The preceding table illustrates that demand response programs are not cost effective for the Ameren Missouri MEEIA Cycle 2016 - 2018 implementation period spanning from 2016-2018 based on the most current Ameren Missouri forward view of MISO capacity prices. A corollary critical assumption associated with demand response program cost ineffectiveness from 2016-2018 is the assumption of a three-year demand response program life. In turn, the three-year program life assumption is tied to the scenario where Ameren Missouri deploys demand response as an additional resource to MISO to induce lower electricity use at times of high wholesale market prices. At such time that Ameren Missouri requires demand response resources to primarily provide relief when system reliability is jeopardized - this implies service as a longer term asset. Ameren Missouri would analyze the cost effectiveness under longer demand response program lives. The purpose or objective(s) for implementing demand response programs for Ameren Missouri customers is essential in the development of the realistic achievable potential for cost effective response.

8.7.12 Ameren Missouri DR Pilot Consideration for 2016-2018[56]

The fundamental objectives of a demand response pilot program are to test either new technologies or theories about innovative program logic prior to implementing a full scale program.[57]

Ameren Missouri is in the process of putting context around a potential DR pilot program that will assess the promise of customer demand-side management in the context of the smart grid. The implementation of the potential pilot is premised on Ameren Missouri converting its customer metering technology from one-way automated meter reading (AMR) to two-way advanced meter infrastructure (AMI) technology beginning as early as 2017. Although Ameren Missouri discusses a framework for the potential pilot in this filing, the final design of the pilot should include the input and insight of the Ameren Missouri EE Regulatory stakeholder working group.[58]

The next generation of demand response programs will evolve from a primary focus on utility "command and control" type programs to also include customer choice type DR programs. The next generation of DSM technologies will enable customers to make more informed decisions about their energy consumption, adjusting when they use electricity and how much they use. A major component of the utility smart grid infrastructure is technology to enable customers to make more informed decisions about their energy consumption. AMI is an architecture for automated, two-way

[56] 4 CSR 240-22.050(2)
[57] 4 CSR 240-22.050(3)(D)
[58] EO-2012-0142 14

communication between a smart utility meter and a utility company. The goal of AMI is to provide utility companies with real-time data about power consumption and allow customers to make informed choices about energy usage based primarily on the price of energy at the time of use.

As the 2014 IRP and MEEIA Cycle 2016 - 2018 filings were being developed, Ameren Missouri is in the process of understanding the business case for converting customer meters from AMR to AMI technology. AMI is a pre-requisite technology for this pilot. Therefore, if AMI installation do not begin by early 2017, it is unlikely that a DR pilot can be implemented during the 2016-2018 implementation period.

There is no budget specified for a potential DR program for the 2016-2018 implementation period. This is due to the lack of certainty around when the next generation metering technology may be installed as well as to the outcome of the collaborative efforts to mutually design a DR pilot that will provide the greatest net benefits to Ameren Missouri customers.

Proposed DR Pilot Program Objective(s)

A preliminary list of objectives for this pilot includes:

1. Deploy statistically significant samples to measure the impacts of the following potential program designs or a subset thereof:
    a. Innovative rates
        i. Critical peak pricing (CPP) and its close relative Peak time rebates (PTR)
        ii. Time of use (TOU)
        iii. Real-time pricing (RTP)
    b. Customer incentives
        i. No incentives
        ii. Cash compensation
        iii. Innovative compensation, i.e., variable bill credits depending on degree of customer behavior change
    c. Information
        i. None
        ii. Event notification
        iii. Historical and real-time consumption and cost
        iv. Comparative usage
        v. Device specific usage
    d. DR technology
        i. None
        ii. Smart thermostats

        iii. Smart appliances/plugs
        iv. Home area networks
        v. Non-obtrusive business DR technologies
    e. Customer education
        i. None
        ii. Targeted by customer segment
2. Test tolerance for increasing frequency and duration of DR events
    a. Reliability events
    b. Price events
3. Quantify both annual peak demand and energy reductions associated with each program design option
4. Understand utility infrastructure challenges, including:
    a. Integrate utility information systems
    b. Understand infrastructure requirements for potential third-party DR providers
    c. Customer contact capabilities to maximize customer satisfaction
5. Define regulatory reforms that will allow Ameren Missouri to capture value from this project if subsequent full scale deployment ensues

8.8 Targeted DSM[59]

As electric distribution networks approach capacity limitations and where there is an expectation for future load growth, building new infrastructure represents a capital intensive and, in some cases, a difficult endeavor.

Targeted load reduction via energy efficiency and demand response, i.e., "targeted DSM", could, in some but not all cases, be more financially beneficial than upgrading infrastructure. With this objective, the Ameren Missouri Energy Delivery team performed a comprehensive review of potential targeted DSM opportunities in 2013 using a well-defined process.

Missouri Division supervising engineers were contacted to request that their engineers review circuits to identify potential candidates for a targeted demand-side management programs. The engineers were asked to identify those circuits where a targeted DSM program might help Energy Delivery avoid capital and O&M expenditures which would otherwise have to be made to provide load relief. In addition to being heavily loaded, the ideal candidate circuits should also have a significant amount of industrial or large commercial load such that the impact could be mitigated by targeted DSM in the near future. The engineers reviewed their most recent 5-year load analysis projections in

[59] EO-2014-0062 f

order to identify any potential candidates. The criteria for significant industrial and large commercial loads were not specified so that the engineers were not constrained and could utilize their engineering judgment regarding the size of the loads relative to circuit overload projections, load growth rates, and other factors.

Two potential candidate circuits were identified. Many of the projects in the 5-year budgets involved rehab and upgrade work, relocations, mandatory reliability work, and other non-load growth related projects. However, two circuits were identified as possible candidates:

Spring Forest 575-52: This feeder needs load relief by 2016 and has two large primary metered connections (approx. 1 MVA each) to supply a school district. Most of the other loads are residential or small commercial.

Barrett Station 318-52: This feeder will require future load relief if a new project proceeds and the addition of a second unit and feeders at Barrett Station are delayed (currently not budgeted, but pending review). Both this circuit and some of the surrounding circuits have heavy commercial loads. The 2nd Unit at Barrett Station may itself be a candidate if a significant driver for the project is determined to be load-related rather than reliability-related. Since there is no capital budget currently in place to upgrade Barrett Station, no financial analysis was performed to determine the magnitude of benefits, if any, relative to a targeted DSM solution.

8.8.1 Spring Forest Situation Analysis

Due to construction of a new 242-home subdivision, there is insufficient capacity from the Spring Forest Feeder to reliably supply it. The subdivision is to be built in four phases. With the addition of the subdivision's 3rd phase, the existing single-phase portion of this feeder is close to its 135-amp limit and the feeder is over its 600 amp limit. The plan is to add a new three-phase feeder to serve customers in the new development. The new feeder will have an average capacity in the 8 MVA range and is currently budgeted for installation in 2015 at a budgeted cost of $597,000. In addition to the increased capacity associated with the new three-phase feeder, the new feeder will also provide increased reliability improvements in terms of splitting circuits which results in less customers being out of service during an outage situation due to having increased switching abilities.

Since the Spring Forest feeder already had an existing budget ($597,000) for capital improvements, Ameren Missouri Energy Delivery engineers worked with the Ameren Corporate Planning department to study the potential for a targeted DSM solution versus the budgeted solution. For purposes of determining a budgetary estimate, Corporate Planning sought cost estimates from a targeted DSM company.

The targeted DSM company focuses on commercial and industrial (C&I) customer load reduction opportunities. Their targeted DSM solution is a fully automated switch installed at C&I customer premises. It intelligently taps embedded responsive load from customers. The utility can schedule, dispatch and monitor events via a secure, real-time portal or any existing utility control system(s).

The targeted DSM solution proposal was turn-key. That means the work and the price included:

- Enrolling and contracting with the end-use customer (with Ameren Missouri Customer/Marketing groups' approvals of the materials and engagement),
- Performing the site surveys,
- Installing the equipment on the site,
- Operating the equipment and
- Provisioning the capacity to Ameren Missouri operators in a fashion that they understand, can schedule and monitor.

The targeted DSM Company provided the following high level bid to address the Spring Forest feeder situation.

- $695/kW plus $43/kW O&M per year and $40/kW Customer incentive per year.

To translate the bid into equivalent dollars to the proposed $597,000 investment at Spring Forest, the following math applies. Assume 8 MVA is equivalent to 8,000 kW. $695/kW x 8,000 kW is $5,560,000. Since $5,560,000 is multiples of $597,000 there is no need to quantify the additional O&M and customer incentive costs associated with the proposed Innovari solution.

Ameren Missouri Energy Delivery engineers will continue to use the targeted DSM methodology outlined above to assess cost effective targeted DSM opportunities in future budget cycles.

8.9 Distributed Generation and Combined Heat and Power Potential[60]

Ameren Missouri commissioned this Demand Side Management (DSM) Market Potential Study to assess the various categories of distributed generation (DG), and

[60] EO-2012-0142 14, EO-2014-0062 f

combined heat and power (CHP) potentials in the residential, commercial, and industrial sectors for the Ameren Missouri service area from 2016 to 2033. The study used updated baseline estimates based on the latest information pertaining to federal, state, and local codes and standards for improving energy efficiency. It also quantified and included estimates of naturally occurring energy efficiency in the baseline projection.

8.9.1 CHP Case Studies

As mentioned above, the study included two types of customer-sited resources as follows:

a) **Distributed generation:** DG systems are technologies that generate electricity and are located onsite at customer premises.

b) **Combined heat and power:** CHP systems generate both electricity and thermal energy that are used onsite.

Before performing the service-territory analysis, we conducted two in-depth case studies of DG-CHP opportunities that were being considered by Ameren Missouri large industrial customers: one at a major corn milling facility and another at a major manufacturing facility.

Specifics regarding installed costs and fuel costs are proprietary to the subject customers. Major, non-proprietary assumptions for the case study analyses were as follows:

a) Natural gas fueled combustion turbine generator with 3+ MW of electricity generating capacity; producing waste heat in the form of steam for process heating

b) Waste heat valuation based on displacing boiler fuel use

c) Annual O&M costs include turbine overhaul cost at half-life

d) 20 year system life

e) $10,000 grid interconnection study cost

f) Real discount rate of 3.95%

g) Uptime of 90%+ hours per year

h) Avoided cost benefits for energy and capacity as provided by Ameren Missouri

The cost effectiveness results of the analysis are shown in Table 8.20. Although the TRC ratios are marginally above 1.0, indicating that the projects are marginally cost-effective, they are sensitive to many factors. For example, during a drought-year, production and heating requirements at the milling facility may fall, reducing the value of waste heat. Another example, in a colder than normal winter, natural gas pipeline capacity may be 100% utilized for home heating, leaving industrial customers with non-firm natural gas transportation contracts subject to natural gas supply interruptions. In a sensitivity analysis to model a prolonged drought scenario, the TRC ratio dropped to 1.01. An additional factor to consider is the customer's Ameren Missouri rate structure, which contains a standby charge (Rider E) for Ameren to maintain the necessary capacity if the customer would choose to revert to grid power in the event of an emergency shut-down of their DG-CHP system. For sizeable systems, the details of this cost result from a complex interconnection study, scenario analysis, and negotiation — and can have a significant impact on the overall project economics. Finally, there are contractual terms and conditions that may alter the benefits of CHP for customers. For example, cost effective electric generation from CHP is dependent upon full utilization of steam output. If steam demand is reduced for any reason, CHP contracts with customers may require take or pay provisions to protect the financial interests of the CHP facility owner if the event of a decline in steam requirements. These are among the considerations that must be taken into account in estimating DG-CHP potential.

Table 8.20: Total Resource Cost (TRC) Test Results for DG-CHP Case Studies[61]

Case Study	TRC Ratio	NPV Net Benefits	NPV Benefits	NPV Costs
Major Corn Milling Facility	1.17	$8,577,664	$58,910,946	$50,333,283
Major Manufacturing Facility	1.04	$1,378,710	$32,167,172	$30,788,462

8.9.2 DG/CHP Technology Options

The first step toward estimating DG-CHP achievable potential was to identify applicable technology options. Based on a thorough review of available and applicable technologies, as well as input from stakeholders, we arrived at the following list:

i) Solar photovoltaic (PV) systems
j) Small wind
k) Reciprocating engine
l) Reciprocating engine with heat recovery
m) Micro-turbine

[61] Volume 5 of the Ameren Missouri DSM Potential Study

n) Micro-turbine with heat recovery

o) Combustion turbine (CT)

p) Combustion turbine with heat recovery

q) Boiler with back-pressure steam turbine

r) Fuel cell

s) Fuel cell with heat recovery

t) Combined cycle combustion turbine (CCCT)

u) Stirling engine

v) Organic rankine cycle

Table 8.21: DG-CHP Technology and Cost Data[62]

Technology	System Size (kW)	Lifetime	$/kW installed cost (2011)	Non-fuel $/kWh annual O&M (2011)	Load factor (% available)	Nat Gas Fuel Use, BTU/kWh	Nat Gas Fuel Avoided, BTU/kWh	Federal tax credit	Inst. Cost Decline from Yr 1 to YrFinal	Peak Coinc. Factor	Useful Thermal Output, BTU/kWh	Effic.of Displaced Boiler	Data Source
Solar PV	6	20	$3,953	$0.002	15.0%	-	-	10.0%	78.7%	47.0%	-		4,5,6,8,10
Solar PV	20	20	$3,867	$0.001	15.0%	-	-	10.0%	78.7%	47.0%	-		4,6,7,10
Solar PV	100	20	$3,688	$0.001	15.0%	-	-	10.0%	78.7%	47.0%	-		4,5,6,7,10
Solar PV	1,000	20	$3,570	$0.001	15.0%	-	-	10.0%	78.7%	47.0%	-		4,5,7,10
Small Wind	3	20	$8,215	$0.020	15.0%	-	-	0.0%	10.0%	20.0%	-		4
Small Wind	30	20	$6,038	$0.020	20.0%	-	-	0.0%	10.0%	20.0%	-		4
Small Wind	300	20	$3,600	$0.020	25.0%	-	-	0.0%	10.0%	20.0%	-		1
Recip Engine	500	15	$1,950	$0.012	80.0%	9,755	-	0.0%	0.0%	80.0%	-		1,2
Recip Engine w/ Heat Recovery	500	15	$2,326	$0.012	80.0%	9,755	5,291	0.0%	0.0%	80.0%	4,233	80.0%	1,2
Recip Engine	1,500	15	$1,650	$0.007	80.0%	9,738	-	0.0%	0.0%	80.0%	-		1,2
Recip Engine w/ Heat Recovery	1,500	15	$1,980	$0.007	80.0%	9,738	5,298	0.0%	0.0%	80.0%	4,238	80.0%	1,2
Micro- turbine	200	15	$3,068	$0.020	80.0%	12,247	-	0.0%	0.0%	80.0%	-		1,2
Micro- turbine w/ Heat Recov.	200	15	$3,068	$0.020	80.0%	12,247	5,331	0.0%	0.0%	80.0%	4,265	80.0%	1,2
Micro- turbine	500	15	$3,068	$0.020	80.0%	12,247	-	0.0%	0.0%	80.0%	-		1,2
Micro- turbine w/ Heat Recov.	500	15	$3,068	$0.020	80.0%	12,247	5,331	0.0%	0.0%	80.0%	4,265	80.0%	1,2
Combustion Turbine (CT)	2,000	20	$3,000	$0.010	90.0%	14,085	-	0.0%	0.0%	80.0%	-		1,2,3
CT w/ Heat Recovery	2,000	20	$2,969	$0.010	90.0%	14,085	7,434	0.0%	0.0%	80.0%	5,947	80.0%	1,2,3
Combustion Turbine (CT)	5,000	20	$1,500	$0.010	90.0%	13,754	-	0.0%	0.0%	90.0%	-		1,2,3
CT w/ Heat Recovery	5,000	20	$1,485	$0.010	90.0%	13,754	7,206	0.0%	0.0%	90.0%	5,765	80.0%	1,2,3
Boiler w back-press steam turb.	3,000	50	$500	$0.005	80.0%	-		0.0%	0.0%	80.0%			2
Fuel Cell w/ Heat Recovery	5	12	$11,976	$0.022	90.0%	8,600	5,000	0.0%	10.0%	80.0%	4,000	80.0%	1,9
Fuel Cell	200	15	$5,048	$0.030	90.0%	8,022	-	0.0%	10.0%	80.0%	-		1, 2
Fuel Cell w/ Heat Recovery	200	15	$5,196	$0.030	90.0%	8,022	2,685	0.0%	10.0%	80.0%	2,148	80.0%	1,2
Fuel Cell	1,000	15	$5,048	$0.030	90.0%	8,022	-	0.0%	10.0%	90.0%	-		1, 2
Fuel Cell w/ Heat Recovery	1,000	15	$5,196	$0.030	90.0%	8,022	2,655	0.0%	10.0%	90.0%	2,124	80.0%	1,2
Stirling Engine	1	15	$18,000	$0.010	90.0%	12,186	7,614	0.0%	0.0%	80.0%	6,091	80.0%	8,10,11,12,13
Organic Rankine Cycle	500	15	$5,700	$0.007	80.0%	-	-	0.0%	0.0%	80.0%	-		1,10

62 Volume 5 of the Ameren Missouri DSM Potential Study

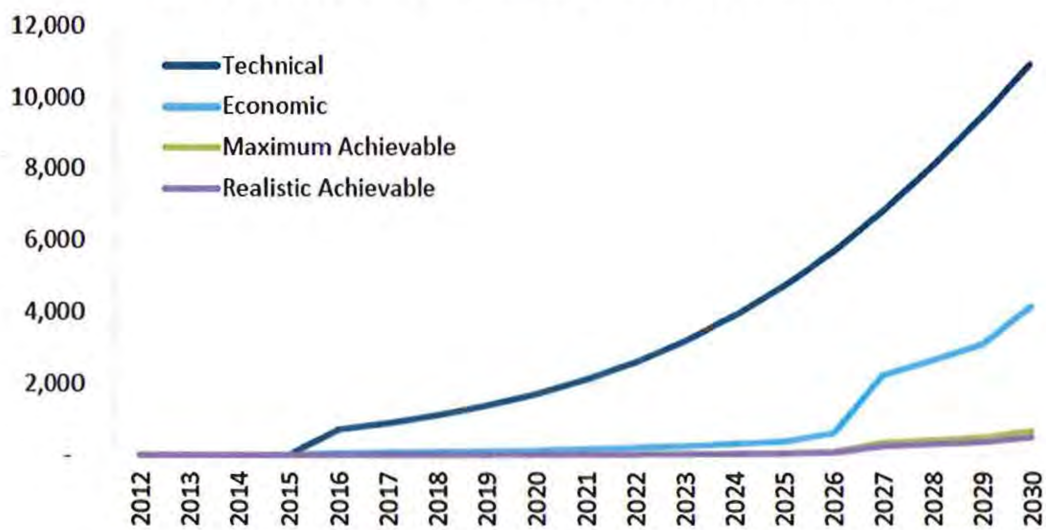
Key to data sources:

1. *Cost-Effectiveness of Distributed Generation Technologies*, CPUC Self-Generation Incentive Program 2011	7. *Catalog of CHP Technologies*, EPA, 2008
2. *Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment*, CA Energy Commission/ICF, 2012	8. *Sunshot Vision Study*, NREL, 2012; http://www1 eere.energy gov/solar/pdfs/47927.pdf
3. Budgetary Quotes (5) from manufacturer Solar Turbines	9. *MicroCHP blog*, http://www.microchap.info/Stirling_engine.htm
4. *Distributed Generation Renewable Energy Estimate Costs*, NREL, July 2012	10. *Tracking the Sun VI:* LBNL Report, 2013
5. *Cost and Performance Data for Power Generation Technologies*, NREL, prepared by Black & Veatch, 2012	11. *Tax Credit information: http://energy.gov/savings/business-energy-investment-tax-credit-itc*
6. *Residential, Commercial, and Utility-scale PV System Prices in the United States: NREL, 2012*	

8.9.3 DG/CHP Potential

Based on the inputs and assumptions described in Table 8.21, Figure 8.16 shown below is an extract from the study that shows the various forms of DG/CHP potential over the planning horizon. As this figure shows, realistic potential is very limited until the 2025-2030 timeframe.

Figure 8.16: DG-CHP Energy Impact Results (GWh)[63]



[63] Volume 5 of the Ameren Missouri DSM Potential Study

8.10 Demand-Side Rate Potential[64]

8.10.1 Approach

The analysis of demand-side rate potential is a new requirement in the IRP rules since Ameren Missouri's last triennial IRP compliance filing in 2011. The specific rule requirement is: "*The utility shall develop potential demand-side rates designed for each market segment to reduce the net consumption of electricity or modify the timing of its use. The utility shall describe and document its demand-side rate planning and design process.*"

Ameren Missouri 2013 DSM Potential Study contractor engaged a subject matter expert subcontractor, The Brattle Group (*Brattle*), to conduct this analysis.[65] *Brattle* reviewed demand-side rates that have been offered to customers by utilities across the U.S. and internationally.[66] Table 8.22 summarizes the utilities that were considered in the analysis.[67] *Brattle* assembled a "menu" of demand-side rates based on this review, and presented them at a workshop with Ameren Missouri's stakeholders. The rates' applicability to Ameren Missouri's service territory was determined through this stakeholder process.[68]

[64] 4 CSR 240-22.050(4) Demand-Side Rates is discussed further in Volume 6 of the DSM Potential Study, EO-2012-0142 14
[65] 4 CSR 240-22.050(4)(G)
[66] 4 CSR 240-22.050(3)(A); 4 CSR 240-22.050(4)(A)
[67] The time varying rates are discussed further in: Ahmad Faruqui and Jennifer Palmer, "The Discovery of Price Responsiveness – A Survey of Experiments Involving Dynamic Pricing of Electricity," Energy Delta Institute, Vol.4, No. 1, April 2012. http://www.energydelta.org/mainmenu/edi-intelligence-2/our-services/quarterly-2/edi-quarterly-vol-4-issue-1
[68] 4 CSR 240-22.050(3)(A); 4 CSR 240-22.050(2)

Table 8.22: Utilities Considered in Demand-Side Rates Analysis[69]

Inclining Block Rates (IBRs)		Time-varying Rates	
Utility	**Location**	**Utility**	**Location**
Arizona Public Service	Arizona	Ameren Missouri	Missouri
Avista Utilities	Washington	Anaheim Public Utilities	California
Consumers Enery	Michigan	Baltimore Gas & Electric	Maryland
FPL	Florida	BC Hydro	Ontario, Canada
Georgia Power	Georgia	Commonwealth Edison	Illinois
Idaho Power	Idaho	Connecticut Light & Power	Connecticut
Indiana Michigan Power Co.	Michigan	Consumers Energy	Michigan
Jersey Central Power & Light	New Jersey	Country Energy	Australia
Pacific Gas & Electric	California	GPU	New Jersey
Pacific Power	Oregon	Gulf Power	Florida
PECO Energy	Pennsylvania	Hydro One	Ontario, Canada
Progress Energy	Florida	Hydro Ottawa	Canada
PSE&G	New Jersey	Idaho Power	Idaho
San Diego Gas & Electric	California	Integral Energy	Australia
Southern California Edison	California	Irish Utilities	Ireland
		Istad Nett AS	Norway
		Marblehead Municipal Light Department	Massachussets
		Mercury Energy	New Zealand
		Newmarket Hydro	Ontario, Canada
		Oklahoma Gas & Electric	Oklahoma
		Olympic Peninsula Project	Washington
		Pacific Gas & Electric	California
		Pepco DC	District of Columbia
		Public Service Electric and Gas Company	New Jersey
		Pudget Sound Energy	Washington
		Sacramento Municipal Utility District	California
		Salt River Project	Arizona
		San Diego Gas & Electric	California
		Sioux Valley Energy	South Dakota
		Southern California Edison	California

Brattle conducted a brief survey of external stakeholders and Ameren Missouri employees connected with ratemaking. The purpose of the survey was to assist Brattle and Ameren Missouri in selecting appropriate new rates that would serve as representative overall demand-side rates for an impact assessment study. The survey sought to answer two primary questions:

1. What are the most important rate-making objectives/criteria for Ameren Missouri and its stakeholders?
2. How do various candidate rates perform in meeting these objectives?

A total criteria-weighted score was created for each rate, based on how individuals assessed each rate's performance for each objective, and weighted by the importance they placed on that objective.

[69] Volume 1 of the Ameren Missouri DSM Potential Study

Based on the results of the survey, four representative demand-side rates were developed as shown in Table 8.23:[70]

Table 8.23: Demand-Side Rates

	Residential	Small General Service	Large General Service
Inclining Block Rate (IBR)	X		
Time-Of-Use (TOU)	X	X	
Critical Peak Pricing (CPP)*			X

[70] 4 CSR 240-22.050(4)(B)

8.10.2 Demand-Side Rate Potential Results

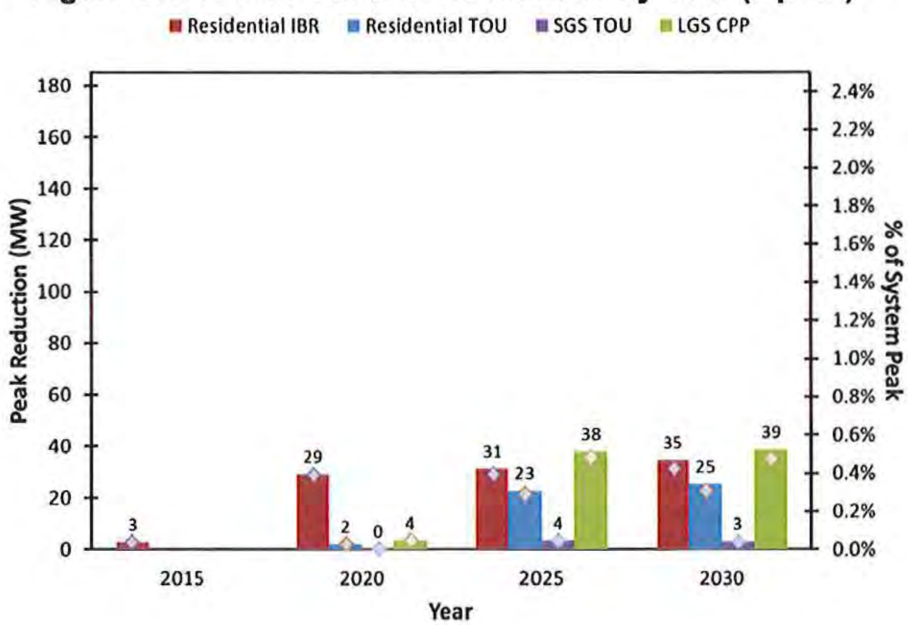
Each of the four demand-side rates were then developed using Ameren Missouri specific revenue requirement data. Data used in the development of the rates includes:[71]

1. Marginal costs
2. Existing rates (i.e., the class revenue requirement)
3. Class load profiles and consumption distribution

Each rate is revenue neutral, meaning that it will generate the same revenue for the class as the existing tariff (in the absence of a change in the class load profile).

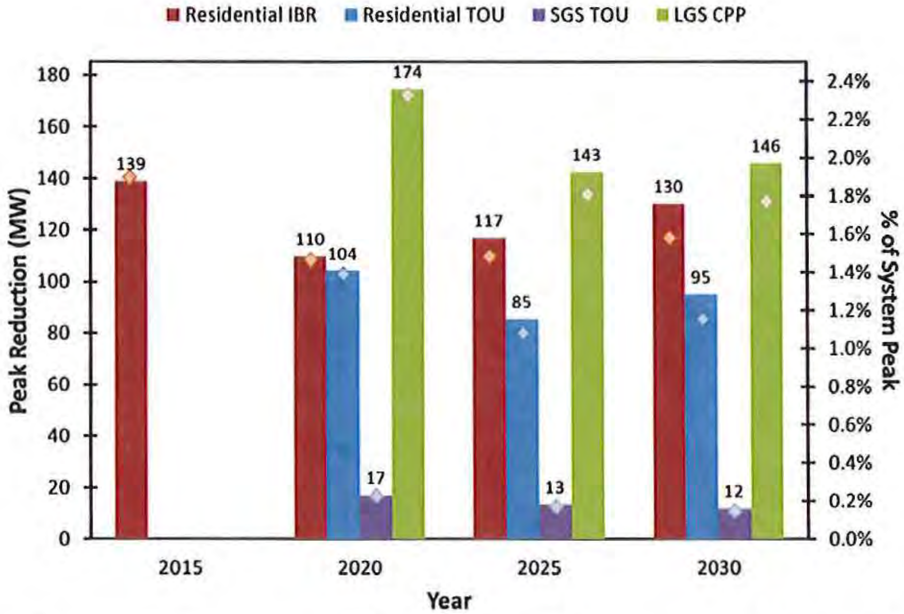
The results of the analysis in terms of the potential for peak demand reduction from demand-side rates are shown in Figures 8.17 and 8.18, which show the potential results based on opt-in and opt-out constructs, respectively.[72]

Figure 8.17: Peak Demand Reductions by Year (Opt-In)[73]



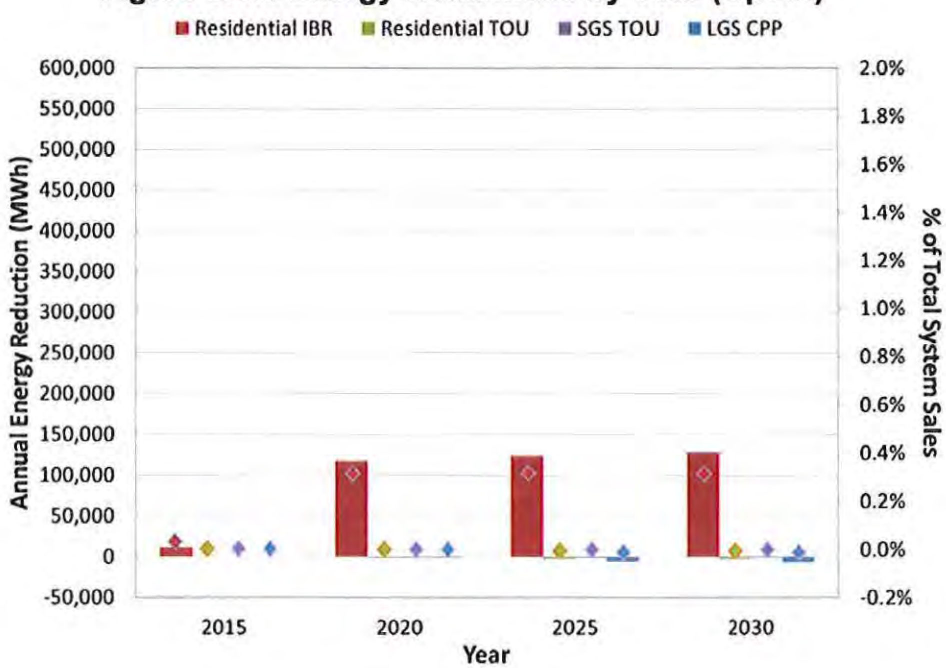
[71] 4 CSR 240-22.050(4)(D)
[72] 4 CSR 240-22.050(4)(D)1
[73] Volume 6 of the Ameren Missouri DSM Potential Study

Figure 8.18: Peak Demand Reductions by Year (Opt-Out)[74]



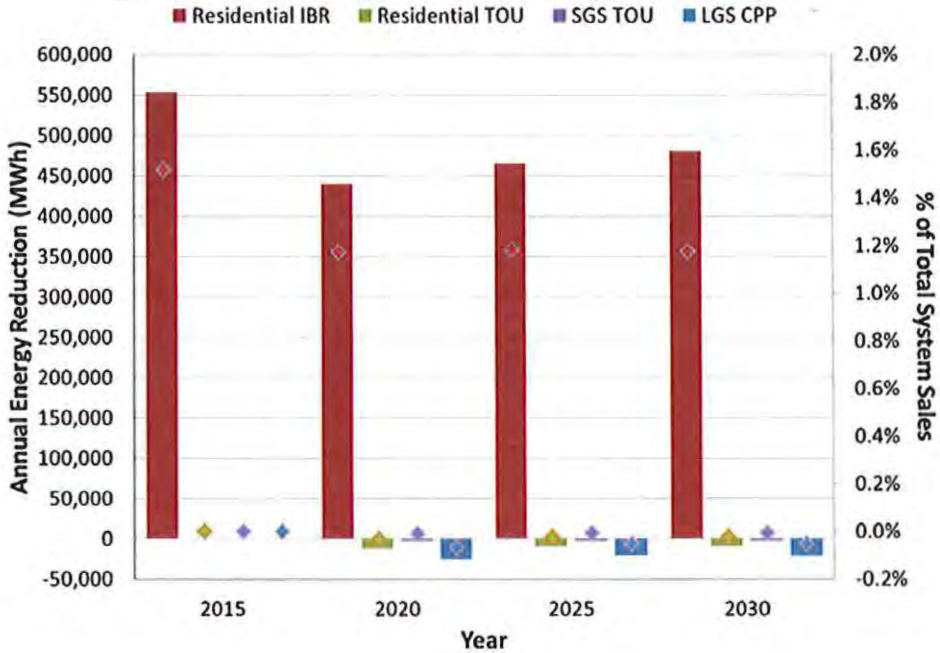
The results of the analysis in terms of the potential for energy reductions from demand-side rates are shown in Figures 8.19 and 8.20, again opt-in and opt-out constructs.

Figure 8.19: Energy Reductions by Year (Opt-In)[75]



[74] Volume 6 of the Ameren Missouri DSM Potential Study
[75] Volume 6 of the Ameren Missouri DSM Potential Study

Figure 8.20: Energy Reductions by Year (Opt-out)[76]



In summary, demand-side rates have the potential to cumulatively reduce system peak demand in the range of 0.8% to 3.5% by 2034.[77] The low end of the range assumes customer opt-in and the high end assumes customer opt-out implementation approaches.

At this time, it is not feasible to attempt an assessment of how the interactions between potential demand-side rates and potential demand-side programs would affect the impact estimates of the potential demand side programs and potential demand-side rates. Accurately capturing interactions between potential demand-side rates and other demand-side programs would require an entirely new study.[78] The study would involve primary market research – specifically referred to as "conjoint analysis" – to determine customer preferences for various demand-side options when offered a menu of choices. Depending on the scope of questions to be answered through such a study, the budget for this type of research is typically in the $100,000 to $300,000 range. However, absent the type of study outlined above, Ameren Missouri studies to date show that demand-side rates, specifically rates with inclining block structures, would likely reduce energy consumption by up to 1.8% per year. The question is whether energy savings induced by rate structures are the result of conservation actions by customers, by energy efficient equipment and services purchases by customers or a combination of

[76] Volume 6 of the Ameren Missouri DSM Potential Study

[77] 4 CSR 240-22.050(4)(D)4; 4 CSR 240-22.050(4)(D)5A through D; 4 CSR 240-22.050(4)(E&G): A comprehensive summary of the Demand Side Rates Analysis can be found in Volume 6 of the potential study

[78] 4 CSR 240-22.050(4)(D)2&3

both. To the extent that reductions are the result of conservation actions, i.e. raising thermostat settings during the cooling season, those actions would diminish cost effective energy efficient equipment and services opportunities for Ameren Missouri energy efficiency programs. The reason is that the conservation activities reduce energy consumption which reduces the incremental energy savings attributable to more efficiency equipment and service. Conversely, to the extent that energy savings induced by rates lead customers to more energy efficient products and services to either reduce overall consumption or to adjust the timing of when energy consuming devices are turned on and off, then those actions would complement Ameren Missouri energy efficiency equipment and service program opportunities.

Ameren Missouri considers the 2013 demand-side rates analysis the beginning of a broader discussion with stakeholders and the Commission around the complex issue of rate design where there is the potential to have customers who are winners and losers relative to the status quo.[79] Consequently, no rate design potential impacts have been assumed in the 2014 Ameren Missouri IRP filing. However, Ameren Missouri is in the process of taking an in-depth look at a Prepay or pay-as-you-go rate delivery option that has the potential to offer multiple customer benefits – one being customer behavior changes that result in lower energy consumption. The potential for an Ameren Missouri DSM program focused on encouraging customers to choose the Prepay option is discussed in Section 8.13.3 of this report.

8.11 2016 – 2018 Implementation Plan[80]

8.11.1 Overview

After adjusting the 2013 DSM Potential Study with 2013 program EM&V impact assessments, Ameren Missouri's proposed energy efficiency plan for 2016 – 2018 contains 10 energy efficiency programs and is projected to produce total first year savings of 426 GWH over the three years of its MEEIA Cycle 2016 – 2018 Implementation Plan.[81] The proposed plan also projects 114 megawatts (MW) of annual peak demand reduction from 2016-2018 attributable to energy efficiency programs. In terms of demand response programs (DR), the 2013 DSM Potential Study shows that demand response is not cost effective for the 2016-2018 implementation period. However, Ameren Missouri is considering the development of a DR pilot program during the 2016-2018 implementation plan. The objective of the DR pilot would be to assess Ameren Missouri customers' tolerance for different demand

[79] 4 CSR 240-22.050(5)(B)2
[80] EO-2012-0142 14
[81] 4 CSR 240-22.050(4)(E); A detailed look at each program including impacts, costs and participation is included in the attached Program Batchtools

response event frequencies and durations. Information from this pilot will be used to assess Ameren Missouri's ability to call upon DR to mitigate system peaks as well as to provide ancillary services to support integration of large scale renewable generation. Finally, Ameren Missouri's proposed budget for the 3-year MEEIA Cycle 2016 - 2018 implementation plan is $147 million in comparison to the MEEIA Cycle 2013 - 2015 implementation plan budget of approximately $150 million.

Table 8.24 shows the projected annual kWh and kW savings, budgets and benefit/cost ratios for the MEEIA Cycle 2016-2018 DSM implementation plan.

Table 8.24: MEEIA Cycle 2016-2018 DSM Implementation Plan

Ameren Missouri Residential Program Designs August 2014 - RAP	TRC		UCT		Net Incremental Energy Savings @ Meter (MWh)				Net Incremental Demand Reductions (MW)				Total Program Cost ($ Millions)			
	3 Yr	19 Yr	3 Yr	19 Yr	2016	2017	2018	3 Yr Total	2016	2017	2018	3 Yr Total	2016	2017	2018	3 Yr Total
Residential EE Portfolio																
Lighting	1.05	0.96	1.06	0.96	20,234	18,345	22,928	61,507	0.008	0.008	0.009	0.025	$ 5.696	$ 5.500	$ 6.717	$ 17.913
Efficient Products	1.29	1.71	1.98	3.17	5,686	1,857	6,737	14,280	2.092	0.706	2.238	5.036	$ 2.441	$ 1.301	$ 2.496	$ 6.238
HVAC	1.34	1.72	1.99	2.70	19,884	13,875	17,198	50,958	8.943	6.241	7.735	22.920	$ 8.301	$ 6.867	$ 7.775	$ 22.944
Appliance Recycling	1.08	1.27	1.08	1.27	2,974	2,664	4,106	9,743	0.737	0.660	1.017	2.414	$ 1.215	$ 1.115	$ 1.667	$ 3.997
Low Income	0.79	1.00	0.81	1.01	3,533	2,735	4,275	10,543	0.844	0.608	0.917	2.370	$ 2.346	$ 1.986	$ 2.488	$ 6.820
EE Kits	1.53	1.57	1.53	1.57	6,194	6,214	6,228	18,636	1.031	1.031	1.031	3.093	$ 1.814	$ 1.838	$ 1.812	$ 5.464
Res EE Portfolio Total	1.22	1.54	1.50	2.19	58,505	45,691	61,472	165,667	13.656	9.254	12.948	35.858	$ 21.813	$ 18.608	$ 22.956	$ 63.377
Res EE Portfolio Total					165,667				35.858				$63.377			

Ameren Missouri Business Program Designs August 2014 - RAP	TRC		UCT		Net Incremental Energy Savings @ Meter (MWh)				Net Incremental Demand Reductions (MW)				Total Program Cost ($ Millions)			
	3 Yr	19 Yr	3 Yr	19 Yr	2016	2017	2018	3 Yr Total	2016	2017	2018	3 Yr Total	2016	2017	2018	3 Yr Total
Business EE Portfolio																
Standard	1.49	2.75	1.93	3.32	18,619	20,853	35,004	74,476	3.320	3.718	6.241	13.278	$ 5.886	$ 6.586	$ 10.963	$ 23.435
Custom	1.67	2.13	2.43	2.84	27,633	53,515	71,962	153,110	10.053	19.467	26.178	55.698	$ 8.709	$ 16.815	$ 22.538	$ 48.063
Retro-commissioning	1.59	2.36	1.59	3.21	-	10,016	8,882	18,898	-	3.206	2.843	6.049	$ -	$ 3.921	$ 3.380	$ 7.301
New Construction	1.46	2.42	2.40	3.82	-	7,543	6,689	14,231	-	1.801	1.597	3.398	$ -	$ 2.909	$ 2.483	$ 5.392
Biz EE Portfolio Total	1.61	2.37	2.22	3.11	46,252	91,927	122,536	260,715	13.372	28.192	36.858	78.422	$ 14.595	$ 30.231	$ 39.364	$ 84.190
Biz EE Portfolio Total					260,715				78.42				$84.190			
TOTAL EE Portfolio	1.45	2.01	1.91	2.72	104,757	137,617	184,008	426,382	27.028	37.446	49.806	114.281	$ 36.408	$ 48.838	$ 62.321	$ 147.57
TOTAL EE Portfolio					426,382				114.28				$147.567			

8.11.2 Timing Issues Associated With Proposed Plan

8.11.2.1 Risk and Uncertainty Associated with Plan

In order to ensure DSM program continuity from MEEIA Cycle 2013 - 2015 with MEEIA Cycle 2016 - 2018 beginning on January 1, 2016, Ameren Missouri must submit its MEEIA Cycle 2016 - 2018 filing no later than December 2014. Working backwards from a January 1, 2016 start date, the following are critical path tasks that have to be in place in order to have MEEIA Cycle 2016 - 2018 programs in place by January 1, 2016:

1. Contractor selection (3 months: April 2015 – June 2015)

   This process involves procuring the following:

a. RES implementation contractors
b. RES EM&V contractors
c. BUS implementation contractors
d. BUS EM&V contractors
e. New DSM Potential and Market Assessment study

2. Development of contractual terms and conditions (June – August 2015)
3. Development of detailed scopes of work (SOW) for each contractor (July – September 2015)
4. MEEIA regulatory approval process
    a. 120 days from the time the filing is made (January – April 2015)
5. 2014-2034 DSM inputs required for integrated resource planning modeling (April 1, 2014)
6. 2013 Ameren Missouri DSM Program draft EM&V assessments issued (February 15, 2014)
7. 2013 Ameren Missouri DSM Potential Study completed (December 2013)

A pictorial view of the timeline for making the Ameren Missouri MEEIA Cycle 2016 - 2018 filing described in steps 1 through 8 above is shown in Figure 8.21 below.

Figure 8.21: MEEIA Cycle 2016 - 2018 Filing Timeline

MEEIA Cycle 2016 - 2018 program designs for DSM programs beginning in 2016 had to be substantially complete by December 2013 in order to meet an October 1, 2014 Ameren Missouri IRP filing due date. This required Ameren Missouri to design programs before having even a full year of DSM program field implementation and evaluation experience from the first year or 2013 of MEEIA Cycle 2013 - 2015 programs.

Draft EM&V reports covering 2013 program impact and process evaluations of each of the nine Ameren Missouri DSM programs were issued on February 15, 2014. Ameren Missouri attempted to update its MEEIA Cycle 2016 - 2018 DSM program designs with the latest EM&V information from those reports in the first Quarter of 2014. However, the 2013 EM&V impact reports were in draft form and the results therein may change based on stakeholder comments and, ultimately, based on Commission review and approval. Also, since the EM&V reports were issued on February 15, 2014 and the IRP project schedule required that DSM program design be complete by April 1, 2014 the review and update process had to be completed at a relatively high level. The final 2013 EM&V report was filed in June, 2014 but is still under approval consideration by the Commission at the time of this filling.

The preceding timeline illustrates the risk and uncertainty associated with MEEIA Cycle 2016 - 2018 DSM program design due to the fact that DSM programs to be implemented beginning in 2016 have to be designed in 2013 using relatively dated information.[82] An explanation of the specific risks and uncertainty is in order.

All cost effective energy efficiency for 2016-2018 annual load reduction goals are based on results from the Ameren Missouri 2013 DSM Potential Study. Energy efficiency measure incremental savings for the 2013 DSM Potential Study came from the Ameren Missouri MEEIA Cycle 2013 - 2015 Technical Resource Manual (TRM) since Ameren Missouri did not have 2013 EM&V data to draw from at the time the DSM Potential Study was commissioned. It is reasonable to adjust the DSM Potential Study results and Ameren Missouri annual load reduction goals accordingly to reflect the best information available at the time to design programs for MEEIA Cycle 2016 – 2018. Likewise beginning with 2016 EM&V results and continuing again in 2017 and 2018 in MEEIA Cycle 2016 - 2018, energy efficiency measure savings and annual load reduction goals should be updated as soon as Commission approved EM&V results are known for each year. Absent this proposed flexibility, Ameren Missouri would be required to meet annual goals that may be based on individual energy efficiency measure savings that may change substantially over time from actual EM&V primary data collected by Ameren Missouri customers who participated in Ameren Missouri DSM programs.

There are competing factors impacting energy savings year over year such that it is imprudent to lock in estimates of DSM portfolio energy savings for 2016 in 2013. The convergence of prior successful Ameren Missouri DSM programs moving the market baselines for many energy efficiency measures coupled with federal intervention in the form of ever increasing appliance efficiency standards and building codes is a challenge. There is the issue with ever changing primary EM&V data collection and ensuing

[82] 4 CSR 240-22.050(6)(C); Additional details can be found in the work papers.

changes in energy efficiency incremental energy consumption. There are the issues of the speed of technological innovation and changes in DSM program structure and delivery in a smarter grid environment. There are regulatory policy issues that could, among other things, change the definitions of demand-side programs to include distributed generation, electric vehicles and electro technologies that may result in lower overall greenhouse gas emissions and lower customer energy intensities and energy costs. These types of issues require Ameren Missouri, stakeholders and the Commission to re-think the issue of how to address 3-year DSM program implementation planning flexibility from plan filing to plan implementation.

8.11.3 Recommendation for Framework to Adjust MEEIA Cycle 2016 - 2018 Program Designs

The building blocks for any DSM implementation plan are:

- Incremental energy savings associated with hundreds of energy efficiency measures
    - A corollary to incremental energy savings is incremental energy measure costs
    - Another corollary to incremental energy savings is the selection of the baseline energy technology against which the more efficient technology is being compared
- Cost effectiveness screening of individual energy efficiency measures
    - Cost-effectiveness is a function of the Ameren Missouri avoided cost of energy, capacity and investment in transmission and distribution infrastructure
        - Although avoided costs are typically "locked in" for a 3-year implementation plan, avoided cost volatility from year-to-year can be meaningful
        - The Commission definition of avoided costs, if changed, could result in substantive changes in the magnitude of benefits associated with DSM measures. For example, the quantification of non-energy benefits including such components as environmental, economic (job creation), and/or comfort are included in some jurisdictions' definitions of benefits. Other energy related benefits include water and natural gas benefits in addition to electric benefits.
    - Assembly of cost effective measures into individual DSM programs
        - The primary issue in assessing DSM program cost effectiveness is the estimation of the individual program net-to-gross (NTG) ratio. This is typically a qualitative assessment on the part of EM&V

contractors that has no statistical validity. NTG results will vary based on contractor, methodology employed, timing of survey – both in proximity to purchase of efficient measure as well as time of day, respondent and weighting or scaling of respondent answers to qualitative questions.

- Another significant program design concern is interactive effects of measures. The installation of one efficient measure may impact the energy savings of a distinctly different efficient measure. For example, assume a home's attic insulation is increased from R-11 to R-30. The increased insulation allows the house to hold heat or cold longer, depending upon the season, thereby reducing run times for HVAC equipment which reduces HVAC equipment incremental energy savings – possibly to levels that render the HVAC incremental energy savings as not cost effective. This is exactly what Ameren Missouri experienced in the evaluation of its 2013 residential new construction program – rendering the program not cost effective.

- The final issue is the appropriate cost effectiveness threshold value or range of values to use in determining whether a program is cost effective. In theory, a program benefit/cost ratio of 1.0 assumes that program net benefits are equivalent to program net costs. However, the risk and uncertainty associated with ex-post impact analysis as well as ex-post NTG analysis is high. On top of this is the consideration of the Ameren Missouri and Commission approved demand-side investment mechanism regulatory framework for DSM program cost recovery, program throughput disincentive and the opportunity to earn financial performance incentives. That mechanism is based on a net shared benefits model that necessarily requires that DSM program benefits exceed costs.

Noting the plethora of uncertainties associated with future DSM program EM&V impacts and changing baselines, it becomes evident that the regulatory filing requirements that necessitate making the MEEIA Cycle 2016 - 2018 plan regulatory filing in the 4th Quarter of 2014 may make the MEEIA Cycle 2016 - 2018 plan, either in whole or in part, obsolete at worst or in need of substantial revision at best by the time implementation begins in 2016. As discussed previously, vast changes in DSM program assumptions can and will occur in a span of two years. Individual energy efficiency measure baseline energy savings may change. An example is residential lighting energy efficiency measures. Current 2014 residential lighting program assumptions are that the halogen bulb which represents the Energy Independence and Security Act of 2007 (EISA) baseline energy consumption represents the baseline. The reality, however, is that the baseline lighting technology should be represented by whatever lighting technology that has the highest market share. What if the majority of residential customers who purchase light bulbs in 2015 purchase CFLs rather than halogens? If so, should the baseline in 2016 be changed to CFLs?

Individual energy efficiency measure incremental energy savings may change. An example is the appliance recycling program. The EM&V contractor developed a regression model to estimate appliance energy usage based on secondary data on refrigerator energy usage from DSM programs in California and Michigan. If the EM&V contractor adds additional secondary data from other jurisdictions to the model, the model parameters will change as will energy savings associated with appliances. In addition, as the age of refrigerators collected in the program decline and/or as the average manufacture date of refrigerators specifically becomes post 1993, energy consumption of collected refrigerators is expected to decline. This is due primarily to newer, more stringent federal refrigerator energy efficiency standards put in place beginning in 1993. Either one of these two occurrences or both will change the energy savings associated with the Appliance Recycling program from what they were assumed to be in the 2013/2014 program designs.

Estimates of NTG include some amount of subjectivity and may vary significantly year over year. The issue is what discrete value for NTG should be assumed for each program that is designed in 2013 but that begins in 2016 and runs through 2018? For example, consider the 2013 residential lighting program. EM&V contractors calculated a 1.19 NTG value for the residential lighting program in 2013. Should 1.19 be assumed as a reasonable placeholder for 2016-2018 for the program? The sum of the parts that equates to a NTG = 1.19 includes free ridership, "like" participant spillover, "unlike" participant spillover, non-participant spillover and market effects. How will each of those individual NTG inputs change between 2014 and 2016 and then through 2018?

New program design concepts and associated metrics can take years to develop. New data and information, not available in 2013, may become available in 2014 or 2015 after the Ameren Missouri IRP and MEEIA Cycle 2016 – 2018 filings are made that justify new DSM programs. An example is the development of cutting edge customer energy behavior change programs. Ameren Missouri is interested in understanding how customer rate and billing options can impact energy consumption behavior. An example of a program under consideration is a customer Prepay or pay as you go billing option for which studies at other electric utilities have quantified annual energy savings of approximately 10% or more. However, the Prepay option ideally requires more advanced metering technologies and IT infrastructure to put in place and to cost out in order to determine if such a program is cost effective from a DSM perspective. Ameren Missouri is in the process of acquiring the data necessary to cost out such a program. The data was not available at the time of the preparation of the 2014 IRP filing.

The benefits of energy efficiency measures and programs are based on the Ameren Missouri avoided costs which are based on the market price of electricity. Avoided energy, capacity and transmission and distribution costs are based on the market price of these commodities at the time program designs were developed for the 2014 IRP filing. Electricity commodity markets are volatile and the forward view of the market price of these commodities change daily, monthly, and annually. The forward view of these commodities at the time program designs were developed for the 2014 IRP filing were at a low point due primarily to the low price of natural gas as well as a sluggish economy that resulted in relatively flat electric load growth. Should the market price of these commodities change prior to the start of MEEIA Cycle 2016 - 2018 programs in the 2016-2018 DSM implementation planning period, the cost effectiveness of the DSM portfolio may change.

Ameren Missouri seeks the flexibility to adjust MEEIA Cycle 2016 - 2018 program designs between the time the IRP is submitted in the 4th Quarter of 2014 to the start of program implementation in January 2016. In addition, Ameren Missouri seeks the flexibility to annually adjust both the TRM as well as annual load reduction targets during the 2016-2018 implementation period to reflect the best available individual measure energy savings estimates from the most recent EM&V impact analyses of all programs. The proposed process to make adjustments has the following components:

- 2014 EM&V results are to be finalized no later than September 2015 per the MEEIA Cycle 2013 - 2015 Stipulation and Agreement;
    - o Ameren Missouri proposes that revised protocols be established that would finalize EM&V results by June

- MEEIA Cycle 2016 - 2018 DSM programs begin in January 2016. Ameren Missouri will adjust its MEEIA Cycle 2016 - 2018 Technical Reference Manual (TRM), which was developed using 2013 EM&V individual measure impact results, to reflect 2014 EM&V results in the 4th Quarter 2015. The adjusted TRM will then be the basis for adjusting 2016 portfolio and program annual load reduction targets.

- The same timing and process will be used to adjust 2017 and 2018 annual load reduction targets for the DSM portfolio and individual programs. In other words, the realities of finalizing annual EM&V impacts and updating the TRM and portfolio and program design result in a process that optimizes updating the TRM for any current program year using actual EM&V data from the program year completed two years prior.

- The Ameren Missouri process and procedure to adjust its DSM Potential Study to reflect changes in individual measure impacts from the latest EM&V impact analyses as described in the latest TRM is described in detail in Section 8.6.3

- The results from the annual updated TRMs will be applied prospectively for purposes of calculating lost revenues and financial performance incentives. TRMs will be based on actual EM&V results that are two years in arrears.

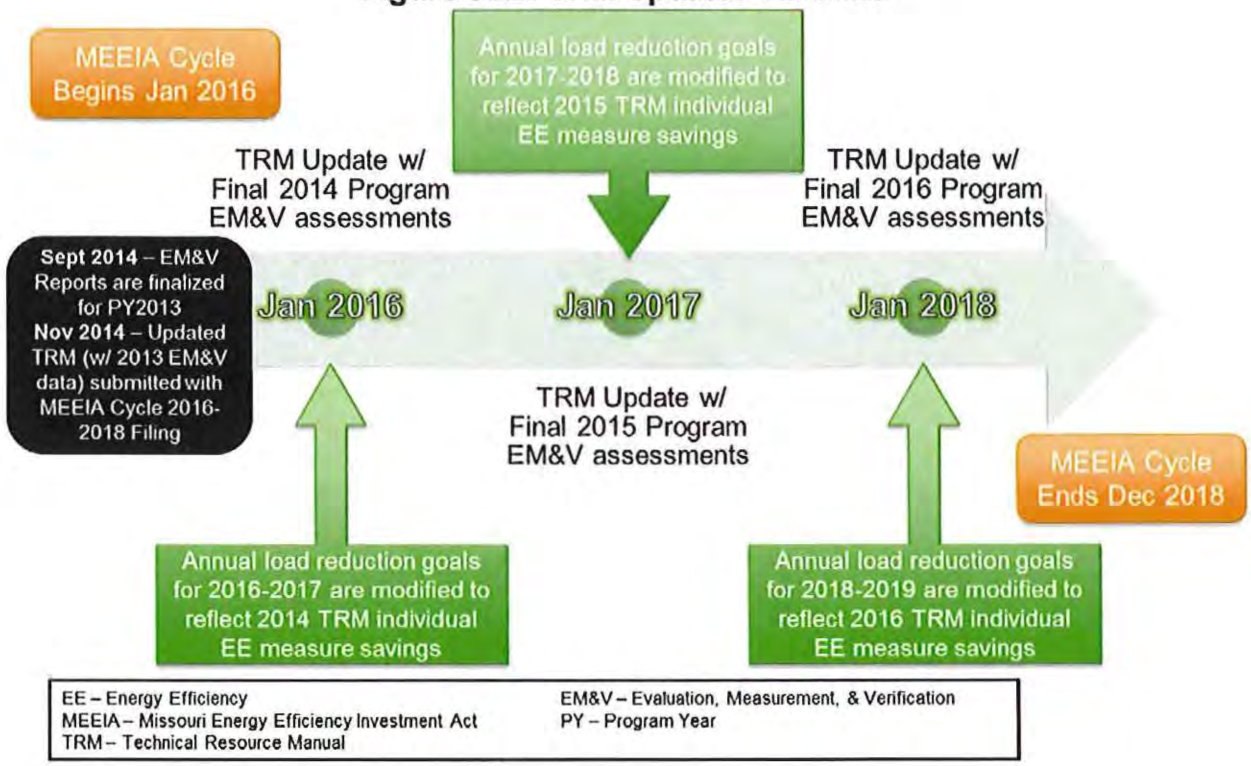
Ameren Missouri also seeks the flexibility to make changes to the programs submitted in 2014 in the MEEIA Cycle 2016 - 2018 filing up to the start date of January 1, 2016 for the MEEIA Cycle 2016 - 2018 DSM programs. Those changes may reflect any one or any combination of the following:

- Information from 2014 and 2015 EM&V impact analyses including:
    - Incremental measure energy savings and costs
    - Efficient measure baseline changes
    - NTG assumptions
- New program design proposals
    - May include input from DSM Implementation contractors engaged to manage MEEIA Cycle 2016 - 2018 programs
    - May include proposals from Ameren Missouri DSM stakeholders
- Modifications to proposed MEEIA Cycle 2016 - 2018 program designs to reflect changes in the constructs of proposed delivery mechanisms, marketing campaigns, EM&V approaches, cutting edge cost effective technologies and customer behavioral change programs
    - Unforeseen but significant changes in DSM program cost effectiveness modeling inputs
    - Lessons learned from MEEIA Cycle 2013 - 2015 program implementation and evaluation
- Future revisions, if any, to MEEIA legislation that may impact program design

If a proposed program change reflects changing the kWh associated with a measure or program, the annual load reduction goals will change proportionally using the procedure identified in Section 8.6.3.

The following timeline illustrates how the desired flexibility would be implemented in MEEIA Cycle 2016 – 2018 for updating the TRM:

Figure 8.22: TRM Updates Timeline



8.11.4 Potential Uncertainty

The potential uncertainty associated with the load impact estimates of the demand-side resource portfolio was calculated for each of the scenarios as can be seen in the table below.[83]

Table 8.25 Uncertainty Scalars

Scenario	Scalar
MAP High	0%
MAP Low	-18%
RAP High	+9%
RAP Low	-9%

The RAP Low and High scenarios were based on a formulaic approach where the top 20 measures for residential, commercial, and industrial customers that accounted for the majority of the energy savings were identified. The 2013 EM&V realization rates for those measures were applied and Post-EM&V values were calculated. The total realization rate was calculated to be 91.2%. The difference between complete

[83] 4 CSR 240-22.050(6)

realization (100%) and 91.2% was deemed to be the scalar (+/- 8.8% ≈ +/- 9%) for the RAP scenarios.

Since there is more EM&V risk around MAP levels and because customers are harder to reach, the RAP scalar was doubled for the MAP low scenario (-18%). By definition MAP is the hypothetical upper limit or ceiling for potential and therefore the MAP high scenario is equivalent to the MAP base scenario.[84] The table below shows the how the realization rates were applied.

Table 8.26: Application of Realization Rates

	Pre-EM&V Top Measures GWH and % of Total Measures		Pre-EM&V Total GWH	PY 2013 EM&V RR for Top Measures	Post-EM&V Total GWH	Overall RR
Residential	228.97	91%	250.97	72.7%	182.52	72.7%
Commercial	403.91	77%	523.00	100.0%	522.89	100.0%
Industrial	24.5	77%	31.67	93.8%	29.71	93.8%
Total			805.64		735.12	91.2%

8.12 MEEIA Cycle 2016 - 2018 Technical Reference Manual (TRM)[85]

Ameren Missouri developed its first TRM to support its first Missouri Energy Efficiency Investment Act (MEEIA) filing in January 2012. The first version of the TRM was a Microsoft Word document supported by voluminous work papers in multiple formats and file locations. Ameren Missouri leveraged previous evaluation reports from its programs implemented between 2009 and 2011 (Cycle 2013 - 2015), Ameren Missouri specific data from its DSM Potential Study, its internal database of measures, and other states' TRMs (where applicable) to develop the first TRM.

Ameren Missouri's second TRM will support its second MEEIA filing for the 3-year DSM implementation plan covering 2016-2018. Ameren Missouri has engaged a contractor to implement TRM development software and populate the software with Ameren Missouri's latest results from its evaluation, measurement and verification (EM&V) of its 2013 DSM programs to provide the basis for its MEEIA Cycle 2016 - 2018 TRM.

Ameren Missouri's primary objective in improving its TRM development process was to acquire a transparent TRM software tool to identify measure level savings values and algorithms (and associated documentation preferably based on primary data collection)

[84] 4 CSR 240-22.050(6)(C)1
[85] EO-2012-0142 14

to develop energy efficiency measure savings estimates. As was also articulated in the MEEIA Cycle 2013 - 2015 filing, it is critical that these values be agreed upon at the beginning of the program implementation and applied prospectively; the MEEIA Cycle 2016 - 2018 TRM will be used by Ameren to provide the transparency sought and the ability to maintain the measure data throughout the implementation period.

The MEEIA Cycle 2016 - 2018 TRM is an online technical reference database containing measure-level data, including savings, savings estimation protocols, and source documentation for all measures in the existing Ameren Missouri TRM.

Customers, Ameren Missouri, the Commission, and stakeholders will realize the following benefits of the state-of-the art TRM system:

- Consolidation and organization of efficiency measures, measure attributes, and supporting data, including all savings values, costs, assumptions, equations, savings estimation protocols and source documentation. An easy-to-use, web-based interface to facilitate access to measure parameters, savings calculation algorithms, effective useful life, and incremental measure costs.

- Automated version control, including logging, retention, and archiving of all measure versions, including interim measure updates. Greater transparency into measure assumptions due to the fact that source documentation can be directly linked to a measure and the relevant attributes and parameters.

- Ability to create customized measure specific reports and/or export files in various file formats; this can be used to develop customized files for program reporting.

- Maintenance of accurate records of TRM savings based on versions for tracking and reporting using the online TRM tool.

8.13 R&D Issues that will Evolve from 2014 to 2016 (Start of MEEIA Cycle 2016 - 2018)[86]

8.13.1 Residential Light Program Design for 2016 – 2018

Background

Ameren Missouri's residential lighting program has provided the majority of the residential DSM portfolio kWh savings since 2009. The majority of the savings from the program have come from the promotion of CFLs.

The Energy Independence and Security Act of 2007 (EISA) changed the landscape for residential lighting programs by effectively mandating that CFL technology become the baseline energy standard for residential lighting beginning in 2020. Citing specific EISA language:

> ...IF THE FINAL RULE DOES NOT PRODUCE SAVINGS THAT ARE GREATER THAN OR EQUAL TO THE SAVINGS FROM A MINIMUM EFFICACY STANDARD OF 45 LUMENS PER WATT, EFFECTIVE BEGINNING JANUARY 1, 2020, THE SECRETARY SHALL PROHIBIT THE SALE OF ANY GENERAL SERVICE LAMP THAT DOES NOT MEET A MINIMUM EFFICACY STANDARD OF 45 LUMENS PER WATT.[87]

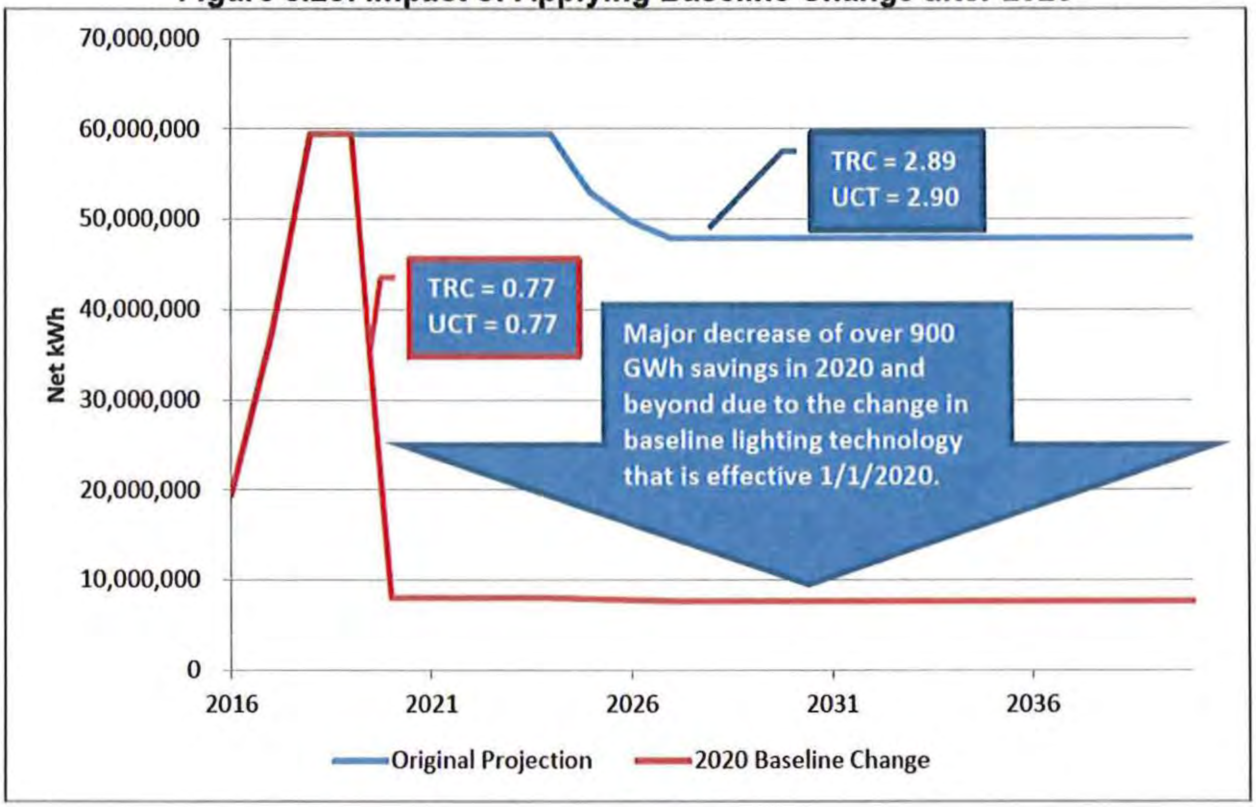
Continuing to provide incentives for CFLs is not cost effective for 2016 and beyond. This is due to the fact that CFLs typically have 8-10 year effective useful lives. Consequently, assuming an 8-year effective useful life, a CFL installed in 2016 would last until 2024. However, since EISA mandates that CFLs, or at least the lumens per watt equivalent to a CFL, become the minimum baseline lighting technology beginning in 2020 then CFLs installed in 2016 should not receive incremental energy savings benefits in 2020, 2021, 2022, 2023, and 2024. If CFLs installed in 2016 only receive incremental energy savings benefits for 2016, 2017, 2018 and 2019, they are not cost effective at the avoided costs used in the MEEIA Cycle 2016 - 2018 filing. It should be obvious that CFLs installed in 2017 and 2018 would be even less cost effective than CFLs installed in 2016.

[86] EO-2014-0062 j

[87] http://www.gpo.gov/fdsys/pkg/PLAW-110publ140/html/PLAW-110publ140.htm

The following graph illustrates the magnitude of the decrease in CFL savings associated with EISA requirements beginning January 2020.

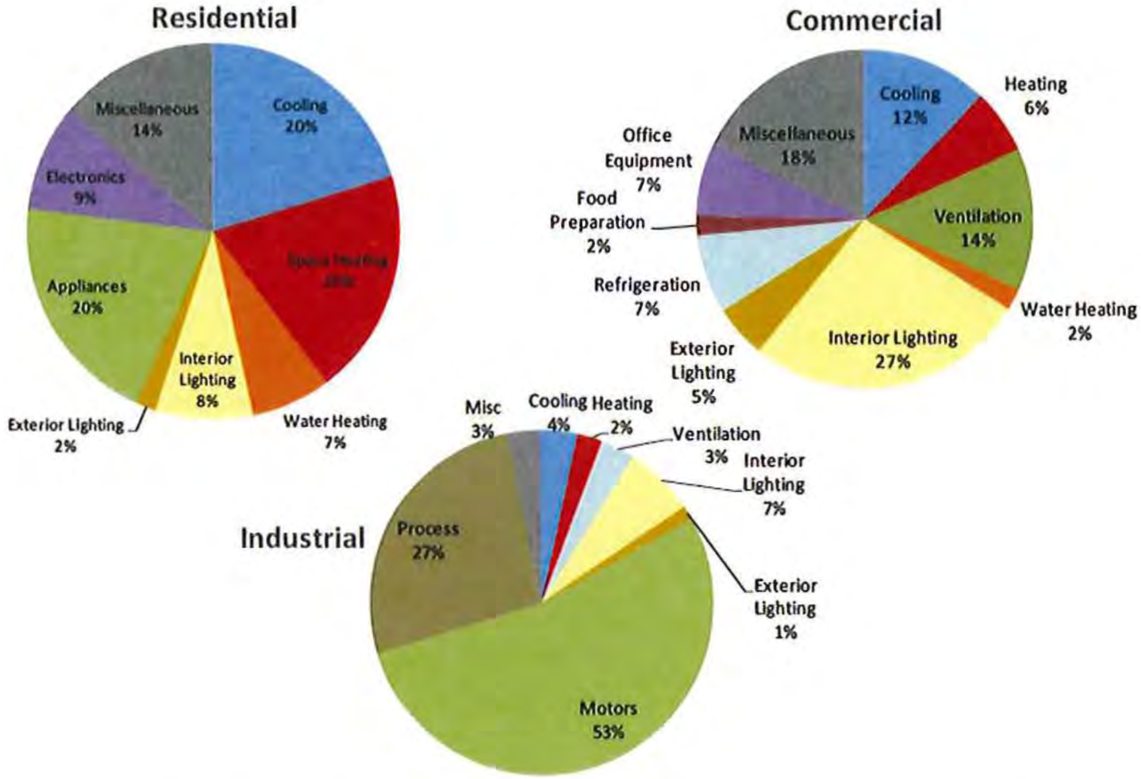
Figure 8.23: Impact of Applying Baseline Change after 2020



8.13.2 Smart Thermostats

The thermostat may be the single most important ubiquitous device that controls electricity use in the home. From the 2013 Ameren Missouri DSM Potential Study primary market research, approximately 40% of all the electricity consumed in the average home goes to heating and cooling the home. See the graph from the DSM Potential Study below:

Figure 8.24: Annual Electricity Use by End Use and Sector (2011)[88]



Ameren Missouri has attempted to maximize energy savings opportunities inherent in thermostatic controls through multiple residential DSM programs – including the HVAC, Efficient Products, and Low Income programs. Unfortunately, 2013 DSM program EM&V results show that customers in general (but there are exceptions) continue to use smart or programmable thermostats in a manual mode thereby negating the energy savings opportunities associated with the technology. In fact, the 2013 EM&V reports for the residential HVAC program, calculated a 15% realization rate for thermostats. The realization rate is the ratio of actual savings to the Ameren Missouri MEEIA Cycle 2013 - 2015 TRM savings.

The fact that customers tend to use smart thermostats in a manual mode is not unique to Ameren Missouri. It is well documented by electric utilities throughout the nation. So much so that in the 2005 timeframe Energy Star rescinded its thermostat certification program citing several studies showing that the programming features were not being used properly, or at all, and that the promised savings had not materialized. However, Energy Star is working collaboratively with thermostat vendors and utilities to devise a new set of thermostat specifications. The new Energy Star thermostat specification that shows promise in terms of the thermostat delivering meaningful energy savings is a

[88] Volume 3 of the Ameren Missouri DSM Potential Study

communications protocol that allows 3rd party developers to enable access to the thermostat's full range of communication and remote control capabilities.

Enter the emerging smart thermostat technologies. The NEST immediately comes to mind due to its prominence in national news articles when Google acquired NEST in early 2014. However, there are several other prominent, user friendly emerging smart thermostats – Carrier ComfortChoice Touch, Honeywell FocusPro, Emerson Smart Energy and Ecobee Smart Si to name a few.

It appears that a transformation of thermostat functionality is imminent. The shift towards communicating thermostats opens the potential for new communications-based functionality. The question remains, however, whether the new standards are an improvement on the previous standards, i.e., whether the new thermostats will actually be used by customers in a way that uses less energy.

It is difficult at the time of this filing to separate the promise from the reality of emerging thermostat technologies.[89] This healthy skepticism is based on the fact that Ameren Missouri incented smart thermostats as part of its residential DSM portfolio in 2013 and EM&V results showed a 15% realization rate. The thermostat marketing blitz touts significant potential for both energy and peak demand savings from the new generation of smart communicating thermostats. For example, early NEST marketing brochures cited potential annual energy savings of 19-35% for the heating and cooling requirements of a home. Savings of this magnitude are basically unprecedented for any type of smart thermostat in the nation heretofore.

The initial NEST marketing blitz was toned down after NEST did a trial of NEST users in 45 states in March 2013. NEST wrote a subsequent white paper on the results of the trial that showed more reasonable average actual energy savings for both heating and cooling seasons in the 5-10% range.

Ameren Missouri is monitoring national EM&V work on emerging smart thermostat technologies being conducted by organizations such as E-Source and electric utilities such as Austin Energy to acquire as accurate and reasonable data as possible to assess the cost effectiveness of this emerging technology.

8.13.3 Prepay

A Prepay program is one where a participant purchases credit for service in advance of consumption, then uses the service, and at any point can purchase additional credit. If the credit is depleted then the consumer no longer has access to that service. A

[89] 4 CSR 240-22.050(1)(E)1&2 Emerging technologies is discussed further on page 6-2 of Volume 3 of the DSM Potential Study

mainstream example is prepaid cell phone service. An additional example is prepaid toll programs like Sun Pass in Florida.

A growing trend among utilities is electric Prepay programs. They were designed to eliminate credit checks, deposits, monthly bills, late charges, disconnect/reconnect charges, help customers budget and manage energy cost, and these programs consistently provide significant energy savings – hence the energy efficiency connection.

Prepaid electricity is a rapidly growing payment option for electric utilities and is a concept widely used with Electric Co-ops. DEFG's (Distributed Energy Financial Group) Prepay Energy Working Group found that customers saved on average 11% of energy consumption in a study of Oklahoma Electric Cooperative (OEC), with a 95% confidence interval going from savings of 10.2% to 13.0%.[90] DEFG engaged economist Michael Ozog, Ph.D. to apply statistical techniques accepted in the evaluation of utility sponsored energy efficiency programs to measure the effect of prepayment on energy use.[91]

The table below shows how significant the OEC Prepay savings are compared to the other OEC efficiency measure savings.

Table 8.27: Annual Savings of Energy Efficient Measures

Measure	Annual Savings	
	kWh	Percent
Duct Sealing	32	0.2%
CFL	62	0.3%
Water Heater Wrap	79	0.4%
Insulation retrofit	96	0.5%
HVAC tune-up	118	0.6%
Low-Flow Showerhead	130	0.6%
Pipe Insulation	133	0.6%
Energy Star Refrig	142	0.7%
Energy Star Cloths washer	200	1.0%
Normative report	300	1.5%
Heat Pump Water Heater	500	2.4%
CAC early replacement	700	3.4%
Refrig. Early replacement	1,376	6.7%
Prepay	1,690	**11.0%**
Ground Source Heat Pump	2,744	13.4%

[90] "The Effect of Prepayment on Energy Use," a report of the Prepay Energy Working Group, DEFG LLC, Washington DC, March 2013.
[91] "The Effect of Prepayment on Energy Use," a report of the Prepay Energy Working Group, DEFG LLC, Washington DC, March 2013.

The reduction in energy consumption has been attributed to the increased awareness of the link between usage and cost. That is because an important aspect of a prepaid program is the constant communication to the customer about usage and cost. This type of communication forces participants to better understand how changes in consumption can save money which then allows those customers to manage their usage more actively.

Ameren Missouri is investigating the potential for a Prepay program, but at this time does not have enough information to propose a formal program.

Metering Hardware

As stated earlier the enabler of Prepay is two-way communication. A typical program would provide information with respect to how much credit is available and how long it will last before more credit is necessary. There are a limited number of hardware options available to allow for this capability. One option is an advanced smart meter, which many utilities are rolling out or already have in place.[92] Another option is a cellular meter and yet another is a local based meter with an in-home-display (IHD). With the advances in smart meter technology and wide use of smart-phones and tablets the IHDs are becoming an outdated technology, which customers will not favor.

Ameren Missouri currently has an AMR system, which is reaching the end of its effective useful life, but is developing a business case for an AMI system. The potential roll out of AMI has considerable effect on a Prepay program and is why Ameren Missouri is unable to file for a program at this time.

Customer satisfaction

Another added benefit of Prepay electric programs is that it increases customer satisfaction. In another study by DEFG, customers had high levels of satisfaction with their Prepay service as 92% of the surveyed customers indicated they were "very satisfied" or "somewhat satisfied" with their Prepay service.[93] Prepay gives customers another option for payment and provides constant communication with the customer with updates on account balance and usage.

Is Prepay An Option For Consideration As A MEEIA DSM Program?

4 CSR 240-3.164 (F) defines a demand-side program as "any program conducted by the utility to modify the net consumption of electricity on the retail customer's side of the

[92] 4 CSR 240-22.050(3)(D)
[93] "Northwest utility Prepay Study," a report of the Prepay Energy Working Group, DEFG LLC, Washington DC, April 2014.

meter including, but not limited to, energy efficiency measures, load management, demand response, and interruptible or curtailable load."

4 CSR 240-3.164 (O) defines an energy efficiency measure as "any device, technology, or operating procedure that makes it possible to deliver an adequate level and quality of energy service while (1) using less energy than would otherwise be required; or (2) altering the time pattern of electricity so as to require less generating capacity or to allow the electric power to be supplied from more fuel-efficient units."

Therefore, Prepay qualifies as a potential MEEIA energy efficiency program pending the passing of appropriate cost effectiveness tests.

8.13.4 LED Street Lights

The MEEIA statute defines "Demand-side program" as any program conducted by the utility to modify the net consumption of electricity on the retail customer's side of the electric meter, including, but not limited to energy efficiency measures, load management, demand response, and interruptible or curtailable load.

Roadway street lighting, however, is primarily Company owned and therefore typically considered a utility infrastructure investment. However, retail customers pay directly for street lighting lumens they use. Unlike other utility infrastructure investments in generation, transmission and distribution, there is a direct link between Customer usage and corresponding customer value from Company owned street lights and customers' electric bills. Consequently, Ameren Missouri would like to explore with the Commission and stakeholders[94] the possibility of proposing both a Company owned and customer owned LED street lighting DSM program utilizing the proposed MEEIA Cycle 2016 - 2018 regulatory framework.

The reason for considering a LED street lighting DSM program is so that Ameren Missouri can complete the majority of the conversion of existing street lighting from high pressure sodium lighting technology to LED lighting technology(ies) during the 2016-2018 MEEIA Cycle 2016 - 2018 implementation period. Absent the MEEIA regulatory framework, traditional rate base approaches may not result in an economic financial decision for the Company and therefore would not result in a "win-win" (i.e., the Company's incentives would not be aligned with the customer incentives to use energy more efficiently, as required by MEEIA). The high up-front capital costs and the lag associated with recovering these investments can outweigh the savings in maintenance costs. The significance of introducing ratemaking realities is that between rate cases the Company may retain any expense savings (i.e., the avoided maintenance costs) but

[94] EO-2012-0142 14

conversely the Company is unable to recover the costs of new capital investments until a new rate case. Therefore there is tension between these two aspects and a thorough analysis can determine which of those effects is more significant. Ameren Missouri performed such an analysis in its July 2013 LED street lighting report to the Commission. The results showed that the initial capital investments were high enough that even when accounting for the maintenance cost savings, the net present value is unfavorable to the Company. It is noteworthy that the previously described revenue requirement modeling analysis assumes all costs are recovered and the analysis indicates positive net benefits (albeit relatively small); however, this analysis shows that under the current ratemaking paradigm in Missouri the Company would not recover all of its costs. The table below summarizes the analysis for each scenario.

Table 8.28: Ameren Financial Impacts

Implementation Scenario	NPV of After Tax Earnings
100% over 3 years	-$1.44 million
100% over 5 years	-$1.42 million
100% over 5 years; 3 year delay	-$1.38 million

The Commission required that the Company update its LED business case analyses again in 2014. The Company is in the process of updating its study and results are not available at the time of the 2014 IRP filing.

Background

In July 2013, Ameren Missouri filed its first LED street lighting Business Case analysis with the Commission. The conclusion was that LED technology was not (as of July 2013) quite suitable for a mass change-out at that time. However, Ameren Missouri learned a great deal about LEDs as a result of doing such an in-depth analysis and recognized that LED technology holds promise in the future. The key observations from the July 2013 analysis were:

1. Although LED SAL technology may be ready for efficiency programs, the technology is not yet cost effective for all LED lighting applications.
2. Key uncertain factors regarding LED SAL cost-effectiveness include: the labor cost of installation, maintenance trip savings, LED price trends, and the effective useful life of LED SAL.
3. Potential stranded costs and regulatory lag in Missouri are additional implementation barriers for LED SAL.
4. There is a high level of risk and uncertainty associated with installing LED SAL.
5. Ameren Missouri will enhance customer choice of light options by proposing a tariff to allow customers to own and install LED SAL.

The Commission approved Ameren Missouri's analysis that the LED business case for street lights did not merit a full scale implementation proposal. However, the Commission also required that Ameren Missouri file annual updates to the LED street light study and determine when the business might be cost effective.

In the third Quarter of 2014 Ameren Missouri sought price quotations from LED street light manufacturers to begin the process to update critical inputs to the LED street light business model. Perhaps the single most critical component of the business case is the capital cost of the LED lights. The refreshed LED price quotations showed that LED street light prices decreased significantly for most of the LED lights in a 12-month time period. The price decrease was of a sufficient magnitude to make many LED light products that were not cost effective in the July 2013 business case cost effective in the 2014 business case analysis.

Table 8.29 shows each type of LED street light, associated quantities of Company owned lights, and associated benefit/cost ratios:

Table 8.29: LED Street Light Types

Light	TRC	Count
Horizontal - enclosed on existing wood pole HPS 117	3.42	16,975
Horizontal - enclosed on existing wood pole HPS 306	2.14	13,639
Horizontal - enclosed on existing wood pole HPS 473	0.96	2,993
Horizontal - enclosed on existing wood pole MV 206	3.36	8,506
Horizontal - enclosed on existing wood pole MV 477	4.39	3,952
Horizontal - enclosed on existing wood pole MV 1095	4.07	76
Horizontal - enclosed on existing wood pole MV 2160	6.47	
Open bottom on existing wood pole HPS 70	∞	59
Open bottom on existing wood pole HPS 117	6.09	56,230
Open bottom on existing wood pole MV 118	∞	3,013
Open bottom on existing wood pole MV 206	15.29	16,691
Post top including 17 foot post HPS 117	0.15	40,831
Post top including 17 foot post MV 118	0.15	110
Post top including 17 foot post MV 206	0.61	9,812
Directional HPS 306	0.33	3,522
Directional HPS 473	0.62	3,574
Directional MH 450	0.57	5,069
Directional MH 1077	2.25	1,005
Directional MV 294	0.29	326
Directional MV 1095	1.91	28
Total Lights		186,411
Total Cost-effective Lights		123,167
% Cost-effective		66.1%

Additional information will be provided in Ameren Missouri's 2014 LED Street Light update.

8.13.5 Small Business Direct Install (SBDI) Program

Ameren Missouri is actively pursuing alternative program design options to better serve small commercial customers. An option is an Ameren Missouri Small Business Direct Install (SBDI) program. The primary components of an SBDI program design typically include:

1. An energy audit performed most likely by a third party contractor
2. Processing of the audit data into information for the customer on relevant cost effective energy efficiency opportunities
3. A specific energy efficiency project proposal complete with energy savings, cost savings, project costs and project paybacks and applicable Ameren Missouri incentives
4. All work is done on a turn-key basis by the Ameren Missouri third party contractor and associated trade allies

Typically audit programs of this type include some type of direct install, "on-the-spot" component, such as efficient light bulbs or faucet flow aerators, so that at least a minimal amount of kWh savings can be garnered from a site visit should the customer choose not to go forward with identified cost effective energy savings opportunities.

In summary, the services to small business customers offered through this program encompass all aspects of project implementation including strategic planning, identification of potential measures through energy audits and other tools such as retro-commissioning, direct installation of low-cost/no-cost measures, as well as installation and financial incentives for capital investment energy efficiency measures. The program would be open to all of Ameren Missouri's qualified commercial customers (typically to those small commercial customers with less than 150 kW demand). The program would target all cost effective end-uses including, but not limited to, lighting, HVAC, refrigeration, and plug loads.

The program design challenge with SBDI is cost effectiveness. Direct install programs generally are more costly to administer and implement. For example, prior to the implementation of the Energy Investment and Security Act (EISA) of 2007 when CFL energy savings were measured relative to a baseline of incandescent light energy savings, SBDI programs generally were marginally cost effective. With more efficient lighting baselines for the 2016-2018 implementation period, it is difficult to adjust the energy efficiency measure mix or to alter the program delivery mechanisms such that the SBDI program is cost-effective – at least from a cost effectiveness modeling perspective.

Ameren Missouri will continue to gather data and analyze alternative program designs and delivery mechanisms to determine if the SBDI program can be cost-effective for the 2016-2018 implementation period. Alternative approaches under consideration include:

- Limit the program to direct install measures only
- Focus on low-cost/no-cost measures including:
    - Chiller or hot water settings
    - Reprogramming the energy management system
    - Correcting building schedules
    - Correcting supply and return fan VFD settings
    - Repairing damaged installation
    - Installing faucet aerators

8.13.6 Weekly Customer Usage Updates

Ameren Missouri expects to roll out a new customer weekly usage update program. This will be an opt-in option for customers to receive real time usage and billing information in a variety of forms delivered via e-mail. Although the program's primary purpose is to assist customers, the program also has energy efficiency implications in the form of customer energy behavior change. Ameren Missouri is exploring opportunities to include targeted energy efficiency messaging with the Billing Alerts program to determine the potential to extract meaningful energy efficiency savings from this program.

8.13.7 Electric Vehicles

Ameren Missouri is considering the development of a program in which residential electric vehicle charging stations are incented to promote the adoption of electric vehicles (EVs).

As defined by MEEIA a:

(F) Demand-side program means any program conducted by the utility to modify the net consumption of electricity on the retail customer's side of the meter including, but not limited to, energy efficiency measures, load management, demand response, and interruptible or curtailable load;

This is a unique program in that most energy efficiency programs apply a measure to replace or upgrade an existing piece of equipment, while a program of this nature involves the shift of "fuel type" from one industry to another in the interest of reducing CO_2 emissions (i.e., the Oil Industry to the Electric Industry).

The internal combustion engine (ICE) has powered motor vehicles for years and dominated the market. Auto manufacturers, in an effort to comply with federal regulation and to attract customers, have tried to increase the fuel economy of their fleet. Many automakers are switching some of the product offerings to EVs, but one of the hindrances to their adoption is the need for charging stations. Ameren Missouri is considering a potential energy efficiency program to incent the full cost and installation of a residential charger for customers who purchase an EV.

A supply chain analysis (of Ameren Missouri generation); comparing a vehicle with an ICE averaging 30 mpg and an electric vehicle with a 16.5 kWh battery results in the electric vehicle emitting almost 3 tons less CO_2 into the atmosphere than the ICE vehicle. If the overall environmental goal is to reduce carbon and mitigate climate change influences from the transportation sector then this is a segment of the market that should be considered alongside other energy efficiency initiatives.

The difference in carbon emissions between ICE and EVs is expected to increase going forward as Ameren Missouri adds more renewable energy resources to its portfolio.

Energy Savings Calculations

Since the traditional way of calculating incremental energy savings (kWh) doesn't apply to a program of this nature Ameren Missouri developed a methodology to convert the carbon savings from CO_2 to kWh. The supply chain energy for both ICEs and EVs was converted to a common unit (BTUs) and then the difference was converted to kWh. In the case of comparing one vehicle powered by an ICE and another by electricity, the resulting savings is 26.44 mmBTU or 7,750 kWh per year per automobile.

An illustrative example of the carbon reduction potential from an EV program - if Ameren incents 100 residential charging stations each year (2016 – 2018), the estimated reduction in CO_2 Emissions is shown below. The first graph shows the emissions saved at the wheel and the second graph includes the source emissions saved.

Figure 8.25: "At the Wheel" Emissions Reduction

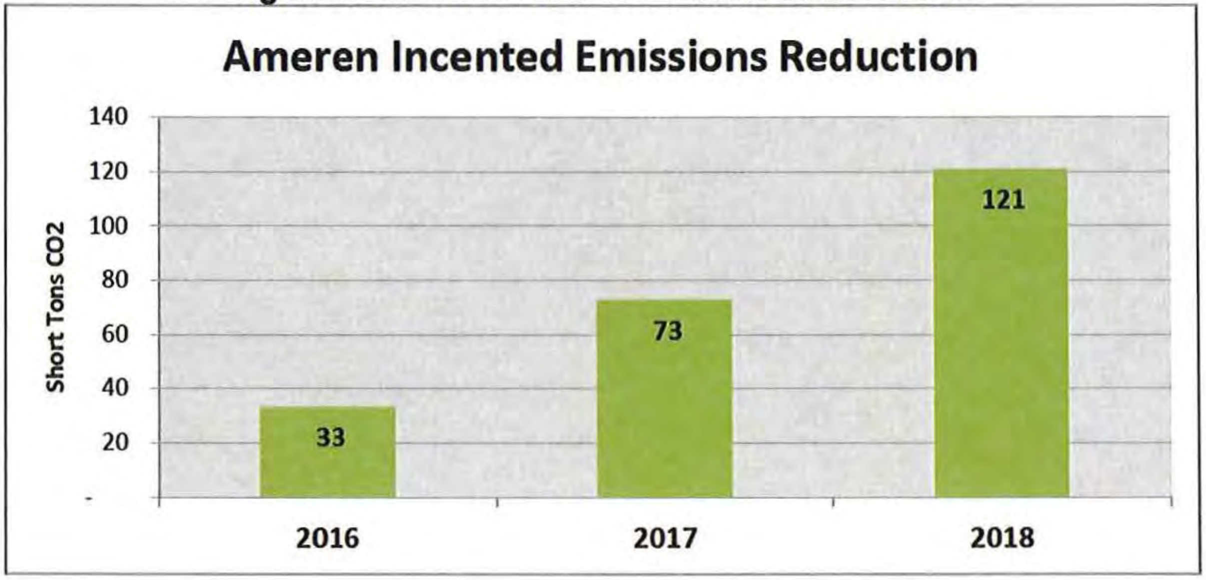
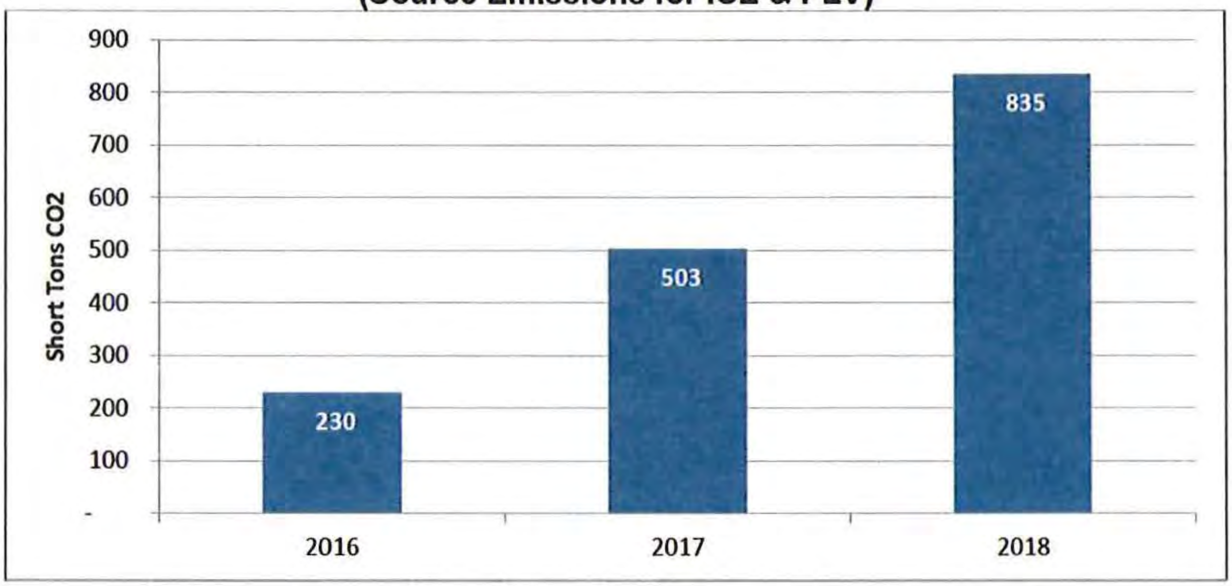


Figure 8.26: Ameren Incented Emissions Reduction (Source Emissions for ICE & PEV)



Issues with Filing an EV Program for MEEIA Cycle 2016 - 2018

The nature of the program does not currently comply with the MEEIA rules as it does not reduce electrical load. However, as cost effective energy efficiency opportunities from traditional electric equipment upgrades diminish over time due to ever increasing baseline efficiency standards, Ameren Missouri seeks innovative approaches to reduce its service territory's carbon footprint. In order for an electric vehicle charging station program to be implemented effectively, MEEIA rule changes appear to be required.

8.14 Compliance References

9. Integrated Resource Plan and Risk Analysis

Highlights

- *Ameren Missouri has developed a robust range of alternative resource plans that reflect different combinations of energy efficiency, demand response, various types of new renewable and conventional generation, and conversion and/or retirement of each of its existing coal-fired generators.*
- *Ameren Missouri has evaluated several reasonable alternatives for its Meramec Energy Center, including conversion of units to natural gas-fired operation and retirement in either 2015 or 2022.*
- *In addition to the scenario variables and modeling discussed in Chapter 2, four critical independent uncertain factors have been included in the final probability tree for risk analysis: Financing Rates, Coal Prices, DSM Impacts and Costs, and Capital Project Costs.*

Ameren Missouri's modeling and risk analysis consisted of a number of major steps:

1. Identification of **alternative resource plan attributes**. These attributes represent the various resource options used to construct and define alternative resource plans – demand side resources, new renewable and non-renewable supply side resources, and existing supply side resource options such as retirement, conversion and environmental retrofits.
2. Development of the **baseline capacity position**, which reflects forecasted peak demand, reserve requirements and existing resources.
3. Pre-analysis was used to determine certain key base elements for alternative resource plans. This included analysis of various options for the Meramec Energy Center and expansion opportunities at our Keokuk hydroelectric facility.
4. Development of **planning objectives** to guide the development of alternative resource plans.
5. Development of the **alternative resource plans**. The alternative resource plans were developed using the plan attributes identified in step 1, the base capacity position developed in step 2, the results of the pre-analysis conducted in step 3, and the planning objectives identified in step 4.
6. Identification and screening of **candidate uncertain factors**, which are key variables that can influence the performance of alternative resource plans.

7. **Sensitivity analysis** and selection of critical uncertain factors, which are key variables that are determined to have a significant impact on the performance of alternative resource plans.
8. **Risk analysis** of alternative resource plans, which is used to evaluate the performance of alternative resource plans under combinations of the scenarios discussed in Chapter 2 and the critical uncertain factors identified in step 7.

This chapter describes these various steps and the results and conclusions of our integration and risk analysis.

9.1 Alternative Resource Plan Attributes[1]

Development of alternative resource plans includes considering various combinations of demand-side and supply-side resources to meet future capacity needs. However, alternative resource plans may also include elements or attributes that serve the other planning objectives described in Section 9.4. Including these elements can significantly affect the capacity position that needs to be considered when developing alternative resource plans. Figure 9.1 includes the attributes considered during the development of resource plans. As has been mentioned, a pre-analysis was used to determine which Meramec and Keokuk options would be included in all alternative resource plans.

Figure 9.1 Attributes of Alternative Resource Plans

Meramec Retirement Options
- Retired 12/31/2015
- Retired 12/31/2022
- Convert Units 1&2 to Natural Gas 12/31/2015 and Units 3&4 Continue on coal; All Units Retired 12/31/2022

Retirements
- Labadie Retired 12/31/2023
- Rush Island Retired 12/31/2024
- Sioux Retired 12/31/2033

New Supply-Side Types
- Combined Cycle (Nat. Gas)
- Simple Cycle (Nat. Gas)
- Nuclear (100% Ownership)
- Nuclear (75% Ownership)
- Pumped Hydroelectric
- Wind
- Wind with Simple Cycle

Keokuk Upgrade
- 50 MW Expansion
- None

Energy Efficiency
- Maximum Achievable Potential (MAP)
- Realistic Achievable Potential (RAP)
- Missouri Energy Efficiency Investment Act (MEEIA) Cycle 1 Only

Demand Response
- MAP
- RAP
- None

Renewable Portfolios
- Missouri Renewable Energy Standard (RES)
- Balanced

[1] 4 CSR 240-22.060(1); 4 CSR 240-22.060(3)

9.2 Capacity Position

To determine the timing and need for resources Ameren Missouri first developed its baseline capacity position including:

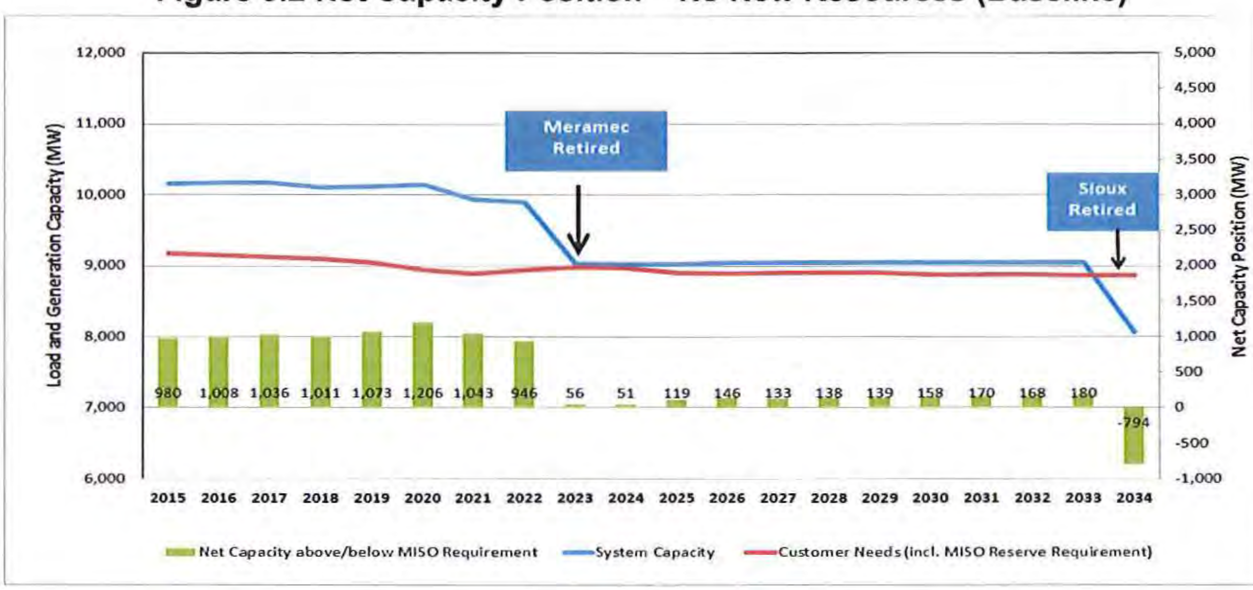
- Existing plant capabilities based on Ameren Missouri's annual generating unit rating update (i.e., July 2014 planned ratings)
- Existing obligations for capacity purchases and sales
- Peak demand forecast, as described in Chapter 3
- Planning reserve margin (PRM) requirement, based on MISO's Planning Year 2014 Loss of Load Expectation (LOLE) Study Report (November 2013). Table 9.1 shows the MISO System PRM from 2015 through 2023. The long-range PRM was assumed to continue at 17.3% through the remainder of the planning horizon.

Table 9.1 MISO System Planning Reserve Margins 2015 through 2023

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

Figure 9.2 shows Ameren Missouri's net capacity position with no new major generating resources. The chart shows the system capacity, customer needs (including the MISO reserve requirement), and capacity above/below the MISO requirement (i.e., long/short position). The customer needs include peak load reductions due to RAP energy efficiency and demand response. The system capacity includes the capacity benefit of the RES Compliance portfolio.

Figure 9.2 Net Capacity Position – No New Resources (Baseline)



Existing Unit Upgrades

The capacity position reflects various upgrade projects for Ameren Missouri's existing generating units. Below is a list of the plant upgrade projects that were included in all resource plans.

- Keokuk Units 5 and 6 – 4 MW in 2016
- Keokuk Units 14 and 15 – 4 MW in 2018

The Keokuk unit upgrade projects listed above have been planned and budgeted based on Ameren Missouri's capital project justification process, which includes an evaluation of the costs and benefits of each project, including the value of energy and capacity provided or saved.

Retirements

Ameren Missouri is considering retirement of some or all of its eight older gas- and oil-fired CTG units – Kirksville, Howard Bend, Fairgrounds, Meramec CTG-1, Meramec CTG-2, Mexico, Moberly, and Moreau – with a total net capacity of 367 MW, over the next 20 years. Chapter 4 - Table 4.2 provides a summary of the planned CTG retirements. The CTG retirements were included in all resource plans.

Coal energy center retirements were also included in the capacity planning process. Sioux retirement by December 31, 2033, was common in all resource plans, based on prior analysis of Ameren Missouri's coal power plant life expectancy by Black and Veatch. Three different Meramec retirement options were considered: 1) retirement by December 31, 2015, 2) retirement by December 31, 2022, and 3) conversion of Units 1&2 to natural gas-fired operation by December 31, 2015, and Units 3&4 continuing to operate on coal with retirement of all four units by December 31, 2022. As discussed in Section 9.3, a pre-analysis was used to determine a single option for Meramec for inclusion in alternative resource plans. While the retirement dates for Labadie and Rush Island, as determined by the Black and Veatch life expectancy study, are beyond the 20-year planning horizon, we have evaluated potential early retirements for both energy centers. Retirement of Labadie by December 31, 2023 was evaluated as was retirement of Rush Island by December 31, 2024. The alternative retirement dates for Labadie and Rush Island were based on the ability to avoid significant costs associated with environmental compliance or environmental risk. In the case of Labadie, the expected need for a scrubber in the 2020-2025 timeframe was the primary driver for the alternative retirement date. In the case of Rush Island, the potential for an explicit price on carbon starting in 2025, included in the scenarios described in Chapter 2, was the primary driver for the alternate retirement date.

Potential Keokuk Expansion

A potential Keokuk Energy Center expansion project was evaluated in the capacity planning process. As discussed in Chapter 4, Option 3 (3-5k)---the addition of five units to the spare bays---was the least cost option and was evaluated further in the integration analysis. The Keokuk expansion would provide 50 MW of additional capacity.

DSM Portfolios

DSM portfolios were included in capacity planning separately as energy efficiency and demand response. Energy efficiency (EE) and demand response (DR) programs not only reduce the peak demand but also reduce reserve requirements associated with those demand reductions. The following combinations of DSM portfolios were evaluated: 1) RAP EE and DR, 2) RAP EE Only, 3) MAP EE and DR, 4) MAP EE Only and 5) MEEIA Cycle 1 Only[2]. The MEEIA Cycle 1 Only DSM portfolio reflects completion of Ameren Missouri's current three-year program cycle with no further energy efficiency during the planning horizon and does not include DR.

Renewable Portfolios

Compliance with Missouri's renewable energy standard (RES) was updated to reflect current assumptions, including baseline revenue requirements, and an updated 10 year forward looking methodology which impacts the calculation of a 1% rate cap.

Ameren Missouri performed its RES compliance analysis with the *2014 IRP RES Compliance Filing Model* (model). The model is designed to calculate the retail rate impact, as required by the Commission's RES rules[3]. This model determines the quantity of renewable energy needed to meet both the overall RES portfolio standard and the solar portfolio standard "carve-out" absent any rate impact constraints. The model then determines the amount of renewable energy, both solar and non-solar that can be built without exceeding an average 1% revenue requirement increase over a ten-year period. Ameren Missouri's expected renewable energy credit (REC) position is presented in Figure 9.3.

[2] EO-2012-0142 12
[3] 4 CSR 240-20.100(5)

Figure 9.3 Ameren Missouri's RES REC Positions

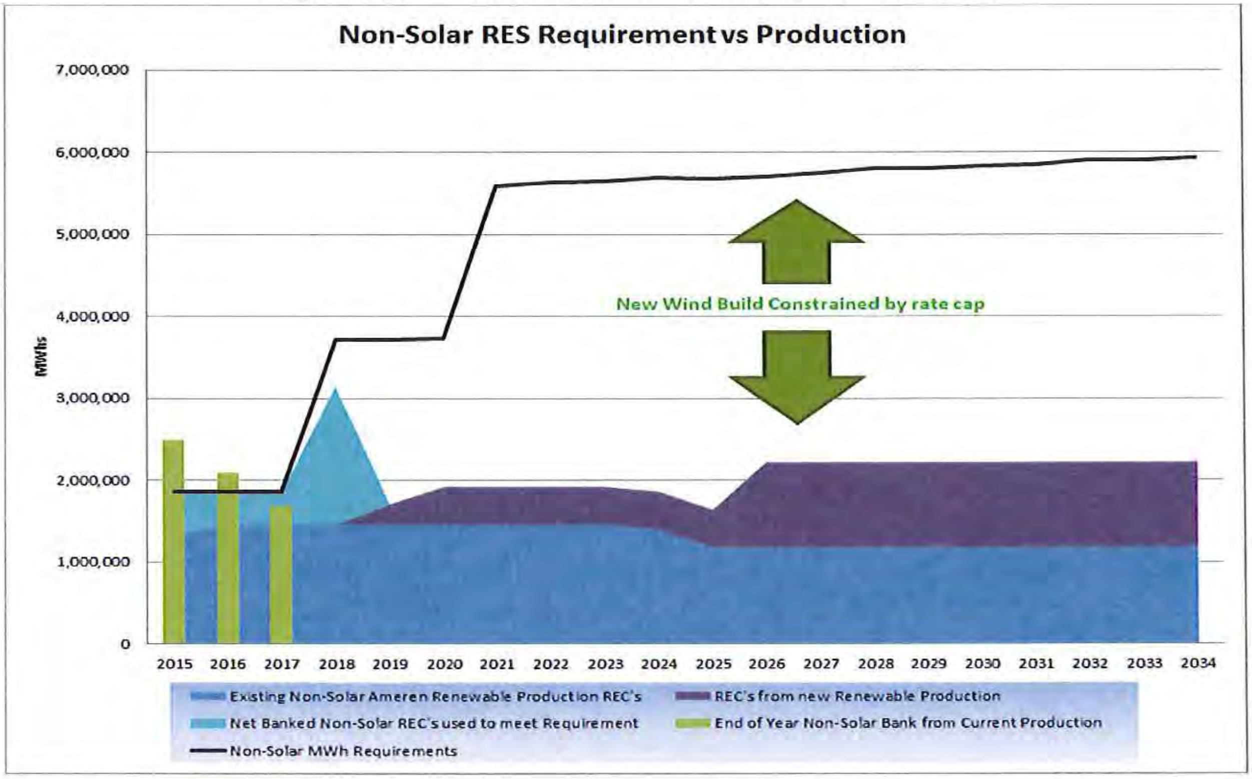


Figure 9.3 shows that Ameren Missouri expects to meet the overall REC requirement until 2018, without being constrained by the 1% rate impact limitation. Ameren Missouri is able to meet the overall standard until 2018 using RECs generated by its existing qualifying resources, including hydro, wind, and landfill gas, and banked RECs from prior years.

Once the standard increases to 10% in 2018, Ameren Missouri exhausts its remaining REC bank then places new wind generation into service starting in 2019. The model shows the amounts of planned new wind and solar resources needed to meet the standard subject to the 1% rate cap. In addition, the model is used to provide a view on RES compliance for both an unconstrained and constrained (i.e., 1% rate impact cap) view of compliance. Table 9.2 shows the unconstrained and constrained amounts of wind, landfill gas (LFG), and solar resources needed. This model was used to develop the RES compliance portfolios for the alternative resource plans. Appendix A shows the unconstrained and constrained amounts of wind, LFG, and solar resources needed in Term 1 (2014-2023) and Term 2 (2025-2034) by year.

Table 9.2 2014 IRP Compliance Filing Model

Description	10 Year Sum TERM 1 (2015-2024)	10 Year Sum TERM 2 (2025-2034)	20 Year Sum (2015-2034)
Unconstrained Full RES REC Requirement met with new builds			
MW's Installed New Solar	5	54	59
MW's Installed New LFG	5	0	5
MW's Installed New Wind	1,003	110	1,114
RES Requirement within 1% Rate Cap Limit			
MW's Installed New Solar	16	10	26
MW's Installed New LFG	5	0	5
MW's Installed New Wind	100	142	242

Several renewable portfolios were evaluated in the capacity planning process using *2014 IRP RES Compliance Filing Model*: 1) RES compliance with RAP or MAP, 2) RES Compliance with MEEIA Cycle 1 Only, and 3) Balanced (i.e., 400 MW Wind, 45 MW Solar, and 20 MW Small Hydroelectric). The RES portfolios were developed using the described in Section 9.2.

When developing the RES compliance investment needs, consideration was given to the potential difference between RAP DSM investment vs a MAP DSM investment due to their differing impacts on customer sales, which is used as the basis for determining the amount of renewable energy needed to comply with the RES portfolio requirements. After modeling both, the difference in the level of renewable generation added was determined to be insignificant, primarily because of the effect of the 1% rate impact limitation on investment levels. Specifically, the difference was less than 1 MW of investment in solar for Term 1 and less than 4 MW's of wind investment for Term 2. Therefore MAP and RAP portfolios are accompanied by the same level of renewable investment when included in alternative resource plans.

Table 9.3 shows the timing of resources for renewable portfolios included in the alternative resource plans.

Table 9.3 Alternative Resource Plans - Renewable Portfolios

Renewable Portfolios		Nameplate Capacity (MW)																				
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	TOTAL
RES with RAP or MAP	Wind	0	0	0	0	50	50	0	0	0	0	0	142	0	0	0	0	0	0	0	0	242
	Solar	5	10	0	0	0	0	2	0	0	0	10	0	0	0	0	0	0	0	0	0	26
	LFG	0	0	0	0	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
	Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RES with MEEIA Cycle 1	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Solar	5	10	0	0	0	0	2	0	0	0	10	0	0	0	0	0	0	0	0	0	26
	LFG	0	0	0	0	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
	Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Balanced	Wind	0	0	0	0	50	50	0	100	0	100	0	100	0	0	0	0	0	0	0	0	400
	Solar	5	10	0	0	0	0	10	0	0	0	10	0	10	0	0	0	0	0	0	0	45
	LFG	0	0	0	0	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
	Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	5	10	0	0	0	20

Non-renewable Supply-side Resources

Non-renewable supply-side resource types were added last in the capacity planning process. If the capacity shortfall in a given year met or exceeded the build threshold, then supply side resources would be added to eliminate the shortfall. The build threshold was determined to be 300 MW (based on half the size of a combined cycle) regardless of the type of supply side resource under consideration. The full rated capacity and the build thresholds for each supply side type are shown in Table 9.4. Ameren Missouri has assumed reliance on short-term capacity purchases to cover shortfalls that are less than the build threshold and has assumed that any long capacity position would be sold into the market. The earliest in-service for each supply-side resource is also shown in Table 9.4. The in-service date constraints represent the expectations for construction lead time as well as the commercial availability of each technology.

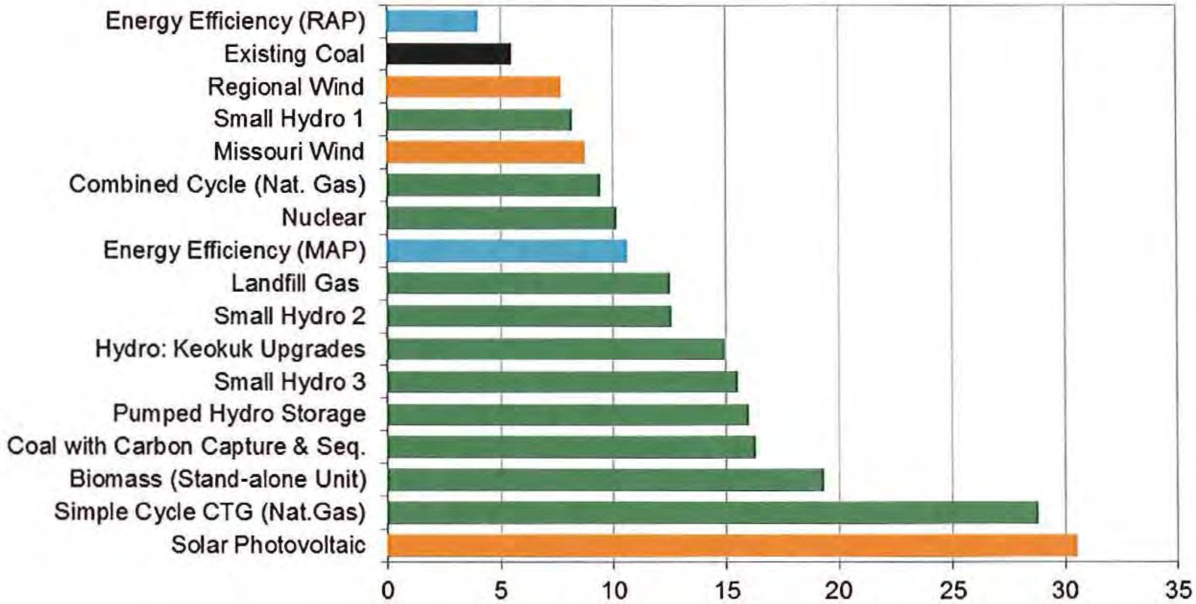
Table 9.4 Build Threshold for Supply Side Types

Supply Side Type	Capacity, MWs	Build Threshold, MWs	Earliest Year In-Service
CC-Natural Gas	600	300	2019
SC-Natural Gas	704	300	2019
Nuclear (100%)	225	300	2025
Nuclear (75%)	169	300	2025
Pumped Hydro	600	300	2020
Wind	465	300	2018
Wind and Simple Cycle	465	300	2020

The remaining net capacity position was modeled in the financial model as capacity purchases and sales priced at the avoided capacity costs as discussed in Chapter 2 and Chapter 8. The capacity purchases and sales were also adjusted for the various peak demand forecasts associated with each of the 15 scenarios and DSM impacts.

Figure 9.4 below summarizes the LCOE for all resources evaluated in the alternative resource plans.

Figure 9.4 Levelized Cost of Energy – All Resources[4]



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

9.3 Pre-Analysis

A pre-analysis consisting of two phases was conducted prior to development of the alternative resource plans to determine two key elements for inclusion in alternative resource plans. This included analysis of various options for the Meramec Energy Center and expansion opportunities at our Keokuk hydroelectric facility. Figure 9.5 provides a high-level overview of the alternative resource plan development process.

Figure 9.5 Alternative Resource Plan High-Level Overview

[4] 4 CSR 240-22.010(2)(A)

Meramec Energy Center Solution

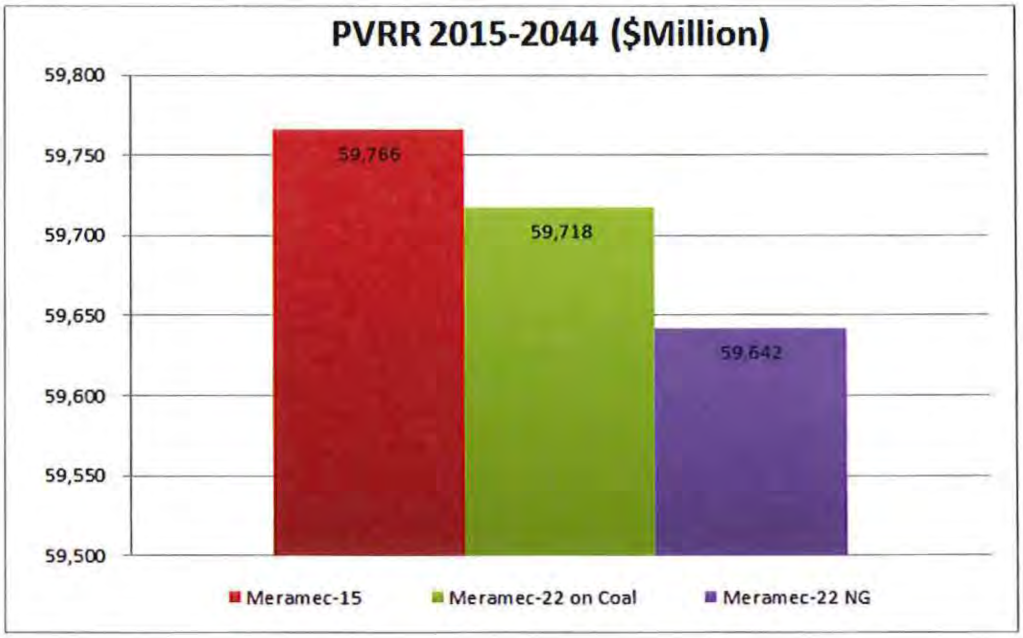
The first phase was to determine a preferred retirement path for the Meramec Energy Center, our oldest coal-fired facility. Three different Meramec retirement options were considered: 1) retirement by December 31, 2015, 2) retirement by December 31, 2022, and 3) conversion of Units 1&2 to natural gas-fired operation by December 31, 2015, and continued operation of Units 3&4 on coal, with retirement of all four units by December 31, 2022. These plans were run against the scenario tree only (no independent uncertain factors) to determine the Meramec solution to be included in all other alternative resource plans.

In 2014, Burns & McDonnell completed a Condition Assessment for the Meramec Energy Center to determine ongoing costs to keep the plant operating safely and reliably through the planning horizon. The Condition Assessment was used to inform the development of the Meramec retirement options. The retirement dates for Meramec were also informed by the expectation for additional costs that would be incurred due to future environmental regulations and GHG regulations. In particular, and as discussed in Chapter 5, we would expect the need for a scrubber and other environmental mitigation investments at Meramec in the 2020-2025 timeframe.

Ameren Missouri conducted an internal preliminary evaluation for the potential conversion of the Meramec Energy Center Units 1-4 from coal to natural gas-fired operations. Units 1&2 were designed with the capability to operate on natural gas; however, these units have not operated at full load on natural gas since 1993. Therefore, restoration of devices and equipment is needed for Units 1&2 to operate fully on natural gas. The expected cost to restore Units 1&2 to natural-gas operations is estimated to be less than $2 million. Units 3&4 are currently capable of coal-fired operations only. The expected cost to convert Units 3&4 to natural-gas operations is expected to be over $40 million.

The PVRR results of the pre-analysis of the three Meramec options are shown in Figure 9.6. Conversion of Units 1&2 to natural gas-fired operation by December 31, 2015, and continued operation of Units 3&4 on coal, with retirement of all four units by December 31, 2022 result in the lowest PVRR and is the preferred solution.

Figure 9.6 Integration PVRR Results: Meramec Pre-Analysis



Keokuk Energy Center Solution

The second phase of the pre-analysis was to determine whether or not the potential Keokuk expansion project would be included in all other alternative resource plans. As discussed in Section 4.3, seven of the 14 potential expansion options from the *Keokuk Hydroelectric Project Expansion Study Concept Report*[5] were evaluated further with approximate additional generating capacity ranging from 4.5 to 162 MW. Option 3 (3-5K) was determined to be the least cost option and was selected for further evaluation in the pre-analysis. Table 9.5 provides a summary of the operating and cost characteristics for Option 3 (3-5K).

Table 9.5 Keokuk Expansion Option: Operating and Cost Characteristics

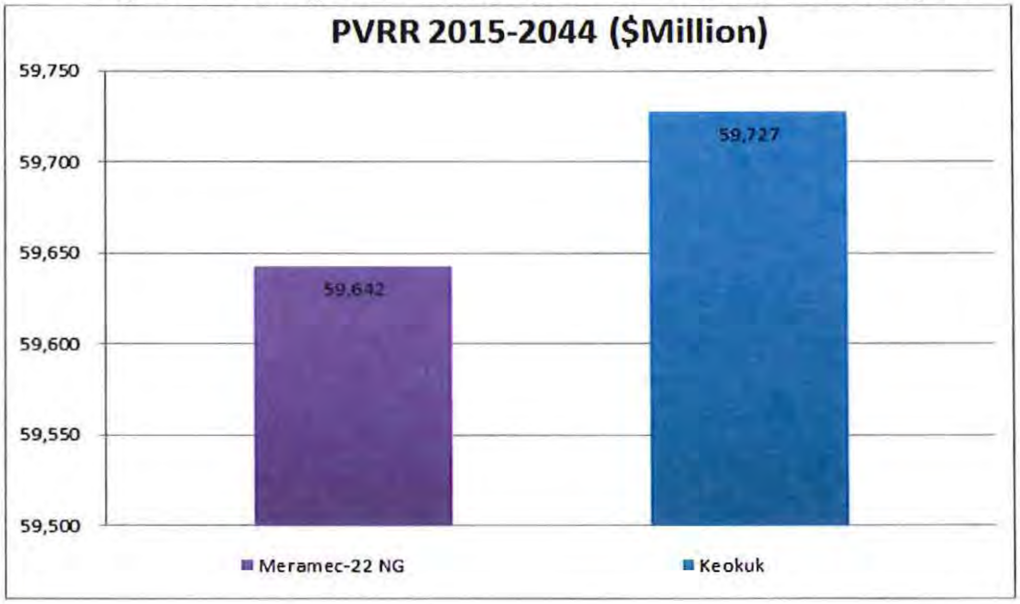
Option	Additional Capacity (MW)	Additional Average Annual Energy (MWh)	Project Cost ($1,000)	Annual Fixed O&M ($/yr), ($1,000)	Annual Variable O&M ($/yr), ($1,000)
3-5K New Units to Spare Bays (Add 5 Kaplan Units)	50	170,408	255,884	255	74

The Keokuk expansion was added to the preferred Meramec solution in the second phase. Figure 9.7 shows the PVRR results from the pre-analysis; adding Keokuk Expansion (50 MW) results in a higher PVRR than that resulting from the preferred Meramec solution without the Keokuk expansion.

[5] HDR Engineering, Inc. (HDR|DTA). *Keokuk Hydroelectric Project Expansion Study Concept Report.* April 20, 2011.

As discussed in Section 9.8, the results of the pre-analysis were validated by evaluating the same options under the full range of scenarios and critical uncertain factors used in risk analysis.

Figure 9.7 Integration PVRR Results: Keokuk Pre-Analysis



9.4 Planning Objectives

The fundamental objective of Missouri's electric resource planning process is to provide energy to its customers in a safe, reliable and efficient way, at just and reasonable rates while being in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies.[6] Ameren Missouri considers several factors, or planning objectives, that must be considered in meeting the fundamental objective. Planning objectives provide a guide to decision making process while ensuring the resource planning process is consistent with business planning and strategic initiatives.

Five planning objectives were used in the development of alternative resource plans: Environmental/Renewable/Resource Diversity, Financial/Regulatory, Customer Satisfaction, Economic Development, and Cost. These planning objectives, which are the same as those discussed in Ameren Missouri's 2011 IRP, were selected by Ameren Missouri decision makers and are discussed below[7]:

[6] 4 CSR 240-22.010(2)
[7] 4 CSR 240-22.010(2)(C)

Environmental/Renewable/Resource Diversity

Ameren Missouri has relied for many years on a portfolio that consists, in large part, of large, efficient coal-fired generators. Current and potential future environmental regulations may have significant impact on Ameren Missouri's coal-fired fleet and its selection of future generation resources. Ameren Missouri seeks to transition its generation portfolio to one that is cleaner and more diverse in a responsible fashion. To test various options for advancing this transition, alternative resource plans were developed to include MAP or RAP energy efficiency, renewables in addition to those required for RES compliance, new gas-fired generation, new nuclear generation, storage resources, and additional coal retirements.

Financial/Regulatory

The continued financial health of Ameren Missouri is crucial as it will need access to large amounts of capital for complying with renewable energy standards and environmental regulations, investing in new supply side resources, and funding continued energy efficiency programs while maintaining or improving safety and reliability. While making its investment decisions, it is important for Ameren Missouri to consider factors that may influence its access to capital markets. This includes measures of cash flow, profitability, and creditworthiness as well as assessment of risks associated with investment management and recovery.[8]

Customer Satisfaction

While there are many factors that can influence customer satisfaction, there are several that can be significantly affected by resource decisions. Ameren Missouri has focused on levelized annual rates, inclusion of energy efficiency and demand response programs, and inclusion of renewables to assess relative customer satisfaction expectations.[9]

Economic Development

Ameren Missouri assesses the relative economic development potential of alternative resource plans in terms of job growth opportunities associated with its resource investment decisions. Plans were rated on a relative scale based on direct jobs (FTE-years) including both construction and operation.[10] We have assumed that second and third level economic impacts would not significantly affect the relative economic development potential of alternative resource plans.

[8] 4 CSR 240-22.060(2)(A)6
[9] 4 CSR 240-22.060(2)(A)4
[10] 4 CSR 240-22.060(2)(A)7

Cost

Ameren Missouri is mindful of the impact that its future resource choices will have on its customers' rate and bills. Maintaining reasonable costs while meeting its other planning objectives is of utmost importance to Ameren Missouri. Cost alone does not and should not dictate resource choices, but it is a very important factor in making resource decisions. Therefore, minimization of present value of revenue requirements was used as the primary selection criterion.[11]

9.5 Determination of Alternative Resource Plans[12]

Nineteen alternative resource plans were developed to incorporate different combinations of demand-side and supply side resource options, incorporate the results of the pre-analysis of Meramec and Keokuk, seek to fulfill Ameren Missouri's planning objectives, and answer key questions, including the following:

- Does inclusion of Demand Response reduce overall customer costs?
- What level of DSM, RAP or MAP, results in lower costs?
- Is early retirement of Labadie Energy Center and replacement with MAP cost effective?
- Is early retirement of Rush Island Energy Center and replacement with MAP cost effective?
- What are the benefits of including renewables beyond those needed for RES compliance?
- What is the impact of pursuing only new renewables?
- How do various supply side resource options compare?
- How would our plans and customer costs be affected if DSM cost recovery and incentive needs are not met?

Table 9.6 provides a summary of the alternative resource plans, including the results of the pre-analysis for Meramec and Keokuk.

[11] 4 CSR 240-22.060(2)(A)1; 4 CSR 240-22.010(2)(B)
[12] 4 CSR 240-22.060(3)

Table 9.6 Alternative Resource Plans[13]

Pre-Analysis

	Plan Name	Meramec Option	Keokuk Expansion	Retirements	DSM	Renewables	Other New Supply
1	*Meramec Option 1*	Retired 12/31/22	None	Sioux 12/31/33	RAP EE&DR	RES Compliance	Combined Cycles
2	*Meramec Option 2*	U1-2 NG 12/31/15 Retired 12/31/22	None	Sioux 12/31/33	RAP EE&DR	RES Compliance	Combined Cycles
3	*Meramec Option 3*	Retired 12/31/15	None	Sioux 12/31/33	RAP EE&DR	RES Compliance	Combined Cycles
4	*Keokuk Expansion*	U1-2 NG 12/31/15 Retired 12/31/22	50 MW Expansion	Sioux 12/31/33	RAP EE&DR	RES Compliance	Combined Cycles

Alternative Resource Plans

	Plan Name	Meramec Option	Retirements	DSM	Renewables	Other New Supply
A	*Combined Cycle*	U1-2 NG, Retired'22	Sioux 12/31/33	RAP EE&DR	RES Compliance	Combined Cycle
B	*Nuclear*	U1-2 NG, Retired'22	Sioux 12/31/33	RAP EE&DR	RES Compliance	CC & Nuclear (450 MW)
C	*Simple Cycle CTGs*	U1-2 NG, Retired'22	Sioux 12/31/33	RAP EE&DR	RES Compliance	CTGs
D	*Pumped Hydro*	U1-2 NG, Retired'22	Sioux 12/31/33	RAP EE&DR	RES Compliance	Pumped Hydro
E	*Wind Plus CTGs*	U1-2 NG, Retired'22	Sioux 12/31/33	RAP EE&DR	RES Compliance	CC & Wind+CTGs
F	*No Demand Response - 1*	U1-2 NG, Retired'22	Sioux 12/31/33	RAP EE Only	RES Compliance	Combined Cycles
G	*Maximum DSM*	U1-2 NG, Retired'22	Sioux 12/31/33	MAP EE&DR	RES Compliance	Combined Cycle
H	*Balanced Portfolio - 1*	U1-2 NG, Retired'22	Sioux 12/31/33	RAP EE&DR	400 MW Wind, 45 MW Solar, 20 MW Small Hydro, 5 MW LFG	Nuclear (169 MW), Combined Cycle
I	*Balanced Portfolio - 2*	U1-2 NG, Retired'22	Sioux 12/31/33	RAP EE&DR	400 MW Wind, 45 MW Solar, 20 MW Small Hydro, 5 MW LFG	Combined Cycle
J	*Balanced w/ No Further DSM After 2015 - 1*	U1-2 NG, Retired'22	Sioux 12/31/33	MEEIA Cycle 1 only	400 MW Wind, 45 MW Solar, 20 MW Small Hydro, 5 MW LFG	Nuclear(169 MW), Combined Cycles
K	*Balanced w/ No Further DSM After 2015 - 2*	U1-2 NG, Retired'22	Sioux 12/31/33	MEEIA Cycle 1 only	400 MW Wind, 45 MW Solar, 20 MW Small Hydro, 5 MW LFG	Combined Cycles
L	*All Renewables*	U1-2 NG, Retired'22	Sioux 12/31/33	MEEIA Cycle 1 only	RES Compliance	Wind Only

[13] 4 CSR 240-22.010(2)(A); 4 CSR 240-22.060(3); 4 CSR 240-22.060(3)(A)1 through 8; 4 CSR 240-22.060(3)(B); 4 CSR 240-22.060(3)(C)1; 4 CSR 240-22.060(3)(C)2; 4 CSR 240-22.060(3)(C)3

Alternative Resource Plans

	Plan Name	Meramec Option	Retirements	DSM	Renewables	Other New Supply
M	*Add'l Coal Retirement - 1a*	U1-2 NG, Retired'22	Sioux 12/31/33 Labadie 12/31/23	MAP EE&DR	RES Compliance	Combined Cycles
N	*Add'l Coal Retirement - 2a*	U1-2 NG, Retired'22	Sioux 12/31/33 Rush Island 12/31/24	MAP EE&DR	RES Compliance	Combined Cycles
O	*Add'l Coal Retirement - 1b*	U1-2 NG, Retired'22	Sioux 12/31/33 Labadie 12/31/23	RAP EE&DR	400 MW Wind, 45 MW Solar, 20 MW Small Hydro, 5 MW LFG	Nuclear(169 MW), Combined Cycles
P	*Add'l Coal Retirement - 2b*	U1-2 NG, Retired'22	Sioux 12/31/33 Rush Island 12/31/24	RAP EE&DR	400 MW Wind, 45 MW Solar, 20 MW Small Hydro, 5 MW LFG	Nuclear(169 MW), Combined Cycles
Q	*Balanced Portfolio w/ Maximum DSM - 1*	U1-2 NG, Retired'22	Sioux 12/31/33	MAP EE&DR	400 MW Wind, 45 MW Solar, 20 MW Small Hydro, 5 MW LFG	Nuclear(169 MW)
R	*Balanced Portfolio w/ Maximum DSM - 2*	U1-2 NG, Retired'22	Sioux 12/31/33	MAP EE&DR	400 MW Wind, 45 MW Solar, 20 MW Small Hydro, 5 MW LFG	Combined Cycle
S	*No Demand Response - 2*	U1-2 NG, Retired'22	Sioux 12/31/33	MAP EE Only	RES Compliance	Combined Cycle

Does inclusion of Demand Response reduce overall customer costs?

Plans F and S differ from plans A and G, respectively, only in that they do not include DR. Therefore, these plans can be compared to assess the impact on cost and other performance measures due to inclusion of DR.

What level of DSM, RAP or MAP, results in lower costs?[14]

Two alternative resource plans provide a comparison to evaluate the cost-effectiveness of RAP vs MAP energy efficiency. Plan F includes RAP EE only and Plan S includes MAP EE only. Additionally, plans with the same attributes except for the level of energy efficiency and demand response resources have been evaluated and provide a comparison for the DSM portfolios: Plans A and G, Plans H and Q, and Plans I and R.

Is early retirement of Labadie Energy Center and replacement with MAP cost effective?

Two alternative resource plans include the early retirement of Labadie Energy Center (i.e., Plans M and O). Plan M evaluates the cost effectiveness of early retirement of Labadie Energy Center and replacement with MAP.[15]

[14] Ameren Missouri added demand response programs to the alternative resource plans starting in 2019 and not only in years where there was a need to reduce peak demand due to shortfalls in Ameren Missouri's planning capacity reserve margins; EO-2012-0142 12; 4 CSR 240-22.060(3)(A)7
[15] EO-2011-0271 Order; 4 CSR 240-22.060(3)(A)7

Is early retirement of Rush Island Energy Center and replacement with MAP cost effective?

Two alternative resource plans include the early retirement of Rush Island Energy Center (i.e., Plans N and P). Plan N evaluates the cost effectiveness of early retirement of Rush Island Energy Center and replacement with MAP.[16]

What are the benefits of including renewables beyond those needed for RES compliance?

Each alternative resource plan evaluated at least meets the minimum requirements of the RES. To assess the relative benefits of including additional renewable resources, several alternative resource plans were developed that exceed the level of renewable investment indicated by the RES compliance model. All alternative resource plans that are identified as "Balanced" (i.e., Plans H, I, J, K, O, P, Q, and R) include investment in renewable resources that are above and beyond needed for RES compliance. Also included are resource plans that feature wind as a major supply side resource (Plans E and L).

What is the impact of pursuing only new renewables?

Plan L is the all renewables alternative resource plan without DSM beyond MEEIA Cycle 1.[17]

How do various supply-side resource options compare?

The relative performance of the new supply-side resources can be determined by comparing Plans A through E.

How would our plans and customer costs be affected if DSM cost recovery and incentive needs are not met?

Plans J, K, and L evaluate the impact if DSM cost recovery and incentive requirements are not met.

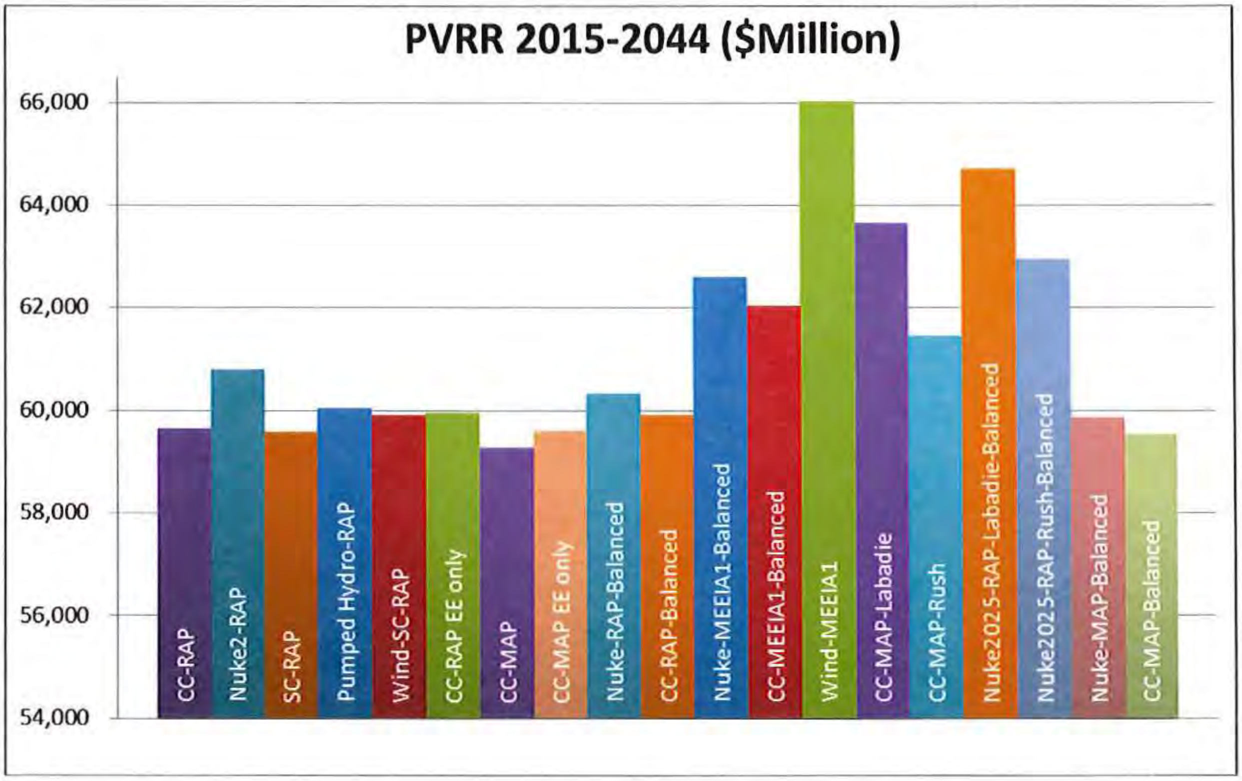
The type, size, and timing of resource additions/retirements for the alternative resource plans (i.e., Plans A-S) are provided in Appendix A and also in the electronic workpapers.[18]

Integration, sensitivity and risk analyses for the evaluation of alternative resource plans were done assuming that rates would be adjusted annually for the 20-year planning horizon and 10 additional years for end effects, and by treating both supply-side and

[16] EO-2011-0271 Order; 4 CSR 240-22.060(3)(A)7
[17] 4 CSR 240-22.060(3)(A)2
[18] None of the alternative resource plans analyzed include any load-building programs 4 CSR 240-22.060(3)(B); 4 CSR 240-22.080(2)(D); 4 CSR 240-22.060(3)(D)

demand-side resources on an equivalent basis. Integration analysis was performed on the most likely scenario of the probability tree (Scenario 8) as explained in Chapter 2. Integration analysis PVRR results are shown below in Figure 9.8 Results for the remaining performance measures for integration analysis are provided in the workpapers.[19]

Figure 9.8 Integration PVRR Results



It should be noted that all costs and benefits in all analyses were expressed in nominal dollars, and Ameren Missouri's current discount rate 6.46% was used for present worth and levelization calculations. Also, in all integration, sensitivity, and risk analyses, it was assumed that rates are adjusted annually (no regulatory lag).[20]

9.6 Sensitivity Analysis

Sensitivity analysis involves determining which of the candidate independent uncertain factors are critical independent uncertain factors. Once identified in this step, critical uncertain factors were added to the scenario probability tree discussed in Chapter 2.

[19] 4 CSR 240-22.060(4)
[20] 4 CSR 240-22.060(2)(B); EO-2011-0271 Order

9.6.1 Uncertain Factors[21]

Ameren Missouri developed a list of uncertain factors to determine which factors are critical to resource plan performance. Table 9.7 contains the list as well as information about the screening process.

Table 9.7 Uncertain Factor Screening

Uncertain Factor	Candidates?	Critical?	Included in Final Probability Tree?
Load Growth	✔**	--	✔
Interest Rates	✔	✘	✔‡
Carbon Policy	✔**	--	✔
Fuel Prices			
Coal	✔	✔	✔
Natural Gas	✔**	--	✔
Nuclear	✔	✘	✘
Project Cost (includes transmission interconnection costs)	✔	✔	✔
Project Schedule	✔	✘	✘
Purchased Power	✘	✘	✘
Emissions Prices			
SO_2	✘	✘	✘
NOx	✘	✘	✘
CO_2	✔**	--	✔
Forced Outage Rate	✔	✘	✘
DSM Load Impacts	✔	✔†	✔†
DSM Cost	✔	✔†	✔†
Fixed and Variable O&M	✔	✘	✘
Return on Equity	✔	✘	✔‡
Nuclear Incentives	✔	✘	✘
Wind Capacity Factor	✔	✘	✘

** Included in the scenario probability tree
-- Not tested in sensitivity analysis
† DSM impacts and costs were combined
‡ Return on Equity and Long-term Interest rates were combined

[21] 4 CSR 240-22.040(5); 4 CSR 240-22.040(5) (B) through (F)
4 CSR 240-22.060(5); 4 CSR 240-22.060(5) (A) through (M)

Chapter 2 describes how three of the candidate uncertain factors were determined to be critical dependent uncertain factors, which defined the scenarios. The three critical dependent uncertain factors are: load growth, environmental policy, and natural gas prices. Energy prices are an output of the scenarios and reflect a range of uncertainty consistent with the scenario definitions.

A review of these candidates prior to the sensitivity analysis determined several could be eliminated without conducting quantitative analysis.

- Purchased Power – Purchased power is excluded since Ameren Missouri is a member of MISO and Ameren Missouri has employed planning criteria that minimize our dependence on the market.
- SO_2 and NOx Emissions Prices – SO_2 and NOx Emissions Prices were excluded as candidates because of the expectation for very low prices as a result of current and expected environmental regulations.

There are two pairs of candidate independent uncertain factors that are highly correlated:

- Interest Rates and Return on Equity
- DSM Cost and DSM Load Impacts

Including all the possible permutations of high/base/low would geometrically increase the size of the analysis, with some combinations being much less meaningful and less probable. Since the expectation is that these factors are highly correlated, we have made the simplifying assumption that the individual probability nodes for each pair be combined into a single probability node reflecting the high value for both, base value for both, and low value for both without explicitly considering the less likely and less meaningful joint probabilities.

Uncertain Factor Ranges[22]

We use the sensitivity analysis to examine whether or not candidate independent uncertain factors have a significant impact on the performance of alternative resource plans, as measured by their impact on PVRR.

Most of the candidate uncertain factors are characterized by a 3-level range of values for this analysis, those 3 levels being low, base, and high values. One of the candidates, nuclear tax incentive, had a 2-level range of values, which were a low value and a high value.

[22] 4 CSR 240-22.060(7)(C)1A; 4 CSR 240-22.060(7)(C)1B

Unless the meaning of low, base, and high are treated in a standardized manner, the probability of occurrence for the value used for "low" for one uncertain factor could be significantly different than the probability of occurrence for the value used for "low" for other uncertain factors. Thus, for majority of the uncertain factors, Ameren Missouri standardized the meaning of low to be the value found at the 5^{th} percentile of a probability distribution of values for an uncertain factor, the value at the 50^{th} percentile to be the base value, and the value at the 95^{th} percentile to be the high value. The probability distribution for each candidate uncertain factor was inferred from a series of estimated values produced by subject matter experts for each uncertain factor.

For the majority of candidate uncertain factors, probability distributions were used to obtain the values for low, base, and high. This process began with subject matter experts providing/revising estimates of (A) an expected value, (B) estimates of deviations from that expected value, and (C) the probabilities of those deviations from the expected value. That information was used to create the probability distribution collectively implied by that data. Values at the 5^{th}, 50^{th}, and 95^{th} percentiles of those implied probability distributions were then obtained for use as the values for low, base, and high for the various candidate independent uncertain factors. Appendix A contains the standard value, estimated deviation and probabilities for project costs, project schedule, fixed operations & maintenance (FOM), variable operations & maintenance (VOM), equivalent forced outage rate (EFOR), environmental capital expenditures, and transmission-retirement expenditures.

Example

The standard value for Fixed Operations & Maintenance (FOM), for the greenfield Combined Cycle option is \$7.62/kW-year (2013\$). FOM and some other candidate uncertain factors are characterized by differing standard values among various supply-side types, while standard values for some other candidate uncertain factors are not uniquely correlated to each supply side type. For example the Long Term Interest Rates uncertain factor does not differ depending on the supply-side type; it is the same across all supply-side types.

The subject matter experts, in this example, members of Ameren Missouri's generation organization, provided estimates of deviations from the standard value as well as the probabilities of those deviations. An example of that initial uncertainty distribution is shown in Table 9.8. In this example, the first of these estimates for FOM deviations was a -20% deviation from the FOM standard value with a 5% probability of occurring. These deviation estimates provide sufficient information to derive continuous

Table 9.8

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

probability distributions from which the low/base/high values can be derived.

The process of developing the probability distributions involved using Crystal Ball software. This software, when provided with a series of observations like these deviation estimates, can determine the probability distribution implied by the set of estimates. An example of the result of analyzing deviation estimates using Crystal Ball is shown Figure 9.9. From this distribution the values for the low, base, and high values ($6.32, $7.64, $9.59) are shown at the respective percentiles in Figure 9.9 and represent the 5th, 50th, and 95th percentiles.

Figure 9.9 Example of Probability Distribution---CC Fixed O&M

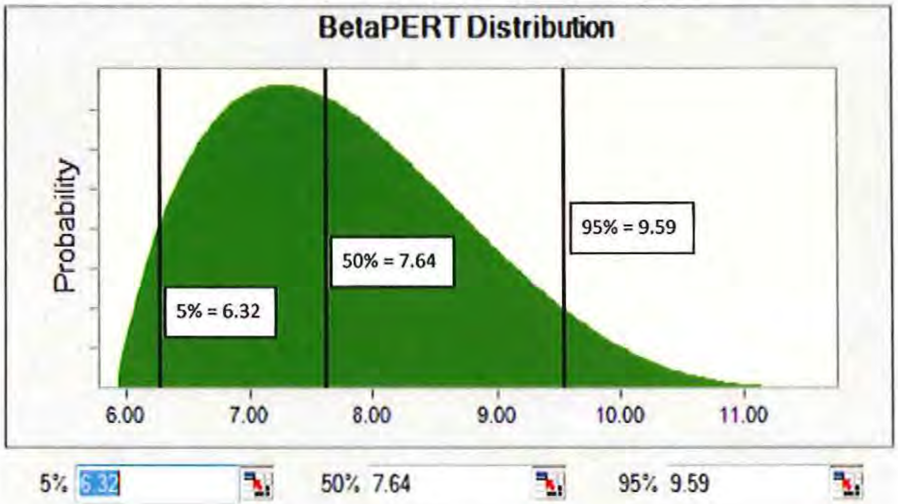


Figure 9.10 shows the resulting range of project costs, which also include interconnection costs estimates, for each new supply-side resource. For most of the technologies shown in Figure 9.10, base values found at 50th percentile were very close to their expected values. For nuclear technology, however, the base value inferred from the probability distribution was 27% higher than the expected value, $6,350/kW vs $5,000/kW.[23] Table 9.9 and Table 9.10 contain the uncertain factor ranges for the various candidate uncertain factors. It should be noted that, for the project schedule uncertainty, as the number of years in a project schedule change, the distribution of the cash flows was also updated to be consistent with those changes.

[23] EO-2011-0271 Order

Figure 9.10 Resource-Specific Project Cost Ranges ($/kW)

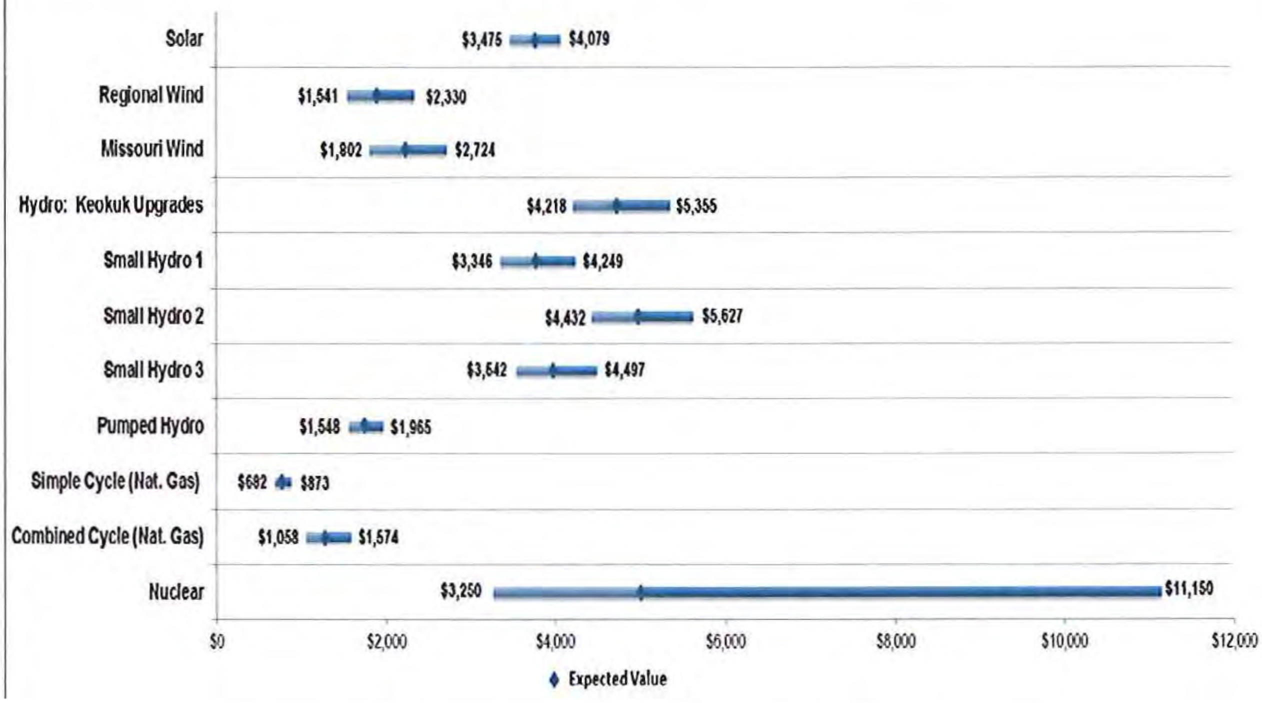


Table 9.9 Resource-Specific Uncertain Factor Ranges

Uncertain Factor	Value	Probability	CC (Nat Gas)	SC (Nat Gas)	Pumped Hydro	Hydro: Keokuk Upgrades	Nuclear (100%)	Small Hydro 1	Small Hydro 2	Small Hydro 3	Solar	Regional Wind	Missouri Wind
Project Cost ($/kW)	Low	10%	$1,058	$682	$1,548	$4,218	$3,250	$3,346	$3,542	$4,432	$3,475	$1,541	$1,802
	Base	80%	$1,297	$774	$1,756	$4,786	$6,350	$3,798	$4,020	$5,030	$3,777	$1,898	$2,219
	High	10%	$1,574	$873	$1,965	$5,355	$11,150	$4,249	$4,497	$5,627	$4,079	$2,330	$2,724
Project Schedule (months)	Low	10%	27	27	55	46	46	46	46	46	18	36	36
	Base	80%	36	36	73	61	61	61	61	61	24	48	48
	High	10%	48	48	95	79	79	79	79	79	32	63	63
Fixed O&M ($/kW-yr)	Low	10%	$6.32	$6.20	$2.81	$4.23	$111.38	$0.00	$0.00	$0.00	$20.76	$24.08	$24.08
	Base	80%	$7.64	$7.48	$3.39	$5.11	$136.89	$0.00	$0.00	$0.00	$25.06	$29.07	$29.07
	High	10%	$9.59	$9.36	$4.23	$6.41	$168.85	$0.00	$0.00	$0.00	$31.42	$36.44	$36.44
Variable O&M ($/MWh)	Low	10%	$1.52	$11.69	$2.82	$0.41	$1.75	$4.35	$4.35	$4.35	$0.00	$0.00	$0.00
	Base	80%	$3.94	$13.92	$3.50	$0.51	$2.17	$5.41	$5.41	$5.41	$0.00	$0.00	$0.00
	High	10%	$6.36	$16.15	$4.42	$0.65	$2.74	$6.83	$6.83	$6.83	$0.00	$0.00	$0.00
EFOR (%)	Low	10%	1%	0%	0%	*	1%	*	*	*	*	*	*
	Base	80%	2%	5%	5%	*	2%	*	*	*	*	*	*
	High	10%	5%	10%	10%	*	3%	*	*	*	*	*	*
Wind Capacity Factor (%)	Low	10%	---	---	---	---	---	---	---	---	---	33.4%	---
	Base	80%	---	---	---	---	---	---	---	---	---	38.5%	---
	High	10%	---	---	---	---	---	---	---	---	---	40.3%	---

Notes: * Assumed capacity factor includes effects of Forced Outage Rate
--- Not Applicable

The Regional Wind capacity factors are based on the Black & Veatch Renewable Portfolio Study for Priority Development Areas 1, 2, 3, 11, 18, and 19 as mentioned in Chapter 6. The low and high capacity factor values are the lowest and highest values, respectively, among the specified priority development areas.

As discussed in Chapter 2, the long-range interest rate assumptions are based on the December 1, 2013, semi-annual Blue Chip Financial Forecast, a consensus survey of 49 economists. Ameren Missouri internal experts used this same set of data and process to develop a range of interest rate assumptions for use in the 2014 IRP. The high and low interest rate assumptions are based on the average of the 10 highest and 10 lowest forecasts from the survey. Additionally, the high and low forecasts for Treasury rates are used as inputs to the calculation of high and low ranges for allowed return on equity (ROE) using the same process as discussed in Chapter 2.

Table 9.10 Non-Resource Specific Uncertain Factor Ranges

Uncertain Factors	Low	Base	High
Probability -->>	10%	80%	10%
Nuclear Fuel Price	Varies By Year		
Coal Price	Varies By Year		
Long Term Interest Rates	5.8%	6.7%	7.6%
Return on Equity	11.0%	11.4%	11.8%
Probability -->>	50%		50%
Nuclear Incentives	No Incentive		$0.018/kWh
Probability -->>	45%	50%	5%
Energy Efficiency Load Impact			
MAP	82%	100%	100%
RAP	91%	100%	109%
Demand Response Load Impact			
MAP	21%	100%	286%
RAP	1%	100%	330%
Demand Side Management Cost			
MAP	78%	100%	113%
RAP	82%	100%	131%

One of the candidates, nuclear tax incentives, was characterized by a 2-level range of values, which were a low value (no incentives) and a high value. As a default, with a 50% probability, no nuclear tax incentives were included. As an alternative, with a 50% probability, a nuclear tax incentive of $0.018/kWh up to $125 million per year was included for the first eight years of operation for nuclear resources.

9.6.2 Sensitivity Analysis Results[24]

To conduct the sensitivity analysis, each of the 19 candidate resource plans was analyzed using the varying value levels (low/base/high or default/alternative) for each of the candidate independent uncertain factors, for the most likely scenario in the probability tree (Scenario 8). An uncertainty-probability weighted result (PVRR) was obtained for each plan for each relevant candidate uncertain factor. Finally, the results of using a "non-base" value were compared to the results of using an integration/base value for each plan for each candidate uncertain factor. The sensitivity analysis results for all of the candidate independent uncertain factors (resource-specific and non-resource specific) are presented in Appendix A.

The sensitivity analysis identified four critical independent uncertain factors: DSM Impacts and Costs, Project Costs, Coal Prices and ROE/Interest Rates. Table 9.11 shows the change in PVRR ranking (i.e., number of positions the plan moved in the ranking) for the four critical independent uncertain factors compared to the integration/base value. Table 9.12 shows the change in PVRR ($) for the four critical independent uncertain factors compared to the integration/base value.

Table 9.11 Critical Independent Uncertain Factors – Change in PVRR Ranking

			Critical Independent Uncertain Factors											
			DSM Impacts			Project Cost			Coal Price			ROE/Interest Rates		
Plan	Plan Description	Integration	DSM-PWA	DSM-Low	DSM-High	Prj Cost-PWA	Prj Cost-Low	Prj Cost-High	Coal Price-PWA	Coal Price-Low	Coal Price-High	ROE-PWA	ROE-Low	ROE-High
A	CC-RAP	5	0	(1)	(1)	0	1	0	0	0	0	0	0	0
B	Nuke2-RAP	12	0	0	0	0	(1)	1	0	0	1	0	0	0
C	SC-RAP	3	(1)	(1)	(1)	0	2	(1)	0	0	0	0	1	0
D	Pumped Hydro-RAP	10	0	(1)	(2)	0	2	(3)	0	0	0	0	0	0
E	Wind-SC-RAP	8	0	0	(2)	0	(1)	1	0	0	0	0	(1)	0
F	CC-RAP EE only	9	(3)	(4)	2	0	0	(1)	0	0	0	0	0	0
G	CC-MAP	1	0	0	0	0	0	0	0	0	0	0	0	0
H	Nuke-RAP-Balanced	11	0	0	(1)	0	(1)	0	0	0	0	0	0	0
I	CC-RAP-Balanced	7	0	0	(2)	0	1	(1)	0	0	0	0	1	0
J	Nuke-MEEIA1-Balanced	15	0	0	1	0	0	0	0	0	2	0	0	0
K	CC-MEEIA1-Balanced	14	0	0	0	0	0	0	0	(1)	0	0	0	0
L	Wind-MEEIA1	19	0	0	0	0	(2)	0	0	(1)	0	0	0	0
M	CC-MAP-Labadie	17	0	0	0	0	1	0	0	0	(1)	0	0	0
N	CC-MAP-Rush	13	0	0	0	0	0	(1)	0	1	(1)	0	0	0
O	Nuke2025-RAP-Labadie-Balanced	18	0	0	0	0	1	0	0	1	0	0	0	0
P	Nuke2025-RAP-Rush-Balanced	16	0	0	(1)	0	0	0	0	0	(1)	0	0	0
Q	Nuke-MAP-Balanced	6	3	4	1	0	(3)	4	0	0	0	0	0	0
R	CC-MAP-Balanced	2	2	4	1	0	0	2	0	0	0	0	0	0
S	CC-MAP EE only	4	(1)	(1)	5	0	0	(1)	0	0	0	0	(1)	0

[24] 4 CSR 240-22.060(5); 4 CSR 240-22.060(7)(A); 4 CSR 240-22.060(7)(C)1A

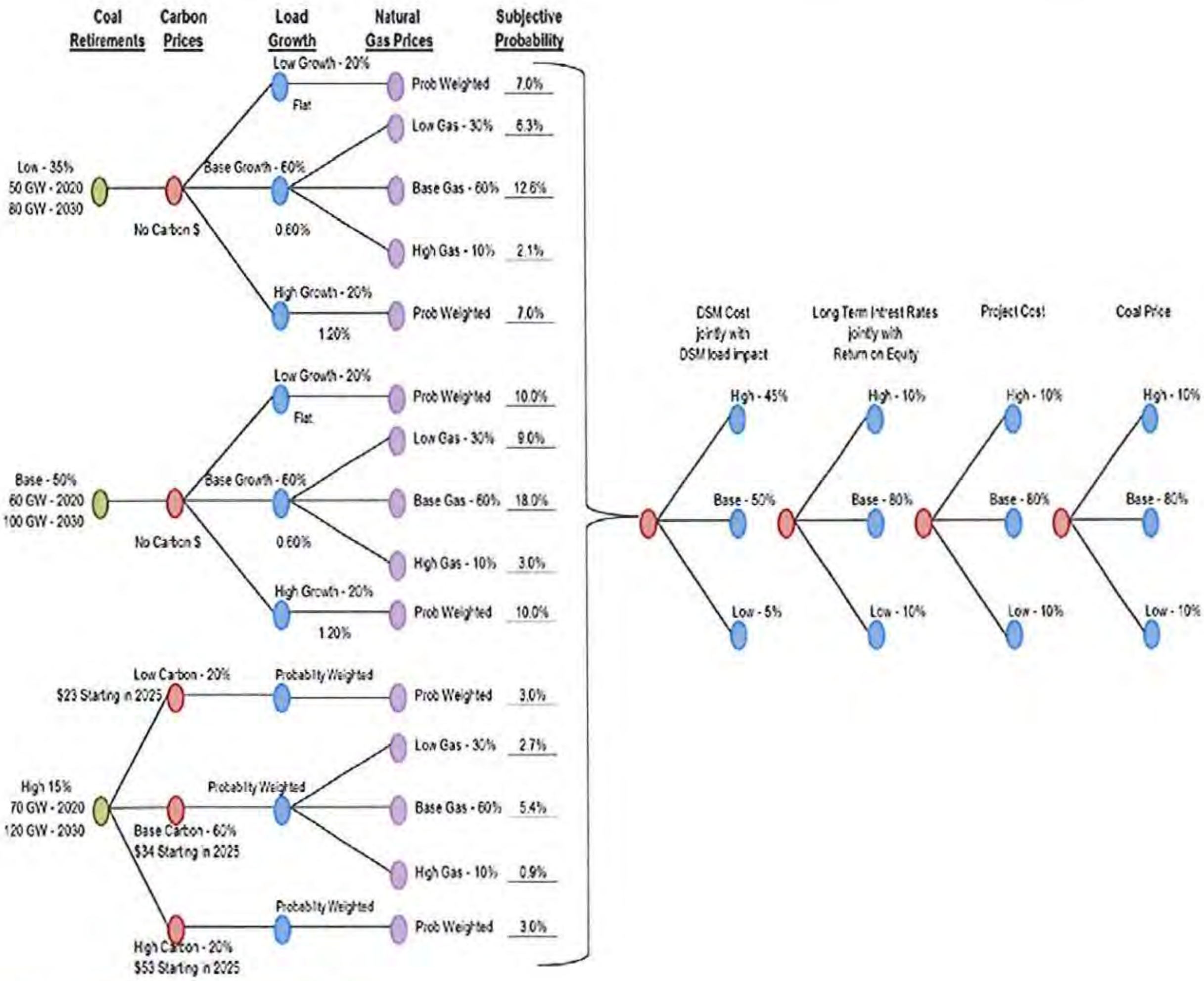
Table 9.12 Critical Independent Uncertain Factors – Change in PVRR ($)

			Critical Independent Uncertain Factors											
			DSM Impacts			Project Cost			Coal Price			ROE/Interest Rates		
Plan	Plan Description	Integration	DSM-PWA	DSM-Low	DSM-High	Prj Cost-PWA	Prj Cost-Low	Prj Cost-High	Coal Price-PWA	Coal Price-Low	Coal Price-High	ROE-PWA	ROE-Low	ROE-High
A	CC-RAP	59,642	129	349	(575)	29	(735)	1,022	(109)	(3,816)	2,729	(12)	(864)	748
B	Nuke2-RAP	60,778	129	349	(575)	75	(1,575)	2,322	(109)	(3,816)	2,729	(13)	(974)	844
C	SC-RAP	59,579	129	349	(575)	28	(690)	968	(109)	(3,816)	2,729	(12)	(857)	742
D	Pumped Hydro-RAP	60,036	129	349	(575)	27	(734)	1,008	(109)	(3,816)	2,729	(12)	(887)	768
E	Wind-SC-RAP	59,890	129	349	(575)	32	(918)	1,241	(109)	(3,816)	2,729	(12)	(905)	783
F	CC-RAP EE only	59,941	62	156	(156)	30	(816)	1,115	(109)	(3,816)	2,729	(12)	(887)	767
G	CC-MAP	59,266	242	588	(463)	29	(735)	1,022	(109)	(3,816)	2,729	(12)	(861)	745
H	Nuke-RAP-Balanced	60,331	129	349	(575)	47	(1,133)	1,607	(109)	(3,816)	2,729	(12)	(926)	801
I	CC-RAP-Balanced	59,888	129	349	(575)	30	(817)	1,119	(109)	(3,816)	2,729	(12)	(883)	764
J	Nuke-MEEIA1-Balanced	62,597	0	0	0	56	(1,469)	2,031	(109)	(3,816)	2,729	(14)	(1,011)	875
K	CC-MEEIA1-Balanced	62,029	0	0	0	34	(1,088)	1,432	(109)	(3,816)	2,729	(13)	(962)	832
L	Wind-MEEIA1	66,021	0	0	0	103	(4,238)	5,266	(109)	(3,816)	2,729	(22)	(1,554)	1,339
M	CC-MAP-Labadie	63,654	242	588	(463)	33	(1,262)	1,594	(65)	(2,194)	1,547	(13)	(936)	804
N	CC-MAP-Rush	61,433	242	588	(463)	30	(934)	1,236	(89)	(2,954)	2,062	(12)	(881)	762
O	Nuke2025-RAP-Labadie-Balanced	64,702	129	349	(575)	66	(1,856)	2,514	(65)	(2,194)	1,547	(14)	(1,018)	875
P	Nuke2025-RAP-Rush-Balanced	62,935	129	349	(575)	64	(1,608)	2,250	(89)	(2,954)	2,062	(13)	(984)	852
Q	Nuke-MAP-Balanced	59,846	242	588	(463)	46	(1,052)	1,514	(109)	(3,816)	2,729	(12)	(901)	780
R	CC-MAP-Balanced	59,512	242	588	(463)	30	(817)	1,119	(109)	(3,816)	2,729	(12)	(880)	762
S	CC-MAP EE only	59,582	161	358	0	29	(735)	1,022	(109)	(3,816)	2,729	(12)	(863)	747

DSM Impacts & Costs and Project Costs were selected as critical independent uncertain factors because of the variety in the change in PVRR ranking. Coal price was selected as a critical independent uncertain factor because of the high impact potential on relative results of early retirement plans compared to other plans. ROE/Interest Rates was selected as a critical independent uncertain factor as a degree of conservatism since it was selected as a critical independent uncertain factor in previous Ameren Missouri IRP's and since it can significantly influence the results of different levels of capital intensiveness between plans in combination with project cost uncertainty.

These four critical independent uncertain factors were added as nodes to the scenario probability tree that was developed in Chapter 2. The updated and expanded probability tree is shown in Figure 9.11, with the four critical independent uncertainty factors shown on the right-hand side.

Figure 9.11 Final Probability Tree Including Sensitivity Analysis Results[25]



9.7 Risk Analysis[26]

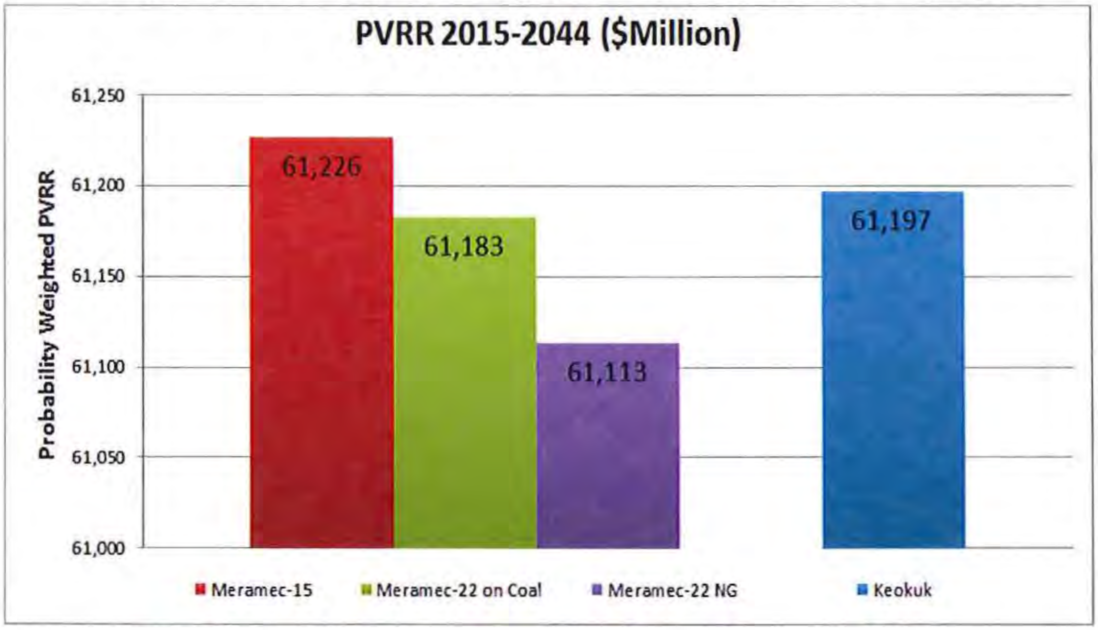
The Risk Analysis consisted of running each of the candidate resource plans (i.e., pre-analysis plans and Plans A-S) in Table 9.6 through each of the branches on the final probability tree shown in Figure 9.11. The probability tree consisted of 1,215 different branches. Each branch is the combination of different value levels among the fifteen scenarios, themselves defined by combinations of the three critical dependent uncertain factors (load growth, gas prices, and environmental regulations/carbon policy), and the four critical independent uncertain factors (DSM cost together with DSM load impacts, interest rates together with return on equity, project cost, and coal price). Each branch therefore represents a unique combination of the critical uncertain factors. Once all the combinations are calculated the sum of the individual branch probabilities equals 100%.

[25] 4 CSR 240-22.060(6)
[26] 4 CSR 240-22.060(6)

9.7.1 Risk Analysis Results

As mentioned in Section 9.3, the conclusions of the pre-analysis were tested by evaluating them under the full range of scenarios and critical uncertain factors used for risk analysis. The pre-analysis PVRR results from the risk analysis are shown in Figure 9.12. Figure 9.12 shows that the PVRR results under risk analysis are consistent with the initial findings for both Meramec and Keokuk and have therefore been appropriately included in all alternative resource plans.

Figure 9.12 Probability Weighted PVRR Results: Pre-Analysis



The PVRR results of the risk analysis of the 19 alternative resource plans are shown in Figure 9.13. The levelized rate results for the risk analysis are shown in Figure 9.14. It is important to consider both the PVRR and levelized rate impacts. The PVRR results are lower for plans with RAP or MAP DSM compared to the other plans. In addition, the plans with RAP or MAP exhibit lower levelized rates compared to the other plans. The additional coal retirement plans (i.e., Plans M through P) exhibit much higher PVRR results and much higher levelized rates compared to the other plans. Plan L (Wind-MEEIA1) exhibits the highest PVRR and the second highest levelized rates. Results for other performance measures can be found in Appendix A.

Figure 9.13 Probability-Weighted PVRR Results: Alternative Resource Plans

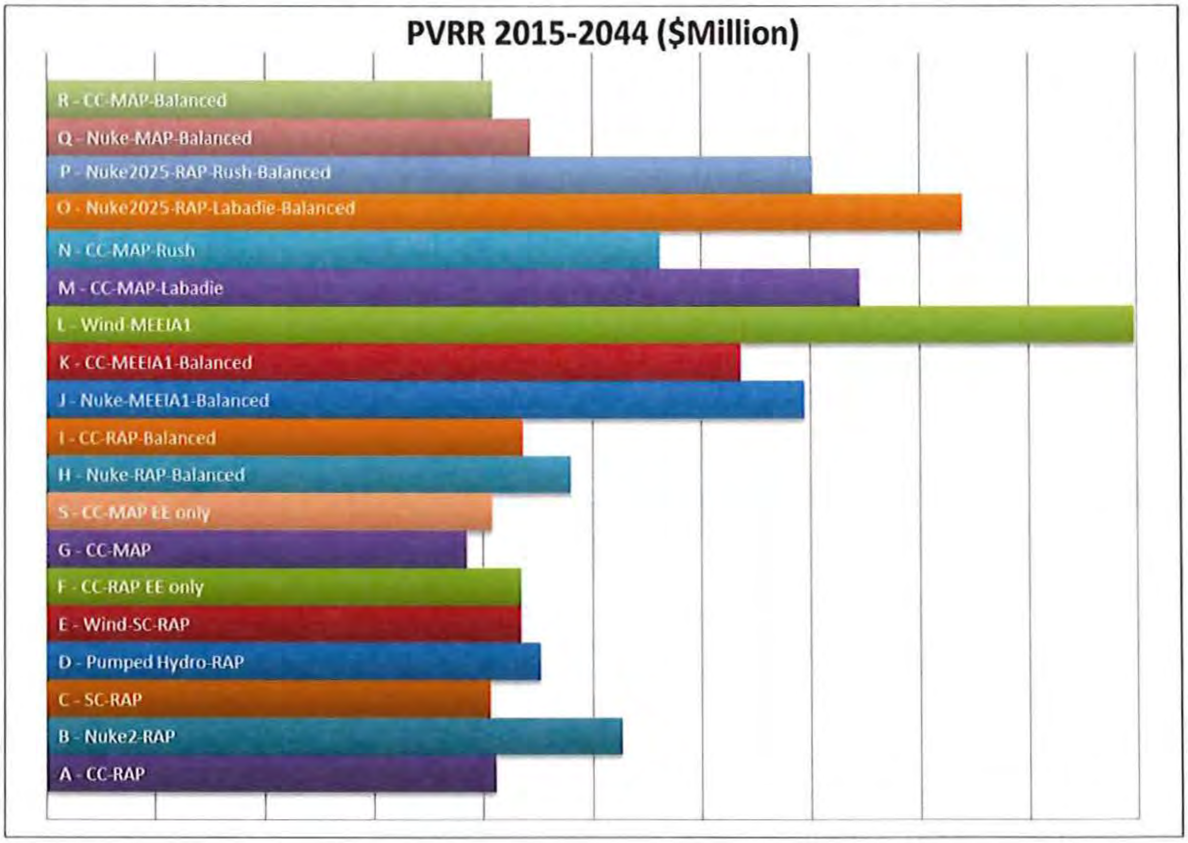
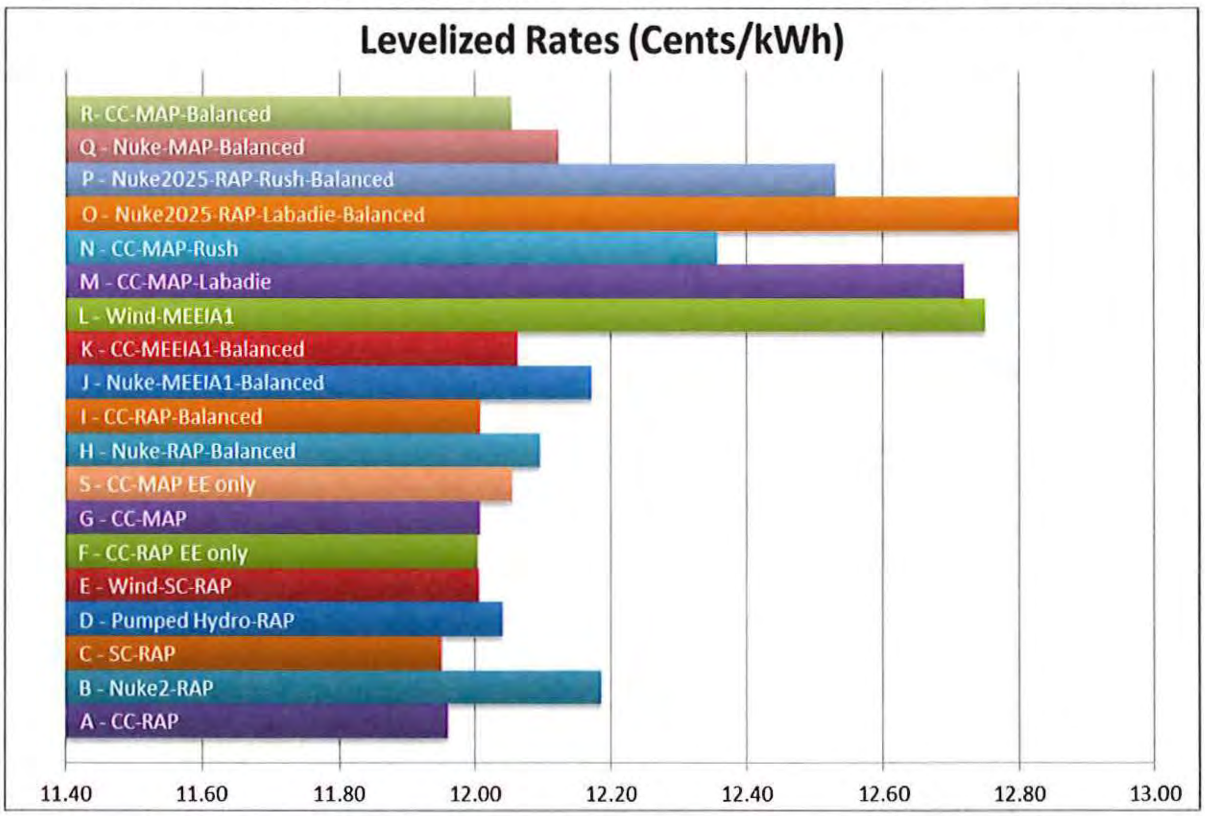


Figure 9.14 Probability-Weighted Levelized Rates: Alternative Resource Plans



If decision making were solely based on PVRR and levelized rate impacts, then the analysis would be complete at this point. Since decision making is multi-dimensional, Ameren Missouri created a scorecard that embodies its planning objectives to evaluate the performance of alternative resource plans. With 19 alternative resource plans, Ameren Missouri can take a closer look at the performance of the plans by evaluating their relative strengths and weaknesses in meeting our planning objectives and whether other factors may be important in the selection of the preferred resource plan. Chapter 10 – Strategy Selection includes the additional analysis and decision-making considerations that lead to the selection of the Resource Acquisition Strategy.

9.8 Conclusions from Integration and Risk Analysis

Below are several conclusions from the integration and risk analysis.

- The risk analysis validates the Meramec Retirement Solution---conversion of Meramec Units 1&2 to Natural Gas December 31, 2015 and Units 3&4 continue on coal with retirement by December 31, 2022---is the solution for the candidate alternative resource plans.
- The risk analysis validates the exclusion of the potential Keokuk expansion from alternative resource plans.
- Inclusion of energy efficiency and demand response results in generally lower costs and rates
- Combined cycle resources are an attractive option for near-term development due to their competitive overall cost, relatively low capital cost and relatively short lead time.
- Meeting all future resource needs with renewable resources (Plan L) results in the highest PVRR and the second highest levelized rates.
- Plans with additional renewable resources beyond those included for RES compliance are competitive from a cost standpoint.
- Nuclear generation remains a competitive resource for future baseload capacity.
- Early retirement of coal generation, even if replaced with cost-effective demand side resources, results in significantly higher costs to customers and rates.

9.9 Resource Plan Model

Ameren Missouri has used a modular approach to modeling for this IRP. Certain challenges associated with the use of the MIDAS model – financial modeling limitations, trouble-shooting difficulty, etc... – led us to reevaluate our modeling tools and approach. Discussions in recent years with Ventyx, the vendor that licenses MIDAS, have indicated that their long-term model plans do not include continued development of MIDAS. After identifying and assessing the capabilities of other "off-the-shelf" alternatives, Ameren Missouri elected to replace MIDAS for integration and risk analysis with a combination of stand-alone models for 1) production costing, 2) market settlements, 3) revenue requirements, and 4) financial statements. Items 2-4 on this list are collectively referred to as the "Financial Model." This approach permitted analysts maximum flexibility, customization and trouble-shooting capabilities. It also lends itself to greater transparency for stakeholders by limiting the use of proprietary third-party software.

Ameren Missouri used a generation simulation model from Simtec, Inc., typically referred to as RTSim (Real-Time Simulation) for production cost modeling.[27] RTSim provides a realistic simulation of an electric generating system for a period of a few days to multiple years. According to Simtec's marketing materials, RTSim finds higher profitability, lower risk, "free market" transactions, maintenance schedules, emission compliance strategies and fuel procurement schedules while maintaining reliable, reasonable cost service to the traditional regulated market sector.

RTSim simulates hourly chronological dispatch of all system generating units, including unit commitment logic that is consistent with the operational characteristics and constraints of system resources. The model plans are based on a capacity planning spreadsheet, which was used to determine the timing of new resources. The RTSim model contains all unit operating variables required to simulate the units. These variables include, but are not limited to, heat rates, fuel costs, variable operation and maintenance costs, emission allowance costs, scheduled maintenance outages, and forced and partial outage rates. The generation fleet is dispatched competitively against market prices. The multi-area mode of the Ventyx Midas® model was used for the creation of forward price curves as described in Chapter 2.

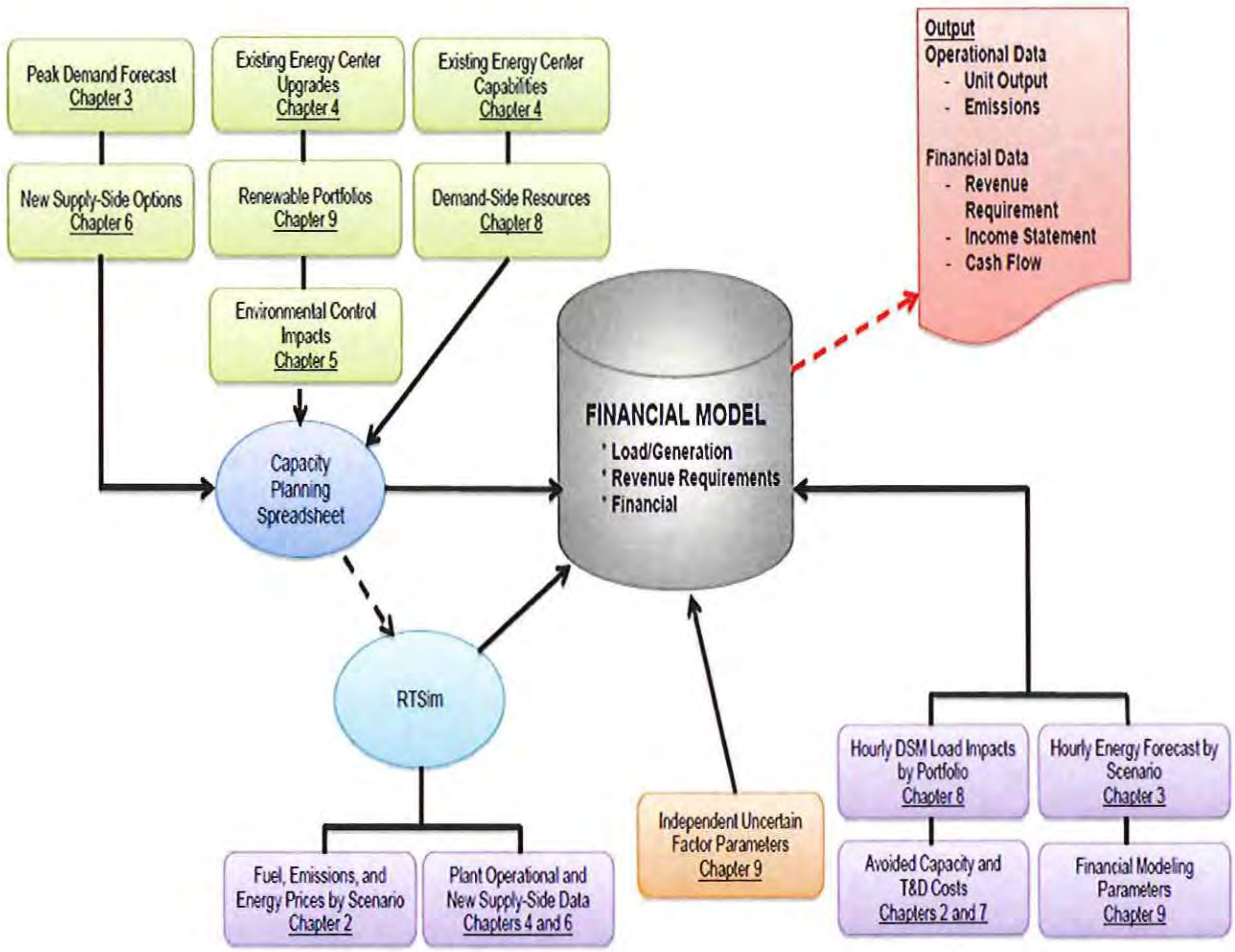
Ameren Missouri developed its own revenue requirements and financial model using Microsoft Excel. This model incorporates the capacity position and RTSim outputs, as well as other financial aspects regarding costs exterior to the direct operation of units and other valuable information that is necessary to properly evaluate the economics of a

[27] 4 CSR 240-22.060(4)(H); EO-2014-0062 d

resource portfolio. The financial module produces bottom-line financial statements to evaluate profitability and earnings impacts along with revenue requirement and various financial and credit metrics.

Figure 9.15 shows how the various assumptions are integrated into the financial model.

Figure 9.15 Resource Plan Model Framework[28]



[28] 4 CSR 240-22.060(4)(H)

Future Plans for Modeling Tools[29]

Ameren Missouri plans to continue to evaluate options for modeling tools for use in its resource planning process. Having developed a modular approach to our modeling for this IRP, we have the flexibility to evaluate models with varying degrees of capabilities (production costing, market settlements, revenue requirements, and financial statements) that can be used in place of, and/or in combination with, the current modules. As a result, we expect that our modeling needs over time will be characterized more by evolution rather than the deployment of a single integrated solution. Our current modular approach was in large part an outcome of our evaluation of solutions that are currently commercially available. For example, we were unable to identify any available integrated solutions that produce full financial statements other than MIDAS, which is no long being developed by Ventyx. Our current approach also allows us to expand our review of production costing solutions beyond those used primarily for long-term resource planning. We may be able to identify a production costing solution that can be applied to long-term resource planning, fuel budgeting, and possibly shorter-term trading support analysis.

We expect to continue our efforts to improve the efficiency, effectiveness and transparency of our modeling tools into 2015. The nature and timing of any changes we make will largely be a function of our assessment of the currently available options. As we consider these options, we plan to share thoughts with other Missouri utilities and with our stakeholder group. This may or may not provide opportunities to move to a common modeling platform. Ameren Missouri will remain open to such an outcome while ensuring that its own tools and processes are able to support our business needs and objectives.

[29] EO-2014-0062 e

9.10 Compliance References

10. Strategy Selection

Highlights

- *Ameren Missouri has developed and is executing on a plan that is focused on transitioning its generation fleet to a cleaner and more fuel diverse portfolio in a responsible fashion over the next 20 years to ensure we provide service to our customers that is safe, reliable and environmentally responsible at a reasonable cost.*
    - *Our plan includes continued customer energy efficiency program offerings, retirement of approximately one-third of our coal-fired generating capacity, which will be reaching the end of its useful life, and expansion of renewable and cleaner-burning natural gas-fired generation.*
    - *Our plan allows us to continue to rely on our existing, low-cost and dependable nuclear generation while also preserving options for future carbon-free nuclear generation.*
    - *By 2035, our plan would result in a diverse, balanced and dependable mix of coal, nuclear, natural gas and renewable energy resources that result in further significant reductions in emissions of carbon dioxide, sulfur dioxide, nitrogen oxides, mercury and particulate matter in addition to those we have achieved since 1990.*
- *Our plan allows us to achieve the goals of the U.S. EPA's proposed Clean Power Plan, reducing carbon dioxide emissions by 30% from 2005 levels, but at a customer cost savings of $4 billion.*
- *Our implementation plan for the next three years includes seeking approval for a new three-year portfolio of customer energy efficiency programs, construction of our second utility-scale solar energy center, identification of potential sites for renewable and gas-fired generation, and actions to preserve contingency resource options and enable us to quickly respond to changing needs and conditions while continuing to ensure safe, reliable and cost-effective service to our customers.*
- *Ameren Missouri will continue to monitor critical uncertain factors to assess their potential impacts on our preferred plan, contingency plans and implementation.*

Ameren Missouri has selected its preferred resource plan and contingency plans in accordance with its planning objectives and practical considerations that inform our decision making. Our selection process consists of several key elements:

- ✓ Establishing planning objectives and associated performance measures to develop and assess alternative resource plans
- ✓ Creating a scorecard based on our planning objectives and performance measures to evaluate the degree to which various alternative resource plans would satisfy our planning objectives
- ✓ Critically analyzing the most promising alternative resource plans to ensure that we select a plan that best balances competing objectives

In addition, Ameren Missouri has subjected its preferred resource plan to testing under several scenarios that represent events that, while not necessarily considered probable, could have a significant impact on our resource needs and the performance of our preferred resource plan. These include 1) the loss of significant customer demand due to a proliferation of distributed solar generation, 2) loss of our largest retail customer, and 3) compliance with proposed regulation of emissions of greenhouse gases (GHG) by existing power plants.

We have established an implementation plan for 2015-2017 that allows us to begin implementing the resource decisions embodied in our preferred resource plan and to preserve contingency options to allow us to effectively respond to changing needs and conditions while continuing to ensure safe, reliable and cost-effective electric service to our customers.

10.1 Planning Objectives

The fundamental objective of the resource planning process in Missouri is to ensure delivery of electric service to customers that is safe, reliable and efficient, at just and reasonable rates in a manner that serves the public interest. This includes compliance with state and federal laws and consistency with state energy policies.[1] Ameren Missouri considers several factors, or planning objectives, that are critical to meeting this fundamental objective. Planning objectives provide guidance to our decision making process and ensure that resource decisions are consistent with business planning and strategic objectives that drive our long-term ability to satisfy the fundamental objective of resource planning. Following are the planning objectives, established in the development of our 2011 IRP, that continue to inform our resource planning decisions.

[1] 4 CSR 240-22.010(2); 4 CSR 240-22.010(2)(A)

Cost (to Customers): Ameren Missouri is mindful of the impact that its future energy choices will have on cost to its customers. Therefore, minimization of present value of revenue requirements is our primary selection criterion.[2]

Costs alone do not and should not dictate resource decisions. Our other planning objectives, reaffirmed by Ameren Missouri decision makers, are discussed below.

Customer Satisfaction: Ameren Missouri is dedicated to improving customer satisfaction. While there are many factors that can be measured, for practical reasons Ameren Missouri focused primarily on measures that can be significantly impacted by resource decisions: 1) rate impacts – average rates and maximum single-year rate increases – and 2) customer preferences – cleaner energy sources and demand-side programs that provide customers with options to manage their usage and costs.

Environmental & Resource Diversity: Ameren Missouri, like other electric utilities in Missouri, produces the majority of the energy it generates from coal. Current and potential future environmental regulations may have a significant impact on Ameren Missouri's existing coal-fired energy centers and its selection of future generation resources. Ameren Missouri is focused on transitioning its generation fleet to a cleaner and more fuel diverse portfolio. To assess resource diversity and environmental considerations, we evaluate the composition of future portfolio options in terms of capacity and energy and assess the relative levels of various emissions for different alterntives.

Financial/Regulatory: The continued financial health of Ameren Missouri is crucial to ensuring safe, reliable and cost-effective service in the future. Ameren Missouri will continue to need the ability to access large amounts of capital for investments needed to comply with renewable energy standards and environmental regulations and invest in demand and/or supply side resources to meet customer demand and reliability needs. Measures of expected financial performance and creditworthiness are evaluated along with potential risks.

Economic Development: Ameren Missouri is committed to support the communities it serves beyond providing reliable and affordable energy. Ameren Missouri assesses the economic development opportunities, for its service territory and for the state of Missouri, associated with our resource choices. We do this by examining the potential for primary job growth, which in turn promotes additional economic activity.

Table 10.1 summarizes our planning objectives and the primary measures used to asses our ability to achieve these objectives with our alternative resource plans.

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[2] 4 CSR 240-22.010(2)(B)

Table 10.1 Planning Objectives and Measures[3]

Planning Objective Categories	Measures
Cost	Present Value of Revenue Requirements
Customer Satisfaction	Customer Preferences, Levelized Rates, Single-Year Rate Increase
Environmental & Resource Diversity	Resource Diversity, CO_2 Emissions, Probable Environmental Costs
Financial/Regulatory	ROE, EPS, FCF, Financial Ratios, Stranded Cost Risk, Transaction Risk, Cost Recovery Risk
Economic Development	Primary Job Growth (FTE-years)

10.2 Assessment of Alternative Resource Plans

Ameren Missouri used a scorecard to evaluate the performance of alternative resource plans with respect to our planning objectives and measures described above. The scorecard and measures include both objective and subjective elements that together represent the trade-offs between competing objectives. It is important to keep in mind that the scorecard is a tool for decision makers and does not, in and of itself, determine the preferred resource plan. The selection of the preferred resource plan is informed by the scorecard and by a more critical analysis of the relative merits of alternative resource plans, including an assessment of any risks or other constraints.

10.2.1 Scoring of Alternative Resource Plans[4]

To score each of the alternative resource plans, we employed a standard approach to scoring for each planning objective on a 5-point scale and determined a composite score by applying a weighting to each planning objective. As Cost is the primary selection criterion, it was given the greatest weight – 30% -- just as it was in the scoring performed for our 2011 IRP.[5] Economic Development carried a weight of 10%. Each of the other three planning objectives – Customer Satisfaction, Environmental & Resource Diversity, and Financial/Regulatory – carried a weight of 20%. The scoring approach for each planning objective is as follows:

[3] 4 CSR 240-22.060(2); 4 CSR 240-22.060(2)(A)1 through 7
[4] 4 CSR 240-22.010(2)(C); 4 CSR 240-22.010(2)(C)1; 4 CSR 240-22.010(2)(C)2; 4 CSR 240-22.010(2)(C)3; 4 CSR 240-22.070(1); 4 CSR 240-22.070(1)(A) through (D)
[5] 4 CSR 240-22.010(2)(B)

Cost – The 19 alternative resource plans were separated into five groups according to probability weighted average PVRR results from the risk analysis discussed in Chapter 9 – four groups of 4 plans and 1 group of 3 plans. The lowest cost group of plans were given a score of 5, the next lowest cost group a score of 4, and so on, with the highest cost group of plans receiving a score of 1.

Customer Satisfaction – Alternative resource plans were evaluated based on levelized annual average rates for a portion of the score. As was done with the PVRR results, the alternative resource plans were separated into five groups according to the probability-weighted average levelized annual average rate results produced from our risk analysis. The plans resulting in the lowest rates were given a score of 5, the next lowest rate group a score of 4, and so on, with the highest rate group of plans receiving a score of 1. Plans that yielded a score greater than 3 for rates were given 2 points in the overall scoring for Customer Satisfaction. In addition, plans which include continued energy efficiency programs (RAP or MAP) were given a point. Also, plans which included demand response programs were given an additional point. Finally, plans that include additional renewable generation sources beyond those needed to comply with legal mandates were given an additional point.

Environmental & Resource Diversity – Alternative resource plans were awarded points for each plan attribute contributing to greater resource diversity and/or environmental impact in terms of emission reductions. Plans were awarded one point each for each of the following:

- ✓ Inclusion of demand-side programs
- ✓ Addition of nuclear generation
- ✓ Addition of combined cycle gas generation
- ✓ Addition of renewables (beyond those needed to comply with legal mandates)
- ✓ Addition of storage resources
- ✓ Retirement of coal generation (beyond Meramec and Sioux)

Financial/Regulatory – Scoring for Financial/Regulatory is based on a default score of 5 with deductions for risks and financial impacts that may detrimentally affect Ameren Missouri's ability to continue to access lower cost sources of capital. Plans that would result in relatively lower free cash flow were reduced by one point. Plans were also reduced by one point each for potential risks associated with:

- ✓ Lack of customer energy efficiency programs
- ✓ Significant risk of not achieving energy efficiency targets
- ✓ Nuclear construction costs
- ✓ Retirement and replacement of additional coal units beyond Meramec and Sioux (one point deduction for every 1,200 MW of additional retirement)

Economic Development – Alternative plans were scored based on direct job creation, including construction and ongoing operation. Estimates for direct job creation were developed using the Jobs and Economic Development Impact (JEDI) Model, developed by Marshall Goldberg of MRG & Associates under contract with the National Renewable Energy Laboratory, or more specific estimates where available (e.g., nuclear). Construction and operating jobs were translated into full-time equivalent years (FTE-years). Alternative plans were ranked based on FTE-years and divided into five groups based on relative rank. The group of plans resulting in the highest FTE-year values were given a score of 5 points each, the next highest FTE-year group a score of 4, and so on, with the lowest FTE-year group of plans receiving a score of 1.

Table 10.2 Alternative Resource Plan Scoring Results

Plan	Description	Overall Assessment
R	600MW CC in 2034, MAP, Balanced	4.10
I	600MW CC in 2034, RAP, Balanced	4.00
E	800MW Wind in 2034, 352MW SC in 2034, 600MW CC in 2034, RAP	3.80
G	600MW CC in 2034, MAP	3.80
A	600MW CC in 2034, RAP	3.60
C	704MW SC in 2034, RAP	3.60
S	600MW CC in 2034, MAP EE Only	3.60
H	169MW Nuke in 2034, 600MW CC in 2034, RAP, Balanced	3.40
F	1200MW CC in 2034,RAP EE Only	3.20
D	600MW Pumped Hydro in 2034, RAP	3.10
Q	169MW Nuke in 2034, MAP, Balanced	3.10
P	169MW Nuke in 2025, 600MW CC in 2025, 1200MW CC in 2034, RAP, Balanced, RI Ret 12/31/2024	3.00
B	450MW Nuke in 2034, 600MW CC in 2034, RAP	2.80
O	169MW Nuke in 2025, 1800MW CC in 2024, 1200MW CC in 2034, RAP, Balanced, LAB Ret 12/31/2023	2.50
N	600MW CC in 2025, 1200MW CC in 2034, MAP, RI Ret 12/31/2024	2.40
K	600MW CC in 2023, 600MW CC in 2031, 600MW CC in 2034, MEEIA1, Balanced	2.10
M	1800MW CC in 2024, 1200MW CC in 2034, MAP, LAB Ret 12/31/2023	2.10
J	169MW Nuke in 2031, 600MW CC in 2023, 1200MW CC in 2034, MEEIA1, Balanced	2.00
L	3300MW Wind in 2023, 3300MW Wind in 2027, 6600MW Wind in 2034, MEEIA1	1.60

Table 10.2 shows the composite scores for each of the 19 alternative resource plans. The full scorecard with scores for each planning objective for each alternative resource plan is shown in Appendix A.

Based on the scoring results, the alternative resource plans were separated into three tiers – Top, Mid, and Bottom. The range of composite scores across the 19 alternative resource plans is 1.6 to 4.1, a difference of 2.5. This range was divided into thirds to establish the plan tiers. Plans with scores greater than 3.27 were placed in the Top Tier. Plans with scores between 2.43 and 3.27 were placed in the Mid-Tier. Plans with scores below 2.43 were placed in the Bottom Tier.

All Top Tier plans include energy efficiency and demand response at the realistic achievable potential (RAP) or maximum achievable potential (MAP) level. In general, plans that include combined cycle gas generation and renewable generation beyond that required for RES compliance scored highest. Only one plan with a Cost score greater than 3 is not included in the Top Tier – Plan F, which includes combined cycle generation and RAP energy efficiency, but no demand response.

10.2.2 DSM Portfolio Considerations

The top two plans identified in the plan scoring include either RAP DSM or MAP DSM. While MAP DSM results in lower total customer costs over the 30 years evaluated in our risk analysis, it is important to further evaluate the performance of MAP relative to RAP, in particular because MAP is defined as the hypothetical upper boundary of achievable demand-side potential, assuming ideal conditions for implementation. To further investigate the relative merits of RAP and MAP DSM portfolios, we evaluated:

- ✓ The inclusion in revenue requirements of the cost to customers of the incentives needed to align customer and utility interests in energy efficiency
- ✓ The inclusion in revenue requirements of participant costs
- ✓ The year-by-year relative net benefits for RAP and MAP
- ✓ A "Mid DSM" portfolio between RAP and MAP

Total Costs with Incentives and Participant Costs

In addition to the risk analysis discussed in Chapter 9, which excludes the cost of DSM incentives and participant out-of-pocket costs for energy efficiency measures, we also examined revenue requirements including these two components, both separately and in combination. Table 10.3 shows the results for the top two plans – one with RAP and one with MAP – under various combinations of assumptions for inclusion of incentive costs and participant out-of-pocket costs.

Table 10.3 PVRR Comparison of RAP and MAP

$ Million	PVRR	PVRR w/ Incentives	PVRR w/ DSM Participant Costs	PVRR w/ Incentives & DSM Participant Costs
R - CC-MAP-Balanced	61,081	61,420	61,834	62,172
I - CC-RAP-Balanced	61,352	61,635	61,928	62,211
MAP Cost Advantage	271	215	94	38

As the table shows, the cost advantage for MAP is reduced when either or both incentives and participant costs are included. Including only the incentives results in a cost advantage of $215 million for MAP, compared to a cost advantage of $271 million excluding incentives. Including participant out-of-pocket costs (and excluding incentive costs) reduces the advantage to $94 million, while including both incentives and participant out-of-pocket costs reduces it to $38 million.

The Missouri Energy Efficiency Investment Act (MEEIA) includes three requirements to ensure the alignment of utility incentives with helping customers use energy more efficiently:

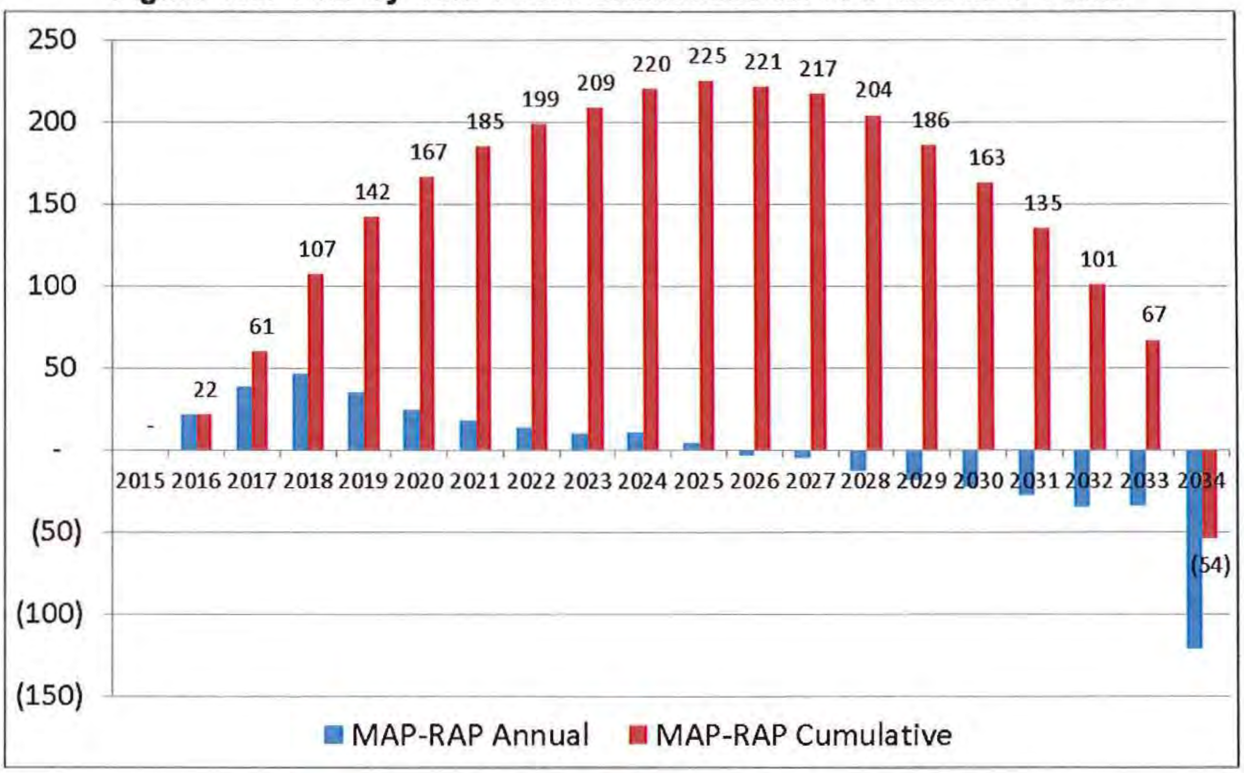
- ✓ Timely recovery of program costs
- ✓ Alignment of incentives to reduce energy consumption (i.e., elimination of the so-called "throughput disincentive")
- ✓ Timely earnings opportunities

The incentives included for RAP and MAP are based on an analysis of equivalency between demand side and supply side resources. Because the top scoring plans include gas-fired combined cycle generation, we based our equivalency analysis on the displacement of combined cycle generation by demand-side programs. We evaluated the earnings opportunity available to Ameren Missouri from a plan with no DSM programs after our current three-year cycle of programs (i.e., 2013-2015) and with combined cycle generation to meet load and reserve margin requirements instead of DSM. The present value earnings opportunity for each of RAP and MAP was levelized over the planning horizon. This amount was then included in the PVRR results including DSM incentives.

Year-by-Year Net Costs/Benefits

Implementation of the MAP energy efficiency portfolio would require a program budget for 2016-2018 that is roughly twice the budget needed to implement the RAP portfolio, although MAP reflects energy savings that are only roughly 35% greater than those for RAP. For the entire planning horizon, the program budget for MAP would total $2.45 billion compared to $1.27 billion for RAP, or 93% more costly than RAP, with energy savings that are only roughly 36% greater. We analyzed the year-by-year revenue requirement impacts of the RAP EE Only plan (Plan F) and the MAP EE Only plan (Plan S), including all costs and benefits. Figure 10.1 shows the annual and cumulative revenue requirement differences between the two plans.

Figure 10.1 Year-by-Year PVRR Differences for RAP and MAP Plans



As the chart shows, the MAP plan results in higher overall costs than the RAP plan through 2025. While the MAP plan results in lower overall costs starting in 2026, the cumulative increase in costs for the MAP plan reaches $225 million in 2025 and persists until 2034, the last year of the twenty-year planning horizon, when an additional combined cycle plant is assumed to be placed in service in the RAP EE Only plan. The greater net benefits of MAP relative to RAP increase significantly once program spending ceases and the persistent energy savings continue to yield benefits in the form of capacity and energy value in addition to deferral of the combined cycle plant.

Portfolios between RAP and MAP

To further evaluate the economics of DSM portfolios and to assist us in addressing the policy goal of MEEIA to achieve all cost-effective demand-side savings, we evaluated the possibility of a DSM portfolio that results in savings that are between those represented by RAP and MAP. Because primary market research exists only to support the development of RAP and MAP portfolios, we must estimate the costs and savings for any other portfolio assumptions.

We started by estimating the costs and savings for a portfolio that lies midway between the RAP and MAP portfolios, called the "Mid DSM" portfolio. The costs and savings were estimated by interpolating between the costs and savings associated with the RAP and MAP portfolios resulting from the primary market research included in our 2013 DSM potential study, described in Chapter 8. We then constructed a test plan including this portfolio and supply side resources necessary to meet load and reserve requirements. The plan was evaluated using the same ranges of assumptions used to evaluate alternative resource plans in our risk analysis. The results of the analysis, with a comparison of comparable plans including RAP and MAP portfolios (Plans I and R), is shown in Table 10.4. As the table shows, the PVRR results for the Mid DSM portfolio are midway between the results for plans with RAP and MAP DSM portfolios.

Table 10.4 PVRR Comparison of RAP and MAP

DSM Portfolio	PVRR
RAP	61,352
MAP	61,081
Mid	61,217

While it is possible to repeat this process, estimating other portfolios between RAP and MAP at different points on a continuum between the two portfolios, it would not provide additional insight into the merits of these various portfolios. Based on the results of our analysis of the Mid DSM portfolio, we would expect such additional portfolios to produce results that are similarly predictable. We would also expect the year-by-year analysis to produce similarly predictable results, showing a net advantage for RAP through 2025 on an annual basis and through 2033 on a cumulative basis.

Pursuing the Policy Goal of MEEIA[6]

As stated previously, the stated goal of MEEIA is to achieve all cost-effective demand-side savings by aligning utility incentives with helping customers to use energy more

[6] EO-2014-0062 a; EO-2014-0062 b

efficiently. Ameren Missouri has demonstrated its commitment to pursuing this goal by implementing the largest utility energy efficiency program in Missouri history. And while we believe this is a goal worth pursuing, it cannot be quantified with any degree of accuracy for the next twenty years. Rather, it is a goal that will constantly be shaped and reshaped through continuous implementation, evaluation, research, testing and readjustment.

As noted earlier, Ameren Missouri has conducted a DSM Potential Study, prepared by a nationally recognized independent contractor team. That study reflects an energy efficiency market assessment using 100% Ameren Missouri appliance saturation surveys, demographics surveys and customer psychographic surveys. The primary objective of the study was to assess and understand the technical, economic, and achievable potential for all Ameren Missouri customer segments for the period from 2016 to 2034. The amount of energy efficiency achieved by customers as a direct result of Ameren Missouri sponsored customer energy efficiency programs is defined as realistic achievable potential (RAP). Assuming regulatory treatment that reflects the requirements of MEEIA, RAP represents all cost-effective energy efficiency because, by definition, it represents a forecast of likely customer behavior under realistic program design and implementation.

10.3 Preferred Plan Selection[7]

In selecting its Preferred Resource Plan, Ameren Missouri decision makers[8] relied on the planning objectives discussed earlier in this chapter and the considerations reflected in the scoring and comparison of DSM portfolios highlighted in the previous section. As was noted previously, the Top Tier plans identified through scoring include combinations of RAP and MAP DSM portfolios as well as renewables, gas-fired resources and nuclear. These define the key options for consideration in the selection of the preferred resource plan.

DSM Portfolio[9] – RAP and MAP DSM portfolios both performed well in the scoring and, importantly, both result in reduced total costs to customers. The decision between the two must involve a consideration of risk and reward from the perspective of both customers and Ameren Missouri. Based on our analysis of the year-by-year cost differences between RAP and MAP, and an understanding of the increased level of risk

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[7] 4 CSR 240-22.010(2)(C); 4 CSR 240-22.010(2)(C)1; 4 CSR 240-22.010(2)(C)2 4 CSR 240-22.010(2)(C)3; 4 CSR 240-22.060(3)(A)5; 4 CSR 240-22.070(1); 4 CSR 240-22.070(1)(A) through (D)

[8] Names, titles and roles of decision makers are provided in Appendix B.

[9] EO-2014-0062 c

in achieving MAP relative to RAP, Ameren Missouri has chosen to include the RAP portfolio in its preferred resource plan.

This is not to say that there couldn't be additional potential energy savings that can be realized. Indeed our uncertainty range for the RAP portfolio includes some significant amount of upside. However, we must consider the immediate cost impact to all customers of a large increase in DSM expenditures (the 2016-2018 budget would be nearly double for MAP) and the uncertainty of the relative long-term benefits. We must also consider that the path for demand-side programs is not "locked in" for twenty years.

Including RAP DSM in our preferred resource plan allows us to continue to offer highly cost-effective programs to customers at roughly the same level of annual spending budgeted for our first cycle of MEEIA programs while also allowing the potential for increased savings if our experience and expectations indicate they could be achieved in a cost-effective manner. Identifying such opportunities will depend on the results of program implementation and periodic updates of our market research.

Renewable Resources – One of Ameren Missouri's planning objectives is to transition our generation portfolio to one that is cleaner and more fuel diverse in a responsible fashion. Compliance with the Missouri RES is reflected in all of our alternative resource plans. This includes approximately 300 MW of wind, solar, hydro and landfill gas generation. While the addition of these resources does help to transition our portfolio, additional renewable resources would further advance this objective while also further mitigating fuel price risks and the risks associated with additional environmental regulation, including regulation of emissions of greenhouse gases. We have therefore included additional wind and solar generation in our preferred resource plan to bring our renewable generation additions to approximately 500 MW.

Supply Side Resources – Considering costs, risks and the ability to further diversify our generating portfolio, we have included combined cycle generation in our preferred resource plan when needed to meet customer load and reliability reserve margin requirements. Based on our planning assumptions, we expect to need new capacity by 2034 to replace our Sioux energy center, which would be retired by the end of 2033. Because combined cycle generation technology is relatively mature, although still continuing to evolve, and is characterized by relatively short lead times, its inclusion preserves a measure of flexibility with respect to deployment for meeting load and reserve requirements. While simple cycle combustion turbine generators (CTGs) also exhibit short lead times and are relatively inexpensive, their operating characteristics prevent them from providing significant benefits in terms of energy diversity, and Ameren Missouri currently has a robust fleet of CTGs. Nuclear remains an attractive option for carbon-free around-the-clock generation with newer commercial and developing technologies.

The plan that embodies these key choices is listed in Table 10.2 as "Plan I". It includes RAP energy efficiency and demand response programs, roughly 500 MW of new renewable generation, and a new 600 MW combined cycle energy center in 2034 along with conversion of Meramec Units 1&2 to natural gas-fired operation in 2016, retirement of all Meramec units by the end of 2022, and retirement of Sioux Energy Center at the end of 2033.

10.4 Contingency Planning[10]

Because any assumptions about the future are subject to change, we must be prepared for changing circumstances by evaluating such potential circumstances and options for providing safe, reliable, cost-effective and environmentally responsible service to our customers. We have identified several cases which could significantly impact the performance of our preferred resource plan. These include cases that may result in 1) significantly higher or lower demand, 2) altered costs and feasibility of continuing to operate existing generating units, and 3) policies that may encourage the development of new nuclear generation.

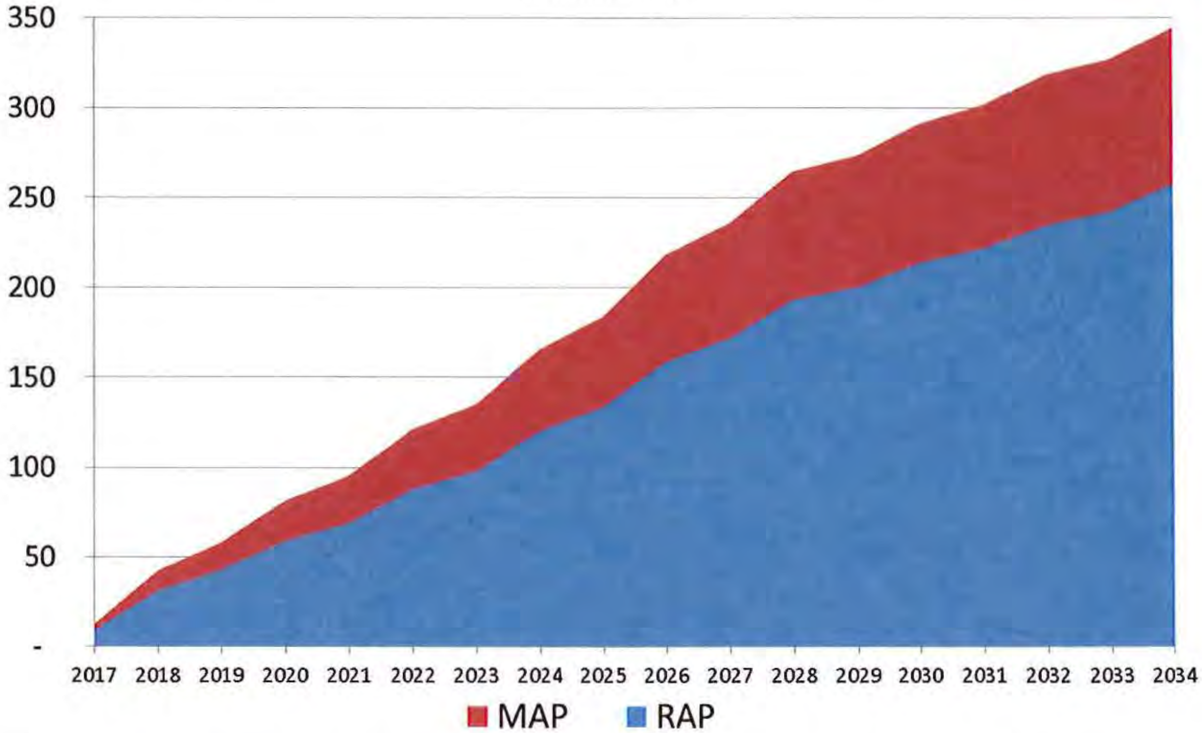
10.4.1 DSM Cost Recovery and Incentives

As stated previously, MEEIA provides for cost recovery and incentives for utility-sponsored demand-side programs to align utility incentives with helping customers to use energy more efficiently. In 2012, the Missouri Public Service Commission (Commission) approved our first cycle of MEEIA programs and supporting cost recovery and incentives. Our preferred resource plan is based on the expectation that supporting cost recovery and incentives will continue to be approved in the future. If such alignment is not achieved, it may be necessary for Ameren Missouri to change its preferred resource plan.

Ameren Missouri expects to file a request with the Commission for approval of a new three-year portfolio of demand-side programs in the fourth quarter of 2014. This portfolio would be implemented in 2016-2018. Program costs are expected to be recovered through our Rider Energy Efficiency Investment Charge (Rider EEIC). In our request, we will also seek recovery of costs associated with the so-called "throughput disincentive." The throughput disincentive results from reduced sales due to energy efficiency programs and rates that are designed to recover fixed costs based on sales volume. Figure 10.2 illustrates the impact of the throughput disincentive on Ameren Missouri's sales revenues for inclusion vs. exclusion of customer energy efficiency programs.

[10] 4 CSR 240-22.070(4)

Figure 10.2 Cumulative Throughput Disincentive for RAP and MAP Plans ($Millions)



In addition to recovery of program costs and addressing the throughput disincentive, MEEIA also mandates that utilities be provided with timely earnings opportunities that serve to make investments in demand-side resources equivalent to investments in supply-side resources. Ameren Missouri will seek such incentives in its upcoming MEEIA filing.

10.4.2 Expansion of Distributed Generation

The deployment of customer-owned distributed generation, particularly solar photovoltaic systems, continues to expand. Ameren Missouri has included its expectation for the deployment of customer-owned solar resources in its load forecast assumptions, described in Chapter 3. Because the economics of distributed generation can change rapidly, as we have seen in recent years, it is important for us to assess a greater-than-expected expansion of these resources. As described in Chapter 3, we identified the potential for additional distributed solar generation consistent with the U.S. DOE's Sunshot Initiative. Based on the DOE assumptions, Ameren Missouri would see an additional 614 MW of distributed solar generation in its service territory by 2034.

We have evaluated the impact of this change in load in two ways. First, we analyzed the impact on the cost of our preferred resource plan if the plan itself were not changed. Second, we analyzed the impact of the reduction in load on our need for, and timing of, new resources. If our resource plan is altered as a result of this significant change in customer load, we would expect to be able to defer the combined cycle generator that is shown in service in 2034 in our preferred resource plan.

The costs (PVRR) and levelized rates for our preferred resource plan, including that for the plan in which the combined cycle generator is deferred, are shown in Table 10.5 for our base distributed solar assumption and for the Sunshot case. The table shows that PVRR would be reduced by over $1.8 billion, while rates would increase by 0.21 cents/kWh if the timing of resources in the preferred plan did not change. It also shows that PVRR would be reduced by over $2 billion, and rates would increase by 0.17 cents/kwh if the combined cycle were deferred beyond the end of the planning horizon. Because the Sunshot Initiative would impact customer load across the Eastern Interconnect, we developed a price scenario using the process discussed in Chapter 2 to reflect the impacts of this additional change in load on power prices.

Table 10.5 Impact of Distributed Generation Expansion

Plan	PVRR ($Million)
Preferred Plan	61,352
DG Expansion-CC in 2034	59,513
DG Expansion-No CC in 2034	59,320

It is important to note that our preferred resource plan provides flexibility in responding to significant changes in load like the change that could be driven by a proliferation of distributed generation, solar or otherwise.

10.4.3 Loss of Large Customer Load

Ameren Missouri's largest customer is the aluminum smelter operated by Noranda Aluminum, Inc., in New Madrid, Missouri. The smelter uses 4,169 GWh of electricity annually with a peak demand of approximately 495 MW and is served at retail rates regulated by the Commission under a contract with Ameren Missouri that expires in May 2020. To evaluate the impact on our preferred plan of a loss of Noranda's load at the end of their current contract, we examined cases in which 1) the resources and timing reflected in our preferred plan are not changed and 2) the resources and timing reflected in our preferred plan are changed. This is similar to the analysis we conducted for the proliferation of distributed solar generation described in the previous section.

The loss of Noranda's load would allow us to defer the combined cycle that is shown going into service in 2034 in our preferred resources plan. The costs (PVRR) and levelized rates for our preferred resource plan, including that for the plan in which the combined cycle generator is deferred, are shown in Table 10.6 for our base assumption with Noranda continuing to take electric service from Ameren Missouri and for the case with no Noranda load after May 2020. The table shows that PVRR would be reduced by nearly $3.4 billion if the timing of resources in the preferred plan did not change. It also shows that PVRR would be reduced by $3.6 billion if the combined cycle were deferred beyond the end of the planning horizon.

Table 10.6 Impact of Noranda Load Loss

Plan	PVRR ($Million)
Preferred Plan	61,352
Noranda Contract Expired-CC in 2034	57,966
Noranda Contract Expired-No CC in 2034	57,755

As with the distributed generation case discussed in the previous section, the flexibility of our preferred resource plan allows us to adjust our resource timing to minimize cost impacts, which in this case would be borne by our remaining customers outside of Noranda.

10.4.4 Incremental Wind Additions[11]

Ameren Missouri has also modeled its preferred plan with the addition of 150 MW of wind resources (beyond that already included in the preferred plan) in year 2022 in order to evaluate the cost effectiveness of additional incremental renewable resources. Table 10.7 shows the results of the analysis, which indicates increased cost to customers for the plan with additional wind resources compared to our preferred plan.

Table 10.7 Impact of Additional Wind

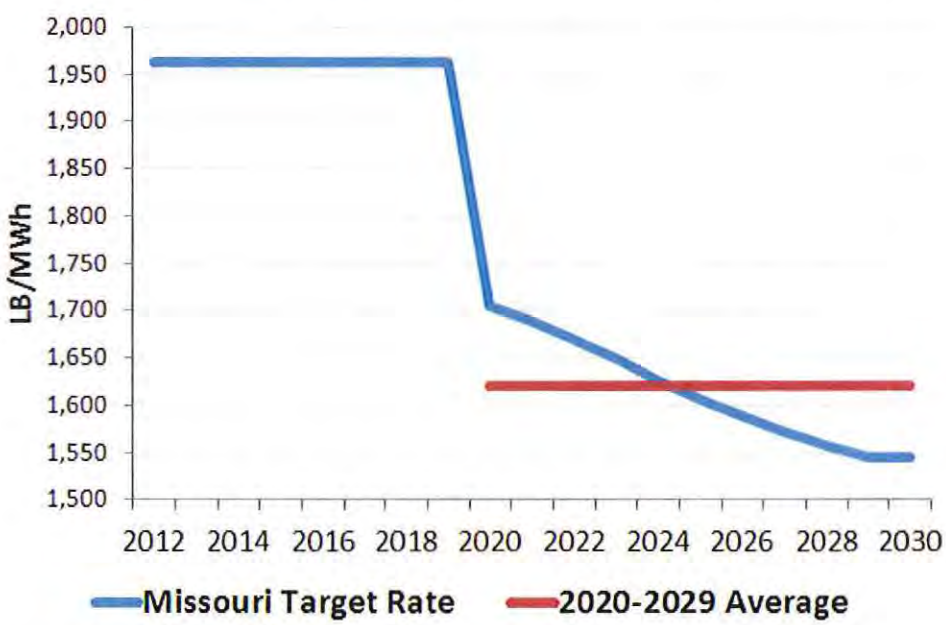
Plan	PVRR ($Million)
Preferred Plan	61,352
Additional Wind	61,455
Difference	102

[11] 4 CSR 240-22.060(4)(E); EO-2011-0271 Order

10.4.5 Greenhouse Gas Regulation

On June 2, 2014, the EPA announced its proposed "Clean Power Plan," which calls for a 30% reduction in carbon dioxide emissions from existing power plants compared to 2005 levels from existing power plants by 2030, with aggressive interim targets beginning in 2020. These targets are not based on mass carbon emission reductions, but instead are based on rates of carbon emitted from existing plants as derived from 2012 levels. The EPA established different targets for each state, including a 21% reduction for Missouri. Figure 10.3 shows the required reduction and timing of carbon dioxide emission rates proposed by the EPA. As the chart shows, much of the targeted 2030 reduction, 13% of the 21% final target, is required starting in 2020 due to interim targets included in the proposed rule. This means that more than 60% of the 2030 reduction goal must be met by 2020.

Figure 10.3 EPA Target Carbon Dioxide Emission Rates for Missouri



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

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

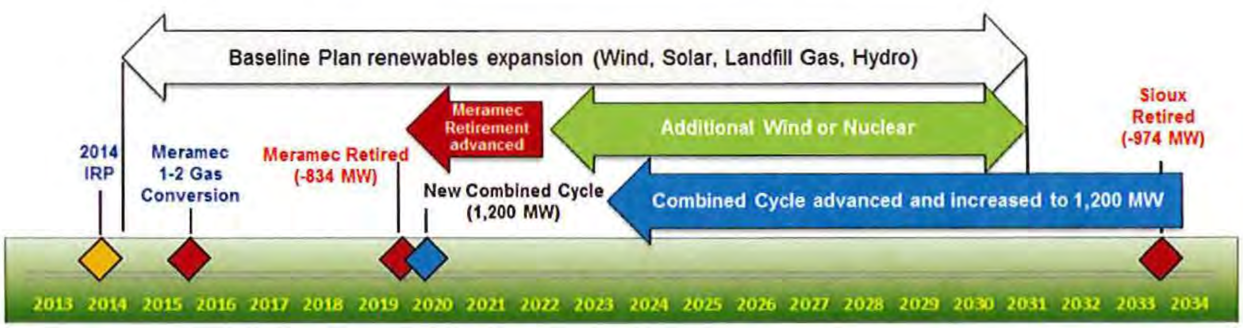
divided by:

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

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

Should the rule be implemented as proposed, Ameren Missouri would have to significantly alter its preferred resource plan in such a way as to lead to much higher capacity reserves by advancing and adding natural gas-fired generation, as early as 2020, and uneconomically dispatching those resources, which would not otherwise be needed until 2034 to meet customer demand and reserve margin requirements for reliability. Figure 10.4 illustrates the changes that could have to be made to Ameren Missouri's preferred resource plan to comply with the proposed regulations.

Figure 10.4 Impacts of GHG Regulations on Preferred Resource Plan



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

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

1. Eliminate the aggressive interim emission reduction targets and give states, who possess intimate knowledge of their system needs, the flexibility to adopt interim milestones as appropriate

2. Treat unreplaced retired coal units as a zero-emitting resource (similar to how customer energy efficiency programs are treated)
3. Give states the flexibility to extend the compliance date to allow the orderly retirement of coal plants as states implement their transition plans

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

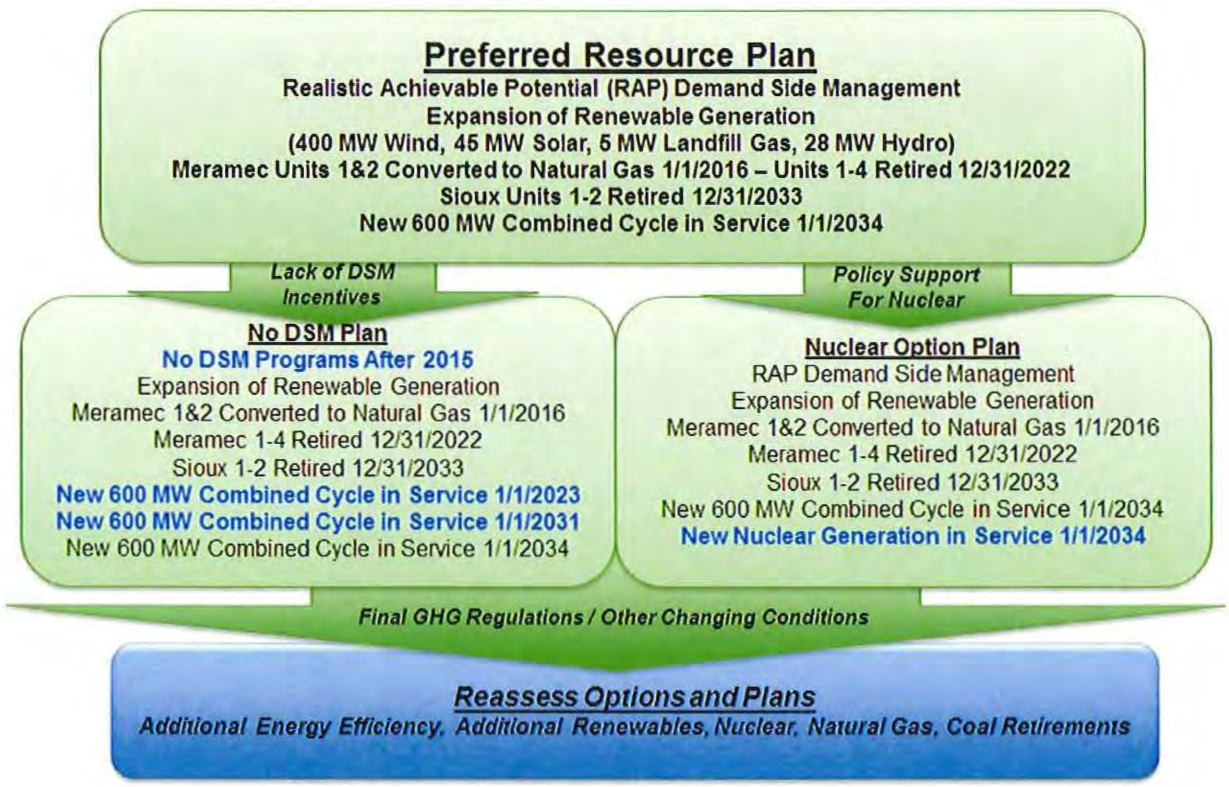
10.4.6 Optionality for New Generation

As the contingency cases described earlier illustrate, it is important to maintain options and flexibility to ensure Ameren Missouri can meet its customers' energy needs in a safe, reliable, and environmentally responsible manner at a reasonable cost. Our analysis has shown that renewables, gas-fired combined cycle, and nuclear generation continue to be attractive options for meeting our customers' future energy needs. It is therefore important to ensure that we can exercise these options when needed and in response to changing circumstances. This includes continuing to evaluate opportunities for developing additional renewable energy resources, evaluating potential sites for new gas-fired generation, and taking actions to maintain an option for future nuclear generation and the associated economic development benefits that would be realized for the state of Missouri. As the discussion of greenhouse gas regulation demonstrates, options for cleaner and dependable resources are also critical for ensuring compliance with such regulations while maintaining safe, reliable, and cost-effective service to customers.

10.5 Resource Acquisition Strategy[12]

Our resource acquisition strategy has three main components. First is the Preferred Resource Plan which is discussed in more detail in Section 10.5.1. The second component of the resource acquisition strategy is contingency planning. Under no ranges or combinations of outcomes for the critical uncertain factors, would the Preferred Resource Plan be inappropriate. Figure 10.5 shows the Preferred Resource Plan as well as several contingency options and the events that could lead to a change in our preferred plan. The final component of the resource acquisition strategy is the implementation plan which includes details of major actions over the next three years, 2015-2017.

Figure 10.5 Preferred Plan and Contingency Plans



[12] 4 CSR 240-22.070(1); 4 CSR 240-22.070(1)(A) through (D); 4 CSR 240-22.070(2);
4 CSR 240-22.070(4); 4 CSR 240-22.070(4)(A) through (C);
4 CSR 240-22.070(7); 4 CSR 240-22.070(7)(A) through (C)

10.5.1 Preferred Plan

As discussed in Section 10.3, our Preferred Resource Plan includes RAP energy efficiency and demand response programs, roughly 500 MW of new renewable generation, and a new 600 MW combined cycle energy center in 2034 along with conversion of Meramec Units 1&2 to natural gas-fired operation in 2016, retirement of all Meramec units by the end of 2022, and retirement of Sioux Energy Center at the end of 2033.

Demand Side Resources

The preferred plan includes RAP energy efficiency and demand response programs. Energy efficiency programs under our current three-year MEEIA plan run through 2015. Energy efficiency programs under subsequent MEEIA cycles begin in 2016. Demand response programs begin in 2019 based on our expectation for higher avoided capacity costs in that timeframe. Program spending for the 20-year planning horizon is $1.41 billion. Cumulative peak demand reductions reach 1090 MW by 2034 (not including planning reserve margin), and cumulative energy savings (at the customer meter) total over 23.6 million MWh.

Renewables

Chapter 9 includes a detailed description of renewable resource requirements. In summary, Ameren Missouri will need additional non-solar resources starting in 2019. We also expect to need additional solar resources to continue to meet the RES solar requirements when SRECs transferred to Ameren Missouri from customer-owned solar facilities are no longer available. Beyond those renewable resources included for RES compliance, we have included additional wind and solar resources to advance our objective to transition our generation portfolio to a cleaner and more fuel diverse mix of resources. Our expansion of renewables includes 400 MW of wind, 45 MW of solar, 20 MW of new hydroelectric, 8 MW of upgrades to existing hydroelectric facilities, and 5 MW of additional landfill gas generation.

Supply-Side Resources

The Preferred Resource Plan calls for the conversion of Units 1&2 at our Meramec Energy Center to natural gas-fired operation in early 2016 and retirement of all Meramec units by the end of 2022. It also includes retirement of Sioux Energy Center by the end of 2033 and a 600 MW combined cycle plant near the end of the planning horizon in 2034.

10.5.2 Contingency Plans[13]

Figure 10.5 presents our key contingency options. In the event that Ameren Missouri's interests are not aligned with helping customers use energy more efficiently, as required by MEEIA, we have included a contingency plan that reflects a discontinuation of demand side programs after our current MEEIA cycle programs expire at the end of 2015. The contingency plan therefore also includes the installation of a 600 MW combined cycle facility to be in service in 2023 and another 600 MW combined cycle in 2031 in addition to the generation resources included in our preferred plan. We are also maintaining a contingency option to reflect policy support for new nuclear generation, which would result in the addition of nuclear generation in 2034. Maintaining an option for new nuclear generation also affords us greater flexibility to comply with requirements of greenhouse gas regulations.

10.5.3 Expected Value of Better Information Analysis[14]

After selecting the preferred plan, Ameren Missouri conducted an expected value of better information (EVBI) analysis to assess the performance of its preferred resource plan under the range of values defined for the critical uncertain factors and to inform its on-going research and implementation activities. Table 10.8 displays the results of the EVBI analysis as measured by PVRR. Under almost all critical uncertain factor values, Plan G results in a lower PVRR than the preferred plan. In part, because it is possible that additional cost-effective energy savings could be identified, we will continue to undertake rigorous evaluation of our programs and periodically update our market research to identify additional such opportunities.

Under the high carbon price scenario, Plan L with only additional renewable resources (no further DSM after MEEIA Cycle 1), performs significantly better than the preferred plan. While the addition of such a vast amount of wind generation may not be practical or feasible, the analysis does indicate the potential for greater value for renewable resources under aggressive scenarios for greenhouse gas regulation. We will continue to evaluate opportunities for additional renewable resources as we identify options and candidate sites for our planned renewable additions and as current efforts to regulate greenhouse gas emissions continue to unfold.

[13] 4 CSR 240-22.070(4)
[14] 4 CSR 240-22.070(3)

Table 10.8 EVBI Analysis Results

Alternative Resource Plans	PVRR Without Better Info	Coal Retirements			Carbon				Load Growth				Natural Gas Price				Project Cost			Interest Rate & ROE			DSM			Coal Price		
		Low	Base	High	None	Low	Base	High	PWA	Low	Base	High	PWA	Low	Base	High	Low	Base	High	Low	Base	High	Low	Base	High	Low	Base	High
A CC-RAP	61,113	59,612	59,551	69,821	59,576	66,484	69,475	74,195	69,821	55,926	59,682	62,910	61,056	61,151	61,179	60,975	60,349	61,084	62,106	60,259	61,124	61,874	61,335	55,439	60,405	57,490	61,223	63,850
B Nuke2-RAP	62,262	60,813	60,757	70,657	60,780	67,488	70,325	74,823	70,657	57,138	60,879	64,127	62,211	62,380	62,307	61,974	60,613	62,187	64,507	61,296	62,275	63,122	62,484	56,484	61,554	58,639	62,372	64,999
C SC-RAP	61,060	59,553	59,489	69,813	59,516	66,421	69,464	74,253	69,813	55,859	59,627	62,838	60,997	61,126	61,122	60,916	60,342	61,033	62,000	60,213	61,072	61,815	61,283	55,392	60,353	57,438	61,171	63,797
D Pumped Hydro-RAP	61,522	60,007	59,943	70,319	59,969	66,910	69,968	74,780	70,319	56,312	60,081	63,291	61,458	61,577	61,586	61,393	60,760	61,494	62,502	60,645	61,533	62,303	61,744	55,811	60,814	57,899	61,632	64,259
E Wind-SC-RAP	61,338	59,881	59,823	69,791	59,847	66,592	69,456	73,993	69,791	56,206	59,946	63,190	61,287	61,438	61,388	61,080	60,389	61,306	62,546	60,444	61,350	62,135	61,561	55,644	60,631	57,716	61,449	64,075
F CC-RAP EE only	61,335	59,840	59,782	70,002	59,806	66,716	69,658	74,317	70,002	56,163	59,906	63,150	61,285	61,347	61,407	61,207	60,490	61,305	62,420	60,459	61,347	62,116	61,431	55,702	61,113	57,713	61,446	64,073
G CC-MAP	60,842	59,360	59,297	69,449	59,323	66,165	69,108	73,758	69,449	55,683	59,425	62,656	60,788	60,909	60,900	60,647	60,078	60,813	61,835	59,990	60,854	61,601	61,192	55,088	60,134	57,220	60,953	63,579
H Nuke-RAP-Balanced	61,800	60,338	60,276	70,290	60,302	67,067	69,953	74,523	70,290	56,665	60,402	63,639	61,748	61,895	61,851	61,552	60,620	61,752	63,359	60,884	61,812	62,616	62,022	56,064	61,092	58,177	61,911	64,537
I CC-RAP-Balanced	61,352	59,870	59,807	69,959	59,833	66,673	69,618	74,270	69,959	56,193	59,936	63,166	61,298	61,418	61,411	61,161	60,505	61,322	62,440	60,479	61,364	62,130	61,575	55,657	60,645	57,730	61,463	64,089
J Nuke-MEEIA1-Balanced	63,935	62,446	62,384	72,575	62,410	69,343	72,234	76,832	72,575	58,794	62,500	65,755	63,897	63,851	64,026	63,892	62,411	63,879	65,908	62,935	63,948	64,825	63,935	58,123	63,935	60,312	64,045	66,672
K CC-MEEIA1-Balanced	63,357	61,846	61,782	72,135	61,808	68,837	71,788	76,477	72,135	58,193	61,900	65,148	63,319	63,226	63,460	63,391	62,235	63,323	64,754	62,407	63,370	64,203	63,357	57,597	63,357	59,735	63,468	66,094
L Wind-MEEIA1	66,973	66,403	66,293	70,570	66,339	69,808	70,444	71,706	70,570	63,035	66,317	69,708	67,029	68,360	66,671	64,256	62,635	66,871	72,134	65,437	66,995	68,337	66,973	60,885	66,973	63,351	67,084	69,710
M CC-MAP-Labadie	64,452	63,500	63,471	69,939	63,483	67,817	69,705	72,761	69,939	59,717	63,621	66,835	64,328	63,624	64,780	65,789	63,158	64,418	66,011	63,526	64,465	65,271	64,802	58,370	63,743	62,360	64,517	66,015
N CC-MAP-Rush	62,617	61,394	61,353	69,686	61,370	66,948	69,396	73,296	69,686	57,649	61,495	64,714	62,523	62,249	62,811	63,194	61,654	62,587	63,823	61,746	62,629	63,393	62,968	56,703	61,909	59,810	62,708	64,701
O Nuke2025-RAP-Labadie-Balanced	65,397	64,489	64,457	70,650	64,470	68,645	70,427	73,326	70,650	60,722	64,602	67,821	65,279	64,624	65,710	66,627	63,477	65,331	67,844	64,390	65,411	66,290	65,620	59,334	64,690	63,306	65,463	66,961
P Nuke2025-RAP-Rush-Balanced	64,018	62,838	62,794	70,853	62,812	68,231	70,573	74,315	70,853	59,109	62,931	66,156	63,929	63,705	64,195	64,487	62,347	63,954	66,202	63,043	64,031	64,886	64,240	58,080	63,310	61,211	64,108	66,102
Q Nuke-MAP-Balanced	61,431	59,982	59,915	69,863	59,942	66,640	69,528	74,091	69,863	56,308	60,045	63,269	61,375	61,581	61,469	61,118	60,333	61,384	62,897	60,538	61,443	62,226	61,781	55,624	60,722	57,808	61,541	64,168
R CC-MAP-Balanced	61,081	59,618	59,553	69,588	59,580	66,354	69,251	73,834	69,588	55,950	59,680	62,911	61,030	61,176	61,132	60,833	60,234	61,051	62,169	60,211	61,093	61,857	61,432	55,306	60,373	57,459	61,192	63,818
S CC-MAP EE only	61,078	59,595	59,532	69,687	59,558	66,402	69,346	73,999	69,687	55,918	59,661	62,891	61,024	61,144	61,136	60,885	60,314	61,049	62,070	60,224	61,089	61,838	61,278	55,376	60,914	57,455	61,188	63,815
Minimum PVRR among plans		59,360	59,297	69,449	59,323	66,165	69,108	71,706	69,449	55,683	59,425	62,656	60,788	60,909	60,900	60,647	60,078	60,813	61,835	59,990	60,854	61,601	61,192	55,088	60,134	57,220	60,953	63,579
Plan with Minimum PVRR		G	G	G	G	G	G	L	G	G	G	G	G	G	G	G	G	G	G	G	G	G	G	G	G	G	G	G
Subjective Probability		35%	50%	15%	85%	3%	9%	3%	15%	17%	51%	17%	40%	18%	36%	6%	10%	80%	10%	10%	80%	10%	45%	55%	5%	10%	80%	10%
Expected Value of Better Info		510	510	510	510	508	510	2,564	510	510	510	510	510	508	511	514	427	509	605	489	510	529	382	568	511	510	510	510

10.5.4 Implementation Plan[15]

As mentioned earlier, the implementation plan outlines the major activities to be completed during the next three years, 2015-2017. Below is a description of those major activities.

Load Analysis and Forecasting Implementation

Ameren Missouri continually works to explore additional data sources and enhanced forecasting and analytical techniques to improve its load analysis processes, and, as of this writing, is in the process of developing and implementing a new sample for its load research program. Ameren Missouri has worked with Enernoc Utility Solutions in 2009 and 2013 to perform extensive primary market research and anticipates continuing to engage in periodic collection of primary data to further enhance its understanding of the mix of end-use appliances and equipment in its service territory. More detail on load analysis research activities is provided in Chapter 3.

Demand-Side Resources Implementation

The detailed implementation plan for RAP DSM is presented in Chapter 8 and includes program templates, evaluation strategies, energy and peak savings goals, budgets, and other information for the implementation period. Table 10.9 provides a summary of the annual energy savings and peak reduction goals, as well as annual budgets, for residential and business programs.

Table 10.9 DSM Implementation Plan Summary

	2016	2017	2018	Total
Residential EE Programs net energy savings (MWh)	58,505	45,691	61,472	165,668
Business EE Programs net energy savings (MWh)	46,252	91,927	122,536	260,715
Total estimated net energy savings (MWh) at meter	**104,757**	**137,617**	**184,008**	**426,382**
Residential EE Programs net demand reduction (MW)	14	9	13	36
Business EE Programs net demand reduction (MW)	13	28	37	78
Estimated net demand reduction (MW) at meter	**27**	**37**	**50**	**114**
Residential EE Programs annual costs ($ millions)	$21.81	$18.61	$22.96	$63.38
Business EE Programs annual costs ($ millions)	$14.60	$30.23	$39.36	$84.19
Estimated costs (Program costs in millions)*	**$36.41**	**$48.84**	**$62.32**	**$147.57**

*Note: The Company may choose to equalize expenditures for each year after finalizing implementation plans with its implementation contractors.

[15] 4 CSR 240-22.070(6); 4 CSR 240-22.070(6)(A) through (D)

Demand-Side Resources Cost Recovery and Incentives

Ameren Missouri continues to implement its first cycle of approved MEEIA programs, which run through 2015. Ameren Missouri expects to file a request with the Commission in the fourth quarter of 2014 for approval of demand-side programs and associated cost recovery and incentive mechanisms to be implemented in 2016-2018. Upon approval, Ameren Missouri will proceed with contractor onboarding and implementation planning.

Combined Cycle

While the preferred resource plan includes new combined cycle generation near the end of the planning horizon, in 2034, our contingency planning indicates a need to prepare for the possibility of needing new generation much sooner. This may be as a result of triggering a contingency option related to DSM cost recovery and incentives or to comply with greenhouse gas regulations. To prepare for such contingency options, Ameren Missouri will be evaluating potential sites for new combined cycle generation.

Nuclear

To preserve the nuclear resource option, Ameren Missouri continues nuclear development activities as necessary to ensure that this option remains viable in the projected needed timeframes. This includes maintaining the existing application for a new nuclear unit on the US NRC docket with the review suspended, interface with vendors developing new small modular light water reactor technologies, and a continued review and evaluation of large light water reactors with passive safety features.

Renewables

Our preferred resource plan includes the addition of new solar generation in 2016, expansion of our existing landfill gas-fueled Maryland Heights Renewable Energy Center in 2018, and new wind resources beginning in 2019. Ameren Missouri will be engaging in activities during the implementation period to support the construction of the new solar generation in 2016, including bid solicitation, contractor selection, applying for a certificate of convenience and necessity, and construction. We will also be continuing to evaluate the feasibility and timing for expansion at Maryland Heights and evaluating potential sites and options for wind generation.

Meramec

Ameren Missouri will be taking steps to convert Meramec Units 1&2 to natural gas-fired operation by early 2016. Because the units were originally designed with the option of operating on natural gas fuel, the work necessary to ensure reliable operation on natural gas is expected to be minimal and cost less than $2 million.

Environmental

Ameren Missouri will continue to monitor changes in environmental regulations and options for compliance. In the near term, we will complete work needed to comply with MATS.

Voltage Control Pilot Project

Ameren Missouri has initiated a Voltage Control Pilot Project to evaluate Volt/Var Optimization effectiveness and to evaluate Conservation Voltage Reduction on selected distribution power lines. Distributed control programming and operational testing are expected to be completed during 2014-2015.

Competitive Procurement Policies[16]

Ameren Missouri assigns a Project Manager to lead the activities necessary to ensure the successful completion of its acquisition and development of supply-side resources. In general, a project team comprised of a Project Manager and various lead engineers will identify all items to be procured and will coordinate with the Strategic Sourcing and Purchasing departments within Ameren to ensure proper contract structures are considered and used for each procurement activity. A Contract Development Team (CDT) is assembled and assists in collecting material and labor estimates based on the overall project design. Strategic Sourcing, CDT and the project team work to set up a number of components as Ameren stock items that are the basis for ordering materials. A detailed procurement matrix is developed to identify the major purchases that are anticipated to be required as part of the project. Material purchases make use of stock items established by the CDT. Where material has not been established as a stock item, the preferred approach is to solicit and obtain at least three quotations from a group of preferred Ameren vendors wherever possible to ensure the most competitive pricing for the material.

In the case of utilizing engineering, procurement and construction contracts (EPC), competitive bids are acquired from multiple vendors capable of meeting the requirements of the project. For the planned 2016 solar project, for example, the EPC contract will be fixed fee-based and the procurement of all components will be in the bid price and therefore under the full responsibility of the contractor.

Ameren Missouri will be following Ameren's Project Oversight Process, which is provided in Appendix C, for monitoring the progress made implementing its Preferred Resource Plan.[17]

[16] 4 CSR 240-22.070(6)(E)
[17] 4 CSR 240-22.070(6)(G)

10.5.5 Monitoring Critical Uncertain Factors[18]

Ameren Missouri will be monitoring the critical uncertain factors that would help determine whether the Preferred Resource Plan is still valid and whether contingency options should be pursued. Below is a description of how Company decision makers will be monitoring the factors most relevant to future resource decisions.

Climate Policy

Ameren Missouri senior management and the Environmental Services Group will continue to monitor and evaluate developments on efforts to regulate greenhouse gas emissions. With EPA scheduled to announce its final rule for existing power plants in June 2015, Ameren Missouri will continue to be engaged at both the federal and state level.

Gas Prices

The President and CEO of Ameren Missouri is updated at least annually by Corporate Planning on trends and drivers of natural gas prices as part of the update on the drivers of forward commodity prices. Ameren Missouri senior management may, in its sole discretion, request more frequent updates to discuss significant changes in natural gas prices.

Load Growth

Corporate Planning will update Ameren Missouri's capacity position as needed based on the latest assumptions regarding load growth. Any significant changes in resource needs, whether timing or size, will be communicated to Ameren Missouri senior management. Corporate Planning will also reassess, at least annually, its assumptions for load growth in the Eastern Interconnect, which is a critical dependent uncertain factor included in our power price scenario modeling.

Coal Prices

Corporate Planning will work with Ameren Missouri's Fuels organization to monitor coal prices, with updates at least annually and as needed.

Project Costs

Corporate Planning, with support from other groups and as directed by Ameren Missouri senior management, will monitor trends in capital costs for all of the candidate supply-side resource options and environmental compliance retrofits with careful attention to those included in the preferred and contingency resource plans. Any significant changes will be communicated to Ameren Missouri senior management.

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[18] 4 CSR 240-22.070(6)(F)

Demand-Side Resource Impacts and Cost

Corporate Planning will continue to evaluate the cost-effectiveness of its DSM programs internally and through the evaluation process. To further enhance our ability to ensure the continued cost effectiveness of our demand side programs, Ameren Missouri will 1) annually adjust its estimate of annual load reductions from its DSM potential study to incorporate the most recent EM&V measure impact energy savings estimates and 2) seek program design changes to account for emerging baseline energy savings constructs that could affect available potential as well as program cost effectiveness. Any major deviations from planning assumptions like participation rates, technology costs, and customer opt-out will be communicated to Ameren Missouri senior management.

Interest Rates and Financial Metrics

Corporate Planning and Treasury will continue to evaluate the impact of interest rates and various financial metrics on revenue requirements consistent with maintaining investment grade credit ratings. This evaluation will include an analysis of the level of interest rates and financial metrics that would trigger consideration of a contingency plan.

10.6 Compliance References

11. Stakeholder Process

Highlights

- *Ameren Missouri conducts an inclusive stakeholder process to solicit feedback on its assumptions and analysis methods.*
- *Ameren Missouri hosted a stakeholder meeting in February 2014 to present our key assumptions and solicit stakeholder feedback.*
- *We have incorporated comments received from stakeholders on draft reports shared during the development of our IRP filing.*
- *Ameren Missouri has also addressed Special Contemporary Issues as ordered by the Missouri Public Service Commission.*

Ameren Missouri conducts an inclusive stakeholder process to solicit feedback on its assumptions and analysis methods used for integrated resource planning. Our stakeholder group includes representatives of state agencies, consumer advocates and environmental advocates. Our process includes the following key elements:

- A stakeholder workshop to review the assumptions and analytical methods used in the analysis of resource alternatives and selection of our preferred resource plan
- Distribution of drafts of certain chapters of our filing and review and incorporation, as appropriate, of stakeholder comments on those drafts
- Addressing Special Contemporary Issues as part of our analysis as suggested by stakeholders and ordered by the Missouri Public Service Commission (Commission)

This chapter describes how these key elements were satisfied pursuant to the Commission's rules and its order on Special Contemporary Issues.

11.1 Stakeholder Group

Ameren Missouri's stakeholder group includes representatives of the following state agencies and private organizations:

- Commission Staff (Staff)
- Office of Public Counsel (OPC)
- Department of Economic Development – Division of Energy (DE)
- Missouri Industrial Electric Customers (MIEC)
- Missouri Energy Group (MEG)
- Natural Resources Defense Council (NRDC)
- Sierra Club
- Renew Missouri

11.2 Stakeholder Workshop

On February 3, 2014, Ameren Missouri hosted a stakeholder workshop at its general offices in St. Louis to present key assumptions and analytical methods to be used in our analysis of resource choices and decisions necessary to meet the electric energy needs of our customers in a safe, reliable, environmentally responsible and cost-effective manner. The workshop included discussion of assumptions for:

- Forecasts of customer energy consumption and peak demand, which is discussed in detail in Chapter 3
- Potential, including costs and benefits, for utility programs to help customers use energy more efficiently and defer or reduce the need for new sources of electric generation, which is discussed in detail in Chapter 8
- Options, including costs and operating characteristics, for new generation, which are discussed in detail in Chapter 6
- Delivery infrastructure (transmission and distribution) needs and plans and relationships to meeting customers' needs, which are discussed in detail in Chapter 7
- Options and costs, including the expected need for environmental equipment investments, for the operation of our existing generating portfolio, which are discussed in detail in Chapters 4 and 5

We also presented our alternative resource plans from which we would select a preferred resource plan and the planned assumptions and analytical methods we expected to use to evaluate those alternative resource plans. This discussion covered the following topics:

- Alternative resource plans, which are presented in Chapter 9
- Assumptions for key variables that could affect the performance of alternative resource plans, as discussed in Chapters 2 and 9
- Our approach to sensitivity and risk analysis, as discussed in Chapter 9
- Planning objectives and measures used to guide the development of alternative resource plans, as discussed in Chapter 9, and to select the preferred resource plan, as discussed in Chapter 10

Feedback received at the workshop was noted and considered in our continuing analysis to support our IRP filing.

11.3 Stakeholder Comments on Draft Report

Following the stakeholder workshop in February, Ameren Missouri distributed drafts of certain chapters for its filing to stakeholders for review and comment. The following chapters were distributed:

- Chapter 3 – Load Analysis and Forecasting
- Chapter 4 – Existing Supply Side Resources
- Chapter 5 – Environmental Regulation
- Chapter 6 – New Supply Side Resources
- Chapter 7 – Transmission and Distribution

In addition, Ameren Missouri indicated that its Demand Side Management Market Potential Study (DSM Potential Study), finalized in early 2014, would serve as a proxy for a draft of Chapter 8 – Demand Side Resources. The DSM Potential Study serves as the source of key assumptions for use in the development of demand side resource portfolios for inclusion in alternative resource plans. Ameren Missouri conducts a rigorous stakeholder process to review and test its assumptions for the DSM Potential Study as it is being developed.

Two stakeholder groups provided written comments to Ameren Missouri on its draft report in accordance with the Commission's IRP rules – Staff and NRDC / Sierra Club. Their comments and our review of them are discussed in the following sections.

11.3.1Comments of Staff

Staff provided written comments on May 14, 2014. Following are the comments provided by Staff and Ameren Missouri's review of each, as well as an indication of any discussion included in our filing to address each comment.

A. ***Staff indicated a concern regarding the DSM portfolios included in Ameren Missouri's alternative resource plans and that inclusion of these portfolios may not satisfactorily facilitate the identification of all cost-effective demand side savings available to Ameren Missouri and its customers.***

   Review and Application – Ameren Missouri has included in Chapter 10 of its filing a discussion of this issue. As noted in Chapter 10, the identification of all cost-effective demand side savings occurs over time and with the aid of ongoing research, analysis, marketing and evaluation of DSM programs and is impossible to quantify in advance with any degree of accuracy for a twenty year period. Missouri's processes to implement the Missouri Energy Efficiency Investment Act (MEEIA) recognize the need for such ongoing adjustment and refinement with the inclusion of requirements for frequent updates of demand side potential, annual evaluations of program performance, and establishment of shorter term goals, cost recovery mechanisms and utility incentives. Ameren Missouri has more explicitly evaluated the savings potential for its next three-year plan of programs to be implemented in 2016-2018 and has determined that our preferred plan allows us to achieve all cost-effective demand side savings for programs implemented under that three-year plan.

B. ***Staff indicated a concern with Ameren Missouri's scorecard approach for evaluation of alternative resource plans, which was used in the development of Ameren Missouri's 2011 IRP filing. Staff suggested that any scorecard include numeric scores rather than qualitative symbols to assess alternative resource plans.***

   Review and Application – Ameren Missouri understands Staff's concern and has used a scorecard that relies on numeric scores rather than qualitative symbols to score its alternative resource plans. The scorecard and scoring approach are discussed in Chapter 10. The scorecard showing the scores for each alternative resource plan for each of Ameren Missouri's planning objectives, as well as an overall composite score, is presented in Appendix A to Chapter 10.

C. ***Staff expressed a concern regarding the absence of certain specific filing requirements with respect to Ameren Missouri's load forecast analysis.***

   Review and Application – Ameren Missouri has included all the specific requirements in its filing in Chapter 3 and Appendix A to Chapter 3.

D. ***Staff expressed concern regarding assumptions that influence independent variables that affect load forecasts. Staff suggested inclusion in Ameren Missouri's filing of a discussion of the relationship between economic***

growth and energy consumption, with specific consideration of this relationship for Ameren Missouri's service territory.

Review and Application – Ameren Missouri has included a discussion of the relationship between economic growth and energy consumption in Chapters 2 and 3. We have also included specific discussion of the role of economic growth in our service territory in the development of forecasted electric demand in Chapter 3.

E. ***Staff provided comments on Chapter 4 – Existing Supply Side Resources. The comments and Ameren Missouri's review and application of each are summarized and discussed together for each comment below.***

Review and Application

i. Staff requested that load and reserve margin requirements be included in a chart of generating capacity and that the nature of the capacity values be indicated. Rather than add load and reserve margin requirements to a chart that is intended to indicate only available generation in the proper context of Chapter 4. Ameren Missouri has included tables and charts with generation, load and reserve margin requirements in Chapter 9, which deals with the development of integrated alternative resource plans to meet load and reserve requirements. Generator ratings shown in Chapter 4 are on an installed capacity (ICAP) basis.
ii. Staff requested that a chart or table be included to indicate the projected reserve margin requirements of the Midcontinent Independent System Operator (MISO). Ameren Missouri has included a table of the annual reserve margin requirements of MISO in both Chapter 2 and Chapter 9.
iii. Staff requested that a discussion be included regarding the status of energy from Ameren Missouri's Purchased Power Agreement (PPA) with Horizon's Pioneer Prairie Wind Farm (Pioneer Prairie) as a renewable energy resource while its cost is excluded from consideration of the 1% rate impact limitation in the Missouri Renewable Energy Standard (RES). Ameren Missouri has included a discussion of the requirements of the RES in Chapter 2 and its analysis of Ameren Missouri compliance in Chapter 9. In that analysis, renewable energy credits (RECs) generated by Pioneer Prairie are used as eligible RECs for meeting the RES requirements, and the cost has been excluded from the calculation of the 1% rate impact limitation.
iv. Staff requested a discussion of RES requirements in Chapter 6. As explained above, Ameren Missouri has included a discussion of RES

requirements in Chapter 2 and Ameren Missouri's analysis of RES compliance in Chapter 9.

v. Staff requested that a single table be included that summarizes certain information regarding potential supply side resource options that were screened by Ameren Missouri. Ameren Missouri conducted its screening of potential supply side options in groups according to fuel sources to ensure that options within each group would be considered for inclusion in alternative resource plans. The groups screened were – renewable resources, storage resources, nuclear resources, and coal and gas resources. As a result the conclusions of our screening analysis are presented and summarized at the group level, including multiple such tables as the one requested by Staff.

F. ***Staff provided comments on Chapter 6 – New Supply Side Resources. The comments and Ameren Missouri's review and application of each are summarized and discussed together for each comment below.***

Review and Application

i. Staff requested that a discussion of resource needs, including existing supply side resource and reserve margin requirements, be included. As explained previously, Ameren Missouri has included in Chapter 9 an evaluation of resource needs, including existing and new resources, forecasted demand and reserve margin requirements.

ii. Staff requested that a single table be included that summarizes certain information regarding potential supply side resource options that were screened by Ameren Missouri. As explained above, our screening of supply side resource options was conducted using groups of options and is thus organized in that manner.

G. ***Staff provided comments on Chapter 7 – Transmission and Distribution. The comments and Ameren Missouri's review and application of each are summarized and discussed together for each comment below.***

Review and Application

i. Staff requested the inclusion of a complete description of Ameren Missouri's affiliate relationship with Ameren Transmission Company of Illinois. That description has been included in Chapter 7.

ii. Staff requested that discussion regarding Ameren Missouri's optimization of investment in advanced technologies be included. That discussion has been included in Chapter 7.

iii. Staff requested that tables and discussion be provided regarding the employment of advanced transmission technologies. Ameren Missouri has relied on the provision in the Commission rule that permits Ameren Missouri to rely on the MISO planning process for consideration of advanced transmission technologies. Ameren Missouri has provided in its filing a link to the MISO Transmission Expansion Plan (MTEP) documents relied upon by Ameren Missouri and has included supplemental discussion and analysis in Chapter 7.

iv. Staff has requested the inclusion as an appendix of excerpts from a 2009 study conducted by Ameren Missouri with EPRI regarding efficiency projects across Ameren Missouri facilities, including transmission and distribution facilities. Because of the age of the report, Ameren Missouri has instead provided new discussion that leverages the conclusions of the 2009 study and includes updated evaluation and conclusions. To avoid confusion with older evaluations and conclusions, Ameren Missouri has elected not to include portions of the 2009 report as an appendix. The full report is available as part of the workpapers filed in connection with Ameren Missouri's 2011 IRP filing, or upon request subject to applicable restrictions.

v. Staff requested that a discussion of Ameren Missouri's Voltage Control Pilot and how it relates to voltage control measures already employed by Ameren Missouri be included. Voltage control measures already employed by Ameren Missouri involve reducing load tap changer (LTC) voltage setpoints at the time of system peak and can be applied for short durations. Voltage Control Pilot, on the other hand, would test the possibility of reducing energy consumption without exceeding allowable voltage limits for longer durations, which cannot be done by reducing LTC setpoints. More explanation has been added to Chapter 7.

vi. Staff requested that the estimated start time for transmission and distribution projects be added to summary tables. The estimated start time has been so added.

11.3.2Comments of Sierra Club and NRDC

Sierra Club and NRDC jointly provided written comments on May 14, 2014. Following are the comments provided by Sierra Club and NRDC and Ameren Missouri's review of each, as well as an indication of any discussion included in our filing to address each comment.

A. ***Sierra Club and NRDC expressed a concern with respect to comparisons of supply side and demand side resources on a levelized cost of energy (LCOE) basis.***

Review and Application – Ameren Missouri has included LCOE charts including both demand side and supply side resources in Chapters 1 and 9.

B. Sierra Club and NRDC expressed concern with the number of alternative resource plans including Maximum Achievable Potential (MAP) DSM portfolios compared to the number of alternative resource plans including Realistic Achievable Potential DSM portfolios.

Review and Application – Ameren Missouri has included additional alternative resource plans that include MAP DSM portfolios and has discussed the rationale used for its development of alternative resource plans in Chapter 9.

C. Sierra Club and NRDC expressed concerns regarding the estimated potential for demand side resource resulting from Ameren Missouri's DSM Potential Study.

Review and Application – Ameren Missouri has conducted its DSM Potential Study with the assistance of expert external consulting firms, as described in Chapter 8. Ameren Missouri also conducted a rigorous stakeholder process throughout the development of its DSM Potential Study to solicit, consider, and incorporate (as appropriate) stakeholder comments and input regarding the assumptions and methods used in estimating DSM potential.

D. Sierra Club and NRDC provided comments on Chapter 3 – Load Analysis and Forecasting. The comments and Ameren Missouri's review and application of each are summarized and discussed together for each comment below.

Review and Application

i. Sierra Club and NRDC requested additional information regarding the planning scenarios developed and used by Ameren Missouri to evaluate alternative resource plans. A complete discussion of scenario assumptions, modeling and results is included in Chapter 2.
ii. Sierra Club and NRDC requested a definition for "Peak Demand Uncertainty." Chapter 3 includes a discussion of the range of peak demand forecasted based on the scenarios described in Chapter 2. The Peak Demand Uncertainty described is simply the difference between the highest and lowest peak demand forecasts based on those scenarios.
iii. Sierra Club and NRDC requested that any secondary sources used to develop demand side potential be listed. Ameren Missouri has included references to secondary sources in Volume 3 (page 2-14) of its DSM Potential Study, which is presented as an appendix to Chapter 8.

iv. Sierra Club and NRDC requested an explanation regarding why natural gas prices were excluded from final load forecast model specifications used to generate energy forecasts. A discussion and explanation of the consideration of natural gas prices is included in Chapter 3.

v. Sierra Club and NRDC asked if the statement, "[a]ll future DSM impacts beyond the first 3-year MEEIA cycle are excluded from the base forecast and are the subject of the DSM chapter of this IRP," means that Ameren (Missouri) does not expect its current portfolio of DSM programs to continue. It does not mean that. Rather, the statement simply means that only the load impacts of the current 3-year portfolio are included in our base load forecasts and that the effects of new or continued DSM programs are included in our planning analysis separately and in accordance with the assumptions and conclusions discussed in Chapter 8.

vi. Sierra Club and NRDC posed questions regarding the pace of employment of distributed solar generation. Ameren Missouri has included a discussion of distributed solar generation in Chapter 3 and an analysis of a higher level of distributed solar deployment in Chapter 10.

vii. Sierra Club and NRDC expressed concern with the treatment of off-system sales as sensitivity. Ameren Missouri has included a discussion of its scenario development, modeling and conclusions in Chapter 2. These scenarios were used for analysis discussed in Chapters 9 and 10. Forecasts of off-system sales were developed as part of the modeling. The analysis of every alternative resource plan includes the use of 15 unique forecasts for off-system sales corresponding to the scenarios described in Chapter 2.

viii. Sierra Club and NRDC pose questions regarding Ameren Missouri's consideration of specific transmission projects for purposes of acquiring renewable energy resources. Ameren Missouri has included a discussion of RES requirements in Chapter 2, a discussion of transmission considerations in Chapter 7, and a discussion of RES compliance in Chapter 9.

E. Sierra Club and NRDC provided comments on Chapter 4 – Existing Supply Side Resources. The comments and Ameren Missouri's review and application of each are summarized and discussed together for each comment below.

Review and Application

i. Sierra Club and NRDC requested a copy of a condition assessment study of Ameren Missouri's Meramec Energy Center performed by Burns &

McDonnell. Ameren Missouri has included a copy of the study report in its work papers.

ii. Sierra Club and NRDC requested a copy of a study of coal-fired power plant life expectancy performed by Black & Veatch. Ameren Missouri has included a copy of the study report in its work papers.

iii. Sierra Club and NRDC ask whether Ameren Missouri has included analysis of replacement of Meramec Energy center with DSM, renewables, storage or some combination. Ameren Missouri has included such options as part of its alternative resource plans, discussed in Chapter 9.

iv. Sierra Club and NRDC requested that information be included in Ameren Missouri's IRP Filing regarding the extent to which (alternative) resource plans rely on off-system sales. Ameren Missouri has included this information as part of its modeling and work papers.

F. Sierra Club and NRDC provided comments on Chapter 5 – Environmental Compliance. The comments and Ameren Missouri's review and application of each are summarized and discussed together for each comment below.

Review and Application

i. Sierra Club and NRDC requested that Ameren Missouri include an analysis of compliance with proposed regulations of greenhouse gases under section 111(d) of the Clean Air Act. Ameren Missouri has included analysis and discussion of the regulations proposed by the U.S. Environmental Protection Agency (EPA) on June 2, 2014, in Chapter 10.

ii. Sierra Club and NRDC posed specific questions regarding Ameren Missouri's assumptions with respect to compliance with environmental regulations. Rather than recite each question, we provide the answers as follows. Ameren Missouri has in fact assumed that operation of Rush Island can continue during the planning period (2015-2034) without the installation of a scrubber. Ameren Missouri has considered whether additional control equipment would be needed for each of its coal-fired energy centers to comply with future NAAQS requirements for ozone and particulate matter. Ameren Missouri has not simply assumed that plants are economical to run after the installation of any pollution control equipment, but has rather included assumptions for control equipment and performed economic analysis based on those assumptions as described in Chapter 9. Ameren Missouri's basis for assumptions regarding installation of scrubbers is included in Chapter 5. Details regarding specific processes used for wastewater treatment underlie our assumptions but are not discussed in Chapter 5 due to the uncertain nature of the regulations at this time.

G. ***Sierra Club and NRDC provided comments on Chapter 6 – New Supply Side Resources. The comments and Ameren Missouri's review and application of each are summarized and discussed together for each comment below.***

Review and Application

i. Sierra Club and NRDC included an editorial comment regarding the cost-effectiveness of certain resources, which does not require a response.

ii. Sierra Club and NRDC requested a copy of a study of wind project siting and costs performed by Black and Veatch. Ameren Missouri has included a copy of the study report in its work papers.

iii. Sierra Club and NRDC asked whether Ameren Missouri has evaluated whether the cost of purchasing wind through PPA's is below the avoided cost of energy generated from its existing supply-side resources. Ameren Missouri has not identified any specific wind PPA opportunities as part of its IRP analysis. We have estimated the LCOE of our existing coal-fired resources to be below the LCOE for new wind resources.

11.4 Special Contemporary Issues

Pursuant to its rules on Integrated Resource Planning, the Commission on October 23, 2013, issued an order establishing Special Contemporary Resource Planning Issues (Special Contemporary Issues) for Ameren Missouri to analyze and document as part of its 2014 triennial IRP filing. Following is a restatement of the Special Contemporary Issues included in the Commission's order and a brief discussion of Ameren Missouri's approach to analyzing and documenting its consideration of each issue and where in its triennial filing more detailed information can be found.

A. ***Describe and document the process Ameren Missouri used to quantify all cost-effective demand-side savings in its upcoming, October 1, 2014, triennial compliance filing;***

Ameren Missouri's Approach – Ameren Missouri evaluated the goal of all cost-effective demand-side savings, as embodied in MEEIA, by analyzing multiple DSM portfolios as part of its alternative resources plans and by performing more detailed analysis of the costs and benefits of DSM portfolios, including shorter-term impacts on customer costs and rates. A full discussion of our consideration of the goal of all cost-effective demand-side savings is included in Chapter 10.

B. ***Describe and document the quantification of all cost-effective demand-side savings for Ameren Missouri in its upcoming, October 1, 2014, triennial compliance filing;***

Ameren Missouri's Approach – As described above, a full discussion of our consideration of the goal of all cost-effective demand-side savings is included in Chapter 10.

C. ***Describe and document how Ameren Missouri's portfolio of demand-side resources in its adopted preferred resource plan in its most recent triennial compliance filing is – or is not – designed to achieve a goal of all cost-effective demand-side savings during the 3-year implementation plan period and during the 20-year planning horizon, to the extent reasonable and possible.***

Ameren Missouri's Approach – As described above, a full discussion of our consideration of the goal of all cost-effective demand-side savings is included in Chapter 10.

D. ***Describe and document generally Ameren Missouri's plans and timing to replace the Ventyx Midas® model currently used to perform its integrated resource planning and risk analysis required in 4 CSR 240-22.060;***

Ameren Missouri's Approach – A discussion of model replacement and future plans is included in Chapter 9.

E. ***Describe and document generally Ameren Missouri's plans and timing to work collaboratively with Staff, the Office of Public Counsel, and other parties to consider the possible transition – over time – to a common software platform to perform the analysis required by 4 CSR 240-22.060;***

Ameren Missouri's Approach – A discussion of model replacement and future plans is included in Chapter 9.

F. ***Analyze and document the impacts of opportunities for Ameren Missouri to implement distributed generation, DSM programs, combined heat and power (CHP), and micro-grid projects in collaboration with municipal, agricultural and/or industrial processes with on-site electrical and thermal load requirements, especially in targeted areas where there may be transmission or distribution line constraints.***

Ameren Missouri's Approach – Ameren Missouri included consideration of distributed generation, DSM programs and CHP in collaboration with municipal, agricultural and/or industrial processes with on-site electric and thermal load requirements as part of its DSM Potential Study. Chapter 8 includes a discussion of these considerations and the DSM Potential Study report is included in our filing as an appendix to Chapter 8.

G. ***Document for use in economic modeling and resource planning low, base, and high projections for natural gas prices, CO_2 prices, and coal prices, to the extent it is not already included in the 2014 IRP filing.***

Ameren Missouri's Approach – Ameren Missouri developed low, base, and high assumptions natural gas prices, CO2 prices, and coal prices as part of its previously established approach to evaluating candidate uncertain factors. A discussion of the development of these and other assumptions is included in Chapter 2, and the results of modeling using these assumptions is presented in Chapter 9.

H. ***Analyze and document the future capital and operating costs faced by each Ameren Missouri coal-fired generating unit in order to comply with the following environmental standards:***

1) Clean Air Act New Source Review provisions;
2) 1-hour Sulfur Dioxide National Ambient Air Quality Standards'
3) National Ambient Air Quality Standards for ozone and fine particulate matter;
4) Cross-State Air Pollution Rule, in the event that the rule is reinstated;
5) Clean Air Interstate Rule;
6) Mercury and Air Toxics Standards;
7) Clean Water Act Section 316(b) Cooling Water Intake Standards;
8) Clean Water Act Steam Electric Effluent Limitation Guidelines;
9) Coal Combustion Waste rules;
10) Clean Air Act Section 111(d) Greenhouse Gas standards for existing sources; and
11) Clean Air Act Regional Haze requirements

Ameren Missouri's Approach – Ameren Missouri has included as a separate chapter a discussion of environmental regulations, including all those listed above, and our assumptions for compliance with those regulations. A full discussion of environmental regulations and compliance assumptions is presented in Chapter 5.

*I. **Analyze and document the cost of any transmission grid upgrades or additions needed to address transmission grid reliability, stability, or voltage support impacts that could result from the retirement of any existing Ameren Missouri coal-fired generating unit in the time period established by the IRP process, to the extent not already included in the 2014 IRP filing.***

Ameren Missouri's Approach – Ameren Missouri has developed specific assumptions for transmission system projects that may be necessary due to the retirement of any of its existing coal-fired energy centers. A discussion of the assumptions and methods used in developing them is included in Chapter 7.

*J. **Analyze the impact of foreseeable emerging energy efficiency technologies throughout the planning period.***

Ameren Missouri's Approach – Ameren Missouri has included consideration of foreseeable emerging energy efficiency technologies in the development of its DSM Potential Study and DSM portfolio assumptions used in the development of alternative resource plans. Our DSM portfolio assumptions are discussed in Chapter 8, and the DSM Potential Study is included as an appendix to Chapter 8.

11.5 Post-Filing Activities

To assist stakeholder in the review of Ameren Missouri's IRP filing, Ameren Missouri plans to host a workshop in the fourth quarter of 2014 to provide an overview of the filing and to answer questions stakeholders may have after having had time to begin reviewing the filing. Ameren Missouri will work with stakeholders to ensure understanding of the assumptions, analyses, conclusions and decisions presented in its IRP filing.