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AMEREN MISSOURI

2026 IRP MARKET PRICE SCENARIOS

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LIST OF ABBREVIATIONS

<u>Abbreviation</u>	<u>Term/Phrase/Name</u>
AP1000	Westinghouse AP1000 Nuclear Reactor
ATC	Around the Clock
BC	Base Carbon
BG	Base Gas
BL	Base Load
CC	Combined Cycle
CO ₂	Carbon Dioxide
CONE	Cost of New Entry
CT	Combustion Turbine
DLOL	Direct Loss of Load
EI	Eastern Interconnect
FOB	Free on Board
HG	High Gas
HL	High Load
IL	Illinois Zone
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
kW	Kilowatt
LC	Low Carbon
LG	Low Gas
LL	Low Load
LMP	Locational Marginal Price
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
MIP	Mixed Integer Programming
MISO	Midcontinent Independent System Operator
MO	Missouri
MW	Megawatt
MWh	Megawatt Hour
OBBBA	One Big Beautiful Bill Act
PJM	PJM Interconnection
PRM	Planning Reserve Margin
PTC	Production Tax Credit
SCCT	Simple Cycle Combustion Turbine
SMR	Small Modular Reactor

Executive Summary

Ameren Missouri engaged 1898 & Co. to develop a comprehensive set of long-term wholesale energy, capacity, and ancillary service price forecasts in support of their 2026 Integrated Resource Plan. The analysis evaluates sixteen market scenarios over a thirty-year horizon and reflects Ameren Missouri's assumptions regarding load growth, natural gas pricing, and carbon policy. These scenarios allow Ameren Missouri to understand a range of plausible market conditions and to test the resilience of future resource decisions under varying economic and policy environments.

The study incorporates Ameren Missouri's current expectations for base, high, and low load growth, including incremental data center load that significantly increases long-term system demand across the MISO footprint. These load trajectories were combined with scenario-specific fuel price forecasts, carbon price paths, technology cost assumptions, and updated federal policy considerations. The EnCompass capacity expansion and production cost model was used to simulate the Eastern Interconnect and identify least cost resource portfolios that maintain required reliability standards while meeting all operational and policy constraints.

Higher load outcomes require materially more renewable, storage, and thermal additions to maintain an adequate reserve margin. Fuel and carbon pricing introduce further differentiation in buildout outcomes. High gas and high carbon price scenarios tend to accelerate renewable and storage additions, while low price cases support continued reliance on thermal generation in the near term. Although the pace varies, all scenarios show a steady increase in renewable penetration across the MISO system, together with a continued need for dispatchable thermal resources that provide reliability support.

Market price projections demonstrate a consistent upward trend in both energy and capacity prices through the study period. Energy prices diverge across scenarios as differences in gas pricing, carbon policy, and load growth intensify over time. Capacity prices rise in most cases due to higher load expectations and the increasing cost of new generation resources. Scenarios with high gas or high carbon pricing show comparatively lower capacity prices because these conditions support earlier buildout of renewable and storage resources, which alleviates long-term capacity constraints.

Ancillary service prices remain modest on an annual average basis, although short-term volatility has increased as the regional resource mix evolves. While ancillary service revenue may offer incremental value to flexible resources, energy and capacity revenues remain the primary economic drivers to consider when evaluating new generation.

Overall, the results offer sixteen unique capacity and energy forecasts that enable Ameren Missouri to assess how different resource portfolios perform when tested against varying market, policy, and load conditions.

Planning Scenarios Price Development

1898 & Co. was retained by Ameren Missouri, a St. Louis-based utility serving millions of customers in central and eastern Missouri as well as southern Illinois, to develop customized wholesale energy, ancillary services, and capacity price curves to support the 2026 Integrated Resource Plan (IRP). Ameren Missouri provided inputs for 16 scenarios to be analyzed over the next 30 years, providing a robust analytical foundation that aligns with Ameren Missouri's scenario-based approach to IRP analysis.

Base Model

1898 & Co. maintains an independent forecast of all North American wholesale energy markets that was used as the starting point for this analysis. This model view includes an informed perspective on how markets will evolve over the next 20-30 years, and the impact this evolution will have on North American energy assets, how they create value in their systems, and the financial and environmental implications. 1898 & Co. used the EnCompass production cost and capacity expansion simulation model to perform this work. EnCompass is an advanced power system optimization and planning software developed by Yes Energy. It supports a broad spectrum of analysis, from short-term production cost modeling to long-term capacity expansion planning, within a unified platform. The software combines full operational detail, such as unit commitment, dispatch constraints, ancillary services, and emissions, with flexible scenario management and high-performance simulation engines. At the heart of EnCompass's long-term planning capabilities is its capacity expansion module, which uses mixed integer programming (MIP) to identify least-cost investment plans that satisfy reliability, policy, and economic constraints over a multi-year horizon. EnCompass co-optimizes capital additions with unit commitment, dispatch, and ancillary service requirements to ensure operational feasibility and reliability. It supports constraints across project groups, allows comparison of multiple expansion plans, and integrates financial detail through user-defined economics. For this study, the Eastern Interconnect (EI) was simulated zonally from 2027 to 2056. The MISO area granularity was down to the load zone, with the Ameren regions being resolved within the load zones. A table showing the Ameren areas of interest in this study has also been provided.

Table 1: Areas of Interest

Load Zone	MISO Zone	EnCompass Area
Ameren - IL	Zone 4	MISO - IL
Ameren - MO	Zone 5	MISO - MO

Scenario Assumptions

Ameren Missouri identified and provided inputs for three primary forecast variables that drove the scenario design: load, fuel prices, and carbon prices. The scenario assumptions used in this study established the foundational inputs that guide how the capacity expansion model evaluates long-term outcomes across the 16 Ameren Missouri-defined futures. All other assumptions remain constant across scenarios so that differences in model results can be attributed directly to changes in these three drivers. The following subsections summarize the key inputs that are common to all scenarios unless otherwise noted.

Peak and Energy Demand

Ameren Missouri provided three long-term load growth forecasts: a base load forecast, a high load forecast, and a low load forecast. These forecasts were incorporated directly into the modeling framework to reflect Ameren Missouri's expectations for MISO and PJM system growth under different scenarios. Broader industry trends continue to influence long-term demand expectations across the electric sector. These trends have recently included more significant forecasted demand increases, driven by data centers, industrial reshoring, and electrification trends. To model a wide range of potential future load scenarios in the IRP, Ameren Missouri provided 1898 & Co. with projections related to existing base load growth and then additional data center load projections to incorporate. The total demand, inclusive of base and data center load growth, is shown below in Figure 1 and Figure 2.

Figure 1: MISO Energy Demand for Base, High, and Low Cases

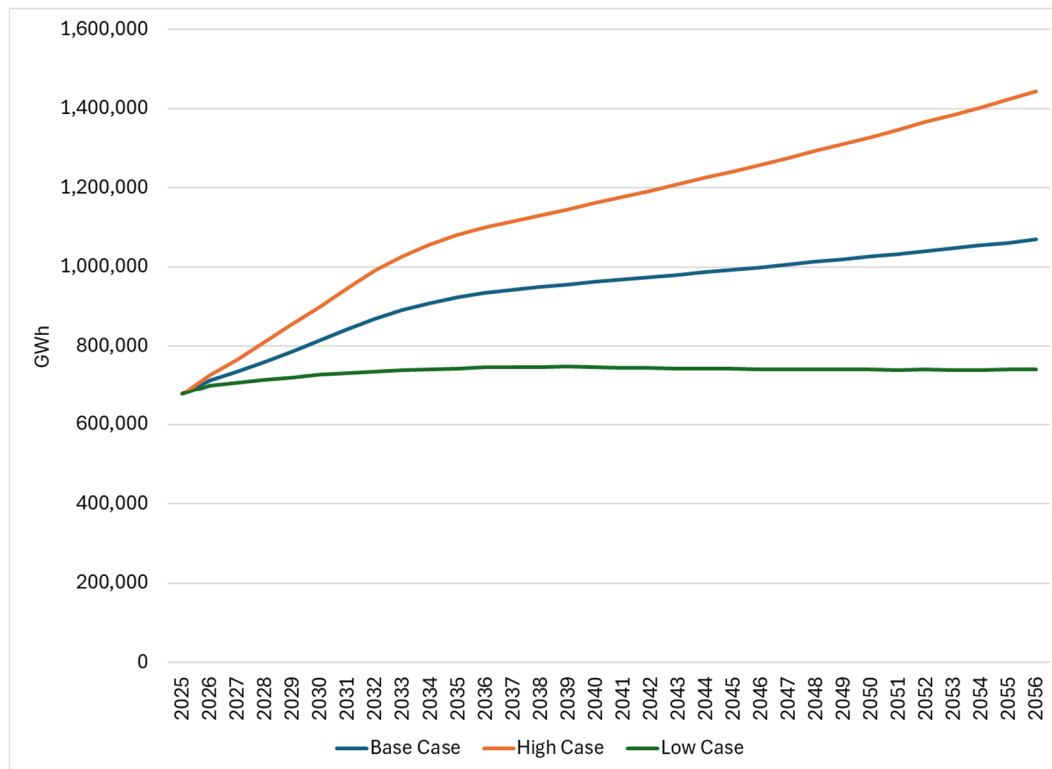
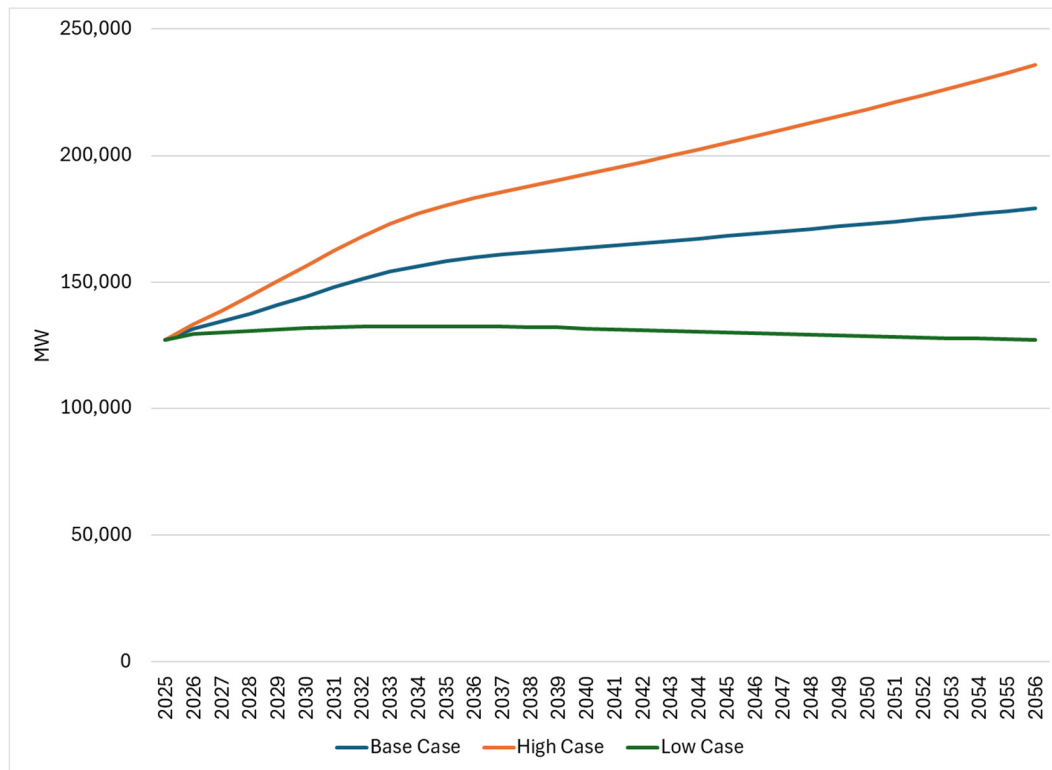
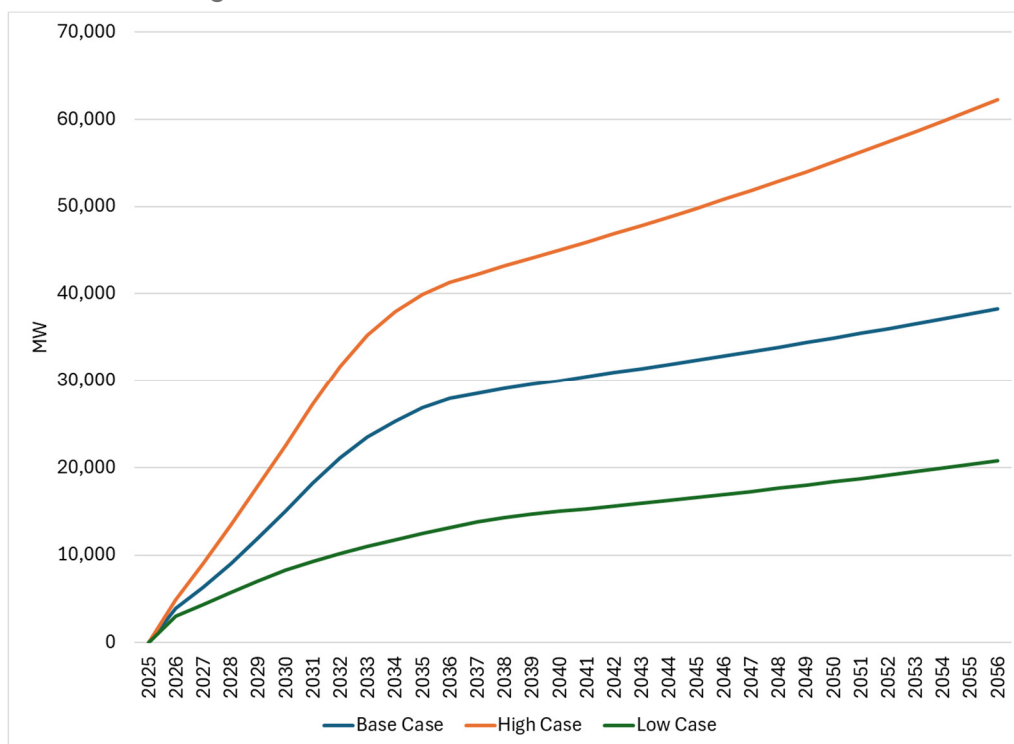


Figure 2: MISO Summer Peak Load for Base, High, and Low Cases



Across the wider MISO footprint, data centers have emerged as a significant driver of long-term load growth, reflecting rapid expansion in cloud computing and artificial intelligence applications that are already increasing electricity demand at the national level. Recent federal and research assessments indicate that data centers account for a growing share of total electricity consumption and are expected to continue expanding in both size and number. However, there is a wide range associated with how much datacenter load will materialize over the coming decades. To account for this uncertainty, Ameren Missouri supplied three unique levels of new data center load projections that were then added to the respective low, base, and high load forecasts. The data center load components are broken out below in Figure 3.

Figure 3: Incremental New MISO Data Center Peak Load



Generation

Existing Generation and Planned Additions

Ameren Missouri provided a list of their existing generating units, along with their associated planned commission and retirement dates, as applicable. This list includes projects already in the Ameren Missouri portfolio as well as those approved through prior planning processes. The 1898 & Co. and Ameren Missouri teams collaborated to review the named and planned additions scheduled to come online within the next few years in the 1898 & Co. reference case, making minor adjustments where appropriate. These confirmed additions form the baseline resource position against which the model evaluates the need for new capacity.

In addition to Ameren Missouri's existing generating fleet, announced nuclear restarts with a high likelihood of proceeding were incorporated into the starting model. These prospective restarts are being pursued in response to increasing data center development and overall load growth across the region. Their inclusion allows the base case to reflect expected resource availability and maintain adequate supply to meet higher long term demand.

Future Resource Options

Within the reference case, several types of new generation can be selected by the model for capacity expansion in order to meet capacity or energy needs across the study footprint. 1898 & Co., working closely with Ameren Missouri, determined which technologies should be available for selection and established annual addition feasibility maximums for each. These technologies represent commercially available or emerging options that could be developed within the MISO footprint during the study period. The following new generator options were considered in the capacity expansion modeling:

- Combined Cycle 1x1 w/o Carbon Capture System (H-Class) - 710 MW
- Combined Cycle 1x1 w/ Carbon Capture System (H-Class) - 710 MW

- Combustion Turbine (F-Class) - 226 MW
- Solar PV - 200 MW
- Wind - 100 MW
- 4hr Battery - 200 MW
- Nuclear (SMR) - 70 MW
- Nuclear (Conventional) - 1100MW

The model makes selections only based on the economics seen in the simulation, so reasonable constraints around new resource timing for selection and quantity need to be applied to simulate realistic limits on the number of new resources that can be added each year. Combined-cycle units (1x1 configurations, with or without carbon capture) and combustion turbines were each limited to an annual maximum of four additions. New renewable and storage resources were limited in the first few years of the study period, with annual caps informed by the quantities currently in development and in the MISO interconnection queue. After these initial study years, the annual constraints on new solar, wind, and battery storage additions were relaxed. New nuclear units were not allowed to be selected until after 2040.

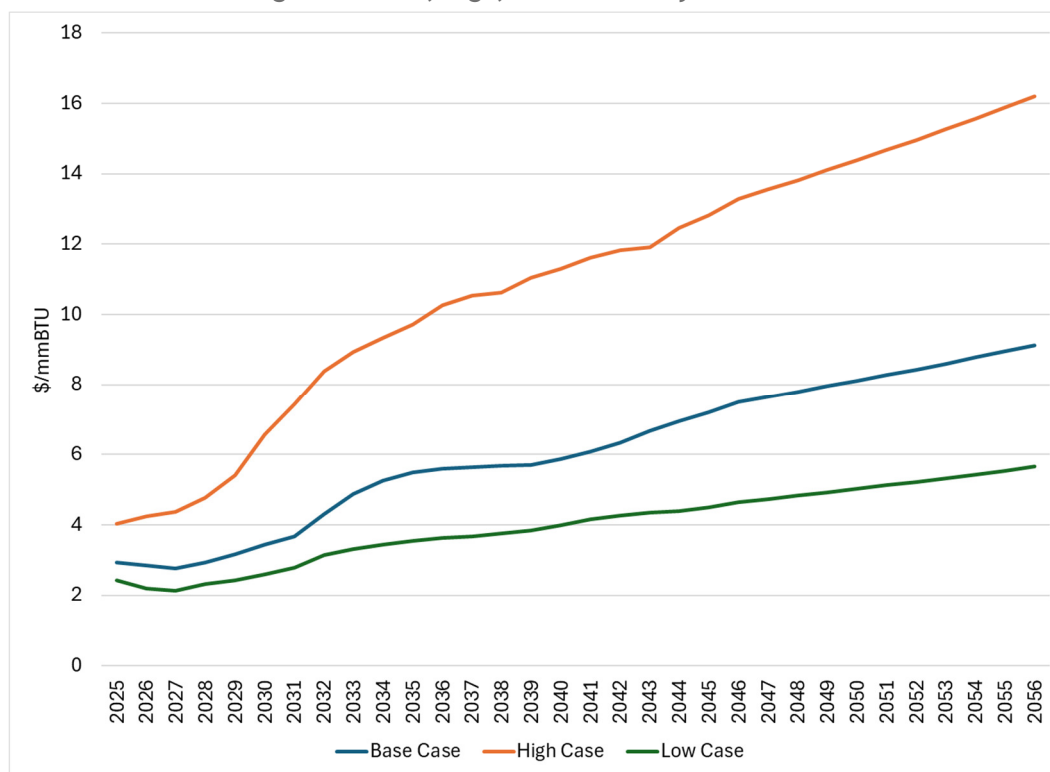
Natural Gas Prices

Ameren Missouri provided Henry Hub natural gas price forecasts for use as the starting point in the modeling.

Ameren Missouri also supplied basis adders that adjust Henry Hub pricing to represent the delivered natural gas costs at Ameren Missouri's generation facilities. These basis adjustments capture transportation and market dynamics specific to Ameren Missouri's footprint. While the basis adders were applied consistently across the scenarios, three different Henry Hub gas prices were studied as part of this analysis.

The wider spread between the high and low trajectories beginning in the 2030s reflects rising uncertainty in long-term gas markets as we move further from the present day, driven by potential factors such as future infrastructure development, LNG export growth, and regulatory changes that influence supply conditions.

Figure 4: Base, High, and Low Henry Hub Prices



Coal Prices

Ameren Missouri provided individual price forecasts for both of their coal facilities. These prices were developed for Illinois Basin coal and for Southern Powder River Basin coal. Ameren Missouri supplied both a Free On Board (FOB) mine price and a delivery adder so that the model could accurately represent the full delivered cost of coal for each plant.

While broader market trends continue to influence expectations for long term coal pricing, coal costs were not treated as a critical uncertainty variable in this study. New coal resources are not considered for addition in the planning horizon, which reduces the relevance of coal price volatility to long term capacity expansion decisions. In addition, coal prices exhibit less short term volatility than natural gas, and most coal units operate under longer term supply and transportation arrangements that further stabilize delivered costs. As a result, fluctuations in coal prices have a more limited impact on market prices or portfolio outcomes, when compared with the sensitivity of results to natural gas prices, CO₂ policy, and load growth.

Nuclear Fuel Prices

Ameren Missouri provided nuclear fuel prices for the Callaway facility, which were implemented directly into the model. Ameren Missouri also supplied the nuclear fuel cost assumptions for any new AP1000 or SMR facilities that may be built in the modeling.

Similar to coal prices, uranium prices were not treated as an uncertainty variable and were constant across the different scenarios.

Policy Updates

Renewable policies were updated to reflect investment tax credit and production tax credit stop dates outlined in the recently passed One Big Beautiful Bill Act (OBBBA). The renewable energy subsidy portion of the OBBBA phases out (or terminates) many clean energy tax credits, especially for solar and wind, unless construction begins within 12 months of enactment (i.e. by mid-2026) or the project is placed in service by the end of 2027. These provisions significantly shorten the window during which solar and wind resources can benefit from federal incentives, reducing the long-term availability of these credits compared to prior law. Nuclear and storage-related incentives were largely preserved, maintaining support for technologies that contribute firm or long-duration capacity.

In addition to tax credit changes, several recent federal actions have created greater uncertainty around future environmental and emissions regulations. Proposed revisions to greenhouse gas standards for fossil-fueled generating units have introduced additional variability in how carbon-related compliance costs may evolve. At the same time, shifting federal priorities have emphasized maintaining or extending the life of existing dispatchable resources to support system reliability, further increasing uncertainty regarding the timing and stringency of potential future regulations.

These policy changes directly affect the economic outlook for new generation projects and the operational considerations for existing units. By updating federal tax credit eligibility and regulatory assumptions in the modeling, the scenarios reflect a policy environment that is more constrained for near-term renewable development and more uncertain for long-term emissions policy trajectories. This policy environment is consistent with the uncertainty captured in the CO₂ price trajectories.

CO₂ Prices

Ameren Missouri provided low, base, and high CO₂ price trajectories. These trajectories were developed using Ameren Missouri's internal analysis together with benchmarking against recent IRPs across the Midwest and several commercially available policy and market forecasts. This approach generated CO₂ paths that reflect a balanced view of potential regulatory outcomes rather than relying on a single forecast source.

The three cases begin to separate meaningfully in the early 2030s as long term policy uncertainty increases. The low case shows gradual and limited price escalation, remaining below \$10 per short ton through the mid-2040s and reaching roughly \$12 per short ton by 2056. This path is consistent with a future in which federal action remains limited and additional carbon regulations advance slowly.

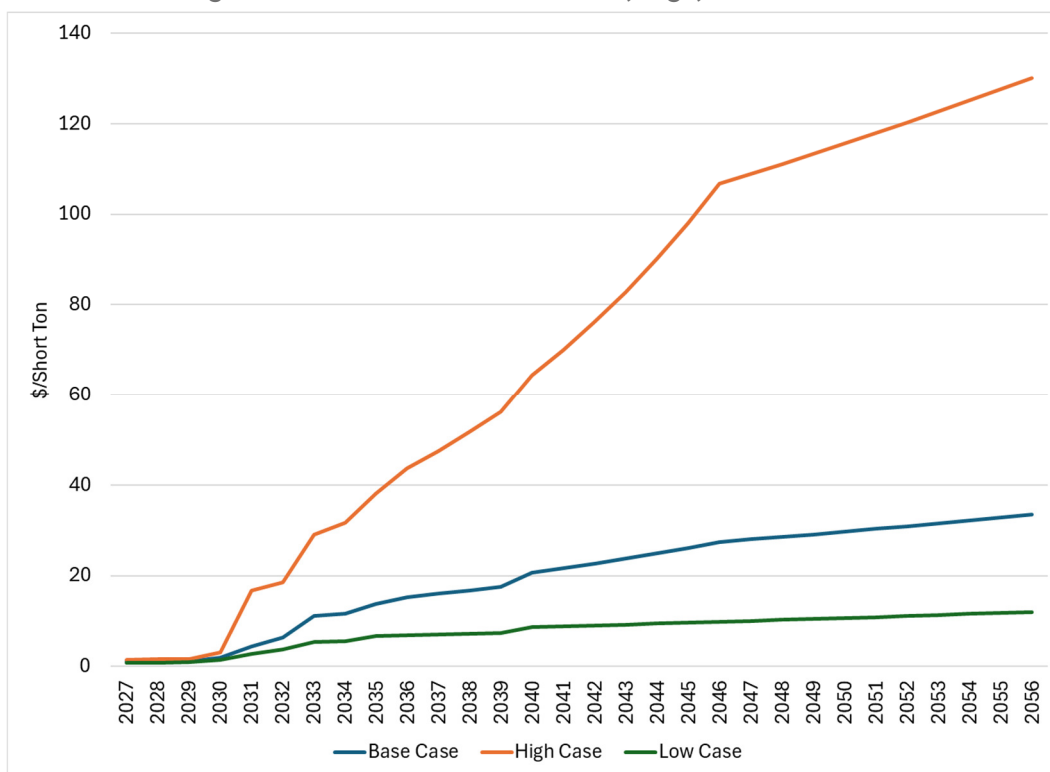
The base case reflects a moderate policy environment in line with the assumptions used in many current utility IRPs. Prices increase from roughly \$1 short ton in 2027 to about \$20 per short ton by 2040 and continue rising to approximately \$34 per short ton by 2056. This trajectory aligns with expectations that state and federal decarbonization initiatives will gradually intensify even without a formal nationwide carbon market.

The high case represents a more aggressive policy future with rapid price escalation beginning around 2030. Prices rise from about \$3 per short ton in 2030 to more than \$16 per short ton in 2031 and continue climbing to nearly \$65 by 2040. By 2056, the high case reaches more than \$130 per short ton. These levels are consistent with upper-bound forecasts used in other regional planning studies and high policy scenarios.

The CO₂ prices supplied by Ameren Missouri were applied to all thermal generators in EI. Within the modeling framework, CO₂ prices increase the variable production cost of fossil-fueled generators in the region according to each unit's heat rate and fuel carbon content. This directly influences the dispatch of existing coal and natural gas units, alters relative market competitiveness among technologies, and affects

wholesale market prices across the study period. CO₂ pricing also plays an important role in the capacity expansion model. Higher carbon costs improve the economic position of lower-emitting and zero carbon resources, which can lead to increased renewable additions and accelerate the retirement or reduced operation of higher-emitting units. By applying the Ameren Missouri-supplied CO₂ trajectories, the model captures both the operational impacts on the current fleet and the long term portfolio changes that occur under different policy environments.

Figure 5: CO₂ Price Forecast for Base, High, and Low Cases



Reserve Margins and MISO Reliability Framework

Reserve Margins

MISO establishes Planning Reserve Margin (PRM) requirements to ensure sufficient accredited capacity is available to maintain system reliability under a range of operating conditions. These requirements represent the additional accredited capacity required above the expected peak demand to meet MISO's standards.

MISO recently transitioned from a single annual PRM requirement to a seasonal construct, recognizing that reliability risks differ substantially across summer, winter, fall, and spring periods. This seasonal approach accounts for evolving load patterns, increasing winter peak risk, resource performance differences across seasons, and the changing accreditation of variable and weather-sensitive technologies. The seasonal construct enhances alignment between modeled capacity needs and real-world operating conditions, facilitating a more accurate assessment of the region's reliability position throughout the year.

The reserve margin assumptions used in the EnCompass modeling were based on values provided by Ameren Missouri from the 2025/2026 Loss of Load Expectation study. These reserve margin requirements were applied consistently all model runs, making sure the capacity expansion model built sufficient accredited resources under all scenarios.

Table 2: MISO Seasonal Reserve Margins¹

Summer	Fall	Winter	Spring
8.9%	16.3%	23.5%	29.2%

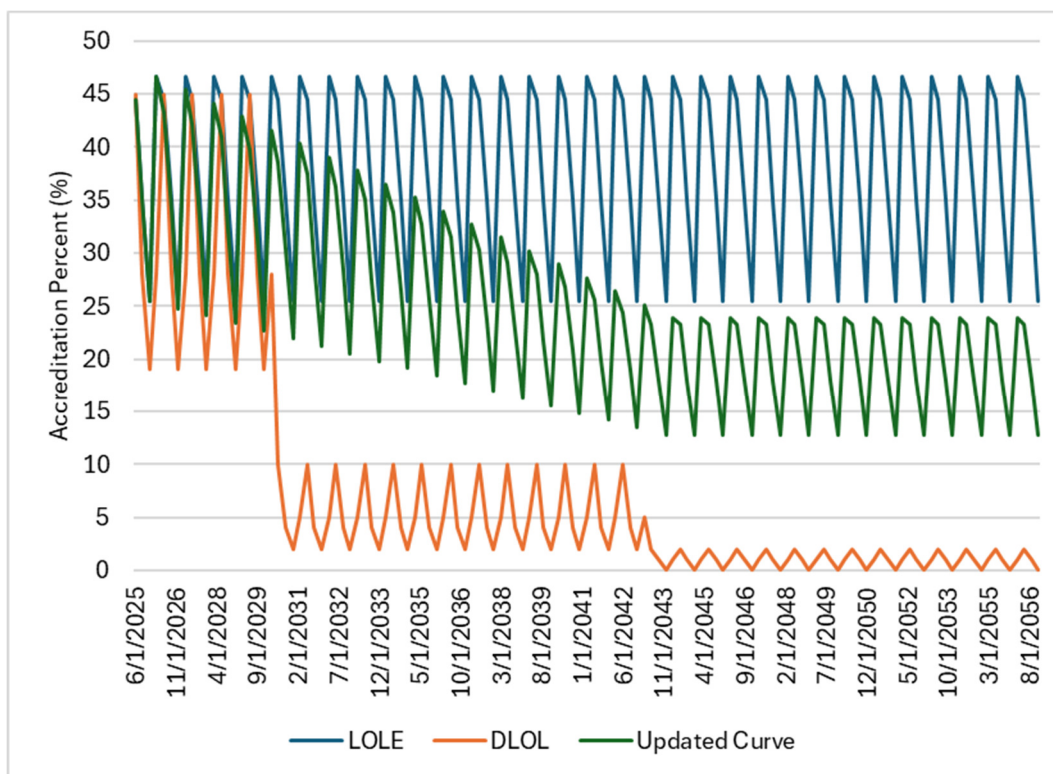
Capacity Accreditation

MISO is in the process of updating its resource accreditation framework to better reflect the reliability contribution of individual technologies. Beginning with a three-year transition that started on September 1, 2024, MISO plans to adopt a Direct Loss of Load (DLOL) accreditation methodology, with full implementation expected for the 2028/2029 Planning Year. Under this approach, a resource's accredited capacity is determined by its performance during periods when the system is most at risk of loss of load, rather than by static seasonal percentages. This transition aligns accreditation more closely with probabilistic Loss of Load Expectation (LOLE)-based reliability modeling and provides finer granularity in evaluating how each technology contributes to avoiding shortfalls across different seasons.

Early assessments from MISO indicate that DLOL will have the greatest impact on variable resources, particularly solar and wind, as their effective contribution during high-risk hours is lower than under previous methods. Solar accreditation is expected to decline as penetration increases and as evening reliability risks become more prominent. While this framework is still in development, there is a high degree of uncertainty around future accreditation projections. To account for this uncertainty, multiple solar accreditation approaches were tested, including a full application of MISO's forecasted DLOL values, a case where accreditation levels were held constant, and several intermediate variants. After evaluating the impact of each approach on long term capacity expansion, a midpoint methodology was selected, shown in green in Figure 6 below, that balances emerging DLOL trends with the uncertainty still present in MISO's final implementation details.

¹ Values shown in the table were applied from 2035-2056, Ameren Missouri provided annual inputs for 2025-2056.

Figure 6: Solar Accreditation Curve



Scenario Development

1898 & Co. evaluated 16 market scenarios that all show plausible futures that may develop over the course of the next 30 years. These scenarios show multiple different market conditions that allow Ameren Missouri to analyze how they would continue to serve customer needs. Ameren Missouri developed the scenarios by creating combinations of the three critical uncertainty variables: load, natural gas prices, and carbon prices. Ameren Missouri selected these 16 combinations because they were the most likely combinations of variables.

Table 3: Sixteen Market Scenarios

Case Number	Scenario Name	Load	Carbon Price	Natural Gas Price
1 (Base)	BL_BC_BG	Base	Base	Base
2	BL_BC_HG	Base	Base	High
3	BL_HC_BG	Base	High	Base
4	BL_LC_BG	Base	Low	Base
5	BL_BC_LG	Base	Base	Low
6	LL_LC_BG	Low	Low	Base
7	LL_BC_LG	Low	Base	Low
8	LL_BC_BG	Low	Base	Base
9	LL_BC_HG	Low	Base	High
10	LL_HC_BG	Low	High	Base
11	HL_LC_BG	High	Low	Base
12	HL_BC_LG	High	Base	Low
13	HL_BC_BG	High	Base	Base
14	HL_BC_HG	High	Base	High
15	HL_HC_BG	High	High	Base
16	BL_No_BG	Base	No	Base

These cases are abbreviated throughout the report to allow ease of labeling. For example, High Load, Base Carbon, and Low Gas would be abbreviated to HL_BC_LG. The scenarios are also labeled by numbers which line up with Table 3. To ensure comparability across all cases, the core modeling framework, input assumptions, and system settings were held constant, except for the specific variables defining each scenario. This approach isolates the influence of load growth, natural gas price trajectories, and carbon price trajectories, while eliminating potential noise from unrelated factors. As a result, differences observed across scenarios can be directly attributed to these targeted drivers, providing clear insight into how variations in demand, fuel economics, and carbon pricing could shape future capacity expansion in MISO and Ameren Missouri's service territory. Collectively, these scenarios capture a wide range of plausible futures, from business-as-usual to high-growth or highly regulated environments, which are also to be studied in Ameren Missouri's IRP analysis.

Results

The following sections cover the model results, including capacity expansion, energy prices, capacity prices, and ancillary services. Results are primarily shown below for MISO as a whole or MISO-MO data. Additional Excel files with data were provided to Ameren Missouri as part of this analysis, including MISO-IL.

Capacity Expansion Results

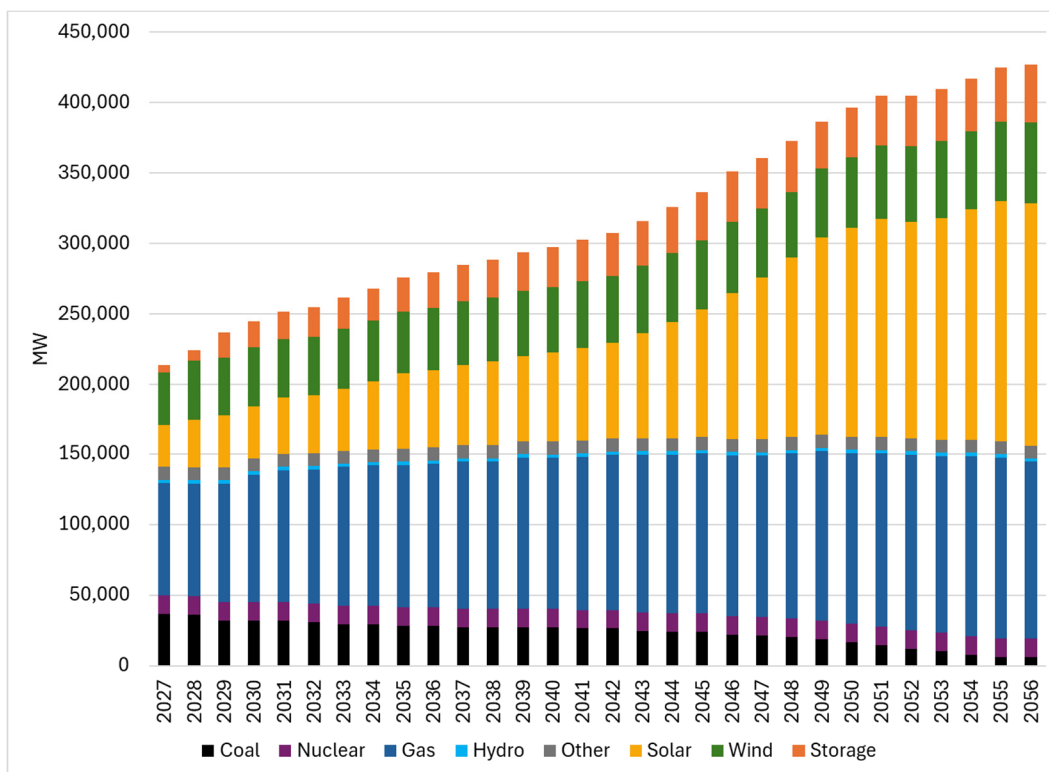
1898 & Co. used the EnCompass planning software to perform the capacity expansion analysis for this study. The capacity expansion model identifies the least-cost mix of new resources required to meet reliability needs under the assumptions and policy conditions defined for each scenario. The model evaluates resource additions over the 2027-2056 horizon and reflects changes in tax credit availability, technology costs, and the scenario-specific values for load, natural gas prices, and carbon prices.

Base Load, Base Carbon, Base Gas Buildout

The Base Scenario (BL_BC_BG) reflects the most probable evolution of system conditions over the study horizon. It incorporates Ameren Missouri's base assumptions for load, natural gas prices, and carbon prices and serves as the reference point for interpreting capacity expansion outcomes.

In the BL_BC_BG scenario, shown in Figure 7, the model builds a significant amount of renewable generation in the early years while the Production Tax Credit and Investment Tax Credit remain available under the OBBBA. Throughout the study period, a relatively consistent amount of new dispatchable combined cycles and combustion turbines are added to the model to maintain reliability as older coal facilities retire. Beginning in the early 2040s, solar additions increase due to declining capital costs relative to other technologies. The charts below are displayed on an installed capacity basis. With solar having a lower accreditation, it also requires more new resource MW to maintain reserve margins than other higher-accredited resources.

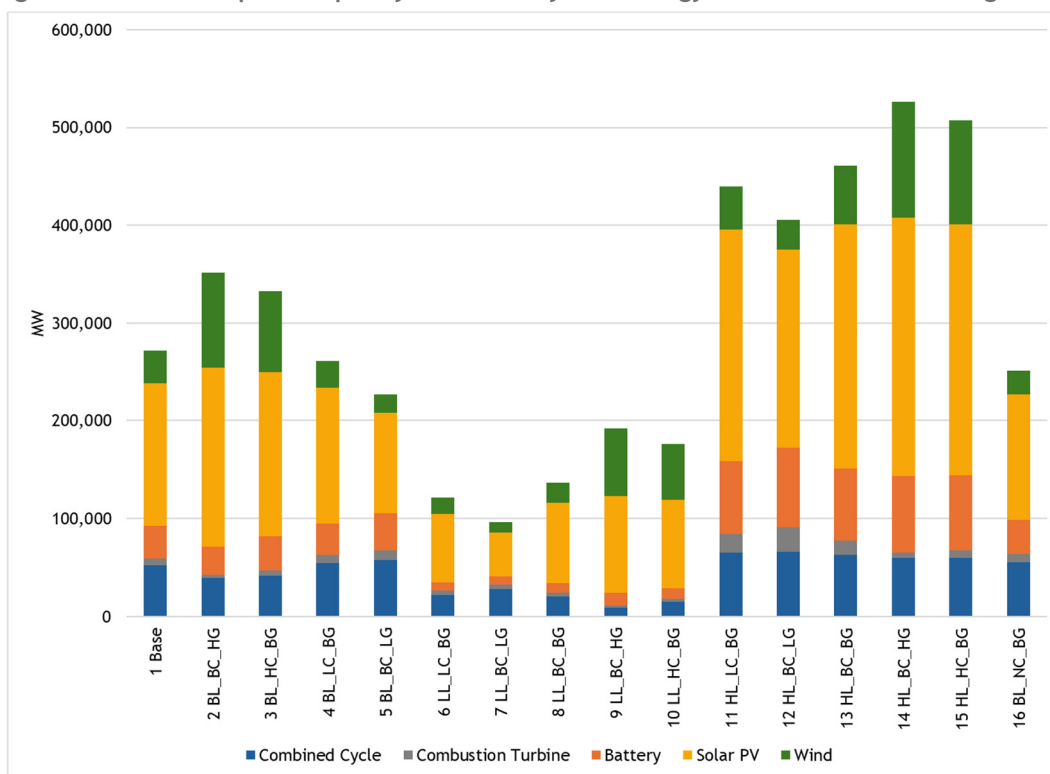
Figure 7: Base Case MISO Capacity Mix Over the Study Period



Scenario Buildout

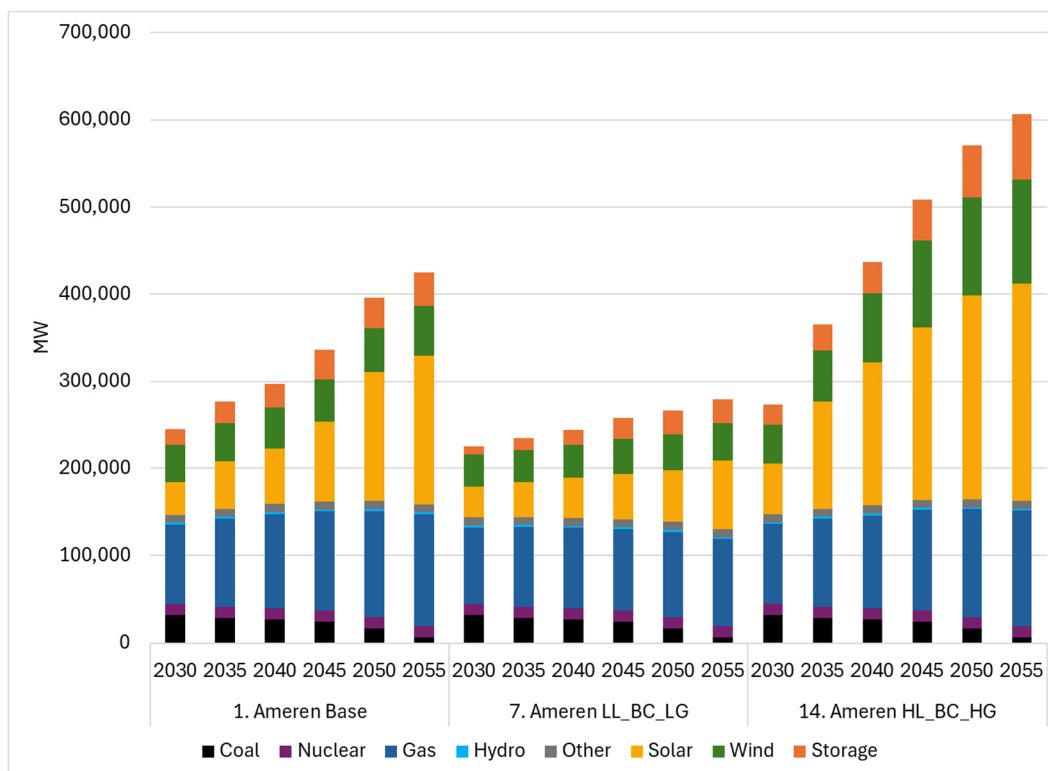
Figure 8 summarizes the total installed capacity mix selected across the 16 scenarios. While the BL_BC_BG case provides a reference pattern, the remaining scenarios vary in the scale of resource additions based on their underlying assumptions.

Figure 8: MISO Nameplate Capacity Additions by Technology for All Scenarios Through 2056



The portfolio outcomes across the EnCompass simulations show clear patterns in how load growth, carbon policy, and natural gas prices shape both the scale and mix of MISO's long-term resource needs. Load is the most direct driver. Higher load scenarios require more new capacity to maintain reliability and serve additional energy needs. Each scenario has a unique buildout, with a mix of new resource technologies being added to the MISO fleet. Lower load cases rely more heavily on the existing fleet, resulting in noticeably smaller additions overall.

Figure 9: MISO Nameplate Capacity Mix



Carbon and gas price assumptions introduce more substantial shifts in technology selection. In low-carbon price cases, thermal resources remain economically viable for longer, which slows the pace at which renewables buildout occurs. As carbon prices rise, dispatch economics begin to change. Higher carbon costs increase the variable cost of coal and gas generation, which increases system energy prices but also drives coal units to operate less frequently, lowering their capacity factors in turn. High gas price cases also push the system toward higher renewable and storage adoption. Low gas price cases improve the cost position of gas units, both for new builds and for energy production, which delays a faster transition toward a renewable heavy resource mix.

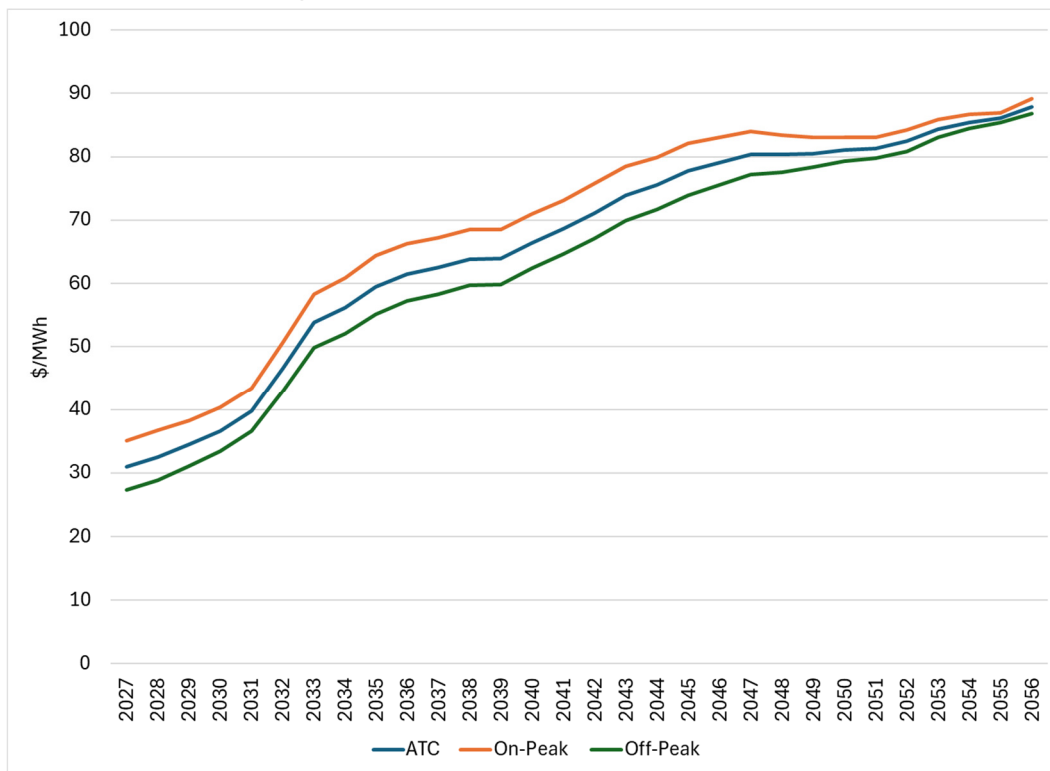
Taken together, these drivers create consistent trends across the scenario set. Renewable energy grows in every case, but the timing and scale of that growth depend heavily on fuel and carbon price conditions as well as long term technology cost trends. Scenarios with high gas and high carbon prices show the largest renewable and storage additions, since both the operating and capital economics support that shift. Lower gas and carbon price combinations see a flatter renewable build trajectory. Even so, the long-term direction remains the same. Across all scenarios, the system gradually shifts toward a portfolio built increasingly around wind, solar, and storage, with thermal resources continuing to play a role.

MISO Energy Market Price Results

In addition to capacity expansion plans, results include a comprehensive set of energy price forecasts, which are critical for evaluating long-term asset performance and strategic investments. 1898 & Co. used EnCompass to simulate every hour of every year through the final year of the study, 2056, with no representative hours, days, or weeks. Figure 10 summarizes the Base Load, Base Carbon, Base Gas (BL_BC_BG) energy prices for around-the-clock (ATC), on-peak, and off-peak periods by year across the study period. In the base case, prices in both the on- and off-peak periods rise at about the same pace for

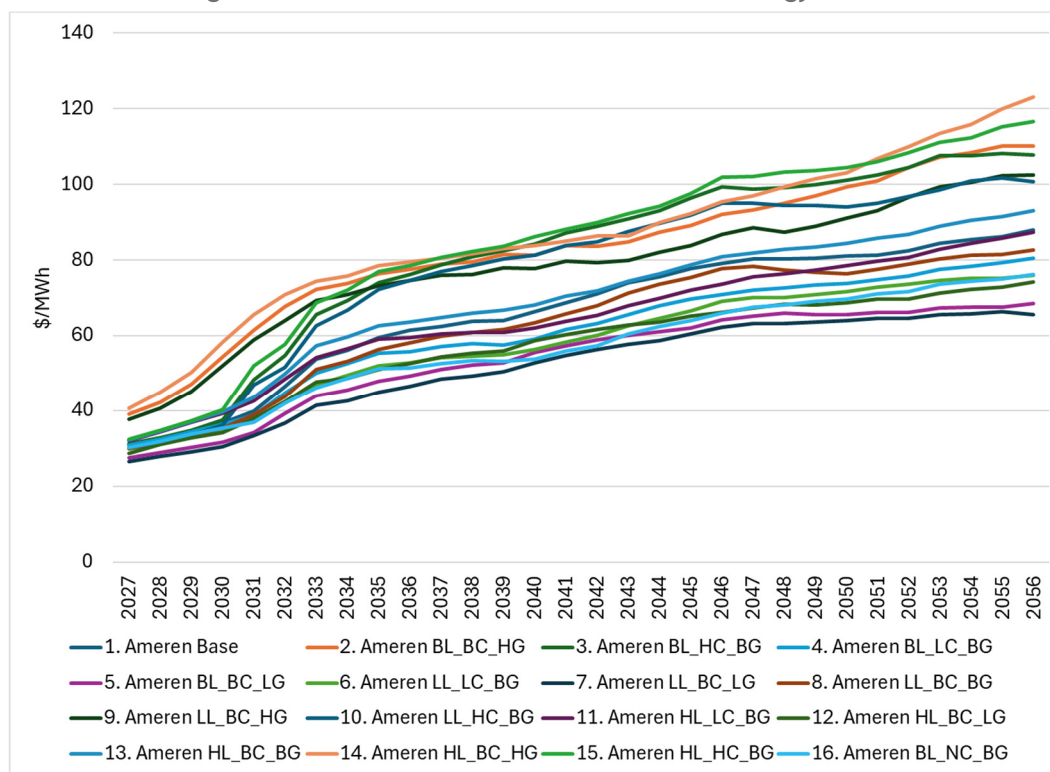
the majority of the study period. In the mid-2040s, the continued solar build out begins to have a more noticeable impact on the on-peak prices, and the relative gap between on and off-peak prices begins to tighten.

Figure 10: MISO-MO Base Case Market Prices



As depicted in Figure 11, the projected annual energy prices for MISO Zone 5 display a significant and widening divergence over the 30-year planning horizon, underscoring the market's sensitivity to shifts in load, gas prices, and carbon policy.

Figure 11: Annual Around-the-Clock MISO-MO Energy Prices



Two scenarios effectively establish the upper and lower bounds of the price forecast. The most extreme price escalation is observed in the High Load, Base Carbon, High Gas (HL_BC_HG) case, where prices are forecast to climb from approximately \$43/MWh in 2027 to \$130/MWh in 2056. In contrast, the Low Load, Base Carbon, Low Gas (LL_BC_LG) scenario provides a floor for the projections, with prices rising more moderately from an initial \$28/MWh to \$67/MWh over the same period.

The high gas price scenarios exhibit higher initial energy prices in 2027, with the high carbon price scenarios undergoing a period of rapid escalation between 2030 and 2036. This price surge is directly attributable to the carbon price escalation beginning in 2030.

While all scenarios project a general upward trend in energy prices, the spread between the highest and lowest outcomes expands considerably after 2040. This increasing divergence points to heightened market uncertainty and price volatility in the later years of the forecast. The resulting price envelope, defined by these bounding scenarios, provides a foundational input for stress-testing portfolio resilience and informing capital planning across a wide spectrum of plausible economic futures.

Reviewing the hourly price patterns rather than just the annual averages provides additional insight into how the different input assumptions shape both the long term capacity expansion outcomes and the resulting dispatch behavior. These hourly trends highlight operational effects that annual averages can mask, particularly in scenarios with large renewable buildouts or higher thermal operating costs.

A pronounced duck curve becomes clearly visible when reviewing the 2050 spring months, selected here because they most cleanly illustrate the effect, though similar dynamics appear in other seasons as well. In 2030 the daily price shape shows only a moderate midday dip, reflecting early solar penetration but still supported by a substantial thermal fleet that limits price volatility. By 2050 the system transitions toward much higher solar deployment, especially in scenarios with a carbon price or elevated natural gas costs. In these cases solar becomes the dominant low cost energy source during daytime hours, resulting in a much

deeper midday price trough followed by steep evening ramps as solar output declines. High solar penetration also increases inter-day price variability because weather driven changes in solar production more directly influence the marginal unit and thus the hourly LMPs.

Evening peaks grow especially pronounced in the carbon and high gas price scenarios, where the system relies more heavily on higher cost marginal resources and storage to meet net peak demand. Together these trends show how the combination of policy assumptions, fuel prices, and technology costs not only affects the long term resource mix but also reshapes the hourly price profile through deeper midday discounts and sharper evening peaks.

Figure 12: 2030 Spring Average Hourly LMPs

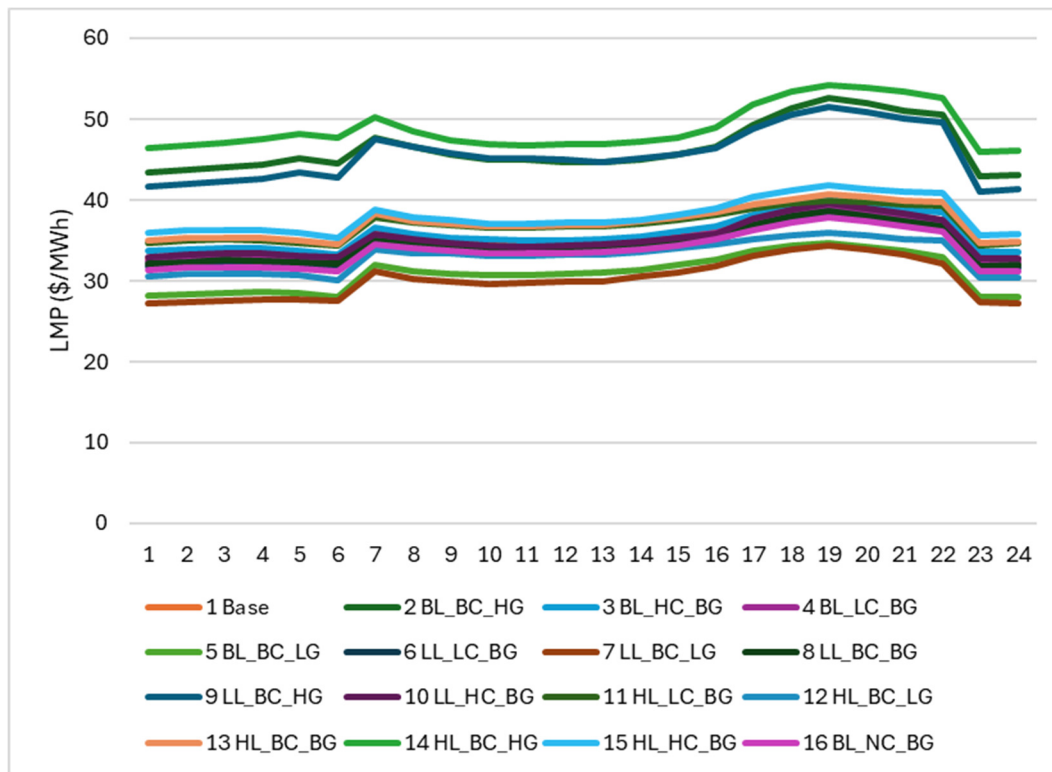
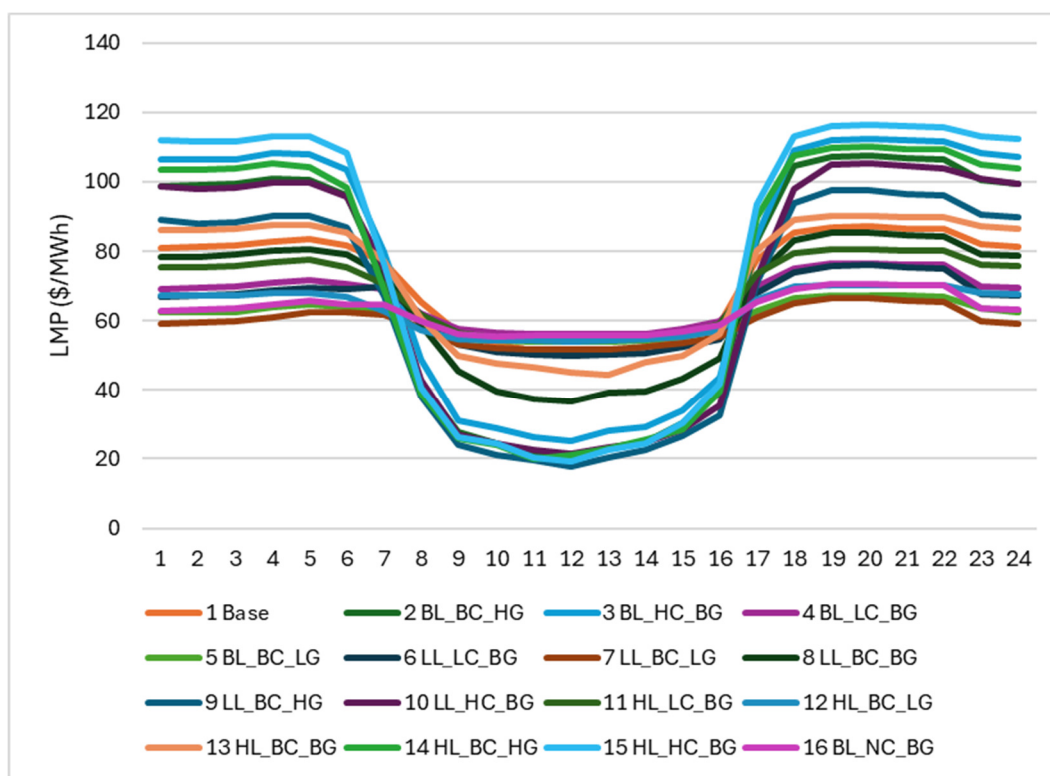


Figure 13: 2050 Spring Average Hourly LMPs



Differences in marginal units across scenarios are driven by how the resource mix evolves and how those resources are dispatched over the course of the day. In scenarios with higher levels of renewable buildout, a larger share of energy during daylight hours is supplied by resources with near zero variable operating costs, including wind, solar, and battery storage when discharging. Because these resources are dispatched ahead of thermal generation, they frequently set or displace the marginal unit during daytime hours, resulting in lower locational marginal prices. As renewable output declines later in the day, particularly in the evening, higher cost thermal resources are increasingly required to meet net load, causing marginal prices to rise during those periods. By contrast, scenarios with lower renewable penetration rely more heavily on thermal generation throughout the day, which causes thermal units to become marginal earlier and more often, elevating LMPs across a broader set of hours.

Fuel and carbon price assumptions further influence which resources set the marginal price by directly affecting the variable cost of thermal generation. Higher natural gas prices or higher carbon prices increase the operating cost of gas and coal units, raising the clearing price in hours when a thermal unit is marginal. Scenarios combining elevated gas and carbon prices therefore exhibit higher marginal prices than cases with lower fuel or carbon costs, even when the overall resource mix is similar. Together, these dynamics explain the observed differences in both average annual prices and hourly price patterns across scenarios. Changes in renewable penetration, fuel prices, and carbon policy alter which resources are marginal and when, and the resulting LMPs reflect those underlying system economics rather than any single driver in isolation.

MISO Market Capacity Price Results

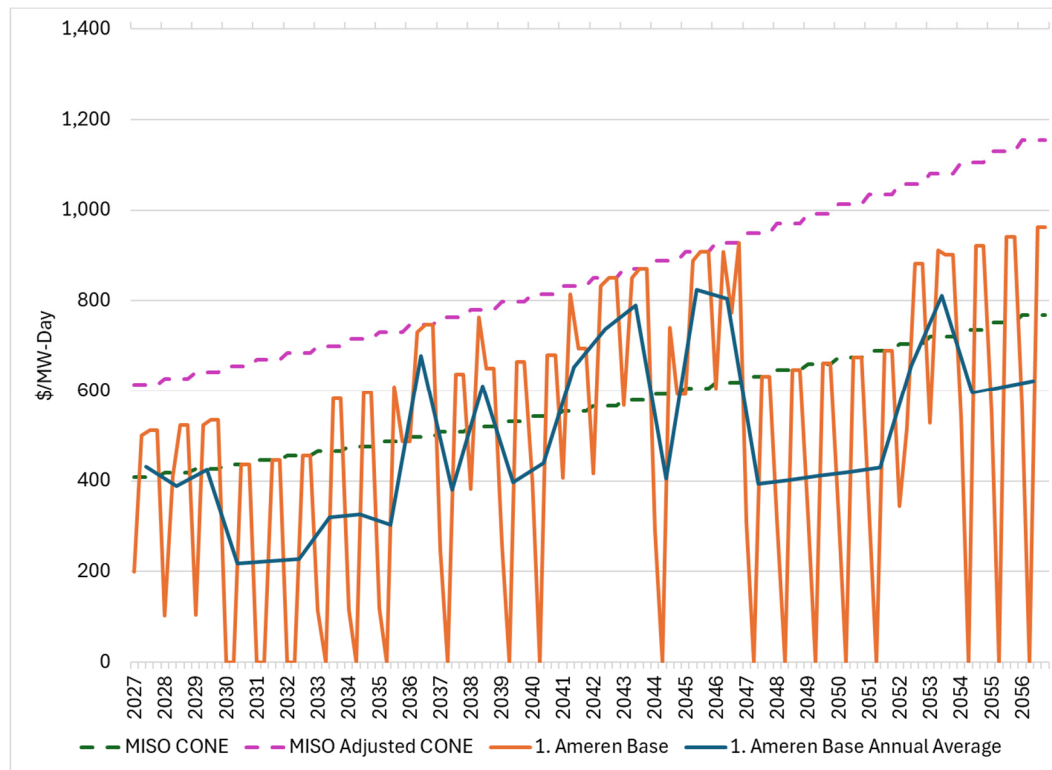
To provide long-term grid reliability beyond daily energy transactions, MISO also administers a seasonal capacity market. The fundamental purpose of this market is to procure sufficient generation resources to

meet peak demand. This is achieved by balancing a system-mandated demand target against capacity offers submitted by resource owners.

MISO's Planning Resource Auction has moved to using a sloped demand curve, which values incremental capacity based on its contribution to system reliability. Under this structure, capacity prices rise gradually as the region approaches a capacity shortfall and fall gradually when surplus resources exist. The sloped demand curve replaces the vertical construct used previously and is intended to better align prices with the probabilistic LOLE methodology and signal the economic value of additional capacity as system conditions tighten. Under the sloped demand curve, the capacity market can now clear at prices above Cost-of-New-Entry (CONE). The higher end of the curve includes a shortage pricing region, where capacity prices can rise above CONE when the system faces tight reserves or a higher reliability risk.

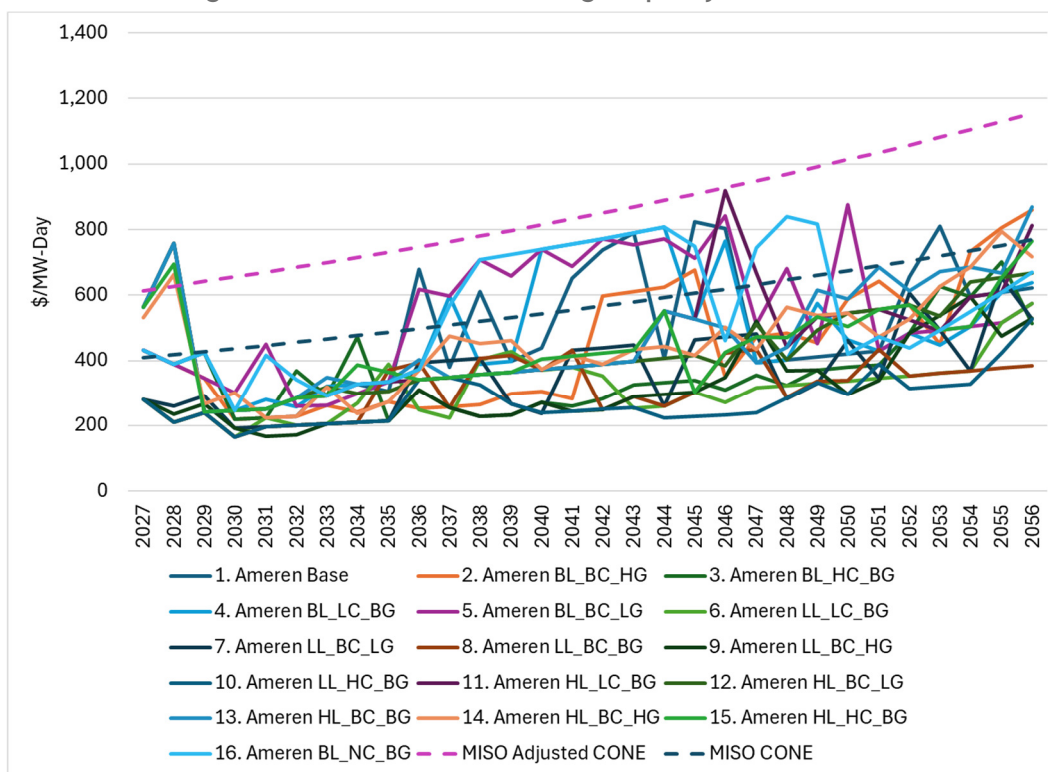
Historical outcomes from MISO's Planning Resource Auction underscore the broad volatility of capacity prices in the region. For example, in the 2024/2025 auction, most zones cleared at only \$30/MW-day, while one zone cleared at the seasonal CONE following a localized capacity shortfall. In contrast, the 2025/2026 auction, following a tighter accredited capacity balance and introduction of the Reliability-Based Demand Curve, cleared at \$666.50/MW-day for summer across much of the footprint. This wide range of past clearing prices highlights how sensitive capacity prices are to reserve margins, accreditation levels, unit retirements, and load growth.

This historical volatility underscores the importance of examining both baseline and sensitivity outcomes in long-term planning. Figure 14 shows the Base Scenario capacity price outlook on both a seasonal and annual average basis. Consistently throughout the study period, prices tend to be higher in the summer and lower in the spring. Capacity prices in the Base Case project are relatively high on average across the study period, driven mainly by consistent load growth.

Figure 14: Base Case Seasonal Capacity Overlayed with the Base Case Annual Average Capacity Price²

² MISO Adjusted CONE was created using the adjusted capital cost for an F-Class Combustion Turbine following the MISO CONE calculation methodology.

Figure 15: MISO-MO Annual Average Capacity Price Outlook



As projected capacity prices reach or exceed the MISO and Ameren Missouri CONE values, the model economically justifies the construction of new generation capacity to mitigate exposure to persistent extreme capacity costs. Over the long-term forecast, capacity prices are projected to range between approximately \$200/MW-Day and \$800/MW-Day. An overall increase throughout the study period is influenced by several factors, including a significant rise in load forecasts, largely driven by the expansion of data centers, and escalating capital costs for new generation resources.

Analysis of scenarios with varying gas prices indicates that, for most of the study period, higher natural gas prices correlate with lower capacity market prices. This result occurs because sustained high gas prices improve the economic viability of renewable resources. This, in turn, incentivizes greater renewable capacity expansion, which adds zero-marginal-cost generation to the system, putting downward pressure on clearing prices.

Similarly, isolating the carbon price variable reveals that higher carbon prices tend to result in lower capacity prices. A significant carbon price increases the operating cost of fossil fuel-based generation, which accelerates the deployment of renewable and other low-emitting generation technologies. The resulting increase in the supply of alternative capacity reduces overall capacity market-clearing prices. Analysis of the load variable demonstrates a direct relationship between electricity demand and capacity prices. Scenarios featuring lower load growth result in lower capacity prices throughout the entire study period, as less new generation capacity is required to meet demand and maintain reliability standards. High load scenarios experience very high capacity prices over the next few years, as new generation deployment takes time to ramp up, causing a tight capacity market over the first part of the study period.

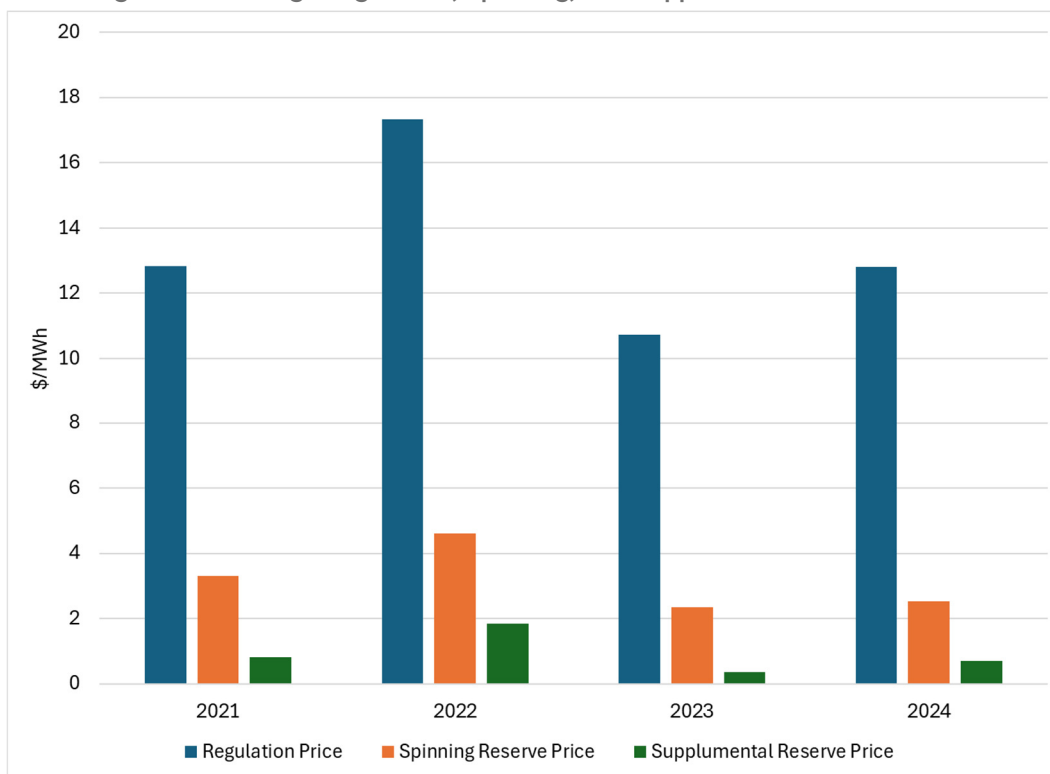
Ancillary Services

MISO's ancillary service framework was originally built around stable reserve requirements designed for a system dominated by synchronous thermal generation. Historically, Regulation Reserve needs were around 400 MW across the MISO system, with Spinning and Supplemental Reserves set to meet standard contingency-recovery obligations. These requirements changed only modestly with seasonal load patterns and were largely supplied by online thermal units capable of meeting the ten-minute deployment window.

Participation has broadened as the resource mix has evolved. Thermal units still provide most spinning and supplemental reserves, but battery energy storage has quickly become a contributor across both regulation and contingency products because of its fast, accurate response. Demand response can supply supplemental reserves when it meets performance standards. Dispatchable renewables may qualify when operating with sufficient headroom, although participation remains limited due to forecast uncertainty and lost energy revenues.

Recent market data from 2022 through 2024 shows that ancillary-service prices have been variable. Higher renewable penetration, local transmission constraints, price impacts of natural gas, and shifting net-load patterns have contributed to more frequent short-term price spikes, even though annual averages remain modest. These patterns reinforce the need to treat ancillary-service revenues as opportunistic adders rather than a stable revenue stream.

Figure 16: Average Regulation, Spinning, and Supplemental Reserve Prices



Long-term forecasting of ancillary-service prices remains difficult. Production cost and capacity expansion models do not capture real-world operational volatility, forecast errors, or the localized scarcity events that influence AS price formation. As these models build significant new storage and flexible thermal capacity over a thirty-year horizon, they frequently show limited AS price escalation. Actual future outcomes may differ, especially as more baseload generators retire, but energy and capacity revenues remain the most

reliable long-term value components for planning purposes. Ancillary services should be viewed as upside potential rather than a core driver of economics.

MISO is continuing to review and update its reserve framework to better align with the changing fleet. The phasing to a dynamic regulation requirement is the most significant change, allowing reserve needs to move hour-by-hour based on load, renewable variability, and system uncertainty. Additional updates under review include refinements to contingency-reserve modeling, reserve demand curves, and ramp-capability products. As these changes progress, flexible resources capable of fast, accurate response may see increased opportunity, although the timing and magnitude of those impacts remain uncertain. Overall, ancillary services remain an important part of system operations, but energy and capacity continue to offer the most consistent long-term revenue outlook for new resources in MISO. Ancillary-service revenues should be considered incremental and variable, with future value dependent on system conditions and ongoing market design updates.



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