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.

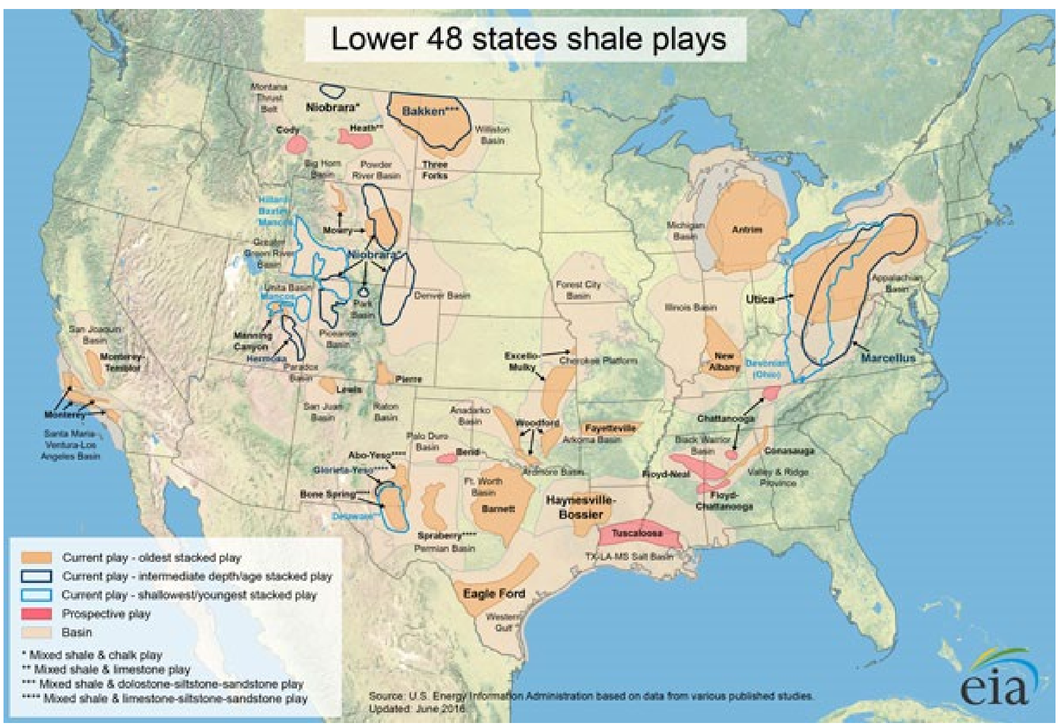
2.5.1 Natural Gas Market[3]

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.

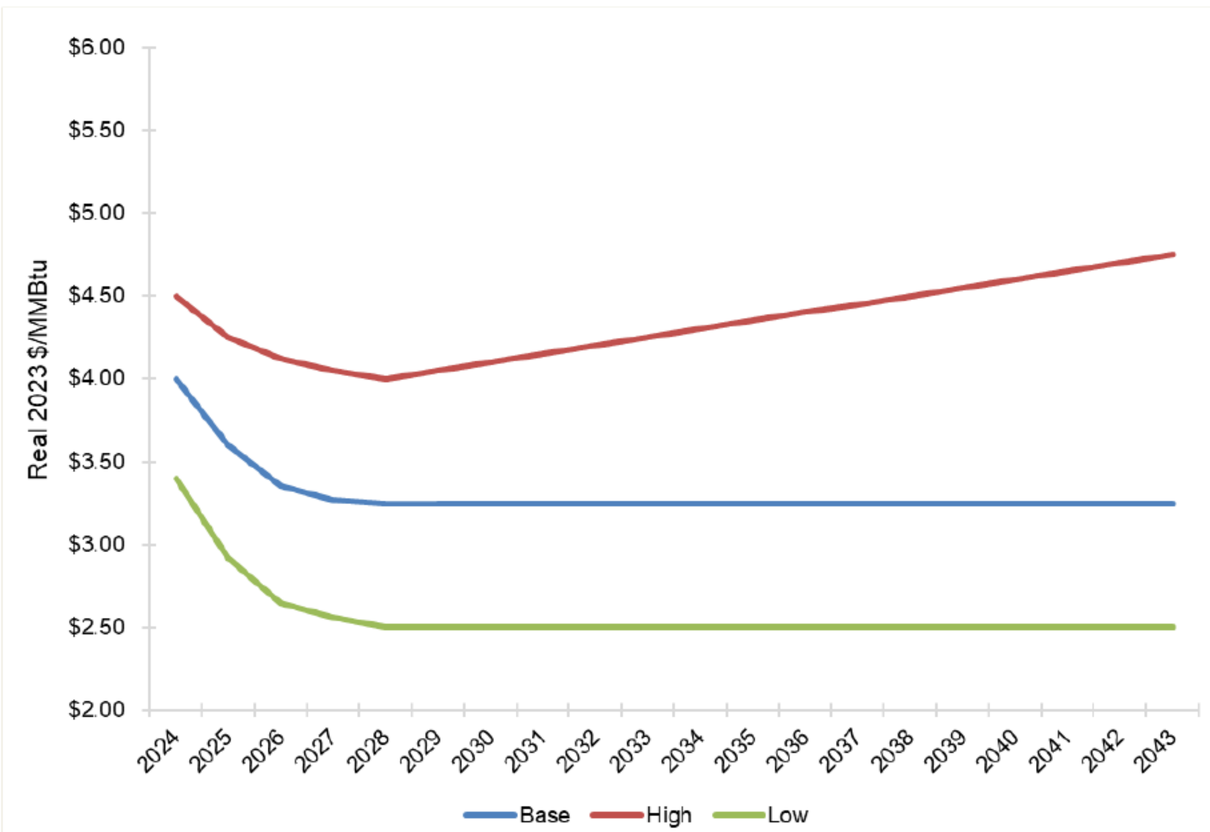
Natural Gas Price Assumptions

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]

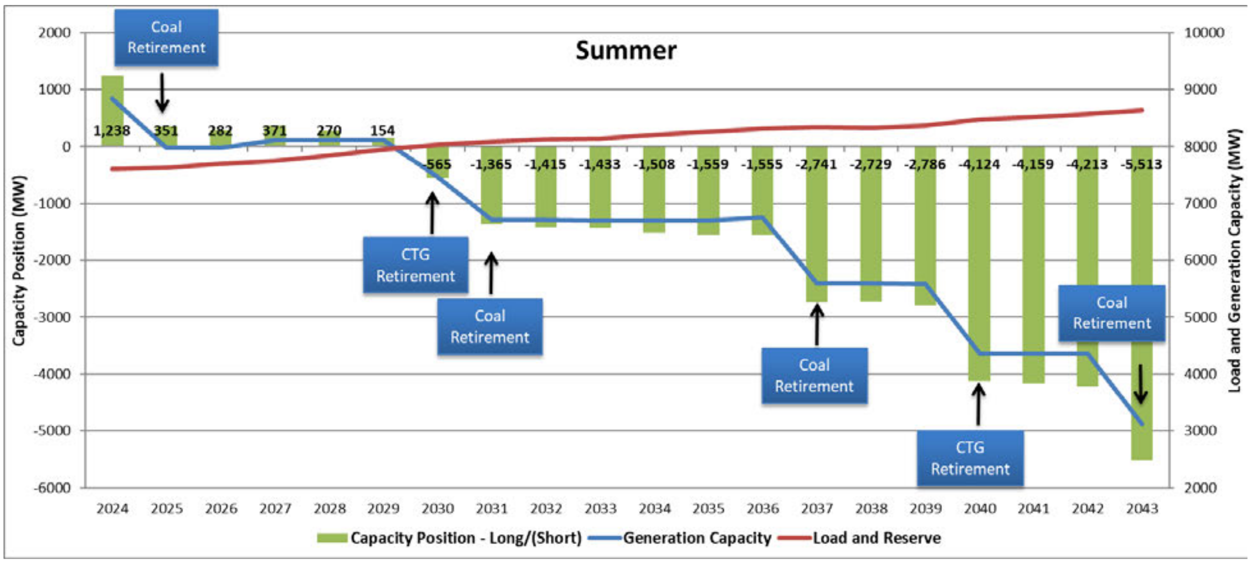
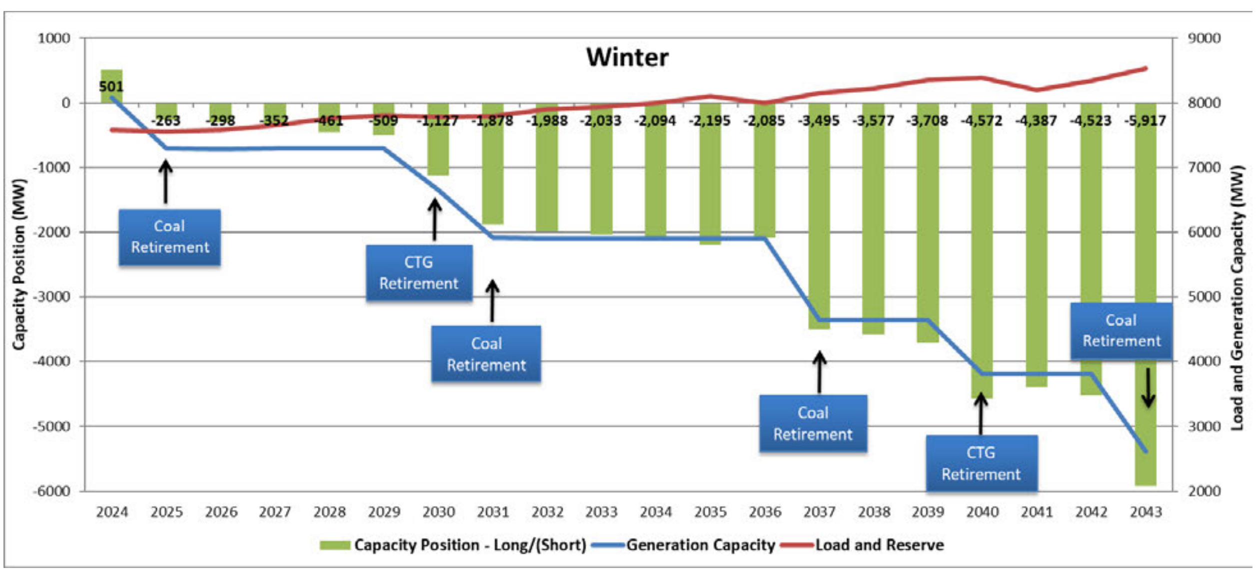


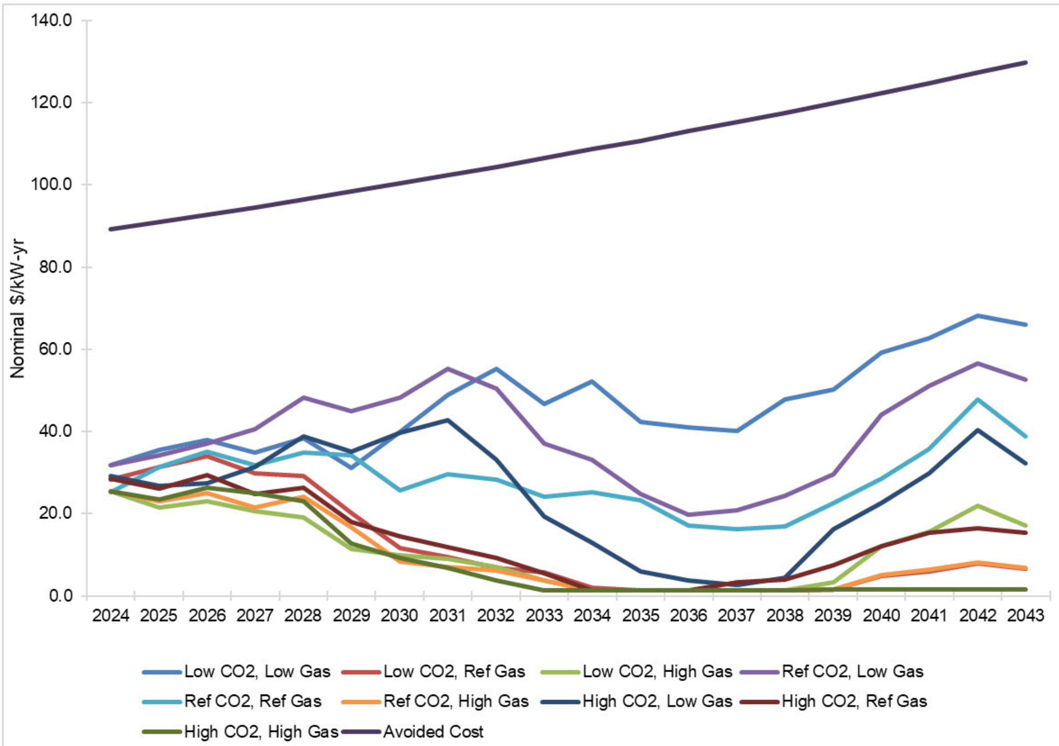
Figure 2.4b Capacity Position without Further DSM – Winter[6]



[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

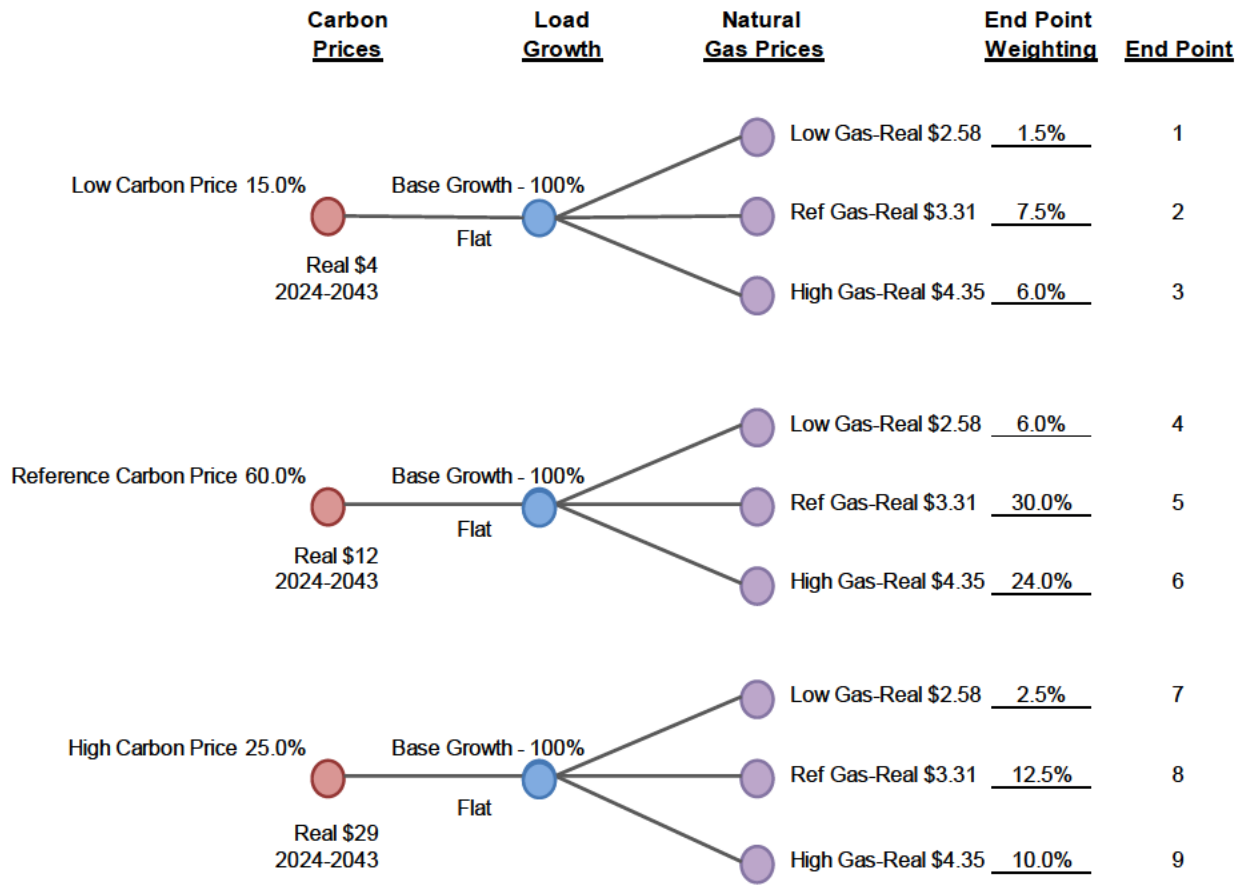
Table 2.9 Carbon Dioxide Emissions Price Assumptions

	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

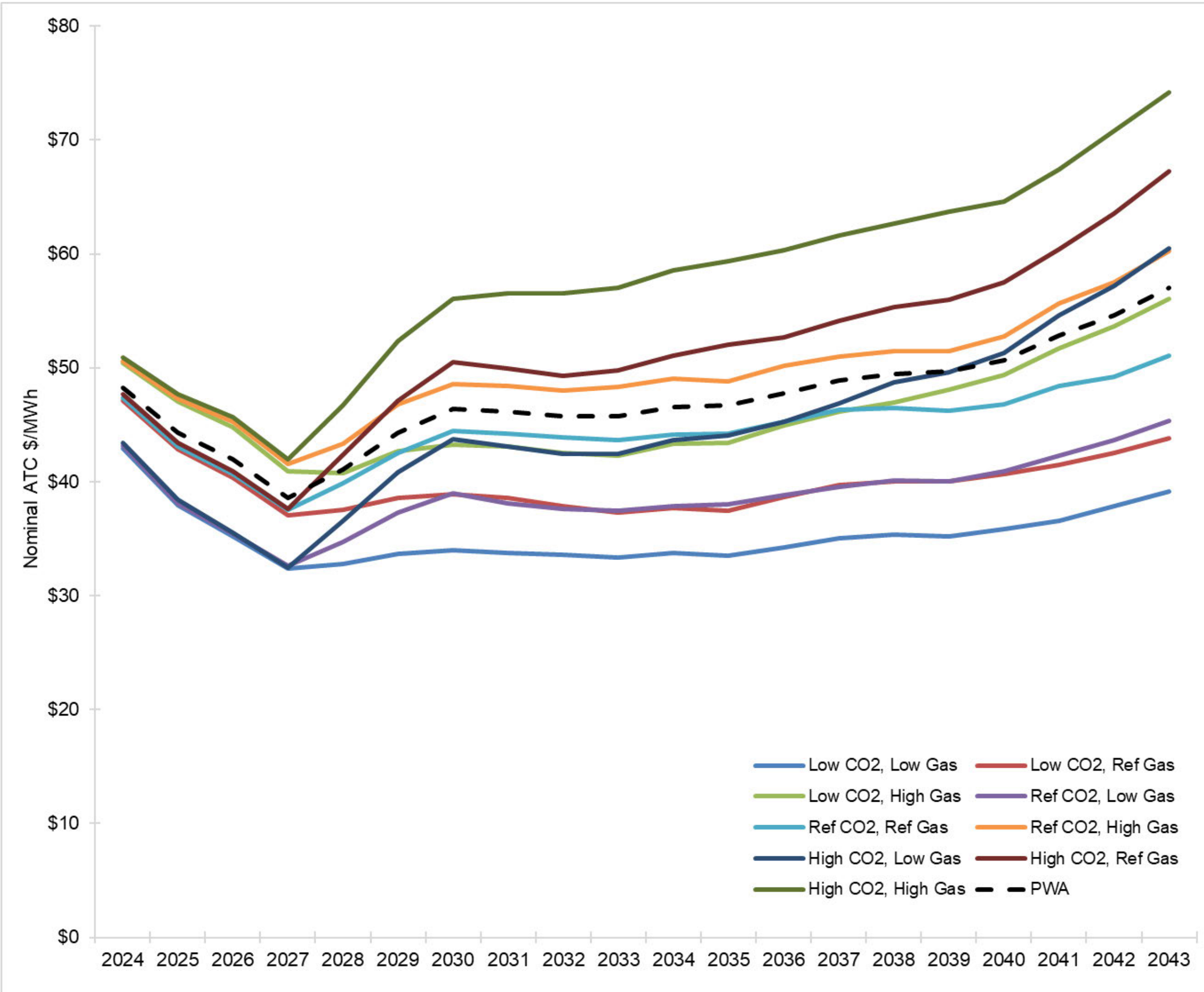
These inputs were varied within the model, and audited by CRA to ensure they were reasonable and comprehensive. This process produced values based on the probability

[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