Demand-side Management Market Potential Study

Volume 4: Demand Response Analysis

Final Report

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Presented on:
December 20, 2013

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CONTENTS

LIST OF FIGURES

LIST OF TABLES

CHAPTER 1

INTRODUCTION

Ameren Missouri commissioned this Demand Side Management (DSM) Market Potential Study to assess the various categories of electrical energy efficiency (EE), demand response (DR), and distributed generation/combined heat and power (DG-CHP) potentials in the residential, commercial, and industrial sectors for the Ameren Missouri service area from 2016 to 2033. 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 projection.

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 (CHP) and distributed generation (DG) installations over the specified time horizon. This report is Volume 4, which addresses the demand response analysis.

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:

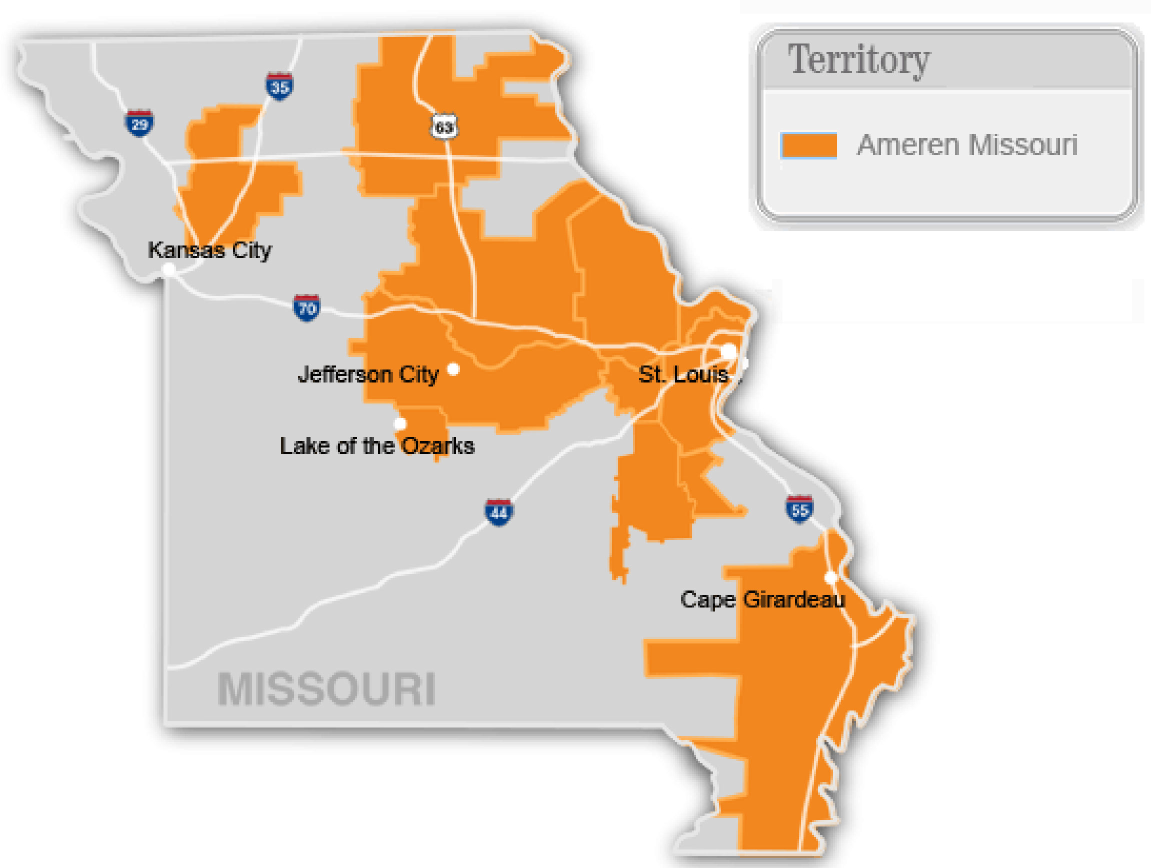
- Conducted primary market research to collect data for the Ameren Missouri service territory, including: electric end-use data, saturation data, and customer demographics and psychographics.
- Characterized how customers in the Ameren Missouri service territory make decisions related to their electric 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 2033 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.
- 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.

- 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.

Background

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

Figure 1-1 Ameren Missouri 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.

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.

Background on Demand Response Considerations at Ameren Missouri

Definition(s) of Demand Response

The Federal Energy Regulatory Commission (FERC) defines demand response as changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized. FERC's definition of demand response conforms to the North American Electric Reliability Corporation (NERC) definition developed by a consortium of utilities and end users – of which Ameren had a leadership role.

The Midwest Independent System Operator (MISO) defines demand response as the ability of a Market Participant to reduce its electric consumption in response to an instruction received from MISO. MPs can provide such demand response either with discretely interruptible or continuously controllable loads (Demand Resources) or with behind-the-meter generation.

The Missouri Integrated Resource Planning (IRP) rules define demand response in the context of the definition of an energy management measure. The Missouri IRP rules define energy management as any device, technology, or operating procedure that makes it possible to alter the time pattern of electricity usage so as to require less generating capacity or to allow the electric power to be supplied from more fuel efficient generating units. Energy management measures are sometimes referred to as demand response measures.

While the definitions have commonalities, the FERC definition of demand response is clear that the purpose of demand response is to either (1) induce lower electricity use at time of high wholesale market prices or (2) provide relief when system reliability is jeopardized. For this analysis, it is important to keep in mind the value proposition to Ameren Missouri customers of DR in terms of both its ability to improve system reliability and its potential to influence wholesale market price impacts relative to the costs of implementing DR.

Another aspect to note in the Missouri IRP rule definition of DR is the inclusion of the term “demand response measures.” Energy efficiency refers to using less energy to provide the same level of service to the energy consumer in an economically efficient way. Energy efficiency is about replacing an inefficient measure, such as an incandescent light bulb, with an efficient measure such as a compact fluorescent light bulb. Demand response, in contrast, is a program based on customer behavior changes to modify their normal electricity consumption patterns. Thus, for demand response there are no baselines and efficient measures as there are for energy efficiency. Furthermore, for purpose of cost-effectiveness analysis, EE measures have an effective useful life, usually tied to the mean time until failure of equipment, over which they continue to provide savings. In contrast, the life of a DR program depends on how long a utility will choose to run the program. With a longer life, start-up costs can be spread over a greater time period and the program is more likely to be cost-effective.

The National Action Plan For Energy Efficiency (NAPEE) paper entitled “Coordination of Energy Efficiency and Demand Response” published in January 2010 echoes the fact that energy efficiency is about the implementation of measures and demand response is about programs. Here are two extracts from the NAPEE paper:

> Page 2-1:
> “The definition of energy efficiency makes three key assumptions: (1) existing consumer devices are replaced with devices that use less energy, assuming no change in operating practice; (2) new energy-using devices should perform their functions using less energy; and (3) actual kilowatt-hour usage is reduced, irrespective of when that reduction occurs (i.e., it is not time-sensitive).”
>
> Page 2-7:
> *“When customers participate in demand response, there are three possible ways in which they can change their use of electricity (DOE, 2006):*
>
> > *Customers can forego or reduce some uses of electricity. Raising thermostat settings, reducing the run time of air conditioners, dimming or reducing lighting levels, or taking some elevators out of service are common customer load curtailment strategies.*
> >
> > *Customers can shift electricity consumption to a time period outside the demand response event or when the price of electricity is lower. For example, an industrial facility might employ storage technologies to take advantage of lower cost off-peak energy, reschedule or defer some production operations to an overnight shift, or in some cases, shift production to companion plants in other service areas. Similarly, with enough notice, commercial or residential customers could pre-cool their facilities and shift load from a higher to lower cost time period. Residential and commercial customers could also choose to delay running certain appliances until prices are lower. Most successful demand response programs have a customer override capability that allows the customer to choose not to adjust its energy use when a specific demand response event is called.”*

Ameren Missouri History of Implementation of Customer Demand Response Programs

Ameren has offered eight demand response programs. They are described below:

1. Ameren Missouri offered an interruptible rate to large industrial customers through 2000. A total of five customers, providing a total contractual commitment of 54 MW, participated on the rate. The interruptible tariff was structured with a 50% demand charge credit that averaged approximately $5/kW-month at the time. Interruptible events were limited to system reliability emergencies. Few interruptible events were called each year. The interruptible rate tariff was discontinued in 2000.

2. Ameren Missouri also offered a subsequent pilot interruptible rate referred to as Rider G for smaller industrial customers with smaller demand charge credits. A total of four customers, providing a total contractual commitment of 17 MW, participated on the rate. As their production demands increased, the four participating customers eventually opted out of the rate. Rider G was discontinued in 2003.
3. Ameren Missouri offered commercial and industrial customers a voluntary curtailment rate option or a peak power rebate (PPR) program referred to as Rider L beginning in 1999. Ameren Missouri opted to offer a non-penalty based price-responsive DR on the premise that customers may be more likely to sign-up for non-penalty based programs and that penalty based and non-penalty based programs have similar response characteristics. The PPR program structure is that customers remain on the standard rate for all non-event hours but are offered an incentive rate for a pre-determined number (in this case 60) of critical-peak event hours during a program year.

   A total of 20 customers representing a total potential load of 67 MW enrolled in Rider L. The last Rider L curtailment event was called in 2009. A total of four Rider L customers participated in the 2009 curtailment events and these customers combined offered a range of approximately 6 to 9 MW peak demand reduction per event.
4. Ameren Missouri also offered a commercial and industrial customer interruptible program with a slight difference from the Rider L program logic. Rider M was also voluntary and paid participating customers a monthly curtailment option fee plus a price per kWh. The fees and kWh prices provided for under Rider M were agreed upon in advance by the Company and the customer, based upon various customer selected curtailment options contracted for with the Company, and were applicable during the summer billing months of June – September.
5. In Case No ER-2007-0002, Ameren Missouri proposed a tariff to implement a new industrial demand response pilot program known as Rider IDR. The pilot program was designed to assess whether industrial process customers would/could respond to load curtailments to interrupt their use of power when they are directed to do so by Ameren Missouri. The tariff defined the occasions when a customer could be asked to interrupt, but the decision to interrupt would be at the discretion of Ameren Missouri. Rider IDR limited the hours available for interruption to 200 hours per year. The customer could choose the amount of curtailable load to be included in the program. The availability of the program was to be limited to no more than five customers with a total demand response aggregated load of 100 MW and would last for three years. Customers who agreed to participate in the program would be paid a demand credit of $2.00 per kW per month with an additional credit of $0.08 per kWh when interrupted.

   Rider IDR was never implemented due primarily to the inability to align the provisions in the tariff with the MISO Business Practice manual to bid demand response resources into the MISO market.
6. In 2004 and 2005, Ameren Missouri conducted a Residential Time-Of-Use (RTOU) Pilot study. The RTOU Pilot study encompassed two innovative rate offerings that provided financial incentives for customers to modify their consumption patterns during higher priced critical peak periods (CPP). Originally, the rate offerings were organized into three treatment groups for the Pilot study:
   - The first group of customers received a three-tier TOU rate[1] with high differentials.
   - The second group of customers received the same TOU rate as the first treatment group but was also subject to a critical peak pricing (CPP) element.

[1] The TOU rates differ by season (i.e., summer versus winter).

- o The third group of customers received the same treatment, i.e., TOU rate and CPP, as treatment group number two but had enabling technology, i.e., a "smart" programmable controllable thermostat, installed by Ameren. The enabling technology automatically increased the customer's thermostat setting during critical peak pricing events.

For 2005, the first treatment group, i.e., the time-of-use rate only, was dropped from the Pilot Study. The principal reason for dropping the time-of-use only group was that this group failed to display a significant shift in load from the on-peak to the mid-peak or off-peak periods. Therefore, the second year pilot focused on the critical peak pricing element and those customers with smart thermostats. Fifteen-minute interval load monitoring equipment was available on the total premises load for a statistically representative sample of customers in each treatment group. In addition to the treatment groups, Ameren Missouri constructed control groups for use in the analysis. Once again, fifteen-minute interval load monitoring equipment was available on a statistically representative sample of control group customers.

The following table presents findings for the eight CPP periods in 2005. The table presents the average demand for the control and RTOU treatment groups. An additional 0.52 kW on average was achieved by the group with the enabling technology.

Three Tier TOU with CPP (CPP)									
CPP Event			Control Group (kW)	RTOU Pilot Group (kW)	Difference Control-RTOU (kW)	Percent Difference (%)	T-Test	Pr>|t|	Ho: Control=RTOU
Date	Hour Ending Start	Hour Ending End							
30-Jun-05	3:00 PM	6:59 PM	5.35	4.85	0.50	9.3%	2.63	0.0088	Reject
21-Jul-05	3:00 PM	6:59 PM	5.71	4.91	0.80	14.1%	3.75	0.0002	Reject
22-Jul-05	3:00 PM	6:59 PM	5.84	5.05	0.79	13.5%	3.54	0.0005	Reject
26-Jul-05	3:00 PM	6:59 PM	5.98	4.91	1.06	17.8%	5.28	0.0000	Reject
2-Aug-05	3:00 PM	6:59 PM	5.38	4.73	0.65	12.1%	3.24	0.0013	Reject
9-Aug-05	3:00 PM	6:59 PM	5.64	4.74	0.90	16.0%	4.33	0.0000	Reject
10-Aug-05	3:00 PM	6:59 PM	5.01	4.24	0.76	15.2%	4.00	0.0000	Reject
19-Aug-05	3:00 PM	6:59 PM	5.61	4.88	0.74	13.1%	3.54	0.0004	Reject
Average			5.56	4.84	0.72	13.0%	3.90	0.0001	Reject

Three Tier TOU with CPP and Thermostat (CPP-THERM)									
CPP Event			Control Group (kW)	RTOU Group (kW)	Difference Control-RTOU (kW)	Percent Difference (%)	T-Test	Pr>|t|	Ho: Control=RTOU
Date	Hour Ending Start	Hour Ending End							
30-Jun-05	3:00 PM	6:59 PM	5.02	4.30	0.72	14.4%	2.93	0.0036	Reject
21-Jul-05	3:00 PM	6:59 PM	5.37	4.09	1.27	23.7%	5.22	0.0001	Reject
22-Jul-05	3:00 PM	6:59 PM	5.38	4.18	1.20	22.4%	5.39	0.0001	Reject
26-Jul-05	3:00 PM	6:59 PM	5.56	4.38	1.18	21.2%	4.93	0.0001	Reject
2-Aug-05	3:00 PM	6:59 PM	5.23	3.66	1.57	30.0%	6.30	0.0001	Reject
9-Aug-05	3:00 PM	6:59 PM	5.47	4.01	1.46	26.7%	5.76	0.0001	Reject
10-Aug-05	3:00 PM	6:59 PM	4.95	3.82	1.13	22.8%	4.95	0.0001	Reject
19-Aug-05	3:00 PM	6:59 PM	5.38	3.97	1.41	26.1%	5.49	0.0001	Reject
Average			5.29	4.05	1.24	23.5%	6.05	0.0001	Reject

7. From 1993 to 1998, Ameren Missouri implemented a residential central air conditioner direct load control program called "No Sweat." The Company invested a total of $1.9 million implementing the program during that time. The program logic was to pay customers an annual incentive payment of $40 for the option to interrupt their air conditioners a finite number of times. Customers participating in the program also received free HVAC diagnostic services from HVAC contractors hired by Ameren Missouri. Communication to switches that cycled customer air conditioners off and on was handled by the existing 154 MHz radio infrastructure at Ameren Missouri. Dead zones and poor reception reduced the cycling benefits, while the manual policing of the radio system added to the program cost.

8. In 2009, Ameren Missouri conducted a Personal Energy Manager (PEM) Rebate Pilot Program that had the dual purposes of assessing the effectiveness of potential residential price response programs and testing the associated technology. Part of the technology test was to determine whether new vendor (Tendril) hardware was compatible with Ameren Missouri's automated meter reading (AMR) system and how well it interfaced with the AMR meters.

This pilot program provided bill credits to residential customers who, at Ameren Missouri's request, voluntarily reduced their electricity consumption during *Price Response Events* designated by Ameren Missouri. To minimize any potential customer inconveniences, participants were recruited from Ameren Missouri staff who volunteered to take part. The program provided technology that enabled interactive energy monitoring and remote thermostat control in the home, allowing Ameren Missouri to test this technology. (The technology also assisted the customer in managing their electricity consumption during non-events.)

The Pilot program was implemented with installation of varying configurations of the new Tendril equipment in the homes of 374 Ameren Missouri employees during June and July of 2009.

The industry name for demand response programs with voluntary participation and no penalties for non-participation when load curtailment events are called is Peak Time Rebates (PTR). A key finding from the 2009 Ameren Missouri PEM pilot in the independent third-party evaluation of the program conducted by the team of Cadmus and PA Consulting was the difficulty in estimating an accurate baseline against which to assess load reductions by program participants. Cadmus and PA noted that customers who had taken no load reduction actions were often given an incentive payment and customers who had taken load reduction actions were often not compensated for their efforts. This may have been the first documentation that questioned the premise that PTR programs had no "losers." Subsequent evaluation, measurement and verification of large scale PTR programs in other jurisdictions, most notably California, have shown that PTR is not a low-cost program when payment for non-performance due to measurement error is considered.

Each of the eight Ameren Missouri demand response programs had a finite effective useful life. Some programs were terminated because the value received was not commensurate with the value paid. Some programs were terminated because they were pilot programs and fulfilled their pilot program testing objectives. Some programs were terminated because they were evaluated to not be cost-effective. Some programs were terminated simply because customers were not interested in participating.

Report Organization

This report is presented in six volumes as outlined below. This document is **Volume 4: Demand Response Analysis**.

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

Abbreviations and Acronyms

Throughout the report we use several abbreviations and acronyms. Table 1-1 shows the abbreviation or acronym, along with an explanation.

Table 1-1 Explanation of Abbreviations and Acronyms

Acronym	Explanation
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
Auto-DR	Automated Demand Response
B/C Ratio	Benefit to Cost Ratio
C&I	Commercial and Industrial
CAC	Central Air Conditioning
CPP	Critical Peak Pricing
C&I	Commercial and Industrial
CONE	Cost of New Entry
DLC	Direct Load Control
DR	Demand Response
DSM	Demand Side Management
EE	Energy Efficiency
EUL	Estimated Useful Life
FERC	Federal Energy Regulatory Commission
ICAP	Installed Capacity
IOU	Investor Owned Utility
IRP	Integrated Resource Plan/Planning
LGS	Large General Service
LPS	Large Primary Service
MAP	Maximum Achievable Potential
MEEIA	Missouri Energy Efficiency Investment Act
MFIQ	Multi-Family Income Qualified
MISO	Midwest Independent System Operator
MW	Megawatt
NAPEE	National Action Plan For Energy Efficiency
NERC	North American Electric Reliability Corporation
NPV	Net Present Value
O&M	Operations and Maintenance
PCT	Programmable Communicating Thermostat
PEM	Personal Energy Manager
PPR	Peak Power Rebate
PTR	Peak Time Rebate
RAP	Realistic Achievable Potential
RTOU	Residential Time-of-use
SGS	Small General Service
SPS	Small Primary Service
TOU	Time-of-use
TRC	Total Resource Cost test
WH	Water heater

ANALYSIS FRAMEWORK AND ASSUMPTIONS

Overview of Analysis Approach

The analysis approach for estimating demand response potential is, by necessity, different from the approach used for energy efficiency. Energy efficiency can occur outside of utility programs to the extent that it is naturally occurring or technology driven; but can be enhanced and enabled by utility programs. Demand response, however, does not exist without a utility program. A program-by-program analysis is therefore at the core of a demand-response potential study. The basic steps used to perform this assessment are as follows:

1. Segment market into customer classes
2. Establish baseline load and population forecast
3. Define relevant DR options by customer class
4. Outline participation hierarchy for DR options by customer class
5. Develop key assumptions (participation rates and impact assumptions)
6. Develop program costs assumptions
7. Assess cost-effectiveness of DR options
8. Estimate DR potential and develop program budgets
9. Present supply curve analysis for DR options
10. Conduct sensitivity analysis

In the remainder of this chapter, we describe the analysis steps in more detail.

Customer Classification

The first level of customer segmentation is by sector into residential and commercial and industrial (C&I) customers. For the DR analysis, further segmentation occurs into customer classes by size, based on maximum demand values. This typically aligns with utility rate schedules.

Table 2-1 shows the classification of residential customers into three segments, based on residential usage strata definitions provided by Ameren Missouri.[2] Stratum 1 customers are classified as Residential-Low segment, strata 2 and 3 are combined into the Residential-Medium segment,[3] and stratum 4 customers are classified as the Residential-High segment.

The residential customer population and coincident peak ratios from 2012 load research data, provided by Ameren Missouri, were used to develop customer population and coincident peak demand for the three residential segments. This is represented in Table 2-2 for the base year.

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[2] The strata definitions were provided by Ameren Missouri. These are given in terms of monthly kWh usage as follows:

- Strata 1 – low summer (0-1500) /low winter (0-1500)
- Strata 2 – low summer (0-1500)/high winter (1500+)
- Strata 3 – high summer (1500+)/low winter (0-1500)
- Strata 4 – high summer (1500+)/high winter (1500+)

[3] We combined strata 2 and 3 into single segment, since end-use saturation data is available for strata 2 and 3 combined, and not separately for the two strata.

Table 2-1 Residential Sector Characterization (2012)

Residential Customers	Number of Customers	Coincident Peak (MW)[4]	Average Per Customer Peak (kW)	Share in Population (%)	Share in Coincident Peak (%)
Res-Low (Stratum 1)	665,760	1,778	2.67	64%	52%
Res-Medium (Strata 2&3)	136,829	472[5]	3.45	13%	14%
Res-High (Stratum 4)	237,492	1,155	4.86	23%	34%
Total	**1,040,081**	**3,405**		**100%**	**100%**

Commercial and industrial customers are segmented into four classes based on Ameren Missouri's rate schedules as shown in Table 2-2. It presents the base year (2012) customer population and coincident peak data for these classes. Note that a large transmission customer has been excluded from the potential estimates due to operational barriers that prevent their small subset of eligible, controllable load from participating in DR events for the requisite number of consecutive hours.

Table 2-2 C&I Characterization (2012)

C&I Customers	Rate Schedules	Maximum Demand (kW)	Number of Customers	Coincident Peak (MW)	Average Per Customer Peak (Summer kW)
Small C&I	Small General Service (SGS)	<100	145,012	832	5.7
Medium C&I	Large General Service (LGS)	101-500	10,154	1,495	147.2
Large C&I	Small Primary Service (SPS)	501-5,000	653	593	907.9
Extra Large C&I	Large Primary Service (LPS)	>5,000	72	570	7,918.5
A large transmission customer		-	1	488	487,559
All C&I			**155,892**	**3,978**	**-**

Baseline Forecast

The next step in the analysis is to develop customer population and coincident peak forecasts by customer class. Ameren Missouri provided monthly customer population forecasts for the residential sector and for the C&I classes.

For the residential sector, the population and coincident peak forecasts were for the sector as a whole. To arrive at population and peak forecasts for the three segments (Res-Low, Res-Medium, and Res-High), we applied the population and peak demand ratios by segment from the load research data. Table 2-3 and Table 2-4 present the baseline population and coincident peak forecasts for residential and C&I customers. Table 2-4 also presents the system peak forecast. The selected years in the tables are the same as those for which potential results are presented in the next two chapters.

[4] The coincident peak demand values are at the customer meter end.
[5] The coincident peak for the medium segment is calculated as the weighted average (weighted by strata population) of the strata 2 and 3 peaks.

Table 2-3 Baseline Customer Population Forecast

Customer Classes	2016	2017	2018	2025	2030
Residential					
Residential-Low	666,767	671,679	676,616	705,218	725,793
Residential-Medium	137,036	138,046	139,060	144,939	149,167
Residential-High	237,851	239,603	241,364	251,567	258,907
All Residential	**1,041,654**	**1,049,327**	**1,057,041**	**1,101,725**	**1,133,867**
Commercial and Industrial (C&I)					
Small C&I (SGS)	158,797	160,207	161,888	180,089	194,633
Medium C&I (LGS)	10,553	10,603	10,661	11,242	11,683
Large C&I (SPS)	667	666	663	666	669
Extra Large C&I (LPS)	75	75	76	78	80
A large transmission customer	1	1	1	1	1
All C&I	**170,093**	**171,552**	**173,289**	**192,076**	**207,067**

Table 2-4 Baseline Coincident Peak Forecast (MW)[6]

Customer Classes	2016	2017	2018	2025	2030
Residential					
Residential-Low	1,704	1,741	1,765	1,856	2,064
Residential-Medium	452	462	469	493	548
Residential-High	1,107	1,131	1,147	1,205	1,340
All Residential	**3,263**	**3,335**	**3,381**	**3,554**	**3,952**
Commercial and Industrial (C&I)					
Small C&I (SGS)	872	849	858	913	807
Medium C&I (LGS)	1,510	1,524	1,523	1,680	1,719
Large C&I (SPS)	611	600	612	661	652
Extra Large C&I (LPS)	584	573	560	610	627
A large transmission customer	488	488	488	484	484
All C&I	**4,065**	**4,034**	**4,040**	**4,347**	**4,289**

[6] Please note that the coincident peak forecasts and all peak demand numbers given in this report are at the customer meter. The coincident peak demand estimates at the generation end will be higher when considering the appropriate loss factors.

Demand Response Options

The study considered three DR options:

- Direct Load Control (DLC)
- Capacity Reduction
- Dynamic Pricing

Table 2-5 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 2-5 Relevant 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) customers 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
Dynamic Pricing	All residential and C&I classes	Any

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.

For energy efficiency, RAP represents a forecast of likely customer behavior under realistic program design and implementation conditions. It takes into account existing market, financial, political, and regulatory barriers that are likely to limit the amount of savings that might be achieved through energy efficiency programs. For example, it considers more realistic incentives (i.e., less than 100% of incremental cost), defined marketing campaigns, and internal budget constraints. Political barriers often reflect differences in regional attitudes toward energy efficiency and its value as a resource. The RAP also takes into account recent utility experience and reported savings.

For energy efficiency, MAP establishes a hypothetical upper limit for the savings a utility can hope to achieve through its programs. MAP involves incentives that represent up to 100% of the incremental cost of energy efficiency measures above baseline measures combined with high administrative and marketing costs.

Demand response RAP and MAP definitions are much different than for energy efficiency due to the fact that demand response is a totally different product offered in a totally different market – the MISO capacity market. 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. 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.

Table 2-6 shows the relevant DR options under the two potential levels. RAP includes only firm DR options that are dispatchable. DLC and capacity reduction are the two options that qualify as firm load reduction options. MAP is defined to include load reductions from non-firm options that include dynamic pricing.

Table 2-6 Relevant DR Options under MAP and RAP

DR Options	Included in RAP	Included in MAP
Direct Load Control (DLC)	Yes	Yes
Capacity Reduction	Yes	Yes
Dynamic Pricing	No	Yes

Table 2-7 shows notification times typically associated with the options considered in our analysis.

Table 2-7 Typical Notification Times

DR Option	Target Market	Notification Timing			
		Day-ahead	**Two to four hours**	**30 minutes to one hour**	**Instant-aneous to 10 min**
Direct Load Control	Residential, Small C&I (SGS)			X	X
Capacity Reduction	LGS, SPS, LPS	X	X	X	
Dynamic Pricing	All Classes	X	X	X	

The demand-response options included in this study are described below.

Direct Load Control

In a DLC program, the program management team or system operator remotely controls the operation of a customer's cooling units and/or water heaters (WH) by either cycling the unit or by shutting it down. In exchange, the customer receives an incentive payment or bill credit. Operation of DLC typically occurs during times of high peak demand or supply-side constraints. During an event, participants' equipment is controlled either by a one-way remote switch or by a Programmable Communicating Thermostat (PCT).

The one-way remote switch is connected to the condensing unit of central air conditioning (CAC) equipment and to the immersion element in a water heater. When activated by a control signal, the switch will not allow the equipment to operate for the duration of the event. For CAC, the compressor is shut down during an event while the fan continues to operate. This allows cool air to be circulated throughout the home even though the compressor is disabled. The operation of the switch is usually controlled through a digital paging network. Most switches also contain multiple relays so that multiple end uses can be controlled by the same switch with independent control strategies for each relay.

More recent DLC programs involve installation of a PCT or smart thermostat for customers. PCTs allow remote adjustment of temperature settings, so the utility can remotely adjust the temperature to reduce demand from applicable units. After an event, load control is released, allowing the thermostat to revert back to the original customer settings for temperature and schedule.

In this study, for simplicity and lower operational costs, only the load control switch is used as a control strategy. We assessed the cost-effectiveness of the PCT option, but ultimately decided not to use it because the higher technology cost caused all segments to fail the economic screen.

Eligible customers for the DLC option are residential and SGS customers with CAC and water heating in Ameren Missouri's service territory. In addition to regular DLC, we consider a program where residential customers are offered a DLC option for controlling smart appliances. Currently, utilities such as Consolidated Edison are offering a similar option to residential customers in their service territory.

Capacity Reduction

Under this option, participating customers agree to reduce demand by a specific amount or curtail their consumption to a pre-specified level. In return, they receive a fixed incentive payment in the form of capacity credits or reservation payments (typically expressed as $/kW-month or $/kW-year). Customers are paid to be on call even though actual load curtailments may not occur. The amount of the capacity payment typically varies with the load commitment level. In addition to the fixed capacity payment, participants typically receive a payment for energy reduction. Because it is a firm, contractual arrangement for a specific level of load reduction, enrolled loads represent a firm resource and can be counted toward installed capacity (ICAP) requirements. Penalties are assessed for under-performance or non-performance. Events may be called on a day-of or day-ahead basis as conditions warrant.

This option is typically delivered by load aggregators, and is most attractive for customers with maximum demand greater than 200 kW. From a benefit-cost perspective, the analysis for this option would be similar to traditional interruptible rates. For our current analysis, we assume that this option will be offered to LGS, SPS, and LPS customer classes.

Dynamic Pricing

Dynamic pricing in this study refers to a 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. Event days are dispatched on relatively short notice typically for a limited number of days during the year. Usually the timing is unknown. However, over time, trigger criteria are well-established so that customers can expect events based on the weather or other factors. Events can also be called during times of system contingencies or emergencies. Notification of an event can either be day-ahead or day-of.

For participation in this option, it is desirable for customers to have advanced meters, primarily for settlement purposes. Therefore, in the current study, we consider that AMI deployment is completed in 2020 and that dynamic pricing is offered to customers starting at that time.

Ameren Missouri Energy Delivery subject matter experts provided the following guidance on future AMI assumptions for the Ameren Missouri DR Potential study even though Ameren Missouri at the time had not developed an AMI business case. The AMR modules on the existing AMR meters will be at the end of their useful lives in 2020 and will have to be replaced. Therefore, a reasonable scenario to assume for DSM Potential Study planning purposes would be to begin replacement of existing AMR meters with AMI meters in 2018. Additional guidance for planning purposes was to assume a two-year installation process to replace all existing AMR meters.

For our current study, we assume that dynamic pricing is offered to all customer classes, except the very largest LPS customers. Because they are often unique cases with more constraints on their rate design, large special contracts do not often participate in dynamic pricing rates. The evaluation literature does not have sufficient data for such large customers to allow an estimate of achievable per customer load reduction impacts.[7]

Studies have shown that dynamic pricing impacts vary among customers with and without enabling technology. The enabling technology would be a PCT in the case of residential and SGS customers. For LGS and SPS customers, the enabling technology option would be in the form of Automated Demand Response (Auto-DR), implemented through energy management and control systems.

Residential CPP not PTR. For this study, CPP was chosen for both the residential and business sectors. This is in contrast to the 2010 Study for which a peak time rebate program was assessed for the residential sector. A PTR program is a pay-for-performance program that pays customers to reduce electricity use during the peak period on selected days (referred to as event days) that are not known until the day before they occur. The incentive is paid based on the difference between the metered load during the peak period on event days and an estimate of what the customer would have used during the same period if the PTR event had not occurred. This estimate is referred to as the baseline load. The accuracy and magnitude of incentive payments are dependent on the accuracy of the baseline estimate. Given the normal fluctuation in any given residential customer's usage across days, it is very difficult to accurately estimate baselines for individual customers on individual event days.

Since 2010, the electric utility industry has learned much more about the costs and benefits of residential PTR programs – primarily from full-scale deployment of PTR programs at California electric utilities. The results have refuted the belief that PTR programs had no "losers" and had only "winners." San Diego Gas & Electric's experience with PTR provides an example.

In 2012, San Diego Gas & Electric Company enrolled approximately 1.2 million residential customers in a PTR program, branded as "Reduce Your Use Rewards." The evaluation of the PTR pilot showed conclusively that baseline calculation and payment errors resulted in payments being made to customers who did not reduce demand and those payment errors must be recovered from all customers.

Program Participation Hierarchy

To avoid double counting of impacts, program-eligibility criteria were defined to ensure that customers cannot participate in multiple programs. For example, residential customers cannot participate in both an air conditioning DLC program and a dynamic pricing program, both of which could target the same load for curtailment on the same days. Table 2-8 shows the participation hierarchy by customer class for applicable DR options.

[7] This assumption was developed in consultation with The Brattle Group.

Table 2-8 Participation Hierarchy in DR Options by Customer Segment

Customer Classes	Priority / Loading	DR Option	Eligible Customers
Residential Small C&I (SGS)	First	Dynamic Pricing	All residential and SGS customers
	Second	Direct Load Control	Residential and SGS customers with CAC and Water Heating, not enrolled in Dynamic Pricing Smart Appliance DLC is offered to customers, already enrolled in the CAC DLC option
Medium C&I (LGS) Large C&I (SPS) Extra Large C&I (LPS)	First	Dynamic Pricing	LGS and SPS customers
	Second	Capacity Reduction	LGS and SPS customers, not enrolled in dynamic pricing All LPS customers

Participation Rates and Load Impacts

Residential Direct Load Control

Table 2-9 shows participation rate and impact assumptions for residential DLC options and indicates the source for these assumptions. The primary source is the FERC 2012 national DR survey database, which is the most comprehensive and up-to-date database on all types of DR programs that are offered by various entities.[8] For residential DLC, both the RAP and MAP cases assume a 19.97% participation rate for residential customers, based on the 75th percentile of comparable DLC programs around the country.[9]

[8] FERC 2012 survey database is downloadable at http://www.ferc.gov/industries/electric/indus-act/demand-response/2012/survey.asp

[9] As part of the study, we conducted program interest surveys which surveyed customers' interest in participating in DR programs. However, the results were deemed unreliable as customers did not have an adequate understanding of DR programs and the actions required on their part to participate.

Table 2-9 Residential Direct Load Control Program Assumptions[10]

Item	Unit	Value	Basis for Development
Participation Rates			
Participation Rate, Steady-state	% of total residential customers	19.97%	75th percentile value from a dataset of 61 utility programs (with more than 5000 customers enrolled), based on FERC 2012 survey of DR programs[11]
Ramp rate for program participation	No. of years to attain above steady –state participation levels	5	Interviews with utility program managers; FERC National Assessment of DR Potential database[12]
Program Impacts by End-Use			
Strata 4 - Per Customer Impact for AC	kW reduction per AC customer	1.05*	Average of impact estimates from FERC 2012 survey, using a dataset of 22 utility programs targeting residential air-conditioners (n=40); the dataset only includes areas that are geographically contiguous to Ameren Missouri, in order to account for climate effects on DLC impacts
Strata 2 & 3 - Per Customer Impact for AC		0.74*	Scaled Strata 4 impact by ratio of Strata Peaks
Strata 1 — Per Customer Impact for AC		0.57*	Scaled Strata 4 impact by ratio of Strata Peaks
Strata 4 — Per Customer Impact for Water Heater	kW reduction per WH customer	0.87	Average of impact estimates from FERC 2012 survey, using a dataset of 26 utility programs targeting residential water heaters (n=26)
Strata 2 & 3 — Per Customer Impact for Water Heater		0.61	Scaled Strata 4 impact by ratio of Strata Peaks
Strata 1 — Per Customer Impact for Water Heater		0.48	Scaled Strata 4 impact by ratio of Strata Peaks

**Alternate method to derive per customer AC impact: Multiply strata peak loads by average impact from 2005 Ameren TOU Pilot study (18%) to get 0.96 kW, 0.68 kW, and 0.53 kW. Corroborates above method for respective strata, high to low 1.05 kW, 0.74 kW, 0.57 kW.*

Residential Smart Appliances Direct Load Control

For the smart-appliances DLC option, impact estimates are based on a review of relevant literature available on the topic. Smart-appliances DLC impact estimates are derived in a bottom-up manner, taking into consideration the various residential appliances that could contribute a portion of their load as controllable (presented in Table 2-10 and Table 2-11). The combined curtailable impact per household for the Residential high usage stratum is 0.1291 kW, while the impact for the medium and low usage stratum is 0.1182 kW. Program deployment is assumed to begin in 2020, after transition to AMI has been completed. Twenty percent of customers enrolled under AC load control are assumed to participate in the smart-appliances DLC option.

[10] For source data and additional detail, please see the 'Res DLC Assumptions Summary' worksheet of the documentation file
[11] http://www.ferc.gov/industries/electric/indus-act/demand-response/2012/survey.asp
[12] http://www.ferc.gov/industries/electric/indus-act/demand-response/dr-potential/assessment.asp

Table 2-10 Smart Appliances DLC Impacts for Res-High Segment

Appliance	Saturation[13]	UEC[14] (kWh)	Peak Factor[15]	Unit peak kW contribution	Peak kW contribution per HH	Available curtailable load (as % of peak)[16]	Available curtailable load (kW)
Dishwasher	82%	400	0.0001416	0.0566	0.0464	23%	0.0107
Clothes Dryer	75%	790	0.0001431	0.1130	0.0848	36%	0.0305
Clothes Washer	97%	96	0.0001334	0.0128	0.0124	23%	0.0029
Room AC	4%	1,853	0.0019455	3.6050	0.1442	36%	0.0519
Refrigerator	100%	725	0.0001402	0.1016	0.1016	23%	0.0234
Freezer	47%	575	0.0001566	0.0901	0.0423	23%	0.0097
Total							**0.1291**

Table 2-11 Smart Appliances DLC Impact for Res-Low and Res-Medium Segments

Appliance	Saturation[17]	UEC[18] (kWh)	Peak Factor[19]	Unit peak kW contribution	Peak kW contribution per HH	Available curtailable load (as % of peak)[20]	Available curtailable load (kW)
Dishwasher	77%	404	0.0001419	0.0573	0.0442	23%	0.0102
Clothes Dryer	88%	472	0.0001434	0.0677	0.0596	36%	0.0214
Clothes Washer	71%	96	0.0001337	0.0128	0.0091	23%	0.0021
Room AC	8%	1331	0.0015423	2.0528	0.1642	36%	0.0591
Refrigerator	100%	723	0.0001402	0.1014	0.1014	23%	0.0233
Freezer	10%	579	0.0001566	0.0907	0.0091	23%	0.0021
Total							**0.1182**

[13] Based on Market Profiles for Residential-Single Family Households in Ameren Missouri's service territory. Single family household customers are used as a proxy for the Res-High segment.
[14] *Ibid.*
[15] Based on LoadMAP model values for the Energy Efficiency Potential analysis section of the current study.
[16] Sastry, Chellury (Ram), Viraj Srivastava, Rob Pratt, and Shun Li. *Use of Residential Smart Appliances for Peak-Load Shifting and Spinning Reserves.* Rep. no. PNNL-19083. Richland: Pacific Northwest National Laboratory, 2010. http://www.aham.org/ht/a/GetDocumentAction/i/51596
[17] Based on Market Profiles for Multi-family home customers in Ameren Missouri's service territory. Multi-family household customers are used as a proxy for the Res-Low and Res-Medium segments.
[18] *Ibid.*
[19] Based on LoadMAP model values for the Energy Efficiency Potential analysis section of the current study. .
[20] Sastry, Chellury (Ram), Viraj Srivastava, Rob Pratt, and Shun Li. *Use of Residential Smart Appliances for Peak-Load Shifting and Spinning Reserves.* Rep. no. PNNL-19083. Richland: Pacific Northwest National Laboratory, 2010. http://www.aham.org/ht/a/GetDocumentAction/i/51596

Small C&I Direct Load Control

Table 2-12 presents participation rate and impact assumptions for the small C&I DLC option.

Table 2-12 Small C&I Direct Load Control Program Assumptions[21]

Item	Unit	Value	Basis for Development
Participation Rates			
Participation Rate, Steady-state	% of total SGS customers	6.01%	75th percentile value from a dataset of 23 utility programs (with more than 100 customers enrolled), based on FERC 2012 survey of DR programs[22]
Ramp rate for program participation	No. of years to attain above steady –state participation levels	5	Assumed to be the same as that for Residential DLC
Program Impacts by End-Use			
Per Customer Impact for AC DLC	kW per AC customer	1.31	AC load reduction impact for small commercial customers assumed to be 25% higher as compared to residential impacts, due to presence of larger sized cooling units (Ref: PacifiCorp DSM Potential Study, 2013)23; 2012 FERC survey data could not be used for derivation of this assumption due to concerns related to data completeness and quality in the FERC survey
Per Customer Impact for WH DLC	kW per WH customer	1.08	Water heater load reduction impacts for small commercial assumed to be 25% higher compared to residential WH DLC impacts, similar to the assumption for AC, most likely due to the presence of larger sized units; 2012 FERC survey data could not be used for derivation of this assumption due to concerns related to data completeness and quality in the FERC survey

[21] For source data and additional detail, please see the 'C&I DLC Assumptions Summary' worksheet of the documentation file

[22] http://www.ferc.gov/industries/electric/indus-act/demand-response/2012/survey.asp

[23] http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/DSM_Potential_Study/PacifiCorp_DSMPotential_FINAL_Vol%20I.pdf

C&I Capacity Reduction

Table 2-13 presents participation rate and impact assumptions for the capacity reduction option, developed using the 2012 FERC survey database. For RAP and MAP potential estimates in the current study, the participation rate assumption of 30.3% was used.[24]

Table 2-13 Capacity Reduction Program Assumptions25

Item	Unit	Value	Basis for Development
Participation Rates			
Participation Rate, Steady-state	% of total customers	30.3%	75th percentile value from a dataset of 7 utility programs used for 'high' participation rate estimation, based on FERC 2012 DR survey information[26]; note capacity reduction type utility programs, which are primarily delivered by load aggregators, are relatively new and much fewer in number as compared to legacy DLC programs; therefore, the dataset size for these programs is relatively small
Ramp rate for program participation	No. of years to attain above steady–state participation levels	3	Implementation and Aggregation experience
Impact Assumption			
Per Customer Impact	% of enrolled load	18.0%	Average of five program impact estimates, based on FERC 2012 survey data[27]; (note that size of dataset for average estimation is relatively small, due to data completeness and accuracy issues in the survey database)

[24] This participation rate assumption is applied to LGS and SPS customers. LPS customers, with extremely high individual loads, are assumed to have lower participation rate. For the current study, participation rate for LPS customers is assumed to be half of the participation rate for LGS and SPS customers.
[25] For source data and additional detail, please see the 'C&I Capacity Program Assumptions Summary' worksheet of the documentation file.
[26] The 2012 FERC survey data is downloadable at- http://www.ferc.gov/industries/electric/indus-act/demand-response/2012/survey.asp
[27] *Ibid.*

Dynamic Pricing

Table 2-14 shows participation rate assumptions for dynamic pricing. The participation rates for dynamic pricing were developed in the demand-side rates analysis portion of this study[28]. Multiple forms of dynamic pricing are considered in the demand-side rates analysis, including critical peak pricing (CPP), time of use rates (TOU), peak-time rebates (PTR), inclining block rates (IBR), and real time pricing (RTP). As stated in that analysis, CPP is the most attractive option in the sense that it strikes the best balance of regulatory acceptance, robust implementation history in industry, and per-customer impact potential. Therefore, the form of dynamic pricing assumed in the DR analysis is critical peak pricing (CPP). For this study, we assume that dynamic pricing is offered on a voluntary basis with opt-in provision to all customer classes after AMI deployment is completed. Participation ramps up linearly in 5 years, and remains steady thereafter.

Table 2-14 Dynamic Pricing Participation Assumptions (% of eligible customers)

Segment	Program Yr 1	Program Yr 2	Program Yr 3	Program Yr 4	Program Yr 5
Residential-Low	4%	8%	12%	16%	20%
Residential-Medium	4%	8%	12%	16%	20%
Residential-High	4%	8%	12%	16%	20%
Small C&I (SGS)	4%	8%	12%	16%	20%
Medium C&I (LGS)	4%	8%	12%	16%	20%
Large C&I (SPS)	4%	8%	12%	16%	20%

Table 2-15 shows the impact assumptions for dynamic pricing which align with the demand-side rates analysis. For LPS customers, pricing impact assumptions are difficult to develop since there are no studies that provide impact estimates for very large sized customers. Therefore, we excluded these customers from the dynamic pricing offer.

Table 2-15 Dynamic Pricing Impact Assumptions

Customer Class	Option	Unit Impact (% of peak load)	Basis for Assumption
All Residential	w/o enabling tech	12.95%	Impacts based on Ameren TOU CPP Pilot results
	with enabling tech	23.44%	
Small C&I (SGS)	w/o enabling tech	1.7%	*The Untold Story: A Survey of C&I Dynamic Pricing Pilot Studies,* Ahmad Faruqui, Jennifer Palmer, Sanem Sergici; Metering International Issue 3, 2010; Data is for Connecticut Light and Power (CL&P) PTP (Peak Time Pricing) Pilot
	with enabling tech	7.2%	
Medium C&I- LGS	all	11.3%	Brattle Demand Side Rates Analysis study for Ameren Missouri, 2013
Large C&I- SPS	all	11.3%	Assumed to be the same as that for LGS customers

[28] The demand-side rates analysis is presented in Volume 6. It was performed by The Brattle Group.

Cost-effectiveness Assessment

The cost-effectiveness assessment of DR options is based on the total resource cost (TRC) test. The benefits used in the TRC test are made up solely of the avoided capacity benefits attributable to the impacts of the proposed programs. Given the small number of hours impacted by DR programs, as well as customer pre-cooling or "snapback" that commonly increases energy usage before or after DR events, this analysis does not consider energy benefits. The costs are made up of program development costs, costs attributable to the purchase and installation of enabling technologies, incentive costs, operational and maintenance (O&M) costs, program marketing and recruitment costs, and general administrative costs. Itemized cost assumptions by DR option and by customer class are presented in the 'Cost Assumptions Summary' worksheet of the documentation file.

In the cost-effectiveness assessment framework, cost-effectiveness of individual DR options with different program start years was assessed, and the first cost-effective year for starting the program was identified. Demand savings for a particular option are realized only in years the option is cost-effective. Once an option is deployed, benefit-to-cost ratios were estimated for each contiguous program cycle independently throughout the study time period. A discount rate of 3.95% was used to calculate the net present value (NPV) of benefits and costs over the useful life of an option.

Cost-effectiveness results for the base case are presented in Chapter 3.

Two variables that factor into the cost-effectiveness calculation warrant additional discussion below.

Demand Response Programs Effective Useful Lives

Unlike an energy-efficiency measure that may have an effective useful life of 18 years if it is a central air conditioning unit or 25+ years if it is an LED light bulb, demand response is a customer behavior change program. Also, demand response is modular. It can be installed in discrete amounts, e.g., 50 MW blocks, and it can be removed in discrete amounts. The history of the eight Ameren Missouri demand response programs illustrates the modularity of customer demand response programs. A non-Ameren Missouri example is the 2013 decision by the Idaho Public Utilities Commission to ramp down two existing demand response programs at Idaho Power Company due to Idaho Power having sufficient generation capacity to meet 100% of its load obligations. Another example is the ramp down of demand response resources bid into the 2016/2017 PJM capacity auction due to PJM's acquisition of new natural gas power supply sources and increased capabilities to import capacity.

Because demand response is modular, there are no best practice guidelines as to what the effective useful lives of demand response programs should be. The development of an effective useful life assumption is critical to the cost-effectiveness calculation of any demand response resource.

For this study, we assumed a three-year useful life for all DR resources 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 almost $0 per kW-year.

Avoided Costs

Two views on the avoided costs of capacity in MISO going forward, which we label the Ameren view and MISO market capacity view, were used in the analysis.

- 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 generation will be needed and the system will incur the Cost of New Entry (CONE) for a peaking generator.

- The MISO market capacity or market trading view of capacity is indicative of a more dynamic market with load and generation ebbing and flowing such that capacity prices approaching those of new CTGs may seldom if ever be reached.

Sensitivity Analysis

For the base case for this study, it was assumed, as discussed above, that all DR options have an estimated useful life (EUL) of three years to correspond with the triennial implementation planning cycles and that the avoided costs are based on the Ameren forward view with the CONE for a peaking generator. In addition to this base case, two sensitivity analyses were performed:

1. Market-based avoided costs: This alternative case used avoided costs based on a projection of historic MISO market prices into the future.
2. Longer program life: This alternative case assumed longer lifetimes for applicable programs.

The results of the sensitivity analysis are presented in Chapter 4.

RESULTS OF DR POTENTIAL ANALYSIS

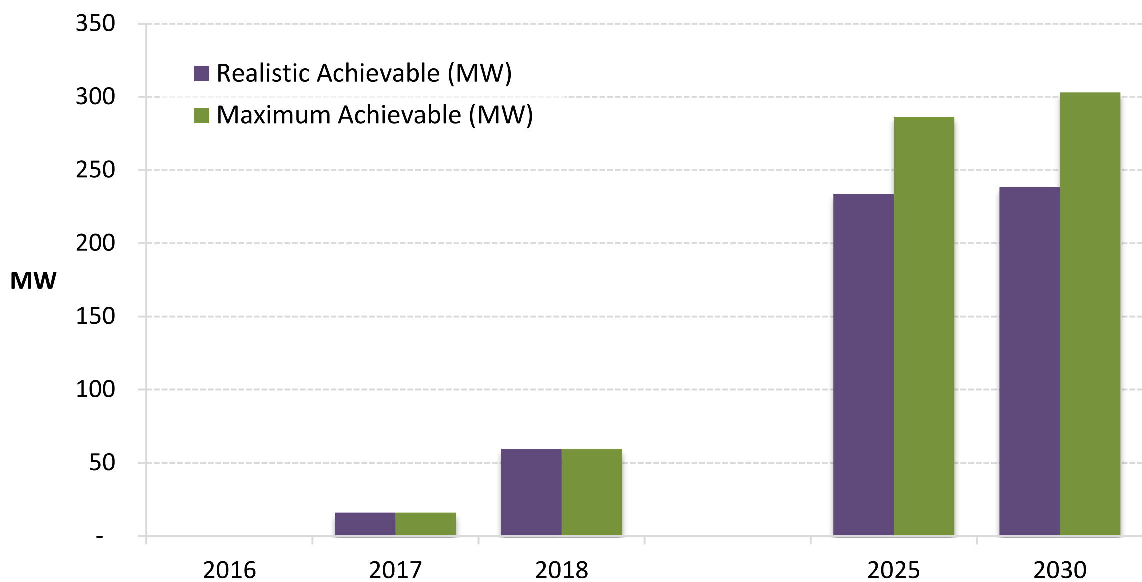
This chapter presents DR potential analysis results at an aggregate level and broken down by DR option and by customer class. It also summarizes the cost-effectiveness results.

Table 3-1 presents the summary of estimated demand savings from relevant demand response options. Under RAP, demand response savings range from 16 MW in 2017[29] 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 3-1 presents the MW savings graphically.

Table 3-1 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)					
Realistic Achievable Potential	-	16	60	234	238
Maximum Achievable 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%

Figure 3-1 Summary of Demand Response Savings



[29] The avoided costs for this analysis are based on the Ameren forward view, reflecting the CONE for a peaking generator, and a three-year program life. The baseline results show that demand response potential in the 2016-2018 timeframe is very small. Chapter 4 shows results of sensitivity analyses performed with respect to avoided costs and program life.

Potential Estimates by DR Option

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. Table 3-2 shows these results while Table 3-3 presents the benefit-cost ratios for DR options by customer class.[30] 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. Therefore 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.

Table 3-2 Base Case Cost-effectiveness Screening Results Summary

Program	Class	Cost-effectiveness (and Program start year)
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)

[30] Please note that once a program is cost-effective and enacted, the TRC ratio is computed over the program's lifetime and therefore is identical until the beginning of the next lifetime.

Table 3-3 Cost-effectiveness Results for MAP

TRC Ratios		**Maximum Achievable Potential**																		
DR Option	Class	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Joint DLC	Residential Low	0.3	0.4	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6								
Joint DLC	Residential Medium	0.4	0.5	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7								
Joint DLC	Residential High	0.6	0.7	0.9	0.99	**1.05**	**1.05**	**1.05**	**3.1**	**3.1**	**3.1**	**5.3**	**5.3**	**5.3**	**2.8**	**2.8**	**2.8**	**2.5**	**2.5**	**2.5**
Joint DLC	Small C&I (SGS)	0.5	0.6	0.7	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9								
Smart Appliance DLC	Residential Low					0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1				
Smart Appliance DLC	Residential Medium					0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1				
Smart Appliance DLC	Residential High					0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1				
Capacity Reduction	Medium C&I (LGS)	0.8	0.96	**1.2**	**1.2**	**1.2**	**1.9**	**1.9**	**1.9**	**1.9**	**1.9**	**1.9**	**1.9**	**1.9**	**1.9**	**1.8**	**1.8**	**1.8**	**1.8**	**1.8**
Capacity Reduction	Large C&I (SPS)	0.9	**1.1**	**1.1**	**1.1**	**1.7**	**1.7**	**1.7**	**1.8**	**1.8**	**1.8**	**1.8**	**1.8**	**1.8**	**1.8**	**1.8**	**1.8**	**1.8**	**1.8**	**1.8**
Capacity Reduction	Extra Large C&I (LPS)	0.9	**1.2**	**1.2**	**1.2**	**1.7**	**1.7**	**1.7**	**1.8**	**1.8**	**1.8**	**1.8**	**1.8**	**1.8**	**1.8**	**1.8**	**1.8**	**1.8**	**1.8**	**1.8**
Dynamic Pricing	Residential Low					0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8				
Dynamic Pricing	Residential Medium					0.9	0.96	0.97	0.97	0.98	0.99	0.97	0.98	0.99	**1.00**	**1.00**	**1.00**	**2.4**	**2.4**	**2.4**
Dynamic Pricing	Residential High					**1.3**	**1.3**	**1.3**	**3.3**	**3.3**	**3.3**	**20.4**	**20.4**	**20.4**	**6.9**	**6.9**	**6.9**	**4.4**	**4.4**	**4.4**
Dynamic Pricing	Small C&I (SGS)					0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3				
Dynamic Pricing	Medium C&I (LGS)					**15.5**	**15.5**	**15.5**	**20.5**	**20.5**	**20.5**	**22.7**	**22.8**	**22.8**	**22.5**	**22.5**	**22.5**	**22.4**	**22.4**	**22.4**
Dynamic Pricing	Large C&I (SPS)					**13.6**	**13.6**	**13.6**	**18.8**	**18.8**	**18.8**	**19.4**	**19.5**	**19.5**	**19.3**	**19.3**	**19.3**	**19.2**	**19.2**	**19.2**

Table 3-4 Cost-effectiveness Results for RAP

TRC Ratios		**Realistic Achievable Potential**																		
DR Option	Class	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Joint DLC	Residential Low	0.32	0.40	0.47	0.54	0.58	0.59	0.59	0.59	0.59	0.59	0.59								
Joint DLC	Residential Medium	0.39	0.49	0.58	0.67	0.71	0.73	0.73	0.73	0.73	0.73	0.72								
Joint DLC	Residential High	0.57	0.71	0.85	0.97	**1.04**	**1.04**	**1.04**	**2.74**	**2.74**	**2.74**	**5.37**	**5.37**	**5.37**	**3.01**	**3.01**	**3.01**	**2.40**	**2.40**	**2.40**
Joint DLC	Small C&I (SGS)	0.47	0.58	0.69	0.80	0.85	0.87	0.87	0.87	0.87	0.87	0.87								
Smart Appliance DLC	Residential Low					0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08				
Smart Appliance DLC	Residential Medium					0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08				
Smart Appliance DLC	Residential High					0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13				
Capacity Reduction	Medium C&I (LGS)	0.78	0.96	**1.15**	**1.15**	**1.15**	**1.87**	**1.87**	**1.87**	**1.87**	**1.87**	**1.87**	**1.86**	**1.86**	**1.86**	**1.83**	**1.83**	**1.83**	**1.82**	**1.82**
Capacity Reduction	Large C&I (SPS)	0.86	**1.07**	**1.07**	**1.07**	**1.75**	**1.75**	**1.75**	**1.82**	**1.82**	**1.82**	**1.81**	**1.81**	**1.81**	**1.79**	**1.79**	**1.79**	**1.77**	**1.77**	**1.77**
Capacity Reduction	Extra Large C&I (LPS)	0.93	**1.16**	**1.16**	**1.16**	**1.73**	**1.73**	**1.73**	**1.80**	**1.80**	**1.80**	**1.79**	**1.79**	**1.79**	**1.77**	**1.77**	**1.77**	**1.75**	**1.75**	**1.75**

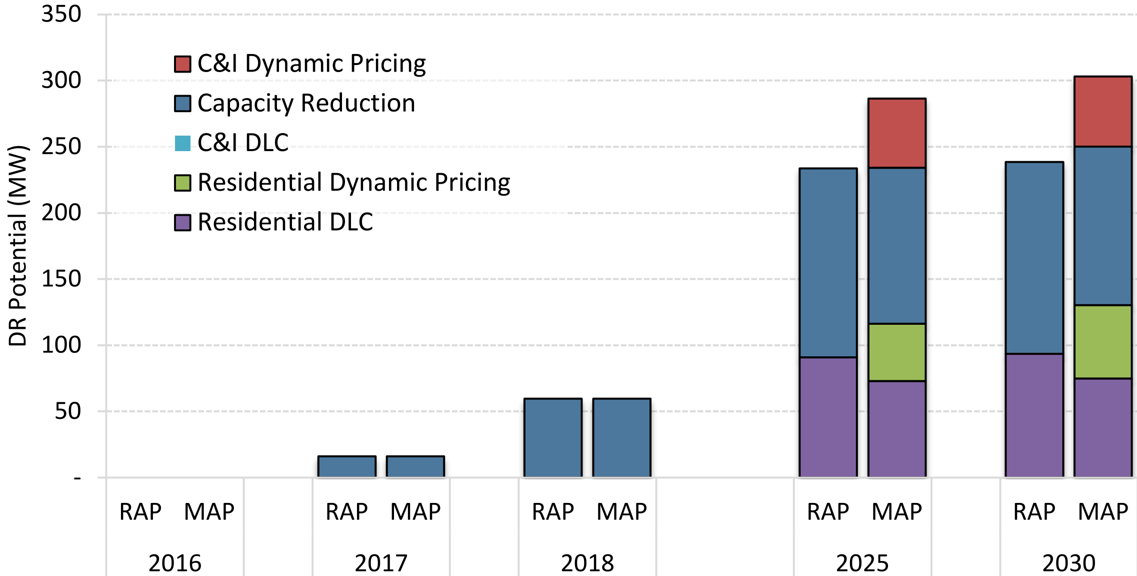
Table 3-5 shows the savings potential by DR option. Figure 3-2 present the same information graphically.

- For RAP, the Capacity Reduction option accounts for about 60% of the savings, compared to 40% for residential direct load control.
- For MAP, dynamic pricing is included. Residential dynamic pricing accounts for a larger portion of the savings than direct load control because dynamic pricing has the first position in the program hierarchy. Effectively, this means that customers will gravitate toward a dynamic pricing program first when available, due to ease of participation with the assumed AMI infrastructure. This in turn draws away from the available base of customers for the DLC program options. In the C&I customer classes, Capacity Reduction continues to account for the majority of savings.

Table 3-5 Demand Response Savings by Option for RAP and MAP

	2016	2017	2018	2025	2030
System Peak Forecast (MW)	7,328	7,368	7,420	7,901	8,241
RAP Savings (MW)					
Residential DLC	-	-	-	91	93
C&I DLC	-	-	-	-	-
Capacity Reduction	-	16	60	143	145
Total RAP Savings	**-**	**16**	**60**	**234**	**238**
RAP Savings (% of System Peak)					
Residential DLC	-	-	-	1.1%	1.1%
C&I DLC	-	-	-	-	-
Capacity Reduction	-	0.2%	0.8%	1.8%	1.8%
Total RAP Savings	**-**	**0.2%**	**0.8%**	**3.0%**	**2.9%**
MAP Savings (MW)					
Residential DLC	-	-	-	73	75
Residential Dynamic Pricing	-	-	-	43	55
C&I DLC	-	-	-	-	-
Capacity Reduction	-	16	60	118	120
C&I Dynamic Pricing	-	-	-	52	53
Total MAP Savings	**-**	**16**	**60**	**286**	**303**
MAP Savings (% of System Peak)					
Residential DLC	-	-	-	0.9%	0.9%
Residential Dynamic Pricing	-	-	-	0.5%	0.7%
C&I DLC	-	-	-	-	-
Capacity Reduction	-	0.2%	0.8%	1.5%	1.5%
C&I Dynamic Pricing	-	-	-	0.7%	0.6%
Total MAP Savings	**-**	**0.2%**	**0.8%**	**3.6%**	**3.7%**

Figure 3-2 Demand Response Savings by Option



Potential Estimates by Customer Class

Figure 3-3 and Table 3-6 show the range of achievable potential by customer class. In the early years, only the C&I customer classes contribute to the potential because only the Capacity Reduction program option is cost-effective. Later in the study, the residential sector makes a significant contribution to the potential, but the C&I sectors continue to dominate.

Figure 3-3 Demand Response Savings by Customer Class under RAP and MAP

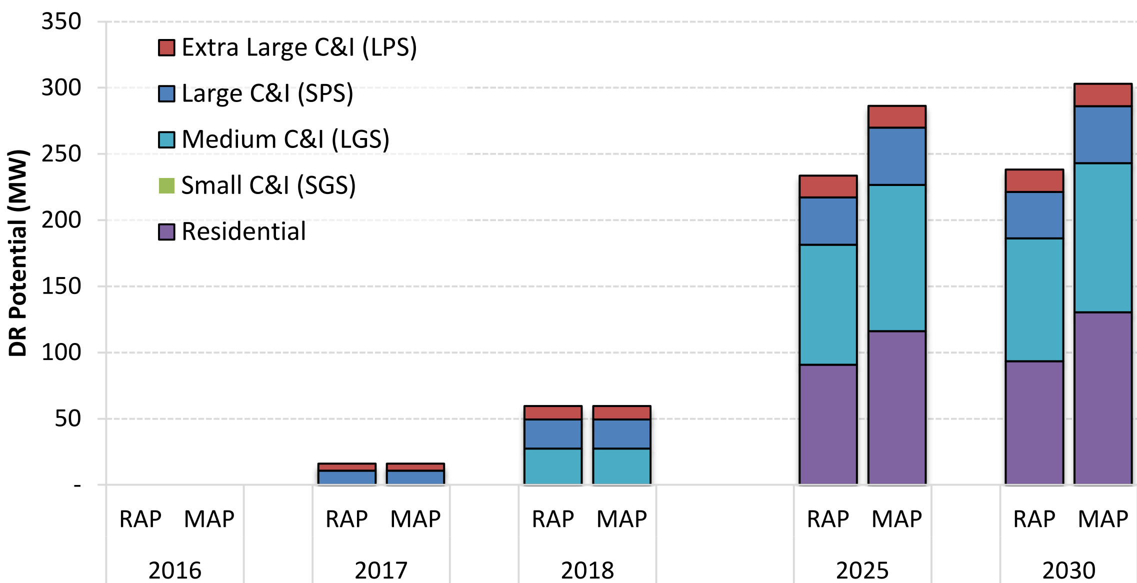


Table 3-6 Demand Response Savings by Customer Class under RAP and MAP

	2016	2017	2018	2025	2030
System Peak Forecast (MW)	7,328	7,368	7,420	7,901	8,241
RAP Savings (MW)					
Residential	-	-	-	91	93
Small C&I (SGS)	-	-	-	-	-
Medium C&I (LGS)	-	-	27	91	93
Large C&I (SPS)	-	11	22	36	35
Extra Large C&I (LPS)	-	5	10	16	17
Total RAP Savings	**-**	**16**	**60**	**234**	**238**
RAP Savings (% of System Peak)					
Residential	0.0%	0.0%	0.0%	1.1%	1.1%
Small C&I (SGS)	0.0%	0.0%	0.0%	0.0%	0.0%
Medium C&I (LGS)	0.0%	0.0%	0.4%	1.1%	1.1%
Large C&I (SPS)	0.0%	0.1%	0.3%	0.5%	0.4%
Extra Large C&I (LPS)	0.0%	0.1%	0.1%	0.2%	0.2%
Total RAP Savings	**0.0%**	**0.2%**	**0.8%**	**3.0%**	**2.9%**
MAP Savings (MW)					
Residential	-	-	-	116	130
Small C&I (SGS)	-	-	-	-	-
Medium C&I (LGS)	-	-	27	110	113
Large C&I (SPS)	-	11	22	43	43
Extra Large C&I (LPS)	-	5	10	16	17
Total MAP Savings	**-**	**16**	**60**	**286**	**303**
MAP Savings (% of System Peak)					
Residential	0.0%	0.0%	0.0%	1.5%	1.6%
Small C&I (SGS)	0.0%	0.0%	0.0%	0.0%	0.0%
Medium C&I (LGS)	0.0%	0.0%	0.4%	1.4%	1.4%
Large C&I (SPS)	0.0%	0.1%	0.3%	0.5%	0.5%
Extra Large C&I (LPS)	0.0%	0.1%	0.1%	0.2%	0.2%
Total MAP Savings	**0.0%**	**0.2%**	**0.8%**	**3.6%**	**3.7%**

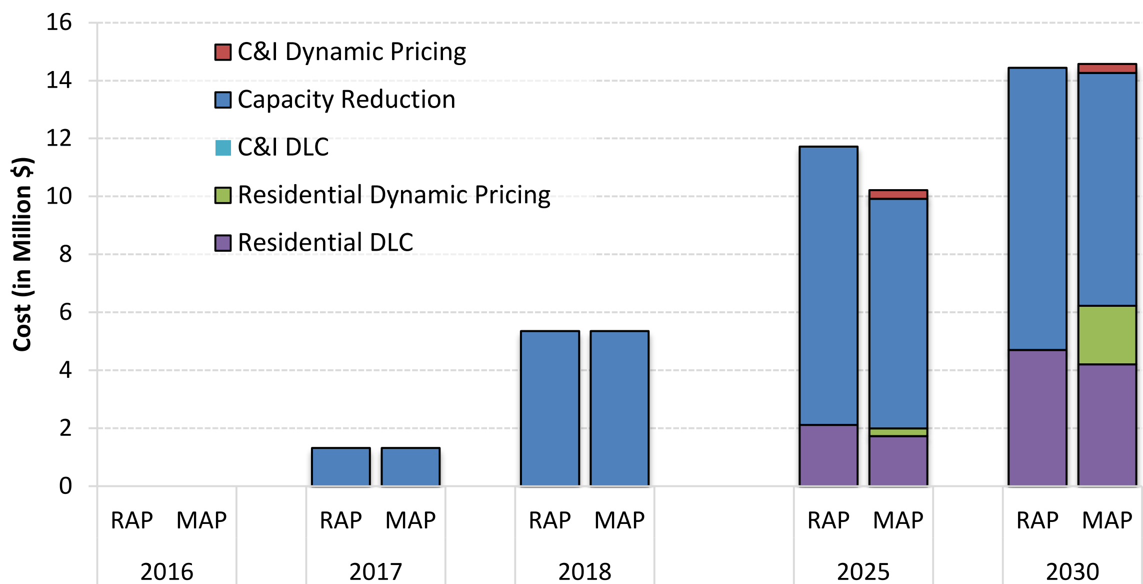
DR Program Costs

Table 3-7 presents program costs in selected years. Capacity reduction has the highest costs, followed by DLC. As expected, dynamic pricing is the least expensive program, due largely to the assumption that the cost of AMI and smart metering infrastructure will occur as a natural course of business outside the purview of this study.

Table 3-7 Demand Response Program Costs (Million Dollars)

	2016	2017	2018	2025	2030
Realistic Achievable Potential (RAP)					
Residential DLC	-	-	-	2.118	4.703
C&I DLC	-	-	-	-	-
Capacity Reduction	-	1.314	5.351	9.596	9.737
Total RAP Costs	**-**	**1.314**	**5.351**	**11.715**	**14.441**
Maximum Achievable Potential (MAP)					
Residential DLC	-	-	-	1.725	4.199
Residential Dynamic Pricing	-	-	-	0.268	2.027
C&I DLC	-	-	-	-	-
Capacity Reduction	-	1.314	5.351	7.919	8.039
C&I Dynamic Pricing	-	-	-	0.299	0.302
Total Costs	**-**	**1.314**	**5.351**	**10.212**	**14.566**

Figure 3-4 Demand Response Program Costs under RAP



DR Program Levelized Costs and Supply Curves

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 Table 3-8 and Table 3-9, and Figure 3-5 and Figure 3-6 below.

Table 3-8 Supply Curve Data by DR Option from 2016–2018 under MAP

Program	Class	Levelized Cost 2016–2018 ($/kW)	Cumulative MW Reductions in 2018
Capacity Reduction	Medium C&I (LGS)	$87.08	27.41
Capacity Reduction	Large C&I (SPS)	$76.63	22.02
Capacity Reduction	Extra Large C&I (LPS)	$70.12	10.08

Figure 3-5 Supply Curves, 2016-2018

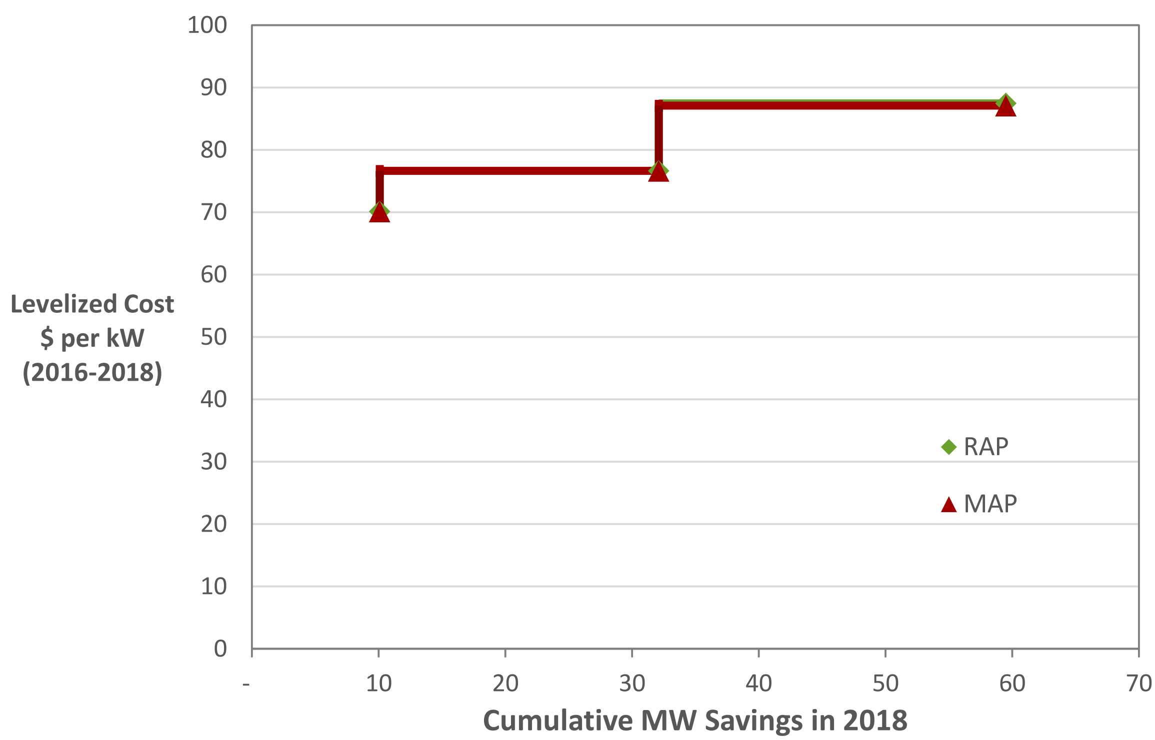
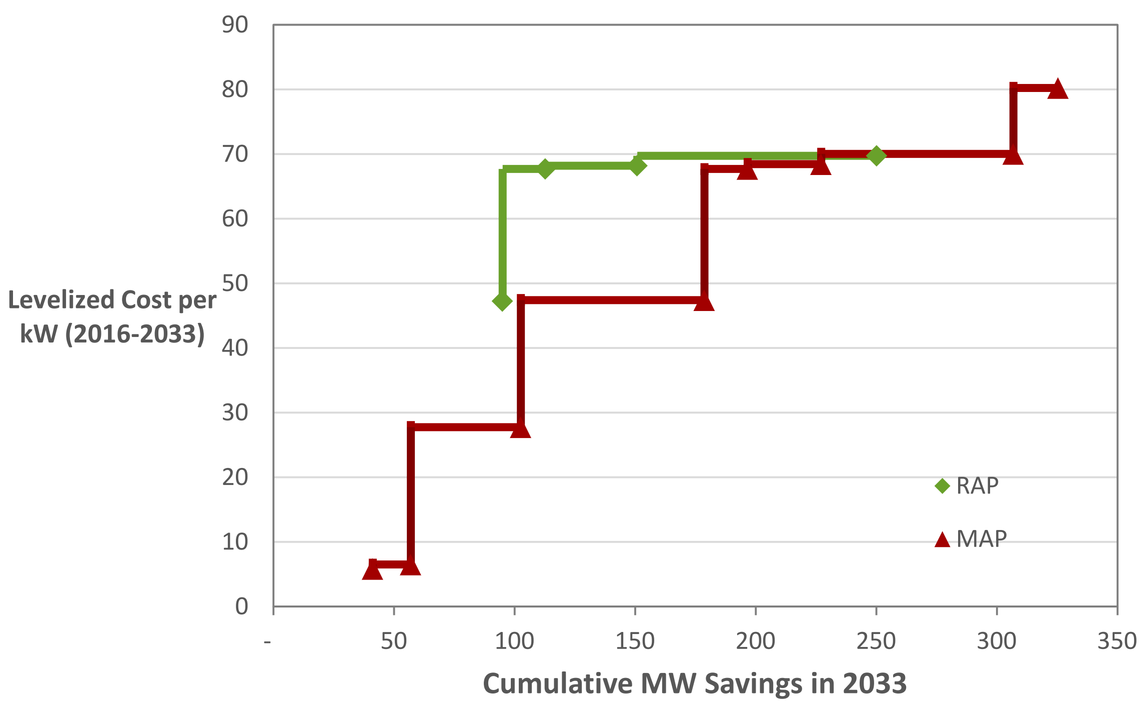


Table 3-9 Supply Curve Data by DR Option from 2016–2033 under MAP

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

Figure 3-6 Supply Curves, 2016-2033



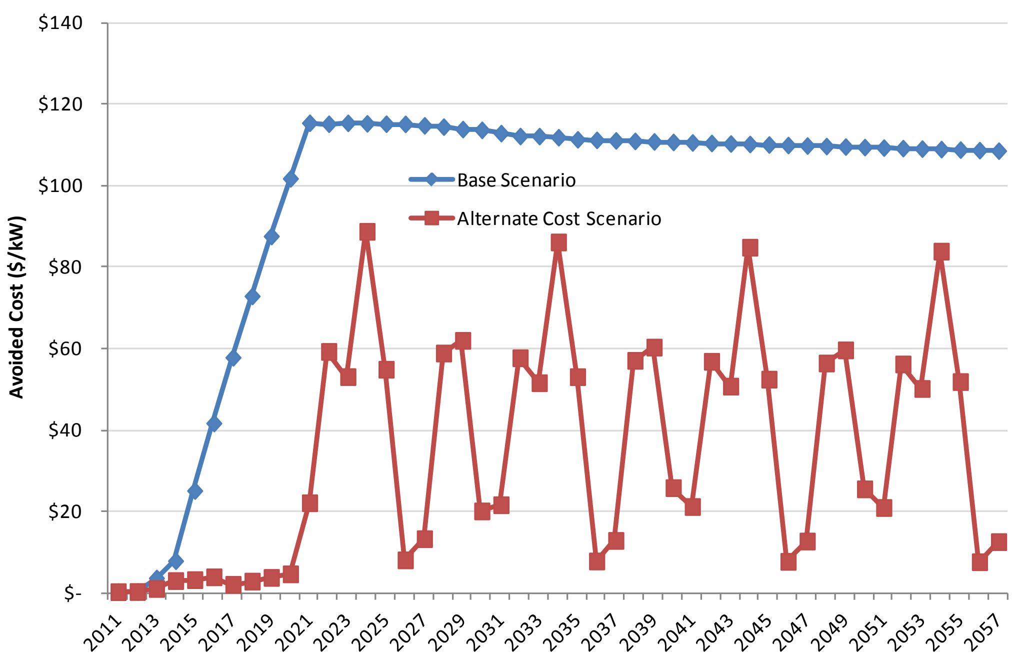
SENSITIVITY ANALYSIS

For this study, we modeled two sensitivity cases to analyze the effects of key inputs:

1. **Market-Based Avoided Costs** — In this first sensitivity case, rather than basing avoided costs on the CONE for a peaking generator, avoided capacity costs are based on Ameren's projection of historic MISO market prices. These values are considerably more volatile than CONE and lower, resulting in both more volatile and lower savings potential. See Figure 4-1.
2. **Longer Program Lifetimes** —In the second sensitivity case, the program lifetime was extended beyond the 3-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:
   - o Direct Load Control lifetime increases from three to ten years
   - o Dynamic Pricing lifetime increases from three to twenty years

   Under this scenario, cost-effectiveness and potential both increase.

Figure 4-1 Avoided Cost Scenarios ($2011)[31]



[31] The avoided cost numbers are represented in real 2011 dollars.

Sensitivity Analysis Results

Table 4-1 presents the cost-effectiveness results for all three cases. Under market-based avoided costs, fewer options are cost-effective. Under longer program lifetimes, more options are cost-effective.

Table 4-1 Cost-effectiveness Results Comparison of Sensitivity Cases

DR Option	Base Case	Market-Based Avoided Costs	Longer Program Lifetime
Residential DLC (AC and Water Heating)	Cost-effective only for the Residential-High segment, beginning 2020.	Not cost-effective over entire study time period.	Cost-effective for all residential segments, beginning 2016
Smart Appliances DLC	Not cost-effective		
Small C&I DLC	Not cost-effective		Cost-effective, beginning 2016
Capacity Reduction	Cost-effective for SPS and LPS customers, beginning 2017; cost-effective for LGS customers, beginning 2018.	Not cost-effective, except for LPS customers over the 2022-2024 program cycle.	Same as base case.
Residential Dynamic Pricing	Cost-effective for the Residential-High segment, beginning 2020; also cost-effective for the Residential-Medium segment, beginning 2029.	Not cost-effective.	Cost-effective for all residential customers, beginning 2020.
C&I Dynamic Pricing	Cost-effective for LGS and SPS customers, beginning 2020; not cost-effective for SGS customers.	Same as base case.	Cost-effective for all eligible C&I classes, beginning 2020

Table 4-2 presents the savings potential for all three cases.

- Potential under market-based avoided costs is substantially lower than for the base case.
- Potential under longer program lifetimes is higher because DLC is cost-effective for all residential classes and also for the SGS C&I class.

Figure 4-2 shows MAP potential by program type. Figure 4-3 and Figure 4-4 show the year-by-year savings for RAP and MAP for each case. The volatility of the market-based rates causes the potential savings to fluctuate from year to year. Under market-based avoided costs, Capacity Reduction is cost-effective only for the 2022-2024 program cycle for LPS customers. Therefore, the RAP potential drops to zero under lower market-based avoided costs, except for very small amount of savings from Capacity Reduction in the period 2022-2024. Residential Dynamic Pricing is also not cost-effective under the lower avoided cost scenario. The only cost-effective option under this scenario is Dynamic Pricing for LGS and SPS customers. Therefore, the MAP potential under the lower market based avoided cost scenario is substantially lower as compared to the base scenario.

Table 4-2 DR Potential - Comparison of Sensitivity Cases (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%

Figure 4-2 MAP Potential by Option – Comparison of Sensitivity Cases

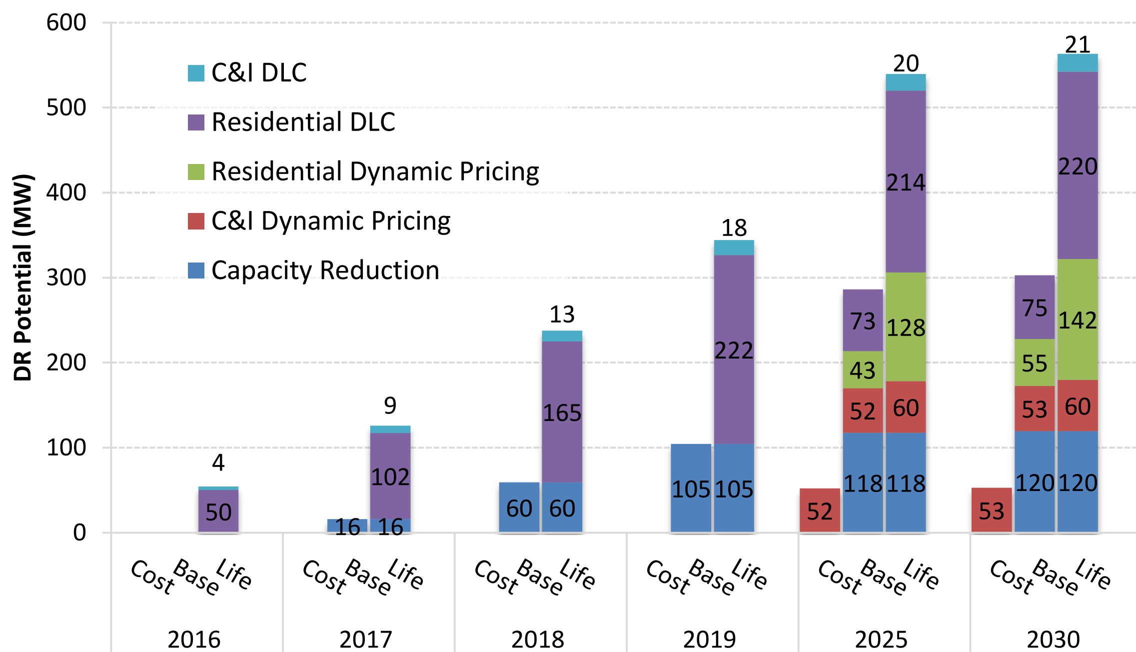


Figure 4-3 RAP Potential across Sensitivity Cases

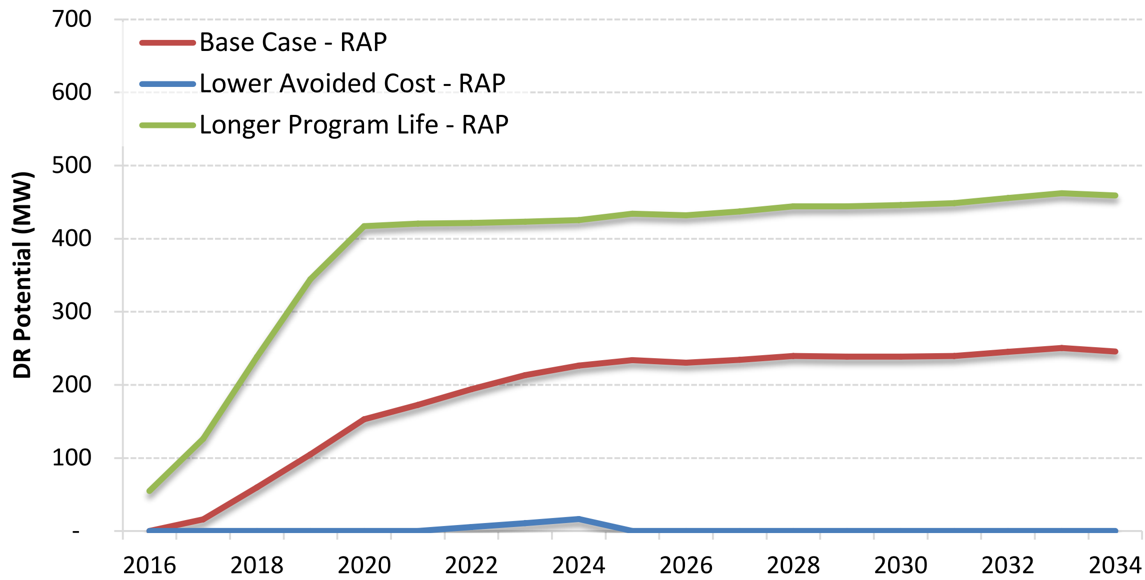
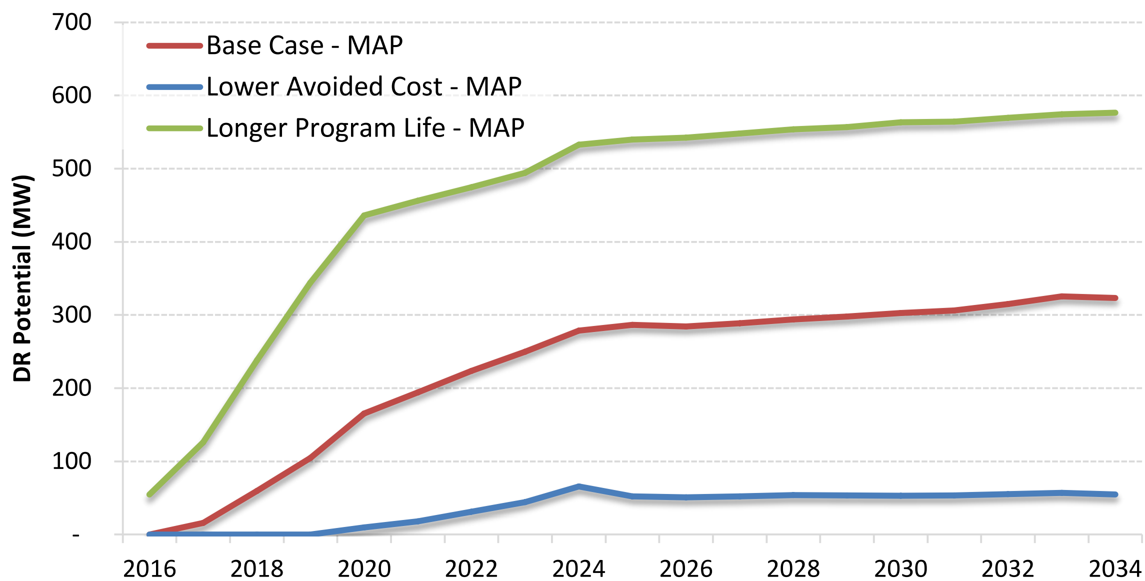


Figure 4-4 MAP Potential across Sensitivity Cases



Comparison with 2010 Ameren Missouri Study[32]

In its previous potential study, Ameren also estimated demand response potential. The results of the 2010 Ameren Missouri demand response potential study are summarized in Table 4-3 and Table 4-4, extracted from the 2010 potential study report.

Table 4-3 RAP MW Savings by Program – 2010 Study

Program		Peak Demand Savings (MW)			
		2009	2010	2020	2030
1	Residential Direct Load Control	0.0	40.3	83.8	87.1
2	Residential Dynamic Pricing	0.0	20.0	489.8	496.1
3	C&I Direct Load Control	0.0	5.4	21.7	23.8
4	C&I Dynamic Pricing	0.0	14.5	150.3	170.0
5	Demand Bidding	0.0	45.1	57.9	68.4
6	Curtailable	0.0	36.1	36.1	38.7
7	DR Aggregator Contracts	1.5	7.5	30.0	30.0
Total MW		**1.5**	**168.9**	**869.5**	**914.1**
Baseline Forecast		**7,642**	**7,749**	**8,356**	**9,127**
Program Savings as % of Baseline		**0.02%**	**2.18%**	**10.41%**	**10.01%**

Table 4-4 MAP MW Savings by Program – 2010 Study

Program		Peak Demand Savings (MW)			
		2009	2010	2020	2030
1	Residential Direct Load Control	0.0	47.7	63.3	65.9
2	Residential Dynamic Pricing	0.0	39.9	656.0	664.4
3	C&I Direct Load Control	0.0	7.6	30.6	33.6
4	C&I Dynamic Pricing	0.0	23.9	200.4	226.7
5	Demand Bidding	0.0	45.1	54.5	64.4
6	Curtailable	0.0	36.1	37.5	41.1
7	DR Aggregator Contracts	1.5	7.5	30.0	30.0
Total MW		**1.5**	**207.9**	**1,072.3**	**1,126.0**
Baseline Forecast		**7,642**	**7,749**	**8,356**	**9,127**
Program Savings as % of Baseline		**0.02%**	**2.68%**	**12.83%**	**12.34%**

Using the end year 2030 for comparison purposes, the 2010 study estimated cumulative peak demand reduction savings of 10.1% and 12.34% for RAP and MAP respectively. Recall from Table 3-5 in this report that the current 2013 study estimates cumulative peak demand savings of 2.9% and 3.6% respectively.

The primary driver for the lower estimates of RAP and MAP savings in the 2013 study relates to dynamic pricing. In the 2010 Study, it was assumed that Ameren Missouri would institute a default or opt-out dynamic pricing tariff and that 75% of the residential customer population would participate in the program, choosing to remain on the rate rather than opt out.

[32] A copy of the final report is available on the following website. Demand response analysis is presented in Volume 4. http://www.ameren.com/sites/aue/Environment/Renewables/Pages/IRPenergyefficiencystudy.aspx

The current 2013 Ameren Missouri DSM Potential study assumes that dynamic pricing is offered to customers as a voluntary or opt-in tariff, which assumes 20% participation as compared to 75% participation for the opt-out tariff. This is more reflective of implementation, planning, and regulatory realities, significantly reducing the achievable potential estimates relative to the previous study.

Table 4-5 shows the comparable results of the 2013 demand response potential study next to those from the 2010 study. It first shows the cumulative MAP potential in 2030 for opt-out participation in the Longer Program Lifetime case of the current study. It also shows a revision of this case (Rev A) which was added to show results for the current study assuming opt-out participation, which more closely parallels the 2010 study. Finally, it shows the 2010 Study results.

"Longer Program Life Rev A" is the pertinent scenario for comparison. It shows that longer program lifetimes and an opt-out rate design for pricing programs would increase demand response potential in 2030 from 3.6% to 10.8%. This is nearly equivalent to the 2010 Study's potential estimate of 12.3%.

Table 4-5 Comparison of Cumulative 2030 MAP Potential from Past and Current Study

DR Option	**Longer Program Life Sensitivity Case:** Opt-in Dynamic Pricing Current Study	**Longer Program Life Sensitivity Case - Rev A:** Opt-out Dynamic Pricing Current Study	**MAP from 2010 Study** (Table 6-1, Page 6-2)
Residential DLC	220	71	66
Residential Dynamic Pricing	142	534	665
C&I DLC	21	7	34
C&I Dynamic Pricing	60	226	227
C&I Capacity Reduction options	**120**	50	136[33]
Total 2030 Potential (MW)	**563**	**887**	**1,126**
Total 2030 Potential (as % of system peak)	**6.8%**	**10.8%**	**12.3%**

[33] This line item combines potential from Demand Bidding, Curtailable, and DR Aggregator Contracts offered to C&I customers.

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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