ENERNOC | UtilitySOLUTIONS consulting

DEMAND-SIDE MANAGEMENT MARKET POTENTIAL STUDY

Volume 1: Executive Summary

Final Report

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EXECUTIVE SUMMARY

Ameren Missouri commissioned a Demand Side Management (DSM) Market Potential Study to assess the various categories of electrical energy efficiency (EE), demand response (DR), distributed generation (DG), and combined heat and power (CHP) potentials in the residential, commercial, and industrial sectors for the Ameren Missouri service area from 2016 to 2034. The study uses updated baseline estimates based on the latest information pertaining to federal, state, and local codes and standards for improving energy efficiency. It also quantifies and includes estimates of naturally occurring energy efficiency in the baseline forecast.

Ameren Missouri will use the results of this study in its integrated resource planning process to analyze various levels of energy efficiency related savings and peak demand reductions attributable to both EE and DR initiatives at various levels of cost. This study also provides estimated levels of combined heat and power and distributed generation installations over the specified time horizon.

Furthermore, Ameren Missouri has adhered to both the Missouri Public Service Commission ("Commission") rules, 4 CSR 240-3.164 regarding potential study requirements for purposes of complying with the Missouri Energy Efficiency Investment Act (MEEIA) and 4 CSR 240-22 regarding potential study requirements for Ameren Missouri's next Integrated Resource Plan (IRP) to be filed in April 2014. Both rules contain new provisions that were not part of Ameren Missouri's previous DSM Potential Study published in 2010.

Ameren contracted with EnerNOC Utility Solutions Consulting (EnerNOC) to conduct this study and EnerNOC has performed the following tasks to meet Ameren's key objectives:

- Conducted primary market research to collect data for the Ameren Missouri service territory, including: electric end-use data, saturation data, and customer demographics and psychographics.
- Characterized how customers in the Ameren Missouri service territory make decisions related to their electric use and energy efficiency investment decisions. Translated that understanding in a clear and transparent manner to establish annual market acceptance rates for EE measures.
- Employed updated baselines that reflect both current and anticipated federal, state, and local energy efficiency legislation. Identified all known pending legislation that may also impact DSM potential.
- Developed Ameren Missouri-specific market acceptance rates for EE for the planning cycle of 2016 through 2034 that, when applied to economic potential, will yield estimates of maximum achievable and realistic achievable potential.
- Analyzed the potential for energy efficiency, demand response, and customer distributed generation/combined heat and power application over the 2016-2033 planning horizon[1].
- Worked with Ameren Missouri to develop sensitivity analyses for assessing uncertainty around DSM potential.
- Analyzed the impact of demand-side rates on DSM potential.
- Provided a series of webinars for Missouri stakeholders to review study assumptions and provide comments for consideration.

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[1] Although estimates were developed through 2034, we show results for 2033, which is 20 years out from the start of the forecast in 2014.

- Clearly communicated the DSM potential and uncertainty in an objective way that is useful for the Commission, Ameren senior management, Missouri stakeholders, Ameren DSM staff, Ameren EE Implementation team, and Ameren IRP staff – both operational and planning. This includes the following:
  - Documented compliance with IRP/MEEIA rule references, including specific references to rule requirements.
  - Provided measure-level information, in a way that is readily compatible with Ameren Missouri's modeling methodology in DSMore.
  - Generated energy efficiency potential supply curves, which clearly show the incremental cost (in dollars per kWh) of increasing DSM energy efficiency efforts (in kWh) over the 2016-2033 planning horizon.
  - Generated demand response potential supply curves, which clearly show the incremental cost (in dollars per kW) of increasing DSM demand response efforts (in kW) over the 2016-2033 planning horizon.
  - Generated distributed generation/combined heat and power potential supply curves, which clearly show the incremental cost (in dollars per kW) of increasing DG-CHP efforts (in kW) over the 2016-2033 planning horizon.

Report Organization

This report is presented in six volumes as outlined below. This document is **Volume 1: Executive Summary**.

- Volume 1, Executive Summary
- Volume 2, Market Research
- Volume 3, Energy Efficiency Analysis
- Volume 4, Demand Response Analysis
- Volume 5, Distributed Generation and Combined Heat and Power
- Volume 6, Demand-side Rates

Background

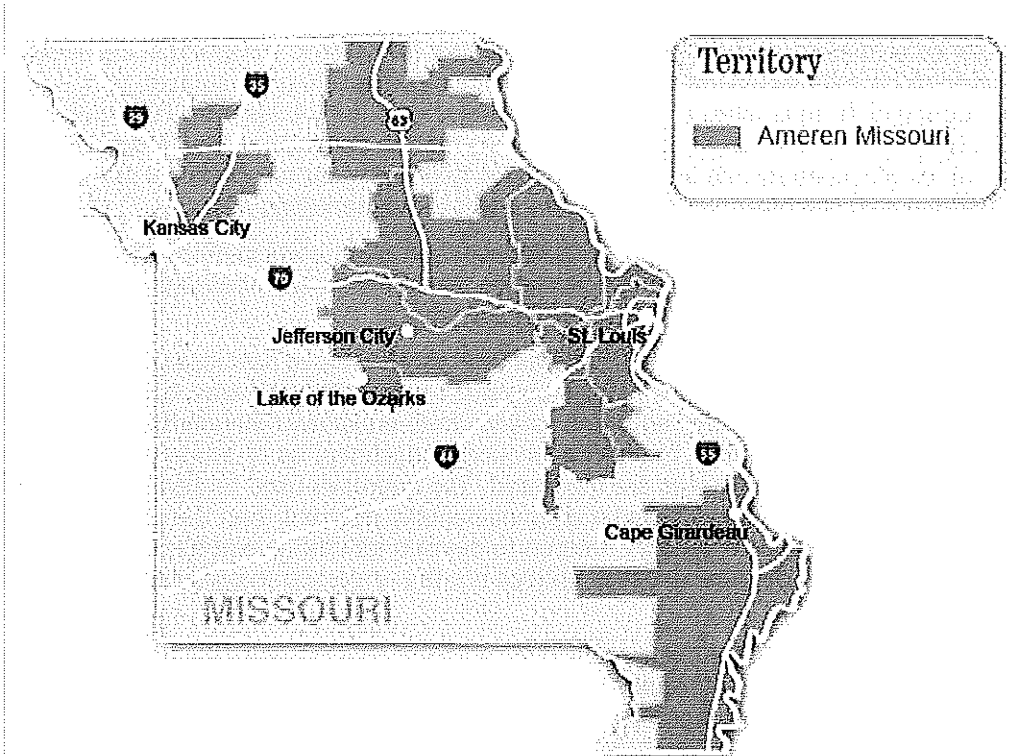
Ameren Corporation is a large investor-owned utility serving large parts of Missouri and Illinois. Figure 1 presents Ameren Missouri's service territory.

Ameren Missouri DSM Overview

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." per Section 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 website. Details of MEEIA are available on the Missouri Public Service Commission website.

Over the past several years, Ameren Missouri has been implementing EE programs and analyzing EE as a long-term resource option. From 2009 through September, 2011, Ameren Missouri implemented full-scale EE programs including five residential and four business programs.

Figure 1 Ameren Missouri Service Territory



Ameren Missouri spent approximately $70 million on energy efficiency programs between 2009 and 2011 and achieved approximately 550,000 MWh of verified energy savings. This level of expenditure resulted in deployment of approximately:

- 4 million CFLs
- 21,000 ENERGY STAR® appliances
- 12,000 upgraded Multi-Family Income Qualified (MFIQ) tenant units
- 9,000 decommissioned refrigerators and freezers
- 3,000 new residential central air conditioning systems
- 3,000 business energy efficiency projects

In 2012, Ameren Missouri scaled back its energy efficiency expenditures to $10 million due to uncertainty regarding regulatory framework issues for its next cycle of energy efficiency programs. Concurrently, in January 2012, Ameren Missouri filed its first 3-year EE implementation plan under the new Missouri rules implementing MEEIA.

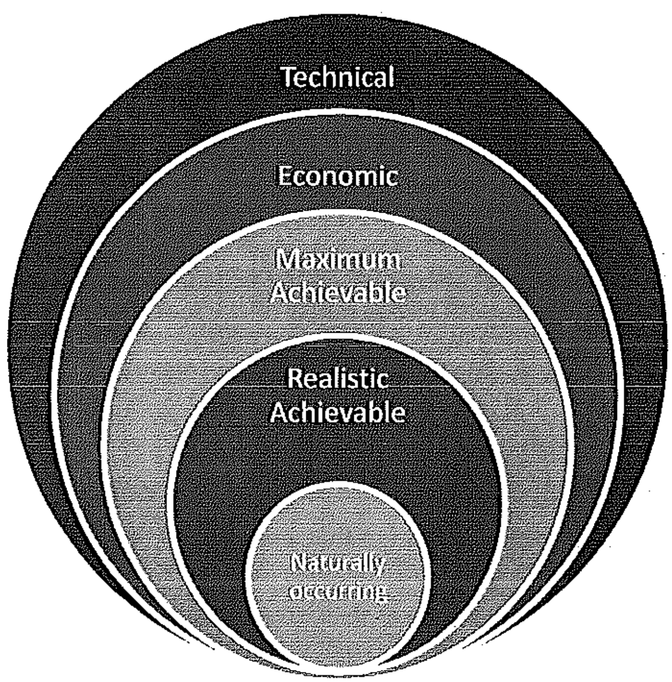
Definitions

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. This is a subset of technical potential.

- **Maximum Achievable Potential** estimates customer adoption of economic measures when delivered through efficiency programs under ideal market, implementation, and customer preference conditions and an appropriate regulatory framework. Information channels are assumed to be established and efficient for marketing, educating consumers, and coordinating with trade allies and delivery partners. Maximum Achievable Potential establishes a maximum target for the EE savings that an administrator can hope to achieve through its EE programs and involves incentives that represent a substantial portion of the incremental cost combined with high administrative and marketing costs.
- **Realistic Achievable Potential** reflects expected program participation given barriers to customer acceptance, non-ideal implementation conditions, and limited program budgets. This represents a lower bound on achievable potential.
- **Baseline projection** 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 savings from equipment standards and building codes that were active and on the books for future enactment as of January 31, 2013. It is the metric against which savings are measured. The approach used to develop this projection is an end-use forecast approach and it is fundamentally different than the statistically-adjusted end-use approach used by Ameren to develop its official load forecasts. However, as much as possible, the forecast assumptions are the same and the resulting forecasts are close.
- **Net savings** represents the energy efficiency potential savings potential that is after naturally occurring energy efficiency has been taken into consideration. Unless specified, all savings listed in this report represent net savings, as opposed to gross savings.
- **Incremental savings** refers to the amount of potential savings that can be achieved in that one particular year. **Cumulative savings** refers to the sum of the incremental savings. Unless specified, all savings listed in the reports are cumulative savings.

Figure 2 Levels of Energy-Efficiency Potential



Overall Conclusions

The business case to capture cost-effective DSM savings is more challenging in the 2013 Ameren Missouri DSM Market Potential Study than it was in the 2010 DSM Potential study. Challenges include:

- The enactment of new federal building codes and appliance efficiency standards are diminishing some of the proverbial "low hanging fruit" or low-cost but high-yield energy efficiency opportunities, such as residential lighting.
- For the 2016-2018 DSM Implementation Planning period, 70% of the measure-level energy-efficiency potential is expected to come from business customers and the remaining 30% from residential customers.
- MISO capacity markets indicate that demand response opportunities have little market capacity value for the foreseeable future. Since Ameren Missouri does not need demand response for reliability purposes, the business case for demand response for Ameren Missouri customers is dependent on the MISO capacity market.
- Since 2010, new program evaluation impact reports in non-Ameren jurisdictions about certain types of demand response programs that in the 2010 study were thought to have no "losers" are now available in the public domain. Specifically, in 2010 the peak time rebate ("PTR") program, where customers are paid if they respond to calls to reduce peak demand but are not penalized if they do not respond to such calls, was thought to have only winners. The evaluation reports based on new empirical data show conclusively that there are both winners and losers in this program.
- The removal over time of the Ameren Missouri $2/Watt rebate for customer-owned solar PV, coupled with the removal of the 30% federal income tax credit in 2017, prevent the solar DG option from being cost effective, at least in the 2016-2018 DSM Implementation Planning period.
- Opportunities for cost-effective combined heat and power applications for Ameren Missouri industrial customers are relatively small due, in part, to industrial customers who have elected to opt out of participation in Ameren Missouri energy efficiency programs.
- The analysis of demand-side rates in the study indicate that inclining block rates ("IBR") and time-of-use rates have the potential to reduce customers' energy consumption. If offered as a customer opt-out option, demand-side rates have significant customer energy usage reduction potential. However, if they are offered as a customer opt-in option, the potential diminishes to relatively modest levels.

Market Research

Comprehensive primary market research about Ameren Missouri customers was conducted for this project. The market research component collected electricity end-use saturation data, customer demographics, and psychographic information that provides insight on how Ameren Missouri customers make decisions related to electric usage and energy-efficiency investments. 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 Ameren. The market research included:

- Residential customers — online saturation surveys with 743 customers
- Residential customers — online program interest surveys with 761 customers
- Business customers — online saturation surveys with 800 commercial and industrial customers
- Business customers — online program interest surveys with 798 commercial and industrial customers
- Largest business customers — 100 onsite surveys of Ameren Missouri's largest commercial and industrial customers

Key highlights from the market research are included below. Volume 2 of the report series presents the detailed results of the primary market research.

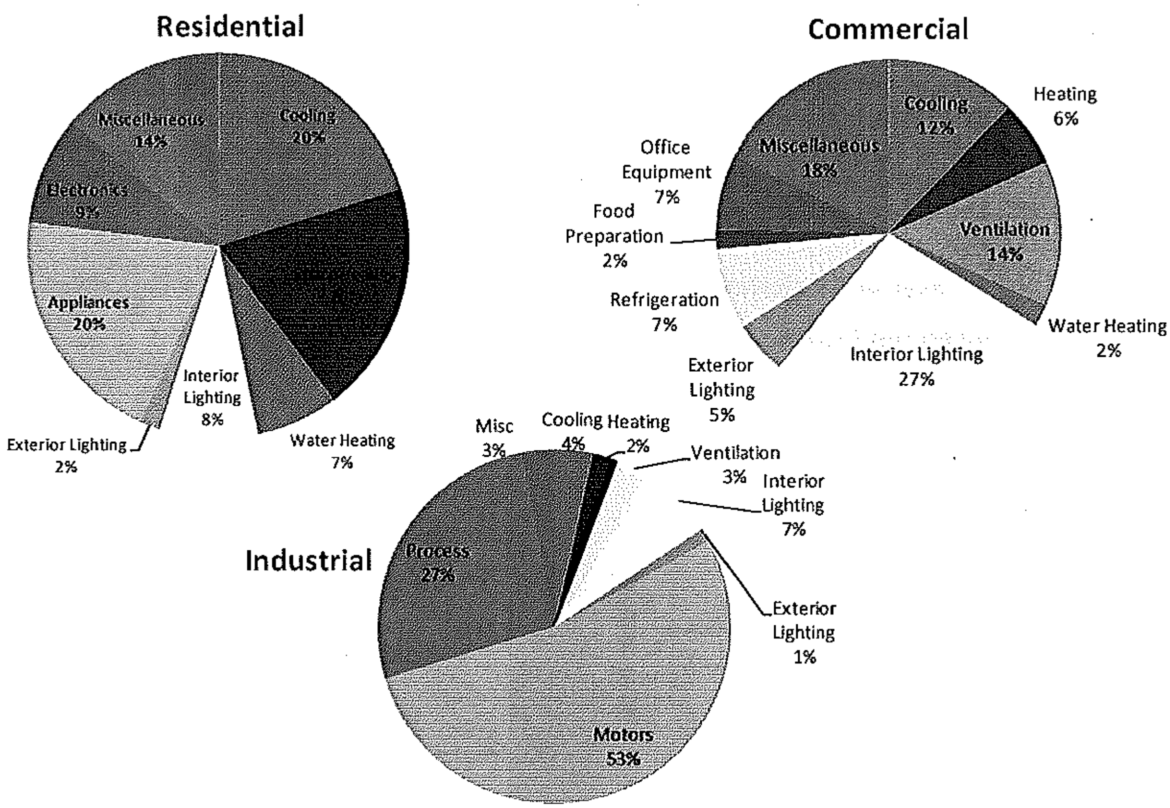
Energy-use Surveys

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

These data were used to develop the energy market profiles for the study base year, 2011, which are summarized as a breakdown of annual electricity use in Figure 3. Details are presented in Volume 3.

Figure 3 Annual Electricity Use by End Use and Sector (2011)



Program-interest Research

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

1. Help Ameren estimate achievable potential
   - o How likely are customers within each sector to participate in various energy efficiency programs Ameren Missouri is considering offering?
   - o Which energy efficiency measures offer the highest likely participation rates?
   - o How does likelihood to participate differ by payback period for the customer?
2. Help Ameren Missouri understand unique customer segments to support customer marketing and outreach

Other relevant questions embedded in this phase of the research to help Ameren Missouri better understand achievable potential include:

- What overall demographic and psychographic characteristics correspond to a higher likelihood to participate in energy efficiency programs?
- What attitudinal or market segments can be derived within the residential and business sectors, and how do these segments differ in terms of their impact on the likelihood to participate, as well as on customer demographic and psychographic characteristics?
- Which of these segments represent the best opportunities for Ameren Missouri to focus their marketing on?

- What messaging strategies would likely be useful to help foster participation among these high opportunity segments?

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 4 illustrates the range of take rates for the residential and business sectors.

Figure 4 Range of Take Rates

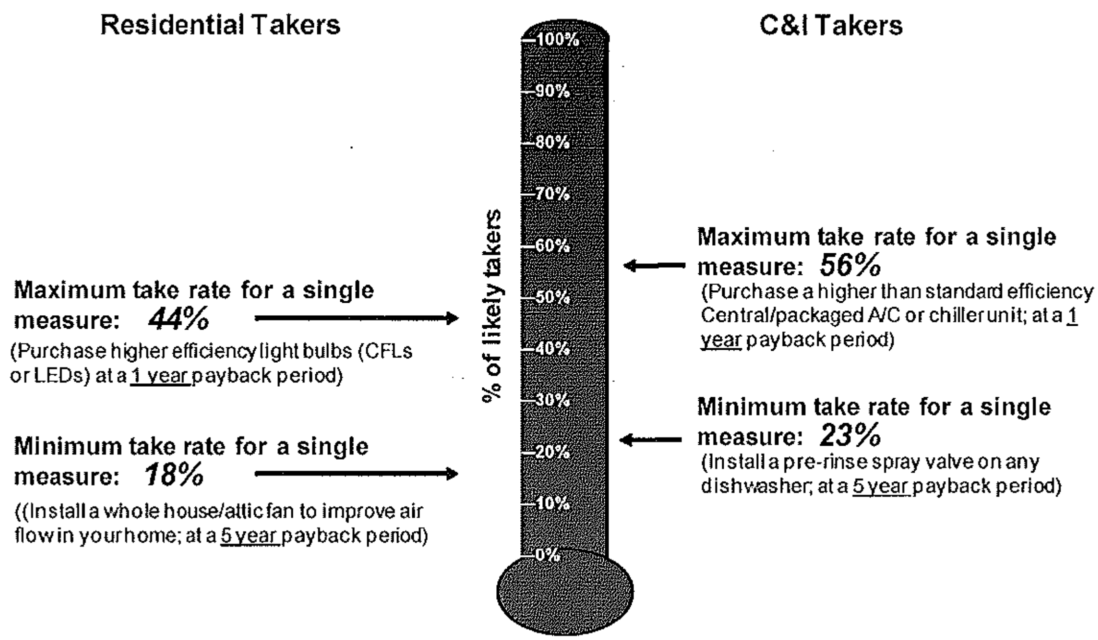
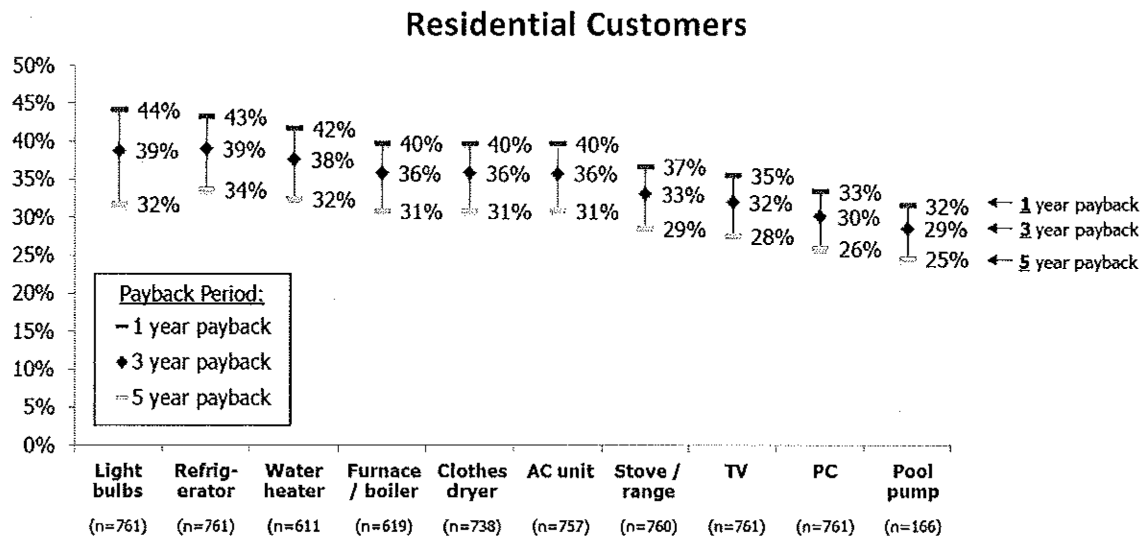
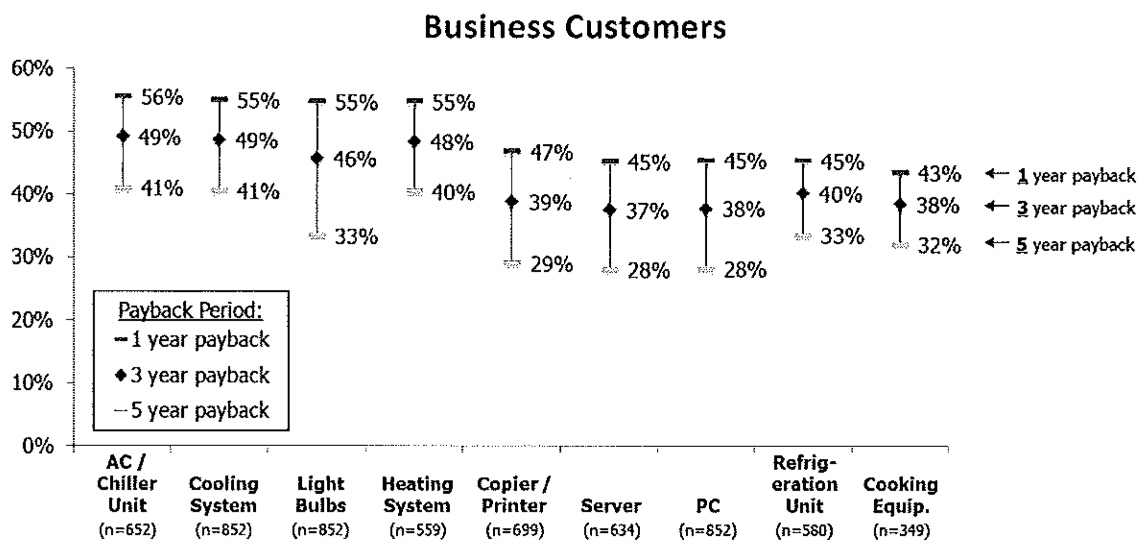


Figure 5 presents likely take rates for specific appliances or equipment measures in the residential sector. This is a subset of the take rates for the residential sector; additional rates were developed for a second category of non-equipment measures such as insulation or low-flow showerheads. The take rates at the three-year payback level were used to estimate realistic achievable potential.

Figure 5 ***Likely Take Rates for Purchasing High-efficiency Equipment***

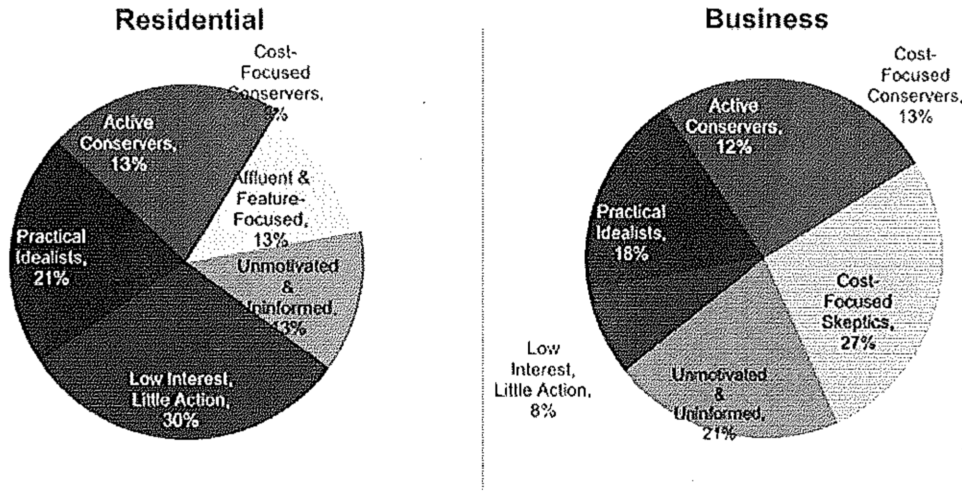


Q25-27/Q28/Q33/-35/Q37-39
*Note: Assumes a normal replacement cycle



In addition to estimating take rates, the study also developed an attitudinal segmentation model that disaggregated residential and business customers into groups that differ in terms of whether, and why, they might be interested in pursuing energy efficiency options. The goal of the segmentation analysis was to define groups of customers that were different in ways that would allow Ameren Missouri to prioritize customer targets for EE program marketing, and to develop targeted messages for each of those segments. Using a variety of attitudinal and behavioral inputs, six residential customer segments that seemed to best represent the differences in this population on these issues were identified. The segments and relative sizes are outlined in Figure 6. The three "green" segments have the highest propensity to take energy-efficiency actions and are the best targets for Ameren programs. The one-year take rates for the Practical Idealists were used to estimate maximum achievable potential. The characteristics of each segment are described in detail in Volume 2.

Figure 6 Attitudinal Segment Distribution



Energy Efficiency

The key findings of the energy-efficiency potential analysis are presented first in terms of measure-level results, where program delivery and implementation concerns have not been considered. Subsequently, program-level savings are developed by considering appropriate program delivery mechanisms and measure bundling strategies based on real-world implementation and evaluation experience. Energy-efficiency potential is estimated relative to a baseline projection that includes the effects of appliance and equipment standards, building codes and naturally occurring energy efficiency. As such, all potential estimates represent "net" savings.

Measure-level Energy Efficiency Potential

Key findings related to measure-level electric potentials are summarized as follows:

- **Technical potential**, which reflects the adoption of all energy-efficiency measures regardless of cost-effectiveness, is a theoretical upper bound on savings. First-year net savings are 1,242 GWh, or 4.1% of the baseline projection. Cumulative net savings in 2018 are 2,728 GWh, or 8.9% of the baseline. By 2030, cumulative savings reach 9,858 GWh, or 29.2% of the baseline projection.
- **Economic potential** reflects the savings when the most efficient cost-effective measures are taken by all customers. The first-year savings in 2016 are 858 GWh, or 2.8% of the baseline projection. By 2018, cumulative net savings reach 1,923 GWh, or 6.3% of the baseline. By 2030, cumulative savings reach 7,718 GWh, or 22.9% of the baseline projection.
- **Maximum achievable potential.** In 2016, savings for this case are 510 GWh, or 1.7% of the baseline and by 2018 cumulative net savings reach 1,179 GWh, or 3.8% of the baseline projection. By 2030, cumulative MAP savings reach 5,377 GWh, or 15.9% of the baseline projection. This results in average annual savings of 1.06% of the baseline each year.
- **Realistic achievable potential.** In 2016, net realistic achievable savings are 339 GWh, or 1.1% of the baseline projection. By 2018, RAP reaches 806 GWh, or 2.6% of the baseline. By 2030, RAP reaches 3,958 GWh, or 11.7% of the baseline projection. This results in average annual savings of 0.8%.

Table 1 and Figure 7 summarize the electric energy-efficiency savings for the different levels of potential relative to the baseline projection.

Table 1 Summary of Cumulative, Net, Measure-Level Efficiency Potential

	2016	2017	2018		2025	2030
Baseline projection (GWh)	30,249	30,449	30,694		32,228	33,721
Cumulative Net Savings (GWh)						
Realistic Achievable Potential	339	561	806		2,697	3,958
Maximum Achievable Potential	510	833	1,179		3,753	5,377
Economic Potential	858	1,374	1,923		5,674	7,718
Technical Potential	1,242	1,955	2,728		7,563	9,858
Cumulative Net Savings as a % of Baseline						
Realistic Achievable Potential	1.1%	1.8%	2.6%		8.4%	11.7%
Maximum Achievable Potential	1.7%	2.7%	3.8%		11.6%	15.9%
Economic Potential	2.8%	4.5%	6.3%		17.6%	22.9%
Technical Potential	4.1%	6.4%	8.9%		23.5%	29.2%

Figure 7 Summary of Cumulative, Net, Measure-Level Efficiency Potential

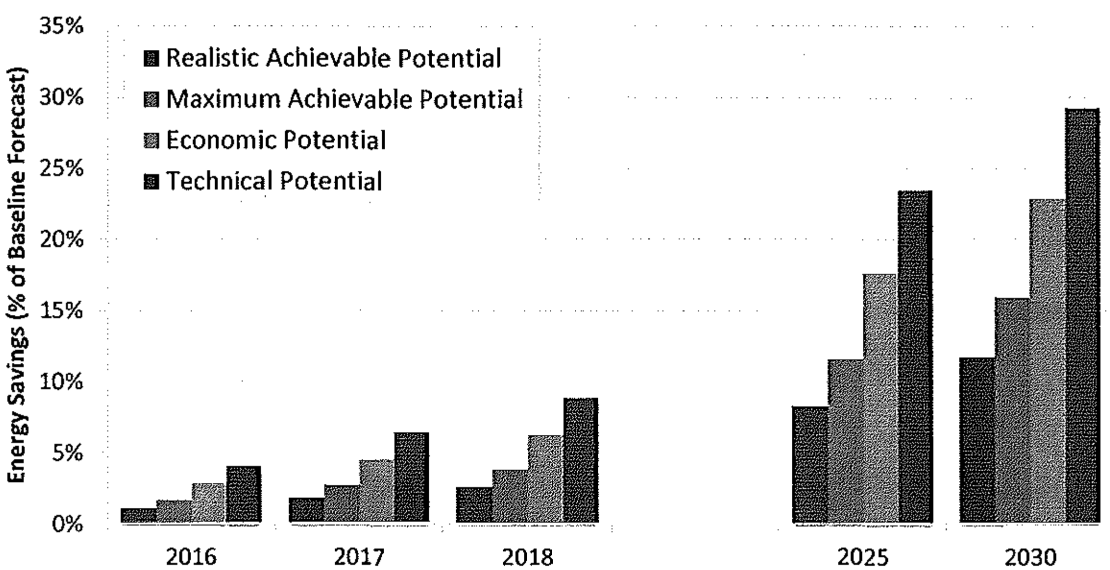
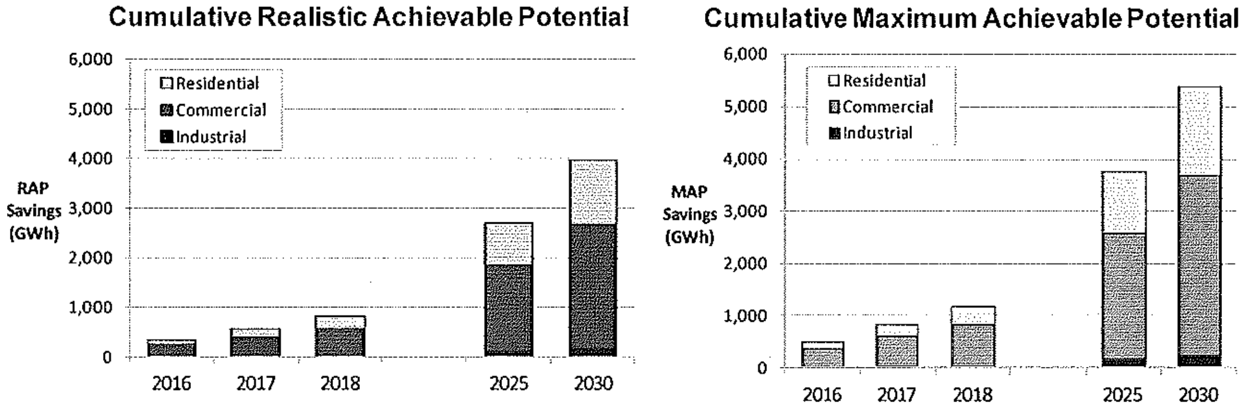


Figure 8 summarizes the range of electric achievable potential by sector. The commercial sector accounts for the largest portion of the savings, followed by residential and industrial.

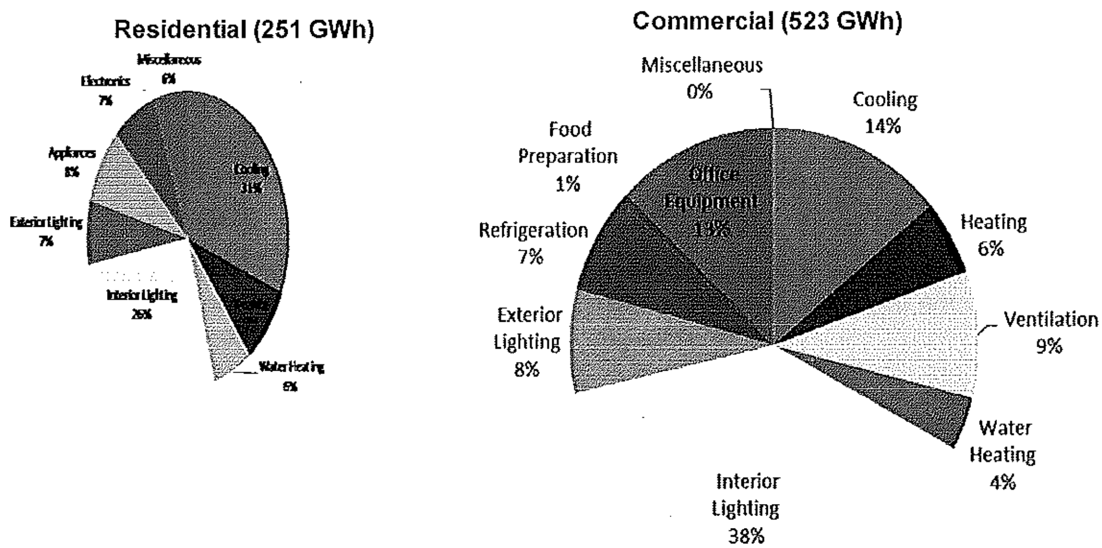
Figure 8 Cumulative, Net, Measure-Level Potential by Sector (GWh)



As shown above, the majority of savings come from the residential and commercial sectors. Figure 9 presents the breakdown of cumulative measure-level savings in 2018 by end use. The key measures that contribute to the savings are:

- Screw-in LED lamps, which account for 26% of the commercial-sector savings and 25% of the residential-sector savings in 2018. These lamps are cost-effective when compared to the infrared halogen lamp that meets the EISA lighting standard starting in 2014. Savings from this measure in RAP are calculated relative to a market baseline that reflects purchases of the infrared halogen lamps, as well as substantial market share for CFLs and LEDs.
- Advanced building design in commercial new construction also contributes significantly to HVAC and lighting savings.
- High-efficiency central air conditioners and maintenance also contribute significantly to cooling savings in the residential sector.

Figure 9 Cumulative, Net, Measure-Level Potential by Sector (GWh)



Supply Curves

Two key results from this study are supply curves for energy efficiency and demand response that represent RAP and MAP. Supply curves were developed using representative program designs that are based on EnerNOC's industry experience and generic program design parameters. Ameren Missouri may use the supply curves as a sanity check to compare with their Ameren Missouri-specific proposed DSM program designs for both long-term IRP planning work, as well as for near-term Missouri Energy Efficiency Investment Act ("MEEIA") three-year implementation planning.

Table 2 and Figure 10 present a high-level summary of representative program potential as well as measure-level potential. At the end of the 2016-2018 DSM Implementation Planning period, program potential is in the range of 539 GWh to 768 GWh. As a percent of the baseline projection, the cumulative savings in 2018 are in the range of 1.8% to 2.5%. By 2030, program RAP and MAP increase to 2,133 GWh and 2,890 GWh, respectively.

Table 2 Summary of Program Energy Efficiency Potential (Energy Savings in GWh)

	2016	2017	2018		2025	2030
Baseline Projection (GWh)	30,249	30,449	30,694		32,228	33,721
Cumulative Savings (GWh)						
Program RAP	174	346	539		1,629	2,133
Program MAP	251	495	768		2,235	2,890
RAP (Measure-Level)	339	561	806		2,697	3,958
MAP (Measure-Level)	510	833	1,178		3,753	5,376
Cumulative Savings (% of Baseline)						
Program RAP	0.6%	1.1%	1.8%		5.1%	6.3%
Program MAP	0.8%	1.6%	2.5%		6.9%	8.6%
RAP (Measure-Level)	1.1%	1.8%	2.6%		8.4%	11.7%
MAP (Measure-Level)	1.7%	2.7%	3.8%		11.6%	15.9%

Figure 10 Summary of Program and Measure-level Energy Efficiency RAP and MAP (% of baseline GWh)

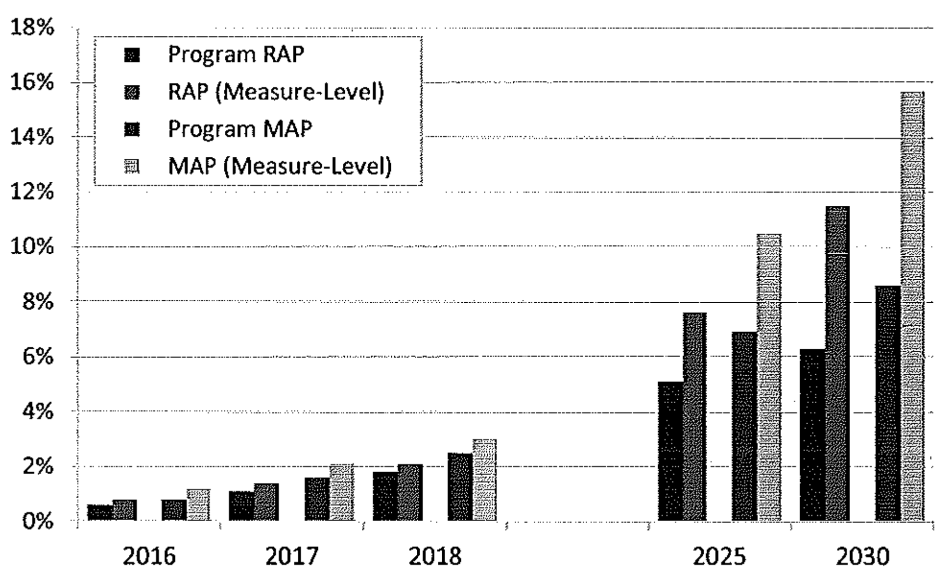


Table 3 Summary of Program EE Potential (Peak Demand Savings in MW)

	2016	2017	2018		2025	2030
System Peak Forecast (MW)	7,328	7,368	7,420		7,901	8,241
Cumulative Savings (MW)						
Program RAP	38	72	110		360	476
Program MAP	54	54	54		492	642
RAP (Measure-Level)	133	203	289		1,153	1,735
MAP (Measure-Level)	199	300	421		1,587	2,308
Cumulative Savings (% of Baseline)						
Program RAP	0.5%	1.0%	1.5%		4.6%	5.8%
Program MAP	0.7%	1.4%	2.1%		6.2%	7.8%
RAP (Measure-Level)	1.8%	2.8%	3.9%		14.6%	21.0%
MAP (Measure-Level)	2.7%	4.1%	5.7%		20.1%	28.0%

As shown in Table 4, the annual program budgets for RAP range from $57 to 75 million and the program budgets for MAP are in the range of $104 to $132 million. This table also shows the breakdown of administrative and incentive costs for each level of program potential.

Table 4 Annual Program Budget Estimates for RAP and MAP

	2016	2017	2018		2025	2030
Annual Program RAP Budget ($000)						
Total RAP Cost	$57,427	$62,874	$66,395		$73,242	$75,332
Administrative	$15,278	$16,526	$17,793		$18,835	$20,039
Incentive	$42,150	$46,348	$48,602		$54,407	$55,292
Annual Program MAP Budget ($000)						
Total MAP Cost	$103,988	$112,083	$117,807		$128,772	$132,240
Administrative	$27,227	$29,111	$31,045		$32,934	$34,615
Incentive	$76,761	$82,972	$86,762		$95,838	$97,625

The program analysis created supply curves that show the relationship between energy efficiency savings and the costs required to reach those savings levels. Figure 11 shows the supply curves for the RAP and MAP portfolios for the program years 2016–2018. Figure 12 shows this information for the period 2016-2034. Each horizontal line represents a discrete program.

Figure 11 *Levelized Cost Supply Curves, 2016–2018, RAP and MAP Portfolios*

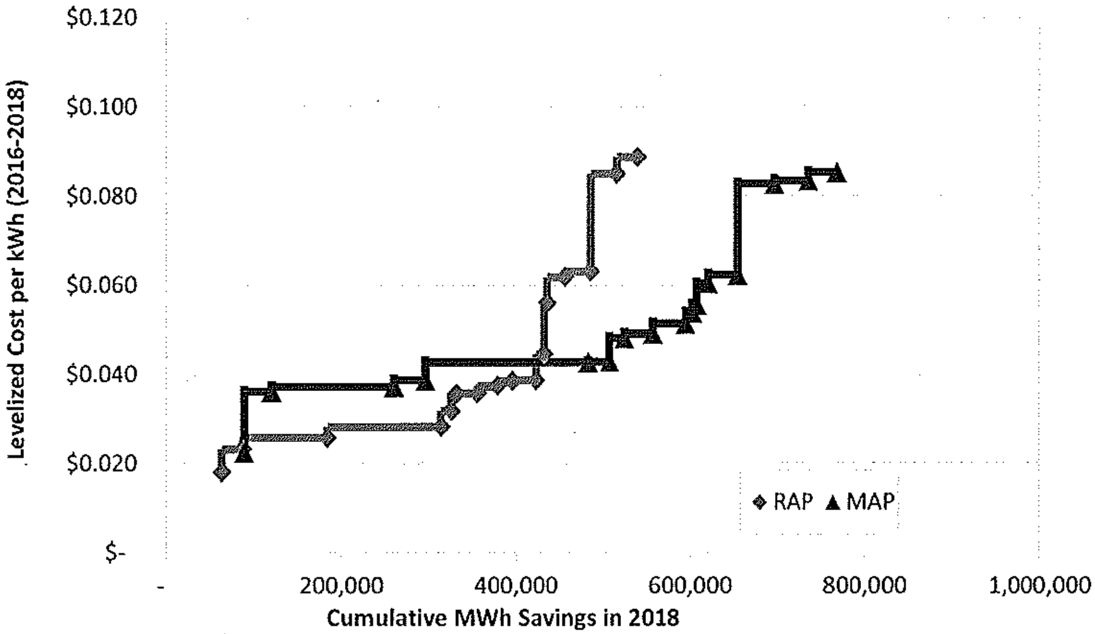
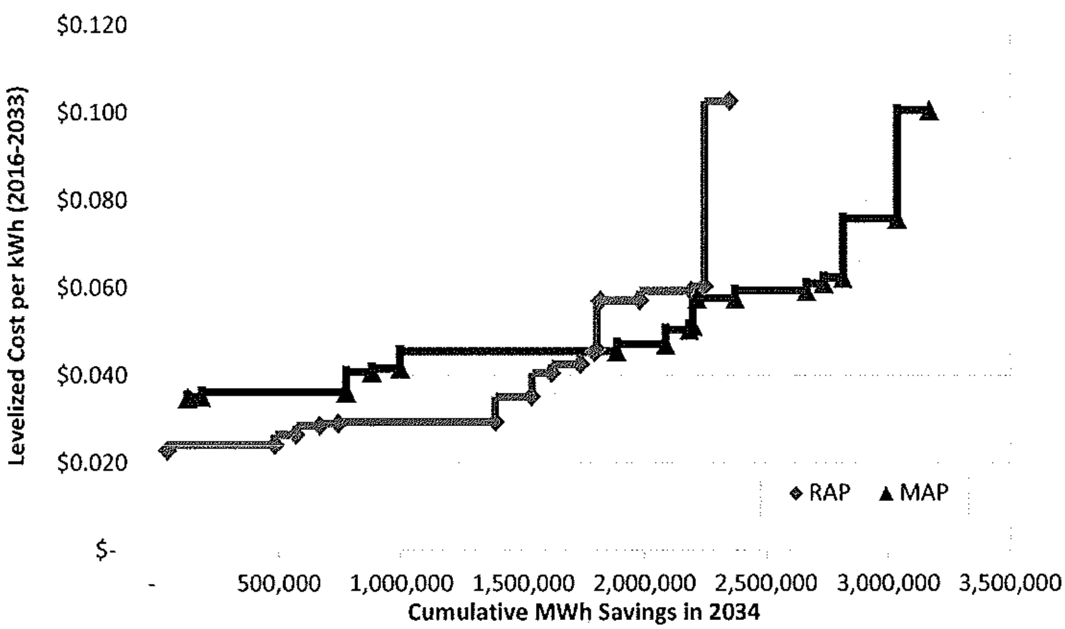


Figure 12 *Levelized Cost Supply Curves, 2016–2033 RAP and MAP Portfolios*



Demand Response

The primary objectives of demand response typically are to either (1) induce lower electricity use at times of high wholesale market prices or (2) provide relief when system reliability is jeopardized. Since Ameren Missouri is projected to have sufficient generation planning reserves throughout most, if not all, of the study period, the Ameren Missouri customer value proposition of demand is to attempt to induce lower electricity use at time of high wholesale market prices.

Definitions of Realistic and Maximum Achievable Potential

The definitions of realistic achievable potential (RAP) and maximum achievable potential (MAP) necessarily are different for energy efficiency and demand response for Ameren Missouri. The reason is that the DR resources must align with current MISO market constructs and practices. The current MISO environment creates certain constraints for the DR portfolio that do not have an analogue in the EE portfolio. Most notably, the MISO rules currently require that resources be contractually firm and dispatchable, ruling out pricing programs that require non-firm, customer behavioral interventions. A second reason why RAP and MAP must be conceived differently is that Ameren Missouri does not have a need for DR assets for reliability purposes in the business-as-usual capacity forecast. Therefore, RAP and MAP are defined as follows for DR:

- Ameren Missouri defines RAP as the case in which Ameren Missouri might acquire customer demand response resources for the sole purpose of bidding into the MISO capacity market as currently configured. This would be a forecast of likely customer behavior under realistic DR program design and implementation, taking into account existing market, financial, political, and regulatory barriers that are likely to limit the amount of savings that might be achieved through demand response programs in other RTO jurisdictions. The DR options considered in RAP are DLC and capacity reduction.
- Ameren Missouri defines MAP as the case in which Ameren Missouri might acquire customer demand response resources for system reliability under *revised* MISO demand response business practices, where non-firm, voluntary customer curtailment programs in addition to firm, mandatory customer curtailment programs would be eligible to participate in the MISO capacity market. All DR options were considered in MAP.

The study considered the full spectrum of demand-response programs available in the industry today. After careful consideration, the options in Table 5 were chosen for analysis. This table shows the eligible customer classes for each DR option and also lists the end uses that are likely to be controlled during DR events.

Table 5 DR Options Matrix

Demand Response Option	Eligible Customer Classes	Targeted End Uses
Residential Direct Load Control (DLC)	Single Family residential customers with central air conditioning (CAC), Water Heating, and Smart Appliances	CAC, Water Heating, Smart Appliances
C&I Direct Load Control (DLC)	Small C&I (SGS) with CAC and Water Heating	CAC, Water Heating
Capacity Reduction	Medium C&I (LGS) Large C&I (SPS) Extra Large C&I (LPS)	Customer specific uses
Dynamic Pricing	All residential and C&I classes	Any

Two additional assumptions were central to the DR analysis:

- A three-year useful life for all DR resources was chosen to coincide with each of Ameren's three-year MEEIA implementation plans. This decision was made, in large part, to mitigate MISO capacity market price risk and uncertainty. This is due to the fact that the value proposition of demand response to Ameren customers in the current planning horizon is to sell capacity into the MISO market for the purpose of reducing revenue requirements. Because MISO is currently 8,100 MW long on generation, the value of capacity is low in the short term and needs to be carefully considered for planning purposes. The 2013/2014 MISO capacity auction yielded capacity prices of $1.05/MW-day, which is nearly $0 per kW-year.
- Dynamic pricing refers to a critical-peak pricing (CPP) option, which uses price signals in the form of high prices during relatively short critical peak periods to encourage customers to reduce their usage on event days. The customer incentive is a larger discount during off-peak hours throughout the year. The CPP rate is modeled as a voluntary or opt-in tariff, which assumes 20% participation[2].

The potential estimates are driven by the cost-effectiveness results for each of the DR options. In this study, cost-effectiveness was tested in each year to determine the first year in which each option was cost-effective. "Cost effective" in the period 2017-2019 requires explanation. The Ameren Missouri forward view of capacity prices is based on the MISO cost-of-new-entry (CONE) capacity price projections. Under CONE, the MISO capacity market is expected to top out at the price of a CTG and remain at that level for the duration of the planning period. The reality is that the neither MISO nor any of the other RTO capacity markets may ever reach the equivalent cost of a CTG much less maintain that price at a constant level for the duration of a planning period. Since the primary objective of the Ameren Missouri demand response potential analysis is to sell capacity into the MISO capacity markets in this study, a critical sensitivity to which a high probability is assigned is a projection of capacity prices that reflect historical capacity pricing patterns. That sensitivity analysis is shown below.

Table 6 shows the results of the cost-effectiveness analysis. Key findings from this assessment are:

- In the year 2016, no demand savings are realized because none of the DR options are cost-effective in that year.
- From 2017–2019, the only cost-effective program contributing achievable DR potential is the capacity reduction option.
- Residential DLC savings begin in 2020, the first cost-effective year for this option. DLC is assessed to be cost-effective only for the Residential High usage segment. The program ramps up over a five-year timeframe from 2020–2025 and savings grow rapidly in that time period and remain steady thereafter.
- Under MAP considerations, additional savings are realized from residential and C&I dynamic pricing. For the residential sector, dynamic pricing is cost-effective for the Residential-High usage segment, beginning in 2020. For the Residential-Medium usage segment, dynamic pricing is cost-effective, beginning in 2029. For the C&I sector, dynamic pricing is cost-effective for medium- and large-sized C&I customers, beginning in 2020.

[2] This is in contrast to the 2010 Study which assumed an opt-out design with 75% participation.

Table 6 Cost-effectiveness Screening Results Summary

Program	Class	Cost-effectiveness
Residential- Direct Load Control (AC and Water Heating)	Residential-Low	*No*
	Residential-Medium	*No*
	Residential-High	Yes (beginning 2020)
Residential- Direct Load Control (Smart Appliances)	All Residential	*No*
C&I Direct Load Control	Small C&I (SGS)	*No*
Capacity Reduction	Medium C&I (LGS)	Yes (beginning 2018)
	Large C&I (SPS)	Yes (beginning 2017)
	Extra-Large C&I (LPS)	Yes (beginning 2017)
Residential Dynamic Pricing	Residential-Low	*No*
	Residential-Medium	Yes (beginning 2029)
	Residential-High	Yes (beginning 2020)
C&I Dynamic Pricing	Small C&I (SGS)	*No*
	Medium C&I (LGS)	Yes (beginning 2020)
	Large C&I (SPS)	Yes (beginning 2020)

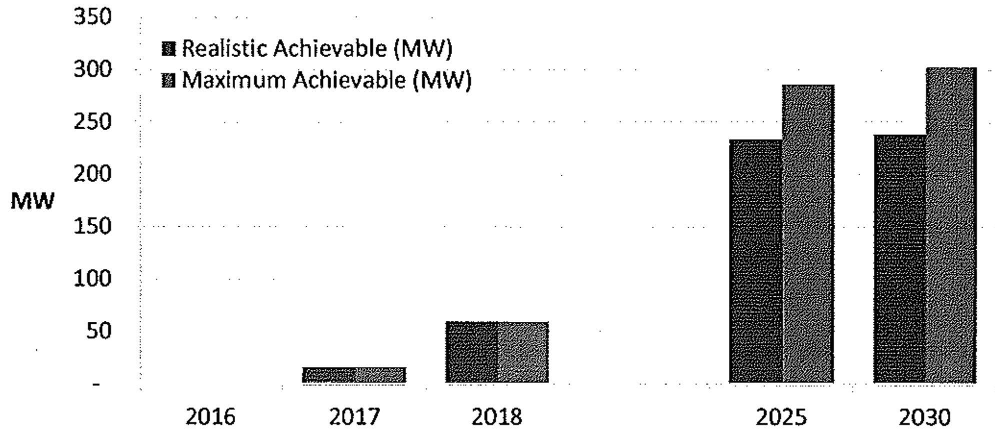
Table 7 presents the summary of estimated demand savings from relevant demand response options. Under RAP, demand response savings range from 16 MW in 2017[3] to 238 MW in 2030. This represents 0.2% to 2.9% of system peak reduction, respectively. The MAP case differs from RAP in that non-firm, pricing options are assumed to gain traction in MISO, allowing additional savings from residential and C&I dynamic pricing. Under MAP, savings in 2030 increase to 303 MW or 3.7% of system peak reduction. Figure 14 shows costs associated with specific demand response programs that comprise the cost-effective potential for realistic achievable potential.

Table 7 Summary of Demand Response Savings

	2016	2017	2018		2025	2030
System Peak Forecast (MW)	7,328	7,368	7,420		7,901	8,241
Peak Demand Savings (MW)						
RAP Program Potential		16	60		234	238
MAP Program Potential		16	60		286	303
Savings (% of System Peak)						
Realistic Achievable Potential	0.0%	0.2%	0.8%		3.0%	2.9%
Maximum Achievable Potential	0.0%	0.2%	0.8%		3.6%	3.7%

[3] The avoided costs for this analysis are based on the Ameren forward view, reflecting the cost-of-new entry for a peaking generator and the results show that demand response potential in the 2016-2018 timeframe is very small. Volume 4 shows results of a sensitivity analysis performed with respect to avoided costs and longer program life. The potential savings during the 2016-2018 time period are zero under an avoided cost scenario where capacity market prices have historical patterns as experienced in more experienced RTOs. Chapter 4 goes into detail on how Ameren Missouri developed alternative scenario capacity market prices and the ensuing cost-effectiveness analyses.

Figure 13 Summary of Demand Response Savings



For each program, levelized costs were developed for two timeframes: the upcoming implementation cycle of 2016–2018 and the entire study period of 2016–2033. The levelized costs and the peak demand impacts are combined to produce data for supply curves. Data sets and graphical depictions of these supply curves are provided for both timeframes in Figure 14 and Table 8 below.

Figure 14 Demand Response Program Costs under RAP

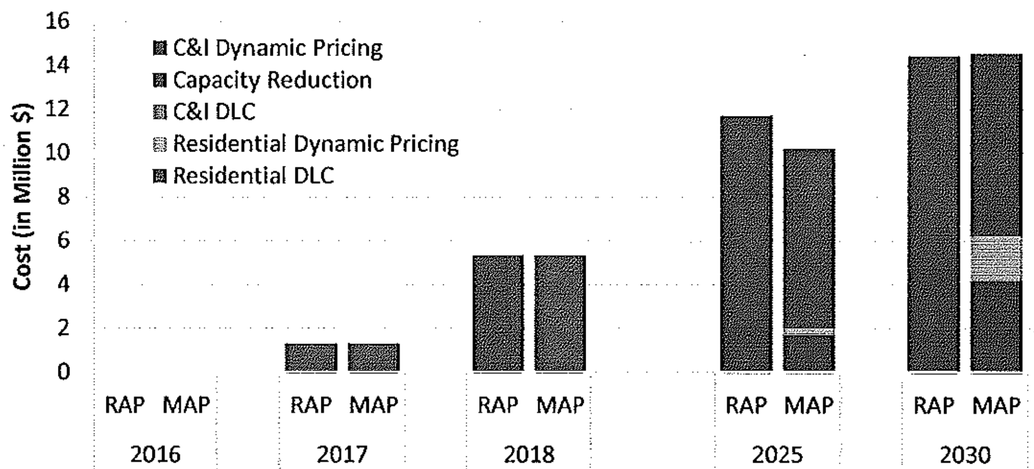


Table 8 Supply Curve Data by DR Option from 2016–2033 under MAP

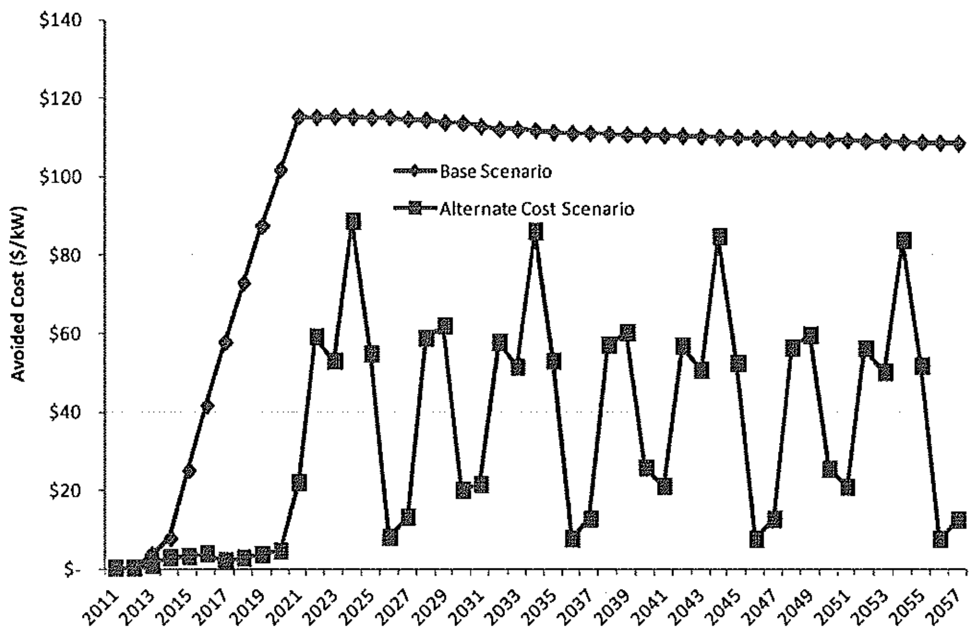
Program	Class	Levelized Cost 2016–2033 ($/kW)	Cumulative MW Reductions in 2033
Direct Load Control	Residential-High	$47.43	76.18
Capacity Reduction	Medium C&I (LGS)	$70.02	79.68
Capacity Reduction	Large C&I (SPS)	$68.43	30.56
Capacity Reduction	Extra Large C&I (LPS)	$67.69	17.78
Dynamic Pricing	Residential-Medium	$80.24	18.67
Dynamic Pricing	Residential-High	$27.77	45.67
Dynamic Pricing	Medium C&I (LGS)	$5.84	41.17
Dynamic Pricing	Large C&I (SPS)	$6.50	15.79

Sensitivity Analysis

One of the key assumptions for the demand response analysis is the avoided-cost forecast. In the base case analysis shown above, the Ameren forward view on avoided costs was used. The Ameren forward view of the market price for capacity is based on the assumption that electric load continues to grow and that there is a finite amount of generation in the market. When load approaches supply, new resources will be required to meet resource adequacy requirements, and these resources will have a cost equal to MISO's assumed Cost of New Entry ("CONE"). The MISO market remains at CONE to the end of the planning horizon. As a sensitivity scenario, an alternate case used more dynamic avoided costs. The avoided costs used in the alternate case are based on a multi-dimensional analysis of MISO's projected capacity position over time, as well as an analysis of the market price of capacity in other more mature RTO markets for capacity. The alternative or market sensitivity capacity view is indicative of a more dynamic market with the balance between load and generation ebbing and flowing such that capacity prices approaching those of new CTGs may seldom, if ever, be reached.

Figure 15 shows the two sets of avoided costs and how they differ.

Figure 15 Avoided Cost Scenarios ($2011)[4]



A second sensitivity analysis was performed around the assumption of the three-year life for DR programs. The program lifetime was extended beyond the three-year program implementation cycle assumed in the base case. This allowed program costs and market ramp-up to be spread over a longer time period for the applicable program options as below:

- Direct Load Control lifetime increases from three to ten years
- Dynamic Pricing lifetime increases from three to twenty years

Table 9 presents a comparison of the two sensitivity analyses with the base case.

[4] The avoided cost numbers are represented in real 2011 dollars. Ameren provided avoided costs in nominal 2011 dollars. A conversion rate was applied based on the Consumer Price Index (CPI) from AEO 2012.

Table 9 DR Potential - Comparison of Sensitivity Case (MW)

	2016	2017	2018	2025	2030
RAP DR Potential (MW)					
Base Case	-	16	60	234	238
Market-based Avoided Costs	-	-	-	-	-
Longer Program Life	55	126	238	434	446
RAP DR Potential (% of the system peak)					
Base Case	-	0.22%	0.80%	2.96%	2.89%
Market-based Avoided Costs	-	-	-	-	-
Longer Program Life	0.75%	1.71%	3.21%	5.49%	5.41%
MAP DR Potential (MW)					
Base Case	-	16	60	286	303
Lower Avoided Costs	-	-	-	52	53
Longer Program Life	55	126	238	540	563
MAP DR Potential (% of the system peak)					
Base Case	-	0.22%	0.80%	3.62%	3.68%
Lower Avoided Costs	-	-	-	0.66%	0.64%
Longer Program Life	0.75%	1.71%	3.21%	6.83%	6.83%

Total Peak Demand Savings from EE and DR

Table 10 presents the combined savings from EE and DR programs. As shown above, energy-efficiency savings contribute the lion's share to the overall peak savings.

Table 10 Total Peak Demand Savings from Energy Efficiency and Demand Response

	2016	2017	2018		2025	2030
System Peak Forecast (MW)	7,328	7,368	7,420		7,901	8,241
Peak Demand Savings (MW)						
RAP Program Potential	38	88	170		594	714
MAP Program Potential	54	118	216		778	945
Savings (% of System Peak)						
Realistic Achievable Potential	0.5%	1.2%	2.3%		7.5%	8.7%
Maximum Achievable Potential	0.7%	1.6%	2.9%		9.9%	11.5%

Distributed Generation and Combined Heat and Power

Distributed generation (DG) systems are technologies that generate electricity and are located onsite at customer premises. Combined heat and power (CHP) systems generate both electricity and thermal energy that are used onsite. This study considered both options.

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

- Solar photovoltaic (PV) systems
- Reciprocating engine
- Micro-turbine
- Combustion turbine (CT)
- Boiler with back-pressure steam turbine
- Fuel cell with heat recovery
- Stirling engine
- Small wind
- Reciprocating engine with heat recovery
- Micro-turbine with heat recovery
- Combustion turbine with heat recovery
- Fuel cell
- Combined cycle combustion turbine (CCCT)
- Organic rankine cycle

Summary of DG/CHP Potential

Table 11 and Figure 16 show the high-level results of the DG-CHP analysis for energy and demand respectively. In general, unfavorable economics screen out a large swath of technical potential, and even for those technology applications that are cost-effective, market adoption is low, given the relative complexity of purchasing, owning, operating, and maintaining the units. The realistic achievable potential savings in 2030 are 488 cumulative GWh or 1.4% of the baseline projection. The corresponding maximum achievable potential savings in 2030 are 672 GWh, or 2.0% of the baseline projection.

Table 11 DG-CHP Energy Impact Results

	2016	2017	2018	2025	2030
Baseline Forecast (GWh)	**30,249**	**30,449**	**30,694**	**32,228**	**33,721**
Cumulative Energy Savings (GWh)					
Realistic Achievable	6	7	9	43	488
Maximum Achievable	8	10	13	60	672
Economic Potential	57	72	90	389	4,159
Technical Potential	720	898	1,119	4,729	10,946
Energy Savings (% of Baseline)					
Realistic Achievable	0.0%	0.0%	0.0%	0.1%	1.4%
Maximum Achievable	0.0%	0.0%	0.0%	0.2%	2.0%
Economic Potential	0.2%	0.2%	0.3%	1.2%	12.3%
Technical Potential	2.4%	2.9%	3.6%	14.7%	32.5%

Figure 16 ***DG-CHP Energy Impact Results (GWh)***

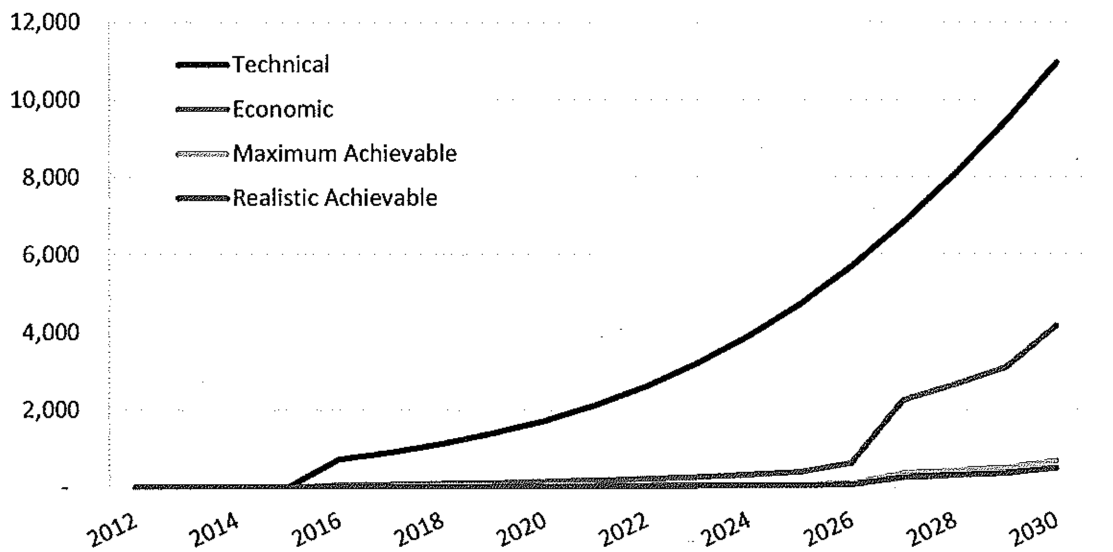
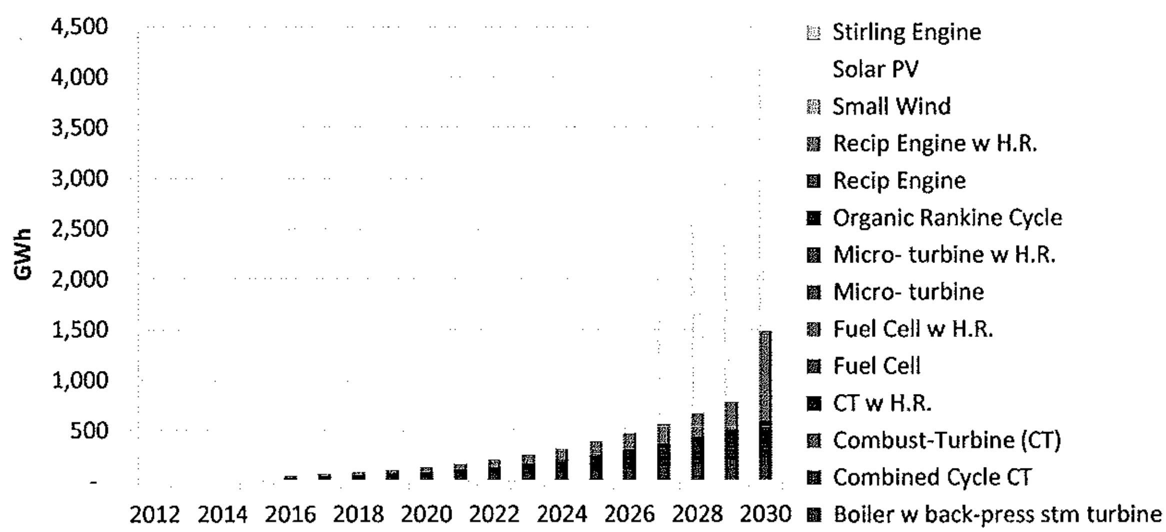


Figure 17 presents a graphical summary for the year 2016-2030. Despite heavy subsidies and declining costs, Solar PV is not cost-effective from a TRC perspective until 2026 for C&I and 2027 for the residential sector.

Figure 17 ***DG-CHP Energy Economic Potential by Technology (GWh)***



In addition to the overall market assessment, this study included in-depth case studies of DG-CHP applications for two Ameren customers: a major corn milling facility and a major manufacturing facility. The customer names and specific details of the case studies are proprietary, but relevant findings and lessons learned are presented here.

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

- Natural gas fueled combustion turbine generator with 3+ MW of electricity generating capacity; producing waste heat in the form of steam for process heating
- Waste heat valuation based on displacing boiler fuel use
- Annual O&M costs include turbine overhaul cost at half-life
- 20 year system life
- $10,000 grid interconnection study cost
- Real discount rate of 3.95%
- Uptime of 90%+ hours per year
- Avoided cost benefits for energy and capacity as provided by Ameren Missouri
- Actual pricing and bidding came from quotes from a manufacturer

As shown in Table 12, the TRC ratios are above 1.0, indicating that the projects are cost-effective, but these results are sensitive to many factors. During a drought-year, production and heating requirements at the milling facility may fall, reducing the value of waste heat. In a sensitivity analysis to model a prolonged drought scenario, the TRC ratio dropped to 1.01. An additional factor to consider is the customer's Ameren Missouri rate structure, which contains a standby charge (Rider E) for Ameren to maintain the necessary capacity if the customer would choose to revert to grid power in the event of an emergency shut-down of their DG-CHP system. For sizeable systems, the details of this cost result from a complex interconnection study, scenario analysis, and negotiation — and can have a significant impact on the overall project economics.

Table 12 Total Resource Cost (TRC) Test Results for DG-CHP Case Studies

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

Demand-side Rates

Well-designed and innovative demand-side rates can provide energy and peak demand reduction savings opportunities. Examples include inclining block rates which are used by other utilities to promote efficient energy use and time-varying rates which are used by other utilities to reduce peak demand and to shift load to off-peak periods.

Demand-side rates pose some risk to customers since they may end up having higher or lower bills depending on the total amount of energy that they consume and/or the coincidence of their load profile with the class average load profile. Some customers may see significant bill increases and that fear keeps many customers from adopting these rates if they were to be offered on an opt-in basis. This makes it difficult to forecast customer adoption for demand-side rates. The rates could be made the default tariff and offered on an opt-out basis. In this case, most customers are likely to stay on the rates because of inertia and the forecasting task is a bit easier. However, if the rates were to be offered on a mandatory basis, the need to make this forecast goes way.

The Brattle Group, as a subcontractor to EnerNOC, engaged with Ameren Missouri stakeholders to identify the most desirable set of rates to analyze for this study. *Brattle* also reviewed demand-side rates that have been offered to customers by utilities across the U.S. and internationally. Table 13 summarizes the utilities that offer or have offered IBRs and TOU rates, and were considered in the review of rate offerings.[5] *Brattle* assembled a "menu" of demand-side rates based on this review, and presented them at a workshop with Ameren Missouri stakeholders. Each rate's applicability to Ameren Missouri's service territory was determined through this stakeholder process.

The stakeholder survey sought to answer two primary questions: What are the most important rate making objectives/criteria for Ameren and its stakeholders? And how do various candidate rates perform in meeting these objectives? A total criteria-weighted score was created for each rate, based on how individuals assessed each rate's performance for each objective, and weighted by the importance they placed on that objective.

Based on this stakeholder feedback, four rate combinations for residential and C&I customers were identified. These included an inclining block rate for residential customers, a time-of-use rate for Residential and Small General Service customers, and a critical peak pricing rate for Large General Service customers.

In the next step, a set of demand-side rates specific to Ameren Missouri's service territory were developed. This required the collection of data on billing distributions, class load profiles, existing rates and avoided costs of energy and capacity. Each rate was designed to be revenue neutral, meaning that it will generate the same revenue for the class as the existing tariff (in the absence of a change in the class load profile). Illustrations of the demand-side rates that were developed for each customer class are included in Volume 6.

Finally, the impact of these rates on peak demand energy consumption was simulated using Brattle's Price Impact Simulation Modeling (PRISM) suite. PRISM contains price elasticities from impact evaluations of inclining block rates and time-varying rates that have been carried out in other jurisdictions[6].

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[5] The time varying rates are discussed further in: Ahmad Faruqui and Jennifer Palmer, "The Discovery of Price Responsiveness – A Survey of Experiments Involving Dynamic Pricing of Electricity," Energy Delta Institute, Vol.4, No. 1, April 2012.
http://www.energydelta.org/mainmenu/edi-intelligence-2/our-services/quarterly-2/edi-quarterly-vol-4-issue-1

[6] The IBR elasticities are supported by the findings of a Stanford University researcher who analyzed the impacts of IBRs in California. In PRISM, price elasticity in the first tier of the IBR is assumed to be smaller than in the second tier. Conceptually, the first tier includes necessary end-uses such as lighting and refrigeration; the second tier includes more discretionary end-uses such as air-conditioning and heating.
Residential TOU price elasticities were based on the results of BGE's four-year (2008 – 2011) dynamic pricing pilot. The BGE elasticities come from a utility with a roughly similar climate as Ameren Missouri and have been adjusted to be consistent with Ameren Missouri's weather conditions (as represented by the temperature-humidity index). The results of simulations with these elasticities align well with the results of Ameren Missouri's 2005 residential CPP pilot.

Table 13 Utilities Considered In Demand-side Rates Analysis

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

Other inputs to PRISM are the customer's existing load profile, existing rates, and new rates. The difference between the existing and new rates is combined with the elasticities to estimate the percentage change in usage that would take place once the new rates went into effect. This percentage change is applied to the existing usage profile to predict the new usage profile on a per-customer basis. The resulting change is multiplied by an estimate of the number of customers who will take the new rates to develop an estimate of the aggregate impact of the rates. Volume 6 includes illustrations of the PRISM modeling framework.

Using this methodology, it was found that demand-side rates have the potential to reduce Ameren Missouri's system peak by between 0.8% and 3.5%. The size of the impacts depends in part on whether the rates are offered on an opt-in or opt-out basis and in part on the specific rates chosen for the analysis.

- Under an opt-in offering, customers must proactively sign up in order to enroll in the new rate. This yields a lower participation rate.
- Under an opt-out offering, customers are automatically defaulted on to the new rate, with the option to revert back to the otherwise applicable rate. This yields a higher participation rate.

Small General Service elasticities were based on research conducted by the California IOUs during the California Statewide Pricing Pilot. Large General Service price elasticities were based on analysis of full-scale rollouts in the Northeastern U.S., as summarized in a study by Lawrence Berkeley National Lab's Demand Response Research Center.

The results of the portfolio-level impacts are summarized in Table 14.

Table 14 Projected Peak Reduction by Portfolio

Combination	Participation Scenario	Residential Rate	SGS Rate	LGS Rate	Peak Reduction (MW)	Peak Reduction (% of System Peak)
1	Opt-In	TOU	TOU	CPP	69	0.82%
2	Opt-In	IBR	TOU	CPP	78	0.93%
3	Opt-Out	TOU	TOU	CPP	259	3.07%
4	Opt-Out	IBR	TOU	CPP	294	3.48%

About EnerNOC

EnerNOC's Utility Solutions Consulting team is part of EnerNOC's Utility Solutions, which provides a comprehensive suite of demand-side management (DSM) services to utilities and grid operators worldwide. Hundreds of utilities have leveraged our technology, our people, and our proven processes to make their energy efficiency (EE) and demand response (DR) initiatives a success. Utilities trust EnerNOC to work with them at every stage of the DSM program lifecycle – assessing market potential, designing effective programs, implementing those programs, and measuring program results.

EnerNOC's Utility Solutions deliver value to our utility clients through two separate practice areas – Implementation and Consulting.

- Our Implementation team leverages EnerNOC's deep "behind-the-meter expertise" and world-class technology platform to help utilities create and manage DR and EE programs that deliver reliable and cost-effective energy savings. We focus exclusively on the commercial and industrial (C&I) customer segments, with a track record of successful partnerships that spans more than a decade. Through a focus on high quality, measurable savings, EnerNOC has successfully delivered hundreds of thousands of MWh of energy efficiency for our utility clients, and we have thousands of MW of demand response capacity under management.
- The Consulting team provides expertise and analysis to support a broad range of utility DSM activities, including: potential assessments; end-use forecasts; integrated resource planning; EE, DR, and smart grid pilot and program design and administration; load research; technology assessments and demonstrations; evaluation, measurement and verification; and regulatory support.

The team has decades of combined experience in the utility DSM industry. The staff is comprised of professional electrical, mechanical, chemical, civil, industrial, and environmental engineers as well as economists, business planners, project managers, market researchers, load research professionals, and statisticians. Utilities view EnerNOC's experts as trusted advisors, and we work together collaboratively to make any DSM initiative a success.

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