4. Thermal Resources

Highlights

- *Ameren Missouri currently owns and operates 9,606 MW of thermal resources: 5,449 MW of coal, 1,190 MW of nuclear, and 2,967 MW of peaking natural gas.*
- *Ameren Missouri, with assistance from Black and Veatch, evaluated 47 coal and gas resource options, five of which were ultimately used in further analysis.*
- *The 1600 MW US EPR from Areva represents the nuclear resource option and was analyzed at 30% and 50% Ameren Missouri ownership levels.*
- *Burns & McDonnell completed a Condition Assessment of the Meramec plant to determine ongoing costs to keep the plant operating safely and reliably through the planning horizon. This analysis facilitates decision making with respect to retirement of the plant.*

Ameren Missouri worked with Black and Veatch to evaluate 47 different coal and gas options. Of those 47, five were evaluated further as part of alternative resource plans, as discussed in Chapter 9. The five coal and gas resources considered to be most promising were: coal with carbon capture, Greenfield combined cycle, Venice conversion to combined cycle, combined cycle retrofit at Meramec, and Greenfield simple cycle.

Ameren Missouri continued to evaluate the 1600 MW US EPR to represent the nuclear resource option and has been following the development of modular reactors. To address financing constraints and provide comparable unit sizes to other supply-side resources, both 30% and 50% ownership levels were considered in the development of alternative resource plans.

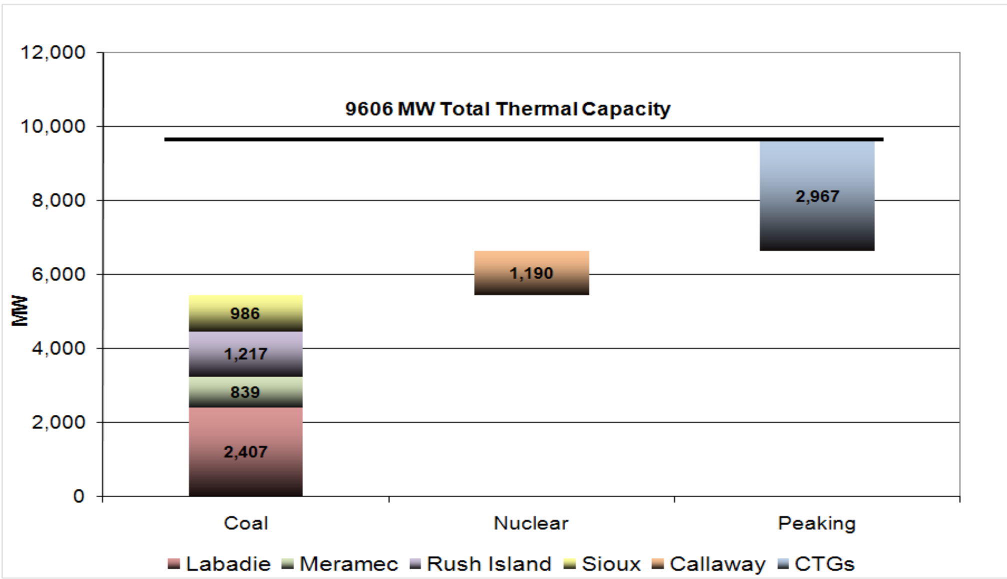
Burns & McDonnell completed a Condition Assessment of the Meramec plant to determine ongoing costs to keep the plant operating safely and reliably through the planning horizon which were included as cost savings in retirement cases. Two Meramec retirement dates, 2015 and 2022, were initially evaluated in the development of alternative resource plans. After the development of two more stringent environmental regulation scenarios, as described in Chapter 8, a retirement date of 2016 was modeled for the final 14 candidate resource plans.

Ameren Missouri has evaluated a range of generation efficiency options as part of a 2009 End-to-End Efficiency Study performed with the assistance of EPRI, which helped identify the most promising projects. Since the analysis was based on generic data, Ameren Missouri will take a closer look at the top projects to determine which ones merit development.

4.1 Existing Thermal Resources

Ameren Missouri owns and operates thermal and hydroelectric power plants to serve the energy needs of its customers. About 96% of generation comes from its coal-fired, nuclear and oil/natural gas-fired power plants. Ameren Missouri continuously evaluates power plant performance and upgrades that are necessary to operate its plants in an efficient, safe and environmentally-friendly way. Figure 4.1 reflects the 2010 summer net capability of Ameren Missouri's existing thermal plants.

Figure 4.1 Existing Thermal Resource Capacity



4.1.1 Existing Coal Resources

Ameren Missouri has four coal-fired plants in its generation fleet. The Labadie, Rush Island, Meramec and Sioux plants have a total summer plant capability of 5,449 MW.

Labadie Plant

Labadie plant is located outside Labadie, MO, on 1,100 acres adjacent to the Missouri River, 35 miles west of downtown St. Louis. The plant consists of four generating units with a summer net capability of 2,407 MW's. The first unit started operating in 1970 and the plant was fully operational in 1973.

Labadie Plant is a national leader in generating electricity cleanly and efficiently:

- The state of Missouri presented Labadie Plant with the Resource Steward Award in 1983 to honor the company's efforts toward "preserving and wisely using Missouri's precious resource" by removing PCBs from our environment. Between

1981 and 1997, Labadie converted more than 4.5 million gallons of PCB-contaminated oil into an estimated 56,000 MWh's of electricity.

- In 1998, Labadie was one of three Ameren Missouri plants to earn the Missouri Governor's Pollution Prevention Award for successfully reducing nitrogen oxide (NO_X) emissions- 50% more than required by Missouri regulations.
- In 2000, Labadie was recognized by the Environmental Protection Agency as the nation's lowest emitter of NO_X.

From 2000 to 2009, Labadie set generation records six out of ten years. Labadie unit 2 Low Pressure (LP) turbine retrofits were among the existing plant upgrades included in the 2008 IRP. The project is scheduled to be completed in 2013, bringing the plant's net summer capability up by 11 MW to 2,418 MW[1].

Rush Island Plant

Rush Island power plant is located 40 miles south of downtown St. Louis, in Jefferson County, Mo., on 500 acres on the western bank of the Mississippi River. The plant has two units with a net summer capability of 1,204 MW (prior to the upgrades discussed below). The first unit started operation in 1976 and the second unit in 1977.

Rush Island LP turbine retrofits were analyzed and passed on in the 2008 IRP. The Rush Island Unit 2 LP turbine retrofit was completed in April 2010, resulting in a 13 MW capacity increase. Unit 1 LP turbine retrofit is scheduled to be completed in 2013, again with a capacity increase of 13 MW[2]. With both upgrades completed, the plant's net summer capability will be 1,230 MW by 2013.

Meramec Plant

Meramec coal-fired plant is located in South St. Louis County on the Mississippi River on 420 acres. The plant began operation in 1953. Net summer capability of the plant, which consists of four units, is 839 MW's. It is the oldest coal plant Ameren Missouri owns. A detailed condition assessment study was performed for Meramec and is discussed in section 4.7.

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[1] 4 CSR 240-22.040(4)
[2] 4 CSR 240-22.040(4)

Warmer river temperatures in the summer months cause an increase in the backpressure on Unit 3 & Unit 4 and, consequently, limit the output of the turbines on both units. To alleviate this problem, a circulating water pump upgrade has been scheduled to be completed before summer of 2011 with $100,000 of capital expenditures in 2010 and $100,000 of O&M in 2011. The modification includes rewinding the current motors to a higher rotational speed on the 3A and 3B circulating water pumps. The increased speed on these circulating water pumps will increase the pumping capacity of both pumps, which will cause more water to be pumped in to the condensers of both Unit 3 and Unit 4 as the 3A, 3B, 4A, & 4B circulating water pumps all feed a common water header that supplies water to both Unit 3 & Unit 4 condensers. The increased water flow through the condensers will allow for improved cooling of the turbine exhaust steam of the Unit 3 & Unit 4 LP turbines, which will result in an improved lower backpressure of the LP turbines on both Unit 3 and Unit 4. The upgrade will increase summer net capacity of Unit 3 and Unit 4 by 5 MW and 10 MW, respectively[3]. The upgrades will bring the total summer net capacity of the plant to 854 MW.

Sioux Plant

Sioux power plant is located in St. Charles County, Mo., 28 miles northeast of downtown St. Louis. It has two units which started operations in 1967 and 1968, respectively, and has a total net summer capability of 986 MW.

Sioux Power Plant accomplished many industry firsts:

- Pioneered slag-removal techniques now used nationwide.
- One of the first to install cyclone furnaces that can burn multiple fuels.
- One of the first to receive coal on the unit train concept.
- Became the first generating plant in Missouri to burn chipped rubber tires to augment coal as an alternate fuel source. Since the program began in 1992, Sioux Plant has burned more than 19 million discarded tires, which would otherwise end up in a landfill, without adversely affecting power plant emissions.

Ameren Missouri has installed scrubbers at its Sioux plant to comply with the federal Clean Air Interstate Rule (CAIR). CAIR requires a major reduction in sulfur dioxide (SO_2) and NO_X emissions on a regional scale by 2015 to help areas in the eastern U.S. achieve healthier air quality. The Sioux scrubbers are capable of removing up to 99%

[3] 4 CSR 240-22.040(4)

of the SO_2 from the boiler flue gas and started operating in October and November, 2010.

4.1.2 Existing Peaking Resources

Ameren Missouri owns and operates oil or natural gas-fired combustion turbine generators (CTG) to provide electricity during times of high demand or when its base load plants are not operating due to a forced outage or scheduled maintenance.

Table 4.1 lists the Ameren Missouri combustion turbines and their 2010 summer net generating capabilities. A MISO deliverability study determined that the Audrain combustion turbines have a transmission constraint which reduces the plant's available output by approximately 30 MW, which is not reflected in Table 4.1. A MISO System Impact Study estimated that transmission system upgrades to regain the 30 MW of Audrain capacity would cost up to $5 million.

Table 4.1 CTG Capability

Plant	Fuel	Net MW
Audrain	Gas	608
Goose Creek	Gas	438
Kirksville	Gas	13
Pinckneyville	Gas	316
Raccoon	Gas	304
Viaduct	Gas	26
Kinmundy	Gas/Oil	208
Meramec CTG	Gas/Oil	112
Peno Creek	Gas/Oil	188
Venice	Gas/Oil	491
Fairgrounds	Oil	55
Howard Bend	Oil	43
Mexico	Oil	55
Moberly	Oil	55
Moreau	Oil	55
Total		2,967

Currently, low power and capacity prices do not warrant an immediate need for Ameren Missouri to remove the transmission constraint. For the purposes of this IRP, the transmission upgrade is expected to occur before the 2020 summer peak.[4]

4.1.3 Existing Nuclear Resource

Callaway plant is located about 100 miles west of St. Louis, Missouri, in Callaway County. The plant started operations in December 1984 and is the only power plant that uses nuclear fuel in Ameren Missouri's generation fleet. It is the second largest power generator on the Ameren Missouri system with a net capability of 1,190 MW, after Labadie coal plant. More than 1,000 Ameren Missouri employees and contractors work at the plant.

[4] EO-2007-0409 – Stipulation and Agreement #15

Ameren Missouri evaluated a 70 MW uprate project during its IRP process[5]. This project was included in the 2008 IRP but was deferred due to budget constraints. The analysis of the project, which is estimated to be $134.6 Million, showed a levelized cost of energy (LCOE) of about 5 cents/kWh. The up-rate is assumed to be completed by 2017, bringing the net plant capability to 1,260 MW.

4.2 New Thermal Resources

4.2.1 Coal and Gas Options

Ameren Missouri engaged Black & Veatch to conduct a supply-side screening analysis of various power generation technologies in support of Ameren Missouri's IRP.

A multistage approach was used to determine the list of options to be characterized in the analysis. The first stage consisted of the development of a "universe" list of potential gas and coal-fueled generation options and a fatal flaw screening. . The universe list was screened to develop an "evaluated" list of options by conducting a high-level fatal flaw analysis, based on Black & Veatch's engineering experience. The universe list and fatal flaw analysis are included in Chapter 4 – Appendix A. Options that did not pass the high-level fatal flaw analysis consisted of those that could not be reasonably developed or implemented by Ameren Missouri.

After the fatal flaw screening, the second stage consisted of a Preliminary Screening. The purpose of the Preliminary Screening was to provide an initial ranking of the evaluated resource options. To support the screening, performance, cost, and operating estimates were developed for each evaluated option, utilizing input from Ameren Missouri and Black & Veatch's internal resources[6]. A scoring methodology was developed with the intent of comparing options within their fuel group. A weighted score was then developed for each option by analyzing the following categories: utility cost, environmental cost, risk reduction, planning flexibility, and operability. Several criteria were established within each category, on the basis of Black & Veatch's experience and considering Ameren Missouri's planning needs. Numerical scores were assigned according to how each option met the criterion. The criteria scores were weighted and summed to obtain a category score. The sum of the category scores resulted in the overall preliminary screening score. The preliminary screening analysis can be found in Chapter 4 – Appendix B. It is important to note that the USCPC and IGCC options with carbon capture did not include any sequestration costs during the screening analysis. Ameren Missouri estimated the sequestration costs per MWh generated using estimates from a Standard and Poor's report[7]. The report estimated CO_2 transportation

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[5] 4 CSR 240-22.040(4)
[6] 4 CSR 240-22.040(8)(B)1; 4 CSR 240-22.040(8)(C)1
[7] http://www2.standardandpoors.com/spf/pdf/events/PwrGeneration.pdf, page 2

cost at $6/ton and storage at $4/ton in 2007 dollars, which equates to a total of $10.61/ton in 2009 dollars using a 3% escalation rate. The sequestration cost per ton ($10.61) was then converted to cost per MWh ($12.45) and was added to the variable cost per MWh in the Midas modeling stage.

From the Preliminary Screening scoring, a limited number of evaluated options were selected as part of the third stage of the analysis. Using the Preliminary Screening scoring results as a guide, Ameren Missouri and Black & Veatch selected 10 candidate options to consider for Ameren Missouri's resource modeling effort. These options are shown in Table 4.2 and are listed by technology type and fuel source.

Table 4.2 Preliminary Candidate Options[8]

Fuel Type	Base Load Technologies
Coal	Greenfield - USCPC
Coal	Greenfield - USCPC w/Carbon Capture
Coal	Greenfield - IGCC
Coal	Greenfield - IGCC w/Carbon Capture
	Intermediate Load Technologies
Gas	Venice - 2-on-1 501F Combined Cycle Conversion
Gas	Greenfield - 2-on-1 501F Combined Cycle
Gas	Meramec - Unit 4 STG in a Combined Cycle Conversion
	Peaking Load Technologies
Gas	Greenfield - Two Siemens 501Fs with SCR
Gas	Mexico - One GE LM6000 SPRINT with SCR
Gas	Raccoon Creek - One GE 7EA with SCR

Once Ameren Missouri completed the screening analysis and started developing Alternative Resource Plans it was evident the number of resource options needed to be reduced because of modeling limitations. As discussed in Chapter 2, Ameren Missouri has assumed that future coal builds will require carbon capture, thus we can eliminate coal resources without carbon capture from further consideration. In addition, it is reasonable to use one coal option to represent coal in the analysis since operating costs and performance for USCPC and IGCC are similar. If the coal option performs well then it may be necessary to do more analysis to determine the best coal technology. Based on the screening analysis, it was concluded that USCPC will be analyzed to represent the coal resource type. Although there are three combined cycle options, each represents a unique configuration – i.e., Greenfield, conversion, or retrofit. Further analysis of the combined cycle options is necessary to help identify which option is best. There is no need to analyze three separate simple cycle options as these

[8] 4 CSR 240-22.040(9)(B)

resources are quite flexible; therefore, the Greenfield option was selected to represent the simple cycle resource option.[9] The final candidate resource options are listed in Table 4.3.

Table 4.3 Final Candidate Options

Technology Description	Load Type	Fuel Type
Greenfield - USCPC w/Carbon Capture	Base	Coal
Venice - 2-on-1 501F Combined Cycle Conversion	Intermediate	Natural gas
Greenfield - 2-on-1 501F Combined Cycle	Intermediate	Natural gas
Meramec - Unit 4 STG in a Combined Cycle Conversion	Intermediate	Natural gas
Greenfield - Two Siemens 501Fs with SCR	Peaking	Natural gas

Alternative resource plans that include Venice combined cycle conversion were modeled by also adding a simple cycle option to replace the capacity converted at Venice so that the total capacity addition in the plan is comparable to the alternative resource plans that include other resource options.

4.2.2 New Nuclear Resource

Ameren Missouri screened twelve different nuclear technologies in its 2008 IRP with consultation from Black & Veatch. After the initial screening, U.S. EPR, ABWR and AP1000 were evaluated in more detail, and U.S. EPR was selected as the choice of nuclear technology and characterized in more detail. For this IRP, Ameren Missouri decided to rely on the results of that study and chose the U.S. EPR to represent the new nuclear resource option.

Although the new nuclear plants in the current global nuclear expansion are large scale reactors employing advanced safety features and enhanced reliability, the United States nuclear industry is considering a different approach by turning away from “bigger is better” toward “smaller is better” reactors. These are often referred to as small modular reactors (SMRs).

Small Modular Reactors

SMR’s have a number of characteristics that illustrate the unique role that they can play in our energy mix: (1) SMR’s are relatively small in power output, from 25 MW to 350 MW, versus large-scale reactors that can have a power output of more than 1,200 MW; and (2) several SMR designs are modular. These two characteristics demonstrate the differences between SMR’s and traditional large-scale reactors. Unlike traditional reactors, SMR’s would be manufactured and assembled at the factory and shipped to the site as nearly complete units, resulting in much lower capital costs and much shorter construction schedules. SMRs also permit greater flexibility through smaller,

[9] 4 CSR 240-22.040(2)(C); 4 CSR 240-22.040(8)(B)2; 4 CSR 240-22.040(8)(C)2; 4 CSR 240-22.040(9)(A)3

incremental additions to baseload electrical generation, and more SMRs can be added and linked together for additional output as needed.

SMR designs and concepts can be grouped into three sets based on design type, licensing and deployment schedule, and maturity of design.

- Light water reactor (LWR) based designs » 10-15 years to commercial availability
- Non-LWR designs » 15-25 years to commercial availability
- Advanced Reactor Technologies » 20-30 years to commercial availability

Of the many contenders in this arena, only two have currently announced their intent to submit an application for design certification with the NRC - the Babcock &Wilcox mPower reactor and the NuScale reactor. Both use Generation III+ light water PWR design and are expected to be submitted for design certification in 2012.

U.S. EPR

The U.S. EPR is a four-loop Pressurized Water Reactor (PWR) with rated thermal power of 4590 MWt, designed by Areva NP. While Areva NP has never built a PWR in the United States, it has extensive experience throughout the world.

Table 4.4 EPR Projects Worldwide

Project	Country	Expected In-Service Date
Olkiluoto 3	Finland	2013
Flamanville 3	France	2014
Taishan 1	China	2013
Taishan 2	China	2015

While the firm's initial expertise was developed while both Siemens and Areva were licensees to Westinghouse Electric Corporation (Westinghouse) in the 1970's and 1980's, their more recent N4, four-loop design was entirely developed in-house.

The U.S. EPR is an evolutionary design with active safety features. The Reactor Coolant System (RCS), loop configuration and main component are similar to currently operating PWRs. The U.S. EPR RCS includes a reactor vessel housing the fuel assemblies, a pressurizer, one Reactor Coolant Pump (RCP) per loop, one Steam Generator (SG) per loop, associated piping and related control and protection systems. This fundamental design is identical to operating PWRs. The RCS is housed within a concrete containment building which is internally lined with steel. The containment building is then enclosed in a Shield Building, with an annular space between the two buildings. The Shield Building is an additional safeguard not found in currently licensed US PWRs.

The plant is designed with four trains of safety systems. These systems are physically separated into four Safeguards Buildings. The Reactor Building, Fuel Building and two of the four Safeguards Buildings are entirely protected against aircraft hazards and external explosions. These levels of redundancy and separation of safety systems are advanced beyond that found in any currently operating US PWR. Each safety train has a dedicated Emergency Diesel Generator (EDG) in the event of loss of off-site power. Two additional diesel generators provide further protection against a simultaneous loss of off-site power and all four EDGs.

The U.S. EPR design philosophy is based upon improving the design of currently operating PWRs in the areas of increased redundancy and separation, reducing core damage frequency, reducing large radioactivity release frequency, mitigating the effects of severe accidents, protecting critical systems from external events, improved man-machine interface and allowing more time for operator actions.

Key U.S. EPR design parameters include the following:

- Design life- 60 years
- Thermal power- 4,590 MW
- Net average electrical power- 1,600 MW
- Efficiency- 36 percent
- Number of fuel assemblies- 241
- Fuel lattice- 17 x 17
- Active Fuel Length- 13.78 ft
- Rods per Assembly- 265
- Refueling Frequency- Up to 24 months

The reactor can use Uranium dioxide enriched in the fissile isotope up to 5% or Uranium and Plutonium mixed oxide[10].

U.S. EPR design certification is currently under U.S. Nuclear Regulatory Commission review with a target date of December 2011 for the final Safety Evaluation Report (SER) to be issued. The overall construction schedule is dependent on site conditions, organization and policies, and local working conditions but the expected contract effective date to commercial operations duration is 70 months, including 6 months of start-up testing[11]. The technology's ability to be licensed and built in a reliable and timely manner is the only constraint of significance[12].

Ameren Missouri analyzed 30% and 50% ownership options on a 1,600 MW unit in this IRP since building a 1,600 MW unit with sole ownership presents a much higher financing risk than Ameren Missouri would be willing to take on given the current economic and financial environment. Also, the size of the new capacity addition with 30% and 50% ownership provides for a more equitable comparison to the other similarly sized resource options modeled in the alternative resource plans, thus avoiding any

[10] 4 CSR 240-22.040(1)(A)
[11] 4 CSR 240-22.040(1)(D)
[12] 4 CSR 240-22.040(1)(J)

advantages/disadvantages due to differences in the size of capacity additions. Moreover, smaller capacity sizes for the nuclear resource option serve as better proxies for possible modular reactors in the future.

Capital Cost

Ameren Missouri conducted a literature search of overnight capital costs including owners' costs. Table 4.5 lists the more recent capital cost per kW estimates from different sources, which include owner's cost but exclude AFUDC.

Table 4.5 Nuclear Overnight Capital Cost[13]

$2009	Connecticut	KCPL	EPRI	B&V	EIA	Lazard	Average
$/kW	4,159	3,792	4,222	3,503	3,520	7,571	4,460

Sources:

- Connecticut- Integrated Resource Plan for Connecticut, January 1, 2008, p.C-4
- KCPL- KCP&L Integrated Resource Plan 2009 Filing, Appendix 4A, p. CRS-97
- EPRI- Program on Technology Innovation: Integrated Generation Technology Options, Dec, 2008, p. 1-12
- B&V- Black & Veatch Market Analysis (2007), National Renewable Energy Laboratory, "Technology Cost and Performance Study", www.**nrel**.gov/analysis/docs/re_**costs**_20090806.xls
- EIA- Assumptions to the Annual Energy Outlook 2009, p. 89
- Lazard- Levelized Cost of Energy Analysis- Version 3.0, June 2009, p. 9

Ameren Missouri chose to use EPRI's capital cost for the nuclear option, which was closest to the average of all cost estimates; therefore bringing the total capital cost of a new 1,600 MW nuclear option to $6.755 Billion.

Scheduled Outage

The refueling cycle requirements control the scheduled routine and maintenance outages for nuclear units. Current enrichment limits of 5 percent prevent fuel cycle lengths longer than 24 months. Ameren Missouri assumed an 18 month refueling schedule; scheduled maintenance would occur in a 24 day period (3.43 weeks) every 18 months. However, for modeling purposes, this was translated into an annual maintenance schedule that equates to 2.29 weeks every year.

Forced Outage Rate and Availability

Based on an expected forced outage rate of 2.0% and scheduled maintenance 24 days every 18 months, annual availability is estimated to be at 94%.[14] Characterization of the

[13] 4 CSR 240-22.040(1)(E)
[14] 4 CSR 240-22.040(1)(H); 4 CSR 240-22.040(1)(I)

technology included three possible forced outage rates and the probabilities around those- the expected FOR 2% with 70% probability, FOR of 3% with 20% probability and FOR of 4% with 10% probability. The probability weighted average FOR, which is 2.4%, was used in Midas modeling.

Waste Generation

In the previous IRP, intermediate and low-level waste volume for U.S. EPR was estimated to be 2,080 m^3.[15]

Water Impacts

In the 2008 IRP, water impacts were evaluated through thermal efficiency, which was estimated to be 36% for the U.S. EPR. Consumptive use of water is primarily attributable to evaporation losses from the natural draft cooling towers. The U.S. EPR will utilize two natural-draft cooling towers with evaporative losses of approximately 22,000 gpm. Blowdown from the new cooling towers will be approximately 5,500 gpm each, or a total of 11,000 gpm. The unit will consume a total of approximately 27,600 gpm including estimated cooling tower drift. In comparison to average annual flow of the Missouri River over 60 years, such losses are estimated to require less than 0.1 percent of river flow. The water resources so committed for plant operation will have no effect on other users downstream from the plant[16].

4.3 Transmission Interconnection[17]

A detailed transmission study at this stage of the planning process was not in Black & Veatch's scope of work, so Black & Veatch made a generic assumption that transmission costs make up 50% of owner's costs. Ameren Missouri sought to include somewhat more specific interconnection costs, and its Transmission Planning Department developed interconnection cost estimates for the candidate resource options based on limited site information and general configuration assumptions[18]. The assumptions and associated cost estimates are summarized in Table 4.6.

[15] 4 CSR 240-22.040(1)(K)2
[16] 4 CSR 240-22.040(1)(K)3
[17] 4 CSR 240-22.040(3); 4 CSR 240-22.040(6)
[18] EO-2007-0409 – Stipulation and Agreement #15, the Callaway 2 interconnection study has been withdrawn from the MISO study queue

Table 4.6 Candidate Option Transmission Cost Estimates

Highly Confidential

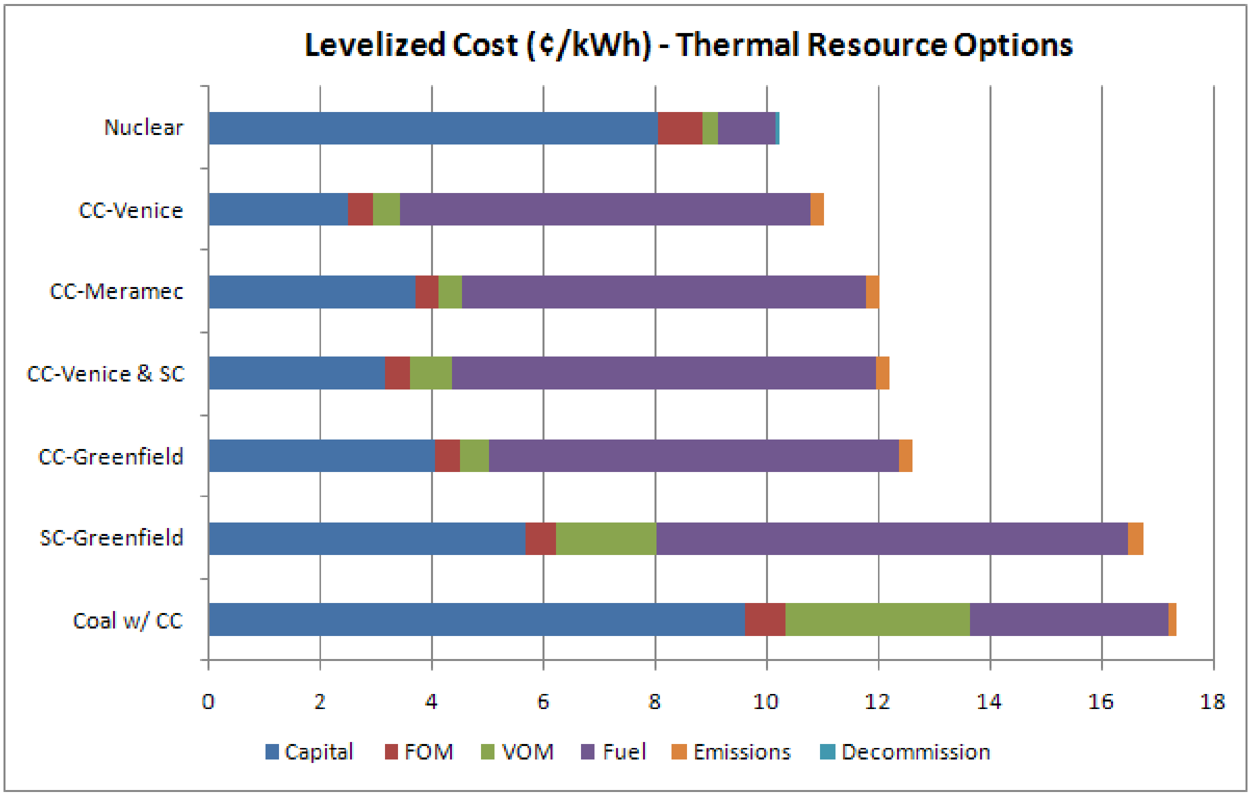
Using the interconnection costs in Table 4.6, owner's cost and the total project cost excluding AFUDC were adjusted for all resource options other than nuclear. Since 50% of owner's cost was assumed to be transmission cost in Black and Veatch numbers, half of owner's cost was subtracted and replaced with the revised transmission costs, resulting in the following owner's costs and total project cost excluding AFUDC as listed in Table 4.7.

Table 4.7 Revised Owner's and Total Project Costs

Highly Confidential

Levelized cost of energy after adjustments were calculated for the final thermal resource options using the probability-weighted average of inputs from the ten scenarios developed and discussed in Chapter 2. The results are shown in Figure 4.2. The LCOE for Venice combined cycle conversion is estimated by itself and also with the addition of a simple cycle option as it was modeled in the alternative resource plans to have a total capacity addition that is comparable to the other resource options.

Figure 4.2 LCOE for Final Candidate Options[19]



4.4 Meramec Retirement

Ameren Missouri retained the services of Burns & McDonnell to complete a Condition Assessment of the Generation Assets at the Meramec Plant and provide relevant information to adequately support a retirement analysis as part of the IRP. The study provided recommendations for future capital projects and ongoing O&M activities in order to maintain a safe and reliably operating plant under three separate scenarios: 1) Continue operation of all units through 2021, 2) Continue operation of all units through 2025 and 3) Continue operation of all units through 2041.

Additional Retirement Dates

In its IRP modeling, Ameren Missouri included 2022 and 2042 retirement cases as well as a 2015 retirement case in the integration analysis. In the risk analysis, due to uncertainties around environmental regulations, a new retirement date of 2016 (the Plant continues operations through 2015) was introduced. Since the 2015 and 2016 retirements were not covered in the Burns & McDonnell study, Corporate Planning estimated related capital expenditures and O&M costs using the data provided in the study.

[19] 4 CSR 240-22.040(2)(C)

The capital expenditure and O&M data for the last few years of the 2022 retirement were de-escalated to coincide with the last few years of the 2015 and 2016 retirement cases. The 2042 retirement case is beyond the planning horizon; therefore, it was considered to be the 'no retirement' base assumption and was assumed to be implicitly included in the long-range capital and O&M costs. The differences between the CAPEX and O&M costs from the 'no retirement' case were entered into the Midas model as cost savings associated with retirement cases.

Capital Expenditures

Burns & McDonnell obtained a record of previous capital projects and the then current 2009 capital and O&M forecast, and all of the planned capital work in the subsequent five years was added to the Master List. Only projects valued above $100,000 were included for comparison against the plant's current assets. The O&M forecast was captured to assess the annual spend for all maintenance activities.

The Master List was expanded to show not only the current forecast projections through 2013, but potential capital projects from 2014 through 2021, 2025 and 2041. Cost estimates were placed in the years selected for each project identified. The timing of each project was based on the expected life of each component and the selection of a projected unit outage.

The budget plan recommended in this study is expected to be in line with past costs and have a justification based on historical requirements and the condition assessment of the plant's components. Both capital expenditures and O&M expenses in 2009 dollars were escalated at 3% to determine nominal costs.

Table 4.8 shows a summary of the major replacements (greater than $5MM each) that have been identified beyond the 2009 Capital Forecast:

Table 4.8 Recommended Major Projects

Major Projects	2015	2016	2022	2042
Unit 2 HP Turbine Rotor Replacement	✗	✗	✓	✓
Unit 1&2 GSU Transformer Replacements	✗	✗	✓	✓
Unit 1&2 DCS Upgrade	✗	✗	✓	✓
Unit 3 DCS Upgrade	✗	✗	✓	✓
Unit 4 FD Fan and ID Fan Rotor Replacements	✗	✗	✓	✓
Unit 4 GSU Transformer 4A Replacement	✗	✗	✓	✓
Unit 1&2 ID Fan Rotor Replacement	✗	✗	✗	✓
Unit 3 Convective Superheater Replacement	✗	✗	✗	✓
Unit 4 Reheater Middle and Lower Bank Replacement	✗	✗	✗	✓
Unit 1&2 Primary Superheater Replacement	✗	✗	✗	✓
Unit 1&2 #1 and 2 Feedwater Heater Replacements	✗	✗	✗	✓
Unit 1&2 Cold End Air Heater Replacements	✗	✗	✗	✓

Major Projects	2015	2016	2022	2042
Unit 1&2 DCS Upgrade	✗	✗	✗	✓
Unit 3 Economizer Replacements	✗	✗	✗	✓
Unit 3 DCS Upgrade	✗	✗	✗	✓
Unit 4 Primary Superheater Horizontal Section Replacement	✗	✗	✗	✓
Unit 4 DCS Replacement	✗	✗	✗	✓

These recommendations were made based on life expectancies of major components on each unit and the goal of continued operation in a safe and reliable manner.

It is important to not only determine the capital expenditures for the scenarios studied, but also the timing of the work. It would not be prudent to spend large amounts on replacements close to the expected retirement of the plant. The budget recommendation for the 2022 retirement date assumes that outages will continue through 2018. This would be close to the last major outage for each unit before retirement. Likewise, outages are recommended through 2023 for the 2026 retirement date, and 2038 for the 2042 retirement date.

The differences in the capital expenditures from the 2042 retirement case were estimated for 2015, 2016 and 2022 retirement dates and were used in the Midas model for the different Meramec retirement scenarios. The capital expenditure savings for these three retirement dates are presented in Table 4.10.

Operations & Maintenance

O&M expenditures were divided into labor and non-labor categories. The labor portion is annually consistent, with increases for overhead adjustments and wage increases, whereas the non-labor portion is heavily outage dependent. Labor and non-labor O&M expenses from the 2009 forecast are summarized in Table 4.9.

Table 4.9 Forecasted Labor and Non-Labor O&M Expenses 2009-2014 (2009 $'s)

Million $'s	2009	2010	2011	2012	2013	2014
Labor O&M	$22.99	$ 22.98	$23.59	$24.23	$ 25.25	$25.84
	Average	*$ 22.39*		*Std Dev*	*0.44%*	
Non-Labor O&M	$13.13	$ 19.42	$25.68	$32.41	$ 28.60	$13.00
	Average	*$ 22.04*		*Std Dev*	*34.89%*	

As illustrated by the small standard deviation of only 0.44%, the Plant's labor-related O&M expenditures are consistent and can be easily projected forward. A cost of $22.4MM with escalation at 3% through 2041 has been projected, to be consistent with Ameren Missouri's 2010-2014 projections.

The large standard deviation of the non-labor O&M costs illustrates that these costs are not annually consistent. Instead, there is a direct correlation between non-labor O&M

expenses and specific unit outages when determining the amount of costs for any given year. Which years had (or are projected to have) scheduled outages were identified and the non-labor O&M expenses estimated. These costs were then projected forward based on the unit outage schedule provided by Ameren Missouri and the estimate of future outage dates through 2041.

Projecting an average O&M cost going forward is not representative of actual costs to be incurred due to the variations discussed above. Outages for the last few years of the plant's life were omitted in each retirement scenario, assuming that on-line maintenance or short boiler outages would be sufficient to keep the plant running, and there would be no need for any large capital projects. In the years when there is a major boiler outage, the non-labor O&M costs increase significantly over the years where no outages occur.

The differences in the O&M costs from the 2042 retirement case were estimated for 2015, 2016 and 2022 retirement dates and were used in the Midas model for the different Meramec retirement scenarios. The O&M savings for these three retirement dates are presented in Table 4.10. Negative numbers are cost reductions.

Table 4.10 Capital and O&M Savings by Retirement Case (Nominal $'s)

	Capital Savings				O&M Savings		
Million $'s	2015	2016	2022		2015	2016	2022
2011	-3	--	--		--	--	--
2012	-12	--	--		-21	-7	--
2013	-37	-37	--		-17	-17	--
2014	-68	-68	--		0	0	--
2015	-10	0	--		-42	0	--
2016	-41	-41	--		-63	-63	--
2017	-78	-78	--		-70	-70	--
2018	-54	-54	-15		-63	-63	--
2019	-11	-11	0		-48	-48	--
2020	-24	-24	-13		-71	-71	-21
2021	-12	-12	0		-51	-51	0
2022	-49	-49	-49		-71	-71	-71
2023	-66	-66	-66		-83	-83	-83
2024	-36	-36	-36		-80	-80	-80
2025	-13	-13	-13		-57	-57	-57
2026	-14	-14	-14		-79	-79	-79
2027	-14	-14	-14		-61	-61	-61
2028	-23	-23	-23		-90	-90	-90
2029	-32	-32	-32		-99	-99	-99
2030	-20	-20	-20		-90	-90	-90

Retirement Cost Amortization

Another input into Midas regarding Meramec retirement scenarios was the net change in depreciation and amortization. The estimated retirement costs are shown in Table 4.11. The amortization period for retirement costs is assumed to be 20 years, and book life for base depreciation expense is 40 years. Amortization of retirement costs and reduction to depreciation expense are estimated, then the difference between the two is entered into Midas as a net change in depreciation and amortization, which results in higher amortization/depreciation for the first 20 years compared to the continue operations case and lower after that.

Table 4.11 Meramec Retirement Costs

Million $'s	Current	2015	2016	2022
Net Book Value Writeoff		405,892	406,099	614,477
Asbestos Abatement	8,773	10,170	10,475	12,508
Ash Pond Closure	13,306	15,425	15,888	18,971
Closure of Intake Structure	3,552	4,118	4,242	5,065
Plant Demolition (Net of Salvage)	12,900	14,955	15,403	18,392
Total Retirement Cost	38,531	450,560	452,108	669,414

Transmission

Transmission expenses related to Meramec retirement were not in the scope of the Burns & McDonnell study, so they were developed by Ameren's Transmission Planning group. The transmission modification costs that would be incurred in the retirement cases unless the Meramec site is used for a replacement resource (like Meramec combined cycle) spread over 5 years are:

- **HC**
- **HC**
- **HC**

The total estimate of ****HC**** was used in Midas model for the plans that include Meramec retirement without Meramec combined cycle replacing the retired coal plant.

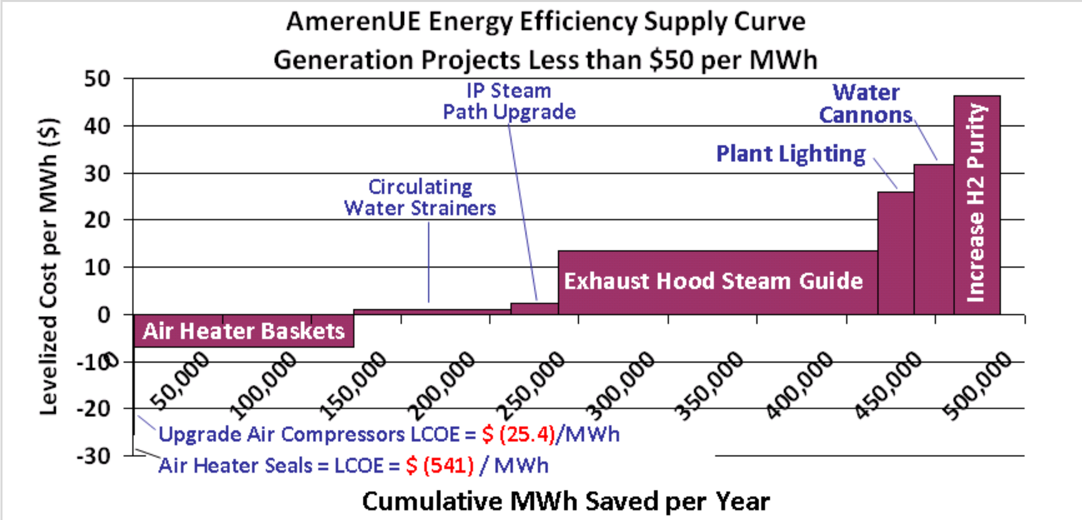
4.5 Existing Plant Efficiency Options[20]

Ameren Missouri recognized the potential for end-to-end energy efficiency, and engaged EPRI to undertake a study to identify, quantify, and prioritize energy efficiency project opportunities across its operations in electricity generation, transmission, distribution, and utilization at Ameren Missouri facilities.

The team developed profiles of 37 candidate generation project types, which were screened on a unit-by-unit basis on technical applicability. The levelized cost of energy (LCOE) was calculated for the remaining 28 project types after the first screening; Figure 4.3 shows the projects identified that have an LCOE of less than $50/MWh.

[20] 4 CSR 240-22.040(4)

Figure 4.3 Generation Efficiency Projects



There are some efficiency projects currently underway:

- Air heater rebasketing is regularly scheduled at RI and Labadie.
- The Labadie 4 condenser debris filter will be installed in 2011 and the sponge cleaning system restored to service.
- Turbine replants continue as planned.

While it is impossible to implement the projects identified all at once, Ameren Missouri will be assessing and implementing the projects that look feasible on an ongoing basis. The screening analysis was the first step to help prioritize the generation efficiency projects. All of the analysis was based on a generic 500 MW unit characterized by EPRI, and those generic numbers were then scaled to Ameren Missouri's units. The next step is to conduct engineering studies on the most promising projects.

4.6 Power Purchase Agreements

After discussions with Ameren Missouri's Asset Management and Trading organization it was determined that there were no pending potential long-term power purchases for consideration at the time of the analysis. Furthermore, Ameren Missouri learned from its experience in developing the 2008 IRP that soliciting the market for long-term power purchases or sales is not productive for bidders given the data at this stage of the analysis is generic. Evaluation of generic power purchase agreements would not be expected to yield different results in terms of relative performance of resource types, as the only reasonable assumption that could be made absent specific information would be that such an agreement would be cost-based.[21]

[21] 4 CSR 240-22.040(5)(A-G)

4.7 Supporting Tables

Uncertainty

The characteristic data provided for the candidate technologies were estimated using the best information available at the time of the study; however, there is uncertainty around the key characteristics that are provided. For Ameren Missouri's risk analysis efforts, uncertainties and the respective probabilities for capital costs, fixed and variable O&M costs, forced outage rates and construction time were developed by Black and Veatch and are presented in in Table 4.12. The ranges and probabilities for these variables were used as the basis for development of the uncertain factor sensitivity analysis discussed in Chapter 9.

Table 4.12 Coal and Gas Options Uncertainty Distributions[22]

Capital Cost Uncertainty Distribution					
Deviation	-20%	-10%	0%	15%	30%
Probability	5%	25%	40%	25%	5%

Project Schedule Uncertainty Distribution					
Deviation	-30%	-15%	0%	20%	40%
Probability	5%	25%	40%	25%	5%

Fixed O&M Uncertainty Distribution					
Deviation	-20%	-10%	0%	15%	30%
Probability	5%	25%	40%	25%	5%

Variable O&M Uncertainty Distribution				
Combined Cycle				
Deviation	-50%	0%	33%	83%
Probability	25%	45%	25%	5%
Coal w/ CC				
Deviation	-60%	0%	40%	80%
Probability	15%	50%	25%	10%
Simple Cycle				
Deviation	-50%	0%	50%	
Probability	25%	50%	25%	

Forced Outage Uncertainty Distribution			
Combined Cycle			
Deviation	-2%	0%	2%
Probability	25%	50%	25%
Coal w/ CC			
Deviation	-4%	0%	4%
Probability	25%	50%	25%
Simple Cycle			
Deviation	-4%	0%	4%
Probability	25%	50%	25%

Uncertainties around the key characteristics for the nuclear resource option were developed using the uncertainty distribution data from the previous IRP and are presented in the Supporting Tables section in Table 4.13.

[22] 4 CSR 240-22.040(8)(B)2; 4 CSR 240-22.040(8)(C)2; 4 CSR 240-22.040(9)(C)

For nuclear project schedule uncertainty, a literature search was conducted in the summer of 2010. Among the results were reports from the US Department of Energy, the International Atomic Energy Agency, and others. These reports listed a variety of actual and planned construction periods in a range of countries including Japan, China, India, Korea, and Finland. When adding the standard 2 years for siting and permitting time obtained from the Black & Veatch study used for other supply side types, the low end for total project schedule was 7 years, the base was 8 years, and the high was 9 years. The 2 year allowance for "preconstruction" within the total project schedule timeframe was consistent with the US Department of Energy report showing 18 months for such activity.

Table 4.13 Nuclear Option Uncertainty Distributions[23]

Capital Cost Uncertainty Distribution						
Deviation	-25%	-10%	0%	10%	25%	40%
Probability	5%	10%	50%	20%	10%	5%

Fixed O&M Uncertainty Distribution						
Deviation	-25%	-10%	0%	10%	25%	50%
Probability	5%	20%	40%	20%	10%	5%

Variable O&M Uncertainty Distribution						
Deviation	-25%	-10%	0%	10%	25%	50%
Probability	5%	20%	40%	20%	10%	5%

Forced Outage Uncertainty Distribution			
Deviation	2%	3%	4%
Probability	70%	20%	10%

[23] 4 CSR 240-22.040(8)(B)2; 4 CSR 240-22.040(8)(C)2; 4 CSR 240-22.040(9)(C)

Table 4.14 Candidate Option Model Inputs[24]

PROJECT TYPE	U.S. EPR Base	CC02 - USCPC w/ Carbon Capture - Greenfield Base	A01.2 - CC - Venice 2x1 501F CCCT Conversion Intermediate	A03.2 - CC - 2x1 501F CCCT - Greenfield Intermediate	A09.2 - CC - Meramec Unit 4 STG in CCCT Conversion Intermediate	A16.2 - SC - Two 501Fs w/ SCR - Greenfield Peaking
Technology Rating (95 F Day)	1600	679	600	600	834	346
Ramp Up Rate, %/min	5	5	5	5	5	7
Ramp Down Rate, %/min	5	5	5	5	5	7
Minimum Up Time, hours	96	24	8	8	24	1
Minimum Down Time, hours	96	16	8	8	16	1
Equivalent Forced Outage Rate	2%	8%	2%	2%	4%	5%
Startup Fuel, MMBtu or $	$381,924	12,400	92	92	138	46 (one CTG)
Fuel Design	Nuclear	PRB Coal	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Capacity Factor	94%	85%	21%	21%	21%	10%
Capital Cost, $1,000	6,755,200	3,525,760	428,120	690,650	890,560	263,950
Overnight EPC Cost, $1,000	5,404,160	3,230,000	374,000	650,000	742,000	244,000
Owner Costs excluding AFUDC, $1,000	1,351,040	295,760	54,120	40,650	148,560	19,950
Capital Cost, $/kW w/o AFUDC	4,222	5,193	1,686	1,151	1,068	763
Construction Cash Flow, Incremental, % of Capital Cost						
Year 1	6%	0.1%	13%	13%	13%	36%
Year 2	7%	13.9%	30%	30%	30%	51%
Year 3	17%	24%	38%	38%	38%	13%
Year 4	21%	36%	20%	20%	20%	
Year 5	17%	17%				
Year 6	11%	4%				
Year 7	13%	5%				
Year 8	8%	4%				
Fixed O&M Cost, $/kW-Yr	44.24	37.30	6.80	7.04	6.37	6.89
Variable O&M Cost, $/MWh	2.01	9.90	3.48	3.65	3.04	12.8
Other O&M Cost		12.45 (1)	3,299 (2)	3,628 (2)	4,455 (2)	1,396 (2)
Polynomial Heat Rate @ 95 F						
Constant (c)	9,788 (3)	-112.4030	71.7295	71.7295	-607.6920	577.8350
1st Term (w)		17.1013	8.1584	8.1584	11.6779	4.8605
2nd Term (x)		-0.0116	-0.0058	-0.0058	-0.0092	0.0239
3rd Term (y)		0.0000	0.0000	0.0000	0.0000	-0.0001
Plant Maintenance Pattern, week/year		4-4-4-6	1-1-2-1-1-6	1-1-2-1-1-6	1-1-2-1-1-6	1-2-1-4
ESTIMATED CONTROLLED EMISSIONS, lbs/MMBtu (HHV)						
NOx	N/A	0.05	0.0075	0.0092	0.0092	0.01
SO2	N/A	0.06	0.0001	0.0006	0.0006	0.0006
CO2	N/A	21.2	117	117	117	117
Hg (percent removal)	N/A	90	N/A	N/A	N/A	N/A

(1) Carbon sequestration cost - $/MWh
(2) Fixed fuel supply cost - $1,000 per year
(3) Net Plant Heat Rate (Btu/kWh)

[24] 4 CSR 240-22.040(1)(E); 4 CSR 240-22.040(1)(F); 4 CSR 240-22.040(1)(G)

4.8 Compliance References

4 CSR 240-22.040(1)(A) 10
4 CSR 240-22.040(1)(D) 10
4 CSR 240-22.040(1)(E) 11, 22
4 CSR 240-22.040(1)(F).... 22
4 CSR 240-22.040(1)(G) 22
4 CSR 240-22.040(1)(H) 11
4 CSR 240-22.040(1)(I).... 11
4 CSR 240-22.040(1)(J) 10
4 CSR 240-22.040(1)(K)2 12
4 CSR 240-22.040(1)(K)3 12
4 CSR 240-22.040(2)(C) 8, 14
4 CSR 240-22.040(3) 12
4 CSR 240-22.040(4) 3, 4, 6, 18
4 CSR 240-22.040(5)(A-G) 19
4 CSR 240-22.040(6) 12
4 CSR 240-22.040(8)(B)1 6
4 CSR 240-22.040(8)(B)2 .... 8, 20, 21
4 CSR 240-22.040(8)(C)1 6
4 CSR 240-22.040(8)(C)2 .... 8, 20, 21
4 CSR 240-22.040(9)(A)3 8
4 CSR 240-22.040(9)(B) 7
4 CSR 240-22.040(9)(C) 20, 21
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