.2%	12.9%	11.4%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- ARMs are above the RML through 2031.
- Natural gas (32%), coal (28%), and nuclear (23%) generation are the dominant fuel types within the assessment area. Hydro, renewables, and other fuel types make up the remaining (17%) generation.
- From 2023 to 2033, SERC-East will retire nearly 2.6 GW of coal generation. Tier 1 addition of 0.7 GW natural gas, 1 GW of BES-connected solar PV, and 0.4 GW BESS is expected during this time. At this time, 24 MW of utility-scale transmission BES-connected BESS. 350 MW of Tier 1 nameplate capacity BESS is expected within 10 years.
- Historically a summer peaking area, SERC-East is forecasting higher peak demands during winter months.
- The net non-coincident internal demand, which includes the available, controllable, and dispatchable DR for the assessment area is expected to grow annually at a rate of approximately 0.8% on average in the next 10 years.

SERC-East Generation Capacity by Fuel Type (Summer)										
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Coal	14,426	14,005	14,005	14,005	12,875	12,875	12,875	12,875	11,828	11,828
Petroleum	1,174	1,174	1,174	1,122	1,122	1,122	1,122	1,141	1,141	1,141
Natural Gas	16,227	16,718	16,718	16,970	16,970	16,970	16,970	16,970	16,970	16,970
Biomass	173	173	173	173	173	173	173	173	173	173
Solar	1,528	1,528	1,943	2,523	2,523	2,523	2,523	2,523	2,523	2,523
Conventional Hydro	3,030	3,115	3,115	3,115	3,115	3,115	3,115	3,115	3,115	3,115
Pumped Storage	3,364	3,364	3,364	3,364	3,364	3,364	3,364	3,364	3,364	3,364
Nuclear	11,789	11,789	11,789	11,789	11,789	11,789	11,789	11,789	11,789	11,789
Battery	11	11	11	361	361	361	361	361	361	361
Total MW	51,721	51,876	52,291	53,421	52,291	52,291	52,291	52,310	51,263	51,263

SERC-East Assessment

Planning Reserve Margins

SERC-East ARMs are above the RML during the first nine years of this assessment period.

Energy Assessment and Non-Peak Hour Risk

Entities are developing ways of evaluating energy risk and rely on production cost modeling to evaluate energy adequacy. Entities continue to identify generation resource constraints in operations planning. Some are developing probabilistic techniques to incorporate more variation of inputs, such as load, force outage rate, and renewable energy generation. The assessment area did not identify increased energy risks during the non-peak hours. However, ramping needs are increasing with the additional solar PV generation penetration.

Probabilistic Assessments

Base Case Summary of Results (2022 ProbA)			
	2024*	2024	2026
EUE (MWh)	5.26	64.33	92.49
EUE (PPM)	0.024	0.272	0.389
LOLH (hours per Year)	0.01	0.06	0.081
Operable On-Peak Margin	15.9%	15.0%	16.1%

* Provides the 2022 ProbA Results for Comparison

SERC-East is peaking during winter months. This is due to the addition of solar PV generation that shaves off summer peak demand and the observed trend toward electrification of heating that drives up winter peak demand. The reliability risk as indicated by the 2022 ProbA is projected to be stable. Higher winter peaks and/or lower supply of capacity during the early winter morning demand contributed to the increase in EUE metric values. The severe cold weather stress-test indicated that there is some risk of customer interruption and loss of energy in the case of combining unusual weather with higher-than-anticipated generator unit outages. The severe cold weather stress-test indicated that there is some risk of customer interruption and loss of energy in the case of combining unusual weather with higher-than-anticipated generator unit outages.

Demand

Historically a summer peaking area, SERC-East is forecasting higher peak demands during winter months. The net non-coincident internal demand, which includes the available, controllable, and dispatchable DR for the assessment area, is expected to grow annually at a rate of approximately 0.8% on average in the next 10 years.

Demand-Side Management

Entities use demand-side management programs to reduce load on the system during times of high peak demand. Seasonal load reduction capabilities for each individual participant are aggregated to determine the estimated program capacities that are available as dispatchable grid reliability resources. Program capacities are continually updated based upon changes in enrollment levels or application of newly acquired peak period data. A continued focus going forward for growth of existing programs and introduction of new programs is on maximizing winter capabilities. Heat strip load control programs can be used for mechanical winter peak reduction for customers. Though they are dependent on the thermostat manufacturer notification and usage rules, they provide the greatest benefit in terms of reduction with minimal customer discomfort. “Bring Your Own kW” programs allow small and medium business participants to compensate for load reduction through any methods they can employ. Electric vehicle managed charging is also being tested in the Carolinas. Other technologies to watch in the short term are Wi-Fi enabled water heaters and BTM storage. Further into the future, smart panels and smart inverters may provide value. Efforts to control voltage are also increasing.

Distributed Energy Resources

The DER resources are mainly solar PV projects. Entities include all future DER resources in their models which have a signed Interconnection Agreement. Any network upgrades associated with those projects are also included in the models. Entities study more light-load scenarios when solar PV resources will be near maximum and a large percentage of system load to reveal any possible transmission issues in that dispatch scenario. The DER forecasts are developed using economic models of payback, which is a function of installed cost, regulatory incentives and statutes, and bill savings. A relationship between payback and customer adoptions is developed through regression modeling, and the resulting regression equations are used to predict future customer adoptions based on projected payback curves. Customer size estimates based on historical adoption data are used to convert the future customer adoptions to capacity and hourly profiles are employed to yield the generation projections. The projected hourly generation from the DER forecasts is incorporated into the load forecasts as a load modifier, thus reducing the expected future load. As the BESS continue to grow, the DER forecasts will be enhanced to include separate projections of BTM solar PV only and BTM solar PV plus storage systems.

Generation

Natural gas (32%), coal (28%), and nuclear (23%) generation are the dominant fuel types within the SERC-East assessment area. Hydro, renewables, and other fuel types make up the remaining (17%) generation. SERC-East assessment area will retire nearly 2.6 GW of coal generation within the next 10 years. Tier 1 addition of 0.7 GW natural gas, 1 GW BES-connected solar PV, and 0.4 GW BESS is expected during this time.

Energy Storage

There is 11 MW of utility-scale transmission BES-connected BESS at this time. 350 MW of Tier 1 BESS is expected within 10 years.

Capacity Transfers and External Assistance

During high demand periods and the simultaneous unavailability of a severe and significant portion of generation, capacity transfer may be limited. Limited coal availability at coal plants located in specific areas of the system could also limit transfer capability. Entities will evaluate transmission projects and coordinate with neighboring TOPs/RCs to manage the interfaces and take needed actions such as generation redispatch, transmission reconfiguration, and TLRs.

Transmission

The assessment area will add another 46.7 miles within the first five years, followed by 0.3 mile in the next five years of new AC transmission lines with the voltage range between 100 to 200 kV. The assessment area will add another 173.6 miles within the first five years, followed by 43.1 miles in the next five years of new AC transmission lines with the voltage range between 200 to 300 kV. These projects are in the planning/construction phase and are projected to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability. Entities do not anticipate any transmission limitations or constraints with significant impacts to reliability.

Reliability Issues

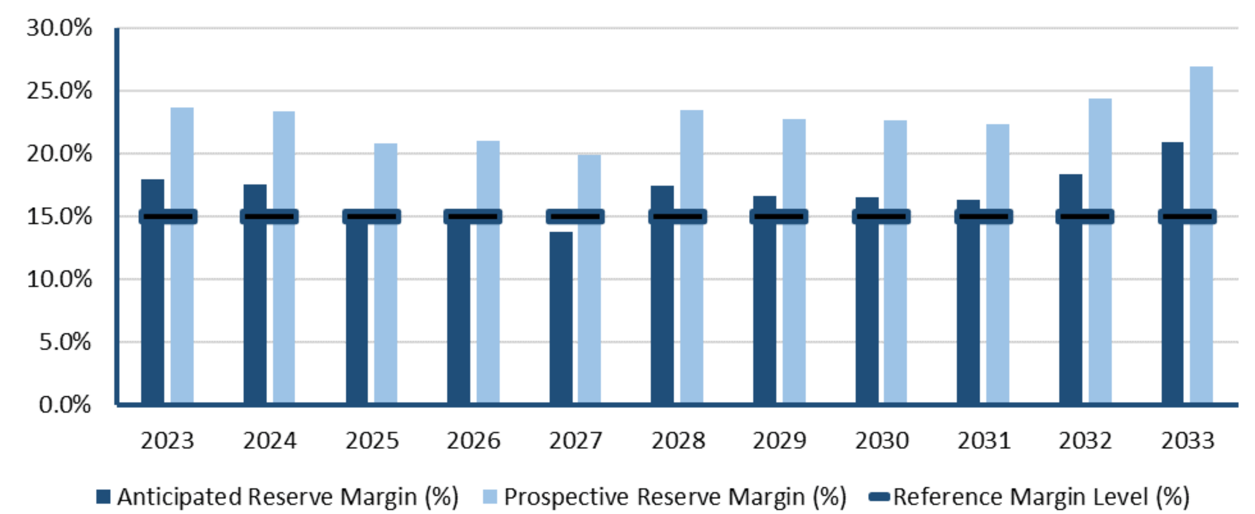
Extreme cold and hot weather preparation with guidance on actions related to forecasted periods of grid stress through risk assessments is an area of focus for this assessment area. One entity reported that it removed natural gas infrastructure from its transmission load shedding plan and coordinates with its natural gas transportation providers in its area to place the appropriate priority on electricity service to any critical natural gas infrastructure. Sensitivity analyses help the entities prepare for changes in generation mix and develop projects to improve future system conditions, and/or operational guidelines to mitigate any observed risks.

SERC-Central

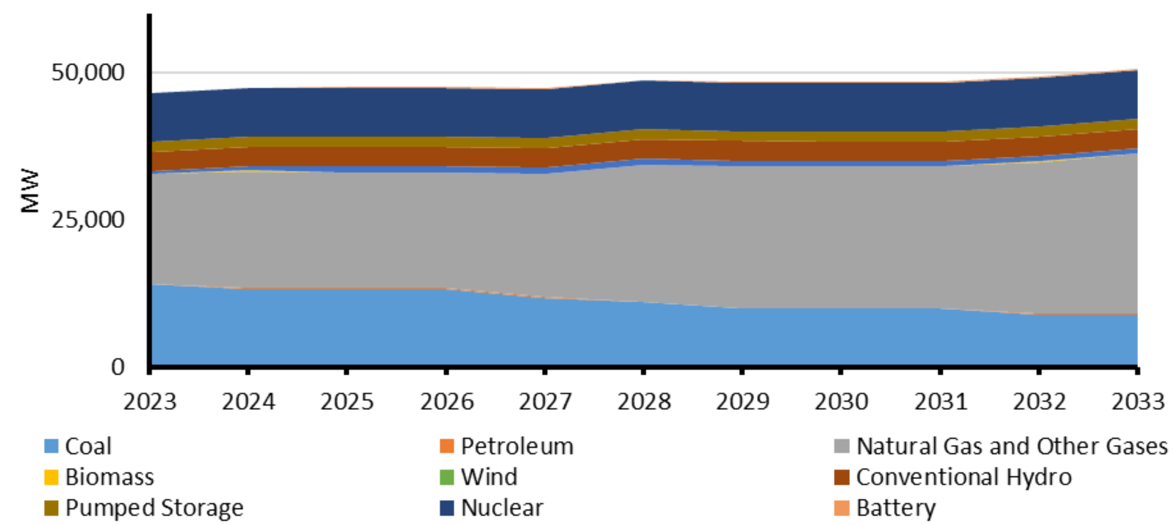
SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission (FERC) approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 34 Balancing Authorities, 27 Planning Authorities (PA), and 7 RCs. See **High Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	42,259	42,595	42,560	42,737	42,739	42,765	42,764	42,858	42,877	43,109
Demand Response	1,851	1,835	1,838	1,842	1,840	1,839	1,837	1,836	1,835	1,834
Net Internal Demand	40,408	40,760	40,722	40,895	40,899	40,926	40,927	41,022	41,042	41,275
Additions: Tier 1	1,600	2,526	2,530	3,876	6,086	6,934	6,934	6,934	8,755	10,081
Additions: Tier 2	20	170	170	170	170	170	170	170	170	170
Additions: Tier 3	28	235	463	1,015	1,568	2,170	2,623	3,075	3,528	3,980
Net Firm Capacity Transfers	198	-677	-677	-677	-677	-677	-677	-677	-677	-677
Existing-Certain and Net Firm Transfers	45,922	44,247	44,247	42,673	41,946	40,816	40,786	40,786	39,818	39,818
Anticipated Reserve Margin (%)	17.6%	14.8%	14.9%	13.8%	17.4%	16.7%	16.6%	16.3%	18.3%	20.9%
Prospective Reserve Margin (%)	23.4%	20.9%	21.0%	19.9%	23.5%	22.8%	22.7%	22.4%	24.4%	26.9%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM falls slightly below the RML during the summer months of 2025, 2026, and 2027. The entities plan to secure firm transmission imports to support operating plans when resources are deficient.
- Natural gas (40%), coal (30%), and nuclear (18%) generation are the dominant fuel types within the assessment area. Hydro, renewables, and other fuel types (12%) are minimal.
- From 2023 to 2033, SERC-Central will retire more than 5 GW of coal generation within the next 10 years. Tier 1 additions of nearly 8.6 GW of natural gas, 0.5 GW of BES-connected solar PV, and 0.1 GW of BESS is expected during this time.
- Historically a summer peaking area, SERC-Central has now become a dual-peaking system.
- The net non-coincident internal demand, which includes the available, controllable, and dispatchable DR for the assessment area, is expected to grow annually at a rate of approximately 0.2% on average in the next 10 years.

SERC-Central Generation Capacity by Fuel Type (Summer)										
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Coal	13,235	13,235	13,235	11,661	10,934	9,804	9,804	9,804	8,836	8,836
Petroleum	148	148	148	148	148	148	148	148	148	148
Natural Gas	19,888	19,618	19,618	20,964	23,174	24,022	23,992	23,992	25,813	27,139
Biomass	36	36	36	36	36	36	36	36	36	36
Solar	647	983	987	987	987	987	987	987	987	987
Wind	4	4	4	4	4	4	4	4	4	4
Conventional Hydro	3,315	3,315	3,315	3,315	3,315	3,315	3,315	3,315	3,315	3,315
Pumped Storage	1,691	1,691	1,691	1,691	1,691	1,691	1,691	1,691	1,691	1,691
Nuclear	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280
Battery	81	141	141	141	141	141	141	141	141	141
Total MW	47,324	47,450	47,454	47,226	48,709	48,427	48,397	48,397	49,250	50,576

SERC-Central Assessment

Planning Reserve Margins

The ARM for the SERC-Central assessment area falls slightly below the NERC target reference margin of 15% during the summer months of 2025, 2026, and 2027. Economic development and load growth contribute to an increase in anticipated demand in the near-term future. SERC-Central is also retiring a total of 3,260 MW summery capacity of mostly coal generation by the year 2027, which is reflected through the three-year span. A Tier 1 capacity addition of 3,556 MW in natural gas generation is expected to alleviate the capacity shortage in summer months starting in 2028. SERC-Central entities will use internal processes to review season-ahead and prompt-year positions to ensure reserve margins are adequate in the near term. The entities are constantly monitoring load growth and use additional market capacity as needed. A large entity has recently entered into several short-term power purchase agreements and secured additional firm transmission to help mitigate near-term capacity needs. The entity maintains a diverse portfolio of generating resources with a variety of fuel procurement sources. This variety provides a natural hedge against supply concerns from any one source that could pose a risk to its overall generation.

Energy Assessment and Non-Peak Hour Risk

Entities incorporate energy risks, such as extreme weather, outages (forced and planned), interchange limits, and renewable variability into their loss-of-load probabilistic studies. These results are used to determine the margin targets, generation portfolios, and power contract requirements. They also assist in long term investment and commercial actions to mitigate reserve margin shortfalls. SERC-Central did not identify any increase in energy risk concerns due to the relatively low solar PV and wind penetration. However, ramping needs are expected to increase over time as more solar PV is added to the system. The entities plan to add more storage and flexible dispatchable gas generation to help mitigate the impacts.

Probabilistic Assessments

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	0.00	0.00	0.00
EUE (PPM)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
Operable On-Peak Margin	18.4%	18.6%	17.1%

* Provides the 2022 ProbA Results for Comparison

SERC-Central has been transitioning from a summer-peaking to a dual-peaking system in the last few years and is projected to continue in that trend. The reliability risk as indicated by the 2022 ProbA is projected to be stable. The 2022 ProbA results indicate no LOLHs or EUE based on data and modeling assumptions. The severe cold weather stress test indicated that there is some risk of customer interruption and loss of energy in the case of combining unusual weather with higher-than-anticipated generator unit outages.

Demand

Historically a summer peaking area, SERC-Central has now become a dual-peaking system. The net non-coincident internal demand, which includes the available, controllable, and dispatchable DR for the assessment area, is expected to grow annually at a rate of approximately 0.2% on average in the next 10 years.

Demand-Side Management

Controllable and dispatchable DR programs are considered available during peak hours from June through September. The amount of MW available is highly dependent on the weather and is estimated based on historical performance. While some program events are dispatched and monitored near real-time, customers receive monthly capacity payments and energy payments based on performance during events. Dispatchable voltage regulation can operate distribution feeder voltages in the lower half of the standard voltage range to lower peak demand. Electric system distribution feeders utilize a voltage feedback loop to bias voltage regulators to maintain the lowest acceptable feeder voltage during an economic event. Interruptible DR program can suspend a portion of participating customers’ load with 5- or 30-minutes notice during times of the power system need.

Distributed Energy Resources

The impact of DER resources is forecasted and incorporated into the total energy and peak demand forecasts. Entities do not always include the growth of DERs in resource planning, however. The BTM solar PV is embedded in the load forecast with an hourly shape derived from solar irradiance. The solar PV is often a fixed energy supply resource modeled as an hourly generation profile in a typical week pattern each month derived from simulated data. Consideration is given to aligning the solar PV generation with the peak load for the week, particularly in the summer when the highest load for the week will likely occur during the sunniest day of the week.

Generation

Natural gas (40%), coal (30%), and nuclear (18%) generation are the dominant fuel types within the assessment area. Hydro, renewables, and other fuel types (12%) are minimal. From 2023 to 2033, SERC-Central will retire more than 5 GW of coal generation within the next 10 years. Tier 1 additions of nearly 8.6 GW of natural gas, 0.5 GW of BES-connected solar PV, and 0.1 of GW BESS is expected during this time.

Energy Storage

There is no utility-scale transmission BES-connected BESS at this time. 246 MW of Tier 1 and 770 MW of Tier 2 and Tier 3 nameplate capacity BESS is expected within 10 years.

Capacity Transfers and External Assistance

Severe system events could reduce transfer capacity, possibly affecting a portion of load under summer conditions. The entity would coordinate with neighboring TOP to expedite returning a line to service and shed load if no other options are available. Entities plan to maintain surplus capacity to meet reliability needs during extreme weather scenarios. They will coordinate with its operations personnel, fuel suppliers, pipeline personnel, and neighboring utilities prior to and during weather events.

Transmission

The assessment area will add another 118.4 miles within the first five years followed by 53 miles in the next five years of new ac transmission lines with the voltage range between 100 to 200 kV. These projects are in the planning/construction phase and projected to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability. Entities do not anticipate any transmission limitations or constraints with significant impacts to reliability.

Reliability Issues

SERC and its members have not identified any other emerging reliability issues without existing or planned solutions. However, entities continue to monitor the possible impacts on the long-term reliability of the BES from the supply chain issues, changing resource mix, transmission projects and temporary mitigations, summer and dual peaking scenarios, extreme weather events, and critical infrastructure sector interdependency.

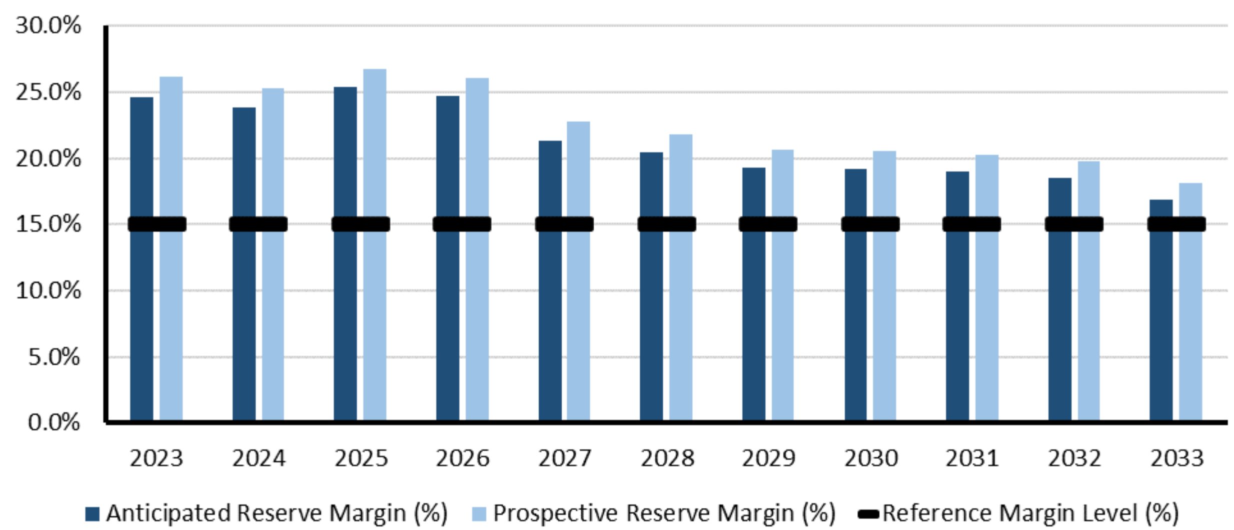
High transfers across the transmission system and their impacts on reliability driven by high regional wind and extreme weather events is an area of risk. To support reliability across the year with changes in generation resources, a dual peaking entity has adopted separate reserve margin targets for winter and summer seasons with plans for effective outage planning in off-peak periods. The entity studied a peak summer demand with low hydro scenario to reflect drought weather conditions and has identified projects to address the more severe reliability concerns. This assessment area can tackle fuel resilience risks with a well-diversified generation portfolio and advantageous location with respect to major gas pipelines, access to multiple coal supply and transport options, and a strong and resilient program to secure nuclear fuel. In addition, entities identified improvement opportunities for both normal operating conditions and to allow for more effective response and restoration activities under severe scenarios.

SERC-Florida Peninsula

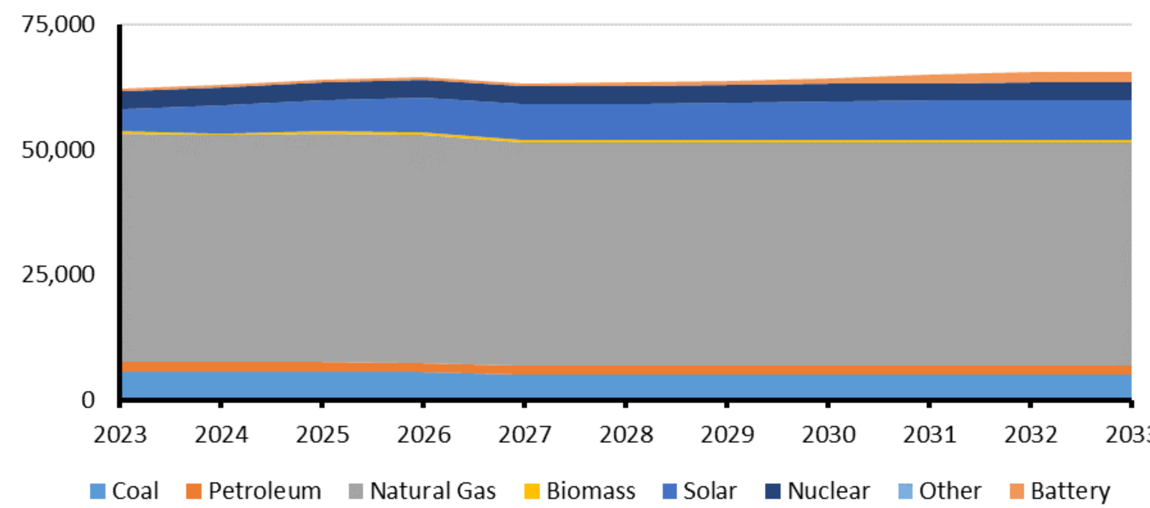
SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 34 Balancing Authorities, 27 PAs, and 7 RCs. See **Normal Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	53,190	53,591	54,107	54,516	54,977	55,719	56,407	57,036	57,847	58,667
Demand Response	2,924	2,957	2,988	3,022	3,064	3,109	3,155	3,202	3,247	3,288
Net Internal Demand	50,266	50,634	51,119	51,494	51,913	52,610	53,252	53,834	54,600	55,379
Additions: Tier 1	1,549	2,394	3,099	3,281	3,464	3,735	4,419	5,004	5,660	5,660
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	594	700	499	499	406	406	406	406	406	406
Existing-Certain and Net Firm Transfers	60,700	61,062	60,624	59,204	59,035	59,035	59,035	59,035	59,035	59,035
Anticipated Reserve Margin (%)	23.8%	25.3%	24.7%	21.3%	20.4%	19.3%	19.2%	19.0%	18.5%	16.8%
Prospective Reserve Margin (%)	25.3%	26.7%	26.1%	22.7%	21.8%	20.7%	20.5%	20.3%	19.8%	18.1%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARMs are above the RML throughout the assessment period.
- Natural gas (73%), coal (9%), and nuclear (6%) are among the primary fuel types within the assessment areas. Renewables and other fuel types make up the remaining (12%) generation.
- From 2023 to 2033, SERC-Florida Peninsula will retire nearly 0.5 GW of coal generation. Tier 1 addition of nearly 0.9 GW natural gas, 3.5 GW BES-connected solar PV, and 1.6 GW BESS is expected during this time.
- SERC-Florida Peninsula is a summer-peaking assessment area.
- The net non-coincident internal demand, which includes the available, controllable, and dispatchable DR for the assessment area, is expected to grow annually at a rate of approximately 1% on average in the next 10 years.

SERC-Florida Peninsula Generation Capacity by Fuel Type

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	5,172	5,172	5,172	4,713	4,713	4,713	4,713	4,713	4,713	4,713
Petroleum	2,017	2,017	1,846	1,718	1,718	1,718	1,718	1,718	1,718	1,718
Natural Gas	44,424	44,717	44,650	43,832	43,756	43,756	43,793	43,793	43,793	43,793
Biomass	429	429	429	414	414	414	414	414	414	414
Solar	5,565	6,273	6,978	7,161	7,344	7,526	7,709	7,891	8,032	8,032
Nuclear	3,502	3,502	3,502	3,502	3,502	3,502	3,502	3,502	3,502	3,502
Other	12	12	12	12	12	12	12	12	12	12
Battery	534	634	634	634	634	723	1,187	1,589	2,104	2,104
Total MW	61,655	62,756	63,223	61,986	62,092	62,364	63,048	63,632	64,288	64,288

SERC-Florida Peninsula Assessment

Planning Reserve Margins

SERC -Florida Peninsula ARMs are above the RML throughout the assessment period.

Energy Assessment and Non-Peak Hour Risk

The entities collaborate and run probabilistic assessments that look at every hour of the 5-year study period to determine where a potential energy adequacy risk may arise. Additional scenario cases are also evaluated, such as unavailability of firm imports, DR, and 90/10 load projection. The study results observed in the months surrounding the peak month simulate additional scheduled maintenance outages while the projected demand begins to ramp up to its seasonal peak levels. The current energy assessments do not explicitly evaluate system ramping needs. Over the next few years, The FRCC Planning and Operating Committees plan to further evaluate system ramping needs and determine if system ramping could become a challenge for the overall footprint. The results of the loss-of-load probability study are used in combination with deterministic analyses to determine if the planned resources meet adequacy requirements.

Probabilistic Assessments

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	2.26	1.09	1.13
EUE (PPM)	0.009	0.004	0.004
LOLH (hours per Year)	0.004	0.002	0.002
Operable On-Peak Margin	11.4%	18.3%	18.6%

* Provides the 2020 ProbA Results for Comparison

SERC-Florida Peninsula is a summer-peaking assessment area. The reliability risk, as indicated by the 2022 ProbA, is projected to be stable. The 2022 ProbA results indicate low to no risk of LOLHs or EUE based on data and modeling assumptions. The severe cold weather stress-test indicated that there is some risk of customer interruption and loss of energy in the case of combining unusual weather with higher-than-anticipated generator unit outages.

Demand

SERC-Florida Peninsula is a summer-peaking assessment area. The net non-coincident internal demand, which includes the available, controllable, and dispatchable DR for the assessment area is expected to grow annually at a rate of approximately 1% on average in the next 10 years.

Demand-Side Management

Controllable DR from interruptible and dispatchable load management programs is treated as a load-modifier and projected to be constant at approximately 6% of the summer and winter total peak demands for all years of this assessment period. Entities develop their own independent forecast of firm controllable and dispatchable DR values to be available at system peak based on their methodology and program policies. These individual reporting entities perform and develop independent analyses of the estimated impacts from their firm DR and load management. The impacts are aggregated for analytical purposes in the assessment area.

Distributed Energy Resources

The FRCC performs an annual collection of Distributed Energy Resources across the membership. Entities utilize the NERC published definitions of DERs when forecasting, monitoring, and reporting. In general, FRCC member DERs are modeled as being netted out with the actual customer demand since they are implicitly accounted for in the load forecasts of entities. Increased penetration levels of BTM PV continues to be observed year over year and is anticipated to continue; however, at relatively low penetration levels when compared to the Total Demand of the assessment area. In addition, members of the resource, transmission, technical and stability analysis subcommittees annually perform reviews of the DER penetration levels to determine if additional study work or sensitivities are needed. At this time, no additional challenges from increased penetration levels of DERs have been identified by the Planning Coordinators and Transmission Planners in the assessment area.

Generation

Natural gas (73%), coal (9%), and nuclear (6%) are among the primary fuel types within the assessment areas. Renewables and other fuel types make up the remaining (12%) generation. From 2023 to 2033, SERC-Florida Peninsula will retire nearly 0.5 GW of coal generation. Tier 1 addition of nearly 0.9 GW natural gas, 3.5 GW BES-connected solar PV, and 1.6 GW BESS is expected during this time.

Energy Storage

There is 519 MW of utility-scale transmission BES-connected BESS at this time. 1,585 MW of Tier 1 nameplate capacity BESS is expected within 10 years.

Capacity Transfers and External Assistance

The assessment area has one interface to the Eastern Interconnection made up of multiple transmission facilities. The owners of these facilities on each side of the subregions study various scenarios to determine transfer capabilities into and out of the assessment area. There are various contingencies that could limit the transfer capability into and out of the subregion that could result in potential reliability impacts. Those potential impacts would be mitigated by the various operating entities affected, including the FRCC Reliability Coordinator and Southeastern Reliability Coordinator.

Transmission

The assessment area will add another 67.6 miles within the first five years followed by 40.2 miles in the next five years of new AC transmission lines with the voltage range between 100 to 200 kV. The assessment area will add another 193.1 miles within the first five years followed by 9.3 miles in the next five years of new AC transmission lines with the voltage range between 200 to 300 kV. These projects are in the planning/construction phase and projected to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability. Entities do not anticipate any transmission limitations or constraints with significant impacts to reliability.

Reliability Issues

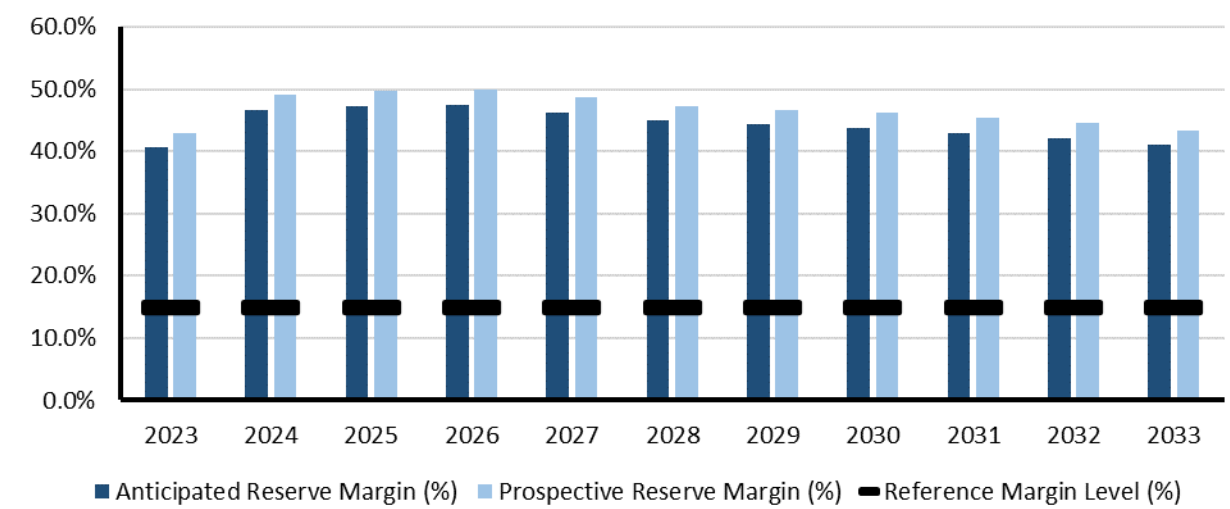
The 10-year projected total reserve margin is above 15%, and this assessment area remains under the industry standard metric of 0.1 loss-of-load probability. Although expected resources meet operating reserve requirements under normal peak-demand scenarios, supplemental analysis on significant and sustained temperature deviations from normal winter peak load and outage conditions identified that operating mitigations (i.e., DR and transfers) and energy emergency alerts (EEAs), including potential load shedding that may be needed under extreme peak demand and outage scenarios studied. The entities continue to monitor the possible impacts on the long-term reliability of the BES from the changing resource mix, the higher penetration of IBR generation, the risks of extreme weather, and the assessment area’s dependency on natural gas as a fuel resource.

SERC-Southeast

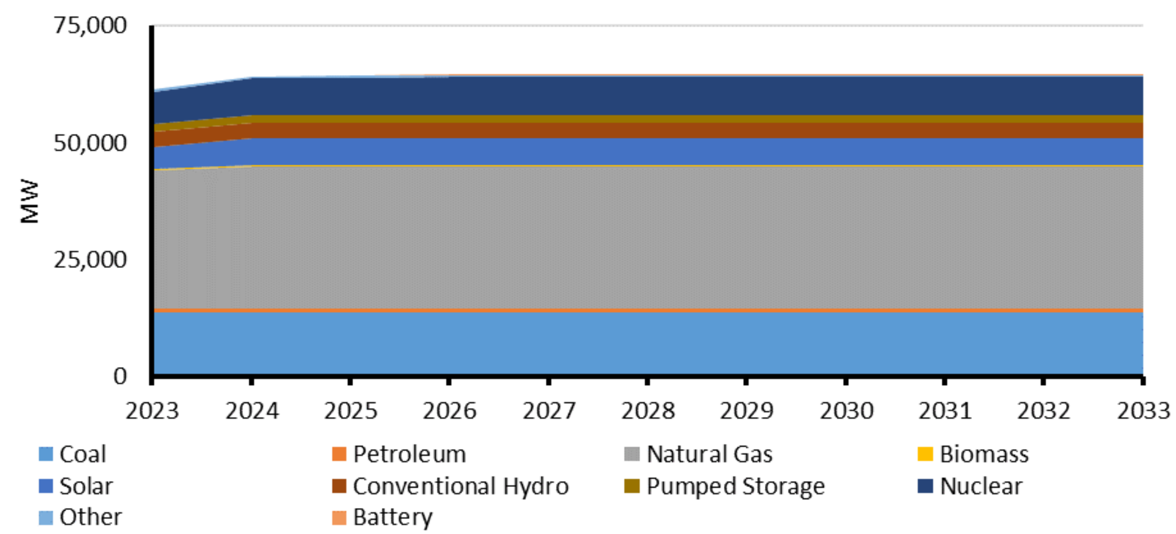
SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 34 Balancing Authorities, 27 Planning Authorities, and 7 RCs. See **Normal Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	46,354	45,595	45,831	46,267	46,555	46,753	47,050	47,311	47,570	47,937
Demand Response	2,069	2,246	2,341	2,380	2,282	2,286	2,285	2,285	2,285	2,285
Net Internal Demand	44,285	43,349	43,490	43,887	44,273	44,467	44,765	45,026	45,285	45,652
Additions: Tier 1	2,679	2,921	3,186	3,186	3,186	3,186	3,186	3,186	3,186	3,186
Additions: Tier 2	218	218	218	218	218	218	218	218	218	218
Additions: Tier 3	299	426	426	426	426	426	426	426	426	426
Net Firm Capacity Transfers	-971	-471	-471	-471	-471	-471	-256	-256	-256	-256
Existing-Certain and Net Firm Transfers	60,294	60,819	60,878	60,878	60,878	60,878	61,093	61,093	61,093	61,093
Anticipated Reserve Margin (%)	42.2%	47.0%	47.3%	46.0%	44.7%	44.1%	43.6%	42.8%	41.9%	40.8%
Prospective Reserve Margin (%)	44.6%	49.5%	49.8%	48.4%	47.1%	46.5%	46.0%	45.1%	44.3%	43.1%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- SERC-Southeast show ARMs above the RML during the first five years of this assessment period.
- Natural gas (47%), coal (22%), and nuclear (13%) generation are the dominant fuel types within the assessment areas. Hydro, renewables, and other fuel types make up the remaining (18%) generation.
- The assessment area will add 788 MW of natural gas generation over the period. 3,937 MW of utility-scale transmission BES-connected Tier 1 solar PV projects are expected in the next 10 years. Overall, there will be 1,878 MW of net additions and retirements within the next 10 years.
- There is no utility-scale transmission BES-connected BESS at this time. 330 MW of Tier 1 nameplate capacity BESS is expected within 10 years.

SERC-Southeast Generation Capacity by Fuel Type										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	13,770	13,770	13,770	13,770	13,770	13,770	13,770	13,770	13,770	13,770
Petroleum	915	915	915	915	915	915	915	915	915	915
Natural Gas	30,023	30,048	30,107	30,107	30,107	30,107	30,107	30,107	30,107	30,107
Biomass	424	424	424	424	424	424	424	424	424	424
Solar	5,496	5,738	5,738	5,738	5,738	5,738	5,738	5,738	5,738	5,738
Conventional Hydro	3,288	3,288	3,288	3,288	3,288	3,288	3,288	3,288	3,288	3,288
Pumped Storage	1,632	1,632	1,632	1,632	1,632	1,632	1,632	1,632	1,632	1,632
Nuclear	8,018	8,018	8,018	8,018	8,018	8,018	8,018	8,018	8,018	8,018
Other	313	313	313	313	313	313	313	313	313	313
Battery	65	65	330	330	330	330	330	330	330	330
Total MW	63,944	64,211	64,535	64,535	64,535	64,535	64,535	64,535	64,535	64,535

SERC-Southeast Assessment

Planning Reserve Margins
SERC-Southeast shows ARMs above RML during this assessment period.

Energy Assessment and Non-Peak Hour Risk
Many entities perform probabilistic assessments to identify energy risk. These assessments cover different scenarios such as hydro generation off-line, low solar PV output scenarios, potential environmental-related generation plant retirements, extreme weather impacting supply to natural-gas-fired generation plants, and unexpected loss of large generation units. The energy adequacy assessment results do not show increased risk outside of expected peak demand hours while considering expected ramping requirements, fuel, and generator availability as well as load forecast uncertainty scenarios. The assessments have demonstrated a need for additional transmission capacity to facilitate the displacement of traditional fossil-fueled generation resources. Lower solar PV output has not yet resulted in system reliability issues due to available alternate resources, but future reserve planning is a concern. DER penetration is currently low and does not significantly contribute to load forecast, particularly for winter periods. The results from the energy assessment are used for support in fuel and capacity appropriation decisions. Additionally, the results are used to determine the amount of seasonal reserve capacity that will be maintained based on the current forecasted peak season demand.

Probabilistic Assessments

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	0.03	0.00	0.00
EUE (PPM)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
Operable On-Peak Margin	30.2%	26.8%	30.8%

* Provides the 2020 ProbA Results for Comparison

SERC-Southeast is slightly winter peaking. The 2023 LTRA data indicates more coal retirements than anticipated in the 2022 LTRA. The reliability risk, as indicated by the 2022 ProbA, is projected to be stable. The 2022 ProbA results indicate no loss-of-load hours or EUE based on data and modeling assumptions. The severe cold weather stress test indicated that there is some risk of customer interruption and loss of energy in the case of combining unusual weather with higher-than-anticipated generator unit outages.

Demand
Each consumer class can have an econometric forecast based on load factor, demand ratio, trend analysis, weather, appliance efficiency, large load adjustment, and load profile models. The weather is a key driver in the forecast process. Regression models relating weather and the economy to energy sales can predict future sales for customers. Load factors and diversity ratios can determine the peaks. Future hourly load shapes are derived from historical hourly load shapes and the forecasted demand and energy. Customer load shapes are added together to form the hourly load shape for its system. Temperature sensitivities are utilized to develop weather case extreme forecast. Discreet adjustments are examined outside of the models for analysis on how DERs impact the forecast. The variable resources do not generally contribute to load forecast uncertainty in long-range forecast. Some entities use the Statistically Adjusted End-Use model, which combines the strengths of econometric and end-use methodologies by incorporating the detail of end-use models while maintaining the ease of use associated with econometric models. The Statistically Adjusted End-Use Model allows the entity to evaluate the function of price, income, population, appliance saturations, market shares, and specifically the importance of weather in determining usage. The model incorporates member cooperative results from their residential end-use surveys, thus capturing any new technology (electric vehicles, residential solar PV) that could affect usage. Each year, historical data will be added to the LF databases for each member, and new regression equations will be developed and evaluated with the SAE model to forecast average residential usage as well as a linear regression equation to forecast non-residential sales. The summer and winter peaks are projected with the most probable weather conditions (50/50 forecast). The historical relationship between total system load levels and weather will continue to be the key component in developing an hourly demand forecast for the total system load.

Demand-Side Management
The demand side management water heater program allows system operators to control appliance usage during peak demand periods. The number of installed water heater control switches are accounted for each month. Historical trends are used to forecast the number of water heater control switches to be installed in future years. Entities monitor and dispatch DR programs per individual contract terms. Annual ELCC simulations are performed to determine the capacity value for each unique and active DR program. An adjustment to that capacity value is then made based on predicted customer response when the program is called or dispatched. The impacts of BTM DERs are accounted for in the development of the annual load forecasts. In front-of-the-meter DERs are considered separate generation resources and do not impact any current demand-side management programs.

Distributed Energy Resources

Some entities record DER contributions by the sum of their capacities for each metering point served via distribution transformers. When DER capacities at a certain metering point meet or exceed a certain level, estimated generation is placed back onto the load bus for load forecasting purposes. Entities model DERs as hourly profiles in all resource planning models, thereby taking into consideration ramping and other operational considerations. The forecast of BTM solar PV is based on a trend model for MWs. This MW forecast is then converted to an energy forecast by using an assumed capacity factor.

The BTM solar PV forecast increases through the assessment period. On a yearly basis, the reliability model is updated based on the latest system Integrated Resource Plan. Capacity values for proposed and newly added DER resources are then calculated based on the current yearly model assumptions. Projections of solar PV are included in the Base Case forecast on the demand side. However, demand-side BESS and other BTM resources are not prevalent and are not included.

Generation

- Natural gas (47%), coal (22%), and nuclear (13%) generation are the dominant fuel types within the assessment area. Hydro, renewables, and other fuel types make up the remaining (18%) generation.
- The assessment area will add 788 MW of natural gas generation over the period.
- Overall, there will be 1,878 MW of net additions and retirements within the next 10 years.
- 2,399 MW of utility-scale transmission BES-connected Tier 1 solar PV projects are expected in the next 10 years.

Energy Storage

- There is no utility-scale transmission BES-connected BESS at this time.
- 330 MW of Tier 1 nameplate capacity BESS is expected within 10 years.

Capacity Transfers and External Assistance

Entity studies confirmed Open Access Same-Time Information System (OASIS) reservations in its long-term assessments and plans for the delivery of those commitments under a variety of scenarios including different load levels and system flow patterns. For imports into the system, OASIS reservations for the capacity benefit margin and Transmission Reliability Margin are included and planned for. Any concerns that are identified in these assessments are reviewed with neighboring utilities, and evaluations are coordinated when necessary to determine optimal solutions.

Transmission

- The assessment area will add another 369.3 miles within the first five years followed by 109.1 miles in the next five years of new AC transmission lines with the voltage range between 100 to 200 kV.
- The assessment area will add another 229.9 miles within the first five years followed by 4.8 miles in the next five years of new AC transmission lines with the voltage range between 200 to 300 kV.
- The assessment area will add another 101.6 miles within the first five years followed by 65.0 miles in the next five years of new AC transmission lines with the voltage range higher than 400 kV.
- These projects are in the planning/construction phase and projected to enhance system reliability by supporting voltage and relieving challenging flows.
- Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability.
- Entities do not anticipate any transmission limitations or constraints with significant impacts on reliability.

Reliability Issues

Electromagnetic transient studies of in-service IBRs in relatively weak areas of the system have been deemed necessary for some entities. This is important to determine appropriate ramp rates, controller settings, and ride-through capabilities for available generation. The potential impacts of driving this need are unexpected responses (voltage oscillations, power quality impacts, etc.) observed during disturbances or abnormal configurations. Extreme weather study processes are evolving, and more emphasis is being placed on extreme cold due to recent events in other areas. Extreme weather events are included as part of the load and weather patterns considered in its probabilistic determination of reserve margins. Additionally, fuel price volatility and fuel availability continue to present challenges that have resulted in various scenarios being studied and evaluated on a continuous basis by some entities. Entities identify potential common mode failures within the natural gas subsector through various processes and studies and coordinate with their critical natural gas facilities, local electric sector participants, and fuel suppliers in performing assessments to ensure any facilities critical to maintaining fuel availability are not included in its load shedding procedures

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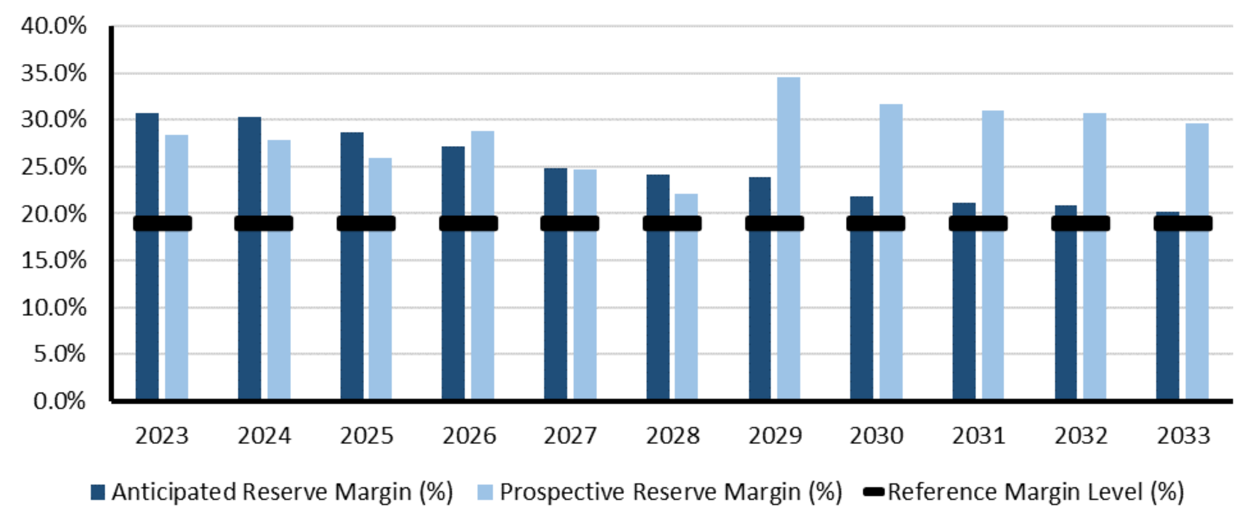
SPP

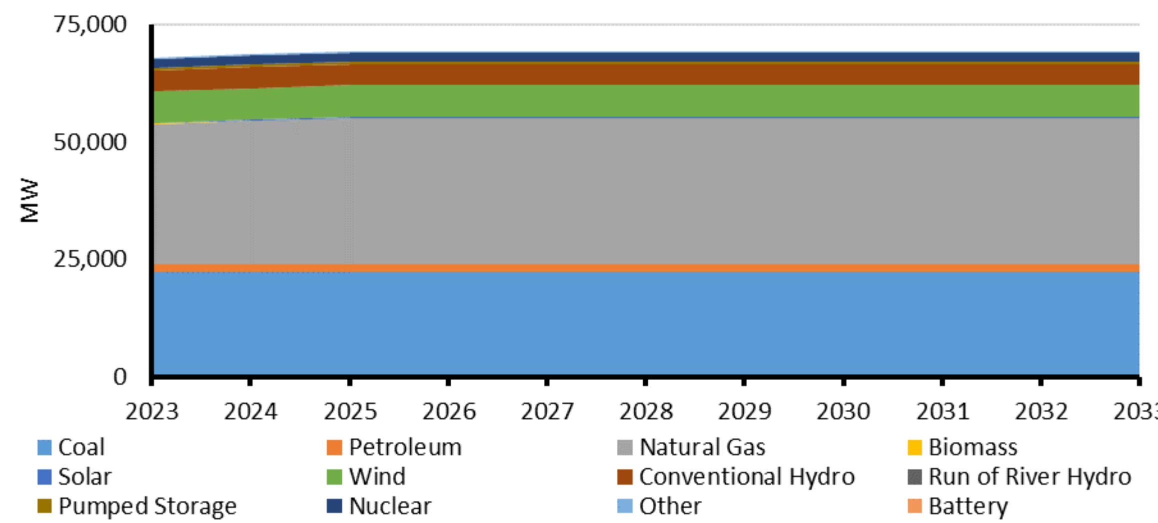
The SPP Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the Planning Coordinator footprint, which touches parts of the Midwest Reliability Organization Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million. See **Elevated Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	53,603	54,846	55,784	56,754	57,048	57,249	58,253	58,557	58,908	59,242
Demand Response	1,353	1,489	1,772	1,798	1,807	1,843	1,851	1,857	2,062	2,046
Net Internal Demand	52,250	53,356	54,012	54,957	55,240	55,405	56,402	56,700	56,846	57,196
Additions: Tier 1	718	1,302	1,302	1,302	1,302	1,302	1,302	1,302	1,302	1,302
Additions: Tier 2	0	0	2,739	2,739	2,739	9,795	9,795	9,795	9,795	9,795
Additions: Tier 3	0	0	4,205	4,205	4,205	4,205	4,205	4,205	4,205	4,205
Net Firm Capacity Transfers	-404	-384	-364	-474	-469	-469	-400	-400	-402	-402
Existing-Certain and Net Firm Transfers	67,371	67,391	67,411	67,301	67,306	67,306	67,418	67,418	67,416	67,416
Anticipated Reserve Margin (%)	30.3%	28.7%	27.2%	24.8%	24.2%	23.8%	21.8%	21.2%	20.9%	20.1%
Prospective Reserve Margin (%)	27.8%	25.9%	28.8%	24.7%	22.2%	34.5%	31.7%	31.0%	30.7%	29.7%
Reference Margin Level (%)	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- ARMs do not fall below the RML for this assessment period.

SPP Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	22,283	22,283	22,283	22,283	22,283	22,283	22,283	22,283	22,283	22,283
Petroleum	1,728	1,728	1,728	1,728	1,728	1,728	1,728	1,728	1,728	1,728
Natural Gas	30,544	31,128	31,128	31,128	31,128	31,128	31,128	31,128	31,128	31,128
Biomass	35	35	35	35	35	35	35	35	35	35
Solar	201	201	201	201	201	201	201	201	201	201
Wind	6,713	6,713	6,713	6,713	6,713	6,713	6,713	6,713	6,713	6,713
Conventional Hydro	4,418	4,418	4,418	4,418	4,418	4,418	4,418	4,418	4,418	4,418
Run of River Hydro	75	75	75	75	75	75	75	75	75	75
Pumped Storage	440	440	440	440	440	440	440	440	440	440
Nuclear	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944
Other	281	281	281	281	281	281	281	281	281	281
Battery	1	1	1	1	1	1	1	1	1	1
Total MW	68,664	69,248	69,248	69,248	69,248	69,248	69,248	69,248	69,248	69,248

SPP Assessment

Planning Reserve Margins

ARMS do not fall below the RML of 19% (based on SPP coincident peak demand) for the entire ten-year assessment period. While the SPP ARM shows a robust amount of excess capacity, these margins reflect the full availability of accredited capacity and do not account for planned, forced or maintenance outages. The SPP ARM also does not reflect de-rates based on real time operational impacts. Similar to the Generation Unavailability scenario in the *2023 NERC Summer Reliability Assessment*, SPP shows the potential to use all of the LTRA ARM capacity, which means there could be times of capacity shortfall based on performance impacts during high load periods. While the potential to use all of the LTRA ARM capacity has a low probability, the assumptions and projections are based around historic unavailability during on-peak periods.

The RML of 19% was established by SPP and its stakeholders and is based on results of the most recent biennial LOLE study.[51] The study analyzes the ability to reliably serve the SPP BA area's 50/50 forecasted peak demand with a security constrained economic dispatch. SPP, with stakeholder input, develops the inputs and assumptions used for the LOLE Study. SPP will study the Planning Reserve Margins such that the LOLE for the applicable planning year (2- and 5-year study) does not exceed 1-day-in-10 years, or 0.1 day per year. At a minimum, the RML will be determined with probabilistic methods by altering capacity through the application of generator forced outages and forecasted demand through the application of load uncertainty to ensure the LOLE does not exceed 0.1 day per year. The 2023 LOLE study is underway in SPP but will not be completed prior to publication of the *2023 LTRA*.

Energy Assessment and Non-Peak Hour Risk

As the resource mix continues to change from a baseload thermal and hydro resources to VERs and short duration energy storage resources, SPP recognizes that its LOLE study must also continue to evolve. A potential change and improvement identified for the 2023 LOLE study includes considering energy adequacy and additional metrics (e.g., EUE).

Probabilistic Assessments

SPP's most recent study performed for NERC's Probabilistic Assessment (2022 ProbA) found negligible risk of load loss in the Base Case for both study years. All unserved energy was concentrated in peak summer months.

Base Case Summary of Results (2022 ProbA)			
	2024*	**2024**	**2026**
EUE (MWh)	0.00	0.27	0.84
EUE (PPM)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
Operable On-Peak Margin	13.3%	19.7%	19.6%

* Provides the 2020 ProbA Results for Comparison

In 2023, SPP completed a probabilistic analysis of a winter risk scenario that paired increases in both conventional forced generation outages and peak demand. The scenario was carried out for the 2026 study year by using the 90/10 winter load forecast and increasing the forced outage rate of the conventional fleet by a factor of two.[52] In this scenario, some energy goes unserved in winter months and overall EUE rises to 1.36 MWh.

Demand

SPP peak load occurs during the summer season. The 2024 load forecast is projected to peak at 53,603 MW, which is a 1% increase compared to the previous year's LTRA forecast for the 2024 summer season. SPP forecasts the coincident annual peak growth based on member submitted data over the 10-year assessment time frame. The diversity factor used to convert members' non-coincident peak demand forecasts to an SPP coincident peak demand forecast is consistent with the percentage used for the 2022 LTRA. The current annual growth rate is approximately 1%.

Demand-Side Management

SPP's EE and conservation programs are incorporated into the reporting entities' demand forecasts. The SPP assessment area is projecting a significant amount of DR to come online over the assessment time frame and is currently working on accreditation methodologies to better access reliability contributions from these programs. DR resources are projected to rise sharply over the assessment period from the current contribution of 829 MW to over 2,000 MW by 2033. As an additional sensitivity to the 2023 LOLE study, SPP modeled high level constraints applied to the current DR programs to understand the possible reliability impacts when constraining the programs to a certain limited number of calls per year and limited number of hours per day. Additionally, SPP is working with stakeholders to gather program specific details that can be modeled. With the footprint's projected DR growth, it will be important to model these programs accurately to better depict the

[51] SPP LOLE Study Report

[52] See 2022 ProbA Regional Risk Scenarios Report. The scenario was created in early 2022. Since then, significantly higher forced outage rates have been observed in severe winter events, such as winter storm Elliott.

reliability implications to the SPP system. DR growth and electrification have the potential to introduce new demand forecast uncertainty and reliability risk.

Distributed Energy Resources

SPP currently has approximately 300 MW of installed solar PV generating facilities. The SPP Model Development, Economic Studies, and Supply Adequacy working groups are currently developing policies and procedures around DERs. SPP implemented resource adequacy policies for DERs that require certain testing, reporting and documentation requirements for resources and programs not registered with approval planned for late 2023.

Generation

Since the 2022 LTRA, SPP members have reported approximately 1,500 MWs of conventional resources being retired. There are no known unaddressed reliability impacts at this time. Retirements continue to be assessed throughout the time frame through planning and operational processes. The reliability impacts that retired generation have on the transmission system are also analyzed in the annual Integrated Transmission Plan. Some projected retirements in the assessment time frame are currently expected to be replaced with renewable resources. The confirmed retirement impact to resource adequacy in the assessment area is being studied in the 2023 LOLE study.

In 2023, FERC rejected SPP's proposed ELCC methodology for wind and solar PV resource capacity accreditation. SPP is currently working on revising ELCC policy for wind, solar PV, and storage with the goal of obtaining internal approvals and refiling with FERC in late 2023. More properly accrediting wind, solar PV, and storage resources becomes critical as more conventional generators nearing retirement cause SPP historical Planning Reserve Margin levels to decline.

Energy Storage

There are approximately 17,000 MWs of energy storage and hybrid resources in SPP's generator interconnection queue that are being studied. A small amount (about 50 MWs) of these resources are currently under contract by members across the SPP assessment area. These resources are modeled as generation in both near and long-term planning assumptions.

Capacity Transfers and External Assistance

The SPP assessment area coordinates with neighboring areas to ensure that adequate transfer capabilities will be available for capacity transfers. On an annual basis during the model build season, SPP staff coordinates the modeling of transfers between Planning Coordinator footprints. The modeled transactions are fed into the models created for the SPP planning process.

SPP and ERCOT have executed a coordination plan that addresses operational issues for coordination of the dc ties between the Texas Interconnection and Eastern Interconnection, block load transfers, and switchable generation resources. Under the terms of the coordination plan, SPP has priority to recall the capacity of any switchable generation resources that have been committed to satisfy the resource adequacy requirements contained in Attachment AA of the SPP Open Access Transmission Tariff. SPP's and ERCOT's last annual update the coordination plan occurred in June 2023.

Transmission

After evaluating more than 1,080 solutions, SPP worked together with its member organizations to create a robust portfolio of 44 transmission projects, including 51 miles of new extra-high-voltage transmission that can holistically address the reliability, economic, policy, and operational needs of the system. The recommended portfolio contains reliability and economic projects that will mitigate 137 system issues.[53] The *SPP 2024 Integrated Transmission Plan Assessment* and the *2022 SPP Transmission Expansion Plan* reports provide details for proposed transmission projects needed to either maintain reliability and/or provide economic benefit to end users.

Reliability Issues

There are concerns of drought conditions impacting the Missouri River and other water sources for generation resources that rely on once-through cooling processes. Low water can impact the generation's capacity output and reduce its ability to support congestion management and serve load. An additional concern could be the low water's impact on coal availability, which could cause units to run at a derated level to conserve coal inventory. In order to identify mitigations prior to peak conditions, these extreme conditions are studied in SPP's seasonal assessment process. Closer to real time, additional analysis are performed with more accurate forecast data.

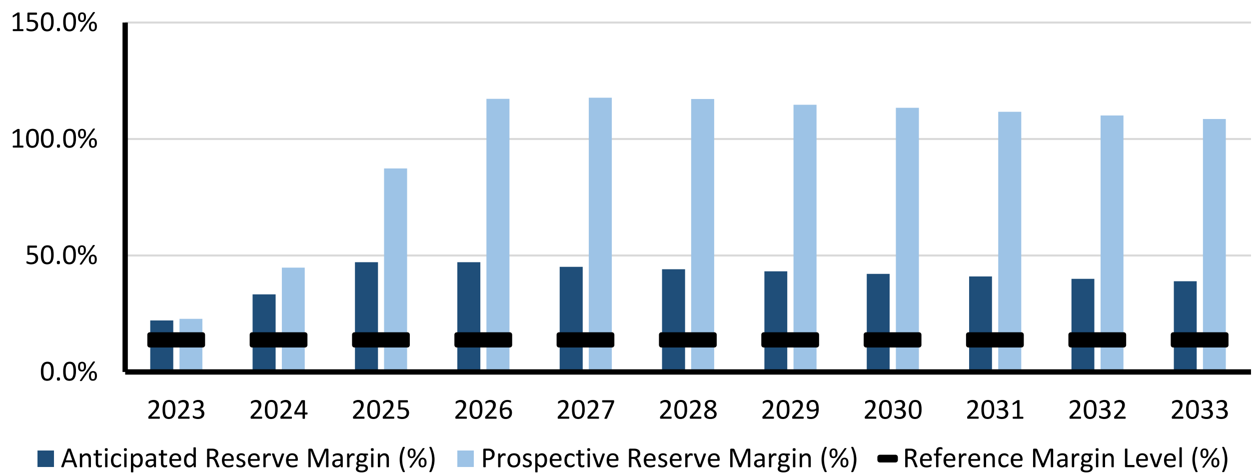
[53] 2022 ITP Report

Texas RE-ERCOT

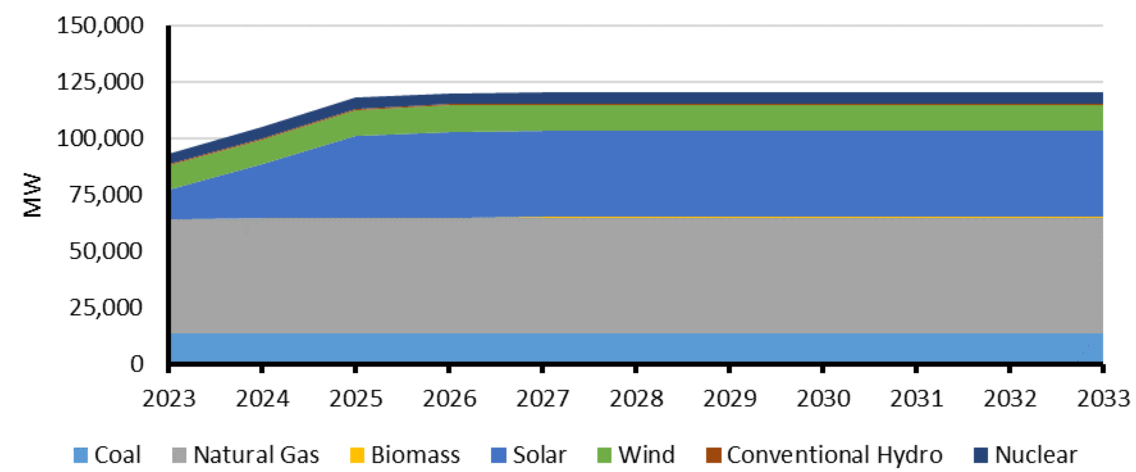
The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single Balancing Authority. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer peaking. It covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,030 generation units, and serves more than 26 million people. Lubbock Power & Light joined the ERCOT grid on June 1, 2021. Texas Regional Entity is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. See **Elevated Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Total Internal Demand	84,325	85,740	87,131	88,518	89,090	89,624	90,298	90,986	91,646	92,296
Demand Response	3,464	3,464	3,464	3,464	3,464	3,464	3,464	3,464	3,464	3,464
Net Internal Demand	80,861	82,276	83,667	85,054	85,626	86,160	86,834	87,522	88,182	88,832
Additions: Tier 1	12,520	25,802	27,852	28,010	28,010	28,010	28,010	28,010	28,010	28,010
Additions: Tier 2	8,618	33,248	58,809	63,012	64,574	64,574	64,874	64,874	64,874	64,874
Additions: Tier 3	7,589	11,955	23,097	26,029	27,828	28,226	28,226	28,226	28,226	28,226
Net Firm Capacity Transfers	20	20	20	20	20	20	20	20	20	20
Existing-Certain and Net Firm Transfers	95,260	95,260	95,260	95,405	95,405	95,405	95,405	95,405	95,405	95,405
Anticipated Reserve Margin (%)	33.3%	47.1%	47.1%	45.1%	44.1%	43.2%	42.1%	41.0%	40.0%	38.9%
Prospective Reserve Margin (%)	44.8%	87.4%	117.2%	117.7%	117.2%	114.7%	113.4%	111.7%	110.1%	108.6%
Reference Margin Level (%)	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Generation resources, primarily solar PV, continue to be added to the grid in Texas in large quantities, increasing ARMs but also elevating concerns of energy risks that result from the variability of these resources and the potential for delays in implementation. The summer ARM is above the RML (13.75%) for all 10 years of this assessment period (2024–2033). The ARM peaks at 47% by summer 2025, reflecting the expected addition of 25,802 MW of Tier 1 capacity, most of which is solar PV.
- ERCOT's summer peak demand is forecasted to increase by 1.1% per year through 2033 while annual energy is forecasted to increase by 2.1% per year for the same period. While these growth rates are close to the values for the load forecast used in the *2022 LTRA*, ERCOT has adopted more extreme weather assumptions to reflect the increasing frequency of extreme weather events experienced over the last several years and the expectation that this trend will continue.
- ERCOT completed its *2022 Regional Transmission Plan* in December 2022. The plan lists 15 major reliability improvement projects out of a total of 89 proposed projects. Currently, there are $10.26 billion of transmission improvement projects that are expected to be put in service between 2023 and the end of 2028.

Texas RE-ERCOT Fuel Composition

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568
Natural Gas	51,088	51,321	51,321	51,471	51,471	51,471	51,471	51,471	51,471	51,471
Biomass	163	163	163	163	163	163	163	163	163	163
Solar	23,587	36,056	38,033	38,191	38,191	38,191	38,191	38,191	38,191	38,191
Wind	11,032	11,612	11,686	11,686	11,686	11,686	11,686	11,686	11,686	11,686
Conventional Hydro	480	480	480	480	480	480	480	480	480	480
Nuclear	4,973	4,973	4,973	4,973	4,973	4,973	4,973	4,973	4,973	4,973
Total MW	104,891	118,173	120,223	120,531	120,531	120,531	120,531	120,531	120,531	120,531

Texas RE-ERCOT Assessment

Planning Reserve Margins

The summer ARM is above the RML (13.75%) for all 10 years of this assessment period (2024–2033). The ARM peaks at 47% by summer 2025, reflecting the expected addition of 25,802 MW of Tier 1 capacity, most of which is solar PV. However, the high reserve margin belies concerns about the resource mix in Texas RE-ERCOT—the continuing trend towards less fully dispatchable resources and more IBRs like solar PV and wind—as well as the availability of thermal resources (and associated fuel supplies) for addressing increasing weather volatility and changes to load patterns.

While investigating for the Public Utilities Commission of Texas a reliability standard that encompasses multiple probabilistic reliability measures, ERCOT has proposed a reliability standard framework composed of three measures: frequency, event duration and event magnitude. Pending direction from the Public Utilities Commission of Texas, continued analysis of the reliability standard framework is planned for this summer.

Energy Assessment and Non-Peak Hour Risk

The penetration of solar PV in Texas RE-ERCOT continues to increase the risk of tight operating reserves during hours other than the daily peak load hour. This issue is most acute for the summer season when solar PV generation ramps down during the early evening hours while load is still relatively high. ERCOT's Probabilistic Reserve Risk Model is designed for analysis of the hours with the highest risk of reserve shortages for a seasonal peak demand day. As shown ProbA Base Case chart, the summer 2023 model indicates a progression of increasing hourly EEA risk probabilities from the early afternoon through the early evening hours with the peak EEA probability now occurring for hour-ending 9:00 p.m.

To address energy adequacy concerns, the Public Utility Commission of Texas adopted a performance credit mechanism (PCM) in January 202) as part of a Reliability Standard that the 87th Texas Legislature (by way of Senate Bill 3) directed FERC to implement. The PCM is a new market product that is intended to incentivize development and preservation of dispatchable generation. Under the PCM, generation resources commit to producing more energy during the tightest grid conditions of the year and sell credits to load-serving entities. Since PCM implementation may take up to four years, FERC directed ERCOT to investigate alternative bridging strategies that can be implemented relative quickly. ERCOT proposed modifying the operating reserve demand curve as the preferred approach. The 88th Texas legislative session has passed several bills that address grid reliability and further promote dispatchable resources by including performance penalties for generators with a signed interconnection agreement after January 1, 2026, and a November 2023 ballot measure to provide $7.2 billion in low interest loans and a completion bonus grants for new dispatchable resources of at least 100 MW. This requires ERCOT to consider implementing a new ancillary services program to procure dispatchable reliability reserve services on a day-ahead and real-time basis and placing a cost limit for the PCM of $1 billion (less the cost of the bridging solution), so ERCOT will need to develop reliability plans for areas with high load growth including the Permian Basin.

Probabilistic Assessments

ERCOT's recent study performed for NERC's 2022 ProbA identified LOLH and EUE risk predominantly in the winter, largely driven by the incorporation of additional forced outage risk.

Base Case Summary of Results			
	2024*	**2024**	**2026**
EUE (MWh)	12.86	492.03	1,235.40
EUE (PPM)	0.03	1.09	2.63
LOLH (hours per Year)	0.01	0.15	0.30
Operable On-Peak Margin	10.2%	36.7%	35.9%

* Provides the 2020 ProbA Results for Comparison

In 2023, ERCOT performed a probabilistic risk scenario that studied the impact of transmission limits on reliability indices as heavy IBRs in one area use transmission to get to its load in the central and eastern parts of Texas for the 2026 study year.[54] Results of this scenario, when compared to the 2022 ProbA Base Case, show that the addition of internal transmission constraints had implications for the reliability of the ERCOT system, resulting in modest EUE increases and a more drastic rise in LOLH.

[54] See 2022 ProbA Regional Risk Scenarios. The scenario was created in early 2022. Since then, significantly higher forced outage rates have been observed in severe winter events, such as winter storm Elliott.

Demand

ERCOT's summer peak demand is forecast to increase by 1.1% per year through 2033 while annual energy is forecasted to increase by 2.1% per year for the same period. While these growth rates are close to the values for the load forecast used in the *2022 LTRA*, ERCOT has adopted more extreme weather assumptions to reflect the increasing frequency of extreme weather events experienced over the last several years and the expectation that this trend will continue. As a result, peak loads are significantly higher than those reported in the *2022 LTRA*. These more extreme weather assumptions are also reflected in the extreme peak loads used for scenario and probabilistic risk analysis.
Since the previous summer, ERCOT has experienced continued rapid load growth in large flexible loads (LFL), i.e., interruptible computer operations such as bitcoin mining. The 2023 load forecast increases the demand due to LFLs by 700 MW per year from 2023 through 2027, resulting in approximately 5,000 MW total LFL load in 2027. LFLs are forecasted to increase ERCOT's 2027 summer peak by 500 MW (10% of this demand responsive load).[55]

Currently there are no adjustments for EVs or BESS in the ERCOT long-term forecast used for the LTRA. ERCOT recently collaborated with a vendor to create an EV forecast that will be integrated into the long-term load forecast in 2023.

Demand-Side Management

Most of the demand-side resources available to ERCOT are dispatchable in the form of non-controllable load resources providing responsive reserve service and ERCOT's Emergency Response Service. The ERCOT Emergency Response Service consists of 10-minute and 30-minute ramping DRs and distributed generation that can first be deployed when physical responsive reserves drop to 3,000 MW and are not projected to be recovered above 3,000 MW within 30 minutes following the deployment of non-spin reserves. Responsive reserve is an ancillary service for controlling system frequency. It is provided by industrial loads and is procured on an hourly basis in the day-ahead market. Post Winter Storm Uri programmatic reforms include increasing the $50 million ERS program budget by 50% and providing ERCOT the flexibility to contract ERSs for up to 24 hours.

The remaining dispatchable DR available to ERCOT is from the transmission and distribution service providers' (TDSP) load management programs. These programs provide price incentives for voluntary load reductions from commercial, industrial, and (most recently) residential loads during EEA events. These programs are available for the months of June through September from 1:00–7:00 pm weekdays (except holidays) and are deployed concurrently with ERSs via ERCOT instruction pursuant to agreements between ERCOT and the TDSPs. TDSP Load Management Programs were also provided for the 2022–2023 winter season.

Distributed Energy Resources

ERCOT is currently working with TDSPs on a more consistent process for how DERs are modelled and dispatched in operations and transmission planning cases. One of the remaining issues to make DERs fully visible for operations and planning assessments is to comprehensively capture "unregistered distributed generation (DG)." Although ERCOT currently has requirements for TDSPs to provide limited unregistered DG data (e.g., rooftop solar PV systems), the data is not suitable for modeling. Approved in the 88th Texas Legislature, HB 3390 authorizes ERCOT to annually require TDSPs to provide unregistered DG information deemed necessary for grid reliability assessment.

Generation

Solar PV capacity continues to be rapidly added to Texas RE-ERCOT, so ERCOT is seeing more severe solar ramps. In June 2023, ERCOT implemented a new ancillary service called "ERCOT Contingency Reserve Service." As the wind and solar PV generation fleet continues to grow, the ERCOT Contingency Reserve Service will give the ERCOT control room the capability to deploy resources that can respond within 10 minutes in anticipation of net demand ramps.

ERCOT conducted a study to assess the impact of integrating potential synchronous condensers in the West Texas system. Following the 2021 Odessa event and subsequent events that resulted in generation loss, ERCOT has intensified its efforts to identify potential corrective measures that can enhance the ride-through performance of IBRs. ERCOT has also proposed new grid code requirements for IBRs to improve voltage ride-through performance to align with IEEE Standard 2800. ERCOT recently proposed that all IBRs must meet the voltage ride-through requirements by the end of 2025.

ERCOT also monitors system inertia on a real-time and forward-looking basis. The need for reliability unit commitment is determined for hours when inertia is not sufficient. ERCOT also uses historical system inertia conditions as an input to determine Responsive Reserve Service requirements and amounts needed for different inertia conditions.

Several mitigation strategies to address fuel acquisition risks have been implemented. For example, ERCOT developed a firm fuel supply service that is intended to help maintain system reliability in the event of a natural gas curtailment or other fuel supply disruption. Firm fuel supply service resources are contracted through a competitive procurement process with a single clearing price with bidders offering capacity with on-site fuel or off-site natural gas storage that meets certain qualification criteria. Based on the procurement experience for the 2022–2023 winter season, ERCOT has proposed improvement to the FFSS procurement process. ERCOT considers limitations for natural-gas-fired generators in its Regional Transmission Plan through the inclusion of extreme events that represent

[55] For the *2023 LTRA*, all LFLs are assumed fully curtailable during an energy emergency condition.

the loss of multiple gas generators following the loss of any single gas pipeline. These events are identified by evaluating the gas-pipeline network topology and survey responses from gas generators.

Improved fuel supply data supports overall reliability operations. During recent cold weather events, not all Resource Entities or their affiliates had purchased enough natural gas to satisfy the level of generation their qualified scheduling entity (QSE) indicated was available in their seven-day Current Operating Plan (COP). To help address this issue, ERCOT has proposed rules requiring a QSE to provide gas purchase constraints data that enables ERCOT to assess the generation resource's ability to run at levels indicated in their Current Operating Plan. ERCOT also recently proposed rules that require a QSE that represents a Generation Resource that uses coal or lignite as its primary fuel to submit to ERCOT a declaration of coal and lignite inventory levels. The proposed seasonal declaration process includes requirements for QSEs to notify ERCOT when inventory levels fall below certain thresholds.

Energy Storage

Currently, there is 3,940 MW of on-line utility-scale BESS capacity in Texas RE-ERCOT that is consuming/discharging energy; these mainly provide ancillary services. For example, BESS provides nearly 68% of ERCOT's regulation up and RRS for PFR. Based on the latest project information in the interconnection queue, ERCOT has 11,800 MW of Tier 1 BESS capacity expected to be operational by the end of 2025.

While BESS can help maintain grid reliability, integration of BESS sources has presented some operational challenges. One challenge is that some BESS systems have failed to deliver the required RRS-PFR response when needed. Another concern is that the growth in non-thermal resources will reduce the diversity of resources providing RRS-PFR, which could lead to NERC Reliability Standard violations. To address this issue, a recently completed study investigates whether there are reliability reasons to establish one or more types of limits on Resources providing RRS-PFR.

Since late 2022, ERCOT has been working on identifying modeling changes to better monitor state-of-charge. ERCOT is researching an initiative to build an state-of-change forecasting system using machine learning models. The forecasts would have a five-minute granularity for the next two hours, and hourly granularity for the next 168 hours.

Capacity Transfers and External Assistance

ERCOT has coordination plans in place with neighboring grids. These plans cover dc tie emergency operations, procedures for generators that can switch between grids, and temporary block load transfers.

Transmission

ERCOT completed its 2022 Regional Transmission Plan in December 2022. The plan lists 15 major reliability improvement projects out of a total of 89 proposed projects. Currently, there are $10.26 billion of transmission improvement projects that are expected to be put in service between 2023 and the end of 2028.

In November 2022, the PUCT amended rules to establish a congestion cost savings test for evaluating economic transmission projects; to require FERC to consider historical load, forecasted load growth, and additional load seeking interconnection when evaluating the need for additional ERCOT reliability transmission projects; to provide exemptions to the certificate of convenience and necessity requirements for certain transmission projects; and to require ERCOT to conduct a biennial assessment of the ERCOT grid's reliability and resiliency in extreme weather conditions. The rule will also allow the PUCT to consider the resiliency benefits of proposed transmission projects as determined by ERCOT's new biennial assessment when determining whether to approve a project. ERCOT has begun implementing the amended rules, including the evaluation of economic projects based on the new criteria using the 2022 RTP economic cases.

Other Reliability Issues

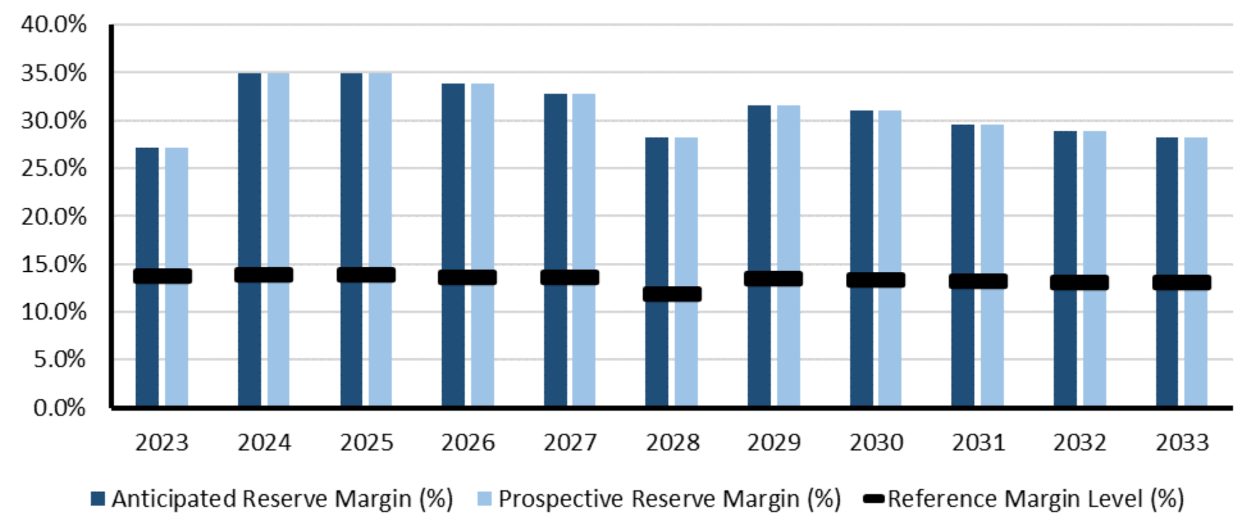
Several proposed rules and rule changes by the U.S. EPA heighten the risk of thermal unit retirements occurring after 2023. ERCOT is working with Generation Owners and state regulators to assess how these rules could impact grid reliability. Unless appropriate reliability safeguards are put in place, there is a risk of regional reliability issues developing, such as overloads on multiple transmission elements as well as the risk of a broader system-wide resource adequacy problem.

WECC-AB

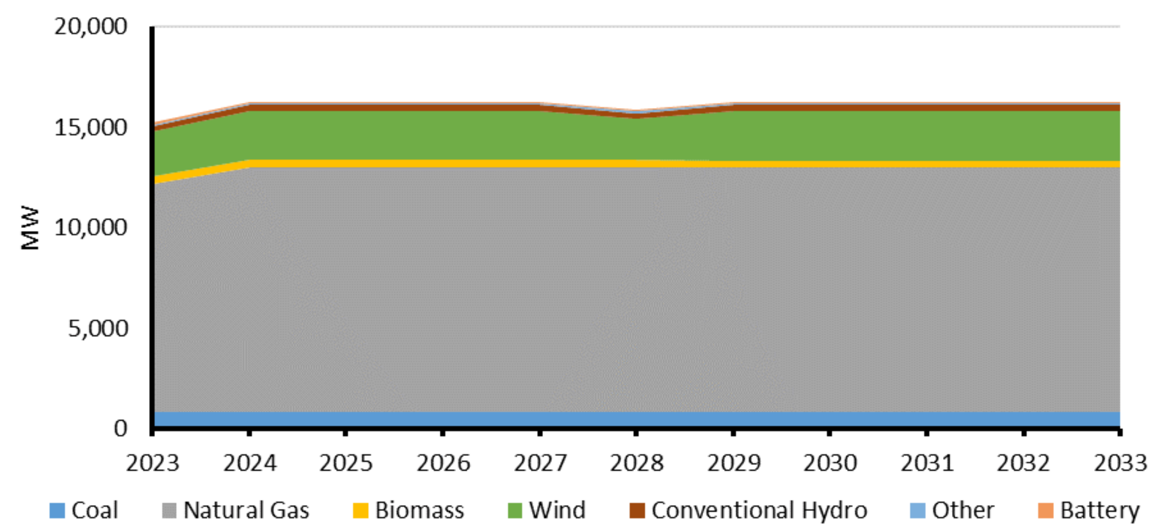
WECC-AB (Alberta) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 90 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between. See **Normal Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	12,065	12,065	12,154	12,257	12,373	12,362	12,413	12,548	12,622	12,689
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	12,065	12,065	12,154	12,257	12,373	12,362	12,413	12,548	12,622	12,689
Additions: Tier 1	2,579	2,579	2,579	2,579	2,437	2,578	2,578	2,578	2,578	2,578
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	1,350	1,771	2,088	2,216	2,187	2,433	2,525	2,579	2,647	2,700
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	13,694	13,694	13,694	13,694	13,435	13,687	13,687	13,687	13,687	13,687
Anticipated Reserve Margin (%)	34.9%	34.9%	33.9%	32.8%	28.3%	31.6%	31.0%	29.6%	28.9%	28.2%
Prospective Reserve Margin (%)	34.9%	34.9%	33.9%	32.8%	28.3%	31.6%	31.0%	29.6%	28.9%	28.2%
Reference Margin Level (%)	13.9%	13.8%	13.7%	13.6%	11.9%	13.4%	13.4%	13.2%	13.1%	13.1%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML.
- Alberta shows the lowest growth rate in the West. The peak hour demand for the Alberta subregion occurs in the winter. The subregion is expected to grow from about 11.9 GW in 2023 to 12.6 GW in 2033, a 6.1% cumulative load growth over the assessment period, or a 0.78% annualized average rate. There was almost no change to the load forecast for this year's plan from last year.
- Several near-term 2023 transmission projects are planned for reliability and economics/congestion. The Provost to Edgerton and Nilrem to Vermilion project is delayed.

Note: the table below reflects the expected 50th percentile, or a 50% probability of energy availability by resource type on the peak hour.

WECC-AB Fuel Composition										
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Coal	800	800	800	800	800	800	800	800	800	800
Natural Gas	12,211	12,211	12,211	12,211	12,211	12,204	12,204	12,204	12,204	12,204
Biomass	336	336	336	336	336	336	336	336	336	336
Wind	2,472	2,472	2,472	2,472	2,054	2,472	2,472	2,472	2,472	2,472
Conventional Hydro	285	285	285	285	301	285	285	285	285	285
Other	81	81	81	81	81	81	81	81	81	81
Battery	88	88	88	88	88	88	88	88	88	88
Total MW	16,273	16,273	16,273	16,273	15,872	16,265	16,265	16,265	16,265	16,265

WECC-AB Assessment

Planning Reserve Margins

The ARM does not fall below the reference margin. The 2024 operable on-peak margin has grown slightly to 26.1% from 22.4% in the last assessment.

Energy Assessment and Non-Peak Hour Risk

WECC uses the Multi-Area Variable Resource Integration Convolution model. The model is a convolution-based probabilistic model and is WECC's chosen method for developing the probability metrics used for assessing demand and variable resource availability in every hour.

WECC performs energy-based probabilistic assessments based on distributions of resource availability and distributions of demand. For resources, WECC uses the 3rd to 97th percentiles of hourly availability. For this reason, WECC does not perform calculations for capacity contributions for VERs or other types of resources, seasonally or otherwise. Similarly, duration is not assumed for storage resources. WECC is still looking at ways of improving BESS modeling.

For variable resources, WECC uses historical hourly generation data to develop expected capacity contributions and the associated probability distributions around the expected capacity contribution on an hourly basis. This is consistent with how the same information was calculated in previous assessments. For the purposes of the LTRA, the expected 50th percentile of the probability density functions is used as the most likely energy contribution from each resource type. For the ProbA, the entire probability density functions are used with the associated probabilities of occurrence. The contributions for all resource types are calculated on a localized, BA footprint. Therefore, solar behavior in one balancing area may not reflect the expected contribution of solar in another balancing area.

Probabilistic Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the one-day-in-ten-year level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than 0.02% of the total area of the demand curve for any given hour).

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	-	-	-
EUE (PPM)	-	-	-
LOLH (hours per Year)	-	-	-
Operable On-Peak Margin	22.4%	26.1%	33.9%

*Provides the 2022 ProbA Results for Comparison

Demand

The peak hour of demand for Alberta occurs in winter in late December around 6:00 p.m. The subregion is expected to grow from about 11.9 GW in 2023 to 12.6 GW in 2033, a 6.1% cumulative load growth over the assessment period, or 0.78% annualized average rate. There was almost no change to the load forecast for this year's plan. Alberta continues to show the lowest growth rate in WECC.

Alberta produces hourly load projections for 20 years with historical load and real GDP, population, employment, oil sands production, gas production, meteorological inputs, and key load impacting events (e.g., past wildfires) in its demand forecasting. The forecast considers transportation electrification and DERs. The next assessment is expected to reflect more explicit modelling of EE, building and industry electrification, and EV charging profiles in the forecast. They incorporate the impact of temperatures on the efficiency of engines and BESS and the unique driving range needs depending on the day of the week.

Demand-Side Management

WECC-AB reported no controllable and dispatchable DR; however, programs are market driven and can be called upon for economic consideration in the AESO area.

Distributed Energy Resources

Alberta has 3,619 MW of existing nameplate wind and 1,165 MW of solar PV. 4,041 MW of wind and 3,310 MW of solar PV are planned. Solar PV is expected to grow at a CAGR of 7.3% while wind capacity is planned to grow at 3.11% and BESS at 2.77%. These rates will lead to a doubling of solar PV, a 40% increase in wind, and a 35% increase in BESS by 2033. BTM resources are netted with load. The renewable resources will be supported by 205 MW of BESS.

Generation

Highlights of Alberta's resource portfolio include almost 800 MW of coal, 11 GW of natural gas (increasing to 16 GW by the end of 2039), and almost 900 MW of conventional hydrogeneration. Almost 800 MW of hydro was built before 1972. No hydro units have retirement dates planned. Alberta has a 30% by 2030 clean energy target.

Energy Storage

Alberta has 90 MW of energy storage and plans to add 105 MW more by 2039, 45 MW of which will be in the next 10 years.

Capacity Transfers and External Assistance

No firm imports are shown to be needed in the model.

Transmission

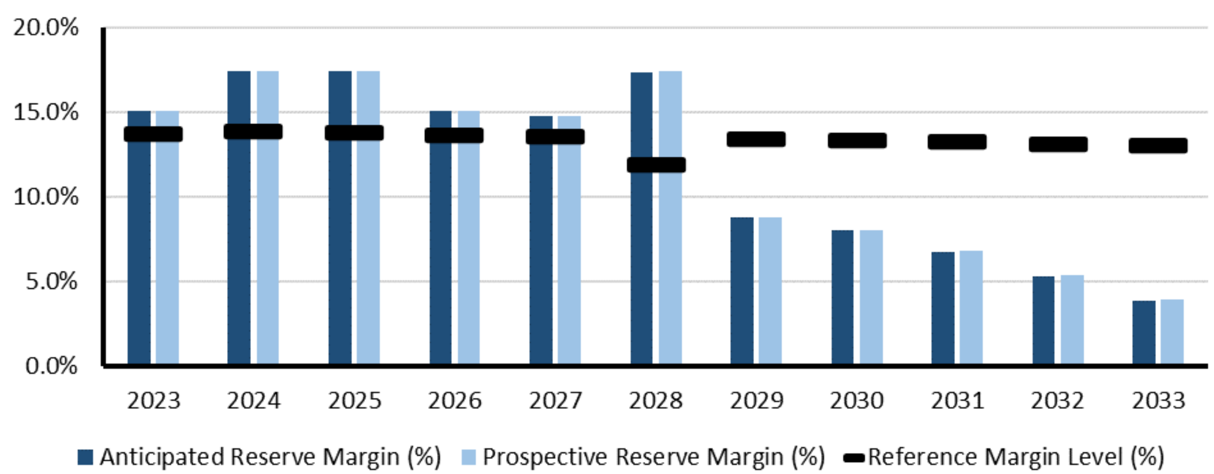
Several near-term 2023 transmission projects are planned for reliability and economics/congestion, covering over 330 miles, and two of which are 400+ kV lines. The Provost to Edgerton and Nilrem to Vermilion project is delayed.

WECC-BC

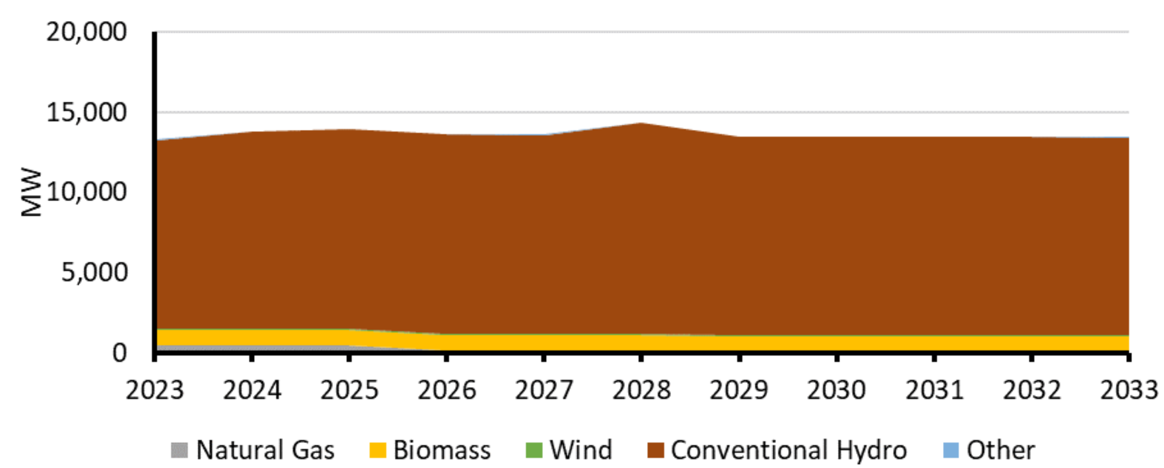
WECC-BC (British Columbia) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 90 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between. See **Elevated Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	11,786	11,897	12,031	12,159	12,270	12,389	12,511	12,657	12,799	12,943
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,786	11,897	12,031	12,159	12,270	12,389	12,511	12,657	12,799	12,943
Additions: Tier 1	672	806	806	1,158	1,627	1,561	1,599	1,599	1,913	2,226
Additions: Tier 2	0	0	0	4	4	4	4	4	4	4
Additions: Tier 3	0	0	2	44	46	44	44	95	95	95
Net Firm Capacity Transfers	0	0	198	334	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	13,166	13,166	13,043	12,799	12,774	11,915	11,915	11,915	11,568	11,220
Anticipated Reserve Margin (%)	17.4%	17.4%	15.1%	14.8%	17.4%	8.8%	8.0%	6.8%	5.3%	3.9%
Prospective Reserve Margin (%)	17.4%	17.4%	15.1%	14.8%	17.4%	8.8%	8.1%	6.8%	5.4%	3.9%
Reference Margin Level (%)	13.9%	13.8%	13.7%	13.6%	11.9%	13.4%	13.4%	13.2%	13.1%	13.1%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM falls below the RML for the peak hour starting in winter 2029–2030.
- BC Planning Reserve Margins are below the RML from December 2029 through the remainder of this assessment period. BC shows a shortfall of existing-certain and net firm transfers, meaning imports may be necessary if new solar PV or conventional hydrogeneration resources were to be delayed. BC is retiring 400 MW of natural gas and refurbishing significant amounts of hydrogeneration that come off-line for about a year.
- The peak hour demand for the BC subregion occurs in the winter. The subregion is expected to grow from about 11.6 GW in 2023 to 12.9 GW in 2033, a slight (average CAGR of 0.25%) increase from the last forecast and an 11.4% load growth over the assessment period, or 1.07% annualized average rate.
- BC is showing hours of demand at risk that are not fully mitigated by the addition of Tier 3 resources.

Note: the table below reflects the expected 50th percentile, or a 50% probability of energy availability by resource type on the peak hour.

WECC-BC Fuel Composition										
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Natural Gas	457	457	170	170	170	61	61	61	61	61
Biomass	944	944	944	944	944	938	938	938	938	938
Wind	111	111	111	111	81	111	111	111	111	111
Conventional Hydro	12,303	12,437	12,404	12,375	13,184	12,343	12,382	12,382	12,347	12,313
Other	22	22	22	22	22	22	22	22	22	22
Total MW	13,837	13,972	13,651	13,623	14,401	13,476	13,514	13,514	13,480	13,446

WECC-BC Assessment

Planning Reserve Margins

For the peak hour, the ARM and PRM fall below the RML starting in winter 2029–2030. BC shows a shortfall of existing-certain and net firm transfers, meaning imports may be necessary if new solar PV or conventional hydrogeneration resources were to be delayed. BC is retiring 400 MW of natural gas and refurbishing significant amounts of hydrogeneration that come offline for about a year.

Energy Assessment and Non-Peak Hour Risk

WECC uses the Multi-Area Variable Resource Integration Convolution model. The model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour.

WECC performs energy-based probabilistic assessments that are based on distributions of resource availability and distributions of demand. For resources, WECC uses the 3rd to 97th percentiles of hourly availability. Looking at all hours of the year and counting existing, Tier 1 and Tier 2 resources, BC shows three potential loss-of-load hours in 2024 and 2025 and 31 om 2026:

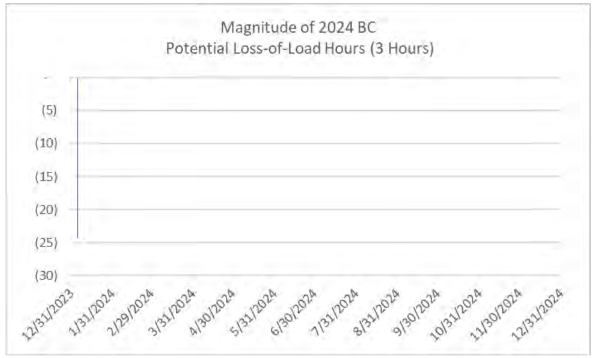
Base Case Summary of Results			
	2024*	**2024**	**2026**
EUE (MWh)	24	47	15,991
EUE (PPM)	0.370	0.71	238
LOLH (hours per Year)	0.002	0.002	0.749
Operable On-Peak Margin	18.5%	12.7%	10.7%

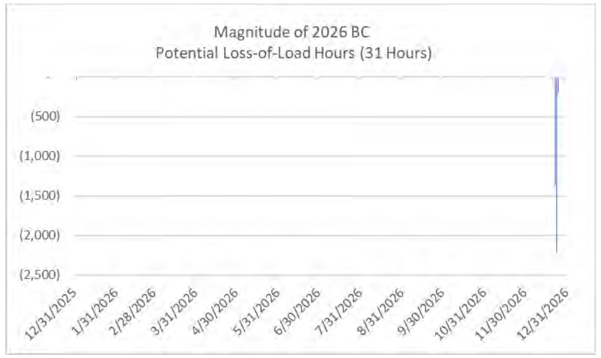
*Provides the 2022 ProbA Results for Comparison

Probabilistic Assessments

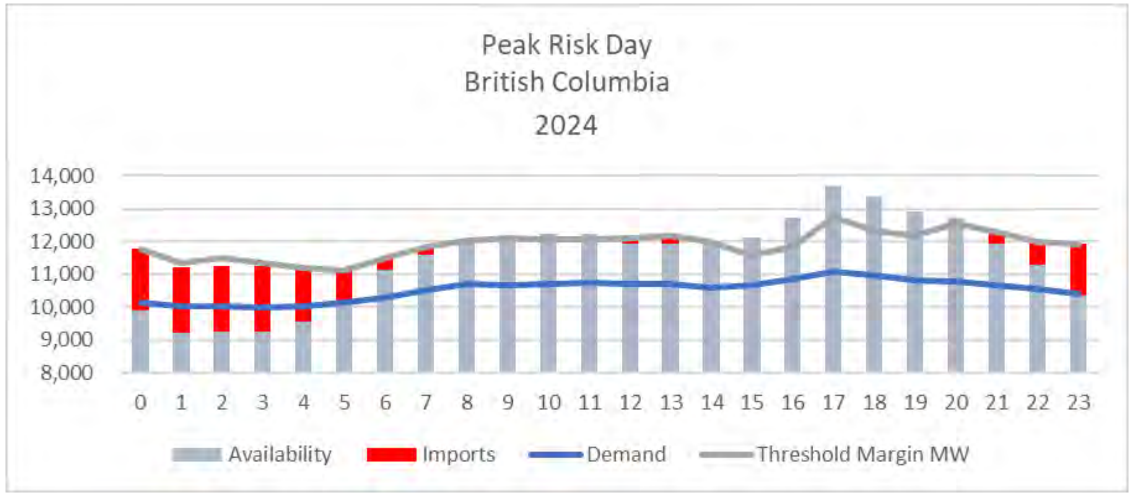
WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the 1-day-in-10-year level, meaning that 99.98% of the demand for each hour is covered by available resources, i.e., the area of overlap is equal to no more than 0.02% of the total area of the demand curve for any given hour.

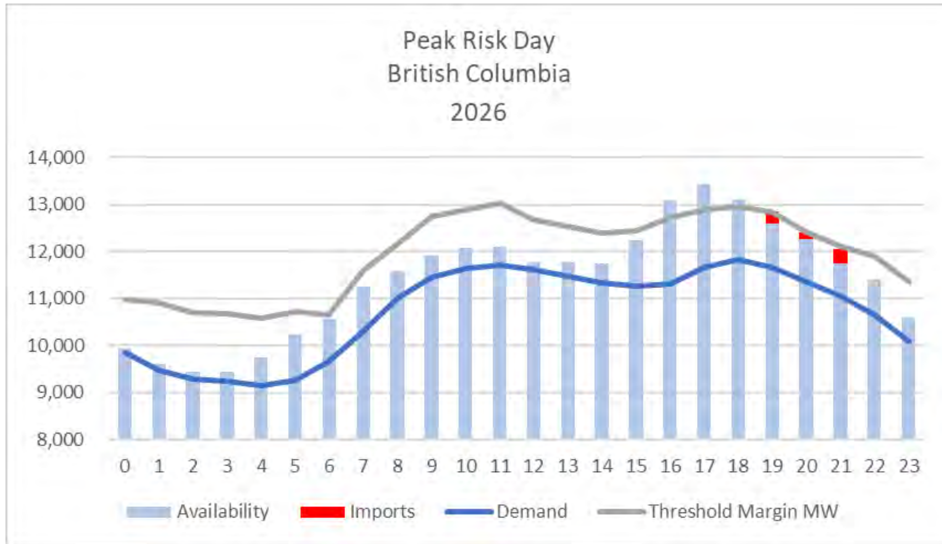
The following plots are outputs from WECC's probabilistic assessment and show the distribution of load loss events in MW across the study years 2024 and 2026.





The following plots are outputs from WECC's probabilistic assessment and show the modeled demand and resources on the peak demand day for 2024 and 2026.





Demand

The peak hour of demand for BC occurs in the winter in late December around 6:00 p.m. The subregion is expected to grow from about 11.6 GW in 2023 to 12.9 GW in 2033, a slight (average CAGR of 0.25%) increase from the last forecast and an 11.4% load growth over this assessment period, or 1.07% annualized average rate.

Demand-Side Management

No controllable or DR program capacities were reported.

Distributed Energy Resources

BTM resources are netted with load. BC has 2 MW of existing solar PV and 30 MW planned, half in 2023 and half in 2027. BC has 15 MW of new wind planned in 2026 to add to its existing portfolio of 747 MW of wind capacity.

Generation

British Columbia is 95% carbon-free today. Its *CleanBC Roadmap to 2030* states, "By 2030, BC will phase out BC Hydro's last gas-powered facility so the electricity we make is 100% clean." In 2023, BC has 462 MW of natural gas, 17 MW of landfill gas, and 143 MW of black liquor fuel. Confirmed retirements increased through 2033 by 1 GW from the last assessment.

Energy Storage

No BESS projects are planned. BC has plentiful hydrogeneration energy storage resources.

Capacity Transfers and External Assistance

BC shows a small amount of import growth in winter 2023–2024 (110 MW), 2026–2027 (198 MW), and 2027–2028 (334) compared to none in last year's result.

Transmission

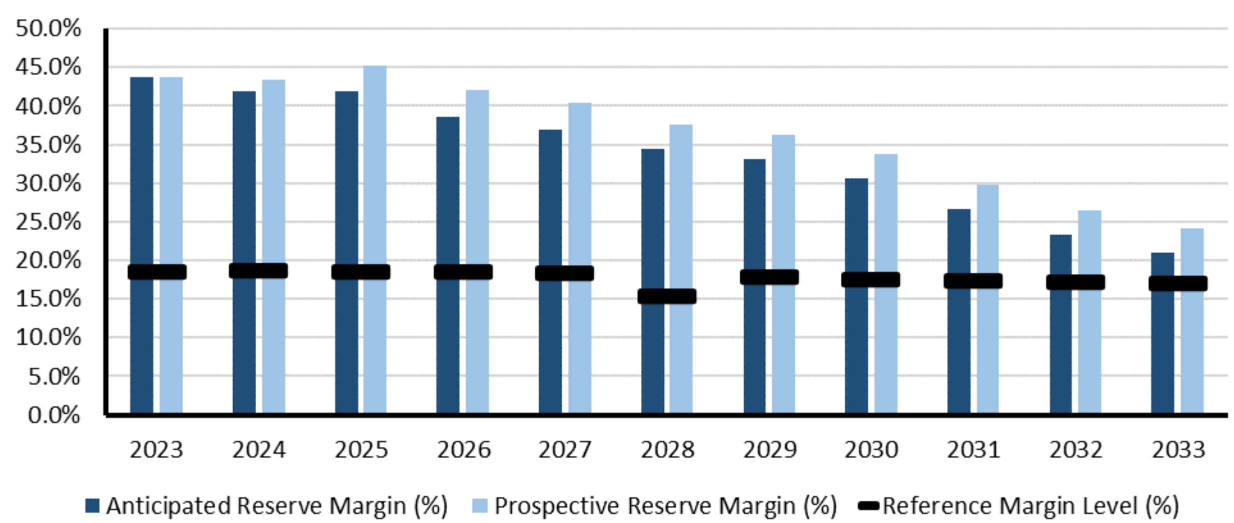
Out of 12 projects, 6 are planned with voltage design of 500 kV and higher in BC. The primary drivers are economics / congestion and reliability. There are also three conceptual projects for 200–299 kV lines for downtown Vancouver.

WECC-CA / MX

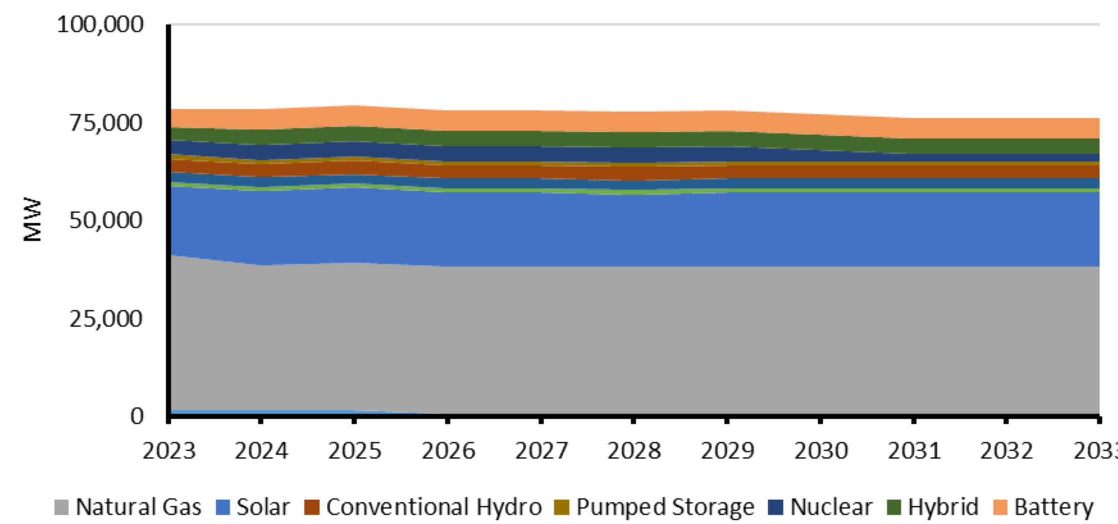
WECC-CA/MX (California/Mexico) is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorizes, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 90 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between. See **Elevated Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	57,178	57,884	58,554	59,380	60,294	61,180	62,213	63,418	64,470	65,449
Demand Response	829	836	841	852	855	866	872	878	883	883
Net Internal Demand	56,349	57,048	57,712	58,529	59,439	60,313	61,341	62,540	63,587	64,566
Additions: Tier 1	10,859	11,771	11,790	11,810	11,610	11,822	11,830	11,830	11,830	11,830
Additions: Tier 2	828	1,964	1,964	1,964	1,932	1,964	1,964	1,964	1,964	1,964
Additions: Tier 3	232	1,957	2,198	3,212	3,316	3,419	3,723	23,547	23,547	23,547
Net Firm Capacity Transfers	0	0	161	338	521	408	1,339	1,572	808	530
Existing-Certain and Net Firm Transfers	69,136	69,136	68,189	68,366	68,281	68,418	68,245	67,374	66,610	66,332
Anticipated Reserve Margin (%)	41.96%	41.82%	38.58%	36.99%	34.41%	33.04%	30.54%	26.65%	23.36%	21.06%
Prospective Reserve Margin (%)	43.43%	45.27%	41.99%	40.34%	37.66%	36.30%	33.74%	29.79%	26.45%	24.10%
Reference Margin Level (%)	18.64%	18.54%	18.42%	18.26%	15.28%	17.81%	17.58%	17.34%	17.17%	17.01%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the reference margin on the peak hour; however, CA/MX shows increasing EUE and LOLH over this assessment period, including 19 hours at risk in 2026 that are not fully mitigated by the addition of Tier 3 resources.
- The ARM falls below the RML in summer of 2027 but is covered by additional resources under the PRM if all 3,212 MW come on-line on time. Starting in summer 2024 onwards, CA/MX shows a shortfall of existing-certain and net firm transfers, meaning imports may be necessary if new resources were to be significantly delayed.
- The peak hour demand for the CA/MX subregion occurs in the summer. The subregion is expected to grow from about 55.5 GW in 2023 to 64.6 GW in 2033, a slight (average CAGR of 0.25%) increase from the last forecast in the long-term but a lower forecast through 2028. This represents a 16.3% load growth over this assessment period, or a 1.52% annualized average rate.
- 16 GW of energy storage is planned, and CA/MX has 2.8 GW of natural gas planned for retirement by the end of 2023, 1.2 GW of coal in 2025, and 2.3 GW of nuclear by the end of 2030.

Note: the table below reflects the expected 50th percentile, or 1 in 2 probability of energy availability by resource type on the peak hour.

WECC-CA/MX Fuel Composition										
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Coal	1,595	1,595	487	487	487	487	487	487	487	487
Petroleum	761	761	761	761	761	757	757	757	757	757
Natural Gas	36,884	37,644	37,644	37,644	37,644	37,639	37,639	37,639	37,639	37,639
Biomass	777	777	777	777	777	775	775	775	775	775
Solar	19,095	19,112	19,130	19,150	18,317	19,166	19,174	19,174	19,174	19,174
Wind	994	994	994	994	1,354	994	994	994	994	994
Geothermal	2,434	2,434	2,434	2,434	2,434	2,428	2,428	2,428	2,428	2,428
Conventional Hydro	3,453	3,453	3,453	3,453	3,495	3,453	3,453	3,453	3,453	3,453
Pumped Storage	1,034	1,034	1,034	1,034	1,057	1,034	1,034	1,034	1,034	1,034
Nuclear	3,880	3,880	3,880	3,880	3,880	3,874	2,770	1,667	1,667	1,667
Hybrid	3,942	3,942	3,942	3,942	3,882	3,940	3,940	3,940	3,940	3,940
Other	29	29	29	29	29	29	29	29	29	29
Battery	5,117	5,252	5,252	5,252	5,252	5,256	5,256	5,256	5,256	5,256
Total MW	79,995	80,908	79,818	79,839	79,370	79,832	78,736	77,632	77,632	77,632

WECC-CA/MX Assessment

Planning Reserve Margins

The reserve margins would fall below the RML in summer of 2027 without Tier 1 resources (3,212 MW) coming on-line. Starting in summer 2024 onwards, CA/MX shows a shortfall of existing-certain and net firm transfers, meaning imports may be necessary if new resources were to be significantly delayed.

Energy Assessment and Non-Peak Hour Risk

WECC uses the Multi-Area Variable Resource Integration Convolution model. The model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour.

WECC performs energy-based probabilistic assessments that are based on distributions of resource availability and distributions of demand. For resources, WECC uses the 3rd to 97th percentiles of hourly availability. Looking at all hours of the year and counting existing, Tier 1 and Tier 2 resources, CA/MX shows 19 potential loss-of-load hours in 2026:

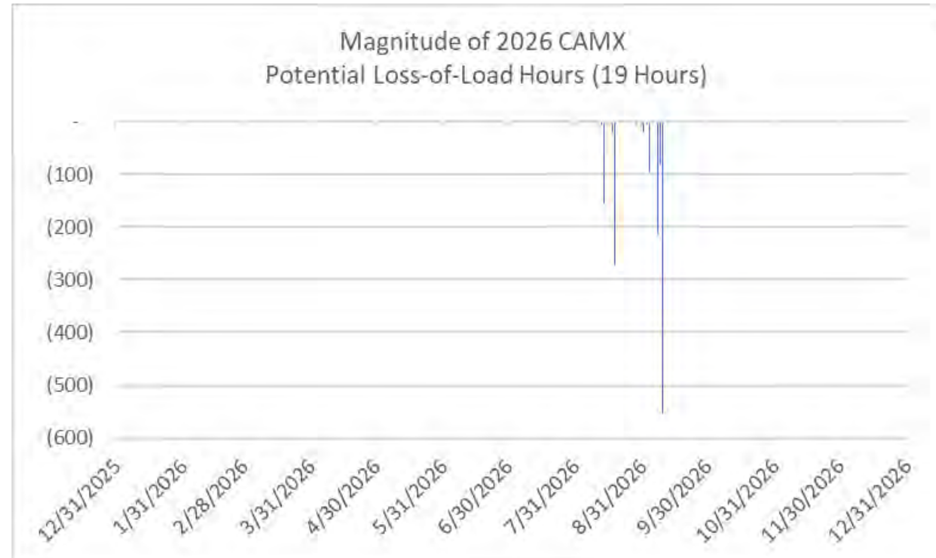
Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	37,305	-	11,731
EUE (PPM)	136	-	43
LOLH (hours per Year)	0.721	-	0.227
Operable On-Peak Margin	30.3%	30.7%	27.5%

* Provides the 2022 ProbA Results for Comparison

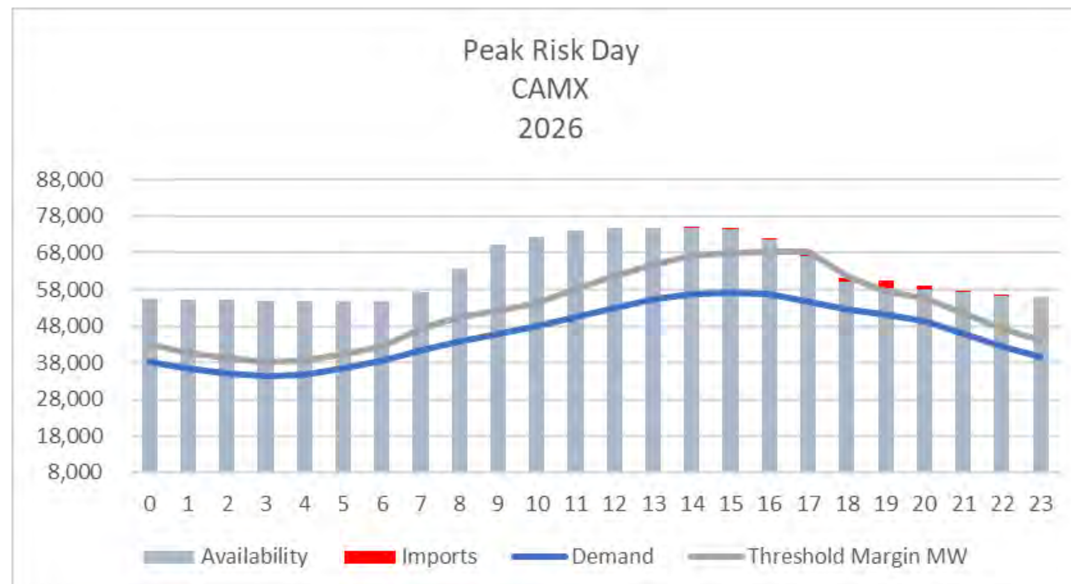
Probabilistic Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the 1-day-in-10-year level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than 0.02% of the total area of the demand curve for any given hour).

The following plot is output from WECC's probabilistic assessment and shows the distribution of load loss events in MW across the 2026 study year.



The following plot is output from WECC's probabilistic assessment and shows the modeled demand and resources on the peak demand day for 2026.



Demand

The peak hour demand for the CA/MX subregion occurs in the summer around the second week of September at 3:00 p.m. The subregion is expected to grow from about 55.5 GW in 2023 to 64.6 GW in 2033, a slight (average CAGR of 0.25%) increase from the last forecast in the long-term but a lower forecast through 2028. This represents a 16.3% load growth over this assessment period, or 1.52% annualized average rate.

Load forecasts are developed by correlation with econometric and demographic factors. In CA/MX, these include population, households, personal income, energy rates, commercial floorspace, employment, and precipitation. For transportation, vehicle attributes, fuel prices, incentives, vehicle miles traveled, duty cycle, and consumer preference surveys contribute to analyses.

Existing electrification is captured through building surveys and DMV vehicle registration data. Multiple scenarios are designed for both vehicle and building electrification to reflect a variety of state and local ordinances.

There are local policies that have taken effect since the last assessment, driving building electrification. Examples include the following:

- Sacramento's All-Electric Only ordinance that went into effect January 1, 2023, for all new construction under three stories and all new construction regardless of height in 2026.
- San Luis Obispo passed an All-Electric Only ordinance for all new construction with an exception for certain natural gas end uses through 2025 if no all-electric alternative is commercially available or viable (for commercial kitchens, ADU water or space heating and for public swimming pools)
- Pasadena passed an All-Electric Only ordinance for new construction (or 50%+ renovations) multifamily, nonresidential and mixed-use buildings with exceptions for ADUs, commercial kitchens, and essential buildings (defined as medical healthcare facilities and research and development labs).

For a full list of electrification measures reflected in zero emission building ordinances, visit the Building Decarbonization Website.[56]

Additionally, there are transportation electrification goals in place to increase the number of EVs. The California Air Resources Board is regulating all new consumer vehicles sold to produce zero emissions by 2035. Seventeen other states adopted similar rules. The California Energy Commission (CEC) provided a calculator to estimate high, low, and expected impact levels by assuming various levels of meeting the targets of Executive Order B-48-18.

Demand-Side Management

CA/MX DSM is expected to grow from 829 MW in summer 2024 to 883 MW in summer 2033. In addition to the controllable and dispatchable programs, voluntary conservation has played a significant role during extreme events. During the widespread heatwave in 2020, demand reductions of approximately five GW were realized, exceeding the amounts available from dispatchable and controllable programs. For comparison, during the 2022 heat event, demand reductions were approximately 1,900 MW, reflecting the reduced geographic area of that event.

The CEC is utilizing the federal Inflation Reduction Act to provide funding for whole house EE. For low to moderate income households, it will also fund point of sale rebates for panel upgrades and qualified high-efficiency electric appliances, such as heat pumps for space heating and cooling. The programs will launch in 2024.

Some areas reported unavailable capacity when connecting new customer or upgrading service along with delays receiving the equipment, such as switchboards and switchgears, needed to connect new electrical services.

Distributed Energy Resources

BTM resources are netted with load. Utility distribution companies are required under Title 20 to report location, capacity, and technology type to the CEC for all interconnected systems, including BTM. Owners of systems larger than one MW must also report generation. Generation for smaller, less than one MW systems is either modeled according to capacity or purchased from third-party vendors.

One area adopted a bass diffusion model to estimate the rooftop PV impact to system load in terms of annual capacity and energy, capturing all BTM installations.

California changed its net metering tariff to a net billing tariff in 2023. This is expected to create a drag on BTM solar PV installations in the near term due in large part to the increased payback period for the investment. California has accounted for the largest share of BTM solar PV in WECC.

[56] **Building Decarbonization**

Generation

CA/MX has almost three GW of natural gas planned for retirement by the end of 2023, over one GW of coal in 2025, and 2.3 GW of nuclear by the end of 2030. In total, almost six and a half GW of coal, nuclear, and natural gas are planned to be retired by 2030. This is offset by 2.8 GW of planned new natural gas, 665 MW of geothermal, 644 MW of petroleum, 627 MW of pumped storage, 35 MW of new conventional hydro, and 55 MW of biomass capacity.

There are several renewable portfolio or carbon-free electricity targets in CA/MX that contribute to a changing resource mix. For example, the electric system operator in Mexico, CENACE, is aiming for 35% by 2025–2029 and California for 60% by 2030.

Coal deliveries were reduced for one area for the past two years, resulting in a reduction of available generation capacity for the foreseeable future. The area has implemented a fuel rationing procedure to maximize coal inventories.

Supply chain issues continue to be a major factor affecting the delivery of new resources, such as utility-scale solar PV and transmission line upgrades. These supply chain issues along with the increased costs of component suppliers have resulted in the need for renegotiations. Balancing areas report developers are seeing a 75-to-80-week delivery time for transformers and circuit breaker equipment compared to the typical 24 weeks prior to Covid-19. PV module deliveries have been significantly delayed for utility-scale solar PV projects. For example, the deliveries of solar modules delayed one very large multi-hundred MW project by 12 months.

Energy Storage

CA/MX is planning on adding 16 GW of energy storage to its almost three GW of existing energy storage, 6.6 GW of which are planned by the end of 2025.

Capacity Transfers and External Assistance

The summer imports through 2029 and compared to last year are decreasing, then increasing 2030 onwards. Winter firm imports are slightly above last year’s results (ranging from 240–632 MW).

Transmission

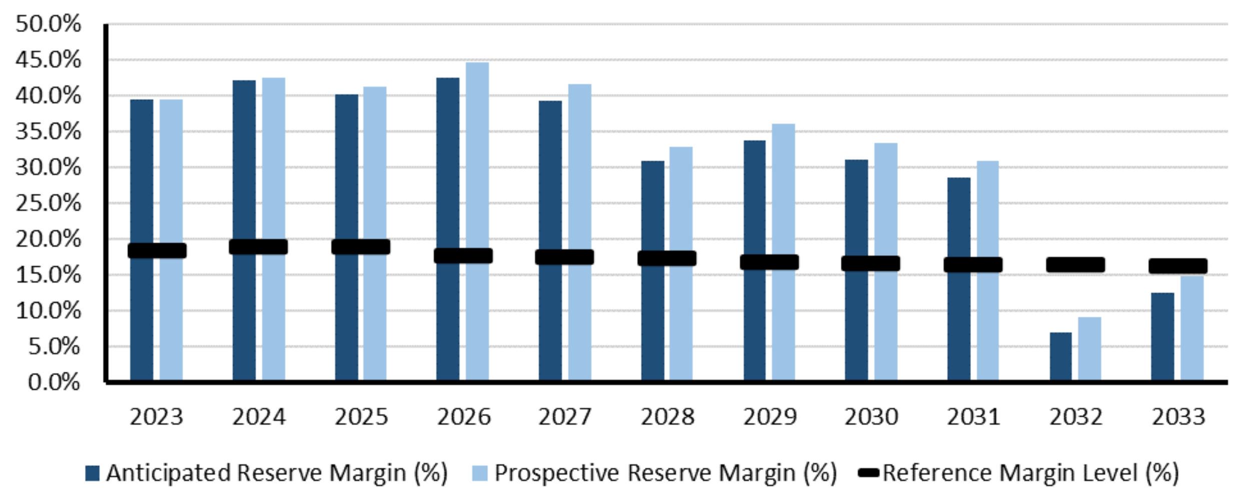
There are 10 planned and 2 conceptual projects with voltage designs of 500 kV and higher in CA/MX, representing a total addition of more than 1,000 miles. A diverse set of 3 conceptual projects spanning 160 miles, driven primarily by economics, congestion, and reliability needs are also in the works. There are 75 projects outside of the conceptual phase and in planning for almost 1,600 miles, plus 6 projects under construction for 35 miles.

WECC-NW

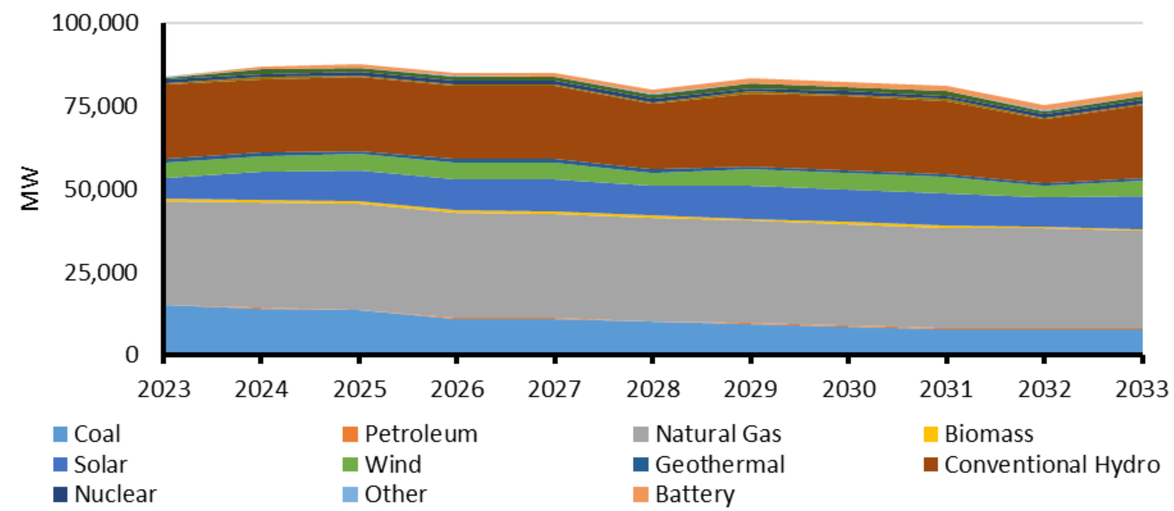
WECC-NW (Northwest) is a summer-peaking assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming and parts of California, Nebraska, Nevada, and South Dakota. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 90 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between. See **Elevated Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	62,899	64,432	65,427	67,732	69,449	70,241	70,881	71,453	73,043	73,661
Demand Response	902	912	917	929	947	955	965	976	872	881
Net Internal Demand	61,997	63,520	64,510	66,803	68,502	69,286	69,916	70,477	72,171	72,780
Additions: Tier 1	7,190	8,450	8,846	9,020	8,938	9,691	9,746	9,801	9,303	9,895
Additions: Tier 2	229	671	1,351	1,463	1,365	1,611	1,628	1,628	1,502	1,645
Additions: Tier 3	676	2,131	3,798	3,865	5,820	7,403	8,994	9,889	10,468	11,898
Net Firm Capacity Transfers	1,157	1,290	6,785	8,002	9,826	9,255	9,293	9,383	1,957	2,103
Existing-Certain and Net Firm Transfers	80,900	80,584	83,100	84,066	80,760	83,028	81,942	80,831	67,904	71,957
Anticipated Reserve Margin (%)	42.1%	40.2%	42.5%	39.3%	30.9%	33.8%	31.1%	28.6%	7.0%	12.5%
Prospective Reserve Margin (%)	42.5%	41.2%	44.6%	41.5%	32.9%	36.1%	33.5%	30.9%	9.1%	14.7%
Reference Margin Level (%)	18.9%	18.9%	17.6%	17.6%	17.4%	16.8%	16.5%	16.4%	16.5%	16.3%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM falls below the RML for the peak hour starting in summer 2032.
- WECC-NW's demand-side management programs are expected to decline from 902 MW in summer 2024 to 881 in summer 2033 and grow from 584 in winter 2024, peaking in 2031 around 686 MW and then declining to 596 MW in winter 2033.
- Significant demand growth coupled with 19 GW of resources planned to retire from 2023 through 2034 are contributing to increasing loss-of-load hours over the planning period. There are several states in the WECC-NW renewable portfolio and carbon-free electricity targets driving the changes in resource portfolios in addition to a plethora of local building, transportation, and industrial electrification measures.

Note: the table below reflects the expected 50th percentile, or 1 in 2 probability of energy availability by resource type on the peak hour.

WECC-NW Fuel Composition										
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Coal	13,883	13,450	10,834	10,834	9,961	9,272	8,631	7,675	7,678	7,675
Petroleum	285	285	285	285	285	279	279	279	280	279
Natural Gas	31,882	31,882	31,634	31,457	31,053	30,862	30,519	30,388	30,144	29,414
Biomass	775	773	767	737	731	671	671	671	669	656
Solar	8,373	9,130	9,492	9,660	8,877	9,883	9,883	9,815	8,622	9,767
Wind	4,864	5,077	5,065	5,065	4,119	5,058	5,037	4,998	3,779	4,928
Geothermal	910	892	926	890	905	858	740	740	670	467
Conventional Hydro	22,220	22,216	22,119	22,111	19,768	22,090	22,090	22,083	19,116	22,081
Pumped Storage	448	448	448	448	434	448	448	448	402	448
Nuclear	1,097	1,097	1,097	1,097	1,081	1,095	1,095	1,095	1,091	1,095
Hybrid	1,293	1,293	1,293	1,293	1,394	1,430	1,430	1,430	1,117	1,157
Other	78	78	78	78	78	77	77	77	78	77
Battery	824	1,124	1,124	1,129	1,186	1,440	1,495	1,550	1,605	1,705
Total MW	86,933	87,745	85,161	85,084	79,872	83,464	82,395	81,249	75,250	79,749

WECC-NW Assessment

Planning Reserve Margins

The ARM falls below the RML for the peak hour starting in summer 2032 and remains insufficient with the additional Tier 2 resources under the PRM following five GW planned for retirement between 2029 and 2032.

Energy Assessment and Non-Peak Hour Risk

WECC uses the Multi-Area Variable Resource Integration Convolution model. The model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour.

WECC performs energy-based probabilistic assessments that are based on distributions of resource availability and distributions of demand. For resources, WECC uses the 3rd to 97th percentiles of hourly availability. Looking at all hours of the year and counting existing Tier 1 and Tier 2 resources, WECC-NW shows 28 potential loss-of-load hours in 2026, which falls to 15 hours at risk when Tier 3 resources are considered.

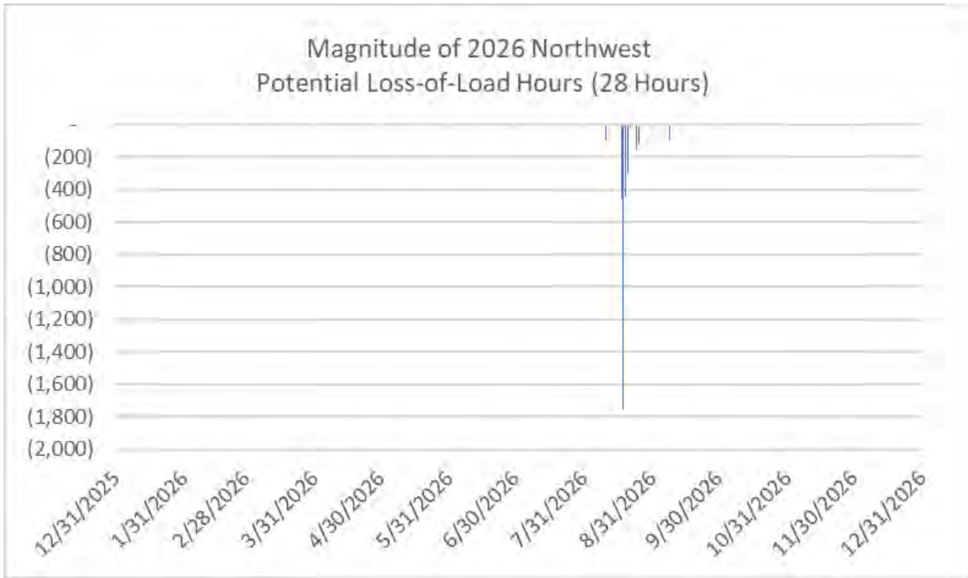
Base Case Summary of Results			
	2024*	**2024**	**2026**
EUE (MWh)	1,722	-	8,101
EUE (PPM)	4	-	21
LOLH (hours per Year)	0.036	-	0.132
Operable On-Peak Margin	25.8%	37.6%	32.5%

* Provides the 2022 ProbA Results for Comparison

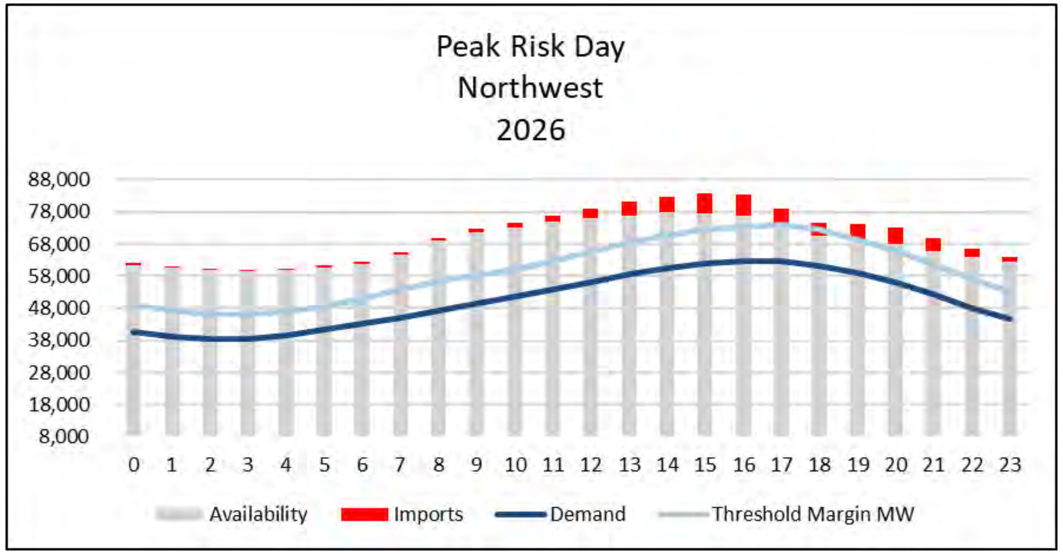
Probabilistic Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the one-day-in-ten-year level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than 0.02% of the total area of the demand curve for any given hour).

The following plot is output from WECC's probabilistic assessment and shows the distribution of load loss events in MW across the 2026 study year.



The following plot is output from WECC's probabilistic assessment and shows the modeled demand and resources on the peak demand day for 2026.



Demand

The peak hour demand for WECC-NW occurs in the summer anywhere from mid-July to late-August around 4:00 p.m.. The subregion is expected to grow from about a 72 GW peak in 2023 to 84 GW in 2033; however, there are significant differences between balancing areas with some showing almost 50% growth compared to last year while others show slight shrinking load. This has been reported to be due to new data centers. This is contributing to some BAs showing a need for increased imports in the model compared to last year. This represents a nearly 17% load growth over this assessment period.

Additionally, there are transportation electrification goals in place to increase the number EVs. WECC-NW serves a portion of Northern California, where the California Air Resources Board is regulating all new consumer vehicles sold to produce zero emissions by 2035. Seventeen other states adopted similar rules. Oregon and Washington will ban the sale of new gas cars by 2035. ACEEE's top three states in the 2023 Transportation Electrification Scorecard are California, Oregon, and Washington for planning and goal setting. The West dominates the top states supporting transportation transitions to electric vehicles with Colorado in 6th and Nevada tied for 12th.

Electrification assumptions are incorporated into the load projects for most areas in WECC-NW, including transportation, building, and some industrial. Several cities across the Northwest have implemented building electrification policies, including Salt Lake City, which has an all-electric requirement, and Park City, Utah, where there are programs that encourage the elimination of natural gas and propane with similar programs in Boulder and Superior, Colorado, respectively. Washington has both statewide and local electrification requirements.

Note that many balancing areas reported supply chain risks in WECC-NW. These include material delays, wires, and meters, causing a variety of projects to be postponed, including connecting new customers. A few said human resources (i.e., staffing) is an equally large problem.

Demand-Side Management

WECC-NW's demand-side management programs are expected to decline from 902 MW in summer 2024 to 881 in summer 2033 and grow from 584 in winter 2024, peaking in 2031 around 686 MW and then declining to 596 MW in winter 2033.

Distributed Energy Resources

BTM resources are netted with load. Wind is expected to grow at CAGR of 2.65%, solar PV at 6.38%, BESS at 19.69% and hybrid resources at almost 28%. Existing solar PV accounts for eight GW of installed capacity and more than 10 GW of capacity are planned through 2033. Over 7.5 GW of wind is planned to be added through 2033 to the existing capacity of over 20 GW.

Generation

There are 19 GW of resources planned to retire from 2023 through 2034. This includes 128 MW of biomass, 8 GW of coal, over 6 GW of natural gas, and 6 MW of petroleum. There are several states in the WECC-NW with renewable portfolio and carbon-free electricity targets that are driving the changes in resource portfolios. These include Montana (15% 2015-19), Nevada (50% by 2030), Oregon (35% by 2030), and Washington state (greenhouse gases neutral with limited offsets by 2030).

Many balancing areas reported supply chain risks in WECC-NW. Supply chain issues are resulting in longer lead times for parts and equipment, delaying resource restoration after forced outages. The impact has been project schedules being extended to account for the procurement issues. Power circuit breaker lead times were being continually delayed. These issues are affecting all resources, both new facilities and updates to existing facilities. It is challenging to prioritize and schedule outages and decisions between stacking versus shifting.

The supply chain issues are expected to contribute to deviations from resource plans in the near term. For instance, solar PV panel supply chain issues have indefinitely postponed the incorporation of a new power supply resource that had been planned for January 2024.

Additionally, coal availability declined, and prices rose due to increased demand spurred by high natural gas prices and weather events. Those issues, combined with transportation constraints, resulted in lower availability. Supply chain issues limited coal inventory during peak hours of the day. This resulted in a new strategy for how units are scheduled on a day-ahead basis and how power is purchased in the real time markets.

Energy Storage

The NW is planning significant increases in BESS, including 425 MW in 2023, 680 MW in 2024, and another 1,130 MW through 2030. Existing BESS capacity is 172 MW.

Capacity Transfers and External Assistance

Significant increases from 1.6 GW to over 9 GW in the latter half of the forecast years compared to no year over 1 GW in the 2022 LTRA results.

Transmission

Four 500 kV and higher planned projects are in WECC-NW. Idaho Power's new 300-mile Boardman-to-Hemingway 500 kV line, originally proposed in 2007 and projected to be in-service in 2013, has cleared its major regulatory requirements and should break ground this year or in 2024 and be energized as early as 2026.

The balancing areas in WECC-NW report supply chain delays to replace, upgrade, and expand transmission equipment, which has delayed project schedules. Transformer lead times reached three years. Breaker lead times were 85 weeks, or over a year and a half. Instrument transformers and other items were also experiencing much longer lead times, causing significant delays to project schedules.

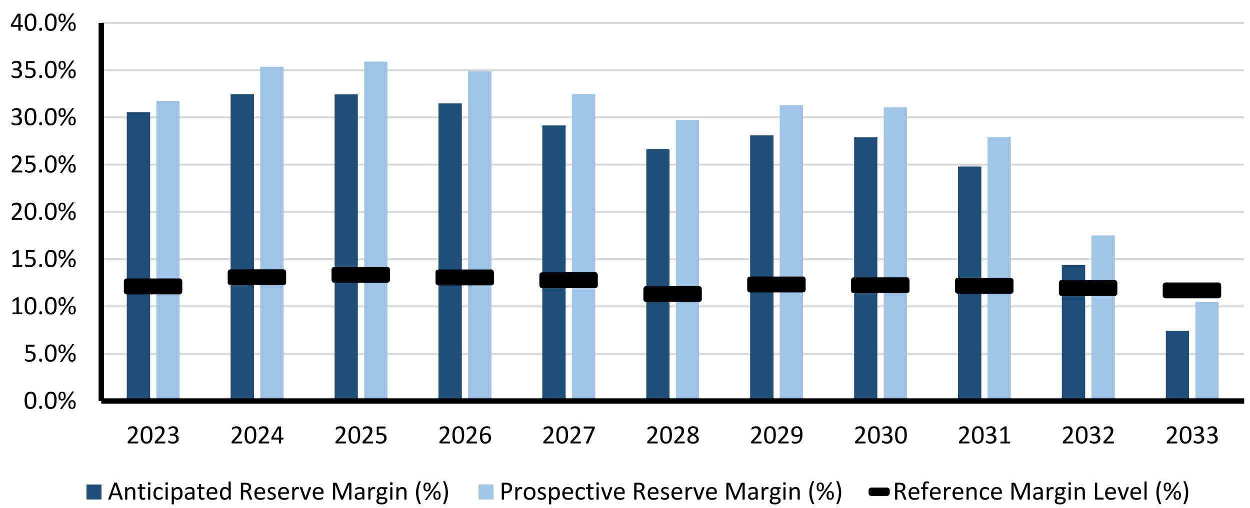
One key transmission risk is unusual outages scheduled during peak summer seasons that limit generation on baseloads, which can ultimately impact reliability.

WECC-SW

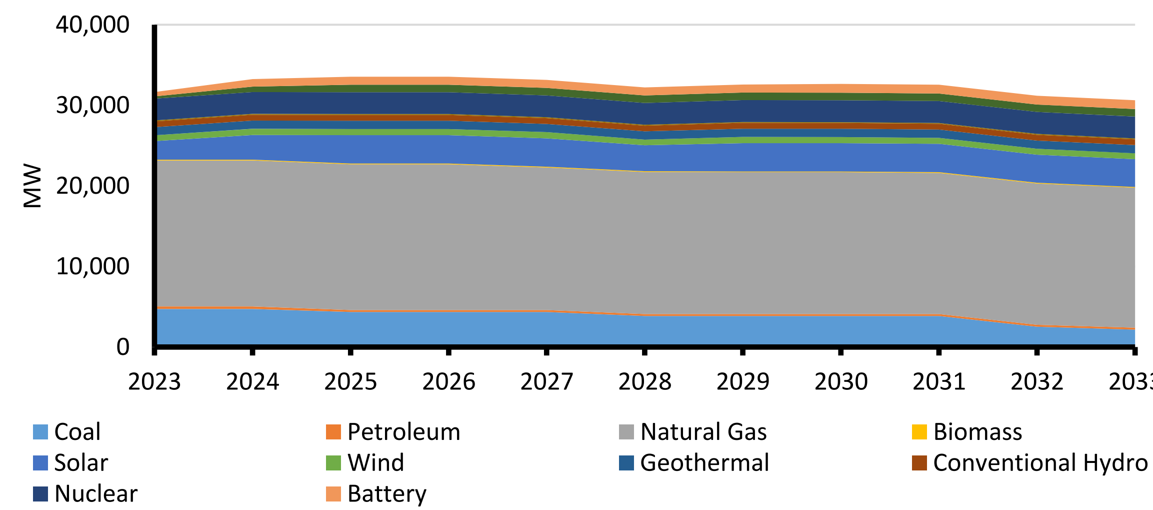
WECC-SW (Southwest) is a summer-peaking assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and part of California and Texas. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 90 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada as well as the northern portion of Baja California in Mexico and all or portions of the 14 Western United States in between. See **Elevated Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	26,749	27,499	28,294	29,029	29,554	29,973	30,400	30,529	30,672	31,234
Demand Response	383	419	384	394	385	388	391	384	394	385
Net Internal Demand	26,366	27,080	27,910	28,635	29,169	29,585	30,009	30,145	30,278	30,848
Additions: Tier 1	3,441	4,217	4,217	4,217	4,046	4,219	4,308	4,308	4,308	4,308
Additions: Tier 2	764	937	948	948	894	948	948	948	948	948
Additions: Tier 3	947	2,074	4,593	4,938	5,081	5,861	6,511	7,277	8,489	8,697
Net Firm Capacity Transfers	1,676	2,316	3,148	3,824	4,731	5,324	5,736	5,072	3,448	2,512
Existing-Certain and Net Firm Transfers	31,484	31,648	32,480	32,765	32,905	33,678	34,075	33,313	30,327	28,828
Anticipated Reserve Margin (%)	32.5%	32.4%	31.5%	29.1%	26.7%	28.1%	27.9%	24.8%	14.4%	7.4%
Prospective Reserve Margin (%)	35.4%	35.9%	34.9%	32.5%	29.7%	31.3%	31.1%	27.9%	17.5%	10.5%
Reference Margin Level (%)	13.1%	13.4%	13.1%	12.8%	11.3%	12.3%	12.2%	12.2%	12.0%	11.7%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML for the peak hour until Summer 2033 when it shows a shortfall of existing-certain and net firm transfers, meaning imports may be necessary if new capacity were to be delayed.
- Looking at all hours, WECC-SW shows demand at risk starting in 2025 and increasing over this assessment period, which is slightly mitigated and delayed until 2027 with the consideration of on-time Tier 3 resource commissioning.

Note: the table below reflects the expected 50th percentile, or 1 in 2 probability of energy availability by resource type on the peak hour.

WECC-SW Fuel Composition										
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Coal	4,724	4,354	4,354	4,354	3,859	3,852	3,852	3,852	2,527	2,159
Petroleum	318	241	241	241	241	241	241	241	241	241
Natural Gas	18,113	18,084	18,084	17,692	17,622	17,604	17,604	17,522	17,522	17,377
Biomass	94	94	94	94	94	94	94	94	94	94
Solar	3,063	3,517	3,517	3,517	3,222	3,517	3,517	3,516	3,493	3,442
Wind	770	770	770	770	708	770	756	741	727	727
Geothermal	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022
Conventional Hydro	719	719	719	719	701	719	719	719	719	719
Pumped Storage	110	110	110	110	113	110	110	110	110	110
Nuclear	2,714	2,714	2,714	2,714	2,714	2,717	2,717	2,717	2,717	2,717
Hybrid	668	929	929	929	929	930	930	930	930	930
Battery	933	995	995	995	995	996	1,085	1,085	1,085	1,085
Total MW	33,249	33,549	33,549	33,157	32,220	32,573	32,647	32,548	31,186	30,623

WECC-SW Assessment

Planning Reserve Margins
ARM and PRM fall below the RML on the peak hour in Summer 2033. Starting in summer 2033, WECC-SW shows a shortfall of existing-certain and net firm transfers, meaning imports may be necessary if new capacity were to be delayed.

Energy Assessment and Non-Peak Hour Risk
WECC uses the Multi-Area Variable Resource Integration Convolution model. The model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour.

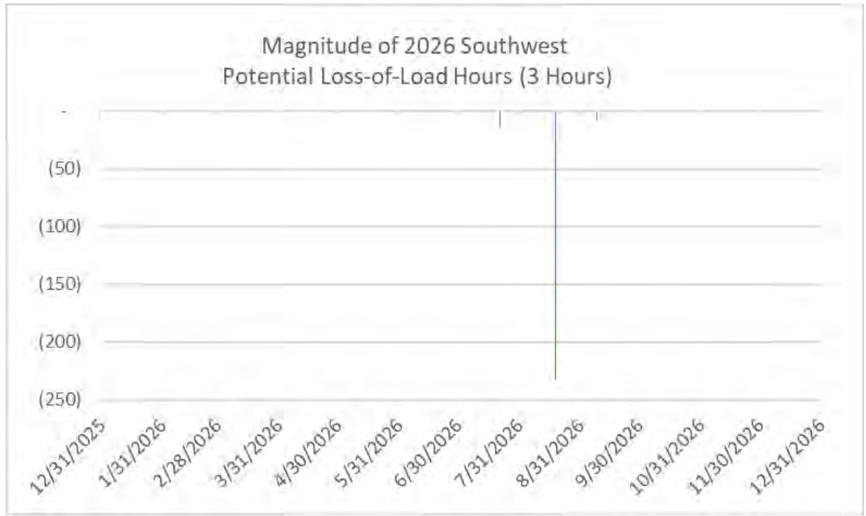
WECC performs energy-based probabilistic assessments that are based on distributions of resource availability and distributions of demand. For resources, WECC uses the 3rd to 97th percentiles of hourly availability. Looking at all hours of the year and counting existing, Tier 1 and Tier 2 resources, WECC-SW shows three potential loss-of-load hours in 2026, which falls to zero hours at risk when Tier 3 resources are considered.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	84	-	818
EUE (PPM)	1	-	6
LOLH (hours per Year)	0.003	-	0.031
Operable On-Peak Margin	28.1%	18.3%	18.4%

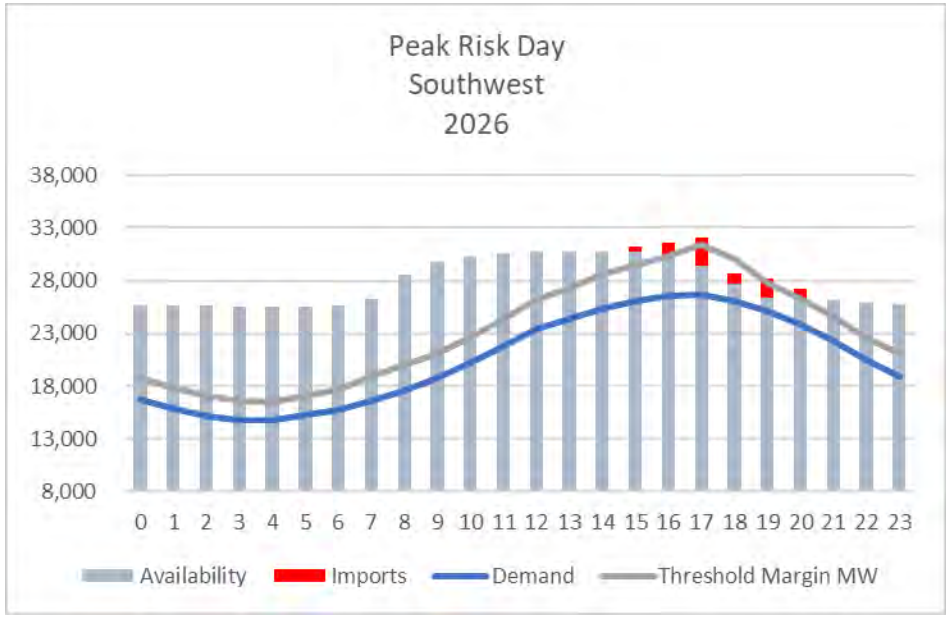
* Provides the 2022 ProbA Results for Comparison

Probabilistic Assessments
WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the 1-day-in-10-year level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than 0.02% of the total area of the demand curve for any given hour).

The following plot is output from WECC's probabilistic assessment and shows the distribution of load loss events in MW across the 2026 study year.



The following plot is output from WECC's probabilistic assessment and shows the modeled demand and resources on the peak demand day for 2026.



Demand

The Southwest's peak demand (summer) CAGR is 1.68%, WECC-SW load forecast is nearly the same as last year's, a slight drop from last year's 1.72%. Over the planning period, WECC-SW goes from a summer peak of almost 27 GW in 2023 to 33 GW by 2033 or 20% over this assessment year. WECC-SW peaks in mid-July around 5:00 p.m.

The load forecasts reflect different degrees of electrification. Most include transportation electrification assumptions, but few are incorporating building and industry electrification impacts. Data centers are another load compounding impact being studied.

Some areas have reported delays energizing customers due to supply chain issues. At times, material has not been available to complete some overhead services on schedule. Alternative design solutions have had to be explored. Due to the supply chain shortages, subdivision projects have been delayed. Chip shortages have impacted meter orders.

Demand-Side Management

WECC-SW summer demand-side management programs are expected to grow from 383 MW in 2024 to 385 MW in 2033 and from 288 MW in winter 2024 to 318 MW by winter 2033.

Distributed Energy Resources

BTM resources are netted with load.

Generation

WECC-SW is retiring 4.1 GW of capacity over this assessment period, which includes almost three GW of coal and 780 MW of natural gas. There are several states in WECC-SW with a renewable portfolio and carbon-free electricity targets driving the changes in resource portfolios. These include Arizona (15% 2025–2029), New Mexico (50% by 2030), and individual utility independent goals.

Almost 350 MW of new geothermal capacity is planned along with 1,230 MW of new natural gas by 2026. Additionally, over 15 GW of new solar PV is in the resource plans, almost 1,200 MW of wind.

Due to fuel shortfalls in 2022, some areas have revamped their communications to manage potential fuel shortages better proactively. Additionally, pipeline outages have been resolved and are now fully available.

Supply chain constraints are impacting WECC-SW. In response, procurement timelines have been accelerated to earlier in projects' processes. Generator step-up transformers have a longer lead time than in prior years, impacting the commercial operation date of new resources in plans through 2026. New utility-scale renewable resource timing has been unstable due to raw material and earth metal accessibility.

Energy Storage

The SW has 3.7 GW of energy storage planned in addition to the existing capacity of 140 MW.

Capacity Transfers and External Assistance

The SW shows increasing firm imports in summer from 1.7 to 5.7 GW over the assessment period and none in winter. Some areas have reported system constraints that could be a future reliability risk for import transfer availability.

Transmission

There are five transmission projects with voltage design of 500 kV and higher planned in the Southwest. In addition, there are 37 conceptual projects to cover almost 250 miles, 43 planned projects for almost 350 miles, and six projects under construction covering 68 miles. The primary driver for a significant majority of projects (137) is reliability followed by VER integration for seven projects and then four projects aimed at economics and congestion.

Areas have reported distribution transformer shortages and control shelter assemblies significantly impacting operations and continue to persist. Furthermore, shortages of 600 v cable have resulted in the need to find secondary suppliers during the summer seasons. Impacts span deferred construction work as crews wait for delated materials to be delivered.

Demand Assumptions and Resource Categories

Demand (Load Forecast)	
Total Internal Demand	This is the peak hourly load[57] for the summer and winter of each year.[58] Projected total internal demand is based on normal weather (50/50 distribution)[59] and includes the impacts of distributed resources, EE, and conservation programs.
Net Internal Demand	This is the total internal demand reduced by the amount of controllable and dispatchable DR projected to be available during the peak hour. Net internal demand is used in all reserve margin calculations.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident[60]**	**Load Forecasting Entity**
MISO	Summer	Coincident	MISO LSEs
MRO-Manitoba Hydro	Winter	Coincident	Manitoba Hydro
MRO-SaskPower	Winter	Coincident	SaskPower
NPCC-Maritimes	Winter	Noncoincident	Maritimes sub-areas
NPCC-New England	Summer	Coincident	ISO-NE
NPCC-New York	Summer	Coincident	NYISO
NPCC-Ontario	Summer	Coincident	IESO
NPCC-Québec	Winter	Coincident	Hydro Québec
PJM	Summer	Coincident	PJM
SERC-East	Summer	Noncoincident	SERC LSEs
SERC-Florida Peninsula	Summer	Noncoincident	
SERC-Central	Summer	Noncoincident	
SERC-Southeast	Summer	Noncoincident	
SPP	Summer	Noncoincident	SPP LSEs
Texas RE-ERCOT	Summer	Coincident	ERCOT
WECC-AB	Winter	Noncoincident	WECC BAs, aggregated by WECC
WECC-BC	Winter	Noncoincident	
WECC-CA/MX	Summer	Noncoincident	
WECC-NW	Summer	Noncoincident	
WECC-SW	Summer	Noncoincident	

57 Glossary of Terms Used in NERC Reliability Standards.
58 The summer season represents June–September and the winter season represents December–February.
59 Essentially, this means that there is a 50% probability that actual peak demand will be higher and a 50% probability that actual peak demand will be lower than the value provided for a given season/year.
60 Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval. This is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year.

Resource Categories

NERC collects projections for the amount of existing and planned capacity and net capacity transfers (between assessment areas) that will be available during the forecast hour of peak demand for the summer and winter seasons of each year. Resource planning methods vary throughout the North American BPS. NERC uses the following categories to provide a consistent approach for collecting and presenting resource adequacy.

Anticipated Resources

- Existing-certain generating capacity: includes capacity to serve load during period of peak demand from commercially operable generating units with firm transmission or other qualifying provisions specified in the market construct.
- Tier 1 capacity additions: includes capacity that is either under construction or has received approved planning requirements
- Firm capacity transfers (Imports minus Exports): transfers with firm contracts
- Less confirmed retirements[61]

Prospective Resources: Includes all "anticipated resources" plus the following:

- Existing-other capacity: includes capacity to serve load during period of peak demand from commercially operable generating units without firm transmission or other qualifying provision specified in the market construct. Existing-other capacity could be unavailable during the peak for a number of reasons.
- Tier 2 capacity additions: includes capacity that has been requested but not received approval for planning requirements
- Expected (nonfirm) capacity transfers (imports minus exports): transfers without firm contracts but a high probability of future implementation.
- Less unconfirmed retirements.[62]

[61] Generators that have formally announced retirement plans. These units must have an approved generator deactivation request where applicable.
[62] Capacity that is expected to retire based on the result of an assessment area generator survey or analysis. This capacity is aggregated by fuel type.

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):[63]
  - Construction complete (not in commercial operation)
  - Under construction
  - Signed/approved Interconnection Service Agreement (ISA)
  - Signed/approved Power Purchase Agreement (PPA) has been approved
  - Signed/approved Interconnection Construction Service Agreement (CSA)
  - Signed/approved Wholesale Market Participant Agreement (WMPA)
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to Vertically Integrated Entities)
- Tier 2: A unit that meets at least one of the following guidelines (with consideration for an area’s planning processes):[64]
  - Signed/approved Completion of a feasibility study
  - Signed/approved Completion of a system impact study
  - Signed/approved Completion of a facilities study
  - Requested Interconnection Service Agreement
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)
- Tier 3: A units in an interconnection queue that do not meet the Tier 2 requirement.

[63] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)
[64] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)

Reserve Margin Descriptions
Planning Reserve Margins: The primary metric used to measure resource adequacy defined as the difference in resources (anticipated or prospective) and net internal demand divided by net internal demand, shown as a percentile
Anticipated Reserve Margin (ARM): The amount of anticipated resources less net internal demand calculated as a percentage of net internal demand
Prospective Reserve Margin (PRM): The amount of prospective resources less net internal demand calculated as a percentage of net internal demand
Reference Margin Level (RML): The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, system planners use this metric is to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increased demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the RML is a requirement. RMLs can fluctuate over the duration of this assessment period or may be different for the summer and winter seasons. If an RML is not provided by a given assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Methods and Assumptions

How NERC Defines BPS Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:

- **Adequacy:** The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components
- **Operating Reliability:** The ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components

When extreme or otherwise unanticipated conditions result in a resource shortfall, system operators take controlling actions or implement procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area); these actions include the following:

- Public appeals
- Interruptible demand that the end-use customer makes available to its LSEs via contract or agreement for curtailment[65]
- Voltage reductions (sometimes referred to as “brownouts” because incandescent lights will dim as voltage is lowered, sometimes as much as 5%)
- Rotating blackouts (The term “rotating” is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, rotating the outages among individual feeders.)

System disturbances affect operating reliability when they cause the unplanned and/or uncontrolled interruption of customer demand. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When interruptions spread over a wide area of the grid, they are referred to as “cascading blackouts,” the uncontrolled successive loss of system elements triggered by an incident at any location.

The BES is a defined subset of the BPS that includes all facilities necessary for the reliable operation and planning of the BPS.[66] NERC Reliability Standards are intended to establish requirements for BPS owners and operators so that the BES delivers an adequate level of reliability (ALR),[67] which is defined by the following characteristics.

- **Adequate Level of Reliability:** It is the state that the design, planning, and operation of the BES will achieve when the following reliability performance objectives are met:
  - The BES does not experience instability, uncontrolled separation, cascading,[68] and/or voltage collapse under normal operating conditions or when subject to predefined disturbances.[69]
  - BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
  - BES voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
  - Adverse reliability impacts on the BES following low-probability disturbances (e.g., multiple BES contingences, unplanned/uncontrolled equipment outages, cyber security events, malicious acts) are managed.
  - Restoration of the BES after major system disturbances that result in blackouts and widespread outages of BES elements is performed in a coordinated and controlled manner.

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[65] Interruptible demand (or interruptible load) is a term used in NERC Reliability Standards. See Glossary of Terms used in Reliability Standards: NERC Glossary of Terms
[66] BES Definition
[67] NERC Informational Filing (to FERC) on the Definition of Adequate Level of Reliability
[68] NERC’s Glossary of Terms defines Cascading: “Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.”
[69] NERC’s Glossary of Terms defines Disturbance: “1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.”

How NERC Evaluates Reserve Margins in Assessing Resource Adequacy

Planning Reserve Margins are calculated by finding the difference between the amount of projected on-peak capacity and the forecasted peak demand and then dividing this difference by the forecasted peak demand. Each assessment area has a peak season, summer or winter, for which its peak demand is higher. Planning Reserve Margins used throughout this *LTRA* are for each assessment area's peak season listed in the load forecasting table of the **Demand Assumptions and Resource Categories**.

NERC assesses resource adequacy by evaluating each assessment area's Planning Reserve Margins relative to its RML—a "target" or requirement based on traditional capacity planning criteria. The projected resource capacity used in the evaluations is reduced by known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations) and compared to the RML, which represents the desired level of risk based on a probability-based loss-of-load analysis. On-peak resource capacity reflects expected output at the hour of peak demand. Because the electrical output of VERs (e.g., wind and solar) depend on weather conditions, on-peak capacity contributions are less than nameplate capacity. Based on the five-year projected reserves compared to the established RMLs, NERC determines the risk associated with the projected level of reserve and concludes in terms of the following:

Adequate: The ARM is greater than RML.

Marginal: The ARM is lower than the RML and the PRM is higher than RML.

Inadequate: The ARM and PRMs are less than the RML and Tier 3 resources are unlikely to advance.

Metrics for Probabilistic Evaluation Used in this Assessment

Probabilistic Assessment: Biennially, NERC conducts a probabilistic evaluation as part of its resource adequacy assessment and publishes results in the LTRA.

Loss-of-Load Hours: LOLH is generally defined as the expected number of hours per time period (often one year) when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated by using each hourly load in the given period (or the load duration curve).

LOLH is evaluated using all hours rather than just peak periods. It can be evaluated over seasonal, monthly, or weekly study periods. LOLH does not inform of the magnitude or the frequency of loss-of-load events, but it is used as a measure of their combined duration. LOLH is applicable to both small and large systems and is relevant for assessments covering all hours (compared to only the peak demand hour of each season). LOLH provides insight to the impact of energy limited resources on a system's reliability, particularly in systems with growing penetration of such resources. Examples of such energy limited resources include the following:

- DR programs that can be modeled as resources with specific contract limits, including hours per year, days per week, and hours per day constraints
- EE programs that can be modeled as reductions to load with an hourly load shape impact
- Distributed resources (e.g., BTM solar PV) that can be modeled as reductions to load with an hourly load shape impact
- VERs can be modeled probabilistically with multiple hourly profiles

Expected Unserved Energy: EUE is the summation of the expected number of megawatt hours of demand that will not be served in a given time period as a result of demand exceeding the available capacity across all hours. EUE is an energy-centric metric that considers the magnitude and duration for all hours of the time period and is calculated in MWhs. This measure can be normalized based on various components of an assessment area (e.g., total of peak demand, net energy for load). Normalizing the EUE provides a measure relative to the size of a given assessment area (generally in terms of parts per million or ppm).

EUE is the only metric that considers magnitude of loss-of-load events. With the changing generation mix, to make EUE a more effective metric, hourly EUE for each month provides insights on potential adequacy risk during shoulder and nonpeak hours. EUE is useful for estimating the size of loss-of-load events so the planners can estimate the cost and impact. EUE can be used as a basis for reference reserve margin to determine capacity credits for VERs. In addition, EUE can be used to quantify the impacts of extreme weather, common mode failure, etc.

NERC is not aware of any planning criteria in North America based on EUE; however, in Australia, the Australian Energy Market Operator is responsible for planning using 0.002% (20 ppm) EUE as their energy adequacy requirement.[70] This requirement incorporates economic factors based on the risk of load shedding and the value of load loss along with the load-loss reliability component.

On the basis of the two years of the ProbA results, NERC determines the risk in terms of the following:

Normal Risk: Negligible amounts of LOLH and EUE.

Periods of Risk: LOLH < 2 Hours and EUE < 0.002% of total annual net energy.

Significant Risk: LOLH > 2 Hours and EUE > 0.002% of total annual net energy.

Understanding Demand Forecasts

Future electricity requirements cannot be predicted precisely. Peak demand and annual energy use are reflections of the ways in which customers use electricity in their domestic, commercial, and industrial activities. Therefore, the electric industry continues to monitor electricity use and generally revise its forecasts on an annual basis or as its resource planning requires. In recent years, the difference between forecast and actual peak demands have decreased, reflecting a trend toward improving forecasting accuracy.

The peak demand and annual net energy for load projections are aggregates of the forecasts of the individual planning entities and LSEs. These resulting forecasts reported in this LTRA are typically “equal probability” forecasts. That is, there is a 50% chance that the forecast will be exceeded and a 50% chance that the forecast will not be reached.

Forecast peak demands, or total internal demand, are electricity demands that have already been reduced to reflect the effects of DSM programs, such as conservation, EE, and time-of-use rates; it is equal to the sum of metered (net) power outputs of all generators within a system and the metered line flows into the system less the metered line flows out of the system. Thus, total internal demand is the maximum (hourly integrated) demand of all customer demands plus losses. The effects of DR resources that are dispatchable and controllable by the system operator, such as utility-controlled water heaters and contractually interruptible customers, are not included in total internal demand. Rather, the effects of dispatchable and controllable DR are included in net internal demand.

Future Transmission Project Categories

- **Under Construction:** Construction of the line has begun.
- **Planned** (any of the following):
  - Permits have been approved to proceed
  - Design is complete
  - Needed in order to meet a regulatory requirement

- **Conceptual** (any of the following):
  - A line projected in the transmission plan
  - A line that is required to meet a NERC TPL standard or power-flow model and cannot be categorized as “Under Construction” or “Planned”

Other projected lines that do not meet requirements of “Under Construction” or “Planned”

[70] https://wa.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf

ERO Actions Summary

The ERO has a range of activities underway to monitor, assess, and reduce long-term BPS reliability risks. The selected ERO activities summarized below will result in new or enhanced Reliability Standards requirements, reliability guidelines, resources, or significant findings and actionable steps for stakeholders to address reliability risks.

Ongoing ERO Actions Addressing the *2023 LTRA* Recommendations		
1: Add new resources with needed reliability attributes and make existing resources more dependable.		
Initiative	**Description**	**Product/Reliability Solution**
Cold Weather Reliability Standards and Activities	New cold weather Reliability Standards adopted by the NERC Board of Trustees in June 2021 went into effect in the United States in 2023. Generator Owners and Generator Operators are required to implement plans for cold weather preparedness and provide cold weather operating parameters to their RCs, Transmission Operators, and BAs for use in operating plans. Additional Reliability Standard requirements have been developed by NERC and industry to address further recommendations of the *FERC-NERC-Regional Entity staff report—The February 2021 Cold Weather Outages in Texas and Southcentral United States.* The NERC Board adopted these requirements in October 2023 and directed NERC to file them with regulatory authorities for approval and industry implementation. NERC and the industry are currently developing the remaining Reliability Standard enhancements to address the staff report. Refer to *Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination* on NERC's standards development page.[71]	Reliability Standards NERC Alerts Event Analysis Reports Lessons Learned
Inverter Based Resources Strategy	NERC's IBR strategy includes four key focus areas: Risk Analysis, Interconnection Process Improvements, Sharing Best Practices and Industry Education, and Regulatory Enhancements. The status of NERC's extensive activities in each area are described in detail in the *IBR Activities Reference Guide*.[72] NERC has investigated and analyzed IBR performance issues during grid disturbances dating back to 2016. Since that time, NERC and its technical groups have published a range of reliability guidelines for studying, modeling, controlling, and interconnecting IBRs. In partnership with many experts from across the industry, NERC maintains an active campaign of education, awareness, and outreach to support its strategy and reduce IBR performance risks. NERC and the RSTC recognized that Reliability Standard requirements would be needed as part of a comprehensive approach to reliability and undertook a full review of existing standards to identify gaps. Several reliability standards projects were initiated following this review. In October 2023, FERC issued order No. 991, which provided clear direction for the industry to develop requirements that address reliability gaps related to IBR in data sharing, model validation, planning and operational studies, and performance requirements.	Reliability Standards NERC Alerts Reliability Guidelines Event Analysis Reports Lessons Learned Educational Webinars
Natural Gas-Electric Interdependence Initiatives	Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised guideline also identifies the fuel risks encountered by industry during recent periods of extreme cold weather and high demand for natural gas. These natural gas supply risks can inform industry's development of planning scenarios. The revised guideline is under review with the Reliability and Security Technical Committee. Refer to the RSTC-Approved Documents page.[73]	Reliability Guideline

[71] Project 2021-07
[72] IBR Activities
[73] RSTC Approved Documents

Ongoing ERO Actions Addressing the *2023 LTRA* Recommendations

2: Expand the transmission network to deliver supplies from new resources and locations to serve changing loads.

Initiative	Description	Product/Reliability Solution
Interregional Transfer Capability Study	NERC's study will analyze the amount of power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems. The study will be conducted in consultation with the six Regional Entities and each transmitting utility in neighboring transmission planning areas. Transfer capability is a critical measure of the ability to address energy deficiencies by relying on distant resources and is a key component of a reliable and resilient BPS. The study, which was directed in the Fiscal Responsibility Act of 2023, must be filed with FERC by December 2, 2024. A public comment period will take place when FERC publishes the study in the Federal Register. After submittal, FERC must provide a report to Congress within 12 months of closure of the public comment period with recommendations (if any) for statutory changes. Refer to the ITCS Initiatives page.[74]	ERO Study and Recommendations

3: Adapt BPS planning, operations, and resource procurement markets and processes to the realities of a more complex power system.

Initiative	Description	Product/Reliability Solution
Energy Assessments Initiatives	NERC conducts seasonal long-term and probabilistic reliability assessments and issues reports like this *2023 LTRA* to advise industry and stakeholder of findings on BPS adequacy, including energy adequacy. In recent years, NERC has enhanced the energy risk analysis in seasonal assessments by incorporating deterministic energy risk scenarios and introducing probability-based assessments. NERC's ProbA uses hourly simulations to examine the ability of resources to meet demand over the entire study year, helping to identify energy risks that could otherwise go unaddressed by peak hour reserve margin resource adequacy analysis. NERC reliability assessments continue to evolve as more sophisticated energy assessment tools, models, and capabilities are developed. The RSTC created the Energy Reliability Assessment Working Group (ERAWG) to support wide adoption of technically-sound approaches to energy assessments by BPS planners and operators. Working group projects and activities are described on the ERAWG page.[75] New and revised Reliability Standards requirements for BPS planners and operators to address energy risks are in development in Project 2022-03 *Energy Assurance with Energy Constrained Resources.*[76] In other Reliability Standard development work, Project 2023-07 *Transmission System Planning Performance Requirements for Extreme Weather*, requirements are being developed that will ensure entities consider extreme heat and cold weather scenarios in BPS planning, including the expected availability of the future resource mix.[77]	Reliability Assessments Reliability Standards
Distributed Energy Resources Strategy	NERC has proactively worked with industry stakeholders to identify BPS reliability risks associated with the increasing DER levels and has initiated actions to support broad awareness and education as well as to provide guidance for industry and enhance Reliability Standards where gaps exist. The status of NERC's extensive activities in each area are described in detail in the *DER Activities Reference Guide*.[78]	Reliability Standards Reliability Guidelines Educational Webinars

[74] ITCS Project
[75] ERAWG
[76] Project 2022-03
[77] Project 2023-07
[78] DER Activities

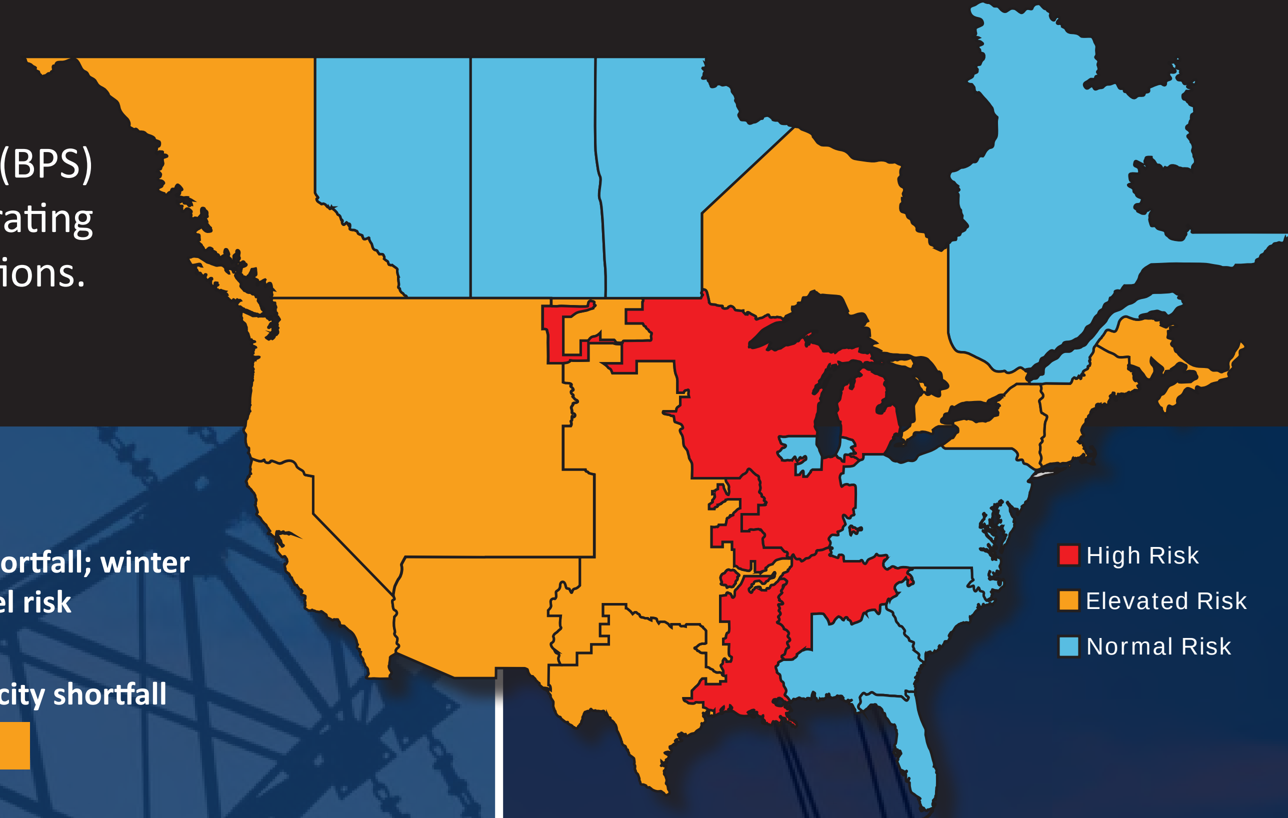
Ongoing ERO Actions Addressing the *2023 LTRA* Recommendations		
4: Strengthen relationships among reliability stakeholders.		
Initiative	**Description**	**Product/Reliability Solution**
Ongoing Strategic Engagements	NERC and regional entities engage in frequent dialogue and conduct outreach with regulators and policymakers at the state/provincial, regional, and federal/national levels.	Constructive Partnerships

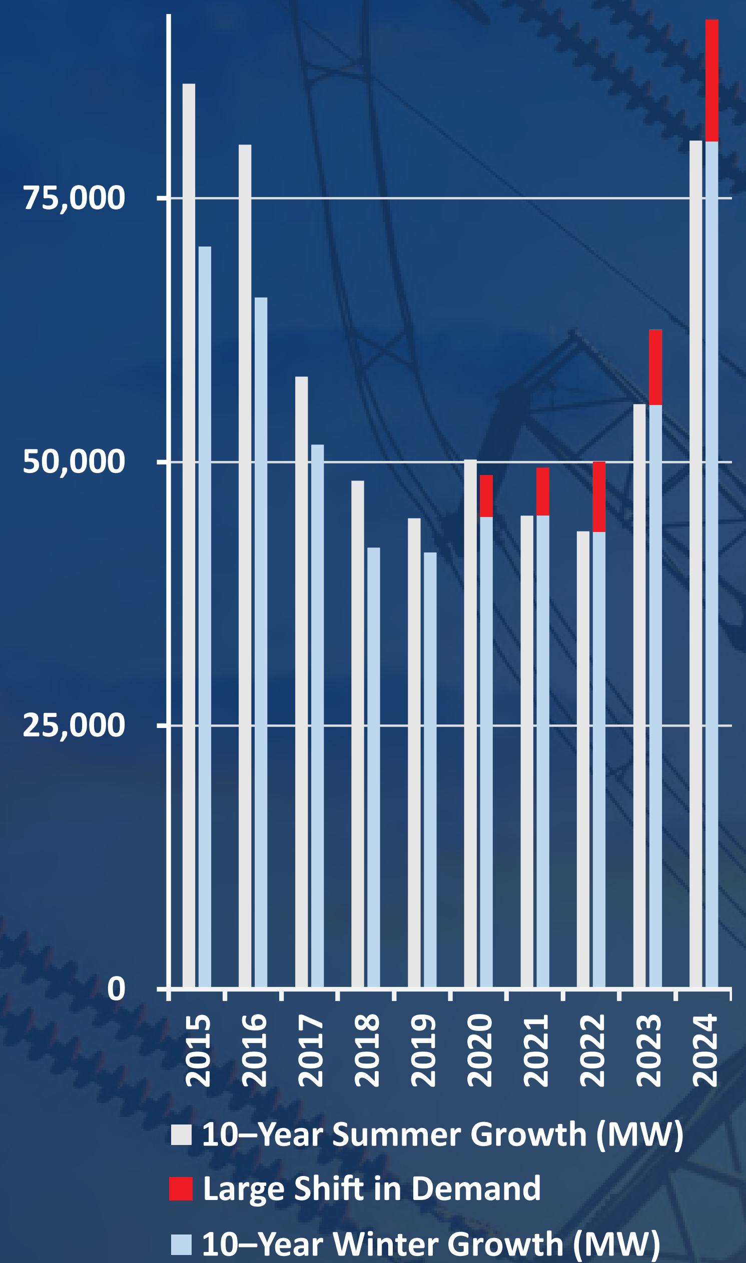
Long-Term Reliability Assessment 2023

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

The LTRA identifies reliability trends, emerging issues, and potential risks to the bulk power system (BPS) over a 10-year assessment period. Industry faces mounting pressure to keep pace with accelerating electricity demand, energy needs, and transmission system adequacy as the resource mix transitions.

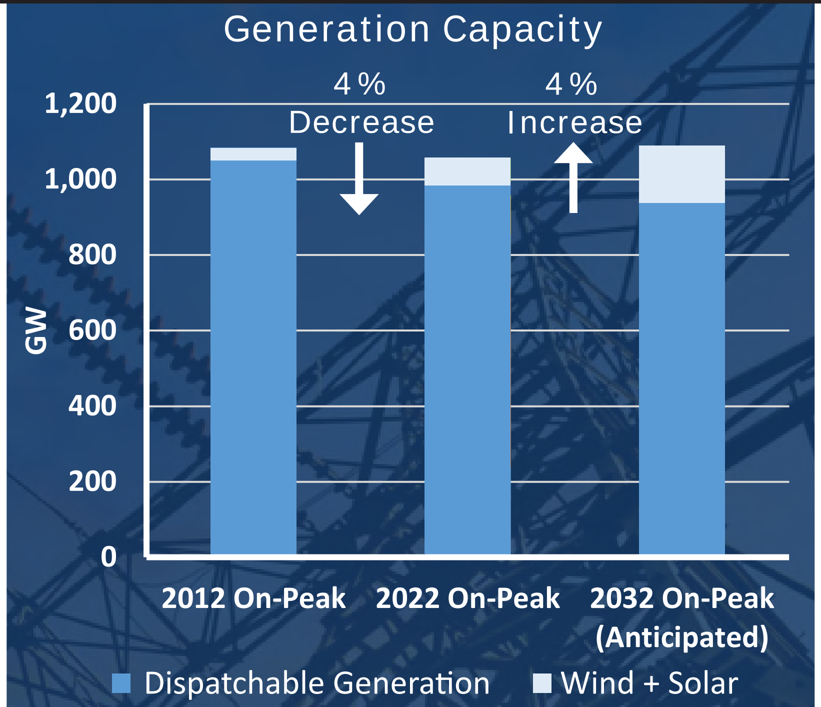
LTRA | Video

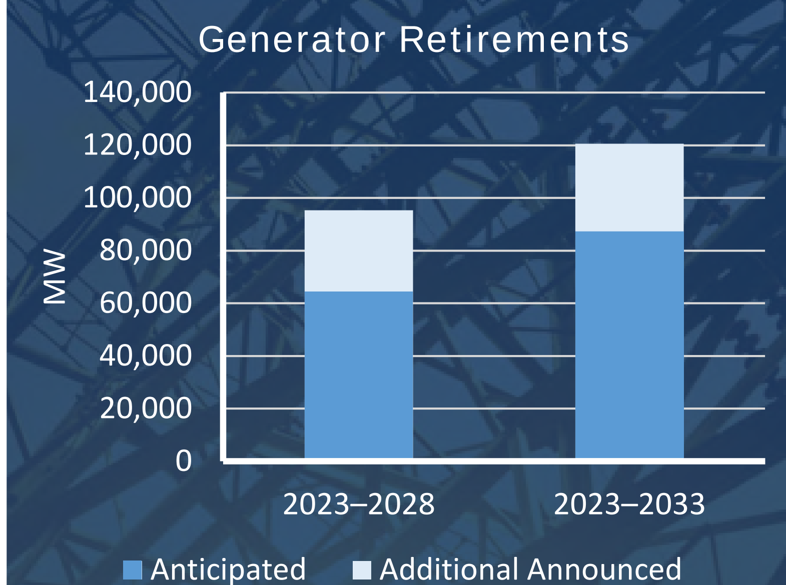




Demand Growth

The BPS is currently forecast to have its highest demand and energy growth rates since 2014, mainly driven by electrification and projections for growth in electric vehicles over this assessment period.





Generation Trends

As fossil generation is retired, resource growth is becoming more challenging. More than 83 GW of generator retirements are planned through 2033, and more are expected. Generation plans need to consider growing energy needs and grid stability.

High Risk Areas

MISO
2028: Capacity shortfall; winter generator and fuel risk

SERC-Central
2025–2027: Capacity shortfall

Elevated Risk Areas

Maritimes
2026: Low capacity reserves

New England
2024: Winter fuel supply risk

New York
2025: Low capacity reserves

Ontario
2028: Low capacity reserves

SPP
2024: Winter generator and fuel risk; insufficient dispatchable resources

ERCOT
2024: Winter generator and fuel risk; insufficient dispatchable resources

WECC-BC
2026–2027: Low capacity reserves

WECC-CA/MX
2026: Insufficient dispatchable resources

WECC-NW
2026: Insufficient dispatchable resources

WECC-SW
2026: Insufficient dispatchable resources

Resource Adequacy Risk

Capacity shortfalls are projected in areas where future generator retirements are expected before replacement resources can be put in service to meet rising electricity demand.

- Add new resources with reliability attributes, manage retirements, and make existing resources more dependable
- Expand the transmission network to provide more transfer capability and deliver supplies from new resources and locations to serve changing loads
- Adapt BPS planning, operations, resource procurement markets, and processes to a more complex power system
- Strengthen relationships among reliability stakeholders and policy makers

Priority Actions

Natural gas supply infrastructure and the BPS form an interconnected energy system. NERC endorses actions to establish reliability rules for the natural gas infrastructure that is necessary for an interconnected energy system.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for a Certificate of Convenience and Necessity for Solar Facilities	)))	EA-2023-0286

AFFIDAVIT OF MATT MICHELS

STATE OF MISSOURI)
) ss
CITY OF ST. LOUIS)

Matt Michels, being first duly sworn on his oath, states:

My name is Matt Michels, and hereby declare on oath that I am of sound mind and lawful age; that I have prepared the foregoing *Surrebuttal Testimony*; and further, under the penalty of perjury, that the same is true and correct to the best of my knowledge and belief.

/s/ Matt Michels
Matt Michels

Sworn to me this 15th day of December, 2023.