Ameren Missouri

Integrated Resource Plan

2011

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1. Executive Summary

Highlights

- *Ameren Missouri has conducted a thorough evaluation of options to meet future customer demand in a safe and reliable manner at a reasonable cost*
- *Future environmental regulation is expected to be a significant driver of the need for new resources*
- *There are several potentially viable paths that Ameren Missouri could pursue, each of which presents unique opportunities and challenges*
- *Ameren Missouri has developed a complete decision roadmap to detail the Preferred Resource Plan and its relationship to several contingency options.*

Ameren Missouri's Integrated Resource Plan (IRP) serves as the basis for the utility's resource acquisition strategy over the next three years and the overall direction of resource procurements for the remainder of the 20-year planning horizon. The IRP provides a snapshot of the Company's resources and loads, and provides guidance regarding resource needs and acquisitions. Since the filing of Ameren Missouri's 2008 IRP there have been several key changes that have impacted Ameren Missouri's long-term planning. Those changes include adoption of a state Renewable Energy Standard (RES), the passage of the Missouri Energy Efficiency Investment Act (MEEIA), the prospect for more stringent environmental regulations, and a severe recession. The current Missouri resource planning rules make it clear that regulators are to evaluate the *process* Ameren Missouri follows to arrive at its Preferred Resource Plan. However, Ameren Missouri believes the importance of resource planning rises above simple rule compliance and includes the need to discuss the *plan*. It is clear based on the analysis included in this IRP that Ameren Missouri and the entire state will be facing some serious challenges in the planning horizon.

The immediate challenges are largely driven by emerging environmental policies. Although activity has recently cooled with respect to greenhouse gas legislation, general activity around more stringent environmental regulations affecting coal plants has increased substantially. New regulations governing air emissions, use of water, and disposal of coal ash are likely to require significant investment in control equipment for coal-fired plants. Given Ameren Missouri's strong reliance on coal (75% today), there could be a substantial impact to Ameren Missouri customers. Ameren Missouri's Preferred Resource Plan balances low cost, reliable service at reasonable rates by including a mix of renewable resources, demand-side resources, upgrades at existing facilities, and new gas-fired generation. This plan is optimal for our customers should existing environmental regulations remain largely unchanged over our planning horizon.

Should environmental regulations become more stringent, which we expect to be the case, Ameren Missouri has developed a robust set of contingency options to consider.

Stakeholder Involvement

Throughout the IRP planning process Ameren Missouri has hosted several meetings of key stakeholders with the purpose of providing a status update and an opportunity to provide feedback at a time when the feedback is most useful. The discussions ranged from conceptual to technical depending on the stage of the analysis. In limited cases offline discussions were held to answer questions. Ameren Missouri also posted meeting materials, transcripts, and supporting studies online to facilitate information sharing. Below is a list of the meetings with a summary of the topics that were discussed.

- January 9th, 2009 – Renewables study conducted by Black & Veatch
- April 2nd, 2009 – Waivers requested by Ameren Missouri for certain requirements of the IRP rules
- August 26th, 2009 – Renewables Follow-up, Coal and Gas Resource Options study conducted by Black & Veatch
- November 20th, 2009 – 2008 IRP Implementation Plan update, Overview of Planning Process
- January 26th, 2010 – Conference Call on Financing Analysis Plan
- March 8th, 2010 – Scenarios, Uncertain Factors, Load Analysis and Forecasting, EPRI End-to-End Efficiency Study, Initial Supply-Side Screening Results
- April 16th, 2010 – Conference Call on Financing Analysis Plan
- May 25th, 2010 – Forecasting Results, DSM Analysis, Alternative Resource Plan Development, Scenario Modeling Results
- September 14th, 2010 – Integration Analysis, Sensitivity Analysis, Critical Independent Uncertain Factors, Decision Framework
- February 22nd, 2011 – Risk Analysis, Environmental Scenarios and Strategy Selection

Drivers of Resource Needs

In determining our future resource needs we must first understand what the future demand for electricity is likely to be. Then, we must consider factors that may impact the ability of our existing power plants to meet those needs. Here are some of the critical drivers we analyze:

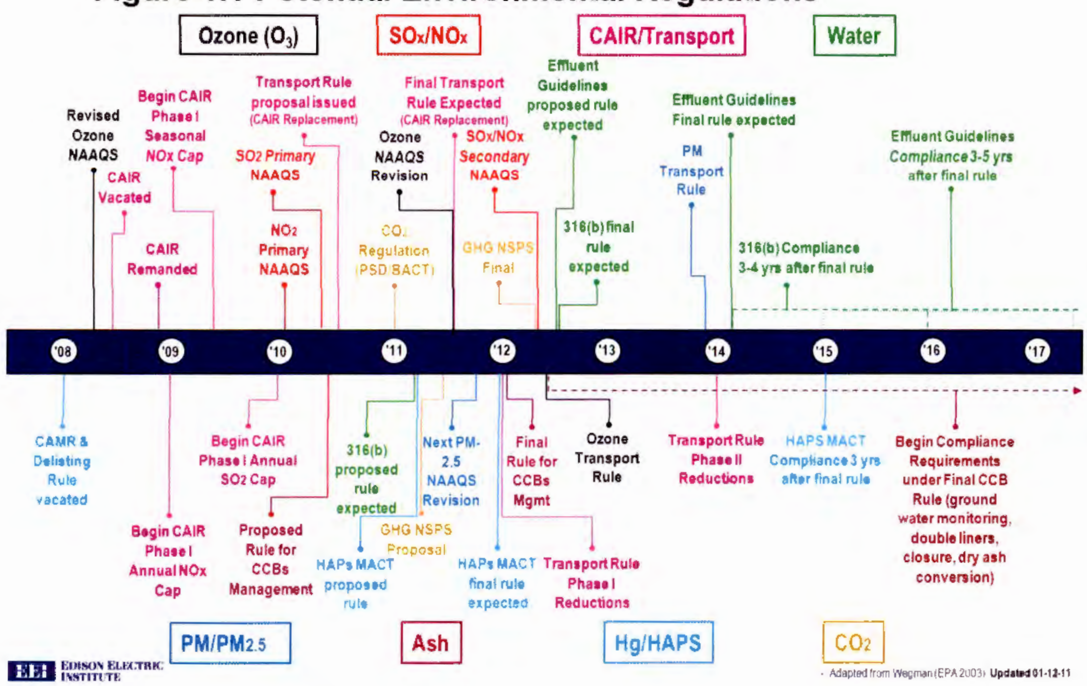
Customer Demand: Missouri's population has grown about 7 percent in the last decade, and this growth has also contributed to the rising demand for power. In the last 20 years, demand for electricity increased by 50% among Ameren Missouri customers.

In the next 20 years, our forecasts show demand for power rising almost another 20% in the Ameren Missouri service area alone.

Customer Expectations: Customers increasingly expect to have near-perfect service reliability. Customers believe that our product provides essential comfort and convenience and is critical to providing health care, personal security, recreation and many other services, so our customers expect us to have an abundant supply of electricity available when they want it.

Environmental Regulations: An area that has received a great deal of focus and attention over the last several years has been environmental regulations. In particular, the U.S. Environmental Protection Agency (EPA) is expected to issue new environmental regulations in the next 12 to 24 months related to air emissions, ash waste and water. Figure 1.1 highlights some of the regulations under consideration.

Figure 1.1 Potential Environmental Regulations



Source: Edison Electric Institute

These new regulations will likely require the installation of expensive environmental control equipment on our coal-fired plants over the next several years. The cost to comply with these regulations will be in the billions of dollars for Ameren Missouri and billions more for the rest of Missouri and the Midwest. These environmental regulations, along with potential legislation limiting the emission of greenhouse gases, will have a significant impact on electric rates and on our state's energy future because coal currently accounts for about 80% of the energy supplied in Missouri. As a result, we are diligently working with legislators, regulators and other key stakeholders to find solutions that balance the need to address environmental concerns with the need to protect our state's economy, energy security and our customers' costs.

Aging Infrastructure: Across the nation and our region, large coal-fired plants that provide most of our power are growing older. The average age of Missouri's large plants is 40 years, and that's at least middle age for a power plant. These plants will not operate forever. In addition, the need to install billions of dollars of environmental controls may not be prudent on some of the older, less efficient plants and may force Ameren Missouri and other generators across the region, state and nation to shutter such plants. Not only does this have economic consequences, but the closing of some of these plants could impact the reliability of our power grid.

These plants won't be quickly or easily replaced. Planning for new generation must be done years in advance. That's why we need clear state and federal energy policies and regulation, as well as a reasonable transition period to implement these regulations so that we can plan effectively for the need to meet our customers' future energy needs in the most prudent and affordable fashion.

Future Resource Options

Meeting existing power demand requires a vast network of different types of power plants, big and small, connected by a network of power lines. For a sense of scale, we can consider how many power plants of a given type would be required to generate the same amount of electricity. One single-unit nuclear power plant or two coal-fired units, for example, produce enough electricity to meet the annual needs of one million households. To meet the needs of the same number of consumers, it could take 1.6 million solar energy panels, 2,000 wind turbines, or three natural gas-fired plants. As the U.S. and other countries seek to ramp up renewable energy production, land use is becoming a more contentious issue; wind and solar energy farms may require 70 – 80 times more land than what is typically needed for traditional energy sources.

Clearly, it takes a combination of resources to reliably supply electricity. What we strive for is a number of power generation options working together within and across regions—so we aren't dependent on any single generation source. Each technology has distinct advantages and disadvantages.

Coal-fired power plants have been our state's energy workhorses for decades and are important energy resources for our state. Today they generate large quantities of low-cost electricity around the clock, but they emit greenhouse gases and other pollutants and release coal combustion byproducts that present waste disposal issues. Due to the potential new environmental regulations discussed previously, future coal plants will likely have to meet more stringent environmental standards in the future. New technologies are under development to meet these standards, including those to capture and sequester carbon dioxide (CO_2). These offer promise as long-term solutions to climate change, but they are still mostly experimental.

Nuclear energy is by far the world's largest source of carbon-free generation. The U.S. is the largest nuclear energy producer with 104 nuclear plants in 31 states, generating about 20% of the nation's electricity. For Ameren Missouri, nuclear energy accounts for approximately 20% of our total generating capacity. U.S. energy providers recently began exploring development of new nuclear plants after decades with no new nuclear units constructed in the nation. Building a new nuclear plant can be a boost to local and regional economies—adding jobs in the tens of thousands during construction and hundreds of permanent jobs. Since 2001, nuclear power plants have achieved the lowest production costs when compared to plants fired with coal, natural gas and oil. However, due to their complexity and the significant regulation controlling nuclear energy, nuclear power plants can be more challenging to build, finance and operate than plants fueled by other sources.

Natural gas-fired generation is generally simpler to build and produces lower greenhouse gas emissions (about half the CO_2 emissions of a coal-fired power plant), but it too presents price uncertainty because natural gas costs have historically been very volatile. However, new uses of existing technologies have opened new domestic sources of natural gas, driving down prices. The current low prices for natural gas have encouraged some electric generators to substitute gas for coal. Environmental concerns about the use of these technologies have surfaced recently and could impact natural gas prices in the future.

Renewable power – solar and wind energy resources don't produce harmful greenhouse gases that contribute to climate change. However, the wind does not always blow, and the sun does not always shine, so you can't depend on these resources for predictable electricity production. Renewable energy also requires development of additional transmission lines to move wind and solar energy to the urban areas where it is needed from windy rural areas, or sunny environments, where it is often generated. That said, the cost of installing wind and solar energy systems has dropped with improvements in renewable technology, attracting customer interest in renewable energy.

To help our customers evaluate various solar power systems, we recently installed five solar power systems at our downtown headquarters building. The project will provide customers with practical information on the effectiveness of solar energy in our area. In the spring of 2011, we will open a viewing area and classroom where visitors will be able to see the rooftop solar systems along with monitors showing how much energy the units are generating.

Hydroelectric generation is environmentally friendly, but it relies on available water supplies and is very time-consuming to permit and costly to build. Largely financed through insurance proceeds, Ameren Missouri's newly rebuilt 440-megawatt Taum Sauk Hydroelectric Plant, which returned to service in 2010, is proving to be a valuable hydroelectric storage resource that can be quickly started during times of high demand for electricity. Taum Sauk Plant stores energy in the form of water, pumped from a lower elevation reservoir to a higher elevation. Low-cost off-peak electric power is used to run the pumps. During periods of high electrical demand, the stored water is released through turbines to create electricity.

Biomass – Common examples of biomass include food crops, crops for energy (e.g., switchgrass or prairie perennials), crop residues, wood waste and byproducts, and animal manure. Biomass can be burned directly in boilers to provide heat or in high-pressure boilers to generate electricity and then provide heat. Biomass can be used to generate electricity 24 hours a day. Coal-fired plants can be modified to burn biomass with coal, a process called "co-firing." Nationwide, biomass fuels less than 1% of the nation's electricity. Power generated from biomass is classified as "renewable" by the current Missouri Renewable Energy Standard, and may qualify as a renewable resource in potential federal legislation. However, biomass has seen limited use as an energy source thus far because it is not readily available as a year-round feedstock, can be expensive to transport and requires costly technology to convert to energy. Ameren Missouri is supporting research on biomass fuel resources, feed systems, storage facilities, and transportation options.

Landfill gas-to-energy projects can generate enough energy to power thousands of homes every day, reducing emissions of greenhouse gases in the process. The Ameren Missouri Methane to Megawatts project, slated to be up and running in 2012, will be the largest landfill gas-electric facility in the state and among the largest in the nation. It will generate enough electricity to meet the demands of about 10,000 homes. But this energy option requires the right kind of landfill and the right kind of technology to be installed, as well as lots of land to obtain meaningful scale.

Energy efficiency – Using energy more efficiently can defer the need for new generation resources. The following section discusses Ameren Missouri's experience to date and the potential for additional energy saving opportunities.

Demand-Side Resources

Demand-Side Management ("DSM") entails actions by the utility that influence the quantity or patterns of energy consumption. DSM can further be divided into energy efficiency and demand response programs. Energy efficiency programs are designed to reduce overall consumption of electricity; whereas, demand response programs are designed to reduce electricity consumption during the few periods of highest demand.

Ameren Missouri has been implementing full-scale energy efficiency programs since 2009 and has several programs for both residential and business customers. Below is a brief description of the existing energy efficiency programs, all of which are scheduled to end September 2011. The future level of investment in these programs is highly dependent on the regulatory framework applied to DSM.

Residential Programs

- Lighting and Appliance Program – Provides an instant rebate or manufacturer buy-downs on Compact Fluorescent Lights (CFLs) and mail-in rebates on new ENERGY STAR®-qualified appliances.
- Social Marketing Distribution Program – Reduces energy use in residential lighting by leveraging the distribution and education capabilities of organizations to distribute CFLs and educational material at no charge to their residential constituents.
- Multi-Family Income Qualified Program – Partners with multi-family building owners and managers to remove energy inefficient lighting and appliances and install program-specified energy efficiency measures (EEMs) in income qualified building units.
- Refrigerator Recycling Program – Prevents the continued use of inefficient, working refrigerators and freezers by taking the units out of homes and recycling them in an environmentally safe manner.
- HVAC CheckMe!® Program – Encourages residential customers to have existing cooling systems evaluated and if feasible, brought back to factory specifications (re-commissioned), or replace less efficient, working central cooling systems with high efficiency central cooling systems.

Business Programs

- Standard Incentive Program – Provides pre-set incentives for energy efficient products that are readily available in the marketplace and will target measures for which energy savings can be reliably deemed, or calculated using simple threshold criteria. Incentives are available for lighting, motor, heating, ventilation and air conditioning (HVAC) and refrigeration projects.
- Custom Incentive Program – The Custom Incentive Program is for projects that save electricity, but are not on the Standard Incentive list. The incentive is $.05 per kWh saved during the first year of operation, with program incentives not to exceed 50 percent of the overall energy efficiency measure costs.
- New Construction Program – Provides financial incentives and technical assistance for energy efficient building design and construction. Eligible facilities include new facilities built from the ground up, additions to existing facilities, or major renovation of existing facilities requiring significant mechanical and/or electrical equipment alteration.

- Retro-Commissioning Program – Provides incentives for energy and demand reduction opportunities achievable through optimizing building control systems.

In January 2010, Ameren Missouri published the results of a major research study aimed at understanding the potential for energy efficiency improvements on the customer side of the meter. To understand customer energy efficiency plans and future needs, a third-party vendor surveyed more than 4,000 residential and commercial customers using both online and onsite surveys. Ultimately the customer research was integrated with cost and performance data of end uses to estimate potential demand and energy savings. Ameren Missouri also developed several portfolios that represent a wide range of energy savings and cost. Figure 1.2 shows the annual energy efficiency budgets for the portfolios while Figure 1.3 shows the potential annual savings.

Figure 1.2 Annual Budgets

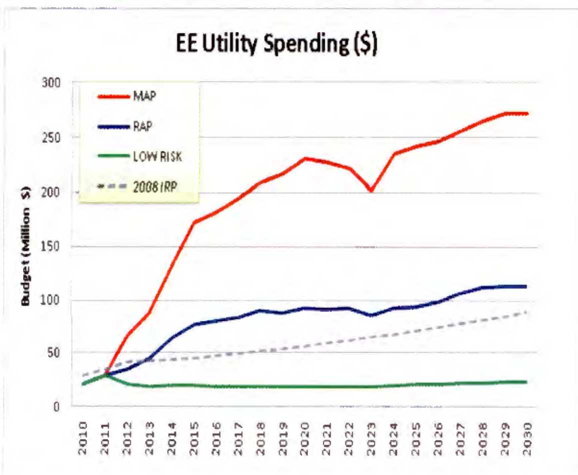
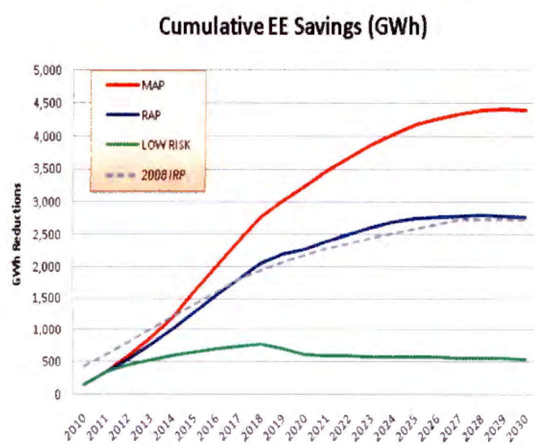


Figure 1.3 Annual Savings



*RAP-Realistic Achievable Potential, MAP-Maximum Achievable Potential

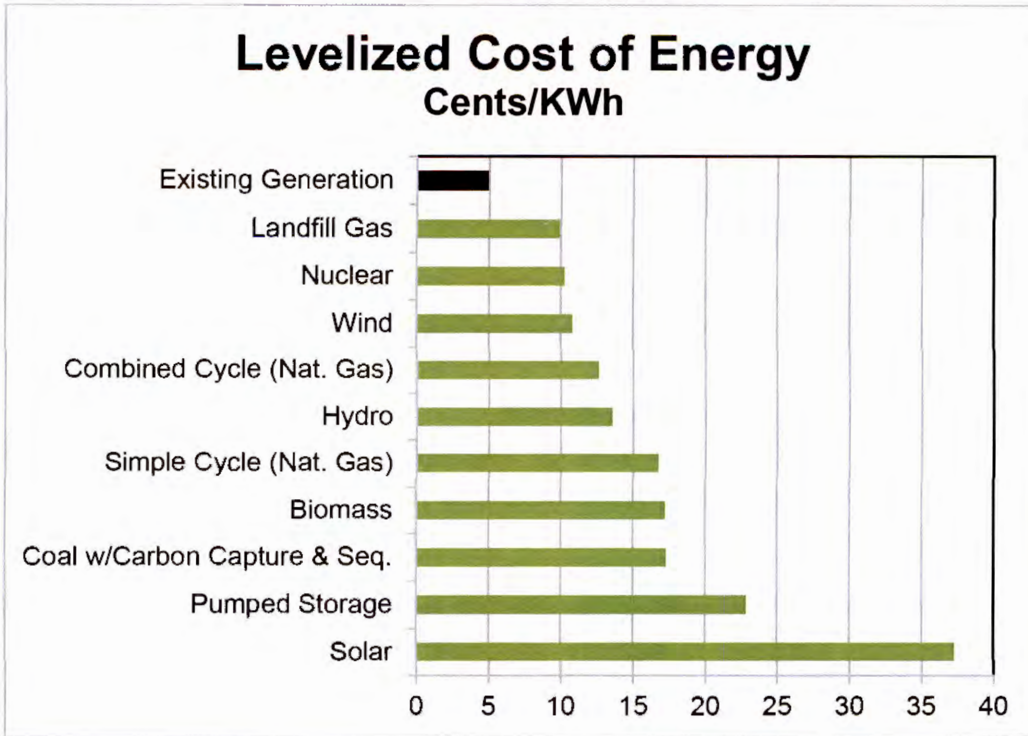
A DSM portfolio is initially measured by its cost-effectiveness. The Total Resource Cost (TRC) test, which measures benefits and costs from the perspective of the utility's customers and society as a whole, is a commonly used measure of cost-effectiveness. In short, if the benefits outweigh the costs then the ratio will be greater than one. It should be noted that the TRC is a screening-level assessment that does not reflect risk and that the results of integration and risk analysis determine cost-effectiveness on a risk-adjusted basis. With a levelized cost of energy near 4 cents/kwh, energy efficiency is less expensive than the supply-side alternatives. Ameren Missouri's analysis has also quantified some of the unique risks associated with implementing demand-side programs.

Relative Costs of Future Resource Options

Some generation technologies cost a lot more to construct and then have much lower operating costs. Others cost a lot less to construct but have higher operating costs. The expected lifetime of generation assets also varies by technology. One way to compare the relative costs of different generation technologies is to calculate a levelized cost of energy. To do this, we calculate the total costs of production - construction and operating costs, including environmental and fuel costs - over the expected life of the plant. Then we divide that by the amount of energy the plant produces over its lifetime. Coal traditionally has been an economically attractive fuel for generating power because it is so abundant.

As shown in Figure 1.4, the levelized cost of energy produced by Ameren Missouri's existing generation fleet (mainly electricity generated by coal and nuclear facilities) is much lower than any new generation resource we might add in future years to meet our customers' rising need for power.

Figure 1.4 Levelized Cost of Energy (Without Incentives)



With potential mandates requiring the reduction of CO_2 and other air emissions and potentially more stringent environmental regulations on water quality and ash disposal, coal becomes more expensive as a future generation source unless technological advances drive these costs down.

Natural gas is also a strong choice, particularly with efficient, smaller gas-fired facilities that are less expensive to build than coal or nuclear plants. But fuel costs for natural gas are about double the price of coal right now, and natural gas prices have traditionally been volatile, meaning that they can change rapidly.

Since 2001, nuclear power plants have achieved the lowest production costs when compared to plants fired with coal, natural gas and oil. In addition, nuclear power produces virtually no air emissions and is a great choice to address future environmental regulations. However, due to their large scale and the significant regulation controlling nuclear energy, nuclear power plants can be more challenging to build, finance and operate than plants fueled by other sources.

It is clear that all new supply-side options are more expensive than Ameren Missouri's existing resources and thus would likely result in increased rates when implemented. This is not unexpected given the age of existing units, some of which were constructed in the 1950's, and the less stringent environmental regulations at the time they were built. It is also why Ameren Missouri has and will continue to evaluate options to extend the life of its existing fleet and increase the production capabilities of existing plants.

Finally, energy efficiency might seem to be a good choice. While not typically considered a traditional generation option, an energy efficiency program that is significantly embraced by customers could be the cheapest choice (that is, similar to our existing generation costs) to meet our customers' future energy needs. However, there are meaningful expenses related to offering customer rebates and discounts on energy efficient appliances, providing weatherization services and energy audits, installing energy efficient equipment, and promoting the efficient use of electricity. In addition, proper incentives and customer acceptance are key drivers.

Key Factors Influencing Resource Choices

Costs alone do not dictate which energy resources offer the greatest development potential. In our planning process, we looked at a range of factors in analyzing possible resources. They include:

Portfolio Diversity: Consistent with other electric energy providers in our state, Ameren Missouri's generation portfolio is heavily weighted toward coal. We must thoughtfully transition our portfolio of generation to other sources, including potentially cleaner coal.

Environmental Regulation: We must assess the current and potential long-term impacts of expected environmental regulations on our power plants.

Costs to Customers: We must be mindful of the impact that our future energy choices will have on our customers' rates and future energy bills.

Ability to Finance Future Energy Sources: In determining the right energy resource, we analyze our ability to finance its construction and the long-term costs to our customers.

Economic Development Impact: We evaluate the economic impact of any decision to add new energy resource projects – the number of jobs, tax revenues, and other economic benefits a project is expected to bring can be very important to the communities we serve and the entire state of Missouri.

Regulatory and Legislative Matters: We need to assess how well the current or future regulatory and legislative frameworks enable our ability to move forward on certain energy resource options. In particular, those frameworks need to provide timely recovery of, and fair returns on, these significant investments, as well as provide appropriate safeguards for our customers.

One example in this arena is the mechanism (or lack thereof) to finance a large new generating plant during construction. Under current Missouri law, costs associated with building a new generating plant cannot be reimbursed through customer rates until construction is completed and the plant is serving customers. Projects of this magnitude take several years to plan and complete and cost hundreds of millions of dollars and in some cases several billion dollars. This framework creates significant challenges to finance and move large scale projects forward and will be a factor in choosing energy resource options in the future.

Another example is the issue of utility incentives for promoting energy efficiency. Because the existing regulatory framework provides an incentive for utilities to maximize sales of electricity, shifting utility incentives in favor of energy efficiency require the use of alternative ratemaking approaches. Rate treatment related to utility energy efficiency programs can be separated into three categories – program cost recovery, lost revenue, and performance incentives. Of these, lost revenue represents the greatest hurdle which must be overcome to align utility incentives with promotion of energy efficiency. The reason for this, simply put, is that for each kwh of reduced sales the utility loses revenue for that kwh until it is reflected in the development of rates in the utility's next general rate case. Until this significant disincentive is addressed, utilities will be reluctant to pursue aggressive energy efficiency goals.

In order to support a more transparent discussion of the trade-offs between cost and other factors, Ameren Missouri used a scorecard approach to screen alternative resource plans and ultimately select its Preferred Resource Plan. Table 1.1 shows the six major categories that represent Ameren Missouri's policy objectives and the various measures used to evaluate plans in each category, reflecting our

Table 1.1 Policy Objectives

Policy Objective Category(ies)	Measure(s)
Environmental & Resource Diversity	Resource Diversity, Carbon Emissions, SO2 Emissions, NOx Emissions
Energy Efficiency	Energy Savings
Financial/Regulatory	ROE, ROIC, EPS, Free Cash Flow, Stranded Cost Risk, Transaction Risk, Recovery
Customer Satisfaction	Average Rates Single-Year Rate Increase
Economic Development	Primary Job Growth (FTE-years)
Cost	PV Revenue Requirement

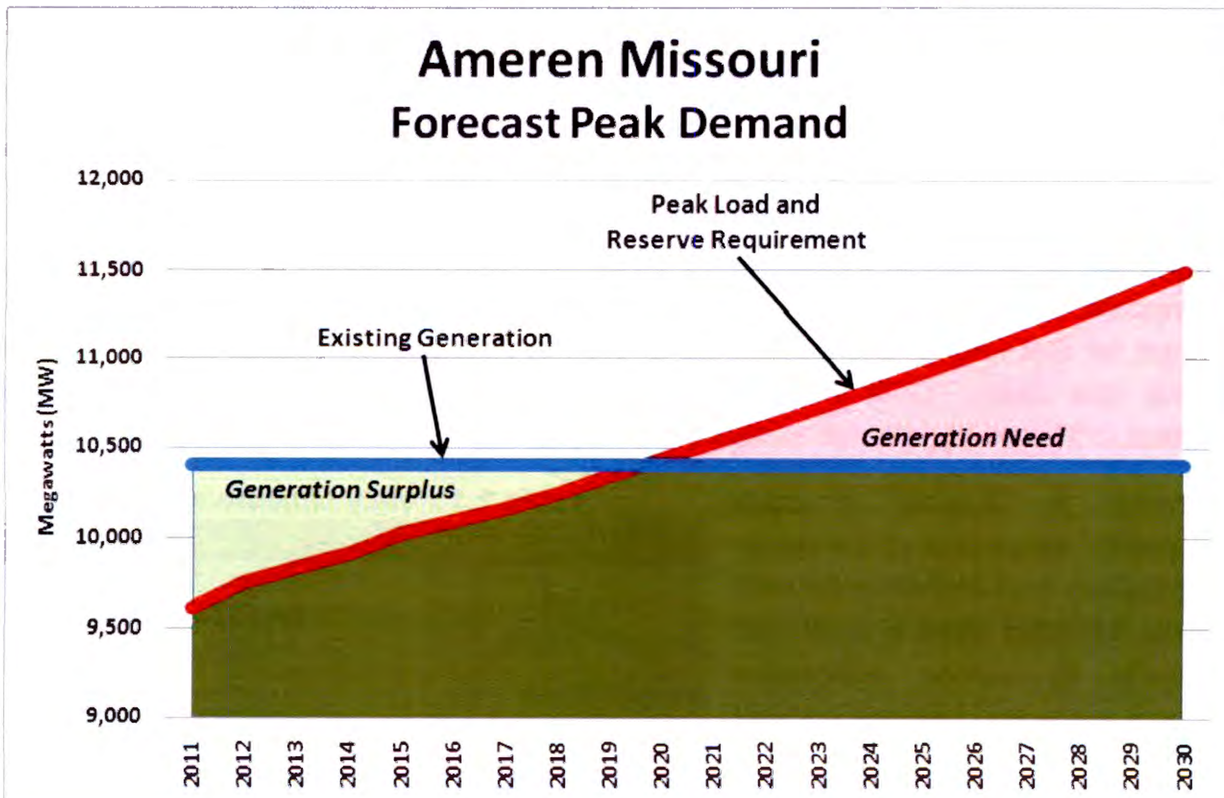
consideration of the factors listed above. Initially, as described in Chapter 9, the 216 alternative resource plans were all screened using this scorecard. At that time only one measure was used per category since there were so many plans being analyzed. Once there were only a few plans remaining, more measures (including qualitative measures) were included to support a richer discussion and differentiation of each plan. While cost remained the primary driver, the other factors weighed heavily into the decision making.

Resource Needs

As stated earlier, we believe the demand for power will continue to grow—in fact, we forecast demand will increase about 20% in our service territory over the next two decades.

As shown in the chart in Figure 1.5, Ameren Missouri currently has about 10,400 megawatts of electric generation capability. The chart also indicates that by 2020, with expected load growth and existing environmental regulations, Ameren Missouri will need additional resources to meet expected customer demand and reliability reserve requirements.

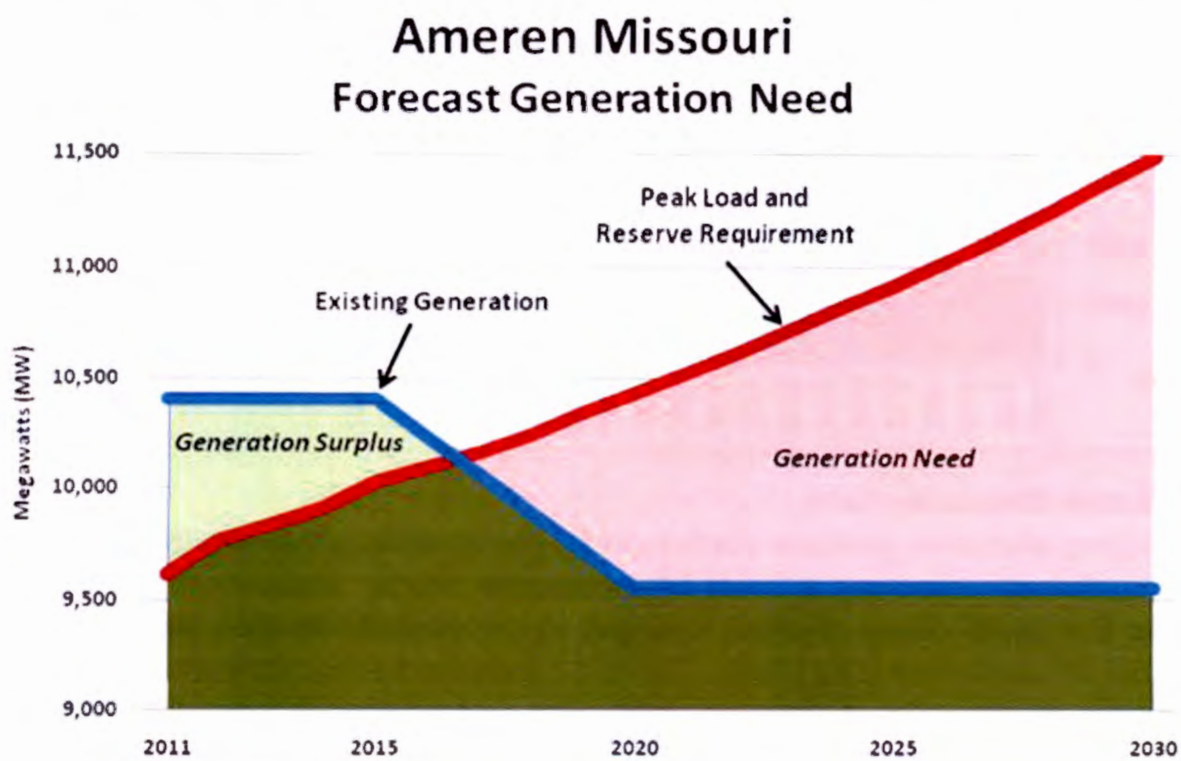
Figure 1.5 Ameren Missouri Resource Position



The previous chart identifies a need for more generation by 2030 should no new environmental regulation be mandated. As stated previously, while there is a great deal of uncertainty in the area of environmental regulation, we do believe that more stringent regulations on air emissions, water and waste will be in place between 2015 and 2020. The costs to meet those regulations are expected to be significant, will drive up energy costs, and are likely to cause older, less efficient coal-fired plants to shut down, including our Meramec Power Plant.

Rising customer demand, when coupled with the shutdown of Meramec Plant, will result in a meaningful shortfall of generation available to meet our customers' needs – about 1000 megawatts by 2020. That shortfall continues to grow through 2030. The chart in Figure 1.6 illustrates the need for resources under such circumstances. The chart presents the resource position in five-year steps to recognize the uncertain nature of the timing of new environmental rules and the potential need for retirement of Meramec.

Figure 1.6 Ameren Missouri Resource Position with Meramec Retired



The adoption by Missouri voters of a state Renewable Electricity Standard ("RES") in 2008 has introduced a new layer into the planning process. Not only does Ameren Missouri need to meet future capacity needs but it also needs to do so while meeting the RES requirements. The state RES has both a solar and non-solar requirement. Ameren Missouri recently installed solar panels at its St. Louis General Office Building, but must acquire additional solar resources to comply in 2011. Table 1.2 shows

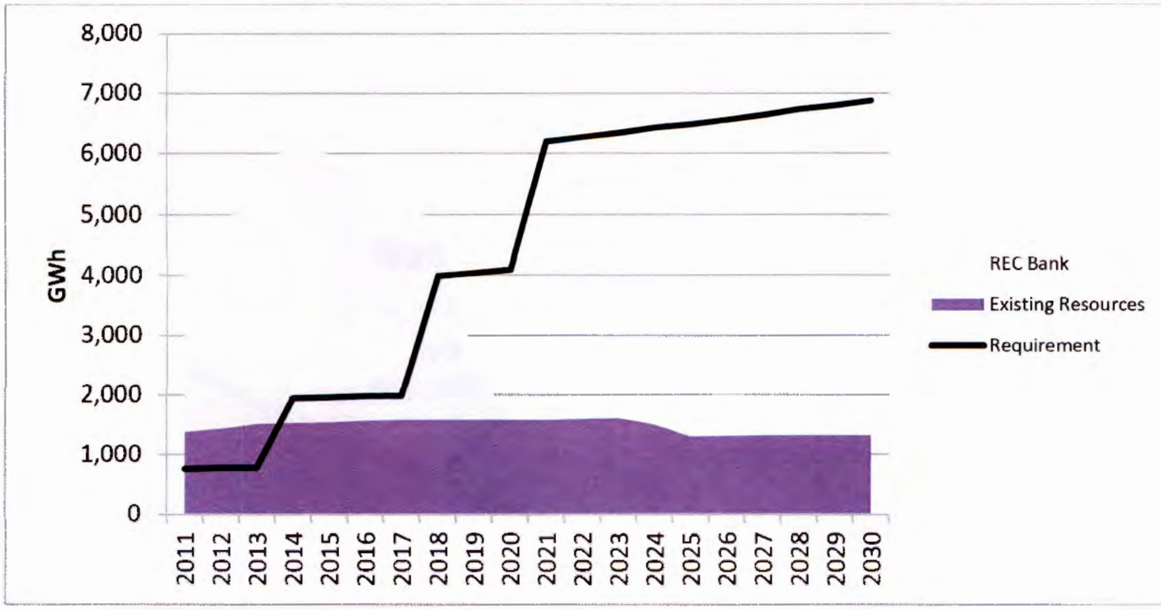
Table 1.2 Solar Energy Needs (MWh)

Year	Solar Requirement
2011	15,049
2012	15,312
2013	15,387
2014	38,718

the megawatt-hour solar requirements over the next several years while Figure 1.7 depicts how Ameren Missouri's existing renewables resource compare to the non-solar RES requirements once banking of credits is considered. It is evident that no additional non-solar resources are needed until 2019.

With the resource needs outlined above in mind, Ameren Missouri has evaluated a range of options to meet these needs. Both supply side options, such as power plants, and demand side options, such as energy efficiency programs, were considered.

Figure 1.7 Ameren Missouri Renewable Position



Alternative Resource Plans

Developing alternative resource plans includes the combination of various demand-side and supply-side resources to meet future capacity needs. However, there are other factors that could cause dramatic changes in the capacity position that need to be considered when developing plans. Figure 1.8 includes the five dimensions considered during the development of resource plans. The permutations of these five dimensions would create 416 plans. However, some combinations may create duplicate resource plans or plans that do not make sense. For example, the Meramec combined cycle option is contingent on Meramec's retirement so the interaction of Meramec continuing and the Meramec combined cycle option would produce an infeasible plan. Ultimately there were 216 plans to be analyzed.

Figure 1.8 Five Attributes of Alternative Resource Plans

Supply-Side Types
- Coal with Carbon Capture
- Combined Cycle (Greenfield)
- Combined Cycle (Meramec)
- Combined Cycle (Venice)
- Simple Cycle (Greenfield)
- Pumped Storage
- Nuke 30% (Partial Ownership)
- Nuke 50% (Partial Ownership)
- Wind with Simple Cycle

Renewable Portfolios
- Federal
- Missouri

Demand-Side Portfolios
- Maximum Achievable Potential
- Realistic Achievable Potential
- Low Risk
- None

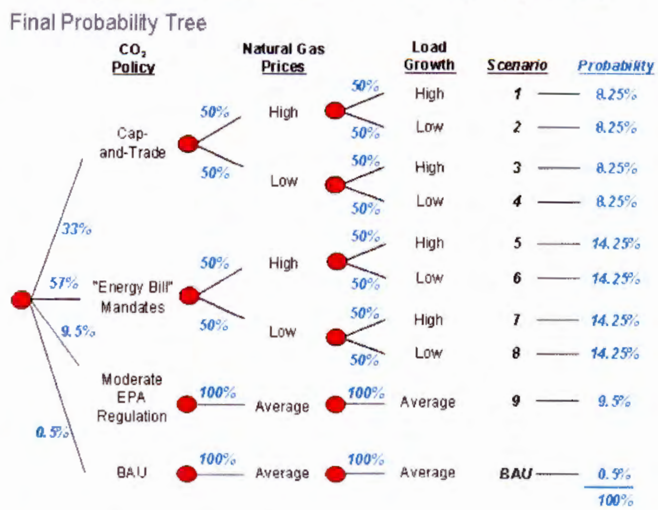
Meramec Status
- Meramec Retired 2015
- Meramec Retired 2022
- Meramec Continues As-Is

Noranda Status
-Noranda Continues
-Noranda Contract Expires 2020

Planning Scenarios

There are various uncertainties that can influence future resource decisions. Some of these uncertainties are highly interactive. That is, a change in one variable may cause a substantial change in another. For this reason it is useful to develop internally consistent scenarios of these uncertain variables. To develop its scenarios Ameren Missouri concluded the three factors with the largest influence on future resource decisions are carbon policy, natural gas prices, and economy-wide load growth. A third party interviewed Ameren Missouri experts to determine the likelihood of different future outcomes of each of those important factors. Figure 1.9 represents the end result those interviews, which culminated in the creation of 10 unique scenarios and associated probabilities. Each scenario is internally consistent with respect to the range of uncertain variables analyzed. This was achieved by using a model that simulates interactions in fuel and energy markets, electricity generation system operation, non-electricity sector outcomes, macroeconomic activity levels, and sector-specific responses to emissions limits. These scenarios and probabilities together comprise a probability tree and allow Ameren Missouri to test potential resource plans under a range of potential futures.

Figure 1.9 Scenario Probability Tree



Environmental Regulation

Coal-fired and other fossil-fired generating resources are subject to an ever-increasing range of environmental regulation. In particular, efforts by the U.S. Environmental Protection Agency in recent years indicate the desire to further limit power plant emissions and environmental impacts. Considering the gamut of potential environmental regulation, Ameren Missouri developed two scenarios, Moderate and Aggressive, to describe combinations of more stringent regulations and then translated those into expected requirements for equipment retrofits for its existing coal fleet. Table 1.3 contains the retrofit timing by scenario and power plant for each category of regulation.

Table 1.3
Plant Retrofit Timing by Scenario

Plant/Unit	Scenario	FGD (Scrubber)	ACI (Mercury)	Mesh Screens	Ash & Landfill	Cooling Tower	Water Plant
Labadie 1&2	Moderate	2020	2015	2017			
	Aggressive	2016	2015		2017	2017	2017
Labadie 3&4	Moderate	2024	2015	2017			
	Aggressive	2016	2015		2017	2017	2017
Meramec 1-4	Moderate		2015	2017			
	Aggressive	*2016*	2015	2017	2017		2017
Rush Island 1&2	Moderate	2016	2015	2017			
	Aggressive	2016	2015	2017	2017		2017
Sioux 1&2	Moderate	*2010*	2015	2017			
	Aggressive	*2010*	2015	2017	2017		2017

The characterization of environmental scenarios was used in the Meramec retirement analysis which considered the retirement of Meramec versus adding environmental controls or converting to a natural gas boiler. The comparisons ultimately indicated, under aggressive environmental regulations, it would be better to retire Meramec.

Financial Analysis

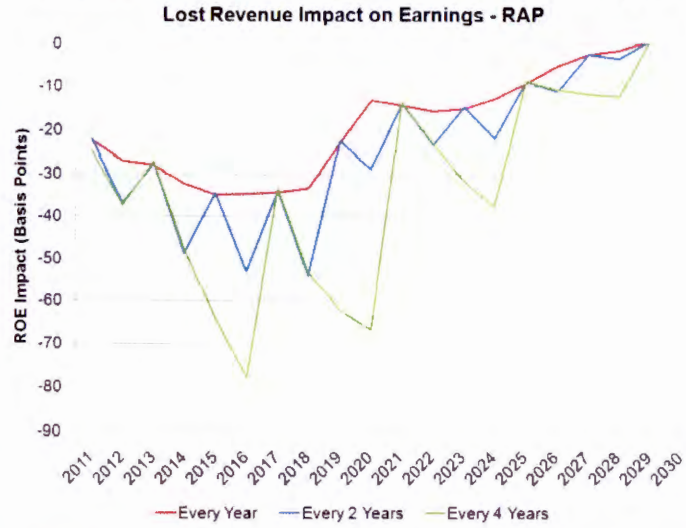
In a perfect world resources and plans can be evaluated assuming perfect ratemaking, unlimited access to capital markets, and perfect knowledge of the future. To accommodate the imperfections of forecasting and general market conditions Ameren Missouri has expanded its analysis to include a more realistic representation of the ratemaking environment and the realities of financial markets. Assuming a rate case every other year and a 6-month lag between the cost period on which rates are set and when they go into effect helps better emulate the financial effects of implementing aggressive energy efficiency programs and large plant capital investments.

The large investment financial analysis indicated compliance with more stringent environmental regulations or construction of large baseload generation assets could strain Ameren Missouri's ability to finance such investments at reasonable rates. It was evident that non-traditional ratemaking treatment may be needed to preserve Ameren Missouri's access to low-cost sources of capital.

The DSM financing analysis highlighted the substantial negative financial impacts to the Company from the implementation of energy efficiency under traditional Missouri regulation. The issue of "Lost Revenue" presents the greatest potential financial impact.

Lost Revenue is revenue the utility is not able to collect, because of reduced sales from energy efficiency gains, between the time energy savings begin to occur and the time customer rates reflect the reduction in sales. Figure 1.10 shows the impact to utility earnings due to lost revenue associated with implementation of the RAP DSM portfolio under varying assumptions for rate case frequency. It will be imperative to Ameren Missouri's DSM expansion plans to properly align utility financial incentives with efforts to help customers use energy more efficiently.

Figure 1.10 Lost Revenue Impact on ROE



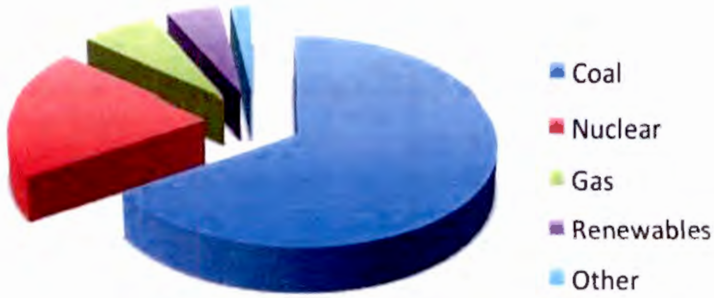
Resource Acquisition Strategy – Preferred Plan and Contingency Options

Considering all the factors that we discussed earlier in this report, a few alternatives rise to the top—from business as usual, to relying heavily on natural gas-fired power, to a combination of natural gas and nuclear energy to a heavy reliance on energy efficiency. Under each of these options, we believe our customers' future energy rates could rise meaningfully from current levels. Here is a summary of our options:

<u>The Preferred Resource Plan</u>

Among the top alternatives, the lowest cost resource plan for our customers under Missouri's current regulatory framework would occur should the environmental regulations for air, ash and water that are in place today remain largely unchanged for the next 20 years. Under this scenario, our current generation portfolio would not change significantly until 2030, when we would add combined cycle natural gas generation to our portfolio. At that time, coal would drop to 66% from its current level of 75%; natural gas would grow to 7% from 1% currently; renewable energy would grow to 5% in compliance with the renewable energy standard in Missouri; and nuclear would remain at about 20%. We would employ a modest program offering incentives to customers to use energy efficiently. Figure 1.11 shows the generation mix for the Preferred Resource Plan.

Figure 1.11 Generation Mix – Preferred Resource Plan



While this is the lowest cost resource plan, it is not likely to be sufficient in light of expected new regulations to be issued by the EPA. As stated previously, we expect those new regulations could be significant and will drive us to consider other resource options in the future. Each of these options will drive customer rates higher to address these new environmental regulations and to meet future customer energy needs. We currently believe the following three options are the best to consider for the future.

The Natural Gas / Nuclear Plan

Under this plan, new environmental regulations in the 2015 to 2020 time frame would cause us to replace Meramec with a combined cycle natural gas plant. As demand continues to grow in the future, those needs would be met with new nuclear generation. With this plan, by 2030 coal's percentage of the total portfolio would drop to 58% with the closing of our oldest coal-fired power plant. Our use of nuclear energy would rise from a current level of 18% to 28%. With the addition of combined cycle units in the 2016 to 2020 timeframe, natural gas-fired generation would grow to around 7%. Figure 1.12 shows the generation mix for the Natural Gas / Nuclear Plan.

Figure 1.12 Generation Mix – Natural Gas / Nuclear Plan

This approach to meeting our future energy needs has several important advantages. First, it would allow us to effectively comply with tougher environmental regulations on a timely basis and better position our future generation portfolio to address more stringent environmental regulations down the road. Second, building a new nuclear plant would create significant jobs and strong economic development opportunities for the state. However, moving forward on a nuclear plant presents construction, financing and operating challenges.

The Natural Gas Only Plan

This plan calls for natural gas to meet the vast majority of our new energy needs. This plan would result in natural gas growing to 12% of the total portfolio, twelve times its current level, while coal-fired generation would drop to 60%. Meramec would be closed between 2016 and 2020, while highly efficient natural gas-fired units were built. The percentage produced by nuclear energy rises slightly to 22% as a result of dispatch changes due to expected future market conditions. Figure 1.13 shows the generation mix for the Natural Gas Only Plan.

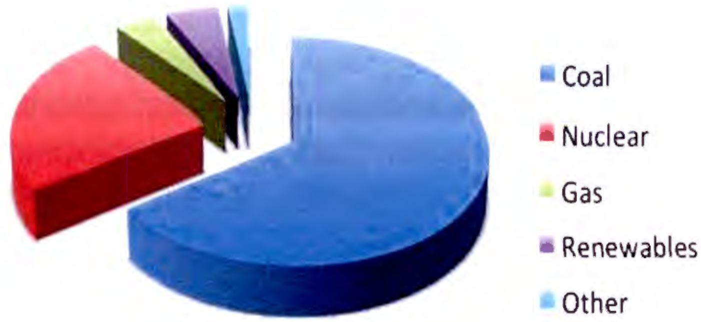
Figure 1.13 Generation Mix – Natural Gas Only Plan

This plan helps us reduce carbon emissions, but natural gas fired plants would still emit half the carbon dioxide of coal-fired units. In addition, as mentioned earlier, natural gas prices have historically been very volatile. Not as many jobs would be created with this option, but construction and operating risks would be lower.

The Energy Efficiency Plan

Under this plan, our future energy needs would be met solely through greater energy efficiency. With this plan, we would aggressively expand our portfolio of energy efficiency programs, with the hope that customers would embrace these programs and realize energy savings. Our oldest coal-fired plant would be retired in the 2016 to 2020 timeframe. This plan calls for nuclear energy's percentage of the total to rise slightly to 24% as a result of dispatch changes due to expected future market conditions. Figure 1.14 shows the generation mix for the Energy Efficiency Plan.

Figure 1.14 Generation Mix – Energy Efficiency Plan



This plan helps us reduce overall emissions with less total generation required. Some jobs would be created as well, through energy efficiency projects completed by our customers at their homes and businesses. The success of this approach depends on a state regulatory framework that encourages utility investment in energy efficiency programs and the willingness of customers to embrace energy efficiency programs and work with us to save energy.

Resource Acquisition Strategy – Decision Roadmap

Each of these plans represents a viable approach that meets our customers' future energy needs and creates different opportunities for our state. Each also has its share of challenges, including cost, construction and financing risks.

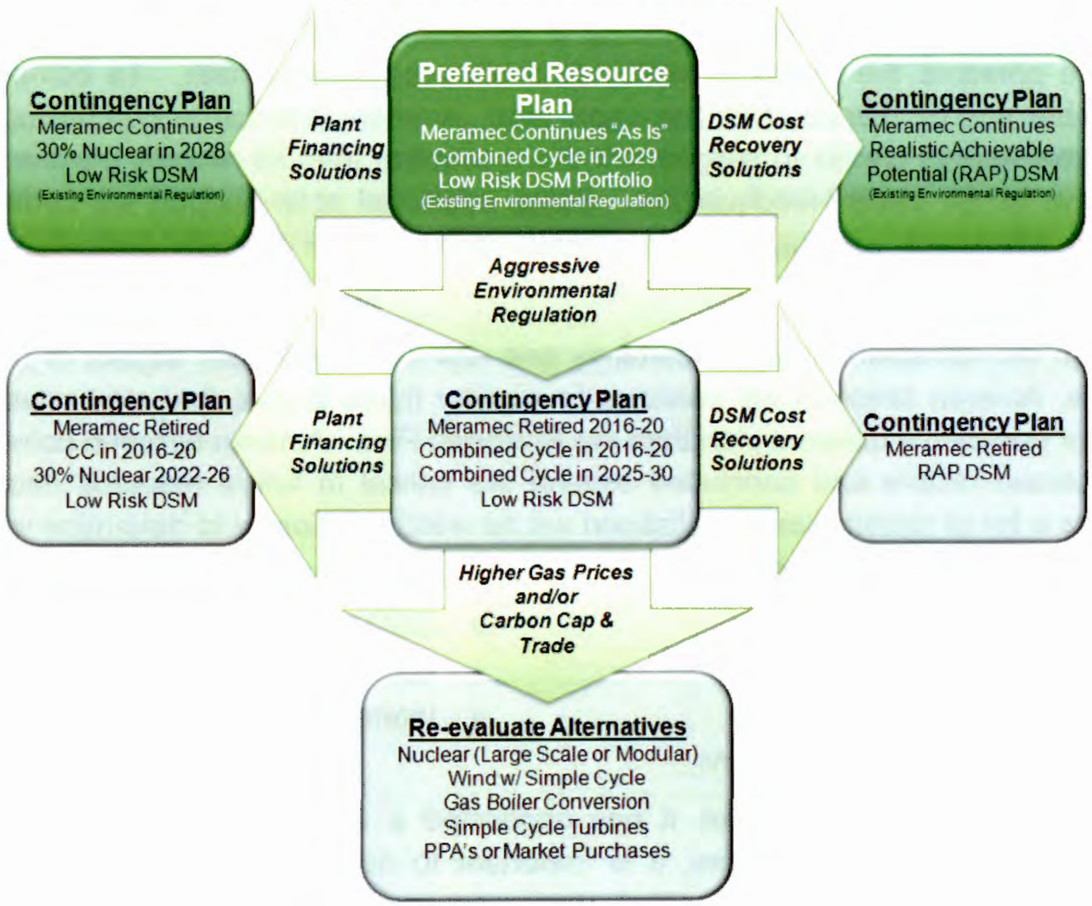
The IRP analysis indicated that retiring Meramec is preferred if future environmental regulations require significant capital investment. Until we have an accurate picture of new regulations and the implications to our existing fleet, Meramec will continue operating without the addition of expensive environmental controls. While both nuclear and aggressive DSM plans are potentially viable alternatives to the natural gas combined cycle plan, both face significant regulatory and financial barriers.

The IRP analysis showed aggressive DSM plans are likely to result in the lowest cost to customers over the planning horizon, so if regulatory barriers to implementation are removed the aggressive DSM plan could become the preferred plan. Although the MAP portfolio was more cost-effective from a TRC perspective, once the additional risk of portfolio energy savings and cost was considered RAP emerged as the dominant DSM portfolio. The significant uncertainty around achieving targeted energy savings levels necessitates that Ameren Missouri preserve viable supply-side resource options and pursue ratemaking options that enable them.

The IRP analysis showed that significant investment in new resources could necessitate the use of alternative ratemaking or financing methods to ensure access to low-cost sources of capital. If alternative ratemaking structures are enabled, then the financial hurdles for those options could be easier to overcome

Figure 1.15 shows Ameren Missouri's Preferred Plan as well as a robust set of contingency options that reflect the alternative paths described above, both with existing environmental regulation and more aggressive environmental regulation. This "Decision Roadmap" highlights the paths that could be taken should regulation change to a degree that causes Ameren Missouri's management to select a different course of action from that represented in the Preferred Plan. Such changes represent seismic shifts in the resource planning landscape that go beyond the capabilities of analyzing uncertainty with ranges and probabilities. However, by considering such important decision factors we can better prepare ourselves to change course when appropriate.

Figure 1.15 Decision Roadmap



Resource Acquisition Strategy - Implementation Plan

Over the next three years Ameren Missouri will be engaging in several activities to implement the Preferred Resource Plan and to keep contingency options open. Although the Preferred Resource Plan does not show the need for a supply-side resource until the latter portion of the planning horizon, the contingency options call for a combined cycle plant as early as 2016 if more stringent environmental regulations result in the retirement of Meramec. Ameren Missouri will start investigating viable sites for combined cycle generation and begin engineering studies in the case environmental regulations become more aggressive and accelerate the need for new resources.

To preserve the nuclear option, Ameren Missouri and a coalition of other utilities will be seeking an Early Site Permit for a second nuclear unit at Ameren Missouri's Callaway site, should appropriate legislation be passed. Furthermore, the cost to continue operations at a plant of Meramec's vintage will impact that retirement decision, so Ameren Missouri will continue to study the ongoing costs to keep Meramec operating safely and reliably.

Ameren Missouri will continue to advocate for better alignment of utility financial incentives to ultimately support the state's goal of achieving all cost-effective DSM. Ameren Missouri will continue pursuing a modest energy efficiency portfolio, which helps to preserve the option to switch to a more aggressive path. To comply with renewable energy mandates in the short term, Ameren Missouri is purchasing solar renewable energy credits to supplement the production from its recently installed solar panels at its St. Louis Headquarters. Some additional solar support will come from Ameren Missouri's existing tariff to procure solar credits through customer-owned generation.

Because the consideration of uncertainty and risk is an important aspect of the IRP process, Ameren Missouri will continue to monitor those factors that may cause it to consider pursuing a different plan than the Preferred Plan. Ameren Missouri considered 22 uncertain factors and concluded several are critical to future resource decisions. Below is a list of factors Ameren Missouri will be watching closely to determine whether changes to its plan are necessary.

- Carbon Policy
- Natural Gas Prices
- Project Costs
- Environmental Regulations
- DSM Impacts and Costs
- Load Growth
- Interest Rates and Financial Metrics

While Ameren Missouri believes it has conducted a thorough analysis of resource needs, options and uncertainties, it is important to note that this IRP represents a snapshot of the Company's expected resources and loads, and provides guidance regarding potential resource needs and acquisitions. Ameren Missouri is continuously planning and adapting to market conditions. In doing so, there will be opportunities for interested parties to engage in discussions on every topic analyzed in this IRP. For that reason the value of the IRP transcends simple compliance with PSC rules and serves as an analytical backdrop to discussions that can shape constructive Missouri energy policies.

2. Planning Scenarios

Highlights

- *Ameren Missouri worked with Charles River Associates to define and model ten planning scenarios.*
- *The planning scenarios are defined by a probability tree which is comprised of three uncertain factors: carbon policy, natural gas prices, and load growth.*
- *The three uncertain factors are dependent in that they have interactive effects. They are also considered to be critical, as different values could sway resource selection.*
- *For each of the three critical dependent uncertain factors, subjective probability distributions were identified by subject matter experts using formal decision analysis techniques.*

Ameren Missouri consulted Charles River Associates (CRA) to help determine the critical factors that should define the planning scenarios, elicit subjective probabilities from Ameren Missouri experts about those variables, and then model those scenarios with their integrated environmental and economic model. Based on prior modeling experience, three interactive variables were chosen to define scenarios and are expected to have the largest impact on future resource choices: carbon policy, natural gas prices, and load growth. Based on the outcomes of the expert interviews, Ameren Missouri adopted 10 scenarios to represent the uncertainty of the three critical variables. CRA modeled each scenario to provide the necessary internally-consistent inputs for further IRP analysis. The load forecasts for Ameren Missouri, as seen in Chapter 3, were developed to be consistent with the same uncertainty expected by internal experts and on which the planning scenarios were based. Chapter 9, Modeling and Risk Analysis, discusses the details of how the scenarios were used to judge the performance of alternative resource plans as well as the results of further sensitivity analysis of additional uncertain factors.

2.1 Scenarios and the Probability Tree

The building and analysis of several "scenarios" of key future market outcomes for national-scale variables is the starting point for the evaluation of resource plans, and the first step of the risk analysis. These scenarios make up a "probability tree," meaning that each scenario has a probability associated with it, and that the scenarios as a group were developed to span a full probable range of relevant market outcomes. The probability tree is developed to describe multiple combinations of critical uncertain factors that have interrelated (or "dependent") impacts on projections of multiple energy and environmental variables. The "critical" variables comprising the probability tree are those for which reasonably likely alternative forecasts could significantly sway the evaluation of candidate resource plans.

For each scenario in the probability tree, Ameren Missouri must have "integrated" sets of forecasts of the "nationally-defined" inputs to IRP calculations of resource plan revenue requirements. In this context, the term "integrated" denotes that all of the individual variable projections for a particular scenario are mutually consistent with one another, which requires a model with the ability to simultaneously simulate interactions in fuel and energy markets, electricity generation system operation, non-electricity sector outcomes, macroeconomic activity levels, and sector-specific responses to emissions limits.

The term "nationally-defined" denotes that the projected outcome is determined by supply and demand events that occur on a scale larger than that of Ameren Missouri or its territory, and would apply to such variables as U.S. electricity demand. Charles River Associates' (CRA's) MRN-NEEM model, a computable general equilibrium representation of the full U.S. economy integrated with a dispatch model of individual electricity generating units, satisfies both of the above criteria. By simulating each scenario as an MRN-NEEM model run, Ameren Missouri can produce integrated, nationally-defined projections of the inputs to the detailed, system-level IRP evaluations.

In the Sensitivity Analysis step of the IRP risk analysis, other uncertain variables are evaluated and the critical independent uncertain factors are identified and then added to the scenario probability tree. As the name implies, independent uncertain factors are those whose impacts on multiple energy and environmental projections are not regarded as interrelated. This topic is discussed in detail in Chapter 9.

2.2 Critical Dependent Uncertain Factors

To determine which variables should comprise the probability tree and to determine the associated probabilities, Ameren Missouri consulted the firm Charles River Associates (CRA) to assist. Although Ameren Missouri developed a list of 22 candidate uncertain factors, as seen in Table 2.1,[1] the relevant variables for this step are those which are subject to a range of uncertainty within which different values might significantly sway the evaluation of

Table 2.11 Candidate Uncertain Factors

Load Growth	DSM Cost
Interest Rates	Off-System Sales
Carbon Policy	Investment Tax Credit
Fuel Prices	Variable O&M
Project Cost	Return on Equity
Project Schedule	Hourly Price Shapes
Purchased Power	Power Price Volatility
Emissions Prices	Nuclear Incentives
Fixed O&M	Wind Capacity Factor
Forced Outage Rate	Solar Capacity Factor
DSM Load Impacts	Transmission Interconnection Costs

[1] 4 CSR 240-22.070(2); 4 CSR 240-22.070(11)(A)2.;

resource plans (i.e., can be critical to the resource plan decision), and that are nationally-defined in scope. Identifying individual variables rather than complex packages of multiple variable outcomes facilitates the expert elicitation process described in the next section of this chapter. The various combinations of these critical, nationally-defined variables, and their associated likelihoods, will form the scenarios represented in the final probability tree. Each of these scenarios will be analyzed as an MRN-NEEM model run, which will produce internally-consistent, integrated projections of key IRP inputs to the standard Ameren Missouri system-level analysis of resource plans.

Following a review of the results and assumptions from previous analysis between Ameren Missouri and CRA, including that performed for Ameren Missouri's 2008 IRP, it was determined that the appropriate variables for probability elicitation were: load growth, carbon policy, and natrual gas prices.

Four other variables were also considered to be potential components of the scenario probability tree[2]. It was determined that the IRP decisions would not be as sensitive to these three variables for the reasons explained below:

- Gross Domestic Product (GDP) – It was determined that uncertainty in this variable would affect IRP outcomes primarily in the way it would affect other critical variables, particularly electricity demand growth and natural gas prices, and thus the IRP-relevant aspects of GDP uncertainty could be folded into the latter two uncertainty representations;
- Lower coal prices – Lower coal commodity prices would tend to be offset by carbon prices under a world with a carbon cap, which we expected would play a high-probability role in the IRP tree. Also, because Ameren Missouri is not modeling new uncontrolled coal as a resource option, the range of uncertainty expected in coal prices is unlikely to substantially affect the choice among the non-coal IRP alternatives;
- Construction costs – Although this variable is expected to influence resource selection it was evaluated as an independent uncertainty in the risk analysis. Construction costs do not have strong interrelated effects compared to the other variables being considered;
- 3-P Emission Prices[3] – Modeling results indicate that, unlike for carbon, wide variations in "3-P" (mercury, SO_2, NO_X) emissions prices have very little impact on IRP-relevant inputs and outputs. The determination to exclude variations in 3-

[2] EO-2007-0409 – Stipulation and Agreement #35; 4 CSR 240-22.070(2)
[3] 4 CSR 240-22.040(8)(D)2.

P policy from the scenario tree was based upon sensitivity analysis conducted for Ameren Missouri's 2008 IRP, in which variations in CAIR and CAMR caps produced insignificant changes to critical IRP drivers. At the time when CRA and Ameren Missouri discussed what variables should be included in the scenario tree both CAIR and CAMR had been remanded, and the form of any replacement legislation was very unclear. For mercury, the political backdrop was gravitating strongly towards a MACT approach and away from cap-and-trade, so the decision was to institute a two-phase mercury reduction requirement (the move to MACT also meant that there was no longer going to be an allowance price for Mercury). However, lacking a specific legislative alternative to CAIR, the CAIR SO_2 and NO_X caps were simulated as originally written. After the MRN-NEEM analysis was completed, the EPA proposed the Clean Air Transport Rule (CATR) to replace CAIR, with more stringent caps. Simultaneously, momentum has gathered behind SO_2 and NO_X MACT requirements triggered by new hazardous air pollutant (HAP) rules. CATR would likely produce higher SO_2 and NO_X allowance prices, but any resulting impacts on critical IRP drivers would not be more influential than the impacts caused by carbon policy, natural gas prices, and load growth. In addition, if CATR were to be paired with MACT requirements for both SO_2 and NO_X, then allowance prices for SO_2 and NO_X might be elevated for one or two years, but would then collapse as all units would be required to add controls thereby making the caps non-binding. Later in the risk analysis Ameren Missouri evaluated more stringent environmental regulations to model the effects on existing plants and the resultant impact on resource needs.

2.3 Assigning Subjective Probabilities

The appropriate individual to assign subjective probabilities is the decision-maker or the person(s) that the decision-maker designates as the best expert(s). Ameren Missouri's management identified several in-house experts to provide the probability distributions for each critical dependent uncertain variable. (Later, senior Ameren Missouri management (the decision-maker) reviewed the resulting subjective probabilities and their basis, and approved them for use in the IRP risk analysis).

CRA structured each probability elicitation session following key principles of sound probability encoding techniques. The process had the following structure.

- First, the purpose of the elicitation process – to minimize natural cognitive biases – was explained, as was the planned use in the IRP of information that would be the subject of the interview. Potential areas of motivational bias were also explored before starting each elicitation. (CRA did not detect any concerns in this regard.)

- Next, the variable to be encoded was defined. The interviewer encouraged the expert to describe events and contingencies that would affect his expectations about the outcome of the uncertain variable. If it became apparent that the expert found that the full uncertainty was too complex to analyze as a whole, the interviewer broke it down into a set of simpler constituent parts, following the structure described by the expert. The formal elicitation was then performed on the various contingent variables. (After the completion of the elicitation, CRA reconstructed the overall probability distribution from the contingent elements and their respective probabilities.)
- Third, the interviewer had the expert identify the specific units for each variable to be encoded, conducted a sequence of "conditioning" questions intended to lessen some common sources of cognitive biases, and used a variety of probability elicitation techniques to obtain quantitative statements that, as a group, described the expert's subjective views on the probability distribution for each variable in question.
- At the conclusion of each interview, CRA showed the expert the produced probability distributions and recapped the experts' general thinking that explained the ranges, areas of likelihood, and contingencies. In each case, CRA verified that these were representative of the expert's beliefs before completing the interview.

There were two experts assigned to each variable. Each was interviewed separately. Such multi-expert elicitations invariably result in different views; indeed, the ability to observe these differences of views is one of the benefits of soliciting information separately from more than one expert. After both had been interviewed, CRA summarized the responses of the two into a comparative format, which was then presented in a conference call to the two individuals together.

Where differences were most pronounced, CRA used the statements from the interviews to highlight what seemed to be the differences in information or perspectives explaining the differences. Discussion of these differences was encouraged, following which the experts were given the opportunity to amend their views in light of the additional discussion. CRA also provided a probability distribution that combined their separate views using equal weights, which could be used in the IRP process, once each expert was fully satisfied with his own individual probability distribution. In this way, CRA developed a single probabilistic statement of potential outcomes for each of the three critical variables that Ameren Missouri's in-house experts agreed was a fair representation of their individual sense of the uncertainty, and the range of opinions across the experts within Ameren. The details and results of those elicitations can be found in Chapter 2 – Appendix A.

2.4 Probability Tree Trimming

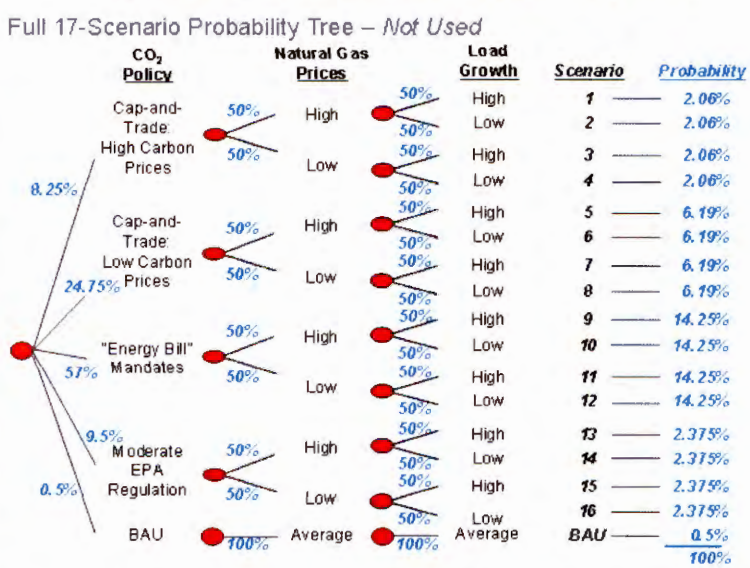
A probability tree is created by combining discretized summaries of multiple uncertain variables. Each individual branch, or case, reflects the expected value for a range of values of a continuous variable, and its probability reflects the cumulative probability associated with that range.

In the context of this analysis, there were three variables chosen for inclusion in the probability tree. This implies that the minimum tree size is 8 scenarios/endpoints; that is, 2 natural gas price branches times 2 load branches times 2 carbon policy branches.

However, the complexity of carbon policy outcomes detailed in the elicitation discussion (see Chapter 2 - Appendix A) implies, at minimum, a 17 scenario tree (and this is only after collapsing the high and low load and gas price cases into average branches for the BAU scenario).

That 17-branch structure is illustrated in Figure 2.1. Half of the scenarios in such a tree would be allocated less than a 2.5% probability: scenarios 1 through 4 each having a 2.06% probability, scenarios 13 through 17 each having a 2.375% probability, and the BAU (Business As Usual) scenario having a 0.5% probability.

Figure 2.41 Untrimmed Probability Tree



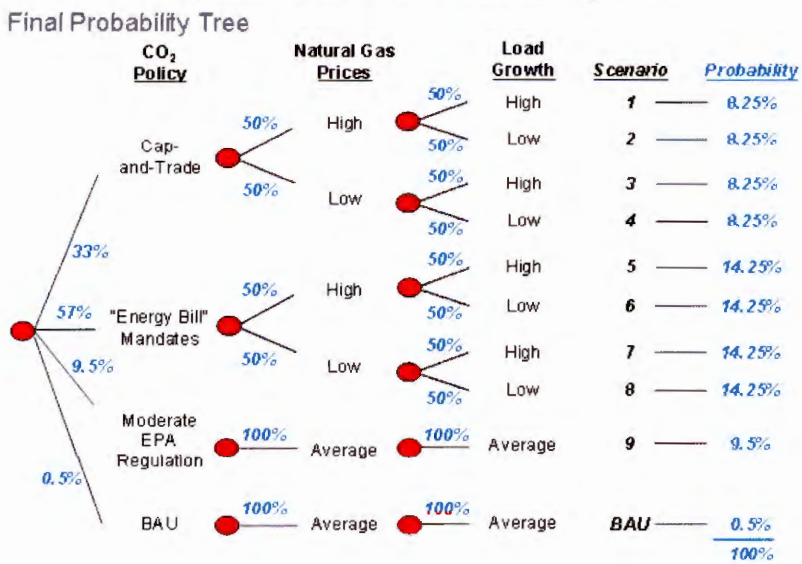
In any IRP, the maximum number of integrated modeling scenarios feasible given time and financial resource limitations must guide how many branches per variable are desirable. It is possible (although not always optimal), to create more branches for some variables (e.g., carbon policy) than for others, depending upon the relative ranges in each expert's CDF (cumulative distribution function), how asymmetric each variable's CDF is, and the sensitivity of each variable on IRP decision criteria (e.g., the present value of revenue requirements). In general, branches with a very small probability should be avoided, except if a low probability outcome range exists that would have exceptionally large impacts on decision criteria outcomes.

In recognition of the modeling resources required of each MRN-NEEM scenario, Ameren Missouri considered the trade-off of decreases in the number of total branches in the tree against the loss in variance that such trimming would imply. The lowest probability branches in the 17-branch tree were a result of having two distinct carbon price pathways. Ameren Missouri decided to collapse these two branches into a single expected value path for carbon price outcomes.

The loss in representation of a wider range in potential carbon price outcomes was deemed acceptable given that it allowed a substantial 23% reduction in tree size (in terms of the number of MRN-NEEM scenarios). The branches associated with Moderate EPA Regulation also represented very small slivers of the overall probability.

All of the different combinations that included EPA regulation were combined into a single branch to create a tree with nine branches and the BAU. Ameren Missouri deemed this a reasonable way to trim the tree as this carbon policy outcome has relatively low probability (9.5%), so the loss in variance by treating it as a single branch in the total tree is small if it is simply analyzed in combination with average natural gas prices and average load growth. The final trimmed probability tree depicted in Figure 2.2 has 10 scenarios, each of which has a balanced share of overall probability.[4]

Figure 2.42 Final Probability Tree



2.5 Scenario Modeling

2.5.1 Top-Down & Bottom-Up Models

CRA[5] uses an integration of two distinct classes of models to simulate the market dynamics of the electricity sector within the broader U.S. economy: (1) a general

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[4] 4 CSR 240-22.070(1); 4 CSR 240-22.070(2); 4 CSR 240-22.070(3); 4 CSR 240-22.070(4)

[5] 4 CSR 240-22.040(8)(D)1.; 4 CSR 240-22.040(8)(A)1.

equilibrium (or top-down) model and (2) an investment and technology decision-based linear programming (or bottom-up) model. These classes of models, in general, are analyzed by employing two distinct modeling paradigms: top-down and bottom-up analysis.

The top-down models are the standard economic framework for analyzing economy-wide policies and are the most commonly used tool for assessing macroeconomic impacts. In this modeling framework, an economy, including production sectors, final household demand, and government taxation and spending, is completely represented, so as to capture economy-wide relationships.

But most importantly, the model is based on rigorous microeconomic theoretical foundations. Under carbon policy scenarios, all agents in the model respond to price changes, including changes in energy prices and products that utilize energy in their manufacture. The inter-linkages within the model enable it to take into account a complete set of feedbacks within the economy.

The top-down models can also be easily expanded to include multiple regions linked by trade. With such flexibilities, top-down models are suitable for simulating a wide variety of policies, such as the impact of energy policies, trade policies, public finance policies, and many other real world policies, to determine who wins and who loses. The MRN model falls under this category.

Bottom-up models, on the other hand, are used to find the choice of least-cost technology that satisfies a portfolio of policy measures. These models involve a detailed characterization of one aspect of the economy. In particular, models of the electricity sector constructed at the unit level with a menu of costs for current and future technologies are often employed to study the impact of environmental policies on this sector. The NEEM model falls under this bottom-up category.

The two approaches are very distinct in both model structure and their representation of the energy-economic system. The top-down model's representation of the economy is complete at a macro-level but lacks detail regarding specific technologies. Specific technologies are best described from an engineering perspective, which general equilibrium models are unable to represent.

In the top-down model, an economic system is represented by production sectors where preferences and technologies are represented by smooth functions. All agents in the model interact to capture economy-wide effects, and are forward-looking, rational optimizers. In contrast, the bottom-up model represents only a portion of the economy (e.g., the energy system or the electricity sector).

The bottom-up model has its limitations but they are compensated by the richness of its technology representation. In addition, bottom-up models like NEEM can encompass each and every generation unit within the electric sector, which adds realism to actual simulation for practical application. Despite these strengths, bottom-up models do not fully represent the economy and fail to account for macroeconomic feedbacks from the rest of the economy. Thus, bottom-up models cannot be used alone for macroeconomic analysis.

The effects of an economy-wide policy such as the proposed CO_2 branches represented in the probability tree ripple through the entire economy, so serious consideration of such a carbon policy requires macroeconomic analysis. At the same time, carbon policy will pointedly affect the electric sector, so the use of a bottom-up model is desirable. Therefore, top-down and bottom-up models have a complementary role to play in policy analysis. If coupled appropriately, they can generate a wide-range of detailed results that are consistent across the two models.

The weakness of the top-down model is well compensated by the strength of the bottom-up model and vice versa. Hence, integrating a top-down and a bottom-up model provides the best of both frameworks. CRA mathematically integrated its two models, MRN and NEEM, into a single MRN-NEEM model to provide a unique and consistent approach for U.S. economy-wide policy analysis.

An overarching difference between the two models is regional detail and definition. Figure 2.3 and Table 2.2 show the relationship between the NEEM and MRN regions. There are 29 U.S. NEEM regions but only 9 MRN regions.

Figure 2.5 Map of MRN-NEEM Regions

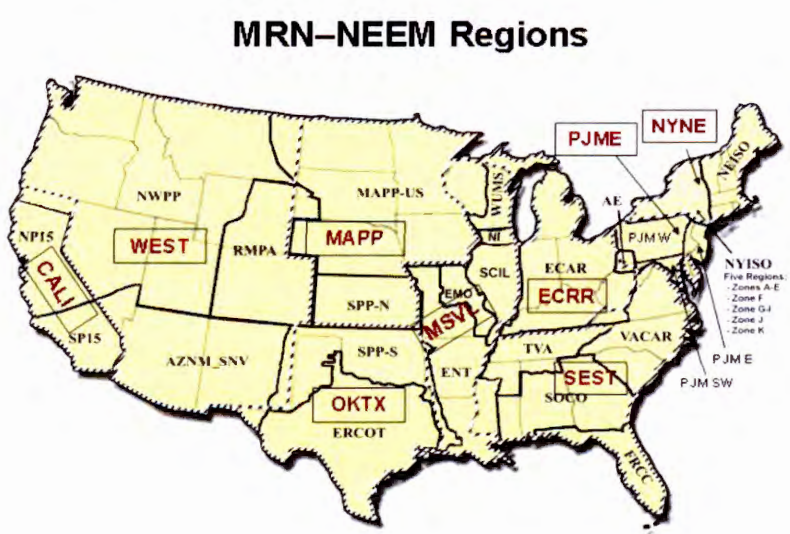


Table 2.5 State Composition of MRN and NEEM Regions

MRN Region	States	NEEM Region
ECRR	MI, IN, OH, KY, WV	ECAR
NYNE	MA, ME, NH, NY, RI, VT, CT	NEISO, 5 NYISO Regions (Upstate, Downstate, Capital, NYC, LIPA)
MAPP	ND, SD, NE, KS, MN, IA	MAPP-US, SPP-N
PJME	PA, MD, DC, NJ, DE	AE, PJM
CALI	CA	NP15, SP15
WEST	WA, OR, AK, HI, ID, MT, NV, UT, CO, WY, AZ, NM	NWPP, RMPA, AZNM_SNV
SEST	MS, AL, TN, GA, SC, VA, NC, FL	SOCO, FRCC, TVA, VACAR
OKTX	TX, OK	SPP-S, ERCOT
MSVL	IL, MO, AR, LA, WI	WUMS, NI, SCIL, EMO, ENT

2.5.2 Top-Down Modeling: MRN Model

MRN (Multi-Region Model) is a top-down, computable general equilibrium (CGE) model of region-specific impacts and regional interaction in the U.S. economy. The CGE tracks every dollar that is spent through the economy (to reduce carbon emissions, for instance), accounting for the economic gains in those sectors that provide the goods and services that result in emissions reductions, as well as the economic costs to those that incur added expenditures. In addition, the negative impacts associated with declining demand under higher, policy-induced prices are captured. The model also accounts for any changes in the distribution of wealth that result from the combined impact of emissions control spending and the disposition of newly created allowances. The results of a model run thus reflect the net impact to the U.S. economy after all the impacts on the winners and losers under a proposed policy have been estimated.

The model also assumes that implementation of a policy such as a carbon emissions cap will occur in a least-cost fashion with fully-functional, competitive product and allowance markets. The only limits imposed on the efficiency of a cap-and-trade market are those that are directly specified in a policy or bill, such as when some sectors are not covered by the proposed cap scheme (even if placed in the offsets category). Leakage of some economic activities outside of the U.S. is also estimated for sectors that face competitors in other countries that do not have their own emissions caps (or have weaker caps).

The model works with perfect foresight of future prices and policy requirements. This means that the model does not include any costs due to uncertainty and "surprises" that will probably also be associated with compliance with a new policy. It also captures only a long-run equilibrium in all of the markets, and thus does not include any of the costs of an overly rapid shift in markets due to the imposition of a new policy.

The CGE model solves for production levels, trade, relative prices, income, and consumption by accounting for technological as well as behavioral responses to changes in policy. The equilibrium is fully dynamic, meaning that investment decisions determine the future capital stock, which in turn determines future income and consumption. Furthermore, decisions to consume or invest are taken with correct expectations about future policy and opportunities (i.e., with perfect foresight). Investment today requires foregoing consumption of current income. Consumer decisions maximize utility inter-temporally, which implies that an optimal financial trade-off is made between consumption today and consumption in the future.

Many of the impacts of policies to reduce carbon emissions indirectly increase the cost of production and consumption, and this has effects on the demand for all commodities. For example, a limit on the quantity of allowable emissions from electric utilities will result in higher electricity prices. Higher electricity prices will then raise production costs throughout the economy, but especially in sectors that use electricity-intensive production processes. As all sectors adjust their production processes to be optimized under post-policy prices, there are changes in demand for labor, materials and commodities, capital, and different types of fuels and primary energy sources. MRN only explicitly models the economy and energy sector in the U.S., but it does also account for foreign imports and exports. Data that characterize the interrelationships of commodity uses within the economy therefore are of primary importance in quantifying the impacts from alternative carbon regulations.

As a starting point for characterizing the inputs and outputs of commodities in the U.S. economy, MRN uses a Social Accounting Matrix (SAM) developed for each state by the Minnesota IMPLAN Group, Inc. (MIG). The IMPLAN database represents the activities in 509 sectors for all 50 states and the District of Columbia. CRA adjusts the original SAM data to be consistent with state level energy data from the U.S. Energy Information Administration (EIA), which are more accurate than the corresponding IMPLAN data with respect to energy flows in the U.S. economy. The SAM that results from the combination of IMPLAN and EIA data exactly matches the intensities of commodity use for the modeled production and consumption sectors for any regional aggregation of states. In addition, the SAM completes the circular flow with an account of factor incomes, household savings, trade, and institutional transfers.

Conceptually, the SAM represents a "snapshot" of the economy at the current point along a dynamic growth path. MRN simulates the dynamic growth path into the future in the absence of major changes to policies that are "on the books" today. This initial growth path is known as the "business-as-usual" case, or BAU. In other words, the initial snapshot is for a single year but the BAU case is a forecast over many years. Calibration of the BAU case from the initial snapshot provided by the SAM is completed by incorporating growth forecasts for industries, population, and carbon emissions.

The regional detail of MRN can be specified at any level of disaggregation down to the state level, depending on the needs of the analysis. Since carbon emissions are highly correlated with energy use, all the important energy sectors contained in the detailed

SAM are represented as individual sectors in MRN. CRA aggregates all of the remaining (non-energy) sectors in the SAM into five groups that capture the diversity in energy-intensity across all economic activities. MRN typically uses the ten production sectors in Table 2.3.

MRN also accounts for household energy uses, as well as all the productive sectors of the economy, so that MRN can correctly account for individuals' responses to higher fuel costs caused by carbon abatement policies. Importantly, personal transportation (i.e., automobile use) is included in the household energy uses, not in the transportation sector listed in Table 2.3.

Table 2.5 MRN's 10 Energy Use Sectors

Energy Sectors	Non-Energy Sectors
Coal extraction	Agriculture
Oil and gas extraction	Energy-intensive sectors
Oil refining distribution	Manufacturing
Gas distribution	Transportation services
Electricity generation	Services

MRN tracks CO_2 emissions from fossil fuel combustion and assumes that the costs of reducing other greenhouse gases are comparable to the cost of reducing carbon dioxide emissions. To incorporate carbon emissions in the model, an emissions permit is tracked for each of the three fossil fuel inputs (refined oil, natural gas, and coal). When there is a carbon cap, a fixed number of emissions allowances is assumed to be available in each modeled year.

If that limit is less than the BAU emissions level, a scarcity of allowances (i.e., when demand for allowances exceeds their supply) will exist. This scarcity increases the price on carbon (starting from zero) up to the point where demand for the allowances is reduced to the limit of their supply. Limiting the number of allowances available imposes an emissions constraint, and the permit price reflects the marginal cost of abatement.

2.5.3 Bottom-Up Modeling: NEEM Model

CRA's stand-alone North American Electricity & Environment Model (NEEM) is a linear programming model that simulates a competitive electricity market for the continental U.S. NEEM minimizes the present value of incremental costs to the electric sector while meeting electricity demand and complying with relevant environmental limits. NEEM was designed specifically to be able to simultaneously model least-cost compliance with all state, regional and national, and seasonal and annual emissions caps for SO_2, NO_X, Hg, and CO_2.

The least-cost outcome is the expected result in a competitive wholesale electricity market. As part of the cost minimization solution, NEEM produces forecasts of short-term and long-term decisions such as coal choices, investments in pollution control equipment, and new capacity additions in a manner that minimizes the total costs to the electric sector.

The model employs detailed unit-level information on all of the generating units in the U.S. and portions of Canada. All coal units larger than 200 MW in summer capacity are represented individually in the model, and other units are aggregated. NEEM models the evolution of the North American power system, taking into account demand growth, available generation, environmental technologies, and both present and future environmental regulations. The North American interconnected power system is modeled as a set of regions (generally NERC regions and NERC sub-regions) that are connected by a network of transmission paths.

Environmental regulations affect decisions about: (1) the mix and timing of new capacity, (2) retirement of existing units, (3) the mix and timing of environmental retrofits at existing facilities, (4) fuel choice, primarily by coal units, (5) dispatch of all units, (6) maintenance scheduling for all units, and (7) the flow of power among regions. NEEM captures all of these impacts in the process of optimizing unit responses to environmental policies. For cap-and-trade policies, NEEM also determines permit banking decisions.

In order to be integrated with MRN, NEEM has been formulated as a quadratic program instead of the linear program structure used in the stand-alone model. It solves for the optimal decisions by maximizing the present value of consumer and producer surplus subject to economic, technical, and policy constraints. The economic constraint is that the supply and demand for electricity be balanced in each region. Technical constraints include operational limits, maintenance requirements, and maximum output. Policy constraints include the required reserve margin and also state and Federal environmental constraints (i.e., emission caps, efficiency standards, and renewable portfolio standards).

The total surplus is equal to the area between the demand and supply curves for electricity. NEEM employs a linear demand curve that is benchmarked to the exogenous forecast of demand and the resulting marginal cost of providing electricity to meet this demand. The electricity supply curve represents the cost of supplying electricity, which includes (1) fixed and variable operating costs for all units, (2) fuel costs, (3) capital investments in new plants and retrofits at new and existing facilities, and (4) the cost of moving power between regions (wheeling charges). To (3) above, because of the long life-span of generating units, capital decisions affect decisions for several years. Therefore, NEEM's model horizon extends past the IRP planning horizon and out to 2050.

On the demand side of the economic constraint, NEEM dispatches to a load duration curve. The load shapes used in NEEM are based upon 2002 actual load profiles from EIA Form 411, and three separate load shapes corresponding to each regional interconnect (Eastern Interconnect, ERCOT, and Western Interconnect) are used. For the eastern interconnect particularly, in which Ameren Missouri falls, the load shape is based upon the load profile for the ECAR region. Comparison of power prices in ECAR and Eastern Missouri, or EMO, (the NEEM region where Ameren Missouri is located) confirms a high correlation between the load profile for the ECAR region and that for the EMO region.

From this point, a load duration curve is created and ultimately inputted into the NEEM data file. The load duration curve first breaks up hourly demand into three seasons: summer, winter, and shoulder. The summer is defined as May through September; the winter as January, February, and December; and the shoulder period as March, April, October and November. Hourly demand in ECAR within each season is then sorted from highest to lowest and placed into load blocks.

For example, as shown in Table 2.4, the 25 hours in load block B11 represent the 25 hours with the highest load in ECAR within the shoulder months. It should be noted that the load blocks have been created to best represent the relative peakiness of energy demand, and, as such, there are fewer hours included in peak demand load blocks and more hours in off-peak demand load blocks. Given this demand structure, NEEM estimates annual regional power prices by load block.

Table 2.5 Load Blocks, Seasons, and Count of Hours

Load Block	Season	Number of Hours
B1	Summer	10
B2	Summer	25
B3	Summer	75
B4	Summer	100
B5	Summer	200
B6	Summer	300
B7	Summer	400
B8	Summer	500
B9	Summer	800
B10	Summer	1,262
B11	Shoulder	25
B12	Shoulder	200
B13	Shoulder	600
B14	Shoulder	900
B15	Shoulder	1,203
B16	Winter	25
B17	Winter	100
B18	Winter	400
B19	Winter	700
B20	Winter	935

Coal units (and other units of interest) are represented in detail as these are most affected by environmental regulation. All but small coal units are modeled at a unit level. All non-coal generating units in the U.S. are also represented in the model, with some level of unit aggregation.

In addition to coal units, NEEM represents the following generation technologies - natural gas combined cycle, natural gas combustion turbine, nuclear, integrated gasification combined cycle (also available with carbon capture and sequestration), hydroelectric, pumped storage hydro, and a range of renewable technologies. Renewable technologies include: wind, solar photovoltaic, solar thermal, landfill gas, biomass, and geothermal.

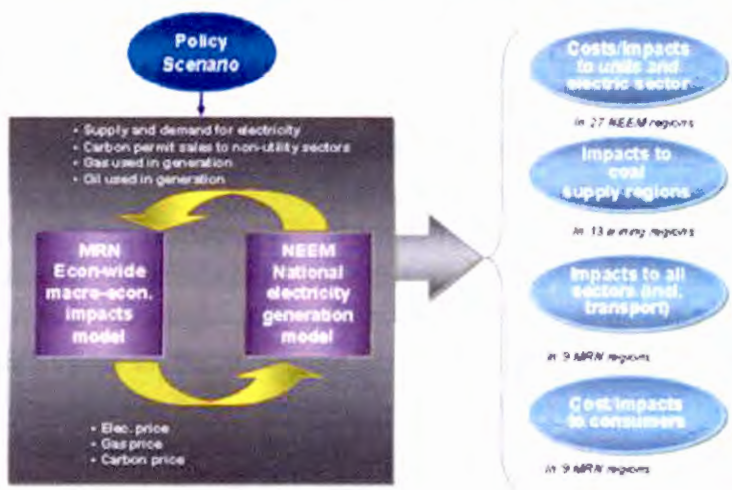
To analyze an environmental policy, NEEM must first be solved for a BAU case in which the policy is not in force. In addition, the BAU case must be consistent in that the exogenously specified demand (i.e., the demand input by the user) matches the demand expected under the set of policies and market conditions assumed in BAU.

From the BAU-case solution, the equilibrium prices that are associated with exogenously specified demands are extracted. These prices along with the exogenously specified demand comprise the benchmark price and quantity points for the electricity demand curve. These electricity demand curves are defined for each region modeled. To solve for the carbon policy, or scenario case, the environmental policy of interest is applied, and the NEEM model is resolved. In the scenario case, electricity demand is no longer fixed and therefore demand is responsive to the environmental policy of interest. The model solves for the optimal set of decisions under the policy.

2.5.4 Integrating MRN with NEEM

As discussed previously, MRN accounts for all sectors except for the electric utility and coal supply sectors. The level of electric sector demand for natural gas, the supply of electricity, and the demand for electricity (all exogenous to MRN) are provided by the NEEM model.

Figure 2.5 Integration of MRN and NEEM



The MRN model is then solved for a new equilibrium and provides NEEM with the supply and price of natural gas, a new electricity demand level and price of electricity, and the non-utility demand and price for coal. If allowing for emissions trading between utility and non-utility sectors, then the MRN model further provides the non-utility carbon allowance demand and price. In short, MRN supplies functions for electricity demand, non-utility coal demand, non-utility carbon allowance demand, and the supply of natural gas. NEEM accepts MRN's outputs as inputs and vice versa, as shown in Figure 2.4. This iterative process continues until convergence in the NEEM and MRN equilibrium price of electricity is achieved.

2.5.5 Natural Gas Price Forecasts[6]

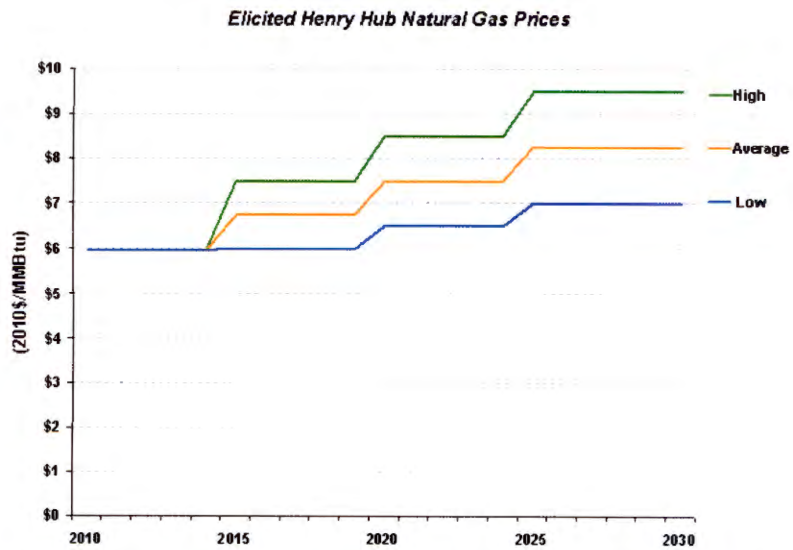
Natural gas prices represent one of the critical, nationally-defined uncertainties encompassed in the probability tree of MRN-NEEM scenarios. During probability encoding sessions conducted by CRA, Ameren Missouri subject matter experts

[6] 4 CSR 240-22.040(8)(A)1-3; 4 CSR 240-22.040(9)(C)

developed two discrete pathways for Henry Hub natural gas prices, allocating 50% probability to each pathway.

Figure 2.5 charts the high and low Henry Hub natural gas price trajectories, along with the average trajectory that arose during the tree trimming process for use with the Moderate EPA Regulation and BAU carbon policy cases.

Figure 2.5 Elicited Henry Hub Natural Gas Prices



There are two key observations to keep in mind. First, these elicited natural gas prices are baseline projections that, per the Ameren Missouri subject matter experts, do not reflect considerations of non-baseline load growth or of carbon policy.

When bundled with particular load growth and carbon policy settings in an MRN-NEEM scenario, these natural gas prices will change. Second, both experts expressed that they would prefer to use NYMEX futures of Henry Hub natural gas prices through 2014, the last year in which this futures market is liquid. It is not until 2015 that the high and low natural gas price trajectories start to diverge. After 2025, the expected value of baseline natural gas prices is the same in each future time period.

These baseline prices are (1) seasonally adjusted based upon historical monthly prices, governed by the month-to-season mapping in Table 2.5, and (2) regionally adjusted based upon June 2009 NYMEX futures of basis differentials from Henry Hub to 25 different U.S. plant gates.

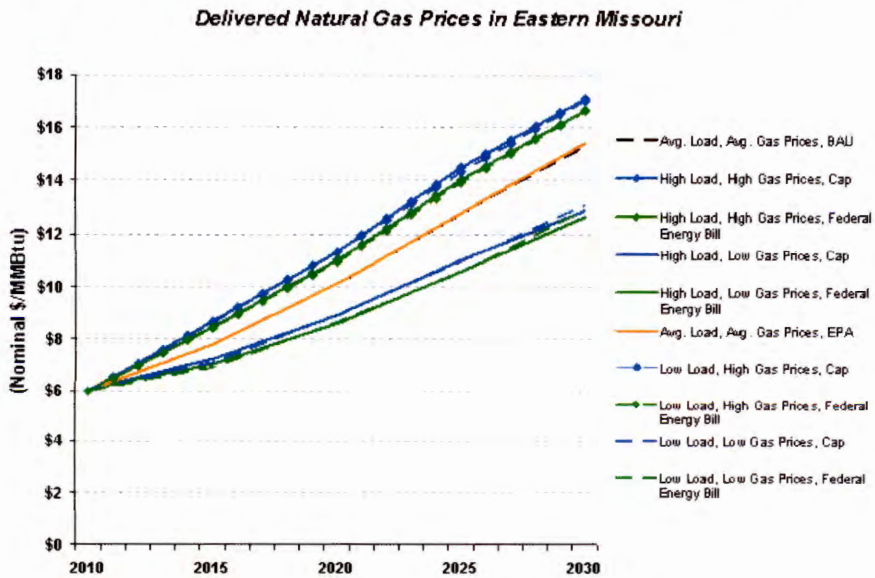
Table 2.5 MRN-NEEM Months to Seasons

Season	Months
Summer	May, June, July, August, September
Winter	January, February, December
Shoulder	March, April, October, November

Each of these regional plant gates are mapped to a contiguous NEEM region, resulting in delivered seasonal natural gas prices in each year for each natural gas-fired unit in the model. Due to higher natural gas demand in residential and commercial heating, the winter months feature higher natural gas prices.

Figure 2.6 presents delivered natural gas prices in Eastern Missouri from each of the 10 modeled MRN-NEEM scenarios. Taking the baseline natural gas prices in Figure 2.5 and the particular load growth and carbon policy parameters as inputs, each MRN-NEEM scenario encompasses the feedback effects throughout the U.S. economy in generating equilibrium natural gas price levels. This is particularly important for a commodity like natural gas, whose consumption profile includes sectors outside of electricity generation.

Figure 2.5 Natural Gas Prices in Eastern Missouri by MRN-NEEM Scenario



In MRN-NEEM, elasticities of production determine supply responses to changes in fuel prices, and higher or lower prices incentivize or discourage exploration and production activities according to these elasticity parameters.

Natural gas price movements most formatively affect levels of natural gas usage because they provide a direct incentive to either ramp down or ramp up consumption. In the electric sector particularly, upswings in delivered natural gas prices can precipitate the switch to other cost-effective generating technologies and away from natural gas, leading to a decline in natural gas consumption.

The profitability and financial condition of producers is a function of the costs of extraction and the prevailing market price for natural gas.[7] Given a baseline natural gas price forecast and any policy prescriptions for CO_2 abatement or otherwise, the MRN NEEM model dynamically models net gains or losses to various production sectors, including oil and natural gas extraction and natural gas distribution. For trade-exposed

[7] 4 CSR 240-22.040(8)(A)1.B.

sectors facing international competitors, MRN-NEEM also simulates the leakage of economic activities outside of the U.S.

It should be noted that the model assumes perfectly functional and competitive commodities markets, and that it plots a least-cost path with perfect foresight of future prices and policy requirements. In only capturing this long term equilibrium, it does not acknowledge the likely costs resulting from abrupt market shifts, such as when electricity generators decisively shift from coal to natural gas or vice versa, that could impact natural gas producers' bottom line.

The MRN-NEEM model accounts for all environmental regulations currently projected through the planning horizon.[8] This includes any restrictions on SO_2, NO_X, and Hg emissions, and any binding RPS requirements throughout the country. Since combustion of natural gas produces significant amounts of CO_2 emissions, Ameren Missouri duly considered the potential for mandatory abatement. The CO_2 policy branches in the probability tree encapsulate what Ameren Missouri deems to be the full range of uncertainty for this variable. Each MRN-NEEM modeling scenario represented in that tree consequently addresses how various CO_2 policies concern natural gas production sectors.

The consumption of natural gas in the U.S. spans sectors characterized by varying degrees of competition, particularly in terms of fuel choice. The electricity generation sector is arguably the most price-elastic, largely due to oil, gas, and coal being relatively substitutable inputs. For instance, persistently high world oil prices, in combination with a smaller world natural gas resource base, leads to higher costs in developing domestic natural gas resources, higher wellhead natural gas prices, and in turn lower natural gas production.

Moreover, higher oil prices could spur greater gas-to-liquids (GTL) production globally, exerting further upward pressure on natural gas prices. In the case of LNG imports, contract prices are often tied directly to crude oil prices. The manifold ripple effects in these illustrative examples demonstrate how interrelated natural gas, coal, and fuel oil prices are. MRN-NEEM is capable of properly accounting for macroeconomic feedback effects between electricity demand, electricity prices, and natural gas, coal, and fuel oil prices and consumption levels.

Sustained high natural gas prices will incite expanded investment in transportation infrastructure.[9] The MRN-NEEM model assumes that enough transmission and distribution (T&D) capacity will be built to accommodate projected growth in natural gas consumption. In turn, MRN-NEEM fixes the regional basis differentials that represent

[8] 4 CSR 240-22.040(8)(A)1.C.

[9] 4 CSR 240-22.040(8)(A)1.D.

the transportation costs from wellhead to end-use location. These regional basis differentials are drawn from June 2009 NYMEX futures at 25 plant gates across the U.S.

Ameren Missouri expects no restrictions on the use of natural gas in electricity generation within the IRP time period.[10] More probable restrictions on electricity generation from other fuel types could influence the pattern of natural gas consumption though. For instance, all of the non-BAU CO_2 policy cases envision a prohibition on new coal-fired plants without CCS. When the existing coal fleet retires, natural gas will move up in the merit order and increasingly serve base load demand.

CRA's MRN-NEEM model has been extensively peer-reviewed by such reputable organizations as the Stanford Energy Modeling Forum, the California Air Resources Board's peer review panel of economists for its analyses of AB32 costs, and (for an earlier version of the model) the International Panel on Climate Change (IPCC).[11] It has been found to represent a best-in-class energy and environmental model capable of producing the integrated projections of key IRP variables, including natural gas prices, essential to sound resource plan selection.

For modeling of resource plans Ameren Missouri used Henry Hub prices from CRA then Ameren Fuels and Services provided appropriate delivery costs for the various pipelines that supply Ameren Missouri natual gas units.

2.5.6 Coal Price Forecasts[12]

Unlike natural gas prices, NEEM actively models the dynamics of coal supply and transportation. As opposed to being an input, prices for each coal type are endogenously calculated within the model based upon the interaction of electric sector demand and annual coal supply curves. This implies that different levels of coal use in different periods lead to different average coal prices. Such an approach ensures internal consistency between allowance prices and coal prices, unlike other models in which coal prices are effectively fixed regardless of the rate of consumption.

Table 2.6 details the 22 different coal types in the NEEM model. These 22 coals were selected to best represent the major coal sub-markets and production regions in the U.S., as presented in Figure 2.7.

[10] 4 CSR 240-22.040(8)(A)1.G.
[11] 4 CSR 240-22.040(8)(A)2.
[12] 4 CSR 240-22.040(9)(C)

Table 2.5 22 Different Coal Types

Coal Type	Rank	SO_2 (lbs/MMBtu)	Hg (lbs/TBtu)	CO_2 (lbs/MMBtu)	Heat Content (Btu/lb)
Northern Appalachia - High Btu, Low Sulfur	Bituminous	2.47	12.31	205.3	12,862
Northern Appalachia - High Btu, High Sulfur	Bituminous	3.95	12.54	205.3	12,900
Northern Appalachia - Low Btu, Low Sulfur	Bituminous	1.72	15.98	205.3	12,097
Northern Appalachia - Low Btu, High Sulfur	Bituminous	3.42	20.87	205.3	11,782
Central Appalachia, Compliance	Bituminous	1.12	5.87	205.3	12,731
Central Appalachia, Non-Compliance - High Btu	Bituminous	1.50	8.24	205.3	12,637
Central Appalachia, Non-Compliance - Low Btu	Bituminous	1.80	9.20	205.3	12,030
Southern Appalachia	Bituminous	1.97	8.73	205.3	12,185
Illinois Basin, High Sulfur	Bituminous	5.20	6.44	205.3	11,395
Illinois Basin, Medium Sulfur	Bituminous	2.80	6.44	205.3	11,395
Illinois Basin, Low Sulfur	Bituminous	1.70	6.44	205.3	11,395
Central Basin	Bituminous	4.82	12.72	205.3	12,077
Lignite	Lignite	2.62	10.80	215.4	6,743
Powder River Basin, Montana	Sub-bituminous	1.19	5.17	212.7	9,043
Powder River Basin, Northern Wyoming	Sub-bituminous	0.89	7.08	212.7	8,380
Powder River Basin, Central Wyoming	Sub-bituminous	0.75	5.42	212.7	8,562
Powder River Basin, Southern Wyoming	Sub-bituminous	0.65	5.76	212.7	8,854
Rocky Mountain, Colorado	Western Bituminous	0.93	3.65	205.3	11,466
Rocky Mountain, Utah	Western Bituminous	1.04	4.14	205.3	11,554
Four Corners	Bituminous	1.44	4.20	205.3	9,666
Import (Columbia)	Bituminous	0.98	5.52	205.3	11,300
Import (Venezuela)	Bituminous	0.98	5.52	205.3	12,750

Characteristics of each coal used by the NEEM model include (1) the rank of coal, (2) SO_2 content (lb/MMBtu), (3) mercury content (lbs/TBtu), and (4) the energy content per pound of coal:

(1) Rank: There are four different ranks of coal within the NEEM coal file. These are bituminous, western bituminous, sub-bituminous, and lignite. These classifications are required because of the specific boiler technology specifications required to burn specific ranks of coal. The model does not allow cost-free switching into sub-bituminous coals, for instance, unless a plant undertakes certain equipment upgrades.

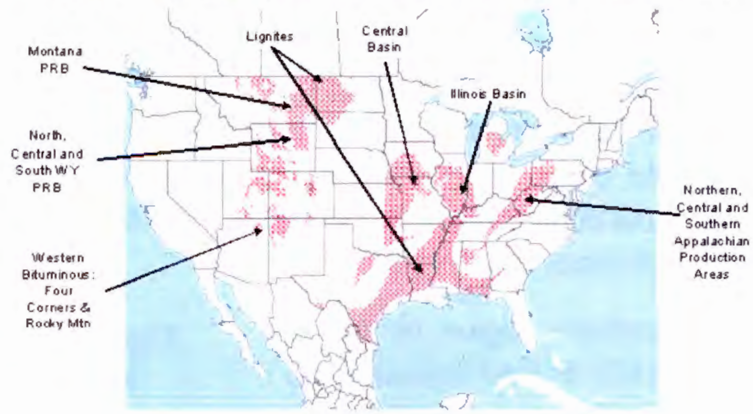
(2) SO_2 content: The SO_2 content is based on information from the Norwest model of the domestic coal supply market.

(3) Mercury content: The source for information on the mercury content of coals is derived from the U.S. EPA's "Information Collection Request for Electric Utility Steam Generating Unit Mercury Emissions Information Collection Effort," or ICR. As part of the ICR effort, coal generators greater than 25 MW were required to

sample the mercury content of their coal shipments in 1999 at least three times each month and submit the information to the U.S. EPA on a quarterly basis. U.S. EPA compiled this information and made it available through its website.

(4) Energy content: The source of the Btu per pound for each coal type is also based on the Norwest model.

Figure 2.5 NEEM Coal Supply Representation



For every mine in the nation, Norwest developed models of both production capabilities and minemouth prices per ton of coal production. Using these data along with supplemental information from the EIA, CRA created step-wise supply curves based on tranches. The number of tranches and the quantity of tons within each tranche vary by coal type and are a function of mine capabilities. These annual supply curves indicate the marginal cost of mining an incremental ton of each coal type in each year of the IRP planning horizon.

Another distinguishing feature of the NEEM model is its exceptional detail of coal electricity generating units. Every existing coal unit with a summer capacity of 200 MW or greater is represented individually in the model, and units under 200 MW are grouped into aggregates of similar size and location. However, both Ameren Missouri coal units under 200 MW in summer capacity, Meramec 1 and Meramec 2, were modeled separately to provide more precise insights regarding the Ameren Missouri coal fleet.

Each coal that can be delivered to a unit has a transportation cost from the mine to the plant gate. CRA represents transportation costs with a set of transportation matrices structured upon four modes of coal transport: barge, truck, rail, and mixed mode (i.e., "trans-load" from rail to barge). The matrices are then populated based on information in the Platts CoalDat database.

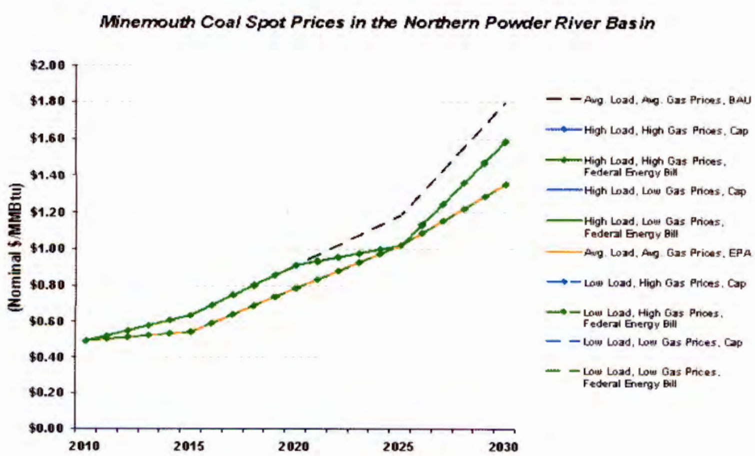
Coal plants that do not have a viable delivery option via one of the modes of transportation have a blank entry in the matrix. If there is a delivery option, then the delivery cost is calculated based on one of the following: (1) the actual transport cost for the plant, (2) the weighted average transport cost for all plants in the region for the particular coal/mode of transportation combination, or (3) a CRA estimate of transport cost based on the plant's distance from the production basin and the cost per ton-mile for that coal.

Starting in 2011, coal delivery costs in all regions except Missouri and Illinois escalate annually at 4% nominal growth rate in order to simulate the increased costs of new rail contracts as existing contracts expire. In Missouri and Illinois, Ameren Missouri projected that transport costs should increase at a much steeper rate, climaxing at 186% and 136% increases, respectively, in 2030.

NEEM's partial equilibrium model provides a set of minemouth prices for each coal type and delivered prices for feasible coals to each plant. At a higher level, this equilibrium is dependent upon the demand for electricity and the demand for coal relative to other fuel types. All other things held constant, greater electricity demand will translate into greater coal consumption, while higher natural gas prices will stimulate demand for coal and thus translate into higher coal prices.

In the northern region of the PRB, the higher load scenarios (represented by the solid lines) induce higher coal consumption and, in turn, minemouth prices as shown in Figure 2.8. Natural gas prices, on the other hand, do not seem to have a significant effect on mine mouth coal prices from the northern PRB. [13]

Figure 2.5 Minemouth Coal Prices Northern Powder River Basin



Section 2.6 of this chapter contains tables by year by scenario of minemouth coal prices for coals typically burned by the Ameren Missouri fleet; that is, the two NEEM coal types from different regions of the Powder River Basin and one NEEM coal from the Illinois Basin.

Given supply curves that determine minemouth coal prices and transportation options that determine delivery prices from mine to plant gate, each NEEM coal unit selects the least-cost fuel from the broad array of options available. For one, NEEM weighs the sulfur and mercury content of each obtainable coal against (1) the environmental controls currently installed or those that could be installed in the future and (2) the prevailing environmental regulations in the region. Two, NEEM compares the energy content per pound across the various coal options.

13 4 CSR 240-22.040(8)(A)3.

As one example, the coals from the various regions in the Powder River Basin range from 8,380 Btu/lb to 9,043 Btu/lb, measured against an energy content of 11,395 Btu/lb for the Illinois Basin coals. Each coal unit with access to both of these supply regions will have to weigh PRB coals' disadvantage in terms of energy content against its significant advantage in terms of lesser SO_2 content.

Especially for units not currently equipped with FGD retrofit technology, switching to PRB coals to reduce SO_2 emissions might represent the most economic decision. This is contingent, however, on the unit's ability to burn sub-bituminous coals like those from the Powder River Basin. For those units without this ability, NEEM does allow for what is called a fuel switch retrofit. This retrofit covers the costs of boiler modifications and coal handling equipment that would likely result from the added capability of burning sub-bituminous fuels. Against this backdrop, and with perfect foresight through the planning horizon, NEEM chooses the fuel strategy that minimizes the net present value of costs to each coal unit in the U.S.

The NEEM model formulates annual supply curves for 22 distinct coal types that represent different regional sources, ranks, and sulfur and mercury contents. These supply curves are based upon detailed information of production capabilities and costs per ton removed at every mine in the U.S. for each year in the planning horizon. As such, they incorporate estimates of domestic recoverable coal resources and baseline trends in exploration and production (E&P) technological improvements. Coal price levels are endogenously calculated to be consistent with the coal consumption levels implied by the supply curves and with allowance prices.[14]

The profitability and financial condition of producers is a function of the costs of extraction and the prevailing minemouth prices for various coal types. The annual coal supply curves for each of the 22 coal types in the NEEM model reflect the extraction costs facing U.S. coal producers, and, in conjunction with the demand for electricity, also determine coal prices. Moreover, the MRN-NEEM modeling framework incorporates the macroeconomic effects stemming from fluctuations in electricity demand, CO_2 prices, and natural gas prices, all of which affect the demand for coal.[15]

Since coal prices are endogenously computed in each model year based upon flexible supply and demand functions that adjust optimally to market conditions, business-as-usual considerations of environmental factors, competition, and regulation on producers are all implicitly acknowledged by the model. Additional policy prescriptions that could

[14] 4 CSR 240-22.040(8)(A)1.A.
[15] 4 CSR 240-22.040(8)(A)1.B.

materially affect coal producers are represented in the probability tree (e.g., the prohibition new coal builds in all non-BAU scenarios).[16]

The matrix of transportation costs described above tabulates the costs of the up to four delivery options (truck, rail, barge, and mixed mode) available to each NEEM coal unit. This matrix is based upon historical data from the Platts CoalDat database. Further, transportation costs increase as described above to replicate what Ameren Missouri judges to be a looming tight rail market as existing contracts expire. From a more general perspective, although the NEEM model does not simulate expansions to the coal transportation network, it assumes that ample infrastructure exists to support the full range of endogenously-determined demand levels.[17]

MRN-NEEM takes for granted any expansions in T&D infrastructure necessary to sustain equilibrium coal demand levels. Depending upon its coverage of the economy, federal CO_2 abatement policies could also penetrate directly into energy intensive coal transport industries, like railroads. MRN-NEEM simulates the increased sector-wide costs that coal rail transporters would incur under such a regime, although these costs are not presently translated into changes in relative costs of delivery for each type of coal considered in the electric sector dispatch decisions. Further, the set of MRN-NEEM modeling scenarios in the probability tree fully spans the range of CO_2 policy uncertainty surrounding the coal transportation and all other energy-intensive sectors.[18]

All of the non-BAU scenarios in the probability tree prohibit the construction of new coal-fired power plants without CCS capabilities. The other features of the carbon policy branches (e.g., the national RES in the Federal Energy Bill cases, CO_2 prices in the Cap-and-Trade cases) represent other government programs that will affect the demand for coal, particularly within the electricity generation sector.[19]

CRA's MRN-NEEM model has been extensively peer-reviewed by such reputable organizations as the Stanford Energy Modeling Forum, the California Air Resources Board's peer review panel of economists for its analyses of AB32 costs, and (for an earlier version of the model) the International Panel on Climate Change (IPCC). It has been found to represent a best-in-class energy and environmental model capable of producing the integrated projections of key IRP variables, including natural gas prices, essential to sound resource plan selection. In addition, Norwest represents one of the

[16] 4 CSR 240-22.040(8)(A)1.C.
[17] 4 CSR 240-22.040(8)(A)1.D.
[18] 4 CSR 240-22.040(8)(A)1.E.
[19] 4 CSR 240-22.040(8)(A)1.G.

world's foremost and most fully-integrated energy and natural resource consultancies, with over thirty years of experience in the American coal industry.[20]

For modeling of resource plans Ameren Missouri used minemouth prices from CRA then Ameren Fuels and Servies provided appropriate delivery costs as seen in table 2.20. Table 2.7 summarizes which coal type is delivered to Ameren Missouri coal plants and a new generic coal unit.

Table 2.5 Coal Types by Plant

	PRB South Wyoming	PRB North Wyoming	IL Basin High Sulfur
Labadie	87%	13%	--
Meramec	65%	35%	--
Rush Island	--	100%	--
Sioux	80%	--	20%
New Unit	100%	--	--

2.5.7 Emissions Price Forecasts[21]

The probable environmental costs related to SO_2, NO_X, Hg, and CO_2 emissions for generic new unit types in the MRN-NEEM model are summarized in Table 2.8.

Table 2.58 Estimated Mitigation Costs for Generic New Capacity

	*Emission Rate (lbs/MWh or TWh)**				*Mitigation Costs ($/MWh)*			
New Unit Type	SO_2	NO_x	Hg	CO_2	SO_2	NO_x	Hg	CO_2
Coal	0.12 - 0.92	0.53	1.61 - 9.23	1,881				
IGCC	0.11 - 0.90	0.61	1.58 - 9.04	1,842				
Coal with CCS	0.13 - 1.01	0.68	1.77 - 10.13	207	***Mitigation Cost = C_t * Emissions Rate, where C_t = Allowance Price per lb***			
CC	-	0.14	-	817				
CT	-	0.87	-	1,265				
Nuclear	-	-	-	-				
Renewables	-	-	-	-				

For coal-based technologies, namely advanced coal, integrated gasification combined cycle (IGCC), and coal with carbon capture and sequestration (coal with CCS), SO_2 and Hg emissions are a function of both the generation/retrofit technology and the type of coal being burned.

CRA's North American Electricity & Environment Model, or NEEM, provides exceptional detail of the U.S. coal sector, with coal supply curves representing 22 distinct coal supply regions and coal types. These coal supply regions are linked to the generation units by a coal transportation matrix with unit-specific transportation costs.

Naturally, each variety of coal differs in the content of SO_2 and Hg per unit of heat input, and the lower and upper bounds for emission rates given in Table 2.5.5 reflects this range (note that the Hg emissions rate is given in lbs/TWh, whereas all other rates are

[20] 4 CSR 240-22.040(8)(A)2.

[21] 4 CSR 240-22.040(8)(D)1-2; 4 CSR 240-22.040(9)(C)

in lbs/MWh). NO_X emission rates, on the other hand, are rather less dependent on the type of coal being used, and are assumed solely determined by generation technology.

NEEM assumes CO_2 emission rates of 205.3 to 215.4 lbs/MMBtu (depending on the type of coal) for coal-based capacity, with CCS technology achieving a 90% reduction in CO_2 emissions. The CO_2 emissions for natural gas-fired combined cycle (CC) and combustion turbine (CT) units are assumed to be 116.7 lbs/MMBtu. NO_X emission rates range from 0.02 lbs/MMBtu (CC) to 0.08 lbs/MMBtu (CT) among emitting new unit types. These rates, in terms of energy input, are then multiplied by the fully loaded heat rate to produce the emission rates of Table 2.5.6, given in terms of the electricity produced.

To clarify, consider the CO_2 emission rate given below for IGCC with CCS capacity. NEEM assumes that this technology captures and sequesters 90% of the 212.7 pounds of CO_2 emitted per unit of energy input. Thus, the rate of CO_2 released into the atmosphere from a coal with CCS generator is 21.27 lbs/MMBtu. NEEM assumes a heat rate of 9.713 MMBtu/MWh for this capacity type. As a result, the emission rate for coal with CCS units is equal to the product of 21.27 lbs/MMBtu and 9.713 MMBtu/MWh, equal to 207 lbs/MWh.

The cost of mitigating the emissions of a particular pollutant is dependent upon the emissions rate and the market price of an emissions allowance, Ct. In the cap-and-trade scenarios, the market price of CO_2 is represented by a simple CO_2 price. Recall that there is no explicit price on CO_2 emissions in the Federal Energy Bill, Moderate EPA Regulation, and BAU branches of the probability tree.

Similarly, this analysis does not simulate the disbanded CAMR cap-and-trade scheme for mercury emissions, and, in turn, does not produce allowance prices for mercury. For SO_2 and NO_X emissions, however, NEEM estimates allowance prices against all existing environmental regulations in fully-functioning allowance price markets. These are:

- Title IV/Clean Air Interstate Rule (CAIR) for SO_2 – Title IV melds into the CAIR SO_2 program beginning in 2010 when units in the CAIR region (including units in Missouri) are required to submit two allowances for every ton emitted. This increases to 2.86 allowances per ton emitted in 2015 and beyond;
- CAIR Ozone Season NO_X – the CAIR Ozone Season NO_X program began in 2009 for much of the Eastern United States including Missouri, with a second, tighter cap scheduled for 2015 – this cap is applicable for the summer months of May through September;

- CAIR Annual NO_X – the CAIR Annual NO_X program began in 2009 for much of the Eastern United States including Missouri, with a second, tighter cap scheduled for 2015.

NEEM dynamically calculates allowance prices for SO_2 and NO_X emissions subject to each of the above constraints. In general, if an emissions cap is binding at any point during the model horizon, the allowance price is equal to the marginal cost of abating one more pound or ton of pollutant.

NEEM allows for banking, so emissions in a given year do not necessarily match the prescribed annual limits of the program, as given in Table 2.9.

Table 2.59 SO_2, NO_X, and Hg Emissions Limits

	SO_2	NO_X	
	Title IV/CAIR	CAIR Ozone	CAIR Annual
Year	Million Tons	Thousand Tons	Million Tons
2010	8.95	568	1.722
2015	8.95	485	1.268
2018	8.95	485	1.268
2020	8.95	485	1.268
2030	8.95	485	1.268

The degree to which the prescribed caps are binding (i.e., the level of emissions), combined with optimal banking choices, sets the equilibrium allowance price. NEEM determines unit-level emissions for SO_2 and NO_X based on unit-specific fuel choices, existing equipment, retrofit choices, and dispatch, the details of which are described below.

SO_2 emissions in NEEM are dynamically calculated over time in response to a number of endogenous factors. Initial data that is used to calculate SO_2 emissions include the quantity and characteristics of the existing coal fleet, particularly the capacity, existing retrofit equipment, and coal types that can be burned at each unit. NEEM models existing federal SO_2 legislation and rules including Title IV and CAIR. These provide a cap on the level of SO_2 emissions.

The model also includes an estimate of the existing bank of SO_2 allowances entering 2009 (approximately 8.8 million tons) and allows for additional banking or withdrawals from the bank in order to comply with the cap in the most cost-efficient manner possible. The emissions from existing coal units will change over time in response to the SO_2 allowance price projected by NEEM and the SO_2 reduction options available to each unit. Units can reduce their SO_2 emissions in a number of ways.

First, units that do not have a flue gas desulfurization (FGD) retrofit may add one. The cost of these retrofits is a function of the size of the unit and the cost parameters included in Table 2.10.

Table 2.5 Retrofit Costs and Characteristics

All costs are in 2010 dollars.	Reference Size	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Removal Rate
FGD	500	$351	$11.53	$2.18	98%
SCR	243	$234	$0.85	$0.77	90%
SNCR	150	$23.44	$0.35	$1.13	35%
ACI90	250	$2.24	$0.90	$0.61	90%
RPJ90	250	$61.55	$1.12	$0.61	90%
CCS (For Coal)	N/A	$1,706	$1.56	$2.76	90%

A unit will add an FGD if the cost of installing the FGD, as measured in dollars per ton of SO_2 removed, is less than the cost of purchasing allowances for that unit over the useful life of the retrofit.

A second option to reduce SO_2 emissions is to change coal types. As shown in Table 2.6, each coal has different SO_2 contents. If a coal can be delivered to the unit then it can switch to burning that coal.

For units that do not currently burn Powder River Basin (PRB) coal, a capital cost would have to be incurred to account for the boiler modifications necessary to burn PRB coals.

Lastly, a unit can reduce its SO_2 emissions by generating less, particularly if SO_2 emissions costs push it higher up the dispatch curve. All new coal units are assumed to include an FGD and therefore have an SO_2 emission rate that reflects 98% removal of inlet SO_2.

NO_X emissions in NEEM are dynamically calculated over time in response to a number of endogenous factors. Unlike SO_2, NEEM includes initial NO_X emission rates for coal, natural gas, and oil-fired plants. This information is based on NO_X rates reported as part of the EPA's Continuous Emissions Monitoring System (CEMS). As previously described, all emitting units are subject to the caps prescribed by the CAIR NO_X Ozone Season and CAIR NO_X Annual programs.

As with SO_2, there are multiple options for reducing NO_X emissions on existing units. Two retrofits are available to coal units: Selective Catalytic Reduction (SCR) or Selective Non-Catalytic Reduction (SNCR). Units will install these retrofits if the cost per ton of NO_X removed is less than the prevailing NO_X allowance price. The costs and characteristics of SCR and SNCR are included in Table 2.10. The other means through which existing unit can reduce NO_X emissions is by simply generating less. New units, in contrast, are assumed to have controls in place necessary to meet New Source Performance Standards (NSPS). As such, new coal units have a NO_X emission rate of 0.06 lbs/MMBtu, new combined cycle units have a NO_X emission rate of 0.02 lbs/MMBtu, and new combustion turbines have a NO_X emission rate of 0.08 lbs/MMBtu.

Similar to SO_2 emissions, Hg emissions are only from coal-fired units. Hg emissions for any coal unit are a function of the coal burned and the pollution control equipment in place. While there are Hg-specific retrofits, Hg can also be removed as a co-benefit from some non-Hg controls such as FGDs and SCRs.

Table 2.5 Mercury (Hg) Co-Benefits

Equipment in Place			% Removal of Inlet Hg		
PM Control	SO_2 Control	NO_X Control	Bituminous	PRB	Lignite
Fabric Filter	Dry FGD	No SCR	85	25	10
		SCR	90	25	10
	Wet FGD	No SCR	85	75	40
		SCR	90	75	40
	No FGD	No SCR	75	65	10
		SCR	75	65	10
Cold-Side ESP	Dry FGD	No SCR	50	15	10
		SCR	85	15	10
	Wet FGD	No SCR	60	35	35
		SCR	85	35	35
	No FGD	No SCR	35	20	10
		SCR	35	20	10
Hot-Side ESP	Dry FGD	No SCR	0	0	0
		SCR	0	0	0
	Wet FGD	No SCR	55	30	30
		SCR	85	30	30
	No FGD	No SCR	20	0	0
		SCR	20	0	0
Venturi Scrubber	Dry FGD	No SCR	25	15	15
		SCR	60	15	15
	Wet FGD	No SCR	25	15	15
		SCR	60	15	15
	No FGD	No SCR	20	5	5
		SCR	20	5	5

The Hg co-benefits given in Table 2.11 were provided to CRA by the Electric Power Research Institute (EPRI), and were used as part of comments filed in response to the then-proposed Clear Air Mercury Rule (CAMR).

An earlier table, Table 2.10, lists the two mercury control options available to coal-fired units in NEEM in order to comply with the 60% and 90% mercury reduction requirements in 2015 and 2020.

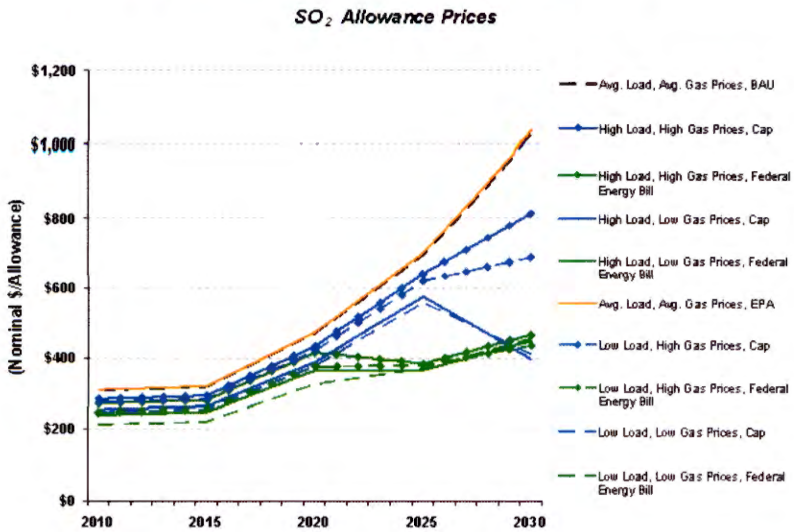
The Activated Carbon Injection (ACI90) technology can only be operated in conjunction with bituminous coal use, and represents a less capital-intensive option for larger units that can rely on existing particulate matter (PM) controls for mercury co-benefits. This ACI90 is only available to units that have already installed a fabric filter. For units without fabric filters, the RPJ90 option is naturally more expensive because it includes the costs of a fabric filter.

With perfect foresight through the end of the modeling horizon, NEEM then optimizes generation patterns, fuel choices and consumption levels, and potential retrofit installations in a manner that minimizes the net present value of total system costs while meeting all reserve margin requirements and complying with all environmental regulations. Allowing for the banking (and subsequent withdrawal) of allowances that could result if permit prices rise faster than the 5% discount rate, NEEM charts an optimal allowance price path through the model horizon.

Again, the resulting allowance price represents the marginal cost of abating one more pound or ton of the pollutant; that is, "Ct," in the equation shown in the column titled "Mitigation Costs" in an earlier table, Table 2.8.

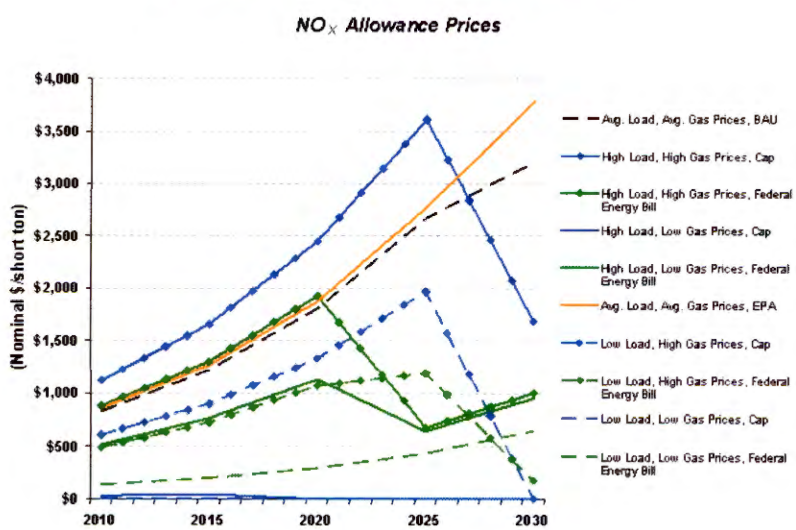
The SO_2 prices for each of the 10 branches in the final probability tree are illustrated in Figure 2.9.

Figure 2.5 SO_2 Allowance Prices



NOx prices for each of the 10 branches in the final probability tree are illustrated in Figure 2.10. For NOx allowance prices, Figure 2.10 presents prices under the CAIR NOx Annual cap.

Figure 2.5 NO_X Allowance Prices



CO_2 permit prices in the cap-and-trade scenarios are shown in Table 2.12.

Table 2.5 CO_2 permit prices

Year	CO2 Price (2010$/metric ton)
2015	$7.50
2020	$17.50
2025	$21.50
2030	$29.25
2035	$37.00
2040	$47.22

Finally, Table 2.13 shows when the SO_2, NO_X, and Hg retrofits are installed on Ameren Missouri coal plants. The year given represents the year when NEEM installs a retrofit on at least half of the unit's capacity.

Table 2.5 SO_2, NO_X, and Mercury Retrofits

Unit	FGD	SCR	ACI90	RPJ90	CCS
Sioux 1	2010			2015	
Sioux 2	2010			2015	
Meramec 1				2015	
Meramec 2				2015	
Meramec 3				2015	
Meramec 4				2015	
Rush Island 1	2020			2015	
Rush Island 2	2020			2015	
Labadie 1	2020			2015	
Labadie 2	2020			2015	
Labadie 3	2020			2015	
Labadie 4	2020			2015	

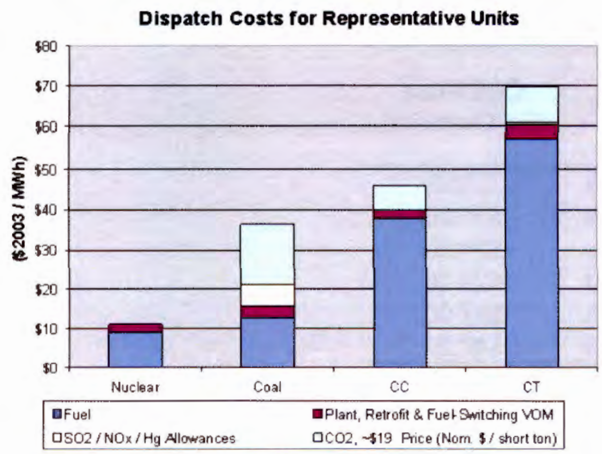
2.5.8 Electricity Price Forecasts[22]

Forecasts of the market cost of power were derived from MRN-NEEM projections of wholesale electricity prices. The integrated MRN-NEEM modeling framework described in subsections 2.5.1 through 2.5.4 furnishes electricity prices by load block and year for the Eastern Missouri (EMO) region encompassing Ameren Missouri's service territory. This equilibrium electricity price represents the marginal cost of supplying an incremental MWh of electricity in a particular region.

It accounts for (1) the dispatch costs of existing resources and potential new additions, (2) planned maintenance and forced outages at generating units in the region, (3) compliance with all environmental regulations, and (4) a dynamic transmission system that allows for imports and exports between regions. Having sorted all available capacity in a NEEM region by dispatch costs, the model then assesses where the so-constructed supply curve intersects with the demand in a given load block. This determines the wholesale electricity price.

[22] 4 CSR 240-22.050(2)

Figure 2.5 Dispatch Costs



The composition of dispatch, or variable, costs for four representative unit types in the NEEM model are shown in Figure 2.11. The relative variable costs of different capacity types determine the merit order of dispatch and, in turn, the shape of the electricity supply curve.

They include fuel costs; plant, retrofit, and fuel-switching variable O&M (VOM) costs; SO_2 and NO_X, allowance costs; and any prevailing CO_2 abatement costs (CO_2 prices and/or CCS transportation and storage costs). The unit types with the lowest variable costs will constitute the bottom of the supply curve and serve base load demand. As given below, nuclear capacity often sits at this point on the curve.

As one moves up the supply curve, the variable costs of dispatch options get progressively higher. Figure 2.11 shows that coal generators generally have lower variable costs than natural gas-fired CC and CT capacity in that order, largely due to differences in fuel costs. However, an aggressive CO_2 policy can transform the merit order of dispatch options, particularly between those fired by coal and natural gas.

Electricity demand is a function of the time of the day and of the season of the year, and these diurnal variations are captured across the model's 20 load blocks. For example, load block B1, which contains the highest demand hours in the summer season, features higher electricity demand than load block B10, which contains the lowest demand hours in the summer. In turn, electricity prices are higher in B1 than in B10.

Demand in typical peak and off-peak load blocks is represented respectively in Figure 2.12 and Figure 2.13 by vertical lines. The intersection of this perfectly inelastic demand curve and the upwards sloping supply curve sets the equilibrium wholesale electricity price, "P*peak" and "P*off peak."

Figure 2.5 Determination of Electricity Prices in a Peak Load Block

Peak Demand

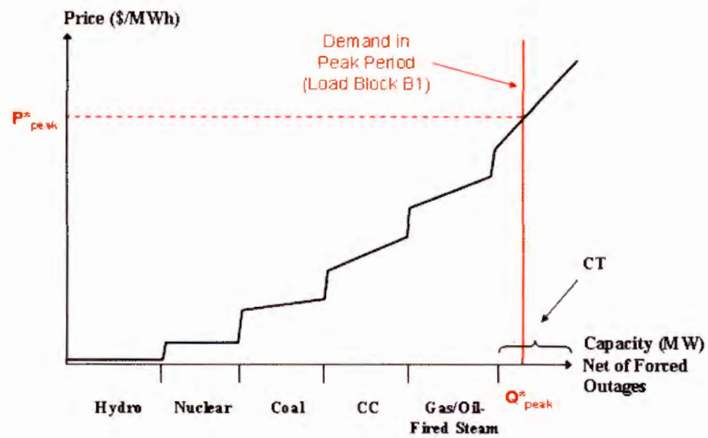
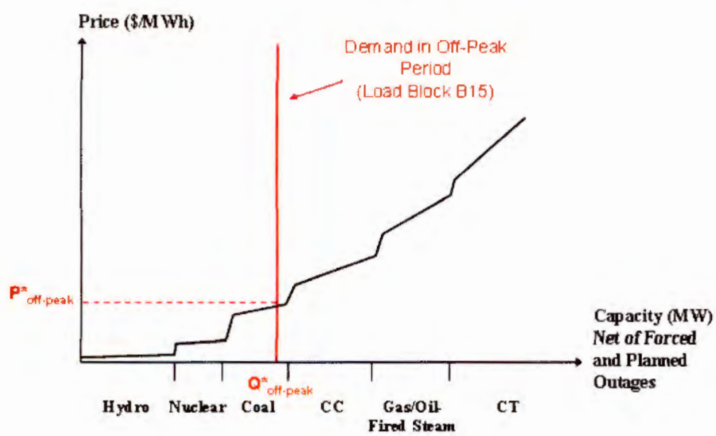


Figure 2.5 Determination of Electricity Prices in an Off-Peak Load Block

Off-Peak Demand



These two graphical depictions delineate the dynamics of electricity pricing in the NEEM model.

- First, demand in an off-peak period is predictably less than demand in an on-peak period, which shifts the inelastic demand curve to the left towards capacity with less expensive dispatch. As such, P*peak is greater than P*off-peak.

- Second, NEEM optimally chooses the shoulder, off-peak load blocks for nuclear and coal capacity to undergo planned maintenance. With less inexpensively dispatched capacity available, the steps in the supply curve corresponding to those unit types shrink. This shortening of the supply curve partially mitigates the difference in off-peak and on-peak prices.

- Third, the supply curve is not a continuous function, and instead is stratified by the unique variable costs of each generation technology. In turn, incremental changes in demand can result in the intersection point jumping from a lower step (e.g., coal) on the curve to a starkly higher step (e.g., gas-fired CC).

In terms of demand changes, MRN-NEEM simulates the macroeconomic feedback loops induced by changes in the cost of energy or electricity. When energy prices increase (as under a carbon policy) more capital and labor (and possibly materials) are substituted for energy in the production of each unit of output. That is, production becomes less energy-intensive relative to the BAU case.

An analogous shift occurs within households, which can involve both the increased adoption of energy-efficient technologies and behavioral changes that result in lower overall (direct) consumption of energy services. As an economy-wide general equilibrium model, MRN is able to capture these phenomena, since it captures all economy-wide relationships, including responses to price changes (in electricity, other energy inputs, and between energy and non-energy goods and services).

The production functions in the model, including those for the energy sectors, the non-energy sectors, and the household sector, capture the impacts of rate changes on electricity demand. When energy prices increase (as under a carbon policy) more capital and labor (and possibly materials) are substituted for energy in the production of each unit of output.That is, production becomes less energy-intensive relative to the BAU case.An analogous shift occurs within households, which require less energy due to the purchase and operation of more capital-intensive (but more energy-efficient) appliances. Households may also simply reduce their demand for energy services in response higher prices. Thus, household demand-response involves both increased adoption of energy-efficient technologies and behavioral changes that result in lower overall (direct) consumption of energy services.

The price elasticity of electricity demand is not a direct input of the MRN model, but is implied. The demand elasticity depends on the elasticity of substitutions (most notably between (1) energy inputs and (2) composite energy inputs with all other inputs) and the value shares of the inputs that characterize the household consumption functions. There is a separate elasticity of substitution for the residential sector and the commercial sectors and this elasticity is time varying.[23]

The model's electricity demand response implies a range of demand elasticity of electricity between -0.14 to -0.17 in the short run (2015) and a range of -0.45 to -0.51 in the long run (2030). The longer-run elasticities are higher, but this is precisely because these are long-run measures – in the long-run capital is more malleable (movement of

[23] 4 CSR 240-22.060(4)(C); 4 CSR 240-22.060(6)(D)

capital is less restrictive) and hence becomes more energy-efficient in response to sustained higher energy prices.

There has been much economic research on the topic of electricity demand responses to changing electricity prices. A primary source for the short-run and long-run elasticities cited above is a 2004 study by James Espey and Molly Espey (Espey 2004). In Espey 2004 the authors analyzed 36 peer-reviewed studies on residential electricity demand, which resulted in 123 estimates of short-run price elasticity and 125 estimates of long-run price elasticity. The short-run elasticity estimates ranged from -2.01 to -0.004 and had a mean of -0.35 and a median of -0.28; the long-run elasticity estimates ranged from -2.25 to -0.04 and had a mean of -0.85 and a median of -0.81.

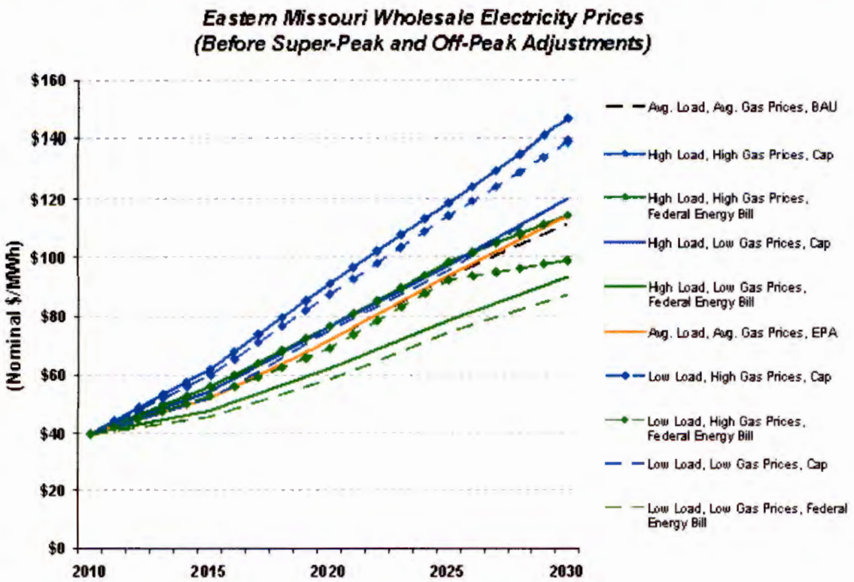
In addition, the U.S. Department of Energy's Energy Information Administration (EIA) released a paper on price responsiveness. The paper describes the price responses of different energy inputs, including electricity, used in the EIA's Annual Energy Outlook. These price responses are based on model simulations in which the price of energy inputs were doubled.

Short-run response (response in the year of a price change and in the two following years) and long-run responses (based on 20 years following sustained price increases) were estimated for residential and commercial electricity consumers. Short-run own-price elasticity for residential electricity demand ranged from -0.20 to -0.34 and long-run own-price elasticity for residential electricity demand was -0.49. For commercial electricity demand, the short-run elasticity ranged from -0.10 to -0.20 and the long-run elasticity was -0.45.

Based on these sources and other work performed by CRA experts, the MRN-NEEM analysis calibrated the utility and production function elasticities of substitution to target a short-run elasticity of -0.20 and a long-run elasticity of -0.80.

Figure 2.14 presents all-hours wholesale electricity prices in Eastern Missouri consistent with the MRN-NEEM methodology described above.

Figure 2.5 Eastern Missouri Wholesale Electricity Prices



The construction of candidate resource plans on a deterministic basis requires the use of a model more local in scope at both the system and regional level. For this phase of the IRP, Ameren Missouri used MIDAS, which is a chronological model in which new build decisions are determined on a year-to-year basis. This model requires electricity prices on an hourly basis for the entirety of the planning horizon. In contrast, the MRN-NEEM model dispatches generators to a load duration curve that aggregates the 8,760 hours in a year into 20 load blocks. Therefore, Ameren Missouri used its own price shaping methodology to estimate hourly power prices using the annual power prices from the MRN-NEEM model.

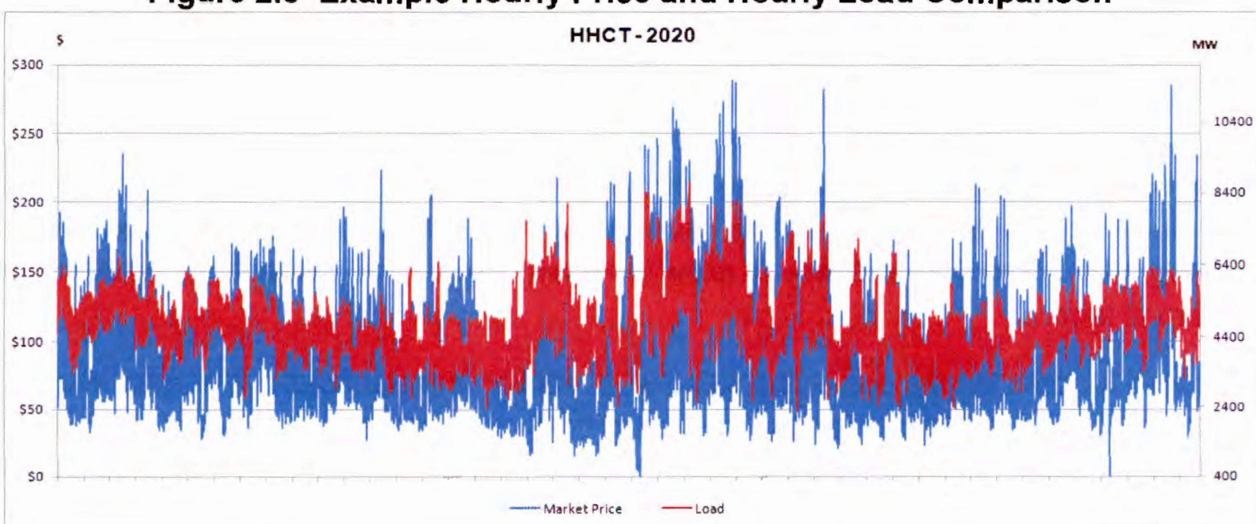
Power Price Shaping

Ameren Missouri obtained the around-the-clock (ATC) prices from CRA as mentioned earlier. However, since the MIDAS model runs on an hourly basis, having only an annual market price or a few blocks for the whole year does not allow the model to dispatch the marginal unit and determine off-system sales/purchases as well as it is capable of doing. Even though it is not possible to predict market prices for each individual hour, it is important to have a reasonable representation. Therefore, Ameren Missouri has decided to use the same methodology it uses in its fuel budgeting models for creating hourly prices.

The first step in creating the hourly price shapes is estimating the monthly price blocks for each year. Ameren Missouri's budget electricity price forecast was used to estimate the 5x16, 7x8, 1x16 Saturday and 1x16 Sunday price blocks for each month. The ratio of 5x16 to ATC, 7x8 to ATC, etc., were estimated using the budget forecast to be applied to the CRA prices. The budget forecast at the time assumed a carbon tax starting in year 2014, while four of the ten CRA scenarios (cap & trade) had a carbon tax starting in 2015, the others did not. Therefore, for the cap & trade scenarios, year 2013 ratios from the budget forecast were repeated in 2014, and then the first year when carbon tax is introduced in the budget forecast (2014) was used for the first year when carbon tax is introduced in the CRA scenarios (2015) and the remaining years of the planning horizon. For the scenarios with no CO_2 price, the ratios from 2013 were used for the remaining years in the planning horizon. Once the price block ratios were determined, they were multiplied by CRA's ATC prices for each year in each scenario.

The next step is estimating the price for each hour that is consistent with the monthly price blocks. For price shaping Ameren Missouri used the 2008 day-ahead prices to maintain a consistent relationship with the hourly loads. The share of each hour in the monthly price block to which it belongs is estimated in the 2008 day-ahead prices and then this ratio is applied to the respective CRA scenario price blocks estimated in the prior step. Once all the hours are estimated, the forecasted load and price shapes are examined to make sure they are consistent. Figure 2.15 shows the resulting price shapes and hourly load forecast for 2020 as an example.

Figure 2.5 Example Hourly Price and Hourly Load Comparison



2.5.9 Nuclear Fuel Price Forecasts[24]

Since CRA's MRN-NEEM model does not fully simulate a competetive nuclear fuel market, Ameren Missouri engaged the Ux Consulting Company (UxC).[25] UxC is a leading firm in the field of nuclear fuel prices, to provide a forecast of nuclear fuel prices for use in this IRP, a role they fulfilled in the 2008 IRP.[26]

[24] 4 CSR 240-22.040(9)(C)

[25] 4 CSR 240-22.040(8)(A)1.

[26] 4 CSR 240-22.040(8)(A)2.

UxC provided annual price forecasts through 2020 for uranium (U3O8), conversion (UF6), enrichment (SWU), and fabrication front-end fuel components. It used the same approaches with each of the components; however, UxC forecasted spot prices for uranium and conversion, while it forecasted base prices for new term contract for enrichment and fabrication.

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. [27]

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.[28] 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 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. Like reactor requirements, the demand for production is growing. In fact, it is growing more quickly than requirements, since the availability of inventory supplies is generally shrinking over time, and HEU feed is earmarked to disappear from the market by 2014. Also, inventory demand is growing, which has the tendency of moving requirements (and demand for production) forward in time.

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 additional supply to the spot market.

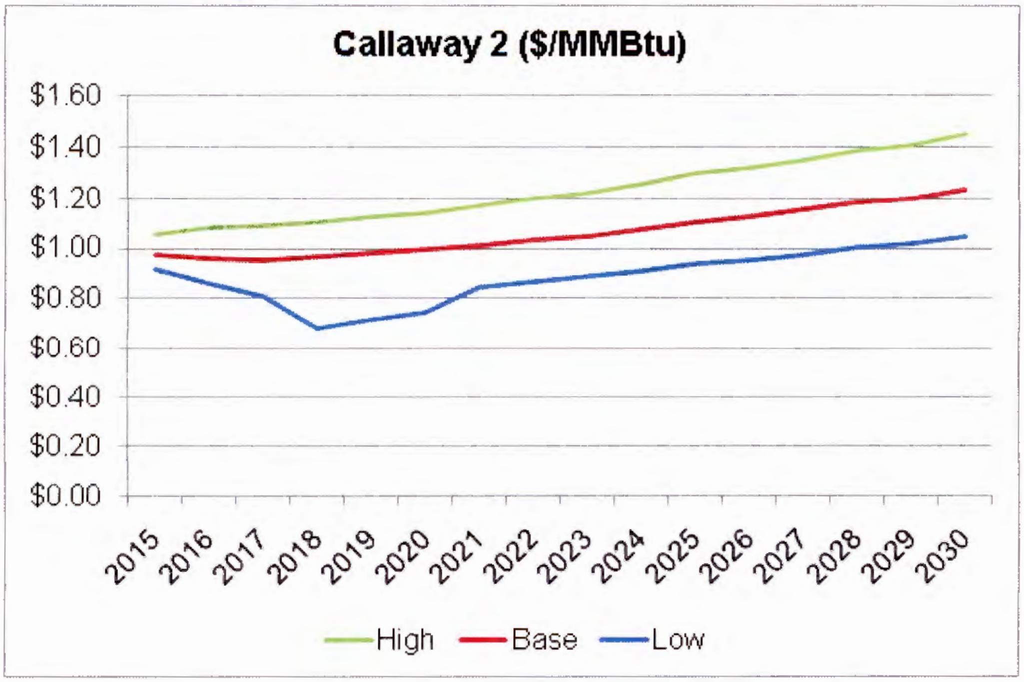
Even more so than the long-term price, the spot price can vary considerably from production costs because it is an inventory-driven price. Ultimately, spot prices are linked to a production-cost based price since an excess/shortage of production causes inventories to rise/fall, and this in turn causes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

[27] 4 CSR 240-22.040(8)(A)1.A.

[28] 4 CSR 240-22.040(8)(A)1.B.

For its uranium, conversion and enrichment forecasts, UxC provides three standard scenario forecasts: High Case, Mid Case and Low Case.[29] With each scenario, specific assumption sets are presented that would lead to the related price case (high, mid or low prices). An annual price range is then provided for each year representing the variance in price movement expected for that year. UxC's standard price forecasts extend through 2020. A mid-point value (simple average price) per year is also provided to aid those customers that need a single price point per year forecast. Table 2.22 contains the forecasts used for modeling both exisitng and new nucler units. Figure 2.16 shows the nuclear price forecasts for a new nuclear unit.

Figure 2.5 Nuclear Fuel Price Forecasts



Each scenario is then assigned an individual probability basis that is related to the likelihood of the associated assumptions. The probabilities for each of the three cases add to 100%, and when each price case is multiplied by its probability and the three cases added together would result in the composite price case. 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. For forecast periods beyond 2020, UxC has suggested using the mid-point price level in 2020 and applying a specific escalation rate that is appropriate with either current market conditions or the client's expectations. At no point in the planning horizon is there expected to be additional restrictions on the use of nuclear fuel for the production of electricity.[30]

[29] 4 CSR 240-22.040(8)(A)3.

[30] 4 CSR 240-22.040(8)(A)1.G.

Nuclear Fuel Cycle

Uranium comes from mined ore and the end product is a powder in a barrel. The next processing step is chemically converting that powder (U3O8) into UF6, a fluorination step. Then the UF6 is enriched in the isotope U235 from 0.711 wt. % in nature to between 4-5%. Due to the same technology used to make nuclear weapons, this sensitive technology is controlled by governments. Then the enriched uranium product (EUP) is sent to the metal fabrication steps were it is transformed into powder, pressed into pellets, and those pellets are inserted into long metal tubes, end plugs are welded on, and those nuclear fuel rods are inserted in a nuclear fuel assembly.

Nuclear fuel is a world-wide market since the relative cost of transportation is very small versus the cost of the enriched uranium. However, in most major international trade, trade barriers can exist from time to time that impede the commercial flow of products and services.[31]

Uranium is the only product, whereas conversion, enrichment, and fabrication are services. There is enough uranium in the world for the conceivable future as ore in the ground. The market supply of uranium and for these other services is more a question of how long it takes for production to expand.

Nuclear fuel cost is made up of uranium, conversion, enrichment and fabrication costs to build a fuel assembly and associated AFUDC prior to heat production. Once the assembly is in heat production, cost accumulation stops, and the cost of the assembly is amortized over the production cycles while it produces energy in the reactor. Additional costs include DOE spent fuel charges.

Uranium

Uranium cost uncertainty dominates the nuclear fuel cost. Actual future prices are difficult to forecast even six months out. Three years out is a very long price forecast. While U3O8 cost of production needs to be under $50/lb. for a new project to proceed, the price can be very much different than production costs due to near term supply and demand in the spot market. There have been some relatively new entrants to the uranium market, uranium metal funds and speculators, which add to demand in rising markets and add more price uncertainty.

World-wide supply vs. demand for uranium is in relative balance from 2007-2013, but there appears to be a large supply gap after that. UxC has all known uranium production, both expansions and new mines in their forecasts. UXC believes the current price is a large motivator to bring on new projects for delivery in that time frame.

[31] 4 CSR 240-22.040(8)(A)1.D.; 4 CSR 240-22.040(8)(A)1.E.

It takes three to ten years to explore for a new large uranium ore body and between five to fifteen years to build a mine to produce U3O8 from ore. So it is difficult to see how the post 2013 supply gap will be filled from the marketplace. For 2011 and 2012, world-wide production expansion is not linked to price since it takes time to get new production online.

Conversion

Conversion is a very small percentage of nuclear fuel costs. The industry is in a short term supply vs. demand balance. The entire industry is subject to a potential major supply disruption if one facility is closed due to acts of god or accidents. Current labor disputes at the Honeywell conversion facility in Metropolis, IL has resulted in the spot price doubling from $6 to $12/kg.

Enrichment[32]

Enrichment prices are historically less volatile than uranium. The UxC forecasted prices should be sufficient to encourage new plants based upon existing centrifuge technology. While uranium and enrichment can be substituted to make EUP, and due to recently high uranium prices, that would assume more enrichment is used and less expensive uranium is used. However, enrichment plants are near capacity world-wide and it takes several years to bring new plants online, centrifuge by centrifuge, and most of that capacity is already sold.

Using Urenco centrifuge technology, the plants that are expanding or new are:

1) Areva current enrichment plant that is replacing its older technology,
2) Urenco's European enrichment plants are expanding,
3) Urenco's National Enrichment facility in New Mexico was recently built and has received its operating permit,
4) Areva's plan for a new enrichment plant in the U.S.

While most of this expansion is sold, additional expansion may become available for sale but it is not expected for deliveries prior to 2015. It is uncertain whether USEC can implement its centrifuge technology and it is also uncertain how long the existing Paducah, Kentucky DOE facility will operate.

There is an existing trade case in the U.S. that effectively limits Russian enrichment to be sold directly into the U.S. The U.S. and Russian governments have agreed to new limit of direct Russian enrichment sales into the U.S. post 2013.[33]

[32] 4 CSR 240-22.040(8)(A)1.F.

[33] 4 CSR 240-22.040(8)(A)1.C.

Fabrication

The fabrication sector tends to be more local and static due to two reasons: 1) governments need to license the fuel design and technology, and 2) there is a high premium placed upon fuel that does not leak so more proven technology and sometimes more local technology is preferred. Fabrication is not a commodity like uranium, conversion, and enrichment. Escalation in contracts is tied to labor, electricity, and industrial commodities.

2.6 Supporting Tables

Table 2.614 SO_2 Allowance Prices (Nominal $/Allowance)

	Avg. Load, Avg. Gas Prices, BAU	High Load, High Gas Prices, Cap	High Load, High Gas Prices, Federal Energy Bill	High Load, Low Gas Prices, Cap	High Load, Low Gas Prices, Federal Energy Bill	Avg. Load, Avg. Gas Prices, EPA	Low Load, High Gas Prices, Cap	Low Load, High Gas Prices, Federal Energy Bill	Low Load, Low Gas Prices, Cap	Low Load, Low Gas Prices, Federal Energy Bill
2010	$306	$283	$271	$254	$238	$309	$274	$245	$246	$212
2011	$308	$285	$273	$255	$239	$311	$275	$247	$248	$213
2012	$310	$287	$275	$257	$241	$313	$277	$248	$249	$215
2013	$312	$289	$277	$259	$243	$315	$279	$250	$251	$216
2014	$315	$291	$278	$261	$244	$318	$281	$252	$253	$218
2015	$317	$292	$280	$262	$246	$320	$283	$253	$255	$219
2016	$347	$321	$307	$288	$270	$350	$310	$278	$279	$240
2017	$377	$349	$334	$313	$293	$381	$337	$302	$303	$261
2018	$408	$377	$361	$338	$317	$412	$364	$326	$328	$282
2019	$438	$405	$388	$363	$340	$442	$392	$351	$352	$303
2020	$469	$433	$415	$388	$364	$473	$419	$375	$377	$324
2021	$513	$474	$408	$426	$364	$518	$459	$376	$413	$333
2022	$558	$516	$402	$463	$364	$564	$499	$376	$449	$343
2023	$603	$557	$396	$500	$365	$609	$539	$377	$485	$352
2024	$648	$599	$390	$537	$365	$654	$579	$378	$521	$361
2025	$693	$640	$384	$575	$365	$700	$620	$379	$557	$370
2026	$760	$675	$400	$539	$382	$767	$633	$390	$528	$387
2027	$826	$710	$416	$503	$398	$834	$647	$401	$498	$403
2028	$893	$744	$432	$467	$414	$901	$661	$412	$469	$420
2029	$959	$779	$448	$431	$431	$968	$674	$423	$439	$437
2030	$1,026	$814	$465	$395	$447	$1,035	$688	$434	$409	$454

Table 2.6 Annual NO_X Allowance Prices (Nominal $/Ton)

	Avg. Load, Avg. Gas Prices, BAU	High Load, High Gas Prices, Cap	High Load, High Gas Prices, Federal Energy Bill	High Load, Low Gas Prices, Cap	High Load, Low Gas Prices, Federal Energy Bill	Avg. Load, Avg. Gas Prices, EPA	Low Load, High Gas Prices, Cap	Low Load, High Gas Prices, Federal Energy Bill	Low Load, Low Gas Prices, Cap	Low Load, Low Gas Prices, Federal Energy Bill
2010	$823	$1,116	$878	$29	$516	$855	$606	$489	$0	$135
2011	$902	$1,224	$962	$32	$565	$937	$664	$536	$0	$148
2012	$981	$1,331	$1,046	$35	$615	$1,019	$722	$583	$0	$161
2013	$1,060	$1,438	$1,131	$38	$664	$1,100	$781	$630	$0	$174
2014	$1,139	$1,545	$1,215	$41	$713	$1,182	$839	$676	$0	$187
2015	$1,218	$1,652	$1,299	$44	$763	$1,264	$897	$723	$0	$200
2016	$1,334	$1,810	$1,423	$35	$836	$1,386	$983	$793	$0	$219
2017	$1,451	$1,969	$1,548	$26	$909	$1,507	$1,069	$862	$0	$238
2018	$1,568	$2,127	$1,673	$17	$982	$1,628	$1,155	$931	$0	$257
2019	$1,685	$2,286	$1,797	$9	$1,056	$1,750	$1,241	$1,001	$0	$276
2020	$1,802	$2,444	$1,922	$0	$1,129	$1,871	$1,327	$1,070	$0	$295
2021	$1,974	$2,678	$1,673	$0	$1,031	$2,050	$1,454	$1,094	$0	$324
2022	$2,147	$2,913	$1,423	$0	$934	$2,230	$1,582	$1,118	$0	$352
2023	$2,320	$3,147	$1,174	$0	$837	$2,409	$1,709	$1,141	$0	$381
2024	$2,493	$3,382	$925	$0	$739	$2,589	$1,836	$1,165	$0	$409
2025	$2,665	$3,616	$675	$0	$642	$2,768	$1,963	$1,188	$0	$437
2026	$2,774	$3,229	$740	$0	$704	$2,973	$1,571	$985	$0	$479
2027	$2,883	$2,841	$805	$0	$765	$3,179	$1,178	$782	$0	$521
2028	$2,991	$2,454	$869	$0	$827	$3,384	$785	$578	$0	$563
2029	$3,100	$2,067	$934	$0	$888	$3,589	$393	$375	$0	$605
2030	$3,209	$1,680	$999	$0	$950	$3,795	$0	$171	$0	$647