

DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

This document was prepared by **Global Energy Partners, LLC (Global)**, a privately-held, employee-owned company. Neither **Global** nor any person acting on its behalf:

- (a) Makes any warranty or representation whatsoever express or implied,
 - (i) With respect to the use of any information, apparatus, method, process, or similar item disclosed in this document, including merchantability and fitness for a particular purpose, or
 - (ii) That such use does not infringe on or interfere with privately owned rights, including any party's intellectual property, or
 - (iii) That this document is suitable to any particular user's circumstance; or
- (b) Assumes responsibility for any damages or other liability whatsoever (including any consequential damages, even if **Global** or any **Global** representative has been advised of the possibility of such damages) resulting from your selection or use of this document or any information, apparatus, method, process, or similar item disclosed in this document.

This report was prepared by

Global Energy Partners, LLC
500 Ygnacio Valley Road Suite 450
Walnut Creek, CA 94596

Principal Investigator(s):

I. Rohmund
G. Wikler
B. Kester
D. Weidberg
A. Duer
J. Priyjanonda
S. Yoshida
B. Ryan
K. Marrin

Sub-contractors:

Momentum Market Intelligence

D. Lineweber
J. Murray
D. Tochen
D. Vournas

The Brattle Group

A. Faruqui
R. Hledik

The report is a corporate document that should be cited in the literature in the following manner:

AmerenUE Demand Side Management (DSM) Market Potential Study Volume 1: Executive Summary, Global Energy Partners, LLC. Walnut Creek, CA. 2010. 1287-1.

Copyright © 2010 Global Energy Partners, LLC. All rights reserved.

EXECUTIVE SUMMARY

AmerenUE engaged a team led by Global Energy Partners, LLC (Global) to perform a Demand Side Management (DSM) Market Potential Study to assess the various categories of electrical energy efficiency and demand response potential in the residential, commercial, and industrial sectors for the AmerenUE service area from 2009 to 2030. The study used updated forecasts of baseline energy use estimates based on the latest information on federal, state, and local codes and standards for improving energy efficiency.

AmerenUE will use the results of this study in its integrated resource planning process to analyze various levels of energy savings and peak demand reductions attributable to both energy efficiency and demand response initiatives at various levels of implementation cost.

This executive summary presents high-level results from this study as well as a preview of selected results from the four-volume report.

Background

The Missouri Rules of the Department of Economic Development (4 CSR 240-22) require that electric utilities in Missouri prepare an Integrated Resource Plan (IRP) that “[c]onsider[s] and analyze[s] demand-side efficiency and energy management measures on an equivalent basis with supply-side alternatives in the resource planning process.” (4 CSR 240-22.010(2)(A)) Section 4 CSR 240-22.050 prescribes the elements of the demand-side analysis, including reporting requirements. A copy of the Missouri rules governing electric utility resource planning is available on the Missouri Secretary of State’s website¹.

In 2009, AmerenUE launched a portfolio of such DSM programs on a substantially larger scale than any related efforts the company has initiated in the past. These programs were analyzed and developed in 2008 drawing upon best available secondary data sources. This DSM Market Potential Study updates the previous analysis using primary market data and more detailed and comprehensive analyses.

The key objectives for this study were to:

- Assess and understand technical, economic, achievable and naturally occurring potential for all customer segments in the AmerenUE service area from 2009 to 2030.
- Analyze savings at various levels of cost.
- Conduct primary market research to collect electricity end-use data, customer demographics and psychographics.
- Understand how customers in the AmerenUE service territory make decisions related to their electricity use and energy efficiency investment decisions.
- Develop several scenarios for assessing DSM potential.
- Clearly communicate the DSM Potential in an objective way that is useful for AmerenUE senior management, AmerenUE stakeholders and AmerenUE DSM and IRP staff.

¹ Rules of Department of Economic Development Division 240—Public Service Commission Chapter 22—Electric Utility Resource Planning (4 CSR 240-22.010) – <http://sos.mo.gov/adrules/csr/current/4csr/4c240-22.pdf>

OVERALL CONCLUSIONS

This study has enlightened AmerenUE about its customer base and the potential for energy savings and peak demand reductions that are possible through energy-efficiency (EE) and demand response (DR) programs. The key highlights are as follow:

- There is more opportunity for program savings than was estimated using secondary data. Achievable potential is higher than what was concluded in the AmerenUE 2008 IRP.
- Concurrent with higher opportunities, budgets to harvest those opportunities reach an annual spend range of \$100 million to \$200 million by 2015. This range corresponds to 4% and 8% of AmerenUE revenues, a spending level which exceeds nearly all electric utilities in the nation.
- A comprehensive view of measures yielded higher economic potential. The study considered hundreds of measures and there are considerable savings to be had.
- AmerenUE customers are different. They express less interest in DSM investments and they do not all consider AmerenUE to be their "trusted energy advisor" at this time.

DEFINITIONS

Before launching into the discussion of results, a few key terms are defined:

- **Technical potential** is a theoretical construct that assumes all feasible measures are adopted by customers, regardless of cost or customer preferences.
- **Economic potential** is also a theoretical construct that assumes all *cost-effective* measures are adopted by customers, regardless of customer preferences.
- **Maximum achievable potential (MAP)** takes into account expected program participation, based on customer preferences resulting from ideal implementation conditions. MAP establishes a maximum target for the EE and DR savings that a utility can hope to achieve through its EE and DR programs and involves incentives that represent a substantial portion of the incremental cost combined with high administrative and marketing costs. It is commonly-accepted in the industry that MAP is considered the hypothetical upper-boundary of achievable savings potential simply because it presumes conditions that are ideal and not typically observed in real-world experience.
- **Realistic achievable potential (RAP)** represents what is considered to be realistic estimates of EE and DR potential based on realistic parameters associated with DR and EE program implementation (i.e., limited budgets, customer acceptance barriers, etc.). RAP is of most interest for this study since it represents the mid-point of achievable potential and corresponds to best practices that are attainable since the estimates are tied to known program experience from around the country.
- **Business as usual (BAU)** represents the existing AmerenUE DSM plan from the 2008 IRP and the associated impacts and costs projected into the future. For this analysis, impacts without alteration were included in the savings and cost-effectiveness assessments to represent a benchmark of what is anticipated under current practices.²
- **Baseline forecast** is a reference end-use forecast developed specifically for this study. This estimates what would happen in the absence of any DSM programs, and includes naturally occurring energy efficiency and any codes and standards that were in place as of June 30, 2009. It is the metric against which savings are measured.

² Note that it was necessary in this assessment to project savings and costs for the BAU for three additional years (2028-2030) since the IRP assessment only went as far as 2027. Savings for those three years were extended without additional growth. Costs for those three years were extended reflecting growth only due to inflation.

KEY FINDINGS

The key findings from this study encompass the potential savings from EE and DR programs, supply curves for EE and DR programs, and scenario analyses for EE and DR programs. Each set of results is summarized below. Details are presented in Volumes 3 and 4.

Energy Efficiency Potential

Realistic achievable potential in 2030 is 3,165 GWh, which represents 7.3% of total forecasted baseline usage for that year. This represents 25% of technical potential and 44% of economic potential.

- MAP in 2030 is 4,758 GWh, about 11% of the total forecasted sales in 2030. This represents more than a third of technical potential and nearly two-thirds of economic potential.
- BAU in 2030 is 2,740 GWh, 6.3% of total forecasted usage in 2030.

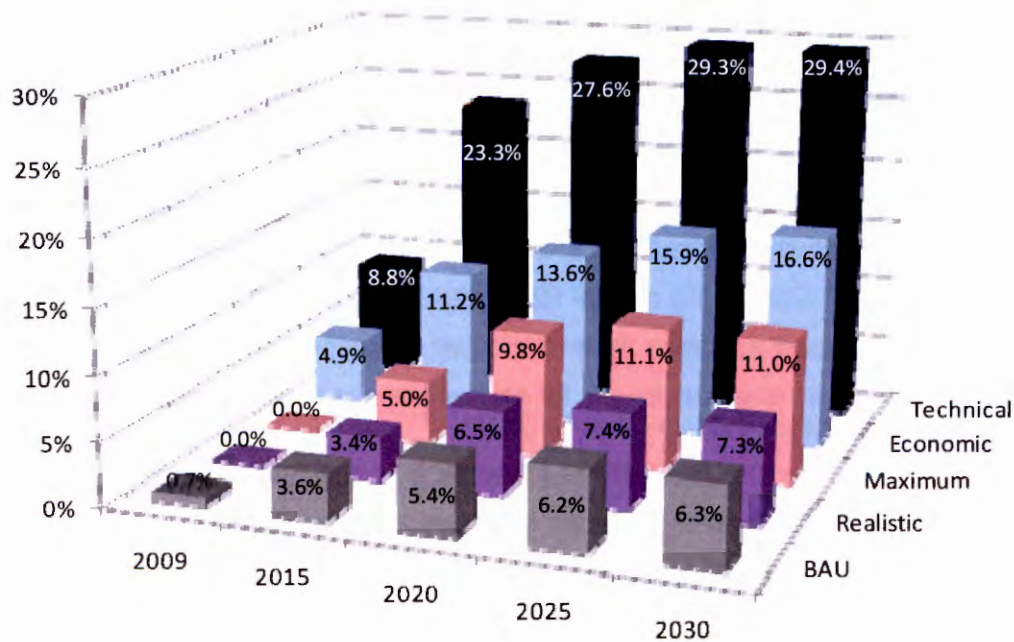
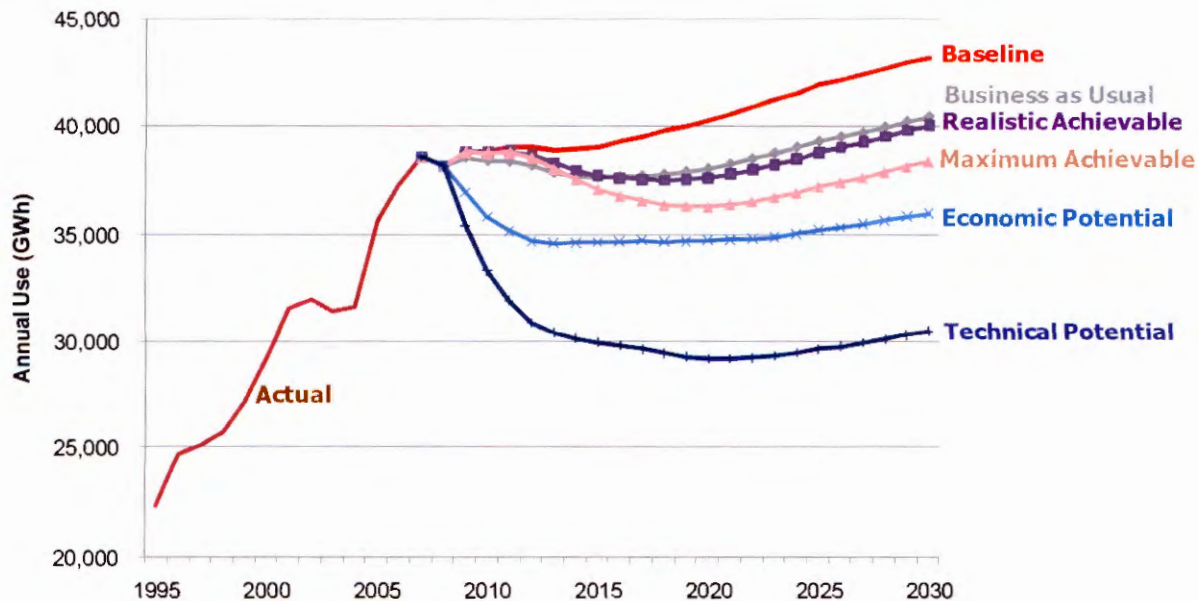
Table 1 and Figure 1 present estimates for all five types of potential for selected years.

Figure 2 presents forecasts of electricity use for each of the five types of potential, as well as the baseline forecast and recent historical sales. By 2030:

- Electricity use in the baseline forecast has increased by 4,432 GWh, an increase of 11.2%.
- RAP offsets growth in the baseline forecast by almost three-fourths.
- MAP more than offsets growth in the baseline forecast.
- Economic potential brings usage down to the level it was in 2005.

Table 1 **Summary of Energy Efficiency Potential**

	2009	2015	2020	2025	2030
Baseline Electricity Forecast (GWh)	38,839	39,057	40,248	41,899	43,181
Energy Savings (GWh)					
Technical Potential	3,434	9,115	11,098	12,296	12,696
Economic Potential	1,895	4,392	5,475	6,657	7,181
Maximum Achievable Potential	13	1,950	3,943	4,655	4,758
Realistic Achievable Potential	12	1,316	2,627	3,098	3,165
Business as Usual	264	1,399	2,184	2,596	2,740
Energy Savings as % of Baseline					
Technical Potential	8.8%	23.3%	27.6%	29.3%	29.4%
Economic Potential	4.9%	11.2%	13.6%	15.9%	16.6%
Maximum Achievable Potential	0.0%	5.0%	9.8%	11.1%	11.0%
Realistic Achievable Potential	0.0%	3.4%	6.5%	7.4%	7.3%
Business as Usual	0.7%	3.6%	5.4%	6.2%	6.3%

Figure 1 Summary of Energy Efficiency Potential (Savings as % of Baseline)**Figure 2 Forecast Summary of Energy Efficiency Potential**

In addition to energy savings (GWh), energy efficiency programs also create savings in coincident peak demand (MW). Table 3 presents peak demand savings from EE programs for all five types of potential. The savings are substantial because many of the EE savings result from measures related to air conditioning across all sectors, C&I lighting and motors, all of which have high usage during peak periods. These EE peak demand savings are combined with DR peak demand savings in the following discussion.

Table 2 *Summary of Peak Demand Savings from Energy Efficiency Programs*

	2009	2015	2020	2025	2030
Baseline Peak Demand Forecast (MW)	7,642	8,003	8,356	8,752	9,127
Peak Demand Savings (MW)					
Technical Potential	837	2,342	2,932	3,377	3,511
Economic Potential	454	1,166	1,444	1,715	1,846
Maximum Achievable Potential	4	563	1,072	1,269	1,253
Realistic Achievable Potential	4	381	716	846	834
Business as Usual	34	173	271	331	352
Peak Demand Savings as % of Baseline					
Technical Potential	11.0%	29.3%	35.1%	38.6%	38.5%
Economic Potential	5.9%	14.6%	17.3%	19.6%	20.2%
Maximum Achievable Potential	0.1%	7.0%	12.8%	14.5%	13.7%
Realistic Achievable Potential	0.0%	4.8%	8.6%	9.7%	9.1%
Business as Usual	0.4%	2.2%	3.2%	3.8%	3.9%

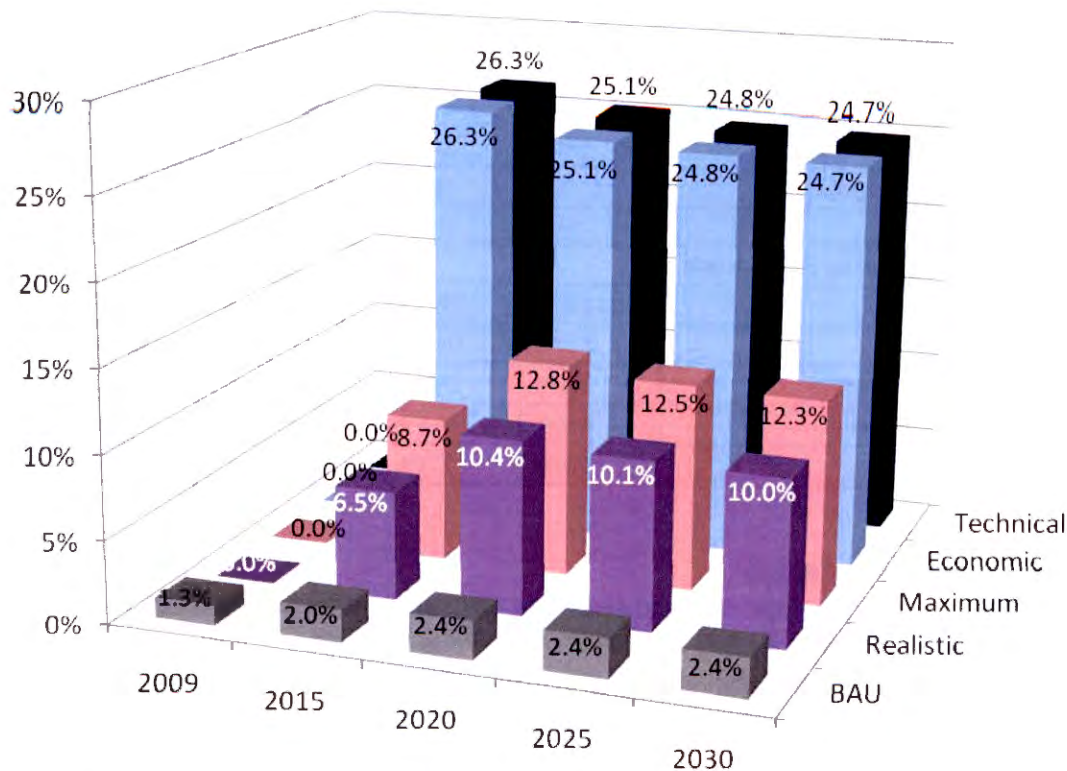
Demand Response Potential

By 2030, achievable savings from demand-response programs are in the range of 914 to 1,126 MW. This represents between 10 and 12% of peak demand in 2030.

Table 3 displays the different levels of potential both as MW/year and as a percentage of baseline forecast. Figure 3 presents the savings as a percentage of coincident peak demand in selected years.

Table 3 *Summary of Demand Response Potential*

	2009	2015	2020	2025	2030
Baseline Peak Demand Forecast (MW)	7,642	8,003	8,356	8,752	9,127
Peak Demand Savings (MW)					
Technical Potential	2	2,102	2,098	2,173	2,254
Economic Potential	2	2,102	2,098	2,173	2,254
Maximum Achievable Potential	2	694	1,072	1,090	1,126
Realistic Achievable Potential	2	520	870	885	914
Business as Usual	97	160	199	213	219
Peak Savings as % of Baseline					
Technical Potential	0.0%	26.3%	25.1%	24.8%	24.7%
Economic Potential	0.0%	26.3%	25.1%	24.8%	24.7%
Maximum Achievable Potential	0.0%	8.7%	12.8%	12.5%	12.3%
Realistic Achievable Potential	0.0%	6.5%	10.4%	10.1%	10.0%
Business as Usual	1.3%	2.0%	2.4%	2.4%	2.4%

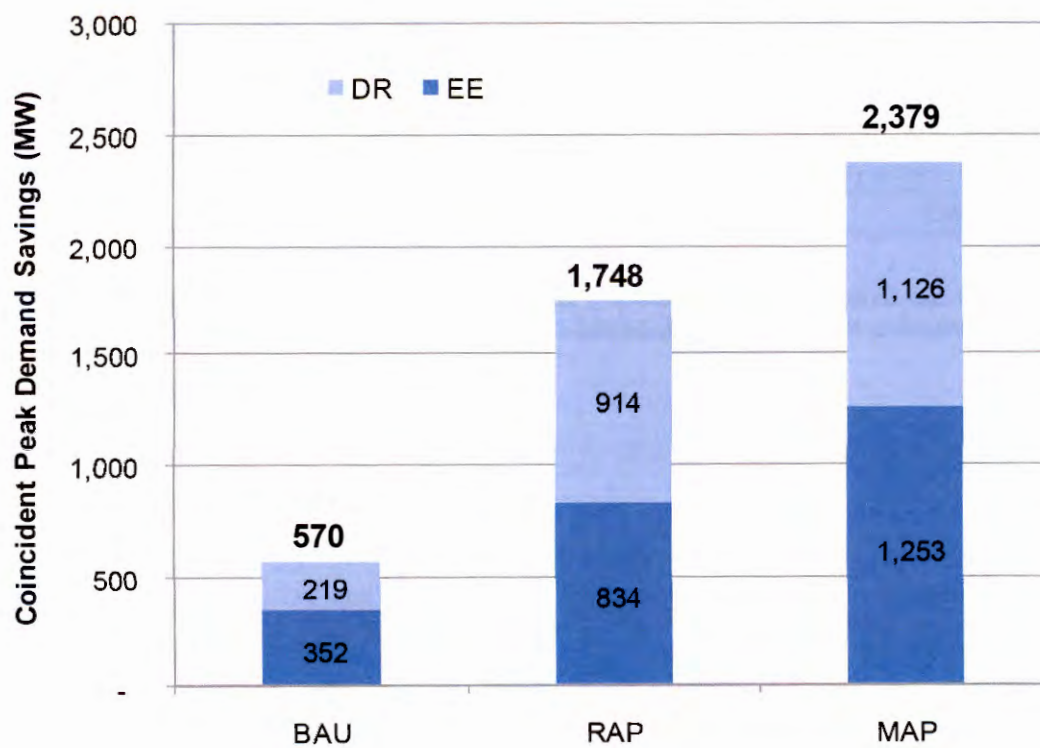
Figure 3 *Summary of Demand Response Potential (Savings as % of Baseline)*

Combined Peak Demand Savings

In addition to peak-demand savings from demand response programs, the energy efficiency programs also yield savings. Throughout the forecast period, peak demand savings from EE programs for RAP and MAP are about the same as the savings from DR programs. However, in contrast to DR programs, the peak-demand savings from EE programs are permanent and non-dispatchable. Together, these savings are substantial and could potentially eliminate the need for new capacity over the next 20 years. Table 4 and Figure 4 present these results.

Table 4 *Summary of Peak Demand Savings from EE and DR*

	2009	2015	2020	2025	2030
Baseline Peak Demand Forecast (MW)	7,642	8,003	8,356	8,752	9,127
EE Peak Demand Savings (MW)					
Maximum Achievable Potential	4	563	1,072	1,269	1,253
Realistic Achievable Potential	4	381	716	846	834
Business as Usual	34	173	271	331	352
DR Peak Demand Savings (MW)					
Maximum Achievable Potential	2	694	1,072	1,090	1,126
Realistic Achievable Potential	2	520	870	885	914
Business as Usual	97	160	199	213	219
Total Peak Demand Savings (MW)					
Maximum Achievable Potential	5	1,257	2,144	2,359	2,379
Realistic Achievable Potential	5	901	1,586	1,731	1,748
Business as Usual	131	333	470	544	570
Peak Savings as % of Baseline					
Maximum Achievable Potential	0.1%	15.7%	25.7%	27.0%	26.1%
Realistic Achievable Potential	0.1%	11.3%	19.0%	19.8%	19.2%
Business as Usual	1.7%	4.2%	5.6%	6.2%	6.2%

Figure 4 *Combined Peak Demand Savings from DR and EE Programs in 2030*

Cost-Effectiveness Analysis

The EE and DR programs were assessed for cost-effectiveness drawing upon the California Standard Practice protocol for DSM economic assessment. For the purposes of this study, four economic test perspectives from the protocol were applied. Each is briefly defined below:

- **The Total Resource Cost (TRC)** test measures benefits and costs from the perspective of the utility and society as a whole.
- **The Utility Cost (UC)** test measures the costs and benefits from the perspective of the utility administering the program.
- **The Ratepayer Impact Measure (RIM)** test measures the difference between the change in total revenues paid to a utility and the change in total costs to a utility resulting from the EE and DR programs.
- The **Participant (Part)** test measures the benefits and costs from the perspective of program participants as a whole.

The cost-effectiveness analysis was performed at an aggregate level, representing the potential effects of each individual EE and DR program in the portfolio.

A spreadsheet model was used as the primary tool for conducting AmerenUE's cost-effectiveness assessment.³ Table 5 presents the results of the cost-effectiveness analysis.

Table 5 TRC Cost-Effectiveness Results

Program	Total Resource Cost (TRC)			
	Lifetime Benefits (Million\$)	Lifetime Costs (Million \$)	Net Benefits (Million \$)	B/C Ratio
Energy Efficiency Programs				
Maximum Achievable Potential (MAP)	\$4,599	\$2,921	\$1,678	1.57
Realistic Achievable Potential (RAP)	\$3,072	\$1,856	\$1,217	1.66
Business as Usual (BAU)				1.95
Demand Response Programs				
Maximum Achievable Potential (MAP)	\$1,124	\$514	\$610	2.19
Realistic Achievable Potential (RAP)	\$898	\$406	\$492	2.21
Business as Usual (BAU)				1.68

Important insights can also be drawn by looking at the levelized cost of achieving the projected savings. Table 6 presents the estimated levelized costs for the various EE and DR program portfolios.

³ Global uses its own in-house cost-effectiveness assessment tool.

Table 6 **Levelized Cost (Utility Cost perspective)**

Type of Potential	Levelized Cost	
	Energy Efficiency Programs (\$/kWh)	Demand Response Programs (\$/kW-yr)
Maximum Achievable Potential (MAP)	\$0.024	\$37.45
Realistic Achievable Potential (RAP)	\$0.017	\$39.69
Business as Usual (BAU)	\$0.021	\$27.50

As the table indicates, by all measures the EE program portfolio is cost-effective from a levelized cost perspective. Industry average levelized cost tends to range from \$0.03 to \$0.05 per kWh saved. With the BAU portfolio, the levelized cost is well under that average. Looking at either the MAP or RAP, it is fair to conclude that the portfolio levelized costs are well within industry expectations. For the DR programs, the portfolio is cost-effective from a levelized cost perspective since the levelized cost of new capacity is typically well over \$75/kW-year.⁴ With any of the three portfolios, the levelized cost is well under half of that average.

Supply Curves

Two key results from this study are two sets of supply curves – one for energy-efficiency programs and the other for demand response programs – that represent MAP, RAP, and BAU.

Figure 5 shows the reference supply curve for energy-efficiency programs for 2030. Key observations include:

- Overall, the 20-year analysis shows a majority of the EE program savings fall under \$0.04/kWh. For the BAU portfolio, a total savings of over 5% falls under a very attractive cost-effective cut-off of \$0.03/kWh.
- For the RAP portfolio, close to 7% total savings falls under a \$0.03/kWh levelized cost.
- The MAP portfolio becomes very costly when reaching beyond the 10% savings level, as the levelized cost to add additional savings beyond a cumulative savings of 10% reaches well over \$0.05/kWh.
- Another interesting observation is that RAP holds steady at a levelized cost under \$0.02/kWh, going from a cumulative savings of just over 2% to over 5%. Program costs do not appear to substantially increase under RAP until the portfolio reaches over 7% savings.
- While most of the programs are considered cost-effective, there are some higher cost programs which include: HVAC, Lighting and Appliance, and Residential New Construction. Residential New Construction costs are significantly higher than the second most expensive program.
- When comparing the three different curves (BAU, RAP and MAP), it is worth noting that there is a clustering of programs that cost roughly the same (on a levelized \$/kWh basis), yet these programs bring about substantial increases in the energy savings potential. For MAP, bringing on the last two most expensive programs brings about measureable increases in savings potential. Thus the slope of the supply curve does not turn in a vertical direction, as is clearly demonstrated in the BAU and to some extent in the RAP cases. This suggests that while MAP is the most expensive portfolio, a bump-up in the expenditures even for the high cost programs yields significantly greater returns in terms of energy savings.

⁴ This was the figure used as a proxy avoided capacity cost for the FERC National DR Potential study.

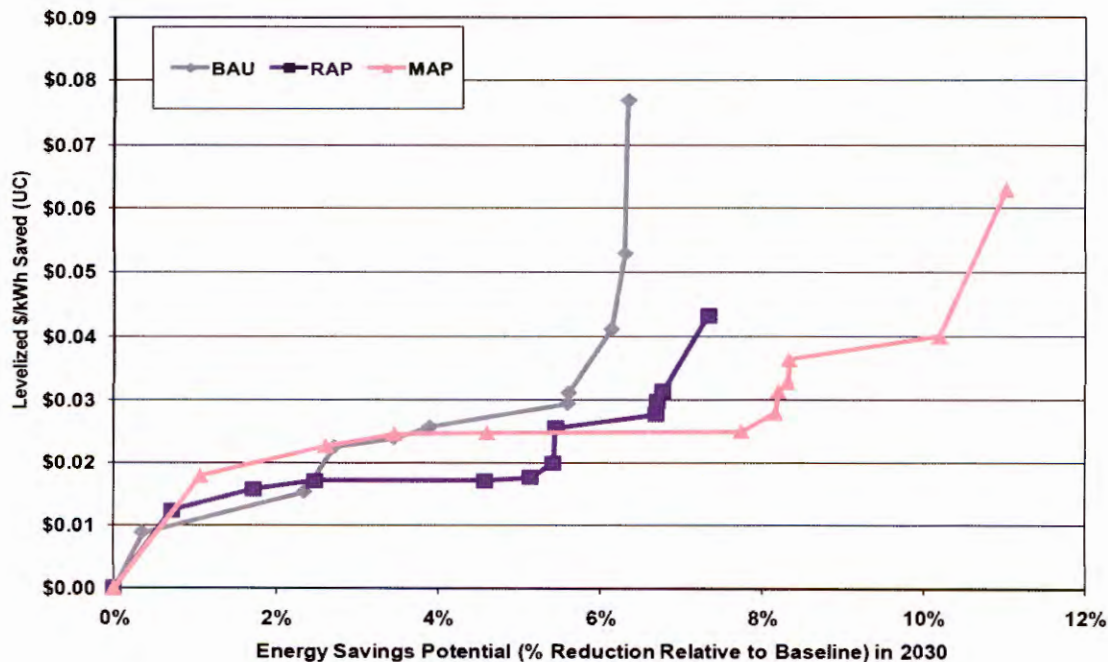
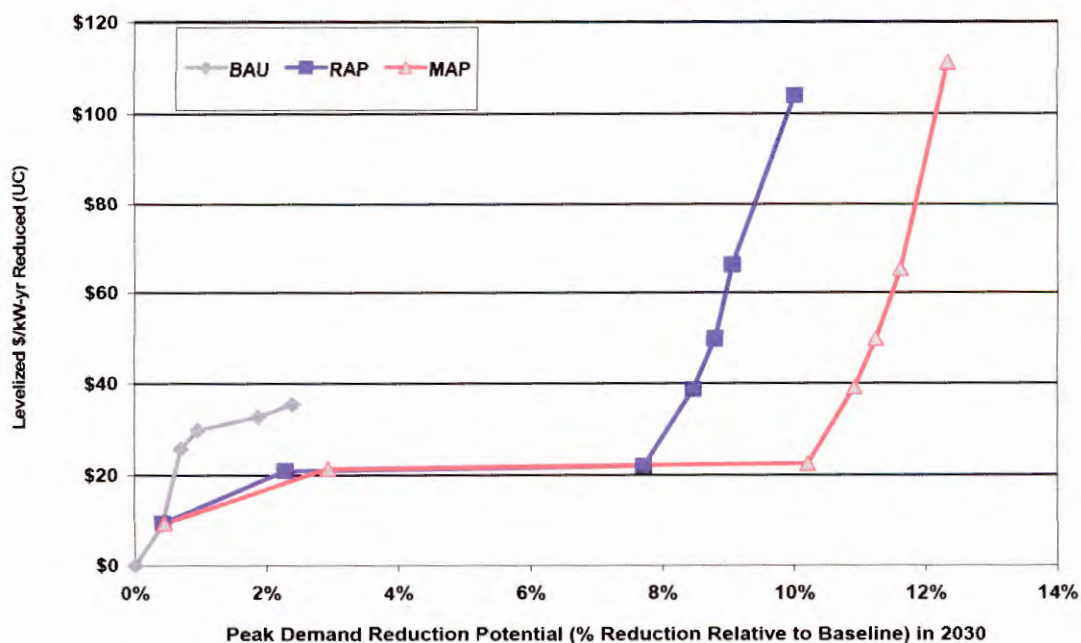
Figure 5 Energy Efficiency Program Supply Curve – Potential by 2030

Figure 6 shows the reference supply curve for demand-response programs for 2030. Key observations include:

- In RAP and MAP, the programs as a whole appear to deliver significant peak demand reductions at a cost that is well below \$30/kW-year. By any measure, this would also be judged very cost effective when compared to supply-side resources and their associated costs.
- For the BAU portfolio, savings do not go much above the 2% mark, with associated costs jumping up to above \$30/kW-year.
- The RAP portfolio brings about savings at over 7% for a cost that is well under \$30/kW-year.
- The MAP portfolio yields a higher savings of over 10% for essentially the same cost that is experienced in the RAP case. The reason these costs are comparable relates to the fact that the main differences between RAP and MAP relate to scale-up of DR programs under scenarios of higher incentives and assumptions about greater levels of opt-out pricing in the MAP case, which bring about significantly greater savings for very little extra cost.
- Again, most of the DR programs in each portfolio have a lower levelized cost than the projected avoided capacity costs used in the FERC National Assessment of Demand Response of approximately \$75/kW-year in year 2030 indicating that all three portfolios are cost-effective as a whole.

Figure 6 Demand Response Program Supply Curve – Potential by 2030

Program Costs

An important result from this study is an estimation of program spending, both from an annual perspective and cumulative. Figure 7 illustrates the year-by-year EE program spending over the entire 22-year time horizon (2009-2030). The figure illustrates that for BAU and RAP, the annual spend is roughly equivalent (yet the RAP savings are significantly higher than BAU in each year after about 2013). The figure also illustrates the fact that the MAP spend is significantly higher than RAP and BAU. Of course, MAP savings are substantially higher than BAU and RAP. The results lead to the obvious conclusion that it will cost significantly more to get additional savings.

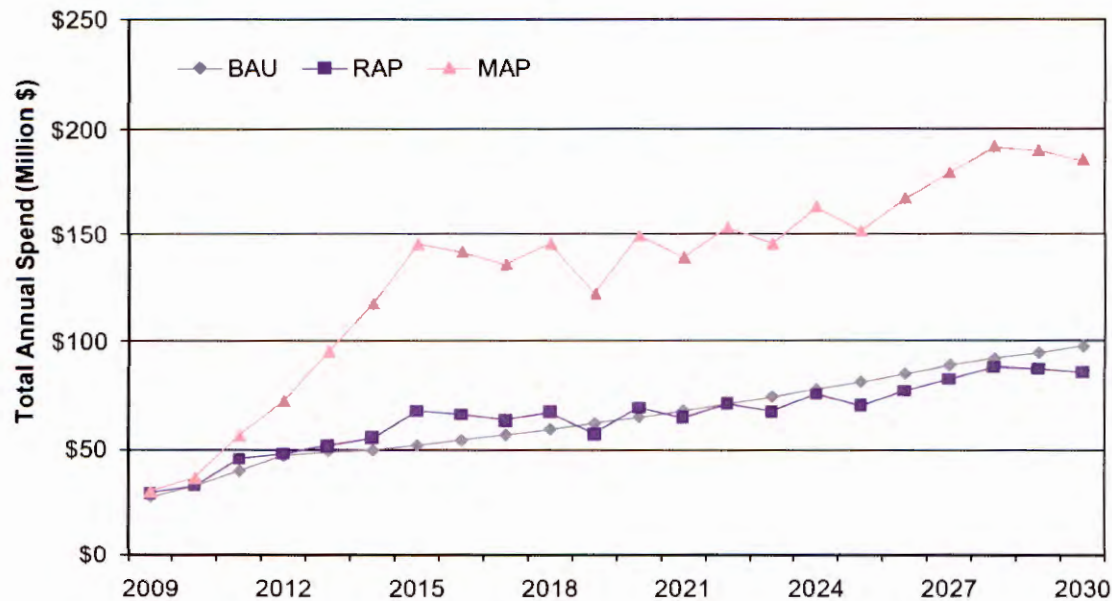
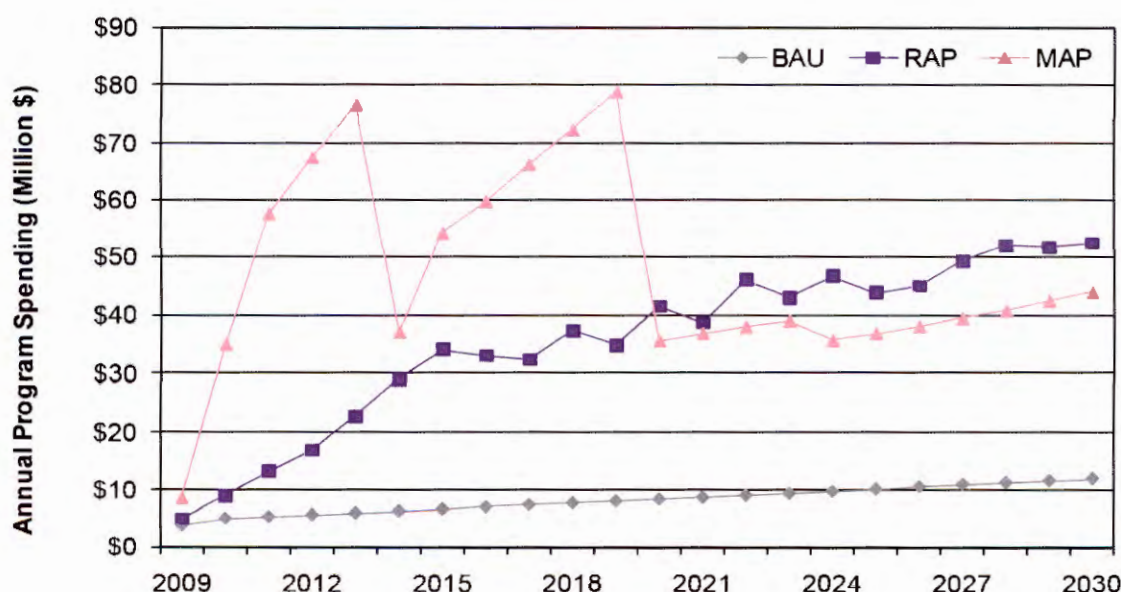
Figure 7 Annual Energy Efficiency Program Spending⁵

Figure 8 illustrates the year-by-year DR program spending over the entire 22-year time horizon (2009-2030). The figure illustrates significant fluctuations in the annual spending for all three cases. In the RAP case, it is assumed that AMI comes in around 2015 and that opt-in dynamic pricing is implemented afterwards. Since opt-in pricing assumes that participants are voluntary, the rates of growth in spending are what would typically be expected in a DR program.

However, for the MAP case, the spending grows dramatically in the first 5 years (2009-2013), reflecting a significant ramp-up of participation in traditional DR programs such as Direct Load Control and Curtailable as well as newer DR programs such as opt-in dynamic pricing tariffs. Beginning in 2014 the spending drops down for the one year, and then again rises dramatically until about 2020. This is occurring because it is assumed that customers are participating in the dynamic pricing programs on an opt-in or voluntary basis through 2013. In 2014, there is a transition in the pricing program designs from the opt-in style to a more mandatory opt-out style. That means that all customers not currently on a time-based pricing tariff would be defaulted to such a tariff. This transition occurs based on the assumption that the AMI meters begin to become deployed starting in 2015. As AMI deployment is initiated, pricing program expenditures rise to bring on the new participants until 2020 when it is assumed that all available participants are transitioned to the various dynamic pricing programs. While it is merely speculation as to whether opt-out dynamic pricing tariffs would actually be implemented in the AmerenUE service territory during this time, the differences in annual spend between MAP and RAP reveal some important insights about the tradeoffs between opt-out dynamic pricing vs. opt-in dynamic pricing. First, it is clear that there would be significant fluctuations in spending in the dynamic pricing case. Such fluctuations may not be feasible from an AmerenUE operational perspective. Second, as mandatory dynamic pricing tariffs take hold, there is a negative impact on program participation for other non-pricing programs. This situation is clearly revealed in the annual spend, where RAP spending in the last 10 years of the plan is actually higher than MAP spending.

⁵ Note that annual spending for MAP and RAP was calibrated to the BAU for the purposes of creating this illustration. The calibration was done such that spending amounts in the first two years of the programs would be roughly comparable across the three levels (MAP, RAP and BAU). The actual analyses of MAP and RAP (in terms of savings and cost-effectiveness) were conducted independently of BAU.

Figure 8 Annual Demand Response Program Spending

Scenario Analysis

Scenario development is a critical part of any planning exercise. While the “reference” case for EE and DR program potential represents the best or most-likely estimate of what the future will look like, it is important to understand the sensitivity of the reference case estimate to key assumptions and to evaluate alternative worlds or scenarios. Based on the results of the potential analysis, it was determined that the realistic achievable potential (RAP) would serve as the representative reference case for conducting the scenarios analysis.

During the various stakeholder meetings convened over the course of this project, several potential future scenarios were outlined and reviewed. In those discussions, it was clear that a whole host of external factors might occur in the future, all potentially influencing the outcome of AmerenUE’s EE and DR programs. As a result, the following three scenarios were considered for the analysis:

- Scenario 1 – Aggressive Codes and Standards:** This scenario represents the implementation of aggressive state building codes which will capture lost opportunities in new construction that might currently be captured (at least in part) in the various DSM new construction programs. Further, the scenario represents aggressive appliance standards that are currently being contemplated at the federal level. As recent increased national attention is being given to role of energy efficiency in the economic recovery and the Smart Grid, it is conceivable that this attention will lead policymakers to increase laws and regulations governing codes and standards beyond existing and planned levels.
- Scenario 2 – High Infrastructure Costs:** This scenario anticipates greater levels of utility spending due to higher than anticipated costs associated with new generation, compliance with environmental regulations and carbon legislation⁶, widespread implementation of the Smart Grid, adoption of distributed generation and solar, and the like.
- Scenario 3 – Prolonged Recession Beyond 2 Years:** This scenario assumes that the economy does not recover in the next two years, but rather that the recession lasts up to

⁶ The Reference scenario assumes passage of legislation similar to the 2009 proposed Waxman-Markey Bill. A carbon cost is included in the forecasts beginning in 2014 that reflects the targets and assumptions therein. These carbon costs are thus included in each scenario unless modified as noted.

five years. As a result, there would be a delayed and weakened carbon legislation passed by the Congress and rate hikes would be kept to a minimum.

Table 7 highlights the key findings of the scenario analysis. The table provides key indicators of the EE and DR programs, including total cumulative expenditure over the entire study time horizon (2009-2030), the levelized cost of saved energy and peak demand, and the percentage reduction relative to the baseline forecast.

Table 7 Scenario Impacts on EE and DR Potential

Parameter	Reference Case (RAP)	Scenario 1: Aggressive Codes and Standards		Scenario 2: High Infrastructure Costs		Scenario 3: Prolonged Recession	
		Value	Percent Change	Value	Percent Change	Value	Percent Change
EE Program Total Expenditure (Million \$)	\$1,856	\$1,555	-16%	\$2,394	29%	\$1,522	-18%
EE Portfolio Levelized Cost (\$/kWh-saved)	\$0.017	\$0.018	8%	\$0.021	23%	\$0.018	4%
EE Portfolio % Reduction Relative to Baseline	7.33%	5.18%	-29%	9.12%	24%	5.88%	-20%
DR Program Total Expenditure (Million \$)	\$406	\$370	-9%	\$657	62%	\$406	0%
DR Portfolio Levelized Cost (\$/kW-yr saved)	\$39.69	\$39.923	1%	\$38.87	-2%	\$38.88	-2%
DR Portfolio % Reduction Relative to Baseline	10.01%	9.32%	-7%	15.21%	52%	9.94%	-1%

Several observations can be made from the results of the scenario analysis:

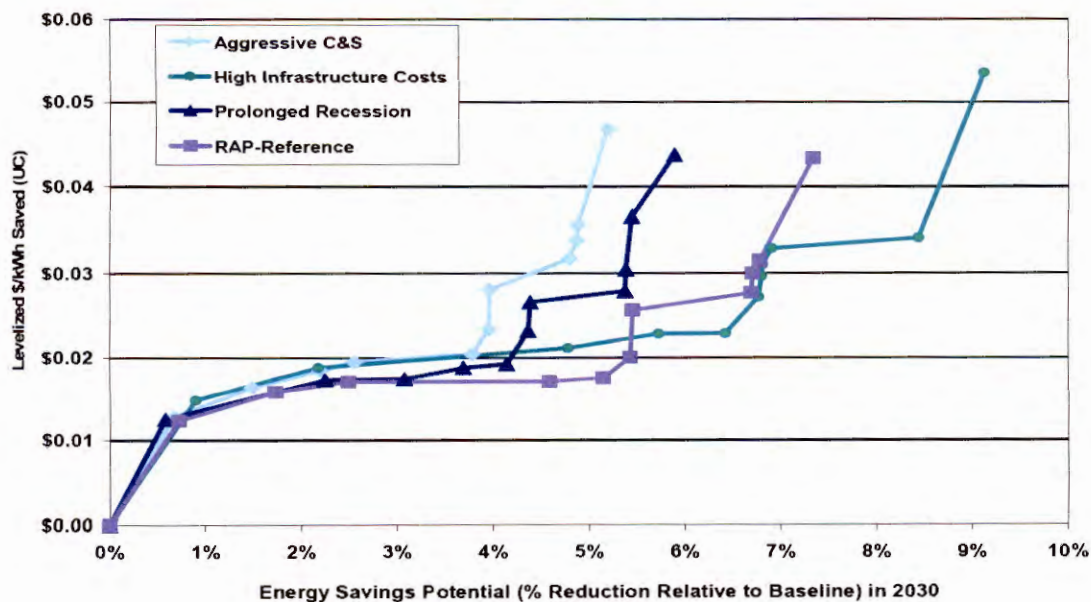
- As we move from the reference case (RAP) to the various scenarios, most of the typical parameters are moving in the direction that is expected. Aggressive codes and standards and a prolonged recession bring about lower expenditure for programs, lower savings relative to the baseline and higher levelized costs. High infrastructure costs bring about higher expenditure for programs, higher savings relative to the baseline and higher levelized cost.
- For Scenario 1 (Aggressive Codes and Standards), total EE expenditures are reduced by 16% and DR expenditures reduced by 9% due mainly to the fact that lower impacts mean that less is being expended for program administration and incentives. Levelized costs for the EE portfolio increase by 8% and for the DR portfolio by 1% indicating that the reduction in expenditures is not leading to a proportional reduction in impacts. Finally, the EE portfolio percentage reduction drops by 29% and the DR reduction drops by 7%, which is largely a function of the aggressive codes and standards taking over nearly a third of the savings projected in the reference case.
- For Scenario 2 (High Infrastructure Costs), total EE expenditures increase by 29% and DR expenditures increased by 62% due mainly to the fact more programmatic activities due to lower avoided costs, more aggressive marketing of programs, and the like. Levelized costs for the EE portfolio increase by 23% and for the DR portfolio drops by a slight 2% indicating that the increase in expenditures is bringing about a proportional increase in impacts (at least for the EE programs). Finally, the EE portfolio percentage reduction increases by 24% and the DR reduction drops by 52%. This again is mainly driven by the fact that the EE and DR programs are operated at higher budget levels thus bringing about a larger number of participants relative to the Reference Case which in turn leads to greater impacts.

- For Scenario 3 (Prolonged Recession), total EE expenditures decrease by 18% and DR expenditures remaining relatively unchanged. The decrease in EE expenditures is due mainly to the fact few program participants is leading to less in incentives being paid out. DR appears to be relatively unchanged by these exogenous factors. Levelized costs for the EE portfolio increase by 4% and for the DR portfolio decrease by 2% indicating that (like Scenario 1) the reduction in EE expenditures is leading to a proportional reduction in impacts which has very little impact on the levelized cost. Finally, the EE portfolio percentage reduction decreases by 20% and the DR reduction increases drops by less than 1%. This again is mainly driven by the fact that the EE programs are not attracting as many participants because the economic situation is inhibiting the ability of participants to make capital investments. Thus, the resulting impacts are depressed relative to the Reference Case. This situation was not as affected in the DR case.

In addition to estimates of potential for each scenario, EE and DR program supply curves were also developed. The reference case (RAP) and each of the three scenarios are represented as separate supply curves on the same graph, in much the same manner as was presented for the various program implementation levels reported in the previous chapter.

Figure 9 shows the supply curve for AmerenUE's potential EE programs, as reflected by each of the three scenarios for the year 2030. The supply curve from the reference case is provided for comparison purposes.

Figure 9 EE Program Supply Curve – by Scenario, Year 2030



Several observations can be made from the results of the 20-year supply curve analysis for the various scenario assessments of the EE programs:

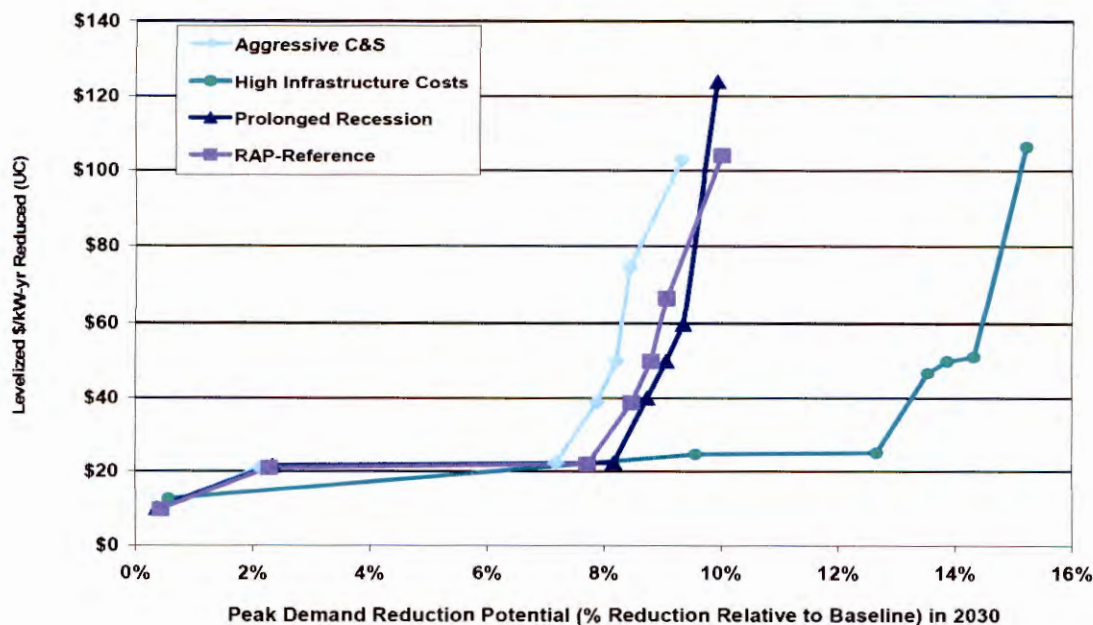
- Up to about 4% energy savings potential, all of the scenarios deliver about the same level of savings at the same level of cost (around \$0.02/kWh or less). However, going above that levelized cost threshold, significant variances occur.

- Neither Scenario 1 (Aggressive C&S) nor Scenario 3 (Prolonged Recession) would be favorable from the perspective of an AmerenUE EE program portfolio. Both cases show significantly higher costs for a relatively minimal increase in savings potential.
- Scenario 2 (High Infrastructure Costs) appears to be most favorable from the perspective of bringing about 6.5% in energy savings potential at the lowest level of cost. However, for every extra kWh saved beyond that level, the costs rise dramatically.

Figure 10 shows the supply curve for AmerenUE's potential DR programs, as reflected by each of the three scenarios for the year 2030. Several observations can be made from the results of the 20-year supply curve analysis for the various scenario assessments of the DR programs:

- There is very little difference between the Reference Case and Scenario 1 (Aggressive Codes and Standards) and Scenario 3 (Prolonged Recession). This has mainly to do with the fact that in both instances these external factors have very little influence on the DR program portfolios.
- For Scenario 2 (High Infrastructure Costs) there is a pronounced improvement in the cost of delivered demand relative to the Reference Case. In other words, it does not appear to cost much more on a \$/kW-year basis but the savings are significantly greater.

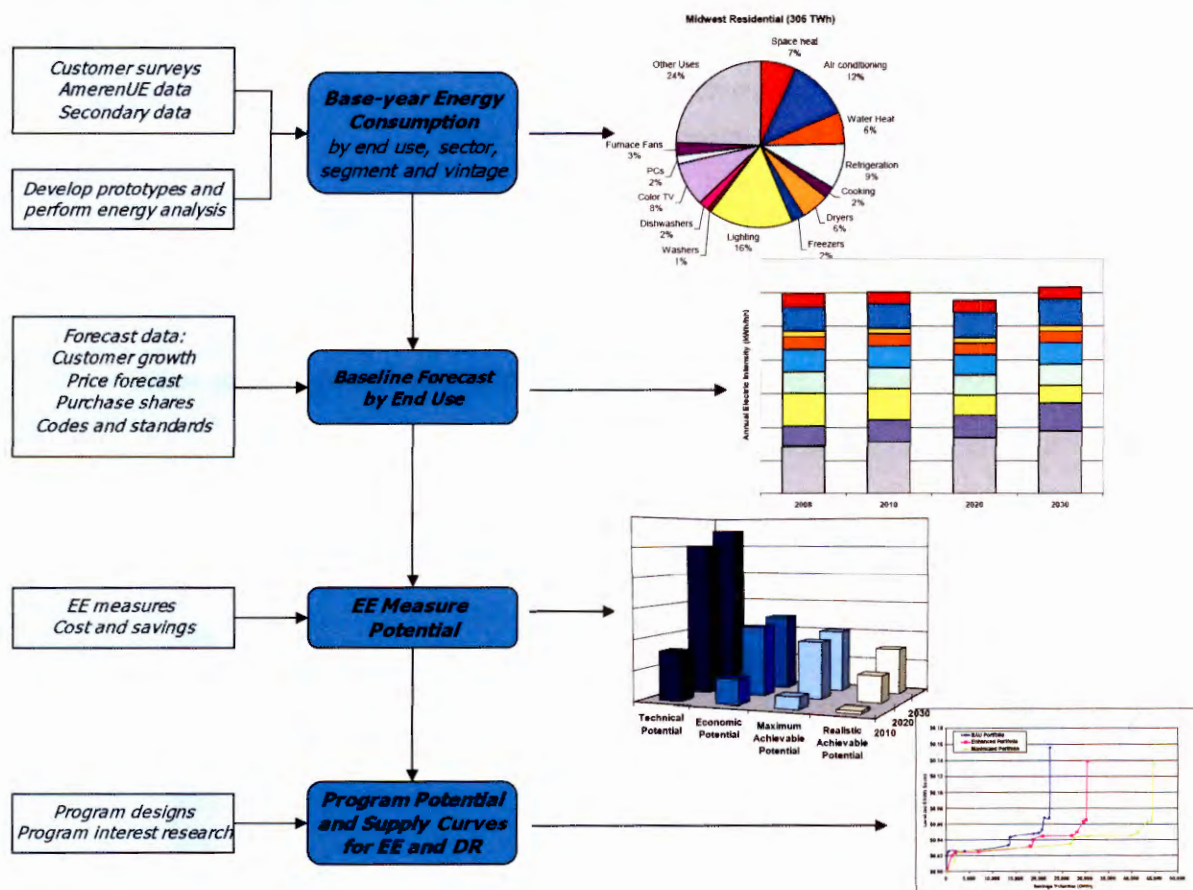
Figure 10 DR Program Supply Curve – by Scenario, Year 2030



STUDY APPROACH

This study represents industry best-practices in assessment of DSM potential. It began with comprehensive market research of AmerenUE customers that covered their current energy-using equipment, behavior and attitudes. The market research results were used to develop base-year usage profiles and the baseline forecast. These, in turn, were used to support the analysis of EE and DR potential at the measure and program levels. Finally, program analysis was used to develop supply curves. Figure 11 depicts this approach.

Figure 11 Overview of Study Approach



The remainder of this Executive Summary provides an overview of the market research and each of the analysis steps.

MARKET RESEARCH

Comprehensive market research about AmerenUE customers was conducted for this project. This research provides a solid foundation for the analyses performed in this study and it also provides a wealth of information for future analyses across many departments at AmerenUE. The market research included:

- Residential customers – online saturation surveys with 1,284 customers and online program interest surveys with 1,126 customers
- Small and medium C&I customers – online saturation surveys with 800 customers and online program interest surveys with 750 customers

- Large C&I customers – online energy-use surveys with 221 customers and online program-interest surveys with 273 customers
- Complex C&I customers – 145 site visits distributed strategically among campuses/locations of AmerenUE's "top customers"
- Trade Allies – 40 telephone interviews

Volume 2 of the report series presents the detailed results of the market research.

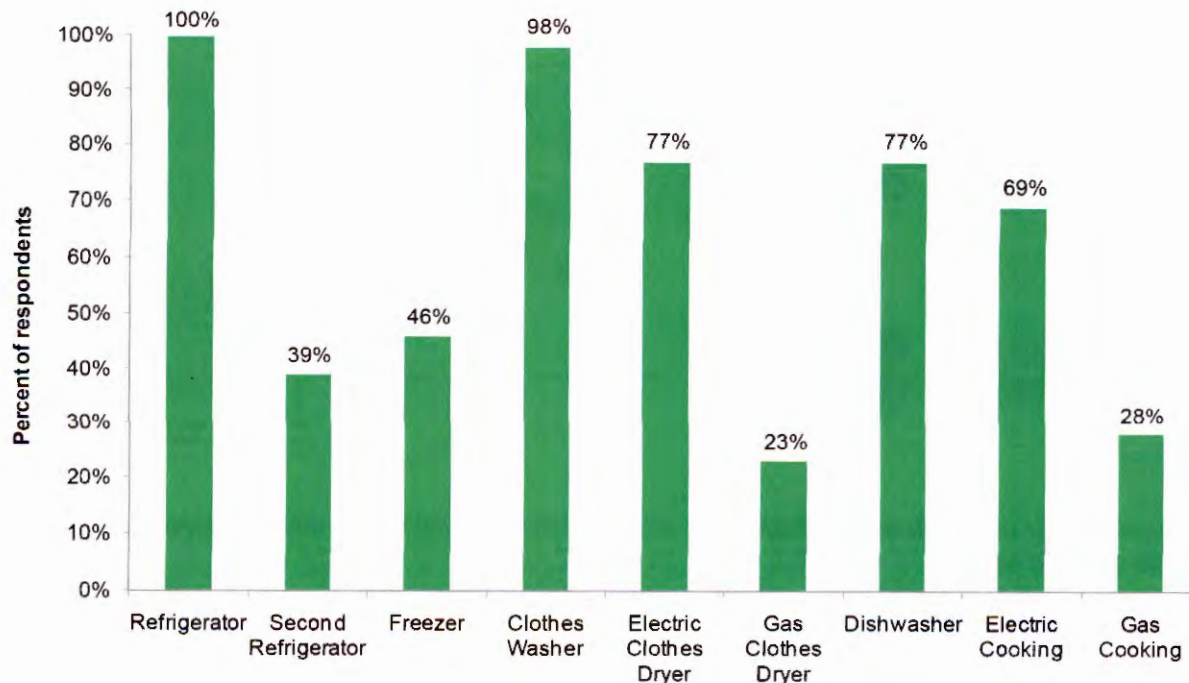
Energy-use Surveys

Energy-use (or saturation) surveys were conducted across all customer classes. Topics included:

- Characteristics of households/homes and businesses/buildings and their occupants
- Heating, cooling and water heating equipment
- Lighting, refrigeration and food service equipment
- Office equipment, electronics and miscellaneous plug loads
- Motors and process uses
- Energy-efficiency measures taken and planned

Figure 12 presents one example of the results from the residential saturation survey.

Figure 12 **Saturation Survey Results – Percent of Single-family Homes with Appliances**



Program-Interest Research

A hallmark of the AmerenUE study is the research of customer attitudes and behaviors toward energy efficiency and demand response measures and programs. The objectives of this research were to:

1. Help AmerenUE estimate achievable potential

- a. How likely are customers within each sector to participate in various energy efficiency programs AmerenUE is considering offering?
 - b. Which of these energy efficiency measures offer the highest likely participation rates?
 - c. How does likelihood to participate differ by payback period for the customer?
2. Help AmerenUE understand unique customer segments to support customer marketing and outreach

The topics covered by the program-interest research included:

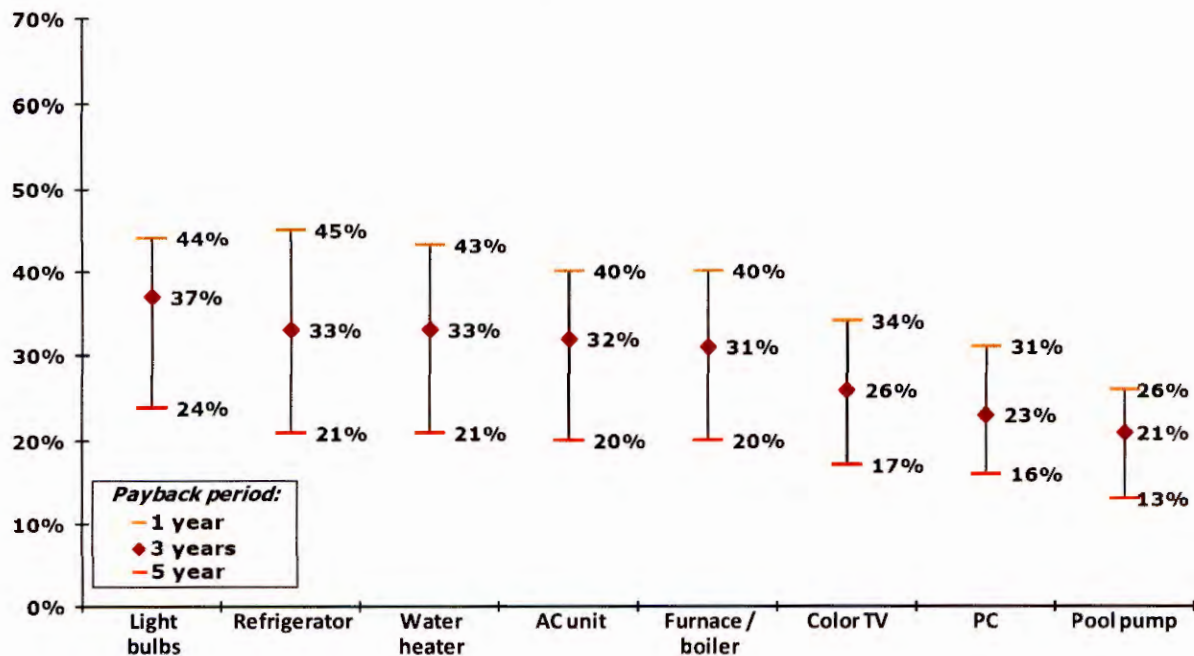
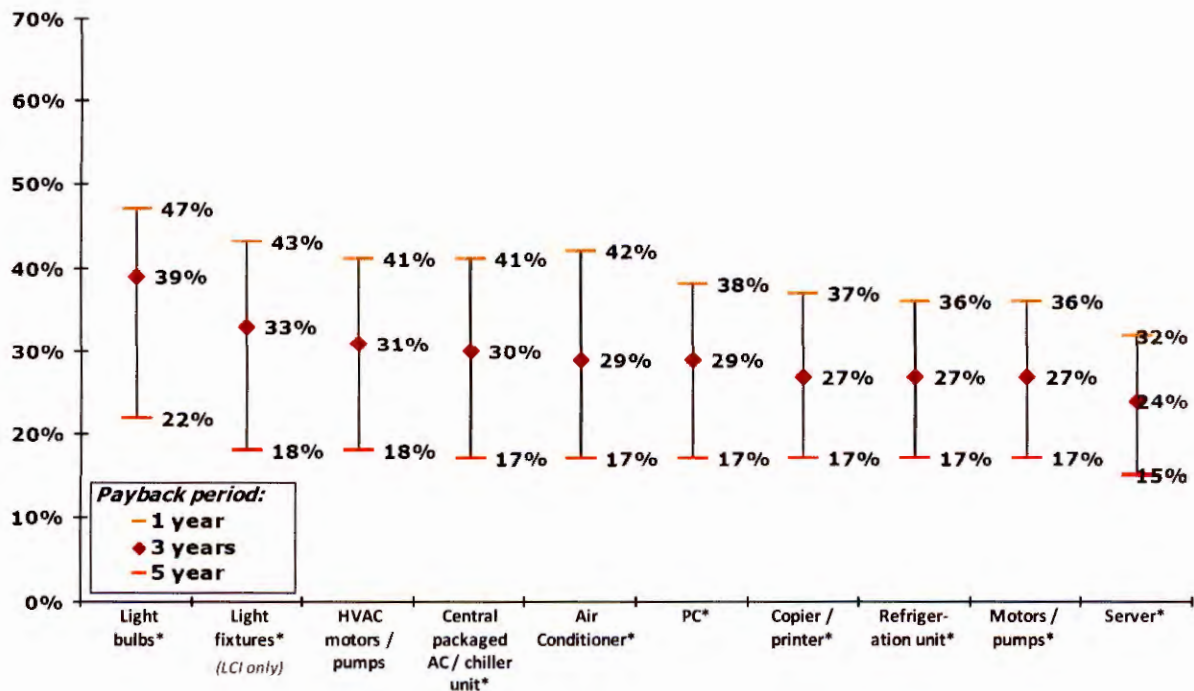
- Attitudinal questions, which included general attitudes about energy use, energy efficiency, environmental concerns, saving money, comfort, etc.; purchasing attitudes, preferences, practices; and attitudes toward electric utility providers in general and attitudes toward AmerenUE
- Assessment of energy efficiency measures already implemented
- Interest in potential energy efficiency and demand response measures offered by AmerenUE that cover appliance and equipment upgrades to high-efficiency models, improvements in processes that would save energy, and likelihood of undertaking certain energy conservation measures.

Key results from the program interest research included “take rates” for various program concepts. Take-rates represent the likelihood that customers will participate in specific programs and they reflect a snapshot of current behavior and circumstances. They have been adjusted for response bias using industry standard techniques to reflect what customers *actually* do rather than what they *say* they will do.

Figure 13 illustrates the range of take rates for the residential and business sectors. Figure 14 and Figure 15 present likely take rates for specific appliances/equipment.

Figure 13 Range of Take Rates



Figure 14 Likely Residential Take Rates for Purchasing High-efficiency Equipment**Figure 15** Likely C&I Take Rates for Purchasing High-efficiency Equipment

These take rates are used directly to estimate the various levels of achievable potential for this study – MAP and RAP. Take-rate estimates at a one-year payback were used to estimate MAP. Take-rates at a three-year payback were used to estimate RAP and were ramped up over the 20-year forecast horizon to reflect increased awareness of utility programs.

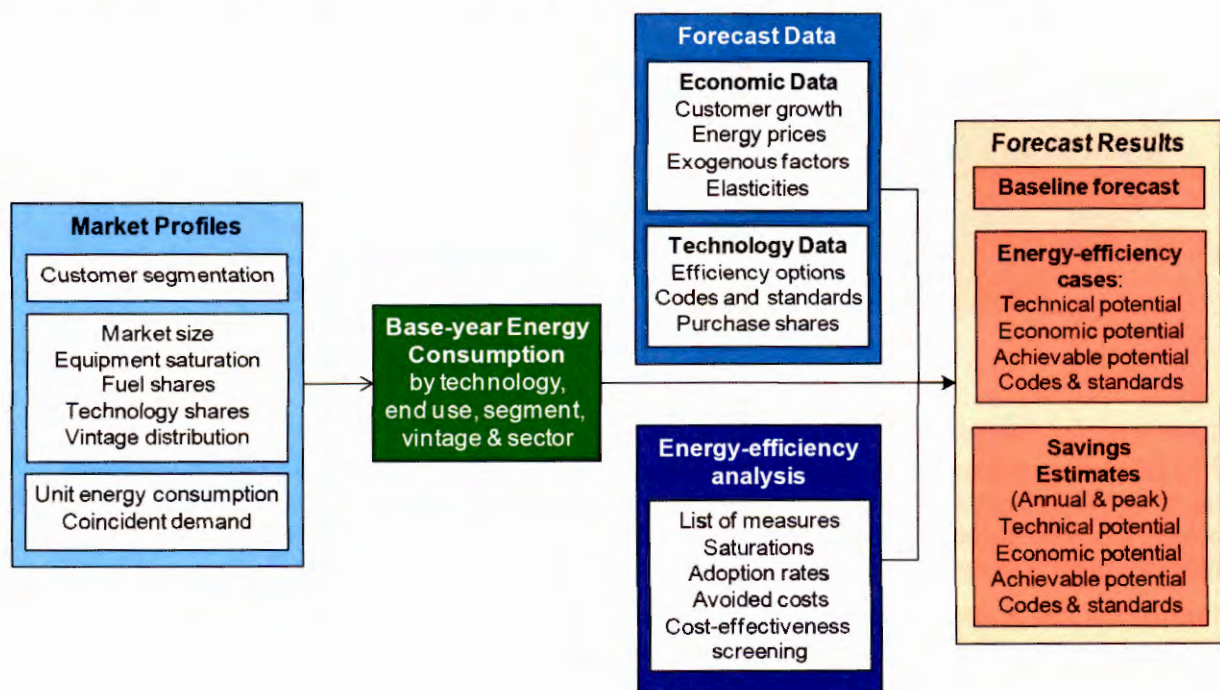
The majority of the AmerenUE take rates under a three-year payback are in the range of 20-40%. Based on observation and expert judgment, these are lower than comparable studies conducted for West Coast and Northeast utilities, which typically show 30-50%. By comparison, a recent similar study conducted by the Electric Power Research Institute identified take rates of 50% or higher, reflecting a mix of states with high and low DSM activity and history.⁷ The result of lower take rates is that MAP and RAP for AmerenUE represent a smaller portion of economic potential than what is projected in some other studies.

In addition to the program take rates, the market research results were used to perform a segmentation analysis. These results are also presented in Volume 2.

DEVELOP BASELINE FORECAST

The market research was a primary source of information for the development of energy market profiles, base-year electricity use by end use and the baseline forecast as illustrated in Figure 16. For this study, 2008 was defined as the base-year because it was the most recent year for which complete billing data were available.

Figure 16 Analysis Framework for Baseline and EE Potentials Forecasts



Base-year Energy Use

In 2008, AmerenUE provided 38,165 GWh of electricity to its residential, commercial and industrial customers. The residential and commercial sectors are roughly equal, each accounting for more than one third of total use. The industrial sector accounts for the remaining 28%.

Residential Electricity Use in 2008

In 2008, AmerenUE provided electricity service to 1.04 million households who used 13,993 GWh. Overall, residential customers used 13,498 kWh/household. The market is dominated by

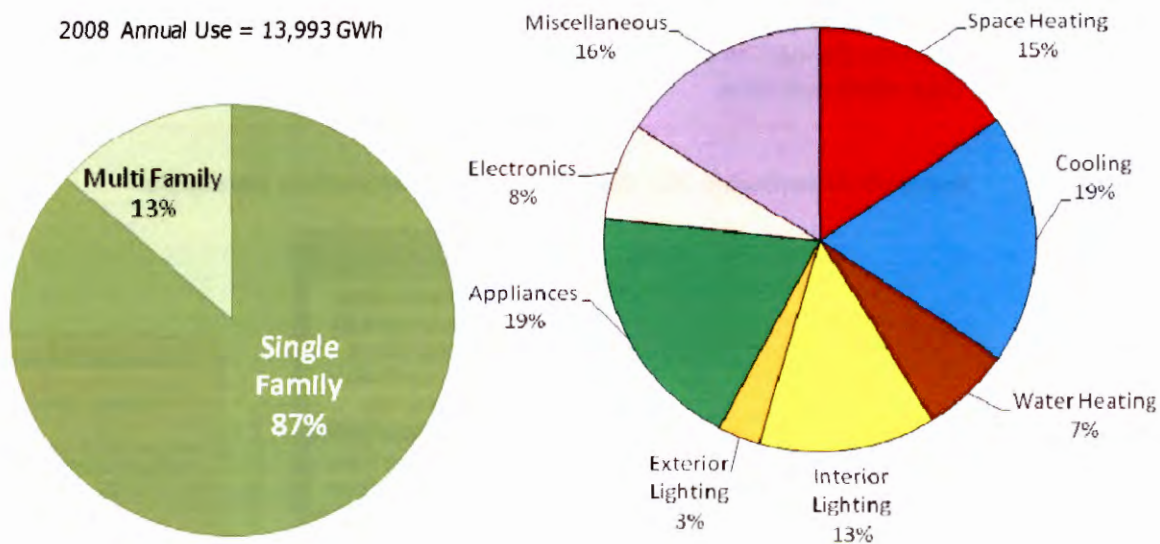
⁷ Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. (2010-2030), EPRI, TR 1016987, January 2009, available at www.epri.com.

single-family homes (see Figure 17), which used 14,682 kWh/household on average, compared to multi-family homes which used 8,883 kWh/household.

Appliance information and dwelling characteristics from the market research were combined to develop descriptions of prototypical houses in the AmerenUE service area. These prototypes were analyzed using an engineering simulation model to estimate end-use consumption.⁸ Comprehensive energy market profiles that characterize electricity usage by end use and segment are presented in Volume 3.

Figure 17 presents a breakdown of 2008 usage by end use. Air conditioning and white-goods appliances are the largest uses, followed by space heating and interior lighting.

Figure 17 Residential Electricity Usage by Segment and End Use



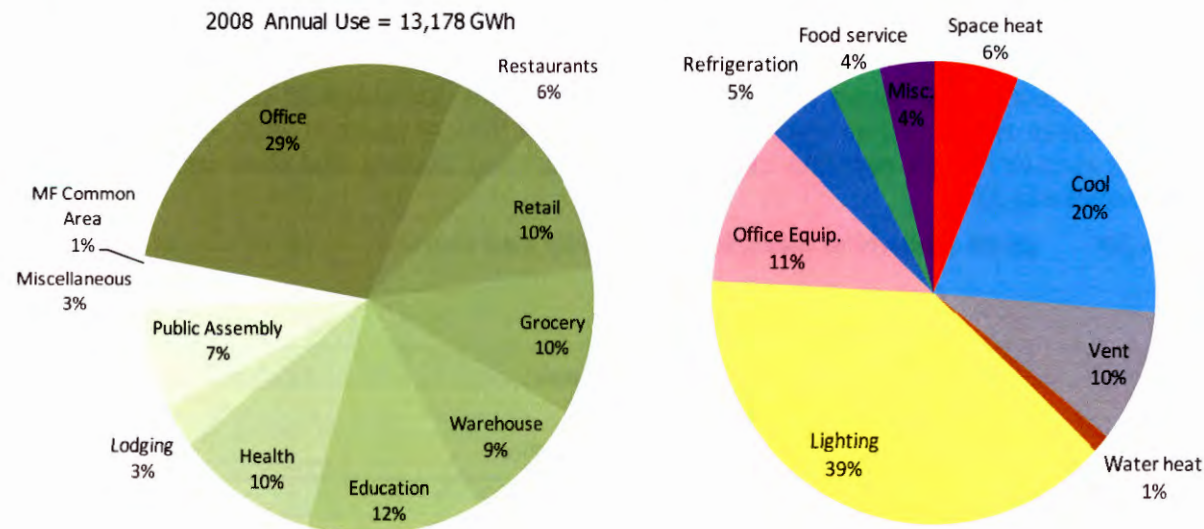
Commercial Sector Electricity Use in 2008

In 2008, AmerenUE provided 13,178 GWh to commercial-sector customers. These businesses occupied 964 million square feet, implying an intensity of 13.7 kWh per square foot per year. The largest segment in the commercial sector is offices, which accounts for 29% of total usage in 2008. All other segments account for 12% or less of total use (see Figure 18).

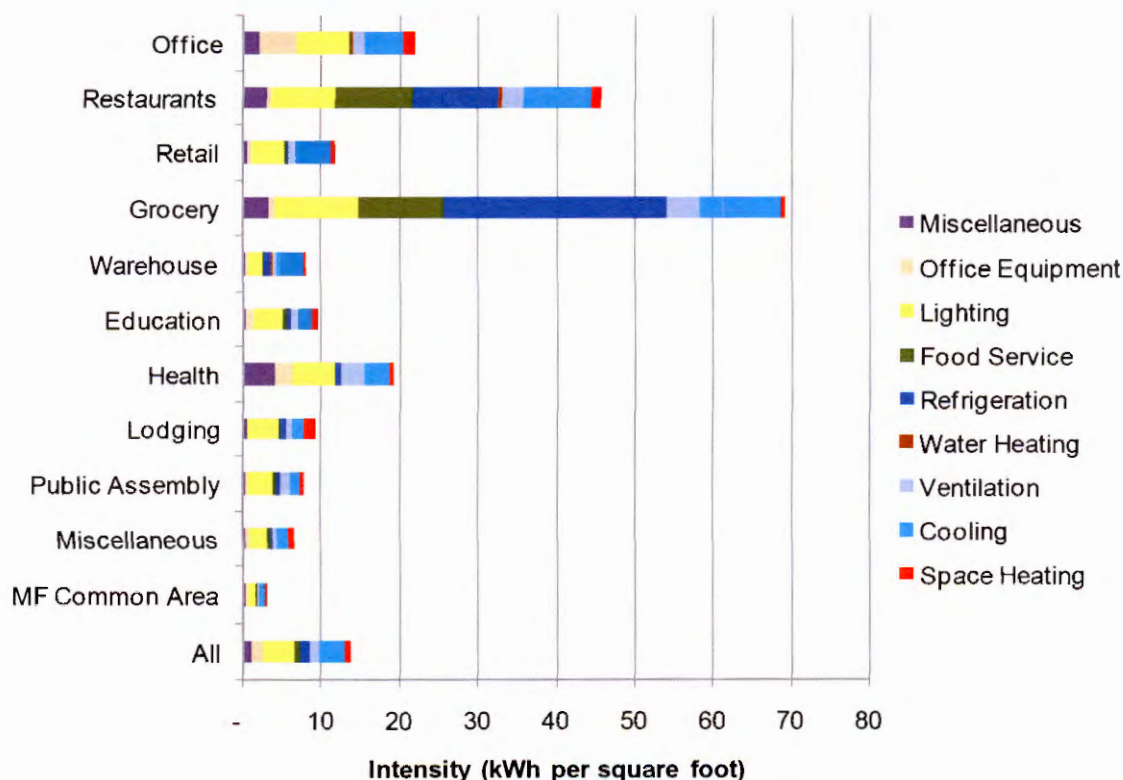
Information about equipment inventories, business operations and building characteristics from the survey were combined to develop descriptions of prototypical building types in the AmerenUE service area. These prototypes were analyzed in BEST to estimate end-use consumption. Comprehensive energy market profiles that characterize electricity usage by end use and segment are presented in Volume 3.

Figure 18 presents a breakdown of 2008 usage end use. Lighting is the dominant use in the commercial sector, followed by space cooling.

⁸ The model used for this purpose is Global's Building Energy Simulation Tool (BEST), which is a user-friendly front-end to the powerful DOE-2 energy simulation model.

Figure 18 2008 Commercial Sector Electricity Usage by Segment and End Use

Electricity use varies considerably by building type and end use. Figure 19 presents the overall intensity in kWh per square foot per year, as well as the end-use breakdown. The grocery and restaurant segments are the most intensive as a result of high refrigeration and food service usage, in addition to lighting and cooling. Lighting and cooling are significant uses across all segments. Office is the largest segment, in terms of absolute kWh usage, and uses about 22 kWh per square foot on average.

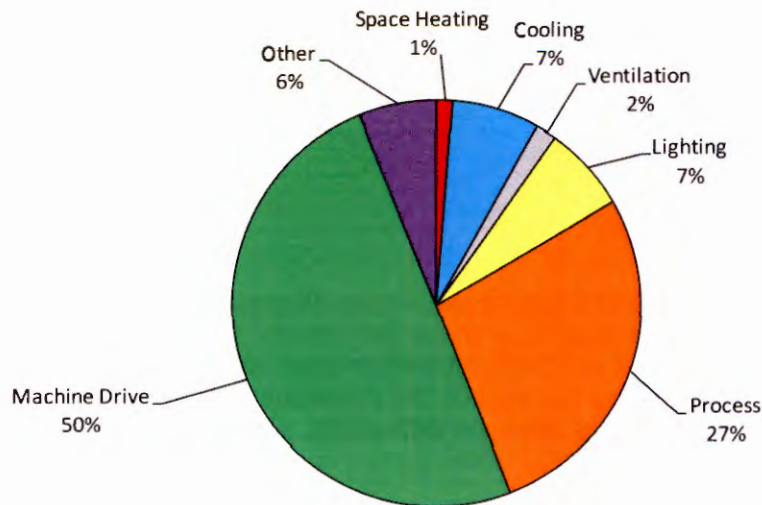
Figure 19 Electricity Use by Building Type and End Use

Industrial Sector Electricity Use in 2008

In 2008, AmerenUE provided 10,994 GWh to the industrial sector. Throughout this study, this sector is treated as a whole to protect the confidentiality of AmerenUE's largest customers who might otherwise be identified.

Figure 20 presents a breakdown of 2008 usage by end use for the industrial sector. Machine drives, primarily motors and air compressors, account for 50% of usage in 2008. Electric processes account for just over one fourth of usage. Lighting, cooling, and other uses account for the remaining 23%.

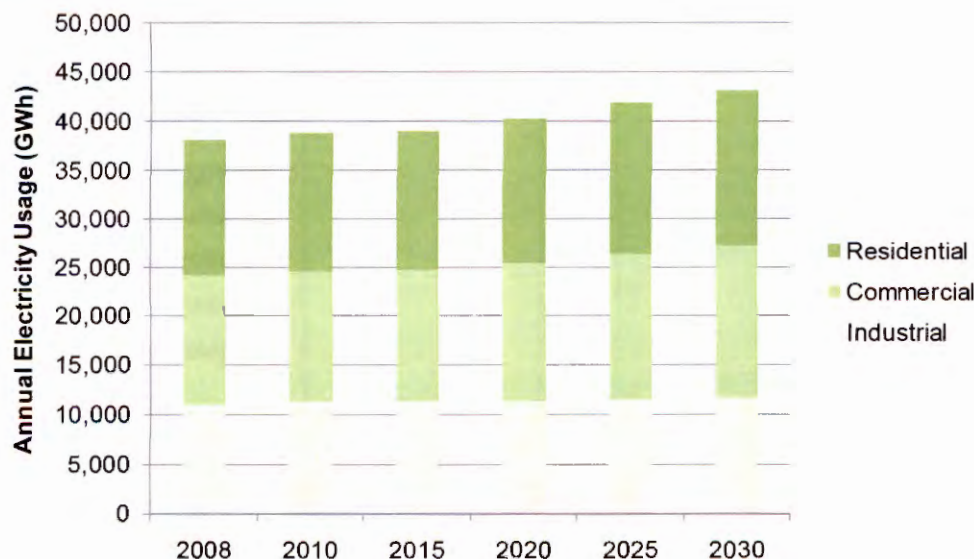
Figure 20 2008 Industrial Electricity Usage by End Use



Baseline End-Use Forecast Results

Using the base-year profiles as a starting point, a baseline end-use forecast was developed for 2009 through 2030 using Global's LoadMAP model. This forecast embodies assumptions about customer growth, electricity prices, technology trends and the impacts of codes and standards. This forecast provides the springboard for the estimation of energy-efficiency potential and is the metric against which EE savings are measured. The total forecast is presented in Figure 21.

Figure 21 Baseline Forecast Summary



Residential Baseline End-use Forecast

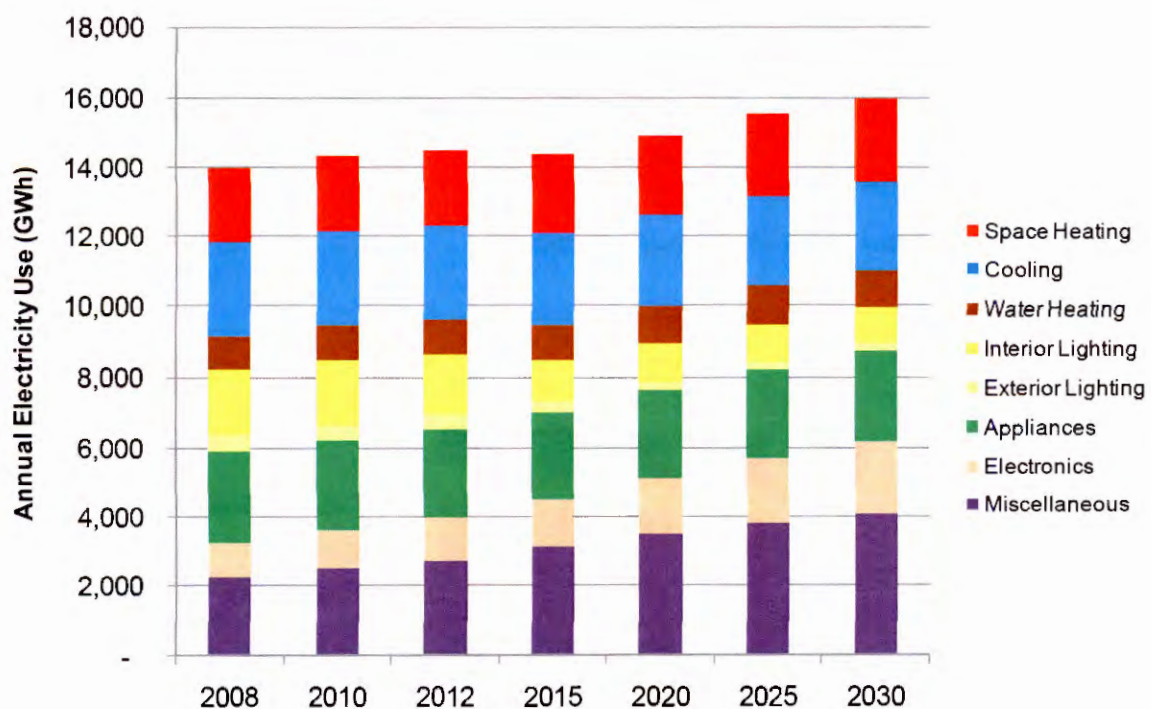
Electricity use is forecast to grow from 13,993 GWh in 2008 to 15,986 GWh in 2030. This is a 14% increase over the 22 years, implying an average growth rate of 0.61%.

Key observations about this forecast include the following:

- Residential lighting is affected by the passage of the Energy Independence and Security Act (EISA) in 2007, which mandates higher efficacies for lighting technologies starting in 2012. Several lighting technologies are anticipated to meet this standard when it goes into effect, including compact fluorescent lamps (CFL), white light-emitting diodes (LED), and advanced incandescents currently under development. Old stock is phased out over time beginning in 2012. The effect of this standard is a decline in electricity for lighting use by 43% over the forecast period, reflecting a low penetration of CFLs in the AmerenUE service area in 2008.
- Growth in electricity use in electronics is strong and reflects an increase in the saturation of electronics and the trend toward higher-powered computers and larger televisions.
- Growth in miscellaneous use is also substantial. This has been a long-term trend and assumptions have been made about growth in this end use that are consistent with the Annual Energy Outlook.

Figure 22 presents the residential end-use forecast.

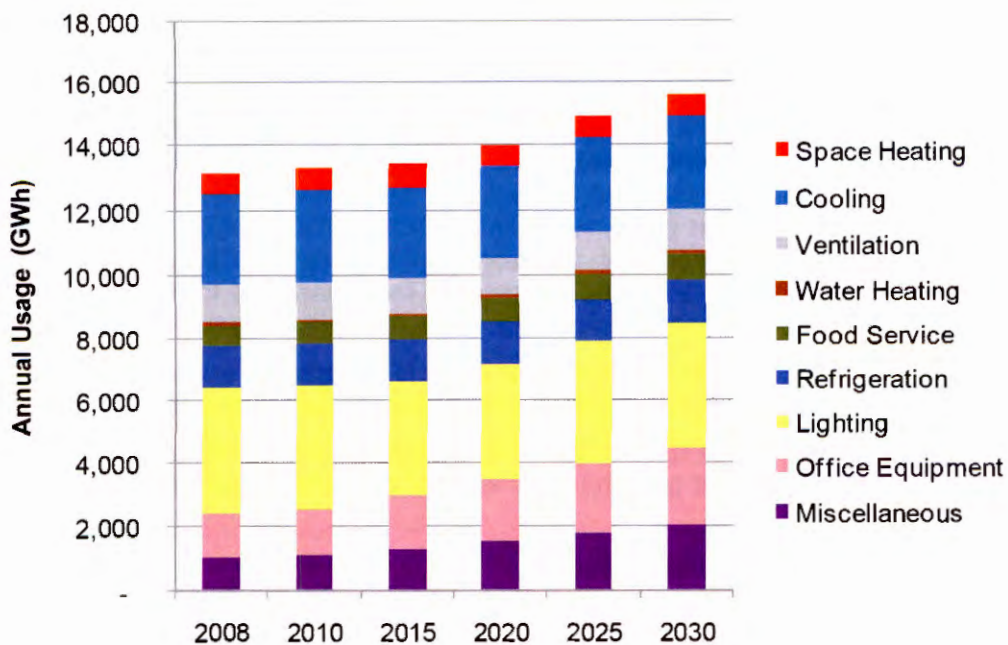
Figure 22 Residential Baseline End-use Forecast



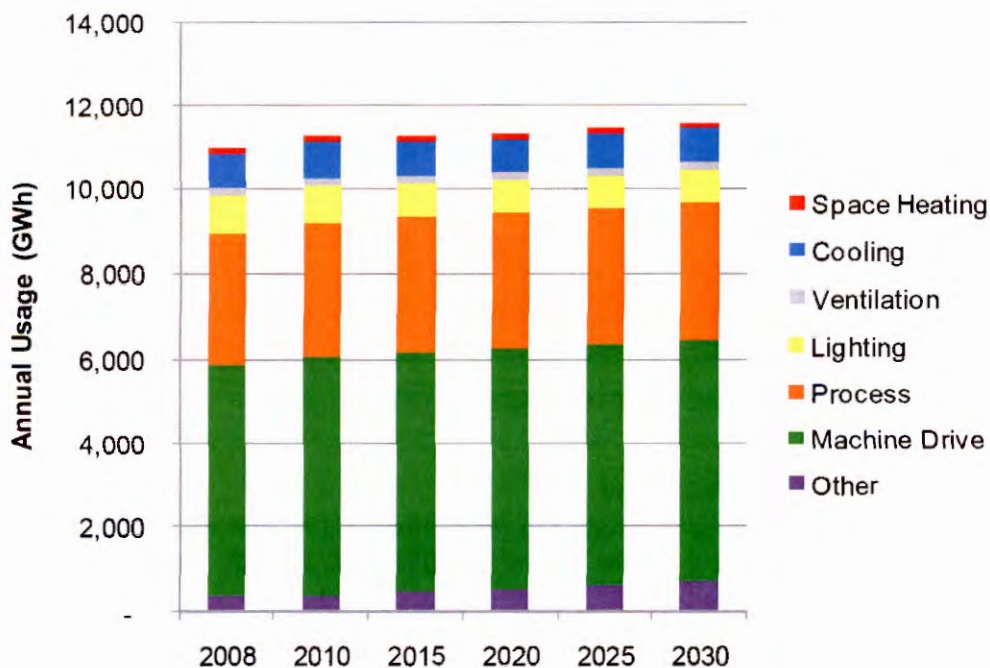
Commercial Baseline End-use Forecast

In the commercial sector, electricity use is forecast to grow from 13,178 GWh in 2008 to 15,615 GWh in 2030. This is an 18% increase over the 22 years, implying an average growth rate of 0.8%.

Figure 23 presents the forecast which shows considerable variation across the end uses. Major uses – cooling, lighting and refrigeration – are relatively flat, while significant growth takes place in office equipment and miscellaneous uses.

Figure 23 Commercial Baseline End-use Forecast**Industrial Baseline End-use Forecast**

Industrial electricity use is projected to stay fairly flat over the next 22 years. Of course, this assumes the continued viability of AmerenUE's largest industrial customers. Electricity use is forecast to grow from 10,994 GWh in 2008 to 11,580 GWh in 2030, an increase of 5%. As in the other sectors, lighting use declines as the result of standards. The primary source of growth is in the other uses. The forecast is depicted in Figure 24.

Figure 24 Industrial Baseline End-use Forecast

POTENTIAL SAVINGS FROM ENERGY EFFICIENCY MEASURES

Once the baseline forecast was developed, analysis of energy-efficiency potential proceeded. This activity began with the identification and screening of energy-efficiency measures. A total of 299 individual measures were considered across all three sectors. The residential analysis included 118 measures, the commercial sector included 120 measures and the industrial sector considered 43 measures. The primary sources for EE measure information include:

- Global's Database of Energy Efficiency Measures (DEEM)
- California's Database of Energy Efficiency Resources (DEER database)
- AmerenUE stakeholder input

The analysis of energy-efficiency measures yielded estimates of energy efficiency for Technical and Economic potential, which were the building blocks of the subsequent program analysis and achievable potentials (see Table 1):

- **Technical potential** is the theoretical upper bound of energy-efficiency savings regardless of cost.
 1. In 2020, technical potential is 11,098 GWh, which represents 27.6% of total usage in that year.
 2. In 2030, technical potential is 12,696 GWh, 29.4% of total usage.
- **Economic potential** is an estimate of all cost-effective energy efficiency savings.
 1. In 2020, economic potential is 5,475 GWh, which represents 13.6% of total usage in that year.
 2. In 2030, economic potential is 7,181 GWh, 16.6% of total usage.

Figure 25 presents the savings as a percent of baseline energy usage in each of selected years.

Figure 25 Summary of Energy-efficiency Measure Potential

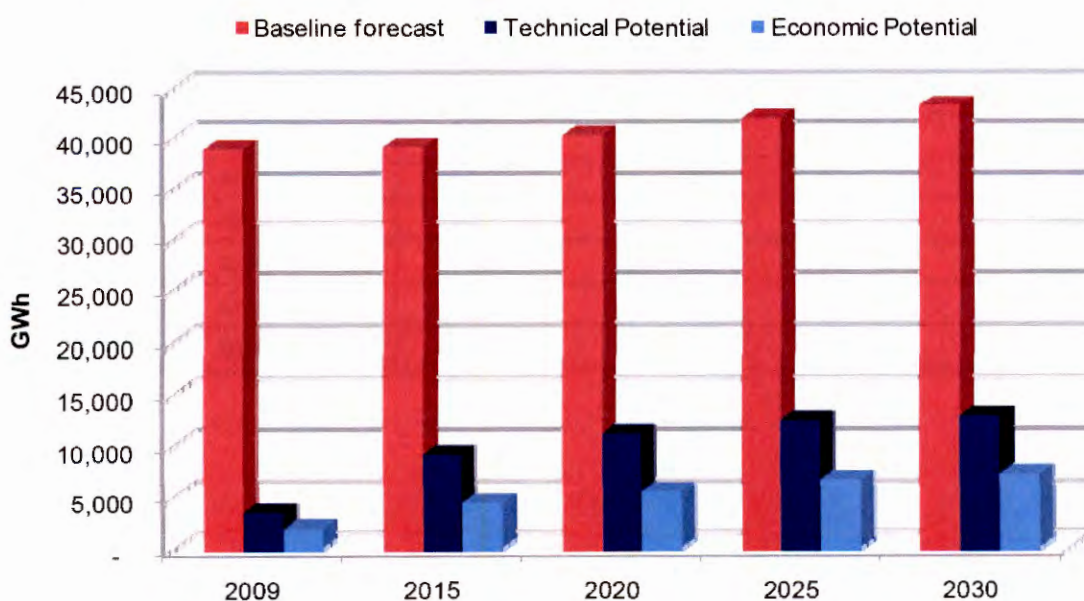
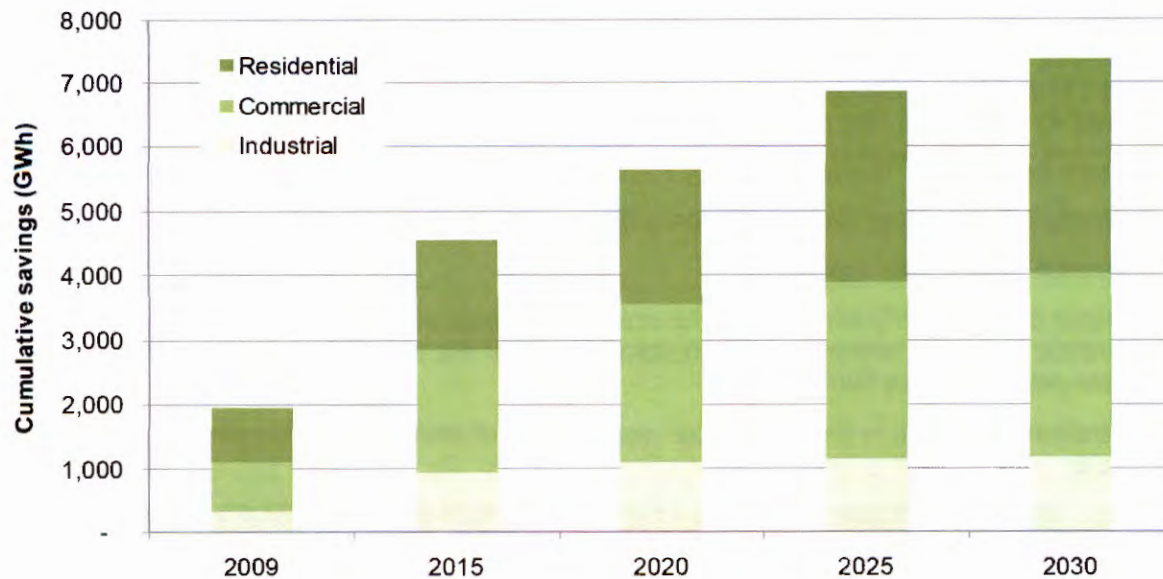


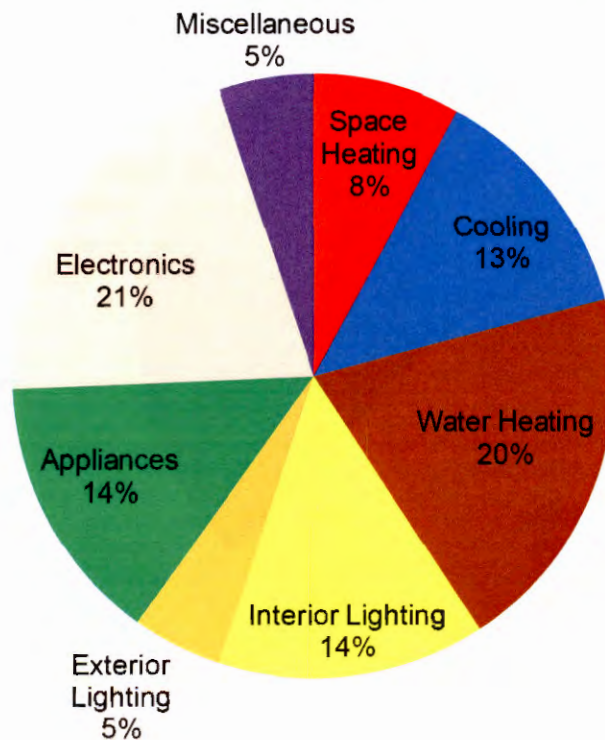
Figure 26 summarizes economic potential by sector. The contributions to savings from the residential and commercial sectors are roughly equal, while the industrial sector is the smallest of the three.

Figure 26 *Summary of Economic Potential by Sector***Residential EE Measure Potential**

Economic potential in the residential sector in 2030 is 3,348 GWh or 21% of baseline residential usage in that year. The breakdown by end use for selected years is presented in Table 8. Figure 27, which illustrates the end-use breakdown in 2030, shows that there are substantial savings across all end uses in the residential sector, even after the effects of appliance standards.

Table 8 *Residential Economic Potential by End Use*

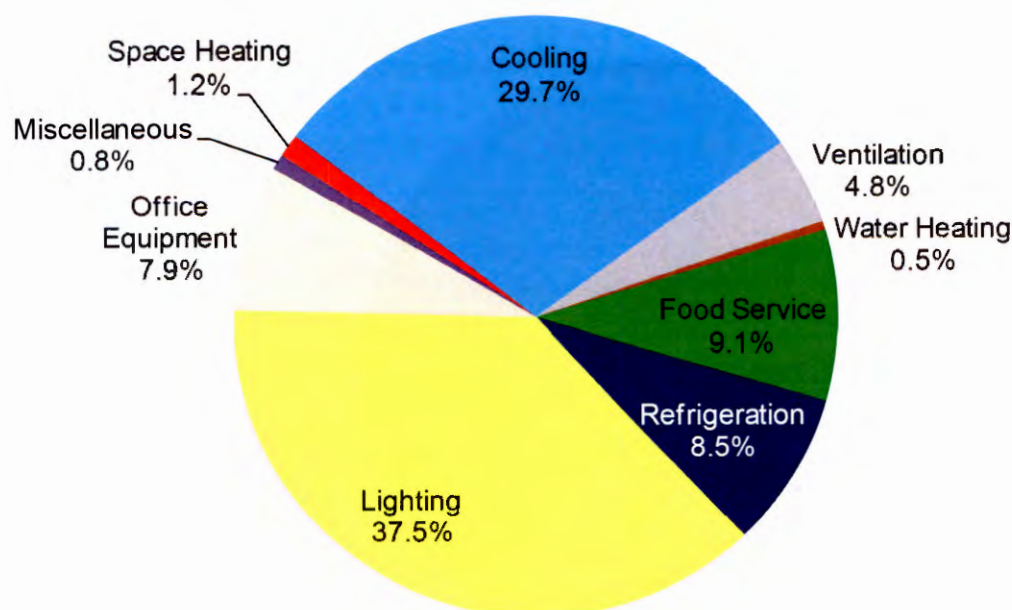
	2009	2015	2020	2030
Space Heating	66	191	214	264
Cooling	95	275	328	436
Water Heating	107	338	446	664
Interior Lighting	354	269	291	484
Exterior Lighting	135	195	164	161
Appliances	14	97	196	482
Electronics	19	205	339	688
Miscellaneous	43	123	152	170
Total	834	1,692	2,130	3,348

Figure 27 *End-use Breakdown of Residential Economic Potential in 2030***Commercial EE Measure Potential**

In 2030, economic potential in the commercial sector is 2,847 GWh or 18% of baseline commercial usage in 2030. The breakdown by end use for selected years is presented in Table 9. Figure 28, which illustrates the end-use breakdown in 2030, shows that lighting and cooling account for the majority of potential savings.

Table 9 *Commercial Economic Potential by End Use*

	2009	2015	2020	2030
Space Heating	13	32	34	35
Cooling	196	542	679	846
Ventilation	14	95	132	136
Water Heating	2	7	10	13
Food Service	13	118	214	258
Refrigeration	14	90	152	242
Lighting	481	852	1,020	1,066
Office Equipment	42	156	178	226
Miscellaneous	2	12	20	24
Total	777	1,903	2,441	2,847

Figure 28 **End-use Breakdown of Commercial Economic Potential in 2030**

Industrial EE Measure Potential

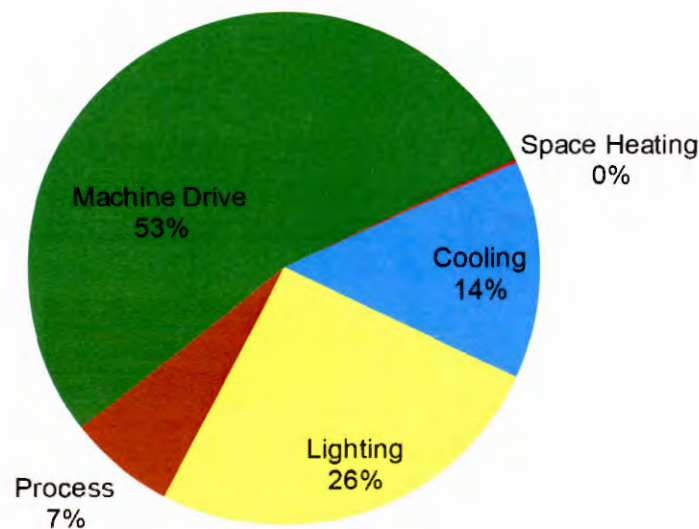
In 2030, economic potential in the industrial sector is 986 GWh or 8.5% of baseline industrial usage in 2030. The breakdown by end use for selected years is presented in Table 10.

Figure 29, which illustrates the end-use breakdown in 2030, shows that machine drives – motors and air compressors account for more than half the potential savings. However, the absolute savings from motors is relatively small for two reasons. First, there are significant savings already embodied in the baseline forecast as a result of the NEMA standards that have been in place for many years and which will begin to require that premium-grade motors be installed in December 2010. Second, industrial customers are savvy and have been able to successfully postpone motor replacement by rewinding existing motors. In addition to motors, there are significant savings opportunities in cooling, lighting and, to a lesser degree, electric processes.

Table 10 **Industrial Economic Potential by End Use**

	2009	2015	2020	2030
Space Heating	1	1	2	2
Cooling	26	63	75	134
Ventilation	-	-	-	-
Lighting	117	252	251	255
Process	25	65	67	67
Machine Drive	114	416	509	528
Total	284	797	904	986

Figure 29 **End-use Breakdown of Industrial Economic Potential in 2030**



DSM PROGRAM ANALYSIS

The process of developing the EE and DR programs for this study involved an assessment process that is illustrated in Figure 30. This figure depicts the sources of information that were used to guide the development of a portfolio of representative EE and DR programs that could then serve as the basis for detailed analyses, including cost-effectiveness analysis, supply curve assessment and scenario analysis. The results of these various analytics will serve as the inputs necessary for AmerenUE to conduct its current IRP assessment, work through the Missouri regulatory process and support the process of implementation.

Figure 30 **Process for Developing Energy Efficiency and Demand Response Programs**

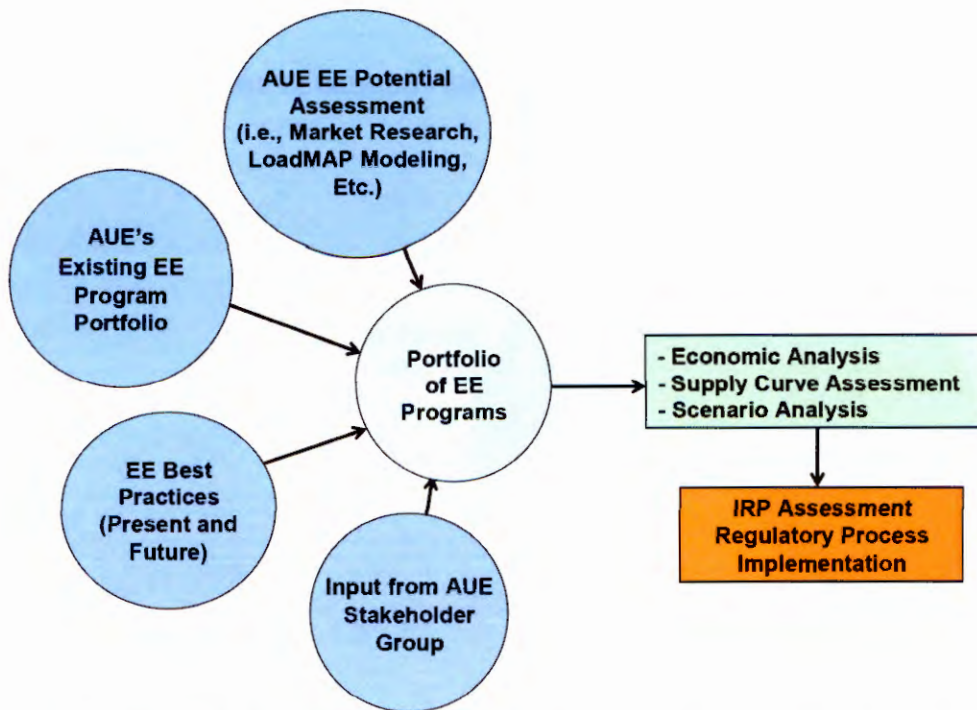


Table 11 identifies the portfolio of energy-efficiency programs considered in the analysis as well as target market segments for each. These programs reflect current industry best practices, but also provide a structure that allows the programs to adapt to meet future needs.

Figure 31 presents realistic achievable potential from energy-efficiency programs in selected years. The largest savings are found in three programs: C&I Standard Incentives, C&I Custom Incentives and Residential Lighting and Appliances

Table 11 **Energy Efficiency Programs**

Energy Efficiency Program	Target Market Segment(s)
1. Residential Lighting and Appliances	All residential customers
2. Multi-Family Common Area	Owners and property managers of multi-family buildings
3. Residential New Construction	Single-family new constructions
4. Residential HVAC Equipment & Diagnostics	Single-family home customers
5. Residential Energy Performance	Single-family home customers
6. Residential Low Income	Low-income residential customers
7. Residential Appliance Recycling	All residential customers
8. Residential Information/Feedback	All residential customers
9. C&I Standard Incentives	All C&I customers
10. C&I Custom Incentives	All C&I customers
11. C&I New Construction	C&I new constructions
12. C&I Retro-Commissioning	All C&I customers
13. C&I Information/Feedback	All C&I customers

Figure 31 **Realistic Achievable Potential from Energy Efficiency Programs**

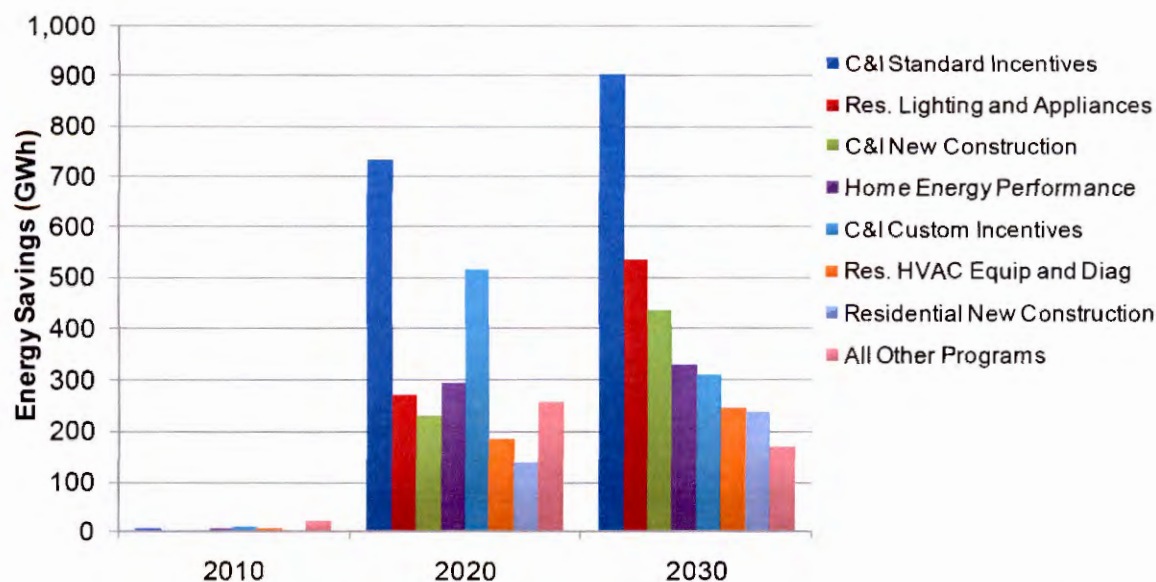
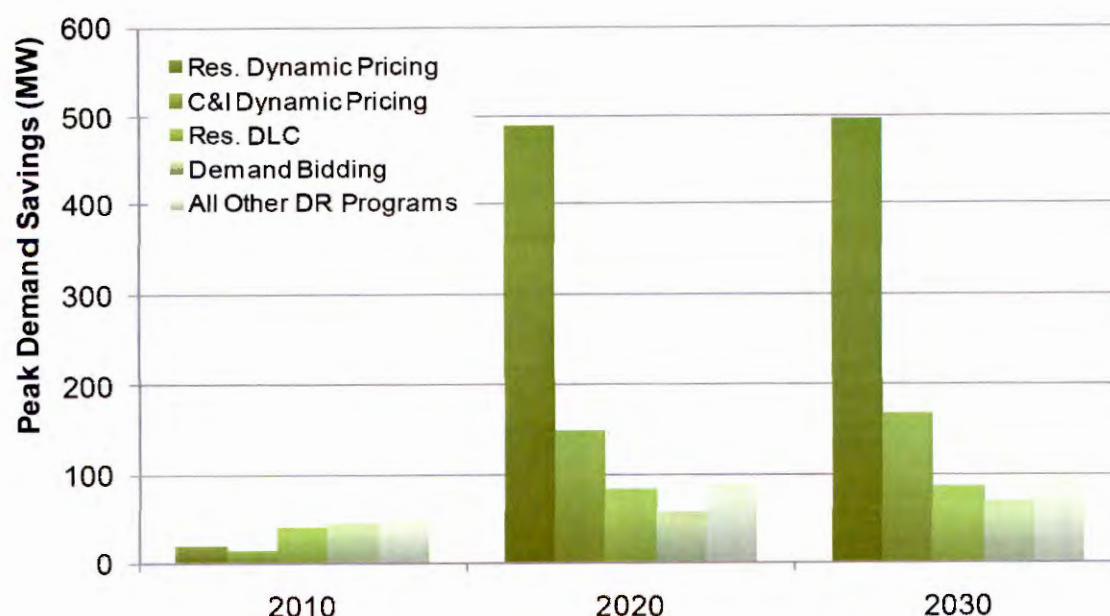


Table 12 identifies the list of demand-response programs included in the analysis together with the target segments for each. Figure 32 presents realistic achievable potential for selected years. In 2010, the majority of savings come from non-pricing programs, but by 2020 the trend is reversed and savings from dynamic pricing programs dominate.

Table 12 Demand Response Programs

Demand Response Program	Target Market Segment(s)
1. Residential Direct Load Control	All residential customers with air conditioning and electric water heating
2. Residential Dynamic Pricing	All residential customers
3. C&I Direct Load Control	All small-sized C&I customers (Rate 2M)
4. C&I Dynamic Pricing	All C&I customers (Rates 2M, 3M, 4M and 11M)
5. Demand Bidding	All medium- and large-sized C&I customers (Rates 3M, 4M and 11M)
6. Curtailable	All large-sized C&I customers (Rates 4M and 11M)
7. DR Aggregator Contracts	All C&I customers (Rates 2M, 3M, 4M and 11M)

Figure 32 Realistic Achievable Potential from Demand Response Programs



COMPARISON WITH OTHER STUDIES

The results of this AmerenUE study have been compared with three recent and relevant studies:

- The EPRI National Potential Study: ***Assessment of Achievable Potential from Energy Efficiency and Demand Response in the U.S. (2010-2030)***, TR 1016987, January 2009
- The Wisconsin Study: ***Energy Efficiency and Customer-Sited Renewable Resource Potential in Wisconsin, For the years 2012 and 2018***, ECW Report Number 244-1, April 2009
- The FERC Study: ***A National Assessment of Demand Response Potential***, Staff Report, June 2009

The EPRI Study

The EPRI Study assessed EE and DR potential for the U.S. and for four Census regions. AmerenUE is part of the Midwest Census region. The EPRI study has a 20-year time horizon and used a bottom-up analysis approach for the residential and commercial sectors, and a top-down approach for the industrial sector. (The AmerenUE study used a bottom-up analysis approach for all three sectors.) The base-year market characterization and the baseline end-use forecast were based on 2008 Annual Energy Outlook prepared by the Energy Information Administration. Energy-efficiency measures were comprehensive but not as extensive as the AmerenUE measure list. Market acceptance rates and program implementation factors were based on a Delphi approach with industry experts. The estimates of realistic achievable potential from this study represent a forecast of what is likely to occur and do not represent what might occur under "aggressive" utility programs. The AmerenUE parameters are based on primary market research with AmerenUE customers.

The Midwest regional results from the EPRI National Potential Study compare with AmerenUE as follows for the year 2030:

- EPRI economic potential in 2030 is 12.3%. AmerenUE economic potential is 16.6% and reflects the more extensive list of energy-efficiency measures.
- EPRI maximum achievable potential in 2030 is 10.1%, compared to the AmerenUE value of 11.0%. This reflects the lower market acceptance rates for AmerenUE based on market research.

- EPRI realistic achievable is 7.5%, compared with 7.3% for AmerenUE.

Even though the AmerenUE economic potential is higher than the EPRI study, the achievable potential estimates are in close alignment reflecting the results of the market research performed for the AmerenUE study.

The Wisconsin Study

The State of Wisconsin Study was conducted by Energy Center of Wisconsin (ECW), with subcontractors ACEEE, GDS Associates and L&S Technical Associates. It defines achievable potential not as a "middle-of-the-road" case, but rather as an upper-bound estimate of what could be achieved with aggressive utility programs. This study used a bottom-up analysis framework for the residential sector and a top-down approach for the C&I sectors. As mentioned above, market and program acceptance rates for AmerenUE are based on primary market research. The Wisconsin study used a Delphi approach to explore an aggressive energy-efficiency future in Wisconsin.

This study is regarded to be aggressive in its findings of energy-efficiency savings. Therefore, the results are compared with the RAP and MAP estimates from AmerenUE. Specifically, over a ten-year horizon, the ECW study concludes:

- Wisconsin economic potential is 18%, compared to 14% for AmerenUE.
- Wisconsin achievable potential is 13%, compared to 7% for AmerenUE RAP and 10% for AmerenUE MAP.

Given the definition of achievable potential used for the Wisconsin study and the approach for developing market acceptance rates, it is not surprising that the Wisconsin estimates of achievable potential are higher than the AmerenUE estimates.

The FERC Study

In 2008-2009, FERC conducted its first assessment of demand-response potential. The analysis was performed for each of the 50 states and the District of Columbia and aggregated to regional and national totals. The results reflect a bottom-up analysis approach that relies on secondary data from a variety of resources.

The definition of achievable potential for the FERC study is similar to that used for the Wisconsin EE study in that it is an aggressive perspective. Specifically, achievable potential is defined as what could be achieved over a ten-year horizon if advanced metering infrastructure (AMI) were deployed universally, dynamic pricing were the default tariff, and other DR programs, such as direct load control, were available to those who opted out of dynamic pricing. The FERC study also estimated an "expanded business as usual" scenario which represents expansion of current programs to all states and with higher participation rates, partial AMI deployment, and optional dynamic pricing tariffs. Participation rates are based on secondary data and expert judgment, whereas the AmerenUE rates are based on primary market research and expert judgment.

The FERC study provides the following estimates for the state of Missouri:

- FERC achievable potential is 19.2%, compared with 11.9% for maximum achievable for AmerenUE
- FERC expanded BAU is 14.1%, compared with 9.6% for realistic achievable potential for AmerenUE.

Since the definition of achievable potential in the FERC study is more aggressive (or optimistic) than that used for the AmerenUE study, it is not surprising that estimates of achievable potential are higher than the AmerenUE estimates.

ABOUT GLOBAL

Established in 1998, Global Energy Partners, LLC is a premier provider of energy and environmental engineering and technical services to utilities, energy companies, research organizations, government/regulatory agencies and private industry.

Global's offerings range from strategic planning to turn-key program design and implementation and technology applications.

Global is an employee-owned consulting organization committed to helping its clients achieve strategic business objectives with a staff of world-class experts, state of the art tools, and proven methodologies.

Global Energy Partners, LLC
500 Ygnacio Valley Road, Suite 450
Walnut Creek, CA 94596

P: 925.482.2000
F: 925.284.3147
E: globalhq@gepllc.com

8. Environmental

Highlights

- *There are many existing and potential new environmental regulations that could affect the operations of Ameren Missouri's power plants.*
- *Although the momentum for carbon legislation has recently subsided, the U.S. Environmental Protection Agency has been aggressively pursuing more stringent regulations of power plant air, water, and solid waste emissions.*
- *Two scenarios, moderate and aggressive, were constructed to evaluate different levels of more stringent environmental regulations.*
- *Both environmental scenarios evaluated require substantial capital investment.*

Environmental regulations are an important factor to consider in resource planning. The planning scenarios, developed in Chapter 2, include alternative regimes for limiting greenhouse gas emissions. In this IRP, it is assumed that any new coal plant will be built with carbon capture as well as meet other more stringent environmental regulations. However, there is still the question about the impacts of more stringent environmental regulations to Ameren Missouri's existing generation fleet, especially its coal assets. This chapter discusses the current major regulations affecting the power industry as well as potential new environmental regulations. In fact, the Environmental Protection Agency (EPA) is expected to issue new environmental regulations in the next 12 to 24 months related to air emissions, ash waste, and water. Ameren Missouri synthesized the potential new environmental regulations into two distinct scenarios and corresponding compliance paths characterized by environmental retrofits to its existing coal fleet. The costs and timing of those retrofits are included in the risk analysis in Chapter 9 and are instrumental to the retirement analysis of Meramec. Ameren Missouri also expanded its financing analysis in Chapter 10 to evaluate the impact of these large investments. Furthermore, the environmental scenarios act as a signpost for decision making and therefore are an important aspect of the strategy selection in Chapter 10.

8.1 Overview

Ameren Missouri is subject to various environmental laws and regulations enforced by federal, state (Missouri and Illinois) and local authorities. The following paragraphs identify the major federal environmental laws governing the operations of Ameren Missouri facilities. The State of Missouri, State of Illinois, and local authorities also have environmental laws and/or ordinances which are intended to implement various provisions of the federal statutes. Significant provisions of these acts affecting the power industry are discussed in this chapter.

In addition, a summary of possible future environmental initiatives that could affect the power industry is included. The information below has been prepared in good faith and there is no assurance or certainty regarding the future of the identified environmental initiatives or their potential requirements.

Major Air Environmental Laws

Current

Clean Air Act (1970, 1977 & 1990)

Acid Rain Program

Clean Air Interstate Rule (CAIR)

Clean Air Transport Rule (CATR) (proposed)

Other Clean Air Act Provisions

National Ambient Air Quality Standards (NAAQS)

Possible Future Initiatives and Regulations

Global Climate Initiatives

Initiatives to Address Transported Air Pollutants

Maximum Achievable Control Technology (MACT) Standards for Mercury and Other Hazardous Air Pollutants (HAPs)

Regulation of Greenhouse Gases (GHGs) under the CAA

Major Water Environmental Laws

Current

Clean Water Act (1977; Federal Water Pollution Control Amendments, 1972)

Safe Drinking Water Act (1974, as amended)

Possible Future Initiatives and Regulations

Clean Water Act, Section 316 (a) Thermal Discharges

Clean Water Act, Section 316 (b) Entrainment and Impingement of Aquatic Organisms

Steam Electric Generator Effluent Guideline Limitations

Major Solid Waste Environmental Laws

Current

Resource Conservation and Recovery Act (RCRA-1976)

Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA or Superfund 1980), Superfund Amendments and Reauthorization Act (SARA-1986)

Toxic Substances Control Act (TSCA-1976)

Emergency Planning & Community Right-To-Know Act (EPCRA-1986)

Possible Future Initiatives and Regulations

Coal Combustion Residual (CCR) Regulation – proposed revisions to RCRA regulations

Ash Pond Closure Initiatives**Potential Limitation of Beneficial Use****Other Environmental Laws**

National Environmental Policy Act of 1969 (NEPA)

National Historic Preservation Act (1966)

Endangered Species Act (ESA-1973)

Migratory Bird Treaty Act (1918, as amended)

Bald and Golden Eagle Protection Act (1940, as amended)

Rivers and Harbors Act (1899)

Local Ordinances and Regulations

8.2 Major Air Environmental Laws**8.2.1 Current Laws*****Clean Air Act (1970, 1977 & 1990)***

The Clean Air Act (CAA) established Ambient Air Quality Standards for SO₂, NO_x, particulate matter (PM), fine particulate matter (PM 2.5), ozone, carbon monoxide (CO) and lead. Ambient standards may be evaluated on a 5 year cycle. More stringent ambient standards continue to be developed through this process. Ambient Standards are managed through emission limits, ambient air monitoring, and air quality modeling conducted by each State as part of State Implementation Plans (SIP). Areas are analyzed and designated as Attainment or Nonattainment with each pollutant. Nonattainment areas are subject to increased pollution control measures.

The CAA also established:

- New Source Performance Standards (NSPS) for determining the pollution control requirements for new sources, including existing sources that become subject to new source requirements due to a “modification” as defined by the statute and relevant rules;
- Requirements to permit new pollution sources and ensure air quality is not deteriorated; the state of Missouri is authorized by the EPA to issue permits.
- National Emission Standards for Hazardous Air Pollutants (NESHAPS) for control of asbestos and other hazardous air pollutants ;
- New Source Review (NSR) programs that mandate review to determine if projects trigger permitting and additional pollution control equipment;
- Prevention of Significant Deterioration (PSD) program, that imposes control requirements on new and modified major sources to protect ambient air quality. These programs do not apply to various actions at existing major sources,

including routine repair & replacement of equipment, and changes which do not increase emissions;

- Maximum Achievable Control Technology (MACT) Standards for hazardous air pollutants; and
- The Acid Rain Program.

Acid Rain Program

The Acid Rain Program established a national cap-and-trade program for SO₂ emissions from generating units, established NO_x emission limits for different boiler types, i.e., tangential fired vs. cyclone fired units, and required the installation of Continuous Emissions Monitors (CEM) on all coal-fired power plants to measure SO₂, NO_x, oxygen (O₂) and carbon dioxide (CO₂) on a continuous basis.

The Acid Rain Program required an SO₂ emissions cap of 15,000,000 tons in 1995 reduced to 10,000,000 tons in 2000 and to 8,950,000 tons in 2010. In addition, generating units are issued thirty (30) years of SO₂ allowances (1 allowance = 1 ton of SO₂ emissions). The SO₂ allowances can be bought, sold, traded, or banked. Three percent of the SO₂ allowances were held back and available for purchase at an annual EPA SO₂ auction.

Clean Air Interstate Rule (CAIR)

The CAIR established a new cap-and-trade program with lower limits on annual SO₂ and seasonal NO_x emissions from generating units, as well as a new cap and trade program for annual NO_x emissions. CAIR is a regional program and applies to electric generating units in 28 eastern states and the District of Columbia. For SO₂ emissions, CAIR established a cap of 5,000,000 tons nationally by 2010 and a cap of 3,500,000 million tons by 2015. CAIR has a two phase program for NO_x emissions; where NO_x emissions are capped annually, and seasonally in the 28 state CAIR region. Phase 1 began in 2009 and phase 2 was scheduled to begin in 2015. Prior to CAIR, the NO_x Budget Trading Program had created a seasonal NO_x emission cap and trade program for twenty-two (22) eastern states including eastern Missouri. The NO_x Budget Trading Program set a very low ozone season (May – September) cap on NO_x emissions by state and created NO_x allowances for the ozone season each year.

Other Clean Air Act Provisions

Section 126 of the CAA allows downwind states to file petitions against upwind states to control emissions in order to achieve attainment with ambient air quality standards.

The Regional Haze Rule is another provision of the CAA. The goal of the Regional Haze Rule is to set visibility equivalent to natural background levels by 2064 in Class I areas. In addition, the Regional Haze Rule is the basis for Best Available Retrofit

Technology (BART) rule setting SO₂ & NO_x control requirements for certain large emission sources and power plants in each state.

Maximum Achievable Control Technology (MACT) Standards

Title III of the Clean Air Act Amendments of 1990 included a requirement for the EPA to establish Maximum Achievable Control Technology (MACT) standards for 188 hazardous air pollutants identified in the Act. The Clean Air Act mandates that compliance with a MACT standard is required within three years of the final rule. The EPA has established MACT standards for numerous source categories including reciprocating internal combustion engines and recently cement kilns. The EPA continues to set MACT standards for other source categories and is expected to propose standards for coal- and oil-fired electric generating units (EGUs) in 2011.

Clean Air Transport Rule (CATR)

On July 6, 2010, the EPA proposed a rule which would replace the 2005 CAIR. A December 2008 court decision kept the requirements of CAIR in place temporarily but directed the EPA to issue a new rule to implement the Clean Air Act requirements concerning the transport of air pollution across state boundaries. The CATR was developed in response to the court's concerns. The rule is planned to be finalized in the spring of 2011. It will become effective in 2012 and replace the CAIR. The CATR will be implemented in two phases. The first phase will begin in 2012. The second phase will begin in 2014. The rule would reduce emissions in 31 states and the District of Columbia. When fully implemented in 2014, SO₂ emissions would be limited to 2.6 million tons per year. NO_x emissions would be limited to 1.3 million tons per year for the annual program and 600 thousand tons for the ozone season. The proposed rule contains three different approaches. The EPA's preferred approach is to allow intrastate trading and limited interstate trading of allowances among power plants but assures that each state will meet its pollution control obligations. Allowance allocations will not be determined until the final rule is issued. On January 4, 2011, the EPA released a Notice of Data Availability and proposed alternative allowance allocation methodologies. The allocation methodology will be chosen by the EPA and communicated to stakeholders in the final rule.

Revisions to the National Ambient Air Quality Standard (NAAQS) for NO₂

On January 22, 2010, the EPA revised the primary NAAQS for NO₂ by adding a one-hour 100 ppb standard. Because the EPA's main health concern was NO₂ concentrations attributable to mobile sources, the revisions included requirements for an expanded near-road NO₂ ambient monitoring network. However the standard also has an immediate impact on stationary sources seeking preconstruction permits. Attainment designations will be made by February, 2012. States with non-attainment areas that do not meet the standard are required to submit attainment plans by January, 2013. Compliance with the new NO₂ ambient standard is required by July, 2017.

Revisions to the National Ambient Air Quality Standard (NAAQS) for SO₂

The EPA adopted an SO₂ ambient standard of 75 ppb on June 2, 2010. The EPA also revoked the annual and 24-hour SO₂ NAAQS. Attainment designations will be made by July, 2012. States with non-attainment areas will be made to submit attainment plans by June, 2013. Compliance with the new SO₂ standard is required by 2017. The EPA also adopted a new approach for determining compliance with the new SO₂ standard. Instead of actually measuring the SO₂ concentration in ambient air, the EPA stated that modeling of major SO₂ sources would be required in lieu of ambient monitoring data to establish that an area attains the new NAAQS. Because of the conservatism of the EPA's models and modeling requirements, such modeling is likely to result in designation of many more nonattainment areas and additional control requirements for power plants.

8.2.2 Possible Future Air Environmental Initiatives

Global Climate Initiatives

Future initiatives regarding greenhouse gas emissions and global warming are actively being considered in the U.S. Congress. On June 26, 2009, the United States House of Representatives passed the American Clean Energy and Security Act of 2009 (ACES). This legislation was introduced by Representatives Henry Waxman (D-CA) and Edward Markey (D-MA). The cap and trade portion of the bill requires electric utilities to cut 2005 CO₂ emissions 17% by 2020, 42% by 2030, and 83% by 2050. ACES requires electric utilities, large-industrial sources and other entities that emit 25,000 tons or more per year of CO₂-equivalents to have tradable federal allowances for each ton emitted into the atmosphere. ACES is estimated to cover over 85% of the United States emissions of greenhouse gases (GHGs). ACES allocates allowances to the electric utility sector based on historical emissions and retail sales. In addition ACES contains a provision allowing emitting sources to use certified offsets (reductions in CO₂ emissions) from reductions made by sources in sectors not covered by the bill. However, the total quantity of offsets allowed in any year cannot exceed 2 billion tons, split evenly between domestic and international offsets. In addition, after 2017 entities that seek to use international offsets to meet their compliance obligation must submit 5 tons of offset credits for every 4 tons of emissions being offset. The bill also includes a Renewable Energy Standard that requires utilities to increase renewable energy generation to 20% by 2020.

The United States Senate began the hearing process to enact climate legislation. In 2010, the Senate passed climate legislation out of its Energy and Commerce Committee. However, the Senate leadership decided to not bring the bill to the floor for debate and vote in 2010.

While we cannot predict the date of enactment or the requirements of any climate change legislation, it is unlikely that some form of federal greenhouse gas legislation will become law prior to the next presidential election in 2012. If and when adopted, future climate change legislation is expected to have a significant impact on Ameren Missouri operations.

Regulation of Greenhouse Gases (GHG) under the CAA

With regard to greenhouse gas regulation under existing law, in April, 2007, the U.S. Supreme Court issued a decision that the EPA has the authority to regulate CO₂ and other greenhouse gases from automobiles as “air pollutants” under the CAA. This decision was a result of a Bush Administration ruling denying a waiver request by the state of California to implement such regulations. The Supreme Court sent the case back to the EPA, which must conduct a rulemaking process to determine whether greenhouse gas emissions contribute to climate change “which may reasonably be anticipated to endanger public health or welfare.” In late 2009, the EPA issued a finding that greenhouse gases contribute to air pollution that may endanger public health or welfare. As a result of that finding, the EPA subsequently issued the Tailoring Rule which would delay smaller sources from being subject to controlling CO₂ emissions. The rule will take effect on January 1, 2011. On December 23, 2010, the EPA announced a Settlement Agreement with states and environmental groups regarding setting greenhouse gas (GHG) new source performance standards (NSPS) for new and existing coal-, gas- and oil-based power plants. In this settlement EPA plans to rely on a little used provision of the Clean Air Act, Section 111(d), that gives EPA the authority to establish performance standards to reduce emissions for which there is no ambient standard. The EPA has made it clear they want the states to take the lead on establishing the GHG emission standards for existing power plants, and the states have considerable flexibility. It should be noted that EPA’s intent by this action is to have existing power plants reduce CO₂ emissions, presumably through energy efficiency or other plant modifications or operating restrictions. EPA plans to propose standards for both new and modified boilers under Clean Air Act section 111(b) and for existing facilities under section 111(d) by July 26, 2011, and finalize the rules by May 26, 2012.

Revisions to the National Ambient Air Quality Standard (NAAQS) for Ozone

The EPA lowered the ambient standard for ozone from 85 ppb to 75 ppb in 2008. In January, 2009, the EPA proposed to lower the standard to a range between 60 ppb and 70 ppb. EPA was required to finalize nonattainment designations for the 2008 standard in March, 2010, however the EPA granted a petition for reconsideration in September, 2009, and proposed to lower the standard in January, 2010. The EPA originally planned to finalize the revision by the end of August, 2010, but extended that date to December, 2010. On December 8, 2010, the EPA proposed to delay the final rule until July 2011. The final rule in July will start a new round on nonattainment designations and

subsequent state attainment plans for future controls. Under the EPA's original proposed accelerated schedule: states make recommendations for areas to be designated attainment by January, 2011; the EPA makes final area designations by July, 2011; states with areas that do not meet the standard are required to submit attainment plans by December, 2013; compliance with the new standard will be required by 2014 to 2031 depending on the severity of the problem. The delay in the rule will push the schedule back about one year.

Revisions to the National Ambient Air Quality Standard (NAAQS) for Fine Particulate (PM_{2.5})

On Feb. 24, 2009, the D.C. Circuit Court of Appeals remanded to EPA several aspects of its 2006 decisions on the PM_{2.5} NAAQS. The Court stated that the EPA had not provided a legally sufficient explanation for its decision to keep the existing annual primary standard of 15 $\mu\text{g}/\text{m}^3$. As a result of the decision, the EPA has folded its response to the remand into the next regular review of the NAAQS. The EPA announced a schedule that calls for a proposal to revise the annual PM_{2.5} standard in February, 2011, and for a final rule in October, 2011, to satisfy the 5-year review requirement of the CAA. It is likely that the EPA would make nonattainment designations for the new annual PM_{2.5} standard in 2013 or 2014, and that compliance with the standard would be in 2018 or 2019.

Initiatives to Control Mercury and Other Hazardous Air Pollutants

In 2005, the EPA promulgated the Clean Air Mercury Rule (CAMR), which defined the mercury monitoring and control requirements for coal-fired power plants over the next ten years. In 2008, the rule was vacated by a Federal Court and remanded to the EPA. In 2009, the EPA dropped its challenge to the court decision. The EPA is planning to replace the CAMR rule with a MACT standard for mercury and other hazardous air pollution emissions from power plants and is required by a consent decree to propose regulations in March, 2011, and finalize regulations in November, 2011. A MACT standard essentially requires the application of the most effective demonstrated pollution reduction equipment commercially viable. It is unclear whether the planned technology for mercury control - namely Activated Carbon Injection - will be acceptable as MACT control for power plants. If it is not, then Flue Gas Desulfurization (FGD) or other technology may be required on all power plants. The EPA is also developing MACT standards for other hazardous air pollutants, such as metals, acids and organics, for power plant emissions. It is unclear at this time what additional technology will be required to control such emissions. EGUs could be required to install additional pollution control equipment including FGD for acid gases (HCl and HF), and particulate controls such as fabric filters for trace metals including



arsenic, chromium, lead and nickel. The EPA conducted an extensive information collection request to obtain emission data from existing units and will use that information to set the standard for each hazardous air pollutant of concern.

8.3 Major Water Environmental Laws

8.3.1 Current Laws

Clean Water Act (Amended 1972)

The Clean Water Act (CWA) establishes pollutant specific water quality standards for various water bodies and groundwater. In addition, the CWA includes provisions to prevent degradation of higher quality waters. This includes a regulatory program covering Total Maximum Daily Load (TMDL) of “pollutants” allowed into waters of the state. Protection of water resources for industrial facilities typically occurs through the National Pollutant Discharge Elimination System (NPDES) permit process. Technology and water quality based effluent limitations are applied to ensure water quality standards are met. In order to meet permit conditions it may be necessary to modify operations or install additional water pollution control equipment to meet a pollutant specific water standard.

Clean Water Act, Section 316 (a) Thermal Discharges

Section 316 (a) of the CWA requires limitations on thermal discharges from power plants and other industrial sources. Power plant cooling water discharges are regulated by EPA and the Missouri Department of Natural Resources (MODNR) through the NPDES permit program. Thermal effluent permit limitations and/or state water quality temperature standards may require the installation of technology - such as cooling towers, cooling lakes or separate discharge streams.

Clean Water Act, Section 316 (b) Entrainment and Impingement of Aquatic Organisms

Section 316 (b) of the CWA was established to protect fish and other aquatic habitat from detrimental impacts associated with industrial sources. At power plants, aquatic organisms can be impinged and entrained within cooling water intake structures/piping and condenser systems. The EPA and MODNR establish rules to limit adverse impacts associated with cooling water intake structure operation through the NPDES permit process. Rules can take the form of performance and/or design criteria, or the utilization of specific control technologies. The impingement and entrainment of threatened or endangered species at a cooling water intake structure can also result in the need for additional operational and physical changes.

Clean Water Act-Wetlands

Construction projects involving “dredge and fill” (earth disturbance) within identified wetlands/streams can require mitigation, based on the total number of acres impacted.

Mitigation involves establishment of replacement wetlands at a ratio of anywhere from 1:1 up to 4:1.

Clean Water Act-Spill Prevention Control and Countermeasures (SPCC) Program

The CWA requires spill prevention plans and containment systems be developed for substations and other electrical equipment installations where 1,320 gallons of oil or more in aggregate are present and there is potential for discharge into surface water. These EPA rules have been revised to clarify that electrical equipment is subject to these rules and are currently scheduled to become final in November 2011. Ameren Missouri has about 650 substations in Missouri that may be subject to these rules. Ameren Missouri has developed a program to assess the risk of oil spills to surface waters for these locations.

Safe Drinking Water Act (1974)

The Safe Drinking Water Act was established to protect the quality of drinking water. The Safe Drinking Water Act establishes monitoring frequency and standards for contaminants and requires public notifications and corrective actions when standards are exceeded. MODNR has primacy to establish regulations and enforce compliance.

8.3.2 Possible Future Water Environmental Initiatives

Clean Water Act, Section 316 (a) Thermal Discharges

Thermal discharges – Power plant cooling water discharges are regulated by the EPA and MODNR through the NPDES permit program. Currently the State of Missouri and the EPA are working on new NPDES permits for Ameren Missouri power plants. Early indications suggest there may be difficulties in meeting revised thermal effluent permit limitations and/or state water quality temperature standards. If these limitations cannot be met, a variance may be sought through section 316 (a) of the CWA, or the facility may be required to install cooling towers. The pursuit of a 316 (a) variance would require environmental field studies focused on aquatic impacts coupled with an evaluation of hydrologic/thermal modeling of cooling water plume characteristics. If a 316 (a) variance demonstration is not successful, existing power plants could be required to reduce generation under certain operating conditions, or undertake infrastructure retro-fits to accommodate the installation of cooling towers. Cooling tower retro-fits will require substantial engineering, design and construction, including possible replacement of condensers. Property acquisition may be necessary at some locations. Cooling tower installations would increase parasitic load requirements and decrease overall plant efficiency.



Clean Water Act, Section 316 (b) Entrainment and Impingement of Aquatic Organisms

The EPA is in the process of revising Section 316 (b) regulations as a result of court challenges to the rule which culminated in Supreme Court decisions in December, 2008, and April, 2009. The rules are designed to limit adverse impacts associated with cooling water intake structure operation through the NPDES permit process. Rules can take the form of performance and/or design criteria, or the utilization of specific control technologies. Control technologies may include the replacement and utilization of a different traveling screen design or other totally different technology. Modified traveling screen designs may incorporate the use of "fine mesh" screens with a low pressure spray wash system to return large and small aquatic organisms to the water body downstream of the intake structure. They may also require the installation of specialized fish collection systems (fish baskets) on the bottom of each traveling screen section. Regulatory agencies may require extensive environmental sampling/testing/studies to demonstrate compliance with performance standards. In order to reduce water approach velocities, and subsequent impingement and entrainment, it may also be necessary to modify and expand the physical size of the intake structure. The EPA may also have the discretion to mandate cooling tower retro-fits at all existing plant sites. The impingement and entrainment of threatened or endangered species at a cooling water intake structure can also result in the need for operational and physical modifications up to and including cooling tower retro-fits. The EPA is obligated by a Court settlement to propose revisions to the CWA 316(b) regulations by March 14, 2011, and finalize the regulations by July 27, 2012.

Clean Water Act, Effluent Guidelines Limitations

Effluent guidelines are established by the EPA to reduce the discharge of pollutants in wastewater from steam electric power plants using nuclear or fossil fuels. The guidelines form the "backbone" for state regulation for Ameren's power plants. The existing steam electric effluent guidelines were last revised in 1982. The EPA conducted a detailed study report in 2008 and determined that steam electric ash ponds and flue gas desulfurization systems are the source of many wastewater pollutants. The EPA is in the process of evaluating the existing effluent limit guidelines (ELGs) for steam electric power plants. In 2010, the EPA issued an information collection request (ICR) to collect data about steam electric power generating plant water discharges. Ameren completed and submitted a response to the ICR in September 2010.

In response to challenges by Environmental groups, the EPA agreed to a consent in November, 2010. The consent required the EPA to propose revisions to the effluent guideline limitations by July 23, 2012, and finalize the revisions by January 31, 2014. States will be required to implement the revisions through regulations and permits. It is expected that the revised effluent guideline limitations will be linked to the final coal

combustion residual (CCR) rule and there is a possibility that additional wastewater treatment will be required to meet more stringent effluent limitations. The scope of the impacts cannot be determined until the proposed revisions are released by the EPA.

8.4 Major Solid Waste Environmental Laws

8.4.1 Current Laws

Resource Conservation and Recovery Act (RCRA - 1976)

RCRA regulates generation, transportation, treatment, storage and disposal of hazardous wastes including solvents, lead, mercury, acids, caustics, and other chemicals; regulates underground storage tanks; and regulates the management of used oil. Currently, RCRA provides guidance on the proper management of solid wastes which includes coal combustion products (i.e. ash disposal).

Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA - 1980), Superfund Amendments Reauthorization Act (SARA - 1986)

CERCLA was initially established as a tax on the petroleum and chemical industries. Then SARA was added to increase the trust fund from \$1.6 to \$8.5 billion. The fund is used to respond to major chemical/petroleum accidents and cleanup historic hazardous waste sites. CERCLA requires release reporting for chemicals that are released into the environment that exceed listed reportable quantities in any twenty-four (24) hour period. In addition, CERCLA required the identification of former sites where hazardous waste had been disposed. The EPA identifies major sites for cleanup actions and places sites with highest risk on the National Priorities List (NPL). CERCLA established joint and several liability for certain categories of entities, such as owners and operators of property upon which hazardous substances are located. Such strict liability can extend to successor companies. Companies that did business with cleanup site owners can also be considered potentially responsible parties (PRPs).

Ameren Missouri has environmental clean-up liabilities under CERCLA for the clean-up of ten (10) former coal gas manufacturing facilities [manufactured gas plant (MGP) sites] in Missouri. In addition, Ameren Missouri has environmental cleanup liabilities under CERCLA for the clean-up of various other types of sites. These liabilities generally result from sending oil-filled electrical equipment with polychlorinated biphenyls (PCBs) to contractors that have caused releases in the course of their business and cannot pay for cleaning up their property; and substations built on former landfills and industrial sites that represent environmental concerns.

Toxic Substances Control Act (TSCA - 1976)

TSCA established regulations to track 75,000 industrial chemicals in the workplace and requires manufacturers to perform hazard assessments related to their products. Also,

TSCA requires specific labeling, inspection, storage, spill cleanup, and disposal requirements for PCBs greater than 50 parts per million (ppm).

Emergency Planning & Community Right-To-Know Act (EPCRA - 1986)

EPCRA was established to help communities protect public health & safety from chemical hazards. EPCRA set up State and Local Emergency Planning and Response Agencies and requires that chemical inventory reports be filed by covered facilities with the local fire department as well as local and state emergency response agencies identifying the locations of hazardous oil and listed chemicals above threshold quantities. EPCRA requires an annual Toxic Release Inventory (TRI) report for each covered facility which exceeds reporting thresholds for various chemical constituents that are released into the environment.

8.4.2 Possible Future Solid Waste Environmental Initiatives

Ash Pond Initiatives

The Tennessee Valley Authority (TVA) ash pond failure in December, 2008, has the potential to change the company's management of ash and other coal-combustion products because it has refocused Congress and the EPA's attention on ash. In 2000, EPA considered classifying ash as a hazardous waste, but decided to classify it as non-hazardous and intended to prepare guidance for State regulations. The electric industry had been working since that time to provide the EPA with information it wanted without additional regulation through the development of a plan that would include voluntary installation of groundwater monitoring at plants. On June 21, 2010, the EPA proposed regulations to regulate coal combustion residuals (CCR). The proposal included two regulatory options: (1) regulating CCRs as so-called "special wastes" under the hazardous waste program of RCRA Subtitle C; and (2) regulating CCRs as non-hazardous wastes under Subtitle D of RCRA. Under the Subtitle C option, the management of CCRs in surface impoundments would have to cease within five years of the effective date of the rules and the impoundments would have to close within two years after the cessation of operations (allowing a possible total of seven years for closing impoundments after the effective date of the rules). A hazardous waste classification for ash, even temporarily, could end most if not all beneficial uses for ash due to the potential user's avoidance of materials that have uncertain regulatory status. The EPA held several public hearings across the country and the public comment period closed on November 19, 2010. It is anticipated that the EPA will issue the final rule in late 2011. It is possible that the final rule could also include requiring closure of ash ponds within some time frame and removal of ash to landfills. The Company has begun building landfills to replace filled ponds, but some are only in the early planning phase and early closure of ponds would result in significant expenditures, in the tens of

millions of dollars per site, to deal with the loss of those pond assets, changes to schedules, as well as possible modifications to the plants.

Ash Pond Closure Initiatives

Historically, coal ash has typically been wet sluiced into ash ponds. Ash ponds are permitted as wastewater treatment devices under the Missouri water permit program and are subject to closure requirements when they are excluded from the water permit process. Ash pond closures may require an evaluation of groundwater conditions and the development of a closure plan that includes an impervious cap and vegetative cover. Sub-surface water conditions may warrant the installation of a groundwater collection and treatment system and/or the acquisition of additional properties. Long term monitoring of groundwater conditions and the integrity of the cap and vegetation may be required. Since there are no specific regulations regarding the requirements for ash pond closures, costs for closures remain uncertain. It is possible that permanent closures could cost millions of dollars at each power plant, and ongoing O&M costs could be in the hundreds of thousands of dollars per site annually. Also, the permanent closure of the ponds would require substantial capital and O&M costs for new wastewater treatment plants to treat low volume wastewater that had flowed to the ash ponds.



8.5 Other Environmental Laws

National Environmental Policy Act of 1969 (NEPA)

The NEPA was established to provide requirements for federal agencies issuing permits/licenses to ensure full review and disclosure of environmental risks involved in construction and operation of facilities- including cultural resources under the National Historic Preservation Act (NHPA) and threatened and endangered species under the Endangered Species Act (ESA). NEPA compliance is required for major construction projects including new generating plants and new gas pipelines or transmission lines. A full Environmental Impact Statement (EIS) is triggered if construction activity will be permitted by a Federal Agency *and* is deemed to have a significant impact on the environment. An Environmental Assessment (EA) is required for less significant construction.

National Historic Preservation Act (1966)

This Act established measures to ensure historic properties [significant landmarks, structures or buildings, and prehistoric (archeological) sites] are adequately safeguarded and protected, or mitigated for, from new construction activities.

Endangered Species Act (ESA - 1973)

ESA was established to protect rare and endangered species and their habitats from adverse impacts resulting from construction projects or other activities. Under NEPA, federally permitted projects must undergo review by United States Fish and Wildlife Service (USFWS) for assessment of potential impacts. Coordination with the state agency (Missouri Department of Conservation) and compliance with their regulations is also applicable to the Migratory Bird Treaty Act (1918)

Under this Act, all native birds are fully protected from “take,” including their eggs and nests and parts (e.g. feathers), except for game species for which seasons/limits are established. The Act established penalties/fines for violations. USFWS is the primary federal agency with authority to enforce.

Bald and Golden Eagle Protection Act (1940)

This Act established full protection from “take” for the Bald and the Golden Eagle, including their nests and eggs and parts (e.g., feathers). The Act established penalties/fines for violations. USFWS is the primary federal agency with authority to enforce.

Rivers and Harbors Act (1899)

Under this Act, construction projects that cross navigable waterways (e.g., electric/gas transmission lines) must apply for a permit from the United States Army Corps of Engineers (USACE) under Section 10 of the Rivers and Harbors Act. Review of impacts under NHPA, ESA, CWA etc. are required under NEPA, should a Section 10 permit be required.

Local Ordinances

Ameren Missouri facilities are subject to many local environmental ordinances. For example, St. Louis County has a local noise ordinance which restricts noise from commercial or industrial operations to the surrounding environment. Construction activities, equipment specifications and noise attenuations are sometimes required to meet these standards.

8.6 Tritium and Other Noble Gases¹

8.6.1 Overview

Tritium is a naturally occurring radioactive form of hydrogen that is produced in the atmosphere when cosmic rays collide with air molecules. As a result, tritium is found in very small or trace amounts in groundwater throughout the world. It is also a byproduct of the production of electricity by nuclear power plants. Tritium emits a weak form of radiation, a low-energy beta particle similar to an electron. The tritium radiation does not

¹ EO-2007-0409 – Commission Order for 4 CSR 240-22.040(1)(K)

travel very far in air and cannot penetrate the skin. A radiation dose from tritium is the same as from any other type of radiation, including natural background radiation and medical administrations.

Tritium is almost always found as a liquid and primarily enters the body when people eat or drink food or water containing tritium or absorb it through their skin. People can also inhale tritium as a gas in the air. Once tritium enters the body, it disperses quickly and is uniformly distributed throughout the soft tissues. Half of the tritium is excreted within approximately 10 days after exposure. Everyone is exposed to small amounts of tritium every day because it occurs naturally in the environment and the foods we eat. Workers in Federal weapons facilities; medical, biomedical, or university research facilities; or nuclear fuel cycle facilities may receive increased exposures to tritium.

Most of the tritium produced in nuclear power plants stems from a chemical, known as boron, absorbing neutrons from the plant's chain reaction. Nuclear reactors use boron, a good neutron absorber, to help control the chain reaction. Toward that end, boron either is added directly to the coolant water or is used in the control rods to control the chain reaction. Much smaller amounts of tritium can also be produced from the splitting of Uranium-235 in the reactor core, or when other chemicals (e.g., lithium or heavy water) in the coolant water absorb neutrons.

Like normal hydrogen, tritium can bond with oxygen to form water. When this happens, the resulting water (called "tritiated water") is radioactive. Tritiated water (not to be confused with heavy water) is chemically identical to normal water and the tritium cannot be filtered out of the water.

Nuclear power plants routinely and safely release dilute concentrations of tritiated water. These authorized releases are closely monitored by the utility and are reported to the NRC. These releases are at fractions of the natural background production rates of tritium. To put the amount of tritium released from nuclear power plants in perspective, it is estimated that during 2009 at Ameren Missouri's Callaway plant, 4.6 drops of tritiated water was mixed with 204 million gallons of water at the plant for batch discharges to the Missouri River and mixed with 1,362 billion gallons of river water.

8.6.2 Current Radiation Protection Limits

The NRC is continuously evaluating the latest radiation protection recommendations from international and national scientific bodies to ensure the adequacy of the standards the agency uses. Among those standards, the NRC and the EPA have established three layers of radiation protection limits to protect the public against potential health risks from exposure to radioactive liquid discharges (effluents) from nuclear power plant operations. The NRC has determined that doses to the general public from the unintended release of tritium at nuclear power plants are significantly below even the

most stringent layer of these protective limits and, therefore, does not pose a risk to public health and safety.

Layer 1: 3 mrem per year ALARA objective — Appendix I to 10 CFR Part 50

The NRC requires that nuclear plant operators must keep radiation doses from gas and liquid effluents as low as reasonably achievable (ALARA) to people offsite. For liquid effluent releases, such as diluted tritium, the ALARA annual offsite dose objective is 3 mrem to the whole body and 10 mrem to any organ of a maximally exposed individual who lives in close proximity to the plant boundary. This ALARA objective is 3% of the annual public radiation dose limit of 100 mrem.

The NRC selected the 3 mrem and 10 mrem per year values because they are a fraction of the natural background radiation dose, a fraction of the annual public dose limit, and an attainable objective that nuclear power plants could realistically meet. Power plants that meet these objectives are considered to be ALARA in reducing exposures to the general public from nuclear power plant effluents (AEC 1971, NRC 1975).

Nuclear power plant operators must monitor the authorized releases (effluents) from their plants. If a given nuclear power plant exceeds half of these radiation dose levels in a calendar quarter, the plant operator is required to investigate the cause(s), initiate appropriate corrective action(s), and report the action(s) to the NRC within 30 days from the end of the quarter.

Layer 2: 25 mrem per year standard — 10 CFR 20.1301(e)

In 1979, the EPA developed a radiation dose standard of 25 mrem to the whole body, 75 mrem to the thyroid, and 25 mrem to any other organ of an individual member of the public. The NRC incorporated these EPA standards into its regulations in 1981, and all nuclear power plants must now meet these requirements. These standards are specific to facilities that are involved in generating nuclear power (commonly called the “uranium fuel cycle”), including where nuclear fuel is milled, manufactured, and used in nuclear power reactors. The EPA determined the basis of the standards by comparing the cost-effectiveness of various dose limits in reducing potential health risks from operation of these types of facilities. The EPA assumed the standards would be able to be met for up to four fuel cycle facilities (e.g., four reactors) at one location (EPA, 1976a). Notably, the NRC’s ALARA objectives are lower than these EPA standards (NRC, 1980).

Layer 3: 100 mrem per year limit – 10 CFR 20.1301(a)(1)

The NRC’s final layer of protection of public health and safety is a dose limit of 100 mrem per year to individual members of the public. This limit applies to everyone, including academic, university, industrial, and medical facilities that use radioactive material.

The NRC adopted the 100 mrem per year dose limit from the 1990 Recommendations of the International Commission on Radiological Protection (ICRP). The ICRP is an organization of international radiation scientists who provide recommendations regarding radiation protection related activities, including dose limits. These dose limits are often implemented by governments worldwide as legally enforceable regulations. The basis of the ICRP recommendation of 100 mrem per year is that a lifetime of exposure at this limit would result in a very small health risk and is roughly equivalent to background radiation from natural sources (excluding radon) (ICRP, 1991). Thus, the ICRP equated 100 mrem per year to the risk of riding public transportation – a risk the public generally accepts (ICRP, 1977). The U.S. National Commission on Radiological Protection and Measurements (NCRP) also recommends the dose limit of 100 mrem per year (NCRP, 1993).

For liquid effluents, including tritiated water, any licensee can demonstrate compliance with the 100 mrem per year dose standard by not exceeding the concentration values specified in Table 2 of Appendix B to 10 CFR Part 20. These concentration values, if inhaled or ingested over the course of a year, would produce a total effective dose of 50 mrem.

8.6.3 Possible Future Radiation Protection Limits

Ameren Missouri believes it is very unlikely that the Nuclear Regulatory Commission (NRC) will revise the regulations associated with effluent releases of tritium since there are no proposals from the EPA, NRC, or legislature to change the regulations associated with tritium or other noble gas releases. Furthermore, the NRC has stated that the NRC's statutory authority in the Atomic Energy Act of 1954, as amended, is limited to regulation based on "health and safety of the public" (see section 3 of the AEA). The NRC has also stated that promulgation of any rule that would result in a change to an existing system or structure, such as would be required to prevent tritium in effluents, would need to meet the standard of the backfit rule such that any backfitting would achieve a substantial increase in the overall protection of the public health and safety and that the costs of the backfitting, both direct and indirect, are justified in light of the overall increased protection. The NRC has evaluated possible regulatory changes which would result in lower quantities of tritium released to the environment and concluded that the NRC does not have the statutory authority to make such changes. The NRC also concluded that attempts to establish more restrictive regulatory limits on effluent releases, such as for tritium, would not meet the requirements of the backfit rule.

Ameren Missouri investigated two levels of mitigation more stringent than current requirements: 50% and 90% reductions in the maximum allowed doses due to liquid

effluents including tritium. These reductions would be applied to the NRC's most restrictive limits.

To assess the impact of the reduction in dose incurred to effluent tritium, the most restrictive ALARA limits were chosen. Shown in the Table 8.1 is the dose due to liquid effluents over the last 3 years of power operations at Callaway Unit 1, the ALARA limits, and more stringent effluent dose limits.

Table 8.1

ALARA Dose Location	Dose due to Liquid Effluents*	Dose due to tritium in Liquid Effluents*	Current Limits	50% Reduction	90% Reduction
Whole Body	0.0144	0.0019	3	1.5	0.3
Maximum Organ	0.0203	0.0019	10	5	1

*Average Actual 2007-2009

As shown in Table 8.1, even with reductions in the most restrictive NRC regulated allowable dose limits associated with effluent releases, the Callaway Plant Unit 1 would still only release a small fraction (less than 5%) of the most stringent limit (90% reduction). Therefore there is no additional cost to meet the analyzed reductions in tritium effluents.

A similar case can be made for gaseous effluents which includes the radioactive noble gases krypton and xenon that are released from Callaway Unit 1. Table 8.2 compares the dose due to gaseous effluents (includes krypton and xenon) with more stringent effluent dose limits.

Table 8.2

ALARA Dose Location	Dose due to Gaseous Effluents*	Current Limits	50% Reduction	90% Reduction
Gamma Air ⁽¹⁾	0.0016	10	5	1
Beta Air ⁽¹⁾	0.0041	20	10	2
Maximum Organ ⁽²⁾	0.0089	15	7.5	1.5

*Average Actual 2007-2009

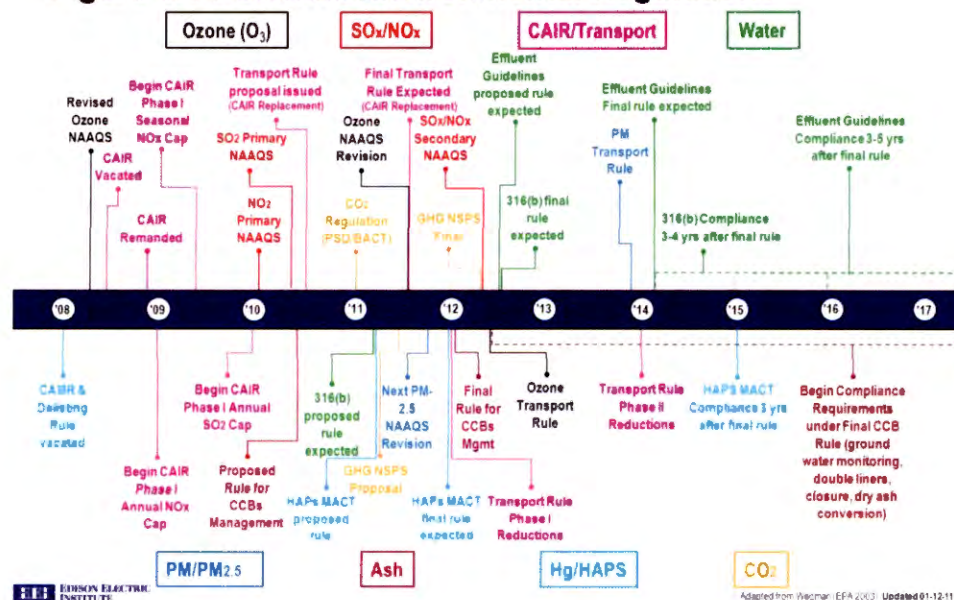
- (1) – Gaseous effluent air doses are based on a hypothetical individual standing at the site boundary throughout the year. (mrad)
- (2) – Gaseous effluent maximum organ doses are based on a hypothetical child residing at the nearest residence giving the highest dose and assumes all of the child's food and milk are produced at that location. (mrem)

As shown in Table 8.2, even with reductions in the NRC regulated allowable dose limits associated with effluent releases, the Callaway Plant Unit 1 would still only release a small fraction (less than 1%) of the most stringent limit (90% reduction). Therefore, there is no additional cost to meet the analyzed reductions in radiological gaseous effluents (including krypton and xenon).

8.7 Environmental Scenarios

An area that has received a great deal of focus and attention over the last several years has been environmental regulations. In particular, the U.S. Environmental Protection Agency (EPA) is expected to issue new environmental regulations in the next 12 to 24 months related to air emissions, ash waste and water. Figure 8.1 highlights some of the regulations under consideration.

Figure 8.1 Potential Environmental Regulations



In order to support analysis of environmental uncertainty, Ameren Missouri has developed two scenarios regarding future environmental laws. The two scenarios, moderate and aggressive, are characterized by the type of control technology required to meet increasingly stringent environmental laws. Table 8.3 summarizes the impacts to Ameren Missouri generating facilities. It should be noted that the planning scenarios described in Chapter 2 already contain multiple alternatives for carbon regulation.

Table 8.3 Environmental Scenario Impacts

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

Therefore these environmental scenarios are designed to describe impacts of various other environmental regulations. The associated impacts of these environmental scenarios are incorporated into the IRP risk analysis (Chapter 9) and strategy selection (Chapter 10). Ameren Missouri also evaluated the financial impacts associated with the capital requirements needed to comply with these more stringent environmental scenarios (Chapter 10).

Table 8.4 summarizes the environmental policy changes for both scenarios and the following sections provide additional details.

Table 8.4 Summary of Environmental Scenarios

Moderate	Aggressive (Moderate plus...)
• EPA Transport Rule (CAIR Replacement) • MACT covers Mercury Only • EPA Regulations for Carbon Initially, but Future Projects Do Not Trigger GHG Controls • No Changes to Current State on Coal Ash (Use Existing Ash Ponds) • No Additional Wastewater Treatment Required	• Federal GHG Legislation in 2018-20 with Allowance Trading and Offsets • Future Projects Trigger BACT for GHG • MACT covers Acid Gases (HCl, HF) and metals –compliance by 1/1/2016 (FGD for most units) • Conversion to Dry Ash Handling; Closure of Existing Ash Ponds • Wastewater treatment plants needed for low volume wastewater when ash ponds closed – compliance by 1/1/2017 • Wastewater treatment for FGD discharge unless closed loop system • Limited Requirement for Cooling Towers – compliance by 1/1/2018

8.7.1 Moderate

The moderate environmental scenario assumes that the Clean Air Transport Rule as proposed by the EPA in the summer of 2010 is enacted as proposed and becomes effective by 2015. The proposed rule allows for some trading among utilities. This is the only regulation enacted to address SO₂ and NO_x emission issues. The scenario assumes the MACT HAPs (maximum achievable control technology for hazardous air pollutants) rules will only apply to mercury control. These rules become effective in 2018. It is assumed that a high level of mercury control will be achieved with investments in fuel additives or co-benefits from other control technology installations. The scenario assumes that EPA regulations on CO₂ do not require the installation of GHG controls. The scenario assumes that coal ash is not re-classified as a hazardous waste. As a result the existing ash ponds are assumed to be able to be used for disposal of ash. Also, current beneficial use of ash is allowed to continue. No

additional waste water treatment is required. Finally, to address water issues the scenario assumes that only fine mesh screens will be required on cooling water intake structures to address any entrainment and impingement issues associated with fish larvae mortality. No cooling towers are required to address thermal discharge issues.

8.7.2 Aggressive

The aggressive environmental scenario assumes that the Clean Air Transport Rule as proposed by the EPA in the summer of 2010 is enacted as proposed and becomes effective by 2012. The proposed rule allows for some trading among utilities. The scenario assumes the MACT HAPs (maximum achievable control technology for hazardous air pollutants) rules apply to acid gases and metals in addition to mercury. These rules become effective in 2016. It is assumed that to achieve compliance with these stringent regulations flue gas desulfurization equipment will be required on most units. The scenario assumes that EPA regulations on CO₂ trigger best available control technology (BACT) requirements for GHG for future projects. The scenario assumes federal GHG legislation becomes effective in the 2018-2020 time period. That legislation would allow allowance trading and use of offsets. The scenario assumes that coal ash is regulated under federal rules. As a result the existing ash ponds are required to be closed by 2017. Also, current beneficial use of ash is no longer possible due to liability issues and all units must be converted to dry ash handling for both fly ash and bottom ash. Waste water treatment plants are needed for low volume wastewater when ash ponds are closed. Also, wastewater treatment of scrubber discharge is required unless it is a closed loop system. All of the waste water treatment must begin by 2017. Finally, to address water issues the scenario assumes that fine mesh screens will be required on cooling water intake structures to address any entrainment and impingement issues associated with fish larvae mortality by 2017. Also, some cooling towers will be required to address thermal discharge issues by 2017.

8.8 Technology Characterization

Below is a description of the control options determined to be necessary to comply with the potentially more stringent environmental regulations described above.

Flue-Gas Desulfurization (FGD) is an emission control technology whose primary purpose is to remove sulfur dioxide (SO₂) from the exhaust gases of coal fueled power plants. There are different types of FGD's. For the purpose of this analysis, it is assumed to be a wet scrubber which uses limestone as the sorbent. A wet FGD is generally able to remove about 95-98% of the SO₂ emissions.

Activated Carbon Injection (ACI) is a system used to remove gas phase mercury (elemental or oxidized) from the exhaust gases of coal fueled power plants. Activated carbon is injected into the ductwork where it comes in contact with gas phase mercury.

The gas phase mercury attaches to the carbon and is removed in an electrostatic precipitator or fabric filter.

Fine Mesh Screens are screens installed on cooling water intake structures to minimize the number of fish larvae drawn into the cooling system. The screens are designed to address entrainment and impingement issues.

Ash & Landfill systems are designed to take the ash and other waste streams and isolate them from any groundwater systems or streams. The likely method of handling will change from wet handling to dry handling. That will result in more costs for the additional processing. In addition, if ash is classified as a hazardous waste the landfill would have to meet all the specifications of a hazardous landfill.

Cooling Towers are heat removal devices used to cool water used in the production of electricity so it can be reused in the generation of electricity. Cooling tower retrofits would eliminate thermal discharges from once-through systems currently being used by Ameren Missouri except at its Callaway plant. These plants currently discharge warm water into the Mississippi and Missouri rivers.

Wastewater Treatment Plants treat the waste water of power plants so that it can be reused in the plant to minimize total water discharge and so that the discharged water complies with effluent quality requirements.

Table 8.5 Characterization of Environmental Control Options

Plant	Control Technology	Nominal 2010 \$MM	2010 \$/kW	Heat Rate Reduction (%)	Capacity Reduction (MW)	Fixed O&M (\$/kW-Year)	Variable O&M (\$/MWh)	Construction Period
Labadie	FGD (Scrubber)	1,103	459	1.5	46	4.49	0.47	5
	ACI (Mercury)	11	5	--	--	0.01	0.32	2
	Fine Mesh Screens	16	7	--	--	0.07	--	2
	Ash & Landfill	120	50	--	--	0.64	0.31	3
	Cooling Tower	400	166	--	20	0.15	0.12	4
	Wastewater Plant	125	52	--	--	0.16	0.40	4
Meramec	FGD (Scrubber)	622	740	1.5	23	6.05	0.65	4
	ACI (Mercury)	10	12	--	--	0.01	0.32	2
	Fine Mesh Screens	13	15	--	--	0.15	--	2
	Ash & Landfill	76	91	--	--	0.96	0.69	3
	Cooling Tower	--	--	--	--	--	--	--
	Wastewater Plant	75	89	--	--	0.27	0.40	4
Rush Island	FGD (Scrubber)	620	525	1.5	23	6.95	0.33	5
	ACI (Mercury)	6	5	--	--	0.01	0.32	2
	Fine Mesh Screens	16	14	--	--	0.14	--	2
	Ash & Landfill	42	35	--	--	0.49	0.57	3
	Cooling Tower	--	--	--	--	--	--	--
	Wastewater Plant	100	85	--	--	0.25	0.40	4
Sioux	FGD (Scrubber)	--	--	--	--	--	--	--
	ACI (Mercury)	6	6	--	--	0.02	0.32	2
	Fine Mesh Screens	13	13	--	--	0.13	--	2
	Ash & Landfill	119	120	--	--	1.80	0.68	3
	Cooling Tower	--	--	--	--	--	--	--
	Wastewater Plant	100	101	--	--	0.30	0.40	4

8.9 Compliance References

EO-2007-0409 – Commission Order for 4 CSR 240-22.040(1)(K)	15
--	----

9. Modeling and Risk Analysis

Highlights

- *Alternative resource plans were developed by considering 5 attributes: supply-side resource type, Meramec status, DSM portfolio, RES requirements, and Noranda status.*
- *Among 216 alternative resource plans, 16 preliminary candidate resource plans were selected for further analysis.*
- *The sensitivity analysis identified 3 critical independent uncertain factors: Interest Rates, DSM Impacts and Cost, and Project Cost*
- *Incorporating the Meramec retirement analysis with the initial risk analysis results ultimately led to the selection of 14 candidate resource plans to be evaluated in the Strategy Selection.*

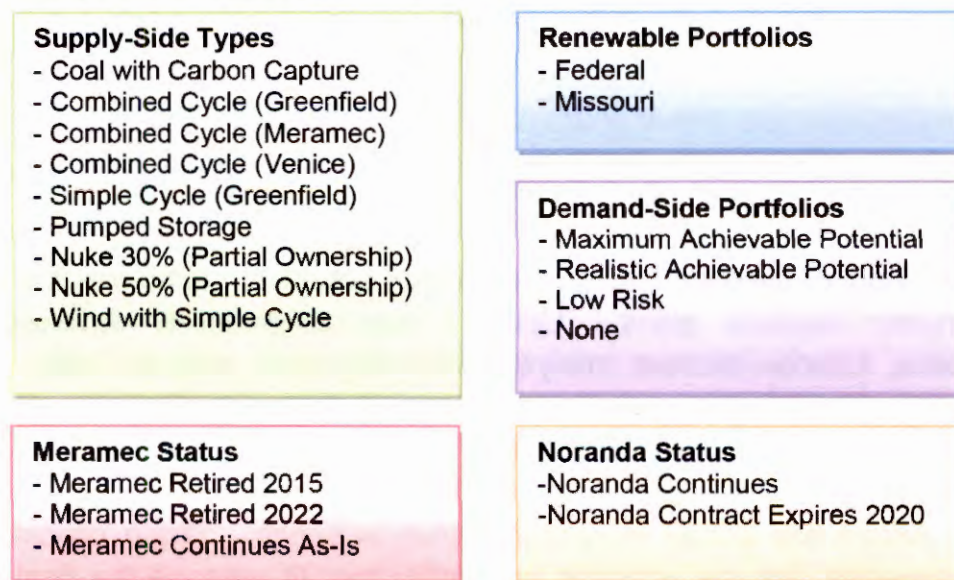
The modeling and risk analysis consisted of several major activities. First was the development of alternative resource plans. Using 5 plan attributes to develop alternative resource plans, Ameren Missouri analyzed 216 alternative resource plans. Next was a screening process based on a scorecard approach that embodied several measures linked to Ameren Missouri policy objectives. With the 16 plans that passed the initial screening process, a sensitivity analysis was performed to determine which independent uncertain factors are critical to resource plan selection. Those critical factors were then incorporated into the scenario probability tree to produce the final probability tree. The initial risk analysis, which incorporated all the critical uncertain factors, helped to further reduce the number of options to be included in candidate resource plans and supported the incorporation of the Meramec retirement analysis. Another round of risk analysis provided risk adjusted PVRs for the 14 candidate resource plans.

In Chapter 10 – Strategy Selection, Ameren Missouri takes an even closer look at the performance of the plans by introducing real-world ratemaking and financial constraints. These constraints help us to better understand the implications of adopting capital intensive plans or an aggressive energy efficiency plan. Ameren Missouri is then able to expand the scorecard to include additional measures based on its policy objectives and ultimately select an appropriate strategy that accounts for trade-offs across multiple planning objectives.

9.1 Alternative Resource Plans¹

Developing alternative resource plans includes the combination of various demand-side and supply-side resources to meet future capacity needs. However, there are other factors that could cause dramatic changes in the capacity position that need to be considered when developing plans. Figure 9.1 includes the five dimensions considered during the development of resource plans. The permutations of these five dimensions would create 432 plans. However, in practice, some combinations may create duplicate resource plans or plans that do not make sense.

Figure 9.1 Five Attributes of Alternative Resource Plans



There are three circumstances that produce duplicate or unusable plans. First is the fact that either Maximum or Realistic Achievable Potential (MAP and RAP) DSM portfolios would meet future resource needs without additional supply-side resources. Second, the Meramec combined cycle retrofit option is not applicable if Meramec is not retired. Lastly, there are a few instances when Meramec continues and Noranda's contract expires in which there is no need for new supply-side resources.

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

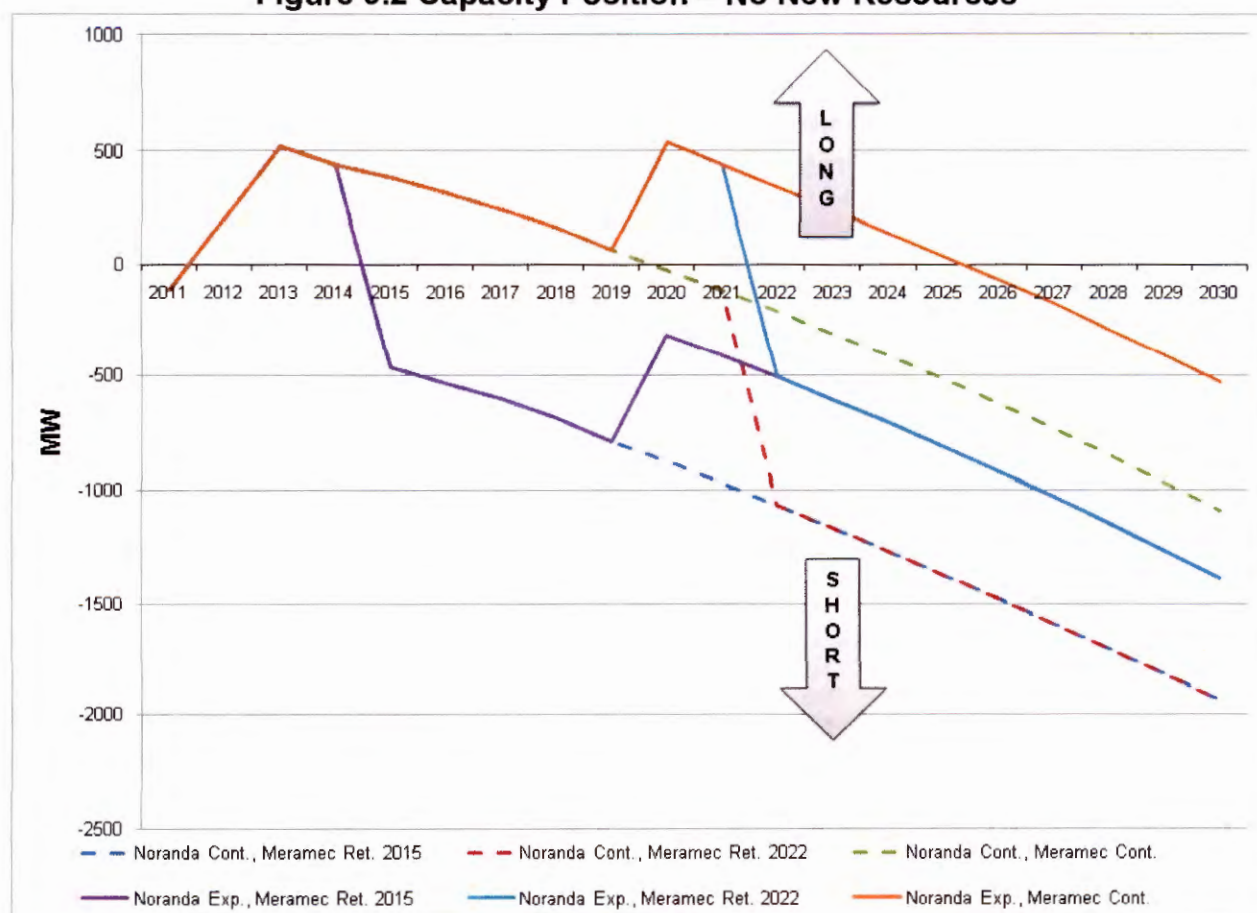
- Existing plant capabilities based on the annual generating unit rating update
- Existing obligations for capacity purchases and sales
- Peak demand forecast
- 100 MW peak demand voltage reduction

¹ 4 CSR 240-22.060(1); 4 CSR 240-22.060(3); 4 CSR 240-22.010(2)(A)

- Reserve margin requirement, based on MISO's 2010 LOLE study, that starts at 15.4% in 2010, ramps up to 17% in 2015, and then continues at 17% through the remainder of the planning horizon. MISO completed its 2011 LOLE study in December, 2010, after Ameren Missouri had completed the bulk of its IRP analysis. The results of the 2011 study indicate a Planning Reserve Margin (PRM) requirement of 17.2% by 2015 growing to 18.2% in 2020. The increase from 2015 to 2020 is driven by assumptions regarding future congestion, which may be addressed through future transmission expansion plans. Without the congestion component, the long-range PRM is consistently near 17%.

Figure 9.2 is a net capacity position chart with no new resources that illustrates the effects of Meramec's status and Noranda's status on capacity needs.

Figure 9.2 Capacity Position – No New Resources



As described in Chapter 5, since renewable requirements are based on retail sales there is direct relationship between the amount of renewables needed, DSM impacts, and the status of Noranda. Therefore, there are 16 unique renewables portfolios which are combinations of renewables requirements (2, federal or state), DSM portfolios (4; None, Low Risk, RAP, or MAP), and Noranda's status (2, expires or continues).

As part of the capacity position build-up there are also various upgrade projects for Ameren Missouri's existing generating units. Ameren Missouri's 2008 IRP demonstrated that cost-effective upgrades will invariably result in lower PVRs. Below is a list of the plant upgrade projects that were included in all resource plans.

- Rush Island Unit 1 – 13 MW in 2013
- Labadie Unit 2 – 11 MW in 2013
- Meramec Units 3 & 4 – 15 MW in 2011
- Callaway Unit 1 – 70 MW in 2017
- Audrain – 30 MW in 2020

Demand-side portfolios were included in capacity planning separately as energy efficiency and demand response. Energy efficiency portfolios were used as developed in Chapter 7, meaning the timing and amounts of energy efficiency were pre-determined for capacity planning purposes. However, demand response was included in alternative resource plans on an as-needed basis to meet capacity needs by shifting the timing only. Energy efficiency and demand response programs not only reduced the peak demand but also reduce reserve requirements associated with those demand reductions.

Major supply-side resource types were added last in the capacity planning process. While new generation might be required, two more considerations were made before concluding that a supply-side type would be built to be in-service for the year having the capacity shortfall.

First, it was determined if the capacity shortfall met or exceeded the build threshold for the supply side type under consideration.

Table 0.1 Build Threshold for Supply Side Types

Supply side type	Capacity, MWs	Build Threshold, MWs	Earliest Year In-Service
Coal w/CCS	679	340	2025
CC-Greenfield	600	300	2015
CC-Meramec	834	417	2015
CC-Venice	600	300	2015
SC-Greenfield	692	346	2014
Pumped Storage	600	300	2017
Nuclear 30%	480	240	2019
Nuclear 50%	800	400	2019
Wind w/Simple Cycle	410	205	2015

The build threshold decision for any particular year was dependent on the capacity of each supply side type compared to the capacity shortfall in any particular year.

The build threshold was determined to be half of the full capacity for whatever supply-side type was under consideration. The full capacity and the build thresholds for each supply side type are shown in Table 0.1. Ameren Missouri would rely on short-term capacity purchases to meet its remaining needs.

Secondly, if a build threshold had been met, it was determined if a sufficient number of years remained between 2011 and the year of that capacity shortfall in order to build that supply-side type for the year in which the build threshold was met. If not, the in-service date was delayed the appropriate number of years to reflect the years required to build each supply side type. Coal with carbon capture is an exception to this rule. Based on Ameren's research full-scale carbon capture is not expected to be available before 2025; therefore, the coal resource option was constrained further. The earliest in-service date for each supply side resource is also shown in Table 0.1.

The remaining net capacity position was modeled in MIDAS as capacity purchases and sales priced at the avoided capacity costs discussed in Chapter 7. The capacity purchases and sales were also adjusted for the different peak demand forecasts associated with each of the 10 scenarios.

A list of the 216 alternative resource plans is shown in the electronic workpapers.² In those workpapers, the names consist of the Supply-Side resource type, Renewables requirements, DSM portfolio, Meramec status, and Noranda status. A 5-digit code is also provided as a plan identifier, which provided a simple short-hand way of referring to a particular plan during the analysis. The electronic workpapers also provide data for these alternative resource plans,³ including: PVRR, PV (Present Value) of probable environmental costs, PV of out-of-pocket costs to participants in demand-side programs, levelized annual average rates, maximum single-year increase in annual average, pre-tax interest coverage, debt ratio, and ratio of net cash flow to capital expenditures.

The spreadsheet that was used to develop the alternative resource plans also includes all the relevant information to populate MIDAS.⁴ Therefore, this spreadsheet was also used to generate all the MIDAS data overlays, translating the resource needs from the capacity position into usable modeling information. This connection dramatically streamlines the modeling process, provides an internal audit trail, and eliminates the potential for manual entry errors.

9.1.1 Resource Plan Model⁵

Ameren Missouri uses the Strategic Planning model from Ventyx, typically referred to as MIDAS. It is the same software that was used in the development of Ameren Missouri's 2008 IRP, and is used for ongoing analysis within Ameren Missouri.

² "216 alternative resource plans - 060(2), 060(4), 060(4)(A).xls" on worksheet "Report";

⁴ CSR 240-22.060(6)(A)

³ 4 CSR 240-22.060(2); 4 CSR 240-22.060(4)

⁴ "Cap Sheet_Risk_100510_GenerallyApplicable.xlsm" on worksheet "Calculations"

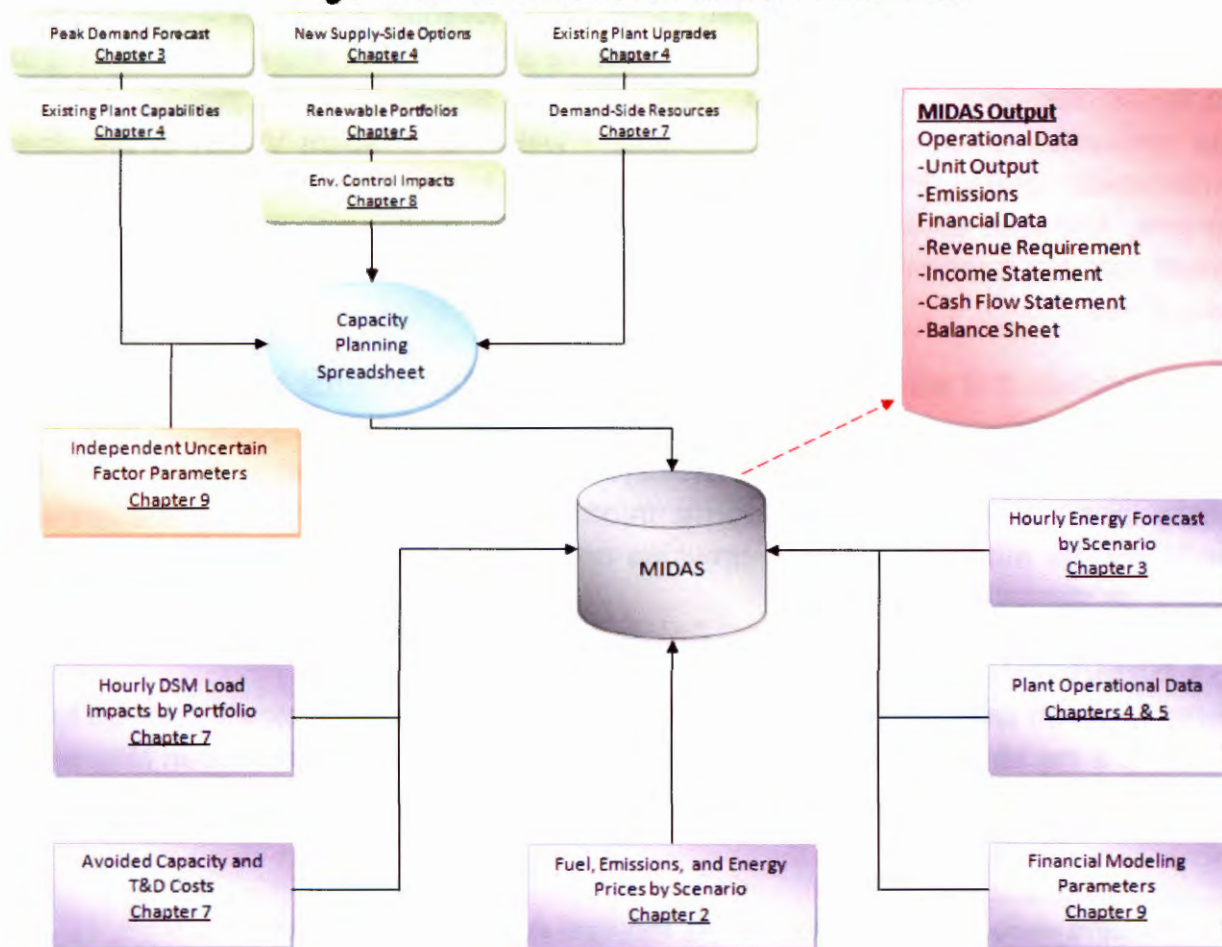
⁵ 4 CSR 240-22.060(6)(E)

MIDAS 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 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, forced and partial outage rates. The generation fleet is dispatched competitively against market prices.

The financial module allows the ability to model 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 generation fleet. The financial module produces bottom-line financial statements to evaluate profitability and earnings impacts.⁶

Figure 9.3 provides an illustration of how the various outputs from other chapters come together as inputs into MIDAS.

Figure 9.3 Resource Plan Model Framework⁷



⁶ 4 CSR 240-22.060(4)(A)

⁷ 4 CSR 240-22.060(4)(D)

9.1.2 Preliminary Candidate Resource Plans

Selection of candidate resource plans from the 216 alternative resource plans began by developing and applying a preliminary scorecard.⁸ This preliminary scorecard is distinguished from a more comprehensive version of the scorecard used for strategy selection. This scorecard used performance measures consistent with general resource planning and Ameren Missouri policy objectives. The results for each measure on the scorecard, as well as others, are provided in the electronic workpapers.⁹

The scorecard itself includes 6 diverse performance measures with varying weights to produce a single overall composite score for each alternative resource plan. Table 9.2 shows the policy objective categories, the measure used for each category, and the weight subjectively assigned to each category.¹⁰

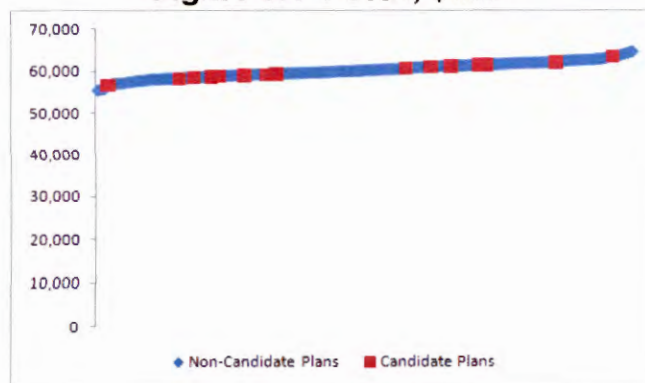
Table 9.2 Preliminary Scorecard

Policy Objective Category(ies)	Measure	Weighting
Environmental/Renewable/Resource Diversity	Total plan carbon emissions	20%
Energy Efficiency	EE Portfolio	10%
Financial/Regulatory	PV Free Cash Flow	20%
Customer Satisfaction	Rate Increases	15%
Economic Development	Primary Job Growth (FTE-years)	10%
Cost	PVRR	25%
TOTAL		100%

Cost (25% Weighting)

Cost was represented by PVRR (Present Value of Revenue Requirements) and was calculated as a simple average of the 10 scenarios' results through 2039. The results for PVRR, the primary measure in IRP analysis, are shown for each of the 216 alternative resource plans in Figure 9.4. Of the candidate plans in the chart, the lowest cost plans are the DSM-only plans, while the baseload plans are the highest cost.

Figure 0.4 PVRR, \$MM



⁸ 4 CSR 240-22.060(4)

⁹ 4 CSR 240-22.060(4); 4 CSR 240-22.060(4)(A); 4 CSR 240-22.060(6)(B)

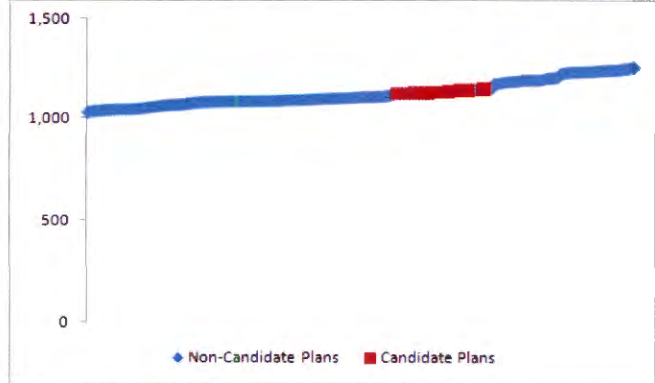
"216 alternative resource plans - 060(2), 060(4), 060(4)(A).xls" on worksheet "Report"

"Scoring matrix with 12-29 data.xls" on worksheet "Scorecard-Report"

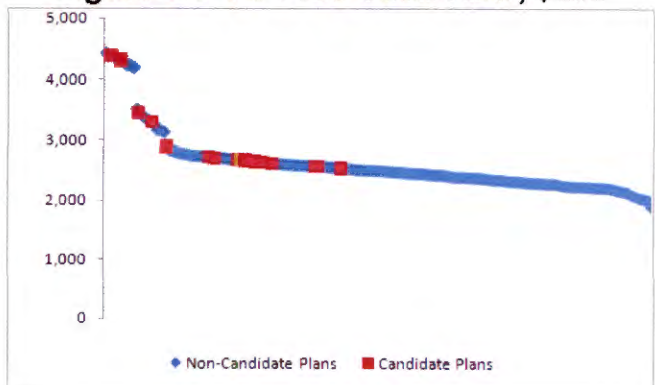
¹⁰ 4 CSR 240-22.060(2); 4 CSR 240-22.010(2)(B)

Environmental (20% Weighting)

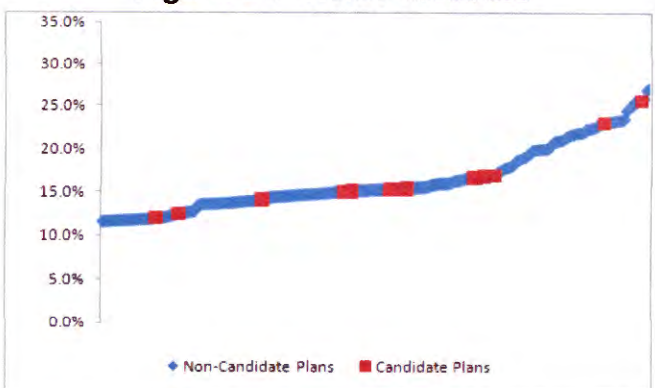
Environmental / renewable resource diversity was represented by total carbon emissions during the 2011-2030 IRP timeframe, and is shown for each of the 216 alternative resource plans in Figure 9.5. The DSM only and nuclear plans produced the lowest carbon emissions. Controlling for Meramec retirement, the natural gas plans have higher carbon emissions. It is noteworthy that the coal resource option included 90% carbon capture; however, coal had higher levels of other emissions, such as SO₂ and mercury, than the gas resources.

Figure 0.5 Carbon Emissions, MM Tons**Financial/Regulatory (20% Weighting)**

Financial/regulatory was represented by PVFCF (Present Value of Free Cash Flow) through 2039, and is shown for each of the 216 alternative resource plans in Figure 9.6. With a shorter amortization period than that used to depreciate supply side resources, the DSM-only plans performed better on PVFCF than other plans.

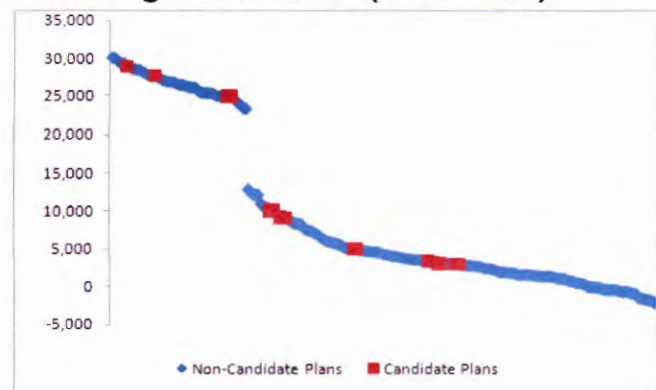
Figure 0.6 PV Free Cash Flow, \$MM**Customer Satisfaction (15% Weighting)**

Customer satisfaction was represented by a composite of two rates measures, and is shown for each of the 216 alternative resource plans in Figure 9.7. That composite was the sum of the maximum single year percentage increase in rates and the average percentage increase in rates across the entire IRP timeframe. The natural gas plans performed best (lowest) on this measure with DSM-only plans in the middle and the baseload plans performing worst (highest).

Figure 0.7 Rates Measure

Economic Development (10% Weighting)

Economic development was represented by each plan's full-time-equivalent job impact, and is shown for each of the 216 alternative resource plans in Figure 9.8. When the value of the Meramec attribute was "Retire", the total overall jobs were relatively low or negative since there were in some cases not enough jobs created by the implementation of other resources to offset those lost jobs at Meramec. On the high end of this measure, both the 30% ownership nuclear and the 50% ownership nuclear supply side types and some of the DSM-only supply side types had relatively high numbers of jobs compared to other plans.

Figure 0.8 Jobs (FTE-Years)

The FTE-year estimates for each major resource option are shown in Table 9.3 and are intended to be comparable and indicative of the different resource types. The estimates are also limited to the direct economic impact; that is, only those jobs that are directly connected to delivery of the resource. The FTE-years estimates for coal, natural gas, and wind were derived from the National Renewable Energy Laboratory's (NREL) Jobs and Economic Development Impacts (JEDI) models, which are publicly available. The Nuclear estimates were from a 2008 Development Strategies study assessing the economic impact of a new 1600 MW unit added at the Callaway site. For purposes of our analysis and screening, the entire total of jobs for nuclear were used regardless of the amount assumed to be owned by Ameren Missouri since the entire plant would have to be built to be a viable resource. The jobs for pumped storage were based on Ameren Missouri's recent experience with rebuilding its Taum Sauk facility. In estimating the economic impacts of the energy efficiency portfolios, Ameren Missouri assigned each program to an appropriate economic activity group that

Table 0.3 FTE-Year Estimates

Supply-Side Type	Construction FTE-Years	Ongoing FTE-Years
Coal w/CCS	7,182	68
CC-Greenfield	1,512	30
CC-Meramec	1,950	42
CC-Venice	937	30
SC-Greenfield	1,156	35
Pumped Storage	3,400	6
Nuke 30%	23,680	400
Nuke 50%	23,680	400
Wind/SC	977	54
EE Portfolio	Total FTE-Years	
MAP	26,790	
RAP	11,960	
Low Risk	3,490	

could be modeled using IMPLAN multipliers. This approach is consistent with how such economic impacts are typically modeled.

Energy Efficiency (10% Weighting)

Energy efficiency spending, 10% weight, was represented by spending on energy efficiency for the value levels of this sub-attribute of DSM. In rating the energy efficiency portfolios MAP was given the highest score of 1 with RAP plans receiving 0.9. The relatively low trade-off in the scoring is consistent with the definitions of the portfolios and RAP being an aggressive portfolio with the most realistic representation of achievable savings. The Low Risk portfolio was given a score of 0.1 while the plans without DSM received a score of 0.

Table 9.4 shows scoring results for a selection of the 216 alternative resource plans. The selection includes plans with only the Proposition C renewable portfolio and Meramec retirement in 2022 and excludes plans with no DSM. This scoring summary provides representative relative performance between the major resource options considered and provides a quantitative basis for the conclusions drawn from this phase of the analysis.

Table 0.4 Scorecard for Selected Alternative Resource Plans

		Category->	Environmental/ Renewable/ Resource Diversity	Energy Efficiency	Financial/ Regulatory	Customer Satisfaction	Economic Development	Cost
		Weight->	20%	10%	20%	15%	10%	25%
Noranda Status	Plan Type	Unitized Score	Unitized Total plan carbon emissions	Unitized Energy Efficiency parameter	Unitized Free Cash Flow	Unitized blend: single yr max & 29yr avg % chg	Unitized Primary Job Growth (FTE- years)	Unitized PVRR
Noranda continues	DSM only-MAP case	0.932	0.922	1.000	0.967	0.873	0.839	0.941
	DSM only-RAP case	0.836	0.921	0.900	0.782	0.878	0.378	0.944
	Nuke 30%-Low Risk case	0.739	0.921	0.100	0.590	0.694	0.962	0.905
	Nuke 50%-Low Risk case	0.719	0.922	0.100	0.585	0.576	0.962	0.899
	SC greenfield-Low Risk case	0.685	0.910	0.100	0.604	0.847	0.161	0.914
	CC Meramec-Low Risk case	0.681	0.903	0.100	0.607	0.822	0.187	0.910
	CC greenfield-Low Risk case	0.678	0.905	0.100	0.599	0.815	0.170	0.911
	CC Venice-Low Risk case	0.677	0.902	0.100	0.603	0.817	0.153	0.912
	Wind with SC-Low Risk case	0.665	0.916	0.100	0.653	0.657	0.160	0.906
	Pumped Storage-Low Risk case	0.659	0.920	0.100	0.612	0.639	0.222	0.896
Noranda expires 2020	Coal with CCS-Low Risk case	0.636	0.916	0.100	0.582	0.484	0.351	0.875
	DSM only-MAP case	0.938	0.925	1.000	0.971	0.862	0.839	0.981
	DSM only-RAP case	0.836	0.923	0.900	0.746	0.863	0.378	0.980
	Nuke 30%-Low Risk case	0.765	0.924	0.100	0.583	0.832	0.925	0.947
	Nuke 50%-Low Risk case	0.753	0.926	0.100	0.531	0.841	0.900	0.943
	CC Meramec-Low Risk case	0.702	0.910	0.100	0.596	0.898	0.181	0.952
	Wind with SC-Low Risk case	0.699	0.918	0.100	0.617	0.863	0.157	0.949
	SC greenfield-Low Risk case	0.698	0.914	0.100	0.603	0.871	0.156	0.955
	CC greenfield-Low Risk case	0.696	0.909	0.100	0.597	0.865	0.168	0.952
	CC Venice-Low Risk case	0.694	0.907	0.100	0.600	0.865	0.150	0.953
	Pumped Storage-Low Risk case	0.690	0.921	0.100	0.606	0.785	0.222	0.940
	Coal with CCS-Low Risk case	0.660	0.919	0.100	0.574	0.582	0.349	0.919

Conclusions¹¹

The observations from the analysis results led to the following conclusions:

- From an overall composite perspective, using the total weighted scores based on the Preliminary Scorecard in Table 9.2, the top plans were the DSM-only plans and nuclear plans.
- Plans with Federal RES requirements are more expensive. This is not surprising considering the Missouri RES rate cap limited the amount of renewable resources added. Only the Missouri RES portfolios were analyzed further.
- The three combined cycle options are nearly indistinguishable on the various performance measures. Since all three options perform so similarly and carry similar risks there is no need to continue to analyze all three options. The Greenfield combined cycle option was analyzed further as a representative of the combined cycle resource type. Further analysis outside this IRP will be needed to determine which site is more appropriate should construction of a combined cycle plant become more certain.
- The 50% nuclear resource option can be eliminated from further analysis considering its relative performance. The 30% ownership option adequately represents the nuclear supply-side type for the remaining analysis.
- Ameren Missouri developed the Low Risk DSM portfolio based on the continuation of the current regulatory framework. The analysis also shows the no-DSM option is more costly than the Low Risk portfolio. Therefore, there is no need to continue to analyze the alternative resource plans without DSM.
- The analysis indicates the cost of a plan increases as the time remaining before retirement of Meramec is shorter. Also, if Meramec continues there is less resource plan diversity since there are fewer resource needs. At this juncture in the analysis it is useful to reduce the number of plans but keep plan diversity. Since further analysis of Meramec retirement was yet to be conducted, only the plans with a 2022 retirement date were used for the sensitivity analysis.

Only 16 alternative resource plans were used for the sensitivity analysis after eliminating plans based on the screening analysis conclusions. Table 9.5 lists the 16 preliminary candidate resource plans¹².

¹¹ 4 CSR 240-22.060(4)

¹² EO-2007-0409 – Stipulation and Agreement #35