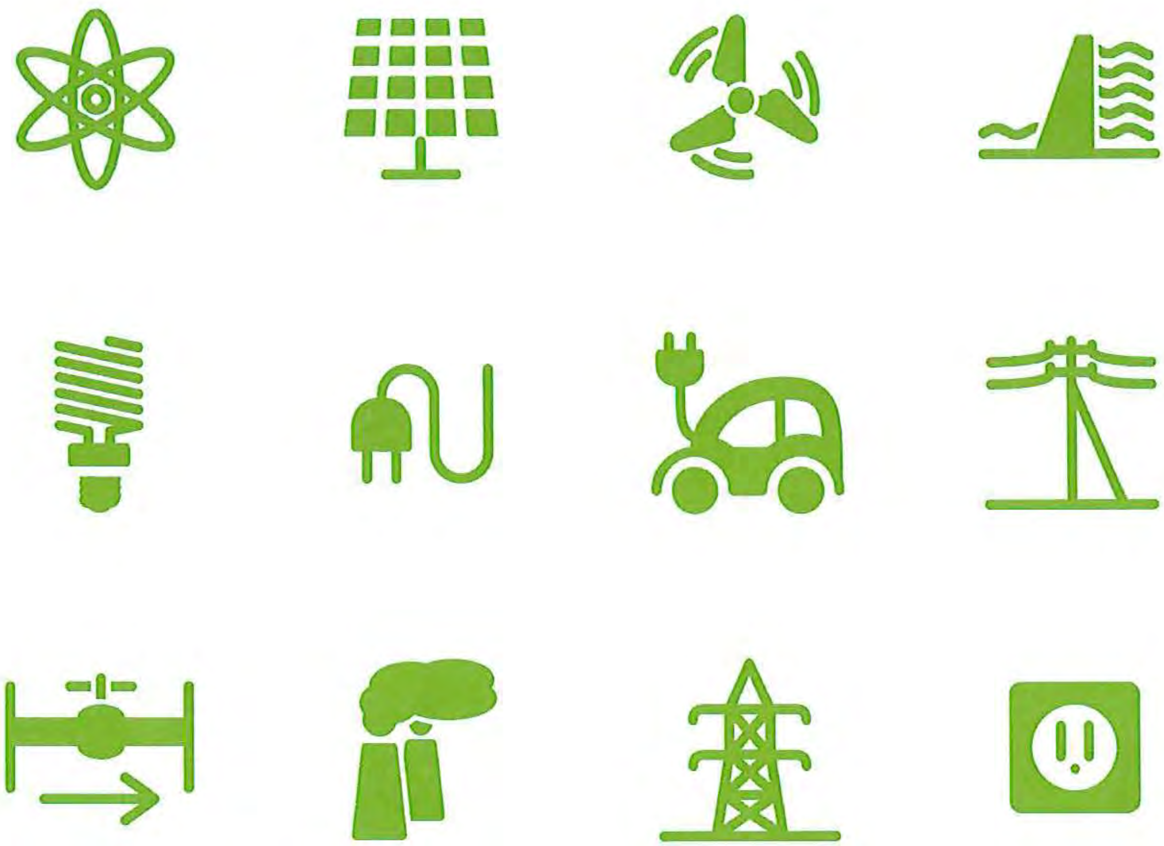
INVESTING IN MISSOURI // 2014 INTEGRATED RESOURCE PLAN



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MISSOURI

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1. Executive Summary

Highlights

- *Ameren Missouri has developed and is executing on a plan that is focused on transitioning its generation fleet to a cleaner and more fuel diverse portfolio in a responsible fashion over the next 20 years to ensure we provide service to our customers that is safe, reliable and environmentally responsible at a reasonable cost.*
- *Our plan includes continued customer energy efficiency program offerings, retirement of approximately one-third of our coal-fired generating capacity, which will be reaching the end of its useful life, and expansion of renewable and cleaner-burning natural gas-fired generation.*
- *Our plan allows us to continue to rely on our existing, low-cost and carbon-free nuclear generation while also preserving options for future nuclear generation.*
- *By 2035, our plan would result in a diverse, balanced and dependable mix of coal, nuclear, natural gas and renewable energy resources that results in further significant reductions in emissions of carbon dioxide, sulfur dioxide, nitrogen oxides, mercury and particulate matter in addition to those we have achieved since 1990.*
- *Our plan allows us to achieve the goals of the U.S. EPA's proposed Clean Power Plan, reducing carbon dioxide emissions by 30% from 2005 levels, but at a customer cost savings of $4 billion.*

Every three years, Ameren Missouri files with the Missouri Public Service Commission its Integrated Resource Plan (IRP). The IRP provides an assessment of the future electric energy needs of our customers for the coming 20 years and our preferred plan for meeting those needs. Ameren Missouri's 2014 IRP presents a resource plan that is focused on transitioning our generation fleet to a cleaner and more fuel diverse portfolio in a responsible fashion. Our plan includes continued customer energy efficiency program offerings, retirement of approximately one-third of our coal-fired generating capacity, which will be reaching the end of its useful life, and expansion of renewable and cleaner-burning natural gas-fired generation. By executing our plan, we will ensure that our customers' long-term electric energy needs are met in a safe, reliable, cost-effective and environmentally responsible manner.

1.1 Transitioning to a More Fuel Diverse Portfolio

The conditions and circumstances in which utilities must make decisions about how to meet customers' future electric energy needs are ever-changing. Decisions are influenced by the costs and availability of different resource alternatives and by conditions in electric energy markets, including changes in environmental regulations, commodity prices, technology advancements, financial markets, and the economy at large. Economic growth has slowed in recent years, and future demand will continue to grow at a slower pace due in large part to increases in energy efficiency. As a result, the need for new sources of generation is being influenced more by the need to replace existing sources of generation as they reach the end of their useful lives and less by the need to serve growing demand.

Ameren Missouri produces over 70% of the electricity it generates from efficient, low-cost coal. These coal-fired generators must be retired when they reach the end of their useful lives. Retirement decisions are driven in large part by expectations for environmental regulation, in addition to coal prices and power prices. In recent years we have seen an increase in the number and complexity of new environmental regulations primarily affecting coal-fired power plants. Most recently, the EPA has proposed regulations on the emission of carbon dioxide (CO_2) from existing fossil-fueled generators. At the same time, we have seen a sustained reduction in the price for natural gas resulting from the continued shale gas boom and a corresponding reduction in wholesale prices for electricity. Environmental regulations and low natural gas prices have challenged the economics of older, less-efficient coal generators. This is not to say that coal-fired power is not economic – far from it. Ameren Missouri's more efficient coal-fired generators are among the most efficient and economic in the country. It simply means that we must be mindful of the challenges and ensure that we balance all the costs and benefits of coal generation.

To ensure that we are able to meet customers' long-term energy needs and to address the challenges of our aging fleet of coal-fired generators, Ameren Missouri has developed and is executing on a plan that is designed to satisfy the following objectives:

- ✓ **Transition Ameren Missouri's resource mix to a cleaner, more fuel diverse portfolio in a responsible fashion over the next 20 years**
- ✓ **Manage the transition of our generation fleet, and plan for eventual closure of aging coal-fired resources at the end of their useful lives, in a way that is beneficial to customers, shareholders, the environment, and our communities**
- ✓ **Create and maintain flexibility – financial, economic, technological, regulatory, environmental, etc. – to be able to effectively adapt to changing conditions**

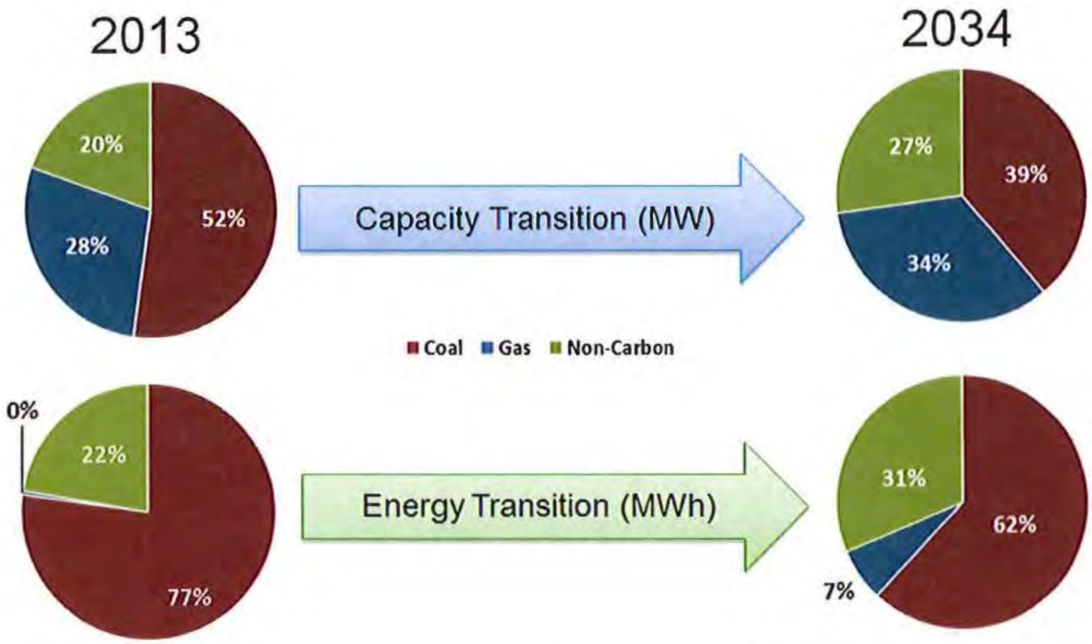
In addition to addressing the challenges of our aging coal-fired fleet, and to fully satisfy our planning objectives, we must also focus on adding new cleaner sources of electric generation that enhance the fuel diversity of our portfolio and reduce emissions. The addition of renewable generation sources such as wind, solar, hydro and biomass can help us to enhance our fuel diversity and also meet the requirements of Missouri's Renewable Energy Standard (RES). Adding natural gas-fired generation will also allow us to enhance our fuel diversity while providing cost-effective replacement capacity for certain retiring coal-fired resources. Nuclear generation is another viable resource option that can be used to replace retiring coal-fired resources while adding no emissions of greenhouse gases and other emissions.

Our preferred resource plan satisfies the planning objectives outlined above by:

- ✓ **Retiring approximately one-third of our coal-fired generating capacity (1,808 MW)**
  - Meramec Energy Center units 1 and 2 converted to natural gas-fired operation in early 2016; all four units retired by the end of 2022
  - Sioux Energy Center retired by the end of 2033
- ✓ **Significantly expanding our portfolio of renewable generation with the addition of:**
  - 400 MW of wind generation
  - 45 MW of solar generation
  - 28 MW of hydroelectric generation
  - 5 MW of landfill gas generation
- ✓ **Continuing to offer cost-effective customer energy efficiency programs**
- ✓ **Adding cost-effective demand response programs**
- ✓ **Adding 600 MW of efficient natural gas-fired combined cycle generation**
- ✓ **Continuing to rely on our existing low-cost nuclear generation**
- ✓ **Preserving options for new nuclear generation**

Figure 1.1 illustrates the impact of our preferred resource plan on our portfolio mix over the next 20 years. Non-carbon generation includes nuclear, renewable and storage resources. As the graphic shows, our portfolio will be transitioned to one that is more fuel diverse and balanced in terms of both capacity (MW) and energy (MWh). As a result of this transition, our plan will also result in a significant reduction of carbon dioxide emissions, allowing us to achieve CO_2 emissions that are 30% below 2005 levels.

Figure 1.1 Preferred Resource Plan Portfolio Transition

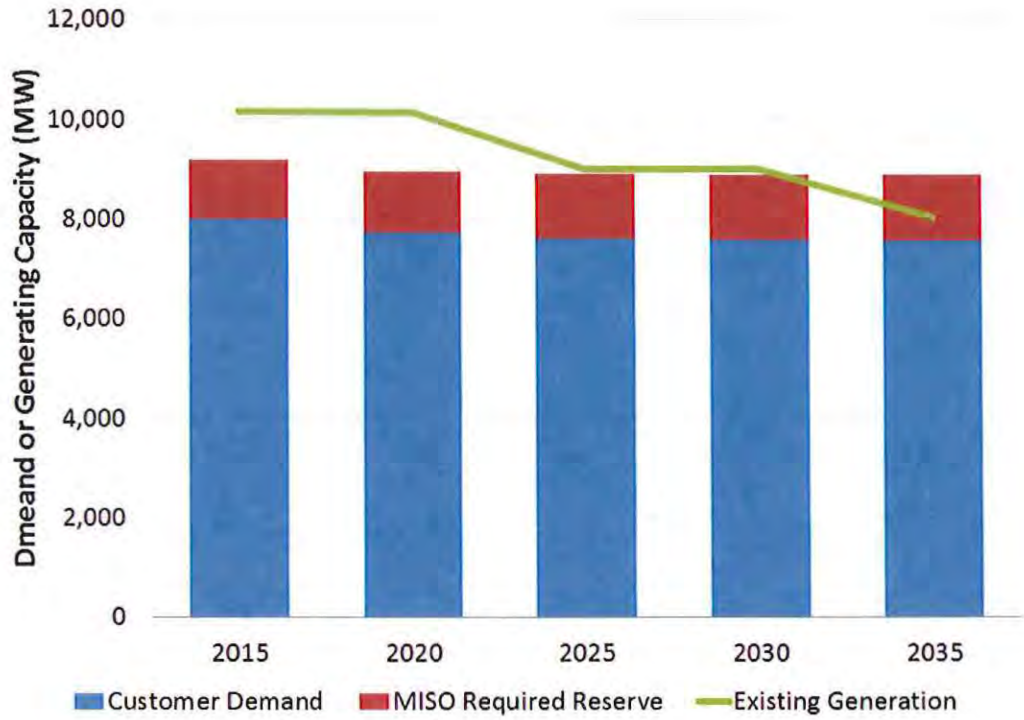


Note: Capacity percentages based on nameplate generation ratings. Non-carbon generation includes nuclear.

1.2 Our Need for New Generating Resources

Ameren Missouri currently has sufficient resources to meet our customers' demand and provide sufficient reserve capacity to ensure reliability of electric generation and support sales into the Midcontinent Independent System Operator (MISO) market. With a slow recovery from the Great Recession and with increasing levels of energy efficiency, growth in demand for electricity has diminished compared to previous historical levels. Figure 1.2 shows our expected customer demand, including customer energy efficiency programs, and reserve requirements and our existing net generating capability available to meet them, including planned retirements. With little or no growth in demand, our need for new sources of generation will be driven primarily by 1) renewable energy needed to comply with the RES and 2) replacement of retired generation when appropriate.

Figure 1.2 Customer Demand, Reserve and Generation



Note: Does not include addition of new generation sources

Ameren Missouri produces over 70% of the electricity it generates from coal. Ameren Missouri's existing fleet of coal-fired generating units are all between 37 and 61 years old, as shown in Table 1.1. Through diligent maintenance and cost-effective equipment replacement we have been able to maintain the efficiency and production capability of our low-cost coal-fired energy centers while also maintaining high standards of safety and reliability. Eventually though, such coal-fired units will be retired and, if necessary, replaced at the end of their useful lives. Retirement of our Meramec Energy Center can be carried out without creating a need for new generating capacity, primarily as a result of the continuation of our cost-effective customer energy efficiency programs. However, retirement of additional coal generation beyond Meramec is expected to result in a need for new generation. As Table 1.1 shows, we expect to retire our Sioux Energy Center by the end of 2033. Upon the retirement of Sioux we expect to need to add new generating capacity to meet customer demand and MISO reserve margin requirements for reliability.

Table 1.1 Ameren Missouri Coal Fleet Profile

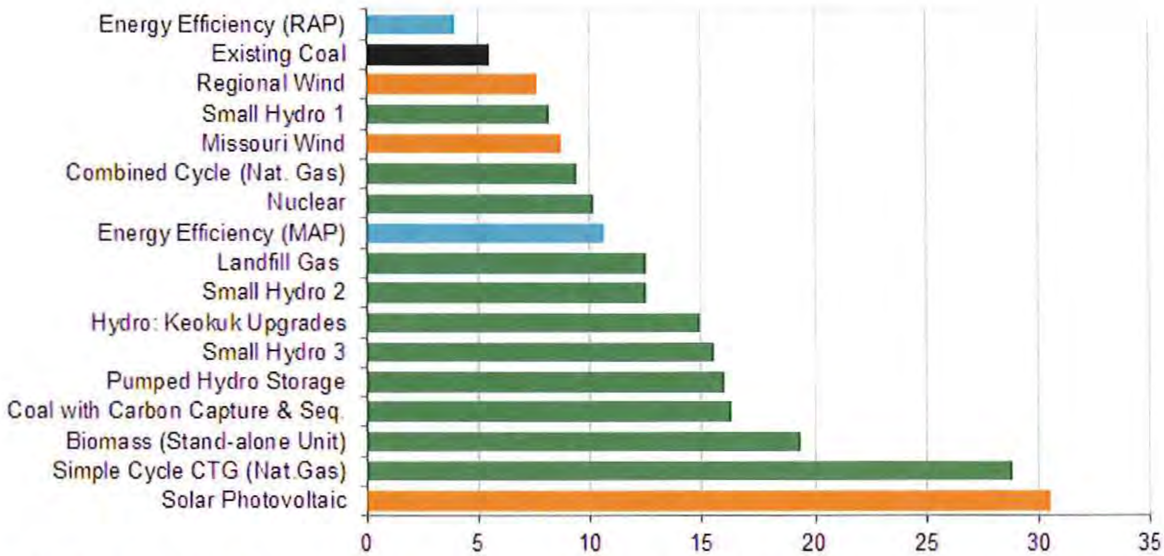
Energy Center	Units	Capacity (MW)	In-Service Year	Age (years)	Estimated Retirement	Age at Retirement
Labadie	4	2,374	1970-73	41-44	2042	65-70
Rush Island	2	1,182	1976-77	37-38	2046	69-70
Sioux	2	972	1967-68	46-47	2033	65-66
Meramec	4	831	1953-61	53-61	2022	61-69
All Coal Energy Centers	12	5,359	1953-77	37-61		61-70

We also have a need for renewable resources during the planning horizon to meet the requirements of Missouri's RES. The RES requires increasing amounts of energy from renewable sources subject to a 1% rate impact limitation. The requirements for renewable energy increase from 5% of retail sales to 10% in 2018 and then to 15% in 2021. Of those renewable energy amounts, at least 2% must come from solar energy resources. To date, Ameren Missouri has been able to rely primarily on renewable energy produced by our Keokuk hydroelectric facility, our purchased power agreement with Horizon's Pioneer Prairie II wind farm, our landfill gas-powered Maryland Heights Renewable Energy Center, and solar energy produced by customer-owned systems and solar panels on our St. Louis General Office Building. However, when the standard requirement increases to 10% in 2018, and to 15% in 2021, we will need additional renewable energy resources to meet it. Ameren Missouri is already taking steps toward meeting our needs for additional solar energy resources with the construction of our 5 MW O'Fallon Renewable Energy Center (OREC) in O'Fallon, Missouri. Greater amounts of renewable energy will be added to our portfolio from additional solar and other renewable sources, such as wind, hydro and biomass, to meet our longer-term needs. We continue to work to identify and evaluate opportunities for expansion of renewable energy resources.

1.3 Resource Options for Meeting Our Needs

There are a number of options available for meeting our customers' future resource needs. These include so-called demand-side resources such as customer energy efficiency programs that can be used to reduce the amount of energy needed to provide the same level of service, convenience and comfort. They also include new generating resources such as renewable, natural gas, or nuclear powered generation. We have taken a fresh look at these and many other options for meeting customers' future needs.

Figure 1.3 LCOE for Resource Options (cents/kWh)



Note: Does not reflect inclusion of tax incentives. Blue denotes energy efficiency. Black denotes existing coal. Orange denotes intermittent resources. MAP energy efficiency reflects costs and energy savings incremental to RAP.

One way to compare these different resource options is to look at the levelized cost of energy for each option. The levelized cost of energy, or LCOE, is a measure of the per-unit cost of energy produced by a resource over its expected useful life expressed in cents per kilowatt-hour (cents/kWh). It includes all of the costs of construction and ownership, such as the recovery of the capital investment and a fair return for investors, and all of the costs of operations, such as the people, fuel, and other resources needed to operate and maintain the facilities in a safe and reliable manner. Figure 1.3 shows a comparison of the LCOE for some of the most promising resource options. It also includes the LCOE for our existing coal-fired resources. As the graphic shows, the more cost-effective resources include energy efficiency, natural gas-fired combined cycle turbines, nuclear, and renewables such as wind, hydro and landfill gas. It also shows that our existing coal generators remain low-cost sources of energy for meeting our customers' needs for the duration of the generators' expected useful lives.

It is important to recognize that while the LCOE provides a useful measure of the cost of energy from various resource options, it is not the only factor that must be considered in making resource decisions. The additional advantages of resources that can provide generation on demand and with short notice, such as simple cycle combustion turbine generators (CTGs) or hydroelectric generators are not accounted for by the LCOE. Nor is the intermittent nature of some renewable resources, such as wind and solar, which can make the energy output of these resources unpredictable. Risk and uncertainty surrounding future environmental regulations, commodity market prices, economic conditions, economic development opportunities, and other factors must be considered as well. Our analysis has shown that a few resource options provide distinct advantages compared to others.

Energy Efficiency – The cost of saving a kWh of energy is generally cheaper than the cost of generating a kWh of energy from a new resource. Figure 1.3 shows that pursuing programs at a level we call realistic achievable potential (RAP) can produce just such a result. Ameren Missouri has found, through its robust market research and actual experience to date, that customer energy efficiency programs are a cost-effective way to reduce our need for new sources of generation while producing meaningful savings for customers who participate. However, unlike a new power plant, the success of energy efficiency programs is highly dependent on the specific choices made by each and every one of our 1.2 million customers. Its success is also dependent on the need for continued constructive regulation. We must therefore proceed thoughtfully with our customer energy efficiency programs to ensure that they achieve the desired results in a cost-effective manner while looking for ways to identify improvement opportunities and maximize the amount of cost-effective energy savings we can achieve.

Wind Power – Wind power continues to be an attractive resource option, not only for meeting requirements of the RES, but also as a low-cost source of large amounts of emission-free generation. Ameren Missouri has identified a number of areas within MISO that are conducive to cost-effective wind power, including areas in the state of Missouri. The key disadvantage of wind is its intermittent nature – it only generates when the wind is blowing. As a result, it cannot be relied upon significantly for generating power at times of peak demand. MISO allows utilities to count approximately 14% of the output capability of wind to meet peak demand requirements for reliability. Even so, wind can provide large volumes of lower-cost energy that can help to replace energy production lost from the retirement of coal resources.

Natural Gas Combined Cycle – With the continued prospects for relatively inexpensive supplies of natural gas, combined cycle gas combustion turbines are an attractive option for new generation. Unlike CTGs, which generate electricity only from burning natural gas, combined cycle generators capture the waste heat from gas combustion and use it to generate additional electricity from steam. As a result, combined cycle generators can achieve operating efficiencies that are significantly higher than those of coal generators and largely offset the higher cost of natural gas fuel compared to coal.

The potential disadvantage of gas-fired generation is fuel price volatility. Natural gas has historically been subject to large and sudden price changes. When considering a natural gas-fired resource, it is important to consider the appropriate amount of exposure to such price fluctuations and the sufficiency of natural gas delivery infrastructure.

Nuclear Power – Nuclear power is capable of providing around-the-clock generation on a continuous basis at a competitive cost. Because a high percentage of the costs of nuclear generation are fixed, it is not as vulnerable to changes in fuel or other variable costs. At the same time, new nuclear generation requires large amounts of capital investment, so it is important to manage the associated financing risks. For Ameren Missouri, nuclear power continues to represent an important option to be maintained as we consider the implications of greenhouse gas regulations and as we look to the longer-term transition of our generation portfolio, as well as the associated economic development opportunities for Missouri

Solar – Investments in new solar generation by Ameren Missouri allow us to bring the benefits of solar energy to all of our customers at an overall cost that is lower than that for individual customer installations. Our O'Fallon Renewable Energy Center project is expected to be completed by the end of 2014 and represents the first of several such projects to provide clean solar energy to our customers. Ameren Missouri is planning another new, and larger, solar energy project to be completed in 2016. When completed, it would become the largest solar energy facility in Missouri, approximately 10 MW.

Other Renewable Resources – While wind power is promising as a lower-cost source of large volumes of emission-free generation, Ameren Missouri is also encouraged by the potential of other sources of renewable energy. The performance of our Maryland Heights Renewable Energy Center landfill gas generating facility demonstrates the viability of a cost-competitive option for around-the-clock renewable generation with the potential for expansion. In the longer term, small hydroelectric projects may provide cost-competitive opportunities for additional renewable energy. Ameren Missouri continues to evaluate the potential and viability for a range of renewable energy sources.

With our strategy to transition our resource portfolio to one that is cleaner and more fuel diverse, it is important that we do so in a responsible fashion and fully consider the benefits that each of these options provides, while balancing and managing the ever-changing energy and economic environment in which we operate.

1.4 Planning Assumptions

To help us determine the appropriate resource balance and path toward a cleaner and more fuel diverse resource portfolio, we evaluate the options described above using robust ranges for key assumptions that can influence our resource decisions. We have found that there are certain key assumptions that can influence our resource decisions:

- *Natural Gas Prices*
- *Load Growth*
- *Environmental Regulations*
- *Coal Prices*
- *Generation Project Costs*
- *Cost of Capital (Debt and Equity)*
- *Cost and Performance of Demand-side Resources*

Natural Gas Prices

The price of natural gas is important not only in assessing the economics of gas-fired resources but also in identifying the range of wholesale electricity prices affecting the economics of all resources. This is because wholesale electricity prices are determined in large part by the price of natural gas. Based on an assessment of the natural gas markets by our internal experts, we assume that long-term natural gas prices will be in the range of $4/MMBtu to $6/MMBtu in today's dollars.

Load Growth

Load growth in the U.S. Eastern Interconnect also affects wholesale prices for electricity – the higher the load growth, the higher the wholesale price of electricity. In addition to factors relating to economic growth and expectations for the level of energy intensity in the economy, we also must assess other factors that could influence the growth of electricity demand such as utility energy efficiency programs and the potential for technological and market advancements in areas such as electric vehicles and distributed generation. Taking into account all these factors, we estimate that load growth in the Eastern Interconnect will be approximately 0.6 percent annually, with reasonable probabilities that it could be higher or lower.

Environmental Regulations

Stricter environmental regulations impact the supply of generation available to serve load, primarily by influencing decisions to convert or retire existing coal-fired generators. This includes regulations affecting air emissions, water use, and waste disposal as well as regulation of greenhouse gases such as carbon dioxide, which is the focus of the U.S. Environmental Protection Agency's (EPA's) recently proposed Clean Power Plan.

The more coal-fired generation that is converted or retired, the more other sources of generation, including natural gas, affect the wholesale price of electricity. Based on the assessment of current and future environmental regulations by our internal experts, we have assumed coal generator retirements of 50-70 GW by 2020 and 80-120 GW by 2030. We have also assumed that there is an explicit price on carbon dioxide emissions under the scenario with the highest level of retirements. The price range we have assumed is between $23/ton and $53/ton starting in 2025. This range is based on research by Synapse Energy Economics, which annually publishes forecasts of carbon prices used in utility planning analysis. It should be noted that the actual cost of complying with greenhouse gas regulations can be higher depending on the specifics of the regulation. As discussed later, we do in fact expect that costs to comply with EPA's proposed Clean Power Plan to be higher than $53/ton.

Coal Prices

When considering retirement of our existing coal generating units, it is important to consider the price of the coal used to fuel these units. Ameren Missouri has developed a range of delivered coal price assumptions to account for the uncertainty in the largest component of its coal fleet operating costs.

Generation Project Costs

The cost of construction for major generation projects is another key factor influencing the relative economics of the various options. This includes not only the costs of new generating facilities, but also the costs to maintain existing generation and add environmental controls to meet new environmental regulations. Our assumptions for project costs approximate those typically found in public sources and reflect ranges for cost uncertainty specific to each resource. Our assumptions for the cost of new generating resources are shown in Table 1.2.

Table 1.2 Project Cost Assumptions for New Generation

Resource	Project Cost - Expected Values ($/kW)
Combined Cycle (Nat. Gas)	1,259
Simple Cycle CTG (Nat. Gas)	766
Nuclear	5,000
Pumped Hydro Storage	1,739
Hydroelectric: Keokuk Upgrades	4,739
Small Hydro 1	3,760
Small Hydro 2	3,980
Small Hydro 3	4,980
Solar	3,777
MO Wind	2,197
Regional Wind	1,879

Cost of Capital (Debt and Equity)

Interest rates and equity returns granted by utility commissions affect the relative economics of options by accounting for the investment returns needed to build, own and operate new generating plant. Interest rates are generally expected to rise over the next ten years. Based on external financial market research, we have assumed interest rates and commensurate utility returns on equity that reflect this expectation over the 20-year planning horizon.

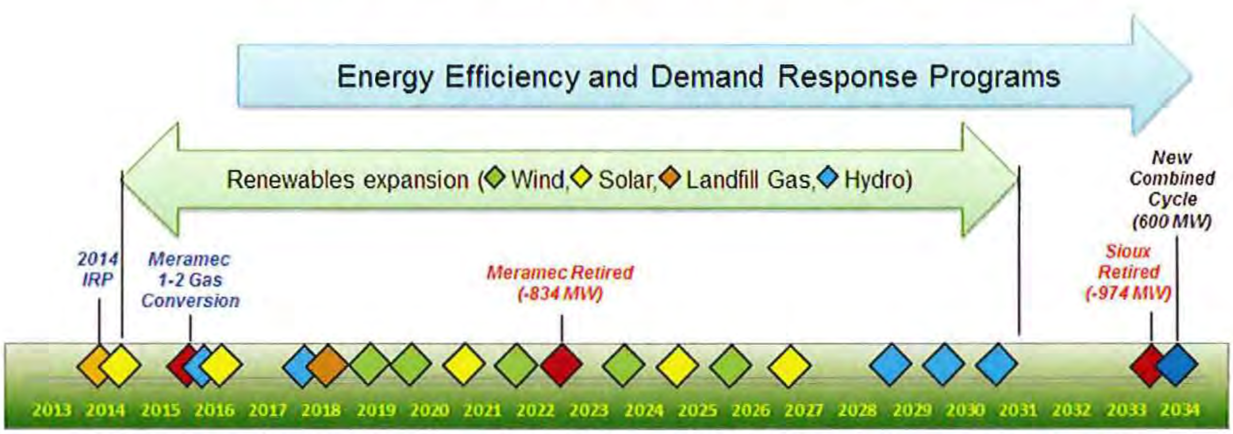
Cost and Performance of Demand-side Resources

The level of customer participation in energy efficiency and demand response programs and the level of customer incentives needed to solicit their participation affect the overall economics of demand side resources. Based on our extensive market research focused on the behaviors and attitudes of customers in Ameren Missouri's service territory, we have made estimates of the amount of achievable energy and demand savings available and the cost to achieve it.

1.5 Ameren Missouri's Preferred Resource Plan

Ameren Missouri has developed and is executing on a plan that is focused on transitioning its generation fleet to a cleaner and more fuel diverse portfolio in a responsible fashion over the next 20 years to ensure we provide service to our customers that is safe, reliable and environmentally responsible at a reasonable cost. Figure 1.4 presents a summary of our resource plan, including coal retirements and the addition of renewable and gas-fired resources.

Figure 1.4 Preferred Resource Plan Summary



Note: Plan allows for the inclusion of optional nuclear generation as a contingency.

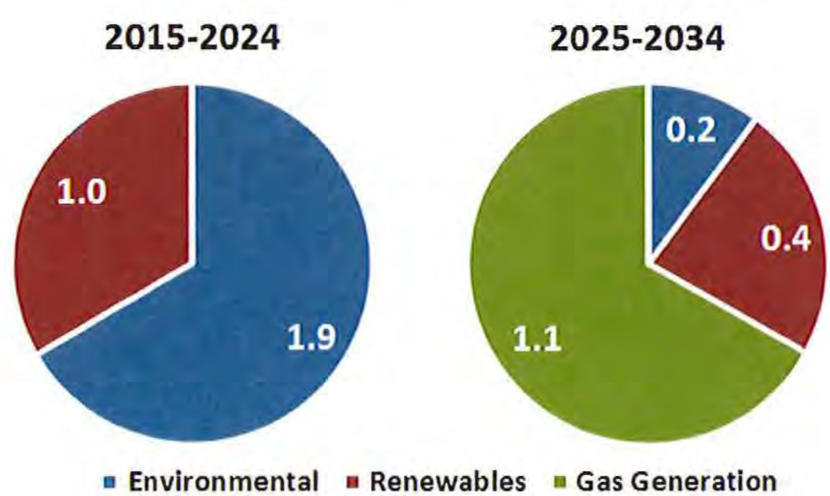
The development of our plan focused on several key elements, including optimizing the use of our existing low-cost generation resources through their normal life expectancy to minimize the cost to our customers, preserving Missouri's economic competitiveness and avoiding unnecessary investments. By 2035, our plan would result in a diverse mix of coal, nuclear, natural gas and renewable energy resources that would in turn allow us to achieve a reduction in carbon dioxide emissions of 30 percent below 2005 levels. It also allows us to comply with the requirements of Missouri's RES.

Our plan systematically incorporates generation resources with lower levels of carbon dioxide and other emissions. It also provides for flexibility in addressing environmental regulations, including those associated with greenhouse gases, while mitigating the potential for unnecessary investments. Because our plan is based on small incremental capital investments over time, it also allows us to effectively manage the risks associated with the development and adoption of distributed generation. In short, our plan allows us to responsibly transition to cleaner, more diverse sources of energy in a way that is beneficial to customers, shareholders, the environment and our communities.

Generation Investments

Our preferred resource plan includes investments in new renewable and gas-fired generation and in environmental controls on our existing generation fleet, as well as ongoing investments to ensure the safe, reliable and cost-effective operation of our existing fleet. Figure 1.5 shows our expected investment in new generation and environmental controls over the next twenty years.

Figure 1.5 Generation Investments ($Billions)



Note: Reflects known and expected future environmental regulations

Implementation

Over the next three years, Ameren Missouri's implementation plan will be focused on several key elements:

- ✓ Securing approval for our next three-year cycle of energy efficiency programs and implementing those programs starting in 2016 will allow us to continue to provide customers options for reducing their energy usage and their electric bills and defer the need for new sources of generation.
- ✓ Completion of our O'Fallon Renewable Energy Center solar facility and development of additional renewable resources, including a subsequent solar project to be completed in 2016, will allow us to comply with the requirements of the Missouri RES and also begin to expand our portfolio of renewable generation.
- ✓ Conversion of Meramec units 1 and 2 from coal to natural gas-fired operation will allow us to begin the managed transition of our coal-fired fleet.
- ✓ Reducing emissions of our existing coal fleet by continuing to make investments in pollution-control equipment
- ✓ We will be working to identify and evaluate sites for new generation such as wind, solar and natural gas combined cycle.
- ✓ Securing an extension of our operating license for our existing Callaway nuclear facility from the Nuclear Regulatory Commission will allow us to continue to rely on low-cost nuclear generation for the next 30 years.
- ✓ Continuing our efforts to support the development of new nuclear generation in Missouri, including the preservation of an option for reliable carbon-free generation and the associated economic development benefits for the state of Missouri.

Contingencies

Because the conditions and circumstances that affect our resource decisions are ever-changing, we must also be prepared for changes in circumstances that warrant a re-evaluation of our plan. There are a few key considerations that may result in a need for such a re-evaluation.

First, the implementation of customer energy efficiency programs requires that our interests are aligned with our customers' interests in using energy more efficiently. The Missouri Energy Efficiency Investment Act (MEEIA), passed and signed into law in 2009, requires that the Missouri Public Service Commission (PSC) provide cost recovery and incentive mechanisms that align our interests with those of our customers. In 2012, the PSC approved energy efficiency programs and associated cost recovery and incentive mechanisms that have allowed us to successfully implement those programs starting in early 2013. That three-year program will run through the end of 2015. Later this year, Ameren Missouri will seek approval for a new three-year program beginning in early 2016. We expect that the PSC will once again provide cost recovery and incentive mechanisms that align our interests in energy efficiency with those of our customers. Should the requirements of MEEIA to align our interests not be met, it will be necessary to alter our plan and may be necessary to build new generating capacity, most likely natural gas-fired combined cycle.

Second, the continued development of nuclear power technology and the potential for financial incentives for implementation of new technologies provide a powerful incentive to maintain the option for adding nuclear power in the future. The associated economic development benefits may warrant a broad statewide effort to expand the use of nuclear power in Missouri. As the owner of the only existing nuclear power facility in Missouri, Ameren Missouri would almost certainly play a key role in any such efforts. With the announcement by the EPA in June of proposed regulations on the emission of greenhouse gases, maintaining an option for carbon-free nuclear generation also provides us with additional flexibility for meeting the requirements of the regulation once it is finalized and fully implemented.

Third, we must be prepared to respond to further changes in environmental regulation. Ameren Missouri will continue to monitor and evaluate proposed regulations and the options available for complying with them. We will also continue to advocate for common-sense changes in proposed regulations that allow us to achieve the desired objectives while minimizing costs to our customers and maintaining flexibility in meeting customers' future electric energy needs.

In addition to these contingencies, we must also be mindful of the potential for changes in customer demand. As stated previously, our reliance on smaller incremental investments over time allows us to better manage the potential risks associated with the development and adoption of distributed generation. It also allows us to better manage the risks associated with the loss of a large customer. The potential impact on other customers of decisions associated with serving a single large customer can be significant. This is not limited to shifts in the responsibility for existing utility costs. It also includes the risks associated with planning to serve such a large customer when that customer may or may not require service from Ameren Missouri in the future. The flexibility to manage this risk is critical.

1.6 EPA's Proposed Clean Power Plan

On June 2, 2014, the EPA announced its proposed "Clean Power Plan," which calls for a 30% reduction in carbon dioxide emissions from existing power plants compared to 2005 levels from existing power plants by 2030, with aggressive interim targets beginning in 2020. These targets are not based on mass carbon emission reductions, but instead are based on rates of carbon emitted from existing plants as derived from 2012 levels. The EPA established different targets for each state, including a 21% reduction for Missouri. Figure 1.6 shows the required reduction and timing of carbon dioxide emission rates proposed by the EPA. As the chart shows, much of the targeted 2030 reduction, 13% of the 21% final target, is required starting in 2020 due to interim targets included in the proposed rule. This means that more than 60% of the 2030 reduction goal must be met by 2020.

Figure 1.6 EPA Target Carbon Dioxide Emission Rates for Missouri

The proposal's basic formula for setting CO_2 emissions reduction requirements is:

CO_2 emissions from fossil fuel-fired power plants (in pounds)

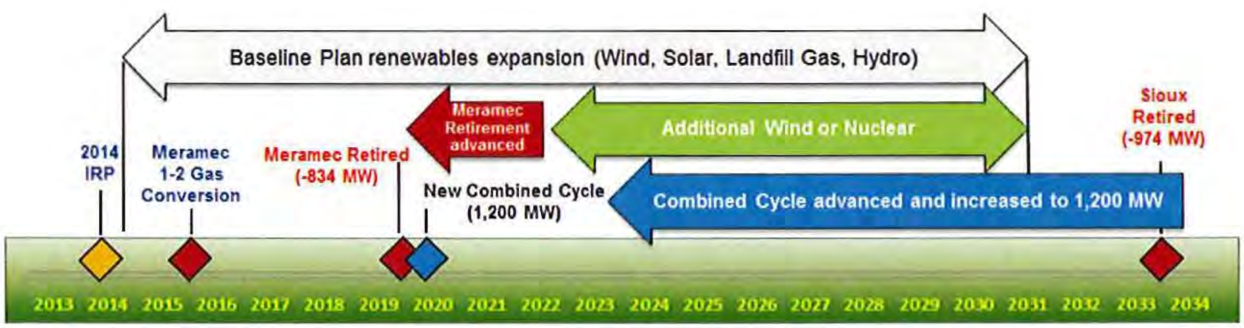
divided by:

Electricity generation from fossil fuel-fired power plants and certain low- or zero-emitting power sources (in MWh)

According to the EPA, this approach "factors in MWh from fossil fuel power plants and other types of power generation, such as renewables, new nuclear and natural gas combined cycle, as well as MWh savings from energy efficiency in the state."

Should the rule be implemented as proposed, Ameren Missouri would have to significantly alter its preferred resource plan in such a way as to lead to much higher capacity reserves by advancing and adding natural gas-fired generation, as early as 2020, and uneconomically dispatching those resources, which would not otherwise be needed until 2034 to meet customer demand and reserve margin requirements for reliability. Figure 1.7 illustrates the changes that could have to be made to Ameren Missouri's preferred resource plan to comply with the proposed regulations.

Figure 1.7 Impacts of GHG Regulations on Preferred Resource Plan



The changes include 1) advancing the retirement of Meramec by three years to the end of 2019, 2) constructing a 1,200 MW combined cycle generation facility to be operational by the beginning of 2020, 3) altering the operation of the new combined cycle and existing coal resources such that gas generation runs more (about twice what it would run otherwise) and coal generators run less than they would under current methods for economic dispatch in MISO, and 4) constructing additional wind (or possibly nuclear) resources in the 2022-2030 timeframe. Making these changes would result in additional costs to customers of approximately $4 billion over the 15 year period starting in 2020 while achieving roughly the same level of annual carbon dioxide emission reductions a few years earlier than under our preferred plan.

Ameren is advocating for changes to the EPA's proposed rules that will allow Ameren Missouri to execute its Preferred Resource Plan and achieve the overall objective of the Clean Power Plan to reduce carbon emissions by 30 percent below 2005 levels over a slightly longer period of time. Specifically, Ameren proposes that EPA:

1. Eliminate the aggressive interim emission reduction targets and give states, who possess intimate knowledge of their system needs, the flexibility to adopt interim milestones as appropriate
2. Treat unreplaced retired coal units as a zero-emitting resource (similar to how customer energy efficiency programs are treated)
3. Give states the flexibility to extend the compliance date to allow the orderly retirement of coal plants as states implement their transition plans

Comments to the rule are due December 1, 2014, and EPA expects to issue a final rule in June 2015. States are required to develop plans to implement the rule by mid-2016, with the possibility of a one or two year extension. Legal challenges to the rule are expected and could in turn cause significant planning and operational challenges in developing and executing plans to comply with EPA's proposed interim targets starting in 2020. The changes we are advocating would alleviate these planning and operational challenges in addition to saving our customers $4 billion.

1.7 Conclusion

Over the last few years, in conjunction with the Missouri Integrated Resource Planning process, Ameren Missouri has developed and is executing on a plan that is focused on transitioning its generation fleet to a cleaner and more fuel diverse portfolio in a responsible fashion over the next 20 years to ensure we provide service to our customers that is safe, reliable and environmentally responsible at a reasonable cost. The development of our Preferred Resource Plan focused on several key objectives, including optimizing the use of our existing low-cost generation resources, minimizing costs to customers, preserving Missouri's economic competitiveness and maintaining flexibility to manage the risks associated with changes in the conditions and circumstances that influence resource decisions. In short, our strategy and plan allow us to responsibly transition to cleaner, more diverse sources of energy in a way that is beneficial to customers, shareholders, the environment and our communities.

2. Planning Environment

Highlights

- *General economic conditions suggest sustained growth that is modest by historical standards, resulting in lower-than-historical load growth when combined with increasing energy efficiency.*
- *Natural gas prices will continue to be driven by large domestic supplies of shale gas and approximate a range of $4 - $6 per MMBtu in today's dollars.*
- *Environmental regulations coupled with relatively low gas prices and slow load growth will continue to drive additional retirements of coal-fired generation*
- *Ameren Missouri has developed and modeled 15 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 the 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 slowly improved in the U.S. over the last few years following the severe recession that occurred in the 2007-2009 timeframe. The nature of the financial crisis that coincided with the recession also caused the recovery from that recession to be unusually slow. Businesses and households were extremely risk averse and capital was difficult for businesses to access for an extended period of time following the financial crisis. After several years of very low interest rates and stimulative monetary policies enacted by the Federal Reserve, the economy has generally overcome the most significant headwinds left by the recession, and GDP is once again growing.

For the decades leading up to the 2007-2009 recession, GDP grew nationally at a pace of approximately 3% per year. Ameren Missouri's expectations are for a return to GDP growth at or near that long term pre-recession trend for a short period of time followed by relatively stable longer term growth, but at a slower pace than has been observed historically, in the 2-2.5% range per year. Generally, demographic factors will provide the greatest long term challenge to growth, as the growth in the labor force, one of the key components of long-term economic growth, is expected to be below its historical rate as the Baby Boomer generation begins to enter retirement. 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 of 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 more slowly than many other major cities and the country as a whole. To be clear, the St. Louis area is experiencing population growth generally, but at a slow pace relative to other parts of the country. While St. Louis does have a diverse economy with some industries that export goods to other regions, the majority of economic activity is local in nature. Population growth 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 EPA regulations regarding emissions primarily from our fossil fueled power plants, regulatory requirements at our Callaway nuclear facility, and an evolving landscape of renewable energy standards currently at the state level along with energy efficiency policies and incentives. At the same time, methods for providing cost recovery and incentives associated with such regulations have been considered, and continue to be considered, by utility regulators in the various states. 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. Considerations with respect to cost recovery treatment are included in our discussion of resource strategy selection, in Chapter 10.

2.2 Financial Markets[1]

In December 2008, in response to the financial downturn and continuing recession, the Federal Reserve (the Fed) lowered the short-term federal funds rate to a range of 0% to 0.25%. Since that time, the Fed has kept short-term interest rates at that historically low level and engaged in several rounds of monetary economic stimulus referred to as quantitative easing. With quantitative easing the Fed is making large-scale purchases of Treasury securities and mortgage-backed securities. Current expectations are for an end to quantitative easing in late 2014 and for interest rates to begin to rise in 2015. As economic conditions continue to improve and unemployment continues to drop, interest rates are expected to rise to historically average levels over a period of several years.

For this IRP, long-range interest rate assumptions are based on the December 1, 2013, semi-annual Blue Chip Financial Forecast. This forecast is a consensus survey of 49 economists from numerous firms including banks, investment firms, universities and economic advisors. Table 2.1 shows the analyst expectations for the yield on 10-year Treasury notes annually for 2015-2019 and a five-year average estimate for 2020-2024.

Table 2.1 Forecast Yield: 10-year Treasury Notes **NP**

[redacted]

**

Long-term allowed return on equity (ROE) expectations for Ameren Missouri were developed using the projected long-term risk-free interest rate identified for 2020-2024 in Table 2.1. Ameren Missouri's equity risk premium was calculated by comparing the allowed ROE from Ameren Missouri's most recently completed rate case to the December 2012 10-year Treasury interest rate and adjusting for future interest rate expectations. Using this approach, the resulting expected value allowed ROE is 11.4% (see Table 2.2).

Table 2.2 Projected Allowed ROE **NP**

[redacted] **

[1] 4 CSR 240-22.060(2)(B); 4 CSR 240-22.060(7)(C)1A

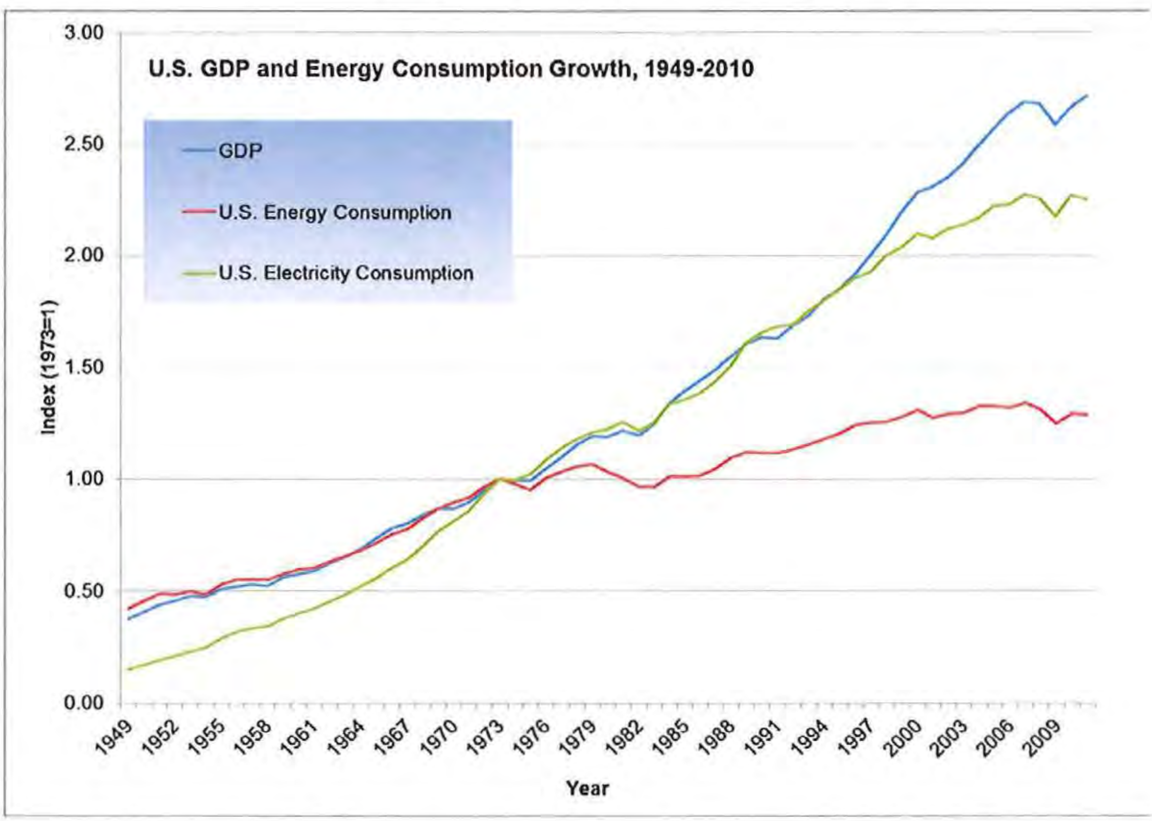
Because planning decisions are made in the present, Ameren Missouri uses its current weighted average cost of capital as the discount rate for evaluating present value revenue requirements and cash flows. Based on Ameren Missouri's most recently completed general rate case, our assumed discount rate is 6.46%. This is based on a capital structure that is 48.5% debt, 51.5% equity, and an allowed ROE of 9.8%.

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.

That study 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). Figure 2.1 illustrates this point.

Figure 2.1 Energy Intensity Trends



[2] 4 CSR 240-22.060(5); 4 CSR 240-22.060(5)(A); 4 CSR 240-22.060(7)(C)1A; 4 CSR 240-22.060(7)(C)1B

The chart shows several decades of U.S. GDP, total U.S. energy consumption, and total U.S. electricity consumption, all indexed so that they take on a value of 1 in the year 1973. When you overlay these three data series on the graph, there are some interesting and clear takeaways that are apparent regarding trends in national energy intensity. From 1949-1973 total energy consumption in the U.S. grew almost 1:1 with economic output, as illustrated by the correlation of the red and blue index lines during those years. This period was characterized by significant growth the nation's manufacturing base, as well as widespread adoption of energy intense transportation and home appliances.

Around 1973, there was a clear change in the pattern, as total energy consumption grew markedly slower than economic output. This was around the time of the first oil embargo and energy price shocks that heightened the focus of the country on energy efficiency. The changes ushered in by those events clearly impacted total energy consumption, but as is apparent from the graph, total electricity consumption (a subset of total energy consumption (represented by the green line) continued to grow in virtual lock step with economic output (the blue line) until about 1990. This period of time saw expanded electrification of industrial processes as capital replaced labor at a high rate, increasing the electrical intensity of the economy. Additionally, air conditioning and other home conveniences were experiencing rapid growth in saturation rates at this time, supporting electric load growth.

From 1990 forward, the same trends that appeared in total energy consumption much earlier appeared in the electricity consumption. The growth of many home and business end uses began to slow as higher levels of saturation of air conditioning and other conveniences were realized. Additionally, federal standards led to improvements in the efficiency of many end use electrical appliances, such as the first refrigerator efficiency standards that date to this era. Finally, the most energy intensive regions of the manufacturing base of the nation began a long period of decline as many industries moved overseas in an effort to achieve lower labor costs.

It is apparent from this macro analysis of trends that the U.S. economy has, for decades, made strides in reducing the energy intensity of economic output, or said another way, become more energy efficient. With that backdrop, our expectation is that that overarching trend will continue. With that said, in order 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. The recent boom in production of natural gas using horizontal drilling and hydraulic fracturing technology has the potential to cause resurgence in domestic manufacturing, particularly in the chemicals industry for which gas is an important feedstock.

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 seen rapid growth 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. While the future of solar equipment costs is uncertain in terms of the timing and magnitude, it is quite possible that the economics of solar will continue to improve over the planning horizon. Should this occur, there will likely be adoption of more systems that displace demand that would otherwise be planned for and served by utilities.

Considering the foregoing, our near term expectation is that load growth will be essentially flat through the 2016 time frame. After 2016, we have assumed a 0.6% average annual growth in load for the Eastern Interconnect across the 20 year planning horizon. A 0.6% rate of load growth would essentially equate to a continuation of the energy intensity trends that were observed for much of the last decade, applied to our base case assumptions regarding future economic growth.

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, an annual average growth rate of 1.2% was assumed. 1.2% growth would result from an energy intensity trend similar to that observed in the 1990s and early 2000's applied to expected economic growth. Again, this would be most likely in the event that the secular decline in manufacturing reversed and we saw growth in chemical industries driven by shale gas or more heavy industries that return operation to the U.S. as overseas labor markets mature and increase in cost.

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

2.4 Reliability Requirements

Ameren Missouri is a member of the Midcontinent Independent System Operator (MISO) and participates in its capacity and energy markets. MISO has established a process to ensure resource adequacy through Module E of its 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 2013, indicates a planning reserve margin requirement of 14.9% (applied to peak demand) in 2015, increasing to 17.3%. Table 2.3 shows the year-by-year PRM through 2023. Ameren Missouri has assumed that the PRM beyond 2023 remains at 17.3%.

Table 2.3 MISO System Planning Reserve Margins 2015 through 2023

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023
PRM $_{\text{Installed Capacity}}$	14.9%	15.0%	15.1%	15.1%	15.6%	16.0%	16.4%	16.8%	17.3%

In addition to establishing the PRM requirements, MISO also establishes a capacity credit for wind generation. The capacity credit is applied to the net output capability (in MW) of a wind farm to determine the amount of capacity that can be counted toward the PRM for resource adequacy. The MISO's value for wind capacity credit based on the 2013 Resource Adequacy report is 14.1%.

2.5 Energy Markets

Energy market conditions that may affect utility resource planning decisions include prices for natural gas, coal, nuclear fuel, and electric energy and capacity. Natural gas prices in particular 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 assumptions for natural gas prices have been updated to reflect Ameren's "2014 Point of View Update". This update is a coordinated, corporate-wide view, developed by internal 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. Although there are significant changes occurring in supply, demand and infrastructure in the near term, natural gas is expected to be a 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. The shale gas plays have proven to hold greater reserves than initially estimated. The Potential Gas Committee[4] estimated that ultimately recoverable domestic potential reserves have grown from 2,241 trillion cubic feet (Tcf) in 2000 to 3,379 Tcf in 2010, to 3,914 Tcf in 2013. At current demand levels, natural gas reserves are sufficient to provide over 150 years of supply. Figure 2.2 shows the shale gas plays in North America.

Technology advancements continue to improve the productivity, energy efficiency and environmental performance of drilling sites. Natural gas production in the Lower 48 states has increased from 50 billion cubic feet (Bcf) per day in 2006 to 65 Bcf per day in 2013, an increase of nearly 30 percent. However, some state and federal regulators continue to challenge hydraulic fracturing ("fracking") technology through drilling moratoriums or stringent regulations.

[3] 4 CSR 240-22.040(5); 4 CSR 240-22.040(5)(A); 4 CSR 240-22.060(5); 4 CSR 240-22.060(5)(D); 4 CSR 240-22.060(7)(C)1A; 4 CSR 240-22.060(7)(C)1B; EO-2014-0062 g

[4] The Potential Gas Committee, an incorporated, nonprofit organization, consists of knowledgeable and highly experienced volunteer members who work in the natural gas exploration, production and transportation industries and in the field and technical services and consulting sectors. The Committee also benefits from the input of respected technical advisors and various observers from federal and state government agencies, academia, and industry and research organizations in both the United States and Canada. Although the PGC functions independently, the Potential Gas Agency at the Colorado School of Mines provides the Committee with guidance, technical assistance, training and administrative support, and assists in member recruitment and outreach. The Potential Gas Agency receives financial support from prominent E&P and gas pipeline companies and distributors, as well as industry trade and research organizations and unaffiliated individuals.

Figure 2.2 North American Shale Gas Plays

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

Demand - There are several drivers positively and negatively influencing demand. Advances in energy efficiency standards and promotion of energy efficiency programs have been effective in reducing residential and commercial heating demand. In contrast, relatively low natural gas prices have encouraged a resurgence of domestic petro chemical production and other industries reliant upon natural gas as a feedstock. Federal energy policy developments connected with clean energy standards and greenhouse gases (GHGs) are also expected to increase demand for natural gas-fired generation. In addition, the development of liquefied natural gas (LNG) facilities and Mexican exports are opening up higher priced global markets for domestic natural gas supplies.

Infrastructure – New pipeline and storage facilities will be required to provide market accessibility, reliability and integrity. Until recent years, the predominant flow of natural gas has been from the Midcontinent, Gulf Coast, Rockies and Texas regions across the

Midwest towards the Northeast. The developments in large gas production in the Marcellus and Utica shale reserves in the Northeast have created a dramatic shift in flow. Changes in the interstate pipeline system will occur as the supply pool for the Northeast grows and strands gas supplies. Natural gas will be directed toward the growing demand from: the petro-chemical industry in the Southeast, gas-fired generation throughout the Midwest, and East, and LNG exports in the Gulf Coast.

Price - Supplies of natural gas are expected to remain robust and will encourage the growth of industrial demand, gas-fired generation and global exports. Long-term, prices are expected to remain relatively low and stable. However, over the next ten years, regional price dislocations may occur as gas infrastructure struggles to keep pace with the changing gas supply and demand. For example, on January 24, 2014, daily spot prices for physical gas in the Northeast topped out at nearly $100/MMBtu while gas exiting the Marcellus (just 100 miles south) and Henry Hub remained below $6/MMBtu.

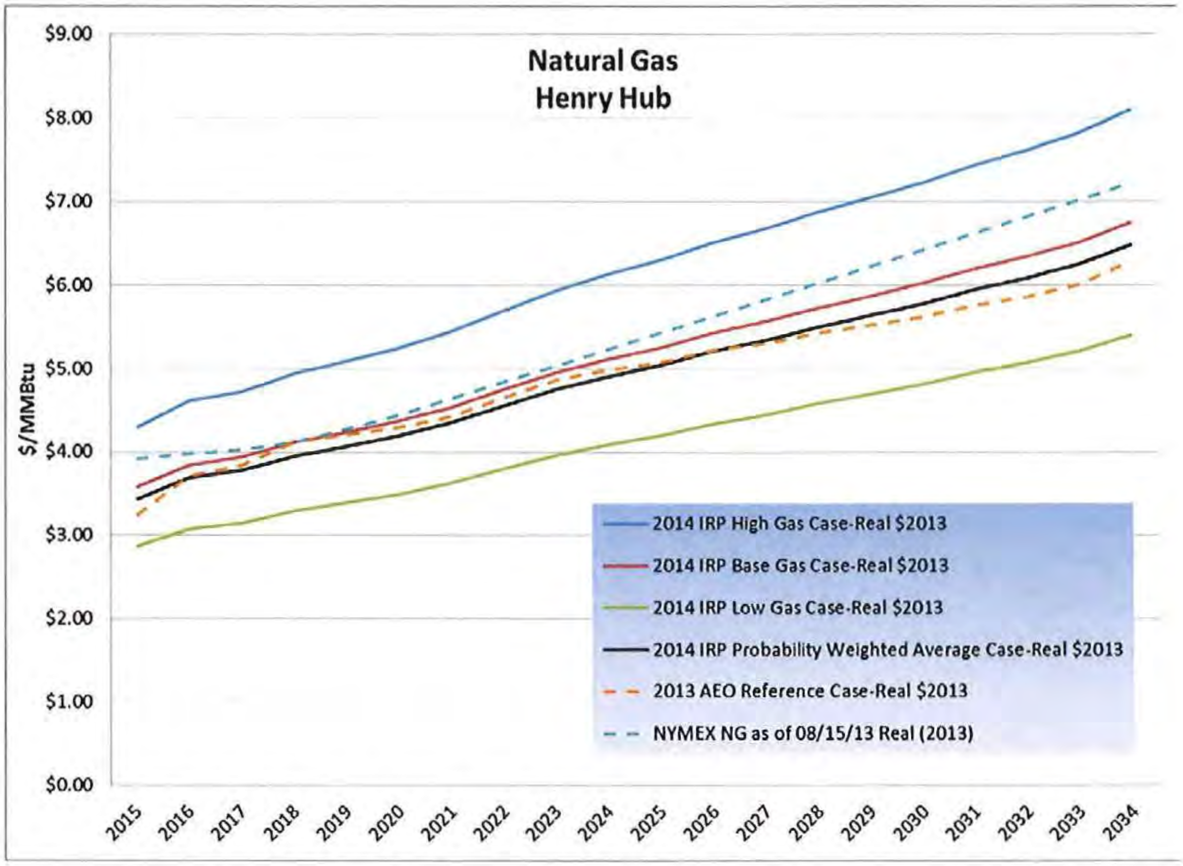
Natural Gas Price Assumptions

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: Wood Mackenzie, Bentek, and the Nymex Henry Hub market prices. These research services, along with internal market knowledge of the natural gas industry, have helped to frame the long-term assumptions used and to provide context based on 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 2.4 and Figure 2.3.

Table 2.4 Natural Gas Price Assumptions

	Real Gas 2013 $									
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High	$4.30	$4.61	$4.72	$4.94	$5.09	$5.25	$5.45	$5.70	$5.94	$6.13
Base	$3.58	$3.84	$3.94	$4.12	$4.24	$4.37	$4.54	$4.75	$4.95	$5.11
Low	$2.87	$3.08	$3.15	$3.30	$3.39	$3.50	$3.63	$3.80	$3.96	$4.08
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
High	$6.30	$6.51	$6.68	$6.87	$7.04	$7.22	$7.43	$7.61	$7.81	$8.10
Base	$5.25	$5.43	$5.56	$5.73	$5.87	$6.02	$6.19	$6.34	$6.51	$6.75
Low	$4.20	$4.34	$4.45	$4.58	$4.69	$4.82	$4.95	$5.07	$5.21	$5.40

Figure 2.3 Natural Gas Price Assumptions



2.5.2 Coal Market[5]

Our development of long term coal prices assumptions includes a review of the drivers that most affect the coal industry and long-term delivered coal. This process was centered on those drivers most directly affecting Powder River Basin coal (PRB) given that the vast majority of our current and expected coal supply will be sourced from this basin. Overall US coal supply is expected to shrink to 600-800 million tons per year over the next 20 years from the current rate of approximately 1 billion tons per year. However, PRB coal will gain a wider market share as the other US coal basins become uncompetitive (with the exception of the Illinois basin, which is expected to grow) due to increasing costs of mining resulting from geologic and regulatory changes.

[5] 4 CSR 240-22.040(5); 4 CSR 240-22.040(5)(A); 4 CSR 240-22.060(5); 4 CSR 240-22.060(5)(D); 4 CSR 240-22.060(7)(C)1A; 4 CSR 240-22.060(7)(C)1B; EO-2014-0062 g

Coal Price Drivers

The long-term demand for PRB coal has been affected by declining natural gas prices and increasing natural gas supply along with declining production from eastern US coal fields, Central Appalachia and Northern Appalachia. PRB demand and pricing is also influenced by environmental regulations, transportation costs, and emission allowance markets. Export markets also impact PRB demand and will be driven by global economic strength, development of US export terminals on the west coast, and competing seaborne suppliers. US coal exports represent the swing supply into the global market and the PRB represents the available capacity to sell into the export market on upturns in demand.

Several factors will contribute to higher PRB production costs going forward including the following:

- Strip ratios (overburden vs. coal seam) are expected to increase
- Government regulations continue to increase reclamation costs
- Severance taxes and coal lease fees
- Cost of materials, supplies and capital equipment such as diesel fuel, explosives & haul trucks
- Haul distances from coal pit to load-out are expected to increase
- Eventual interference with the railroad mainline

As mining progresses from east to west in the PRB, the coal seams dive deeper such that strip ratios will increase by 25% or more over the next 20 years. The western progression also infringes upon the railroad mainline such that mines will be faced with the decision to either "leap over" the railroad and essentially start up a new mine or move the rail lines onto reclaimed property and continue the mining progression. This will affect the PRB mines on the "jointline" (served by both the BNSF and the UP railroads) at varying timeframes over the planning horizon. The exception is the Antelope Mine, which is already located to the west of the jointline.

Given our current plan to meet emission compliance for SO_2 standards is to burn ultra-low sulfur coal (considered 0.55 lb SO_2/MMBtu or less) our analysis explicitly assumes this in the development of market prices for delivered coal to the Ameren Missouri energy centers. Long term supply of ultra-low sulfur PRB coal is expected to be 200-350 million tons per year. Such supply range for this product will be driven by coal retirements over the planning horizon and a mix of scrubbed versus unscrubbed coal plants to balance the needs and supply for ultra-low sulfur coal.

Coal Price Assumptions

In the development of the coal price forecasts for use in the 2014 IRP the Ameren Missouri fuels team shaped low, base and high long-range forecasts for PRB coal delivered to our existing coal plants. This process included an assessment of current coal contracts (FOB at the mine) and rail contracts for delivery to each of our four coal plants. Next, a review of coal price projections from several outside services including Ventyx, Wood Mackenzie, Energy Ventures Analysis Inc. (EVA), US Energy Information Administration (EIA) and SNL were analyzed along with market-based forward curves. The coal price forecasts for low, base and high coal prices are shown in Table 2.5

Table 2.5 Delivered Coal Prices **NP**

[redacted]

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2.5.3 Nuclear Fuel Market[6]

Nuclear Fuel Price Drivers

Ameren Missouri relied on UxC for forecast of nuclear fule forecasts as we have for prior IRP analysis. Uxc provided annual price forecasts through 2025 for uranium (U3O8), conversion (UF6), and enrichment (SWU), front-end fuel components. It used

[6] 4 CSR 240-22.040(5); 4 CSR 240-22.040(5)(A); 4 CSR 240-22.060(5); 4 CSR 240-22.060(5)(D); 4 CSR 240-22.060(7)(C)1A; 4 CSR 240-22.060(7)(C)1B

the same approaches with each of the components. However, UxC forecasted spot prices for uranium and conversion, while it forecasted base prices for a new term contract for 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 the Ux Consulting Company (UxC). UxC was used in this role in the 2008 and 2011 IRP, and the 2012 IRP update. The Westinghouse nuclear fuel cost model was used in calculating the small modular reactor (SMR) nuclear fuel cost forecast and the Surfnonline model by HTH Associates 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. Figure 2.4 shows the low, base and high nuclear price forecasts for a new nuclear unit.

Figure 2.4 Nuclear Fuel Price Forecasts**NP**

[redacted]**

Each scenario is then assigned an individual probability basis that is related to the likelihood of the associated assumptions. The probability weighting is assigned on a year-by-year basis for uranium, while a single probability weighting is assigned for all years for conversion and enrichment.

2.5.4 Electric Energy Market

Ameren Missouri is 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 the 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 capacity price forecast used in the 2014 IRP is based on a fundamental supply-demand relationship developed by MISO. Ameren Missouri is a member of MISO and actively participates in the MISO capacity markets. As mentioned previously, MISO publishes a report annually, its LOLE study report, for which analysis is performed to develop MISO's expectation for capacity planning reserves. This study provides a framework that includes the amount of installed generation capacity, peak load demand and transfers used to meet the reserve requirements as determined by a loss of load expectation study. The models used in this analysis include power flows within the MISO system and an expectation for transfers into and out of the MISO market.

This analysis was performed for three future years by MISO to determine how reserves will change over time; they include planning years 2014-2015, 2018-2019 and 2023-2024. The results of these studies as shown in the MISO LOLE report were used to determine when the MISO system would need additional capacity to meet reserve requirements. The results of this MISO study were adjusted to align with Ameren Missouri's expected coal plant retirement outlook developed for the IRP, discussed later in this chapter.

Additionally, our capacity price framework is based on the published value by MISO each year for the cost of new entry (CONE), which is based on the levelized cost of a new simple cycle gas-fired combustion turbine generator. Our assumption for capacity prices reflects the expectation that the market value of capacity will reach CONE when the MISO market is expected to become capacity constrained and additional capacity is needed to meet reserve requirements. This approach results in an expectation that the MISO market will become capacity constrained in 2021. Using a market-based price for the first several years and transitioning to CONE by 2021 results in assumed forward prices for capacity as shown in Figure 2.5. These capacity price assumptions were used as the basis for avoided capacity costs used to assess the cost-effectiveness of demand-side measures, discussed in Chapter 8. It was also used to assess the costs and revenues associated with capacity transactions modeled in the analysis of alternative resource plans, discussed in Chapter 9.

Figure 2.5 Capacity Price Assumptions **NP**

[redacted]

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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 invester owned regulated Missouri utilities to supply an increasing level of energy from renewable energy resources or acquire the equivalent renewable energy credits (REC's) 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 REC's or SREC's. Our analysis of RES compliance is presented in Chapter 9.

2.6 Environmental Regulation[7]

With increasingly stringent regulation of coal-fired power plants, including continuing efforts to regulate GHG emissions, the effects of these regulations on the electric energy market must be considered in assessing potential resource options and portfolios. More specifically, the environmental statutes and regulations include:

- Clean Air Act (CAA)
  - National Ambient Air Quality Standards (NAAQS)
    - Clean Air Interstate Rule (CAIR)
    - Cross State Air Pollution Rule (CSAPR)
  - Acid Rain Program
  - Prevention of Significant Deterioration (PSD)
    - Maximum Achievable Control Technology (MACT) for new sources
  - Section 111
    - Section 111(b) GHG New Source Performance standards for new, reconstructed and modified coal and gas fired power plants
    - Section 111(d) GHG New Source Performance standards for existing coal fired power plants
  - Mercury and Air Toxics Standards (MATS)
- Clean Water Act (CWA)
  - Section 316a regulations covering thermal discharges
  - Section 316b regulations covering water intake structures
  - Wetlands/Waters of the U.S.
  - Spill Prevention Control & Countermeasures (SPCC)
  - Effluent Limitations Guidelines Revisions (ELGs)
- Safe Drinking Water Act
- Solid Waste Disposal Act
  - Coal Combustion Residuals (CCR)
- Resource Conservation and Recovery Act (RCRA)
- Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA)
- Superfund Amendments Reauthorization Act (SARA)
- Toxic Substances Control Act (TSCA)
  - PCB regulations
- Emergency Planning & Community Right-To-Know Act (EPCRA)

In addition to this list, the potential for new and more stringent laws and regulation create a changing landscape for investment decisions over the planning horizon. While

[7] EO-2014-0062 h

the effects of these current and potential future regulations are complex, a primary consideration is how they will affect power prices. Given this goal, our process established that changes in power markets would most significantly be impacted through the degree and timing of coal plant retirements across the entire Eastern Interconnect.

In addition to the existing and future regulations outlined above, we must also consider potential actions with respect to climate policy and regulation of GHG emissions beyond what was recently proposed by EPA in the form of its Clean Power Plan. To help frame the ongoing possibilities for carbon policy and regulation of GHG emissions, we examined reports from several research and consulting companies, such as Wood Mackenzie, IHS Cera, and Synapse Energy Economics, Inc. We also reviewed US government reports on the so-called "social cost of carbon." Through this process we considered the structures a future GHG policy could be implemented which included the following;

- Legislative
- Regulatory
- International Treaty

We identified three general mechanisms by which GHG policy could be implemented through any of the above structures. Each implementation path could seek to achieve GHG reductions through any, or a combination of, three mechanisms:

- Policies to mandate and/or promote low/no carbon resources
- Specified limits on GHG emissions (emission rates or mass emission)
- Implementation of an explicit price on GHG emissions

This framework provided a vehicle for discussion with our internal experts to identify the probable ranges of coal retirements and carbon prices that define our scenarios. Through this process an updated set of assumptions was developed to reflect environmental policy effects on coal retirement expectations, as well as the timing, magnitude and probability of an explicit price on carbon dioxide emissions.

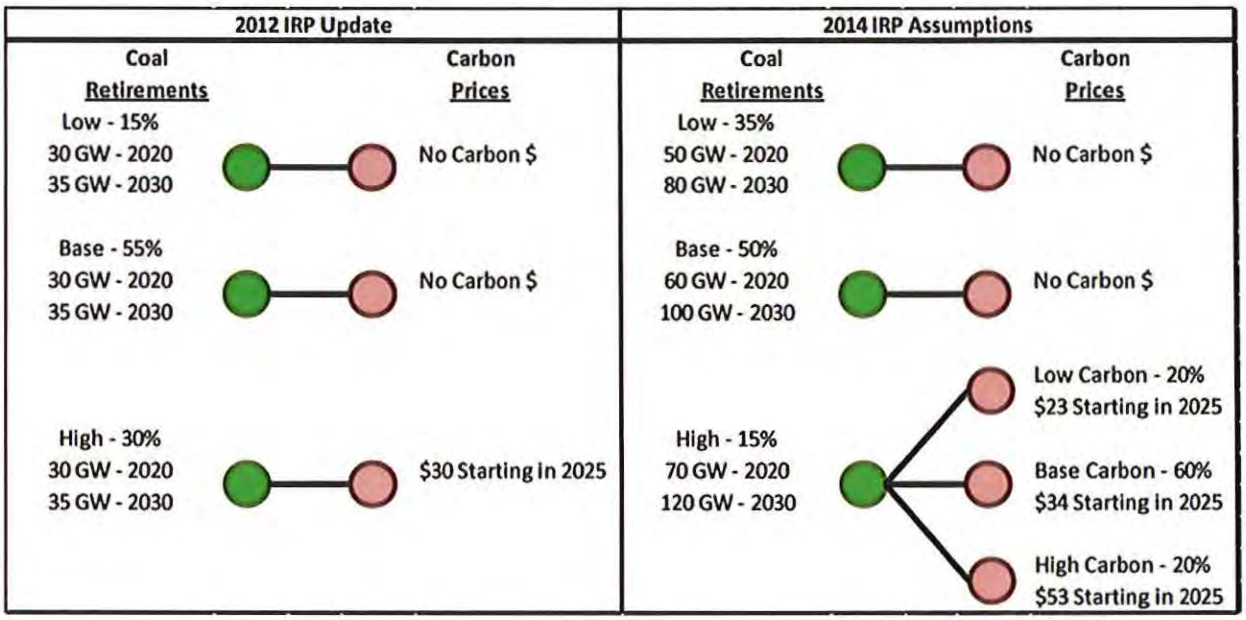
Coal Plant Retirements[8]

Our power price scenario model, described in section 2.7, relies on Ventyx' s national dataset. This dataset includes assumptions for expected coal plant retirements spanning the 20-year time frame of the IRP and was used as a starting reference. This dataset includes plant closures based on company announcements and Ventyx's analysis given current laws and regulation at the time of publishing the dataset used in

[8] 4 CSR 240-22.040(2)(B); 4 CSR 240-22.060(5)(C)

the study. This set of retirements was reviewed in light of the current and expected regulations over the planning horizon. In order to reflect the range of possible environmental futures that represent the planning horizon, our previous coal plant retirements assumptions for three levels – low, base, and high – were updated based on review and multiple discussions with internal experts involved in environmental regulation and policy. Figure 2.6 shows the changes made for the 2014 IRP.

Figure 2.6 Coal Retirement Assumptions



Carbon Dioxide Emissions Prices[9]

In addition to coal plant retirements, an update to the carbon price expectation and the timing of this price was reviewed. To represent a range of prices for carbon dioxide emissions, we have relied on Synapse's November 1, 2013, Carbon Dioxide Price Forecast report. We have used the low, mid and high case prices from this report. However, only those values from 2025 and beyond are included in our analysis based on the expectations for carbon policy of our internal experts. The price of carbon dioxide emissions is assumed to be zero in all years prior to 2025. We have assumed a high level of coal plant retirements in conjunction with an explicit price on carbon dioxide emissions given the expectation that this carbon price will result in the most restrictive operations of coal facilities. Table 2.6 shows the values from Synapse used in the current IRP analysis. A symmetrical weighting was used to represent the probability of

[9] 4 CSR 240-22.040(2)(B); 4 CSR 240-22.040(5); 4 CSR 240-22.040(5)(D); 4 CSR 240-22.060(5); 4 CSR 240-22.060(5)(C); 4 CSR 240-22.060(5)(H); 4 CSR 240-22.060(7)(C)1A; 4 CSR 240-22.060(7)(C)1B; EO-2014-0062 g

each of these cases with 60% weighting on the mid case and 20% each on the high and low cases.

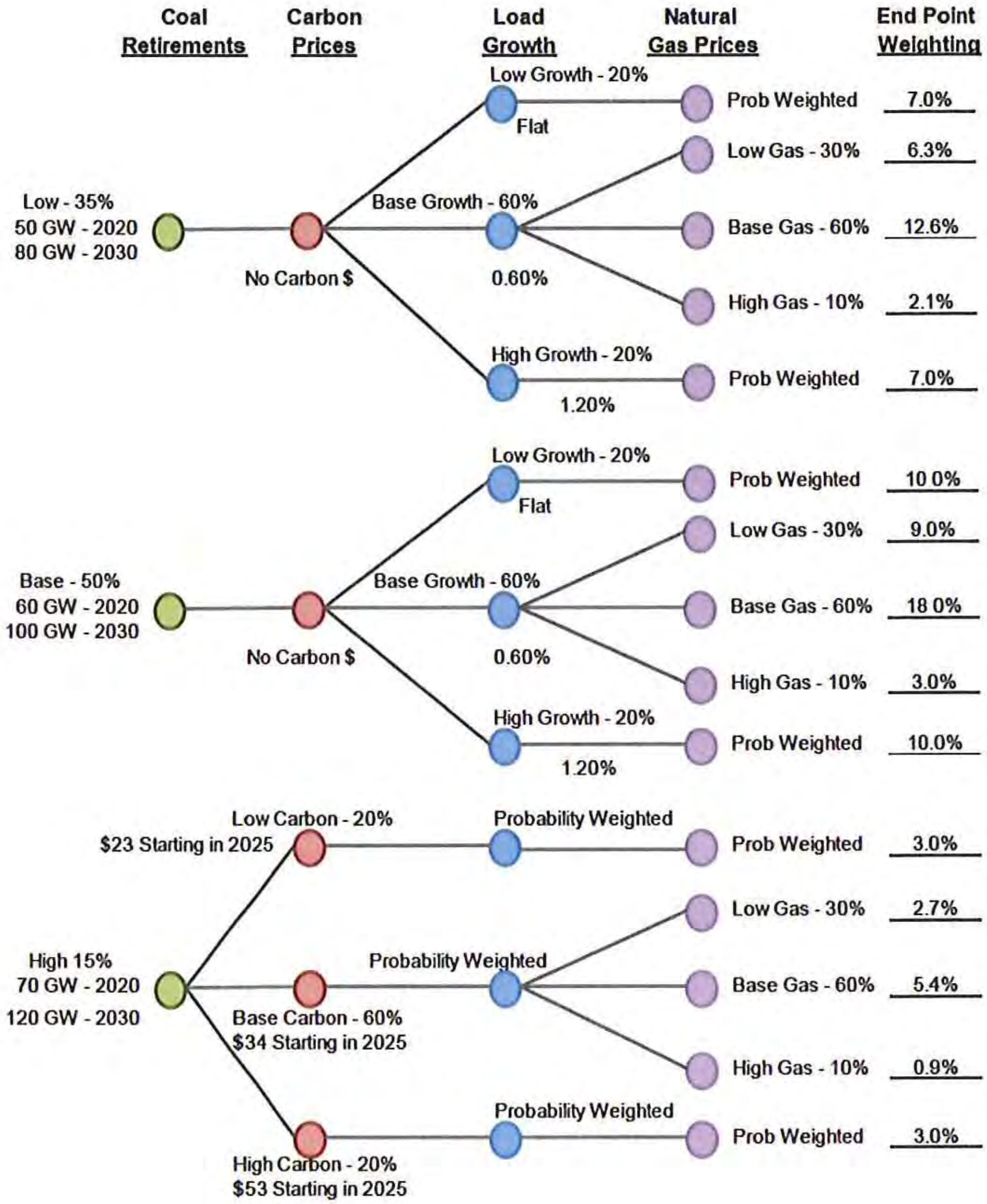
Table 2.6 Carbon Dioxide Emissions Price Assumptions

Synapse 2013 Report						
	2012 $/Ton Real			Nominal		
	Low Case	Mid Case	High Case	Low Case	Mid Case	High Case
2025	$18	$26	$41	$23	$34	$53
2026	$19	$29	$45	$25	$38	$59
2027	$21	$31	$48	$28	$41	$64
2028	$22	$33	$51	$30	$45	$70
2029	$24	$35	$54	$33	$49	$76
2030	$25	$38	$58	$36	$54	$82
2031	$27	$40	$61	$39	$58	$89
2032	$28	$42	$64	$42	$62	$95
2033	$30	$44	$67	$45	$67	$102
2034	$31	$47	$71	$48	$72	$109
2035	$33	$49	$74	$51	$77	$116

2.7 Price Scenarios

Power prices are influenced primarily by electric demand, the mix of available generation, and natural gas prices. Using our assumptions for load growth, coal retirements, carbon prices, and natural gas prices, we developed scenarios based on various 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 2.7 shows the final scenario tree.

Figure 2.7 Final Scenario Tree



Electric Power Prices[10]

To support our analysis of alternative resource plans, as described in Chapter 9, we developed forward price forecasts at the Indy Hub using modeling software provided by Ventyx and commonly referred to as "Strategic Planning" or "MIDAS". This detailed simulation modeling software provides an economic dispatch production cost projection that utilizes load, fuel price, power production capabilities and many other assumptions

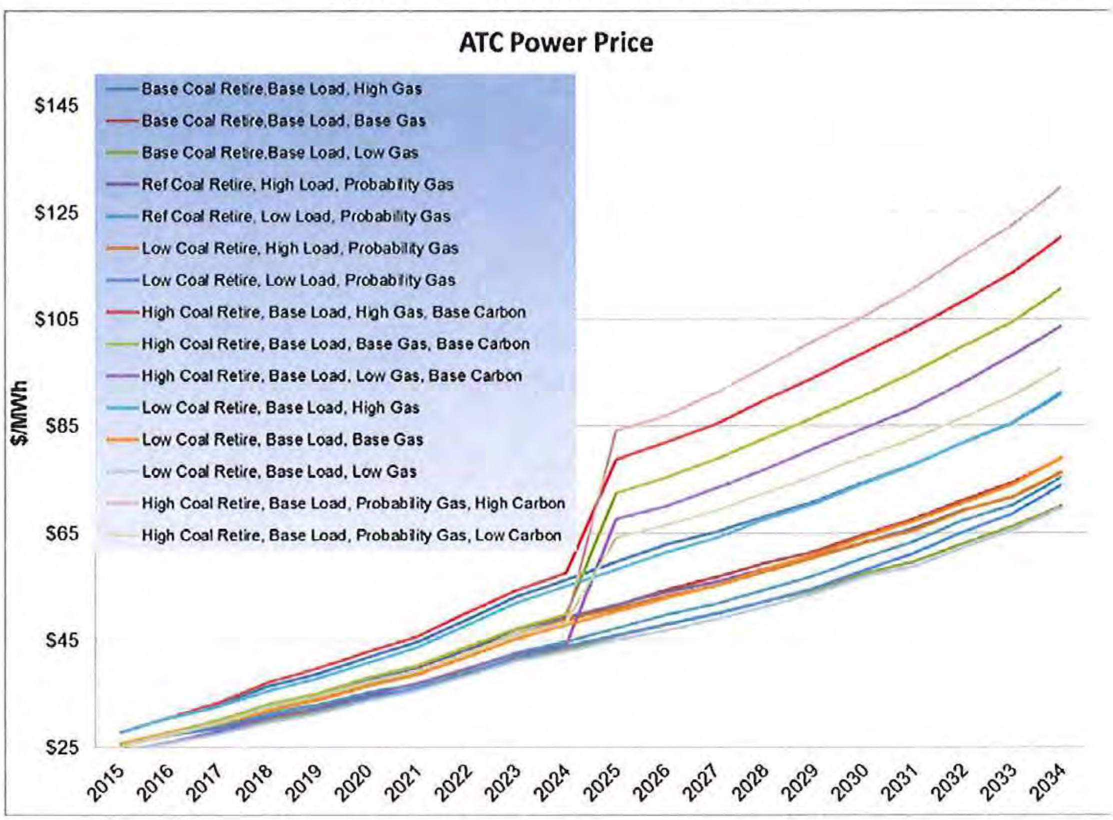
[10] 4 CSR 240-22.060(5)(G); 4 CSR 240-22.060(7)(C)1A; 4 CSR 240-22.060(7)(C)1B

and projections. To provide the detailed data needed to populate the Strategic Planning model for purposes of developing a forward electric price forecast, Ventyx provides a service that incorporates all the assumptions that are used in their Power Reference Case. The Ventyx Power Reference Case is an iterative integrated process used to determine the impacts that capacity additions and retirements have on power markets. This process also considers the renewable energy expansion necessary to meet state Renewable Portfolio Standard targets but no federal renewable standard. The Spring 2013 Reference Case incorporates CAIR and MATS emission assumptions along with Regional Greenhouse Gas Initiative compliance.

To ensure that a range of possible future power prices were 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;

- Long-term assumptions for load growth
- Natural gas prices
- Coal plant retirements representing the impacts of environmental regulation
- An explicit price on carbon dioxide emissions in some cases

Figure 2.8 Scenario Power Prices



These inputs were varied in the model from the Ventyx reference case provided. This process produced values based on the probability tree shown in Figure 2.7. The results of this modeling for each branch yields different power price futures. Figure 2.8 shows those price curves corresponding to the scenarios described earlier in this section.

Power Price Shaping

It is necessary to convert the ATC Power Prices for the Indiana Hub (obtained in the manner explained above) into 8,760 hourly prices for each year by scenario in order to achieve reasonable results from the RTSim production cost model, which uses an hourly dispatch to model the system. For this IRP, Ameren Missouri has used the same methodology for shaping block prices into hourly prices as it uses in its fuel budgeting modeling.

Before such shaping can occur, the ATC Power Prices for the Indiana Hub must first be basis adjusted for time (real time to day ahead (DART)) and for location (INDY Hub to Ameren Missouri generation).

Once ATC prices have been basis adjusted they are broken down into monthly block prices for each year in each scenario utilizing historical ratios of individual months to the annual ATC price, and peak blocks (5x16, 2x16 and 7x8) within a month to that month's price. These block prices by month are then shaped into hourly prices utilizing the 2011 day ahead price curve applicable to Ameren Missouri's base load generators. 2011 was selected as the reference year to maintain consistency with use of the same year for load shaping.

These power prices were used in the analysis of alternative resource plans described in Chapter 9. They were also incorporated into unique forecasts of Ameren Missouri load for each scenario to account for price-demand elasticity, as described in Chapter 3.

2.8 Compliance References

3. Load Analysis and Forecasting

Highlights

- *Ameren Missouri expects energy consumption to grow 12% and peak demand to grow 8% over the next 20 years.*
- *The commercial class is expected to provide the most growth while federal efficiency standards continue to slow residential growth compared to historical trends.*
- *Key forecast uncertainties include growth in miscellaneous plug load, the future mix of customers and the impact that has on energy intensity of the local economy, and the impact of rising prices.*

Ameren Missouri has developed a range of load forecasts consistent with the scenarios outlined in Chapter 2. These load forecasts provide the basis for estimating Ameren Missouri's future resource needs and provide hourly load information used in the modeling and analysis discussed in Chapter 9. In addition, the Statistically Adjusted End-use forecasting tools and methods used to the develop the forecasts provide a solid analytical basis for testing and refining the assumptions used in the development of the potential demand-side resource portfolios discussed in Chapter 7.[1] The energy intensity of the future economy and the inherent energy efficiency of the stock of energy using goods are explored throughout the analysis to arrive at reasonable estimates of high, base, and low load growth.

3.1 Energy Forecast

This chapter describes the forecast of Ameren Missouri's energy, peak demand, and customers that underlies the analysis of resources undertaken in this IRP. In order to account for a number of combinations of possible economic and policy outcomes, fifteen different forecasts were prepared. Based on the subjective probabilities of these scenarios identified by Ameren Missouri, a sixteenth case was developed to represent the planning case for the study. The planning case forecast projects Ameren Missouri's retail sales to grow by 0.59% annually between 2014 and 2034, and retail peak demand to grow by 0.40% per year.

[1] 4 CSR 240-22.030(1)(A)

As with any forecast of energy, there are several underlying assumptions. Expectations for economic growth underlying the load forecast are from Moody's Analytics' (formerly Economy.com) forecast of economic conditions in the Ameren Missouri service territory. Expectations about future energy market conditions, such as fuel prices and the impact on electricity prices of different environmental policy regimes are based on interviews with internal Ameren subject matter experts.

Compared to Ameren Missouri's last IRP, filed in 2011, both the level and the growth rate of the forecast are lower. The initial level of sales is lower primarily because of the unusually severe recession that Missouri and the U.S. experienced between 2007 and 2009 and the sluggish recovery from it. Additionally, Ameren Missouri has implemented significant energy efficiency programs that were not assumed in the base case forecast in the 2011 IRP. The 0.59% growth rate in retail sales for the 2014-2034 time period in this filing is also lower than the 1.09% retail sales growth rate expected for the study period in the 2011 IRP forecast largely due to a combination of factors. First, projections of economic growth coming out of the last recession predicted a more robust recovery than we have actually experienced. At this point the economic recovery has gained traction, but we are living with slower growth than was anticipated in the immediate aftermath of the recession. Second, the impacts of both energy efficiency standards and the programs of Ameren Missouri are being felt in a decline in the energy intensity of the service territory economy. This forecast assumes significant savings from DSM programs that are already into the implementation phase. Those programs were still being studied at the time of the 2011 IRP. Due to both economic and efficiency factors, the forecast has shifted down over the last three years.

It should be noted that in the development of this forecast, expectations of improving energy efficiency of end use equipment and appliances is reflected only to the extent that it is due to market conditions, federal standards, or the first three year cycle of energy efficiency programs Ameren Missouri is running under the Missouri Energy Efficiency Investment Act (MEEIA). The first cycle of MEEIA programs is included in the load forecast because it is already planned and approved and in the process of being implemented by the company. Future energy efficiency programs are the subject of the DSM chapter of this IRP and the impacts of those programs will be included according to their role in the various alternative resource plans.

3.1.1 Historical Database[2]

Ameren Missouri tracks its historical sales[3] and customer counts by revenue class (Residential, Commercial, and Industrial), and also by rate class (Small General Service, Large General Service, Small Primary Service, and Large Primary Service).[4] Ameren Missouri uses these rate classes as the sub-classes for forecasting, both because the data is readily accessible from the billing system and because it provides relatively homogeneous groups of customers in terms of size. Historical billed sales are available for all rate and revenue classes back to January 1995 and calendar month sales and class demand data[5] resulting from Ameren Missouri's load research and analysis efforts is available beginning in July 2003. The distinction between billed and calendar sales is the timing of when usage is reported. Billed sales are based on customer meter readings and represent usage that is relevant to the specific dates associated with the company's meter reading schedule for the time period in question. Calendar month sales are based on load research and analysis, which, among other things, estimates how much of the billed usage actually occurred within the specific days of the reporting month, regardless of the timing of the meter reads. At the time of the preparation of the load forecast modeling for this IRP, historical sales were known through June of 2013.[6] Prior to the completion of reporting, sales for the remainder of 2013 became available. In general, any data presented in this chapter or its appendix for 2014 or beyond is forecasted data, and data from 2013 and earlier is actual metered or weather normalized sales data. Historical energy consumption and customer count data is available in the Appendix to Chapter 3.

Ameren Missouri routinely weather normalizes the observed energy consumption of its customers to remove the impact of unusual weather patterns. The process for weather normalizing sales is described in section 3.3, and weather normalized historical consumption from 2003 forward is also reported in the Appendix. The appendix includes use per unit energy sales and demand data for all classes. In each case, the unit included in the analysis is the customer count for the class.[7] This is selected because it is a measured value for each class that is accessible and meaningful in all cases. It is worth noting about the weather normalized energy sales and demand data reported in the appendix that they will not match values reported in the 2011 IRP. This is true for two reasons. First, the period used to calculate weather normals has changed since that IRP was prepared. The 2011 IRP normals were based on the 30 year period from 1971-2000, and the current IRP is based on 1981-2010. Adjustments to the historical sales and

[2] 4 CSR 240-22.030(1)(B)
[3] 4 CSR 240-22.030(2)(B)1
[4] 4 CSR 240-22.030(2)(A)
[5] 4 CSR 240-22.030(2)(B)2
[6] 4 CSR 240-22.030(2)(F)
[7] 4 CSR 240-22.030(2)(C)1

demands have been made so that both the history and forecast periods are based on a comparable set of weather normals.[8] Second, all monthly, seasonal and annual energy values are reported based on load analysis estimates of calendar month sales rather than billed sales that were reported in previous IRPs.

3.1.2 Forecast Vintage Comparison

Independent variables[9]

Section 4 CSR 240-22.030(6)(C)3 of the Missouri IRP rules requires a comparison of prior projections of all independent variables used in the energy usage and peak load forecasts made in at least the last 10 years to actual historical values and to projected values in the current IRP filing. Actual historical values for each independent variable for a period of at least the last 20 and up to 40 or more years are acquired by Ameren Missouri from Moody's Analytics, along with forecasts of each variable for the entire planning horizon.[10]

The following discusses only the independent variables used in the energy usage forecasts, since the peak load forecast comes from further processing the energy forecast. The growth rates in peak demand are driven by the energy forecasts for each class and end use as described later in this chapter, so the same economic variables used in the energy forecast are also being used to forecast the peak loads.

The prior projections subject to this requirement are from the 2005 IRP, the 2008 IRP, the 2011 IRP, the 2012 Annual Update, and the 2013 Annual Update. Besides these prior projections, projections for this 2014 IRP are included, and the values for historical years shown for the 2014 IRP serve as the actuals for years up to 2013.

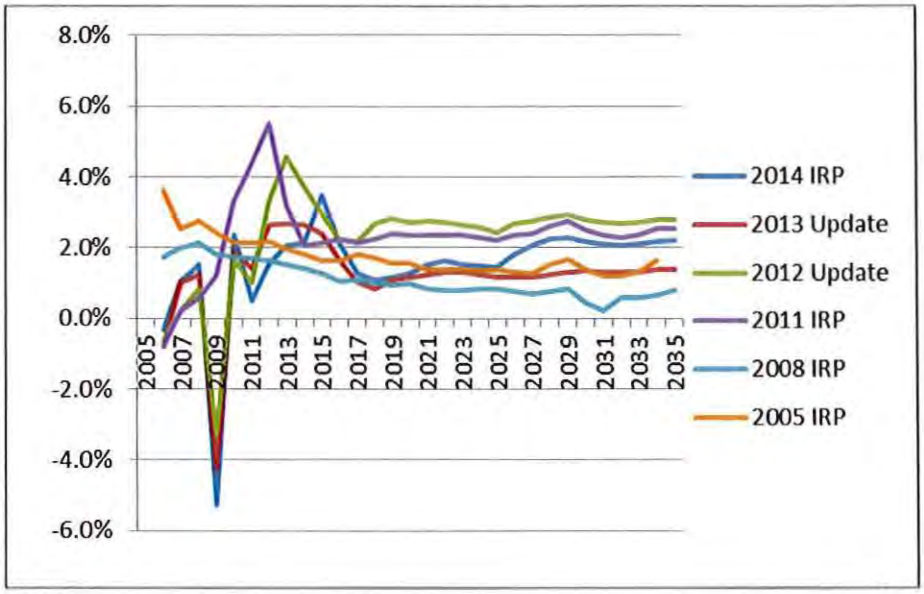
In some cases the base year for the variables' values was changed by the data vendor, and also between certain IRP's Ameren Missouri changed its methodology for weighting together county level variables into a service territory indicator, so the absolute level of the values for the same year among various vintages may be significantly different. However, the key is the growth rate or trend in these values, so each table is expressed in terms of the year over year growth rate and is accompanied by a chart showing the same, which overcomes the problem of sometimes different bases for some of the variables.

For the residential energy forecast, independent variables used in these forecasts were Households, Population, and Personal Income. For the commercial and industrial energy forecasts, independent variables used in these forecasts were total GDP and GDP for

[8] 4 CSR 240-22.030(2)(E)
[9] 4 CSR 240-22.030(6)(C)3
[10] 4 CSR 240-22.030(6)(C)1

several sectors of the economy, including Manufacturing, Retail Trade, Information Services, Financial Services, Education/Health Services, total non-farm employment, and manufacturing employment. Service territory GDP variable from each archived forecast is shown below in Figure 3.1. The growth rates for each of the variables discussed above is shown in chart and tabular form in Appendix A to this chapter.

Figure 3.1: Ameren Missouri Service Territory GDP Forecasts from Prior IRP Forecasts



Forecasts[11]

Section 4 CSR 240-22.030(6)(C)4 requires a comparison of prior projections of energy and peak demand made in at least the last 10 years to the actual historical energy and peak demands and to projected values in the current IRP filing.

Figures 3.2 and 3.3 below show previous forecasts of energy and peak demand, including those for the 2005 IRP, 2008 IRP, 2011 IRP, 2012 Update, 2013 Update, the 2014 IRP and actual historical values. The data from these charts is presented in tabular form in Appendix A to this chapter.

[11] 4 CSR 240-22.030(6)(C)4

Figure 3.12: Ameren Missouri Actual Historical Energy Sales and Past IRP Energy Forecasts

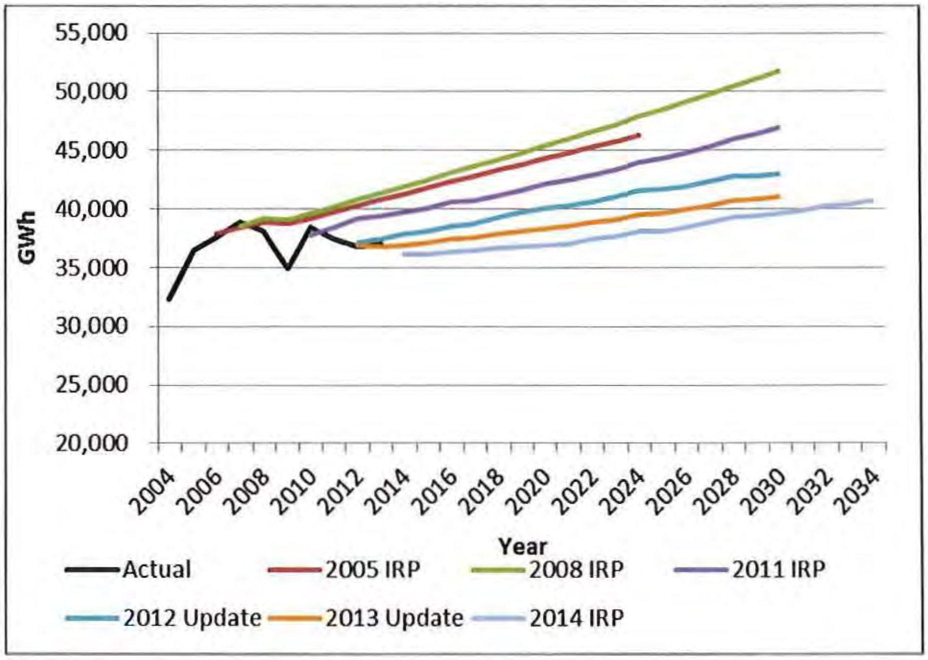
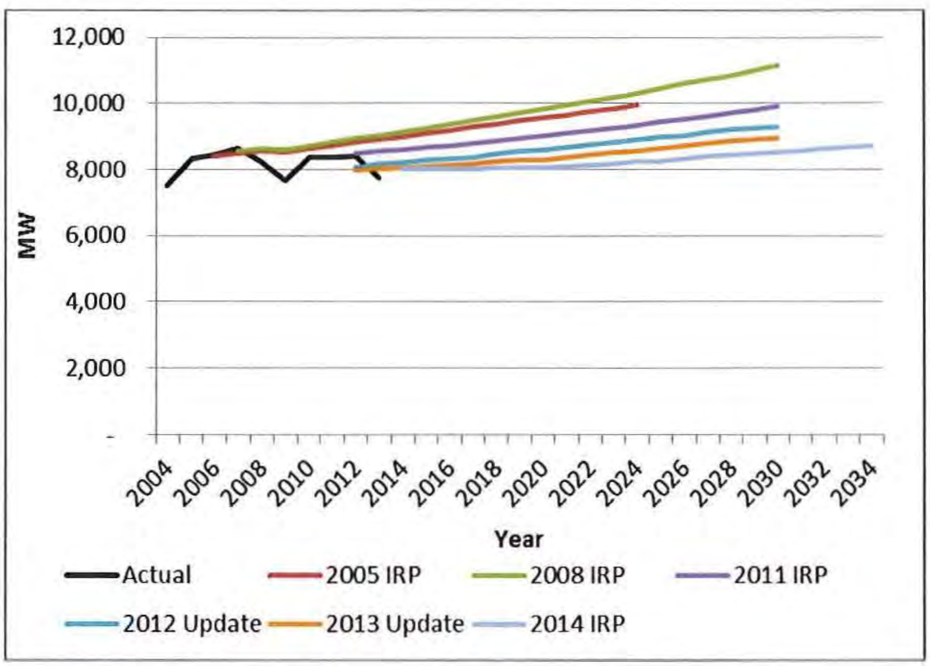


Figure 3.13: Ameren Missouri Actual Historical Peak Demand and Past IRP Peak Demand Forecasts

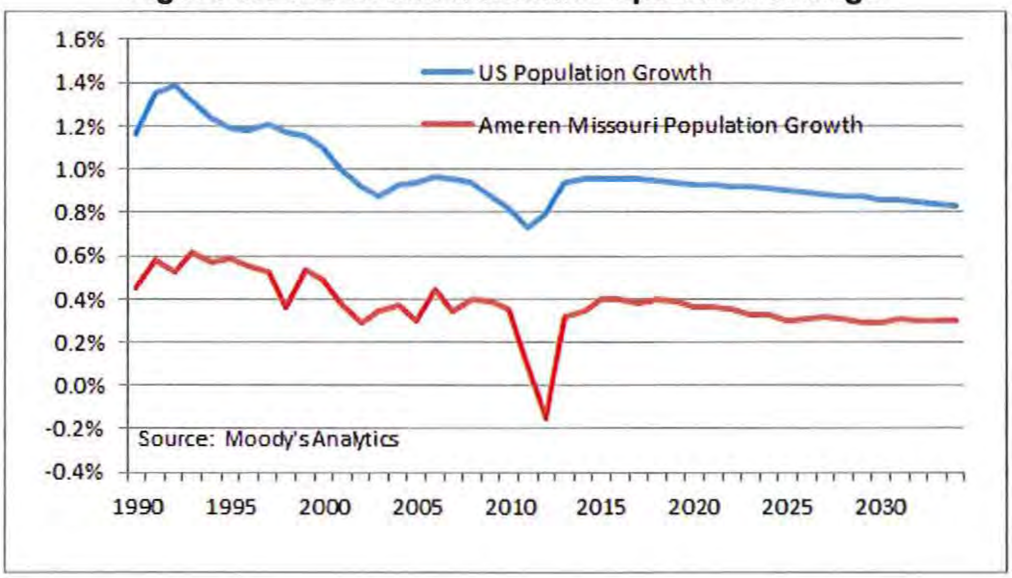


As is evident from the forecasts in the tables, over time the projections of both energy consumption and peak demand have come down quite significantly. This is due to a couple of factors. First and most significantly, the severe recession of 2007-2009 had a significant negative impact on Ameren Missouri's customers. Emerging from the recession, both the absolute level and the growth rate of energy consumption were markedly lower than they had been before the economic downturn. Secondly, an increase in the efficiency of end uses of electricity has reduced electric consumption relative to the earlier projections. As an example, the Energy Independence and Security Act of 2007 included an efficiency standard for light bulbs that significantly reduces the energy consumption associated with lighting. This and other standards, as well as the energy efficiency programs that have already been implemented by Ameren Missouri have served to reduce the rate of growth in energy and peak demand below what they otherwise would have been. Many of these changes in standards and program offerings occurred after the 2005 and 2008 IRP forecasts had been completed.

3.1.3 Service Territory Economy

The Ameren Missouri electric service territory is comprised of 59 counties in eastern and central Missouri. It should be noted, however, that although Ameren Missouri serves customers in 59 counties, it does not necessarily serve every electric customer in those counties. As would be expected, the level of sales is highly correlated with the behavior of the economy in the service territory.

Figure 3.14: U.S. and Missouri Population Change



Historically, the Ameren Missouri service territory has been characterized by slower population growth than the U.S. as a whole due to demographic and migration factors. In that respect, the service territory's economy is not terribly different from most other

Midwestern states and metropolitan areas. Like much of the Midwest, the region's economy was based on manufacturing for many years, but over the past several decades the share of the territory's employment in manufacturing has been declining while employment in services, particularly health care, has grown. So although the service territory still has a higher than average share of employment in manufacturing, it is no longer the employment growth engine it once was. The allocation of service territory employment by NAICS sector is shown in Figure 3.5; a list of some of the largest employers in the service territory is in Table 3.1.

Figure 3.5: U.S. and Ameren Missouri Service Territory Employment by Industry

The territory's major employers are spread across a number of different industries, but the region's single biggest employer is a hospital system, BJC Healthcare. Two other healthcare systems and three universities are among the largest employers in the territory, highlighting the importance of the health and education services to both the growth and level of employment, as well as to electricity sales.

As noted above, the service territory economy has grown at a slightly slower pace than the U.S. as a whole because of slower population growth. In addition to the trend of slower population growth, the St. Louis region did not experience as big of a boost from the housing bubble as some other markets did.

The service territory economy also contains a number of nationally known financial firms, including Wells Fargo and Edward Jones.

Table 3.1: Major Employers in Ameren Missouri, per Moody's Analytics

Rank	Employer	Industry	Employees
1	BJC Healthcare	Education or Health Services	24,882
2	Boeing Defense, Space & Security	Manufacturing	15,600
3	Washington University in St. Louis	Education or Health Services	13,483
4	SSM Health Care System	Education or Health Services	12,548
5	Scott Air Force Base	Federal Government	12,344
6	Schnuck Markets Inc.	Retail Trade	10,951
7	Wal-Mart Stores, Inc.	Retail Trade	10,802
8	St. John's Mercy Health Care	Education or Health Services	8,926
9	AT&T	Information	8,900
10	University of Missouri-Columbia	Education or Health Services	8,608
11	St. Louis University	Education or Health Services	7,758
12	McDonald's Corporation	Retail Trade	6,700
13	Wells Fargo	Financial Activities	5,300
14	Enterprise Holdings	Trans./Warehouse/Utilities	4,887
15	Edward Jones	Financial Activities	4,873
16	Ameren Corporation	Trans./Warehouse/Utilities	4,615
17	University Hospital & Clinics	Education or Health Services	4,468
18	Monsanto Company	Manufacturing	4,100
19	Anheuser-Busch Companies	Manufacturing	4,000
20	CitiMortgage Inc.	Financial Activities	4,000
21	Dierbergs Markets	Retail Trade	4,000
22	Express Scripts Inc.	Education or Health Services	3,910
23	Boone Hospital Center	Education or Health Services	1,655
24	US Department of Veterans Affairs	Federal Government	1,278
25	MBS Textbook Exchange Inc.	Financial Activities	1,239