

## 8.Demand-Side Resources

### Highlights

- *Ameren Missouri completed its Demand Side Management (DSM) Potential Study and Market Assessment in 2016.<sup>1</sup> Key components were:*
  - *Energy efficiency potential*
  - *Demand response potential & Demand-side rate potential*
  - *Distributed generation potential*
  - *Combined heat and power potential*
- *Ameren Missouri has kicked off a collaborative portfolio development process for its next energy efficiency plan by issuing a Request for Proposals (RFP). The results of this RFP will inform the budgets and savings targets for the Company's next 6-year demand-side resource plan.*
- *Ameren Missouri has undertaken additional relevant analysis to supplement the 2016 DSM Potential Study results regarding demand side rate potential. Further investigation indicates that while there are promising cost-based demand-side rate design opportunities; there are still significant barriers to implementation.*

Ameren Missouri continues to build on its DSM planning, implementation and evaluation performance leadership from the employment of DSM programs since 2009 which now includes two Missouri Energy Efficiency Investment Act (MEEIA) program cycles for 2013 to 2015 and the current program cycle which began in 2016 and ends in early 2019. Examples of performance leadership include:

- Continued use of project management processes and procedures
- Market segmentation strategies to tailor specific DSM messages to specific market segments<sup>2</sup>
- Use of national best practice evaluation processes and procedures

<sup>1</sup> 4 CSR 240-22.050(1)(A)1 through 3

<sup>2</sup> 4 CSR 240-22.050(1)(A)1 through 3; 4 CSR 240-22.050(3)(B) The market segmentation is discussed further in sections 6.2 and 8.2 of the 2016 Ameren Missouri 2016 DSM Potential Study

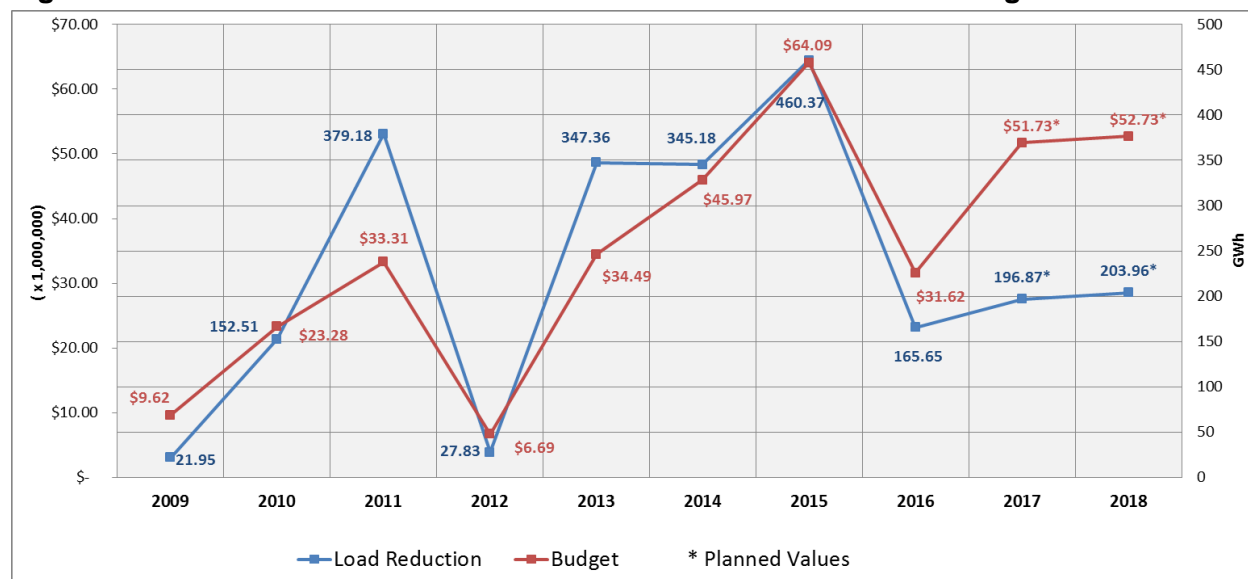
- Addition of new and improved demand-side programs tailored to ever-changing markets, customer and program needs.
- Development of a program continuity plan to better meet customer needs for long term commercial and industrial projects. Such program continuity permits long term projects to qualify for incentives even though those projects will complete outside the MEEIA implementation period.

## 8.1 Implementation Plan Summary

### 8.1.1 Introduction

Since the inception of its large scale DSM programs beginning in 2009, Ameren Missouri has achieved impressive accomplishments from its expanding energy efficiency portfolio. Figure 8.1 shows the annual energy savings and associated budgets from 2009 through 2016 and projected values for 2017 and 2018. These programs, when paired with viable cost recovery mechanisms, have been very successful in providing benefits that delay future investments and save customers money for years to come.

**Figure 8.1 Ameren Missouri DSM Annual Net Load Reductions and Budgets**



As the DSM landscape for utilities steadily evolves, there continue to be outside variables that impact the availability of energy efficiency opportunities for Ameren Missouri to pursue going forward. Unlike the past decade, the near term outlook for building codes and appliance efficiency standards appear to be relatively static.

Currently only two appliance standards are slated to potentially take effect within the next decade:

1. Advanced Incandescent – Tier 2, where newly manufactured general service light bulbs must achieve a minimum efficiency of 45 lumens per watt
2. Top load washing machines must have a minimum Modified Energy Factor (MEF) of 2.0, where a higher MEF indicates lower per cycle energy requirements for washing clothes.

With that said, these standards likely may be altered in some manner due to unknown technologies or changes in the economic or political climate. In the near term though, building codes and efficiency standards appear to have minimal impacts on potential for DSM programs.

The process for developing the avoided costs is described in Chapter 2 - Planning Environment. The avoided costs curves developed for use in the 2016 DSM Potential Study differ from those developed for this 2017 IRP because the potential study started in mid-2016 and conditions have changed since that time.

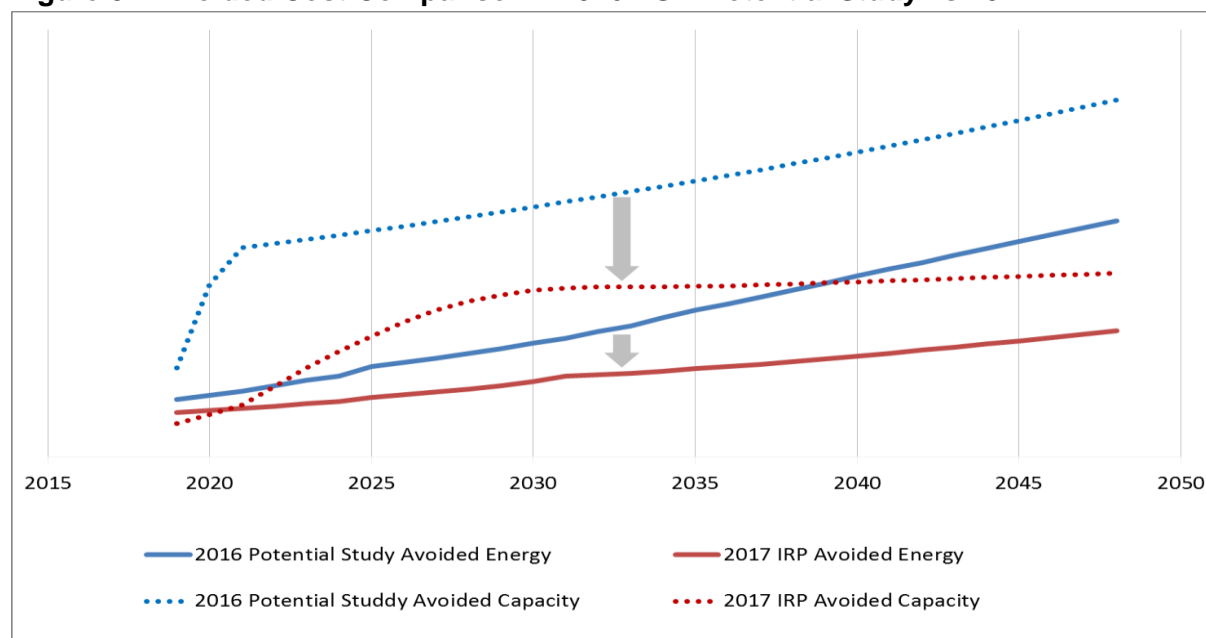
The process for developing the avoided costs is described in Chapter 2 - Planning Environment and Chapter 7 – Transmission and Distribution.<sup>3</sup> The most significant and immediate impact to DSM potential opportunities involves the current avoided costs projections for both energy and capacity that have continued to decline from levels used in the 2014 Integrated Resource Plan (IRP) filing, the MEEIA Cycle 2016 - 2018 program analysis work, and even since the recent 2016 DSM Potential Study. The benefits associated with demand-side measures are a function of the level of avoided energy and capacity costs. The lower avoided costs yield lower benefits which increase the likelihood that marginally cost effective measures fall out of the mix. According to the 2016 DSM Potential Study<sup>4</sup>, there is still a large amount of demand-side potential, but that potential continues to narrow in scope and become more expensive.

The reduction in avoided costs is attributable to the low price of natural gas as well as the overall state of the economy where electric load growth has flattened. Figure 8.2 illustrates the dramatic differences between the avoided energy and capacity costs used in the 2016 DSM Potential Study as compared to the more recent avoided costs presented in the 2017 IRP. Even so, the updated 2017 IRP avoided costs are within the range of the avoided cost scenarios analyzed in the 2016 DSM Potential Study.

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<sup>3</sup> 4 CSR 240-22.050(5)(A)1 through 3; 4 CSR 240-22.050(6)(C)2; Chapter 2 of the Ameren Missouri 2016 DSM Potential Study discusses the sensitivity analysis performed around avoided cost

<sup>4</sup> See the full 2016 DSM Potential Study included in Appendix A of this document.

**Figure 8.2 Avoided Cost Comparison – 2016 DSM Potential Study vs 2017 IRP**

## 8.2 DSM Potential Study & Implementation Plan

### 8.2.1 2016 Ameren Missouri DSM Potential Study

#### 8.2.1.1 Overview

Ameren Missouri worked together with interested stakeholders to develop a scope of work, select contractor(s), review plans, analyze data, and report results for the 2016 DSM Potential Study. The contractor selected to perform the study was GDS Associates. Once the MEEIA 2016-2018 programs were approved, work on the potential study was initiated and completed within approximately one-third of the time that is normally allotted to conduct a market potential study. To maximize the extensive work done with Enernoc in 2014, GDS subcontracted with EMI Consulting (“EMI”) to review and update the market research content provided in the 2014 DSM Potential Study. The market research task consisted of a comprehensive review and analysis of all relevant existing data (primary and secondary) without the development of new data generated through primary research. This approach combined multiple analytical methods and datasets including Ameren Missouri MEEIA program implementation results and implementation results of peer utilities.<sup>5</sup> From this data GDS then compiled their market and industry research into estimations of the technical, economic, and achievable levels of energy efficiency and demand response potential (2019-2036).

<sup>5</sup> 4 CSR 240-22.050(1)(D); 4 CSR 240-22.050(3)(A)

The 2016 DSM Potential Study also assessed the potential for customer distributed generation, combined heat and power and demand-side rates.<sup>6</sup>

### **8.2.1.2 Stakeholder Interactions during DSM Potential Study**

During the 2016 DSM Potential Study there was significant communication and interaction with interested stakeholders. Ameren engaged, informed, and updated interested stakeholders throughout the planning process. In consideration of reducing scope, budget, and schedule of the 2016 DSM Potential Study, Ameren Missouri was granted a variance to augment prior primary market research with recent program experience as opposed to re-conducting full primary market research.

### **8.2.1.3 Overall Conclusions**

- Continuing the trend from the 2016-2018 DSM implementation planning period, 55-60% of the program-level energy-efficiency potential is expected to come from commercial and industrial customers in the immediate future.
- There is significant energy efficiency and demand response program potential but projected programs costs are significantly higher than current spending levels. Regarding demand response, while there has been volatility in the capacity markets, long term value exists.
- The initial analysis of demand-side rates in the study indicate that inclining block rates (IBR) and time-of-use (TOU) rates have significant customer energy usage reduction potential. However, Ameren Missouri conducted in depth analysis on the demand side rate potential which indicates significantly reduced impacts. This topic is discussed further in chapter 8.6 of this report - Demand Side Rate Potential.

For more detail, the complete 2016 DSM Potential Study is attached to this chapter of the IRP as Appendix A.

### **8.2.1.4 Energy Efficiency Potential**

Key findings related to program level potentials as compared to the base energy forecast are summarized as follows:<sup>7</sup>

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<sup>6</sup> 4 CSR 240-22.050(1)(C) See chapter 8 of the 2016 DSM Potential Study (Appendix A) for more detail

<sup>7</sup> 4 CSR 240-22.050(2)

**Table 8.1 Energy Efficiency MWh Savings as Percent of Total Forecasted Sales**

	2019	2020	2021	2022	2023	2024	2030	2036
Technical Potential	28.9%	31.0%	32.4%	34.1%	35.7%	36.8%	42.1%	44.0%
Economic Potential	22.4%	24.0%	25.0%	26.2%	27.4%	28.3%	32.3%	34.0%
MAP	2.5%	4.5%	5.8%	7.4%	8.8%	10.1%	16.2%	18.5%
RAP	1.3%	2.5%	3.7%	4.9%	6.1%	7.2%	12.3%	14.3%
Program MAP	2.3%	4.1%	5.3%	6.7%	8.0%	9.2%	15.2%	17.5%
Program RAP	1.0%	2.0%	3.1%	4.2%	5.4%	6.4%	11.3%	13.5%

\*the percentages above reflect the energy efficiency and behavioral program potentials against the IRP forecasted sales.

- **Technical potential** reflects the adoption of all energy-efficiency measures regardless of cost-effectiveness, is a theoretical upper bound on savings.
- **Economic potential** reflects the savings when the most efficient cost-effective measures are utilized by all customers.
- **Maximum Achievable Potential (MAP)** establishes a maximum target 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 efficient measures above baseline measures, combined with high administrative and marketing costs. It also considers a maximum participation rate by customers.<sup>8</sup>
- **Realistic Achievable Potential (RAP)** represents a forecast of likely customer behavior under realistic program design and implementation. 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.<sup>9</sup> 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.

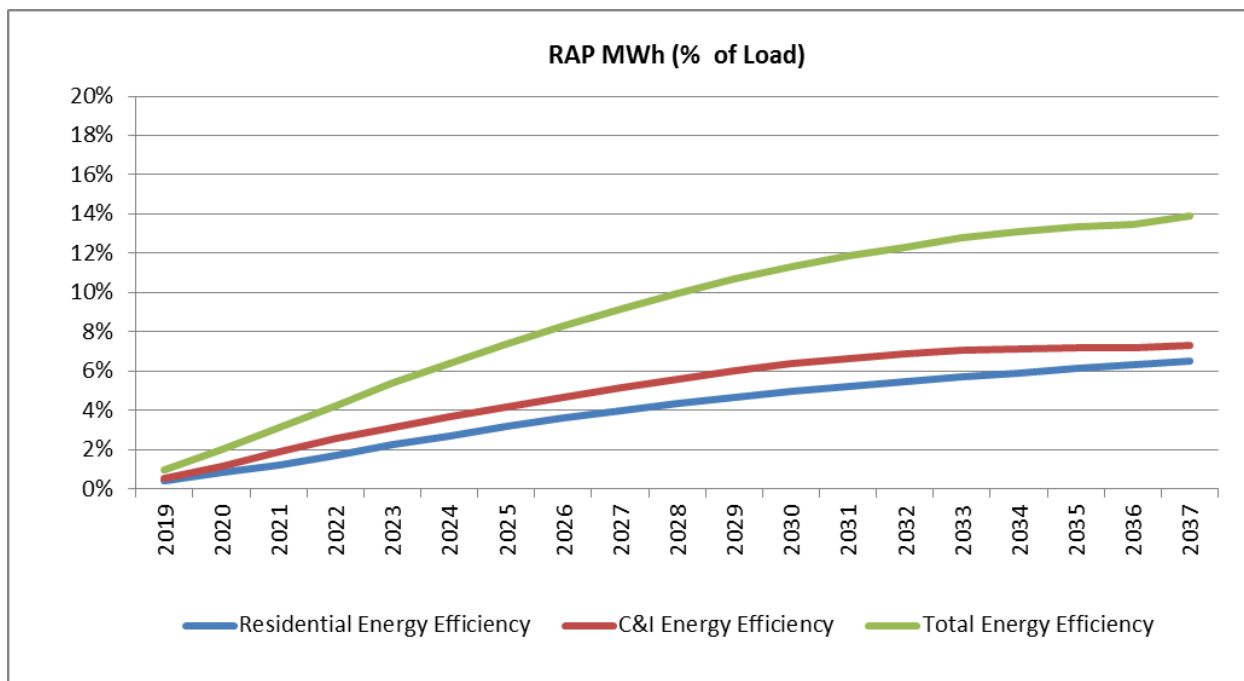
There is an important distinction to make when describing energy efficiency potential. There are two types of potential estimates – measure level and program level. Measure level potential does not include costs such as program administration and portfolio administration, in addition to impacts such as historical program activity, interactive effects between measures, and net to gross impacts. When these additional items are included, it is not unusual to remove marginally cost

<sup>8</sup> 4 CSR 240-22.050(3)(G)5B

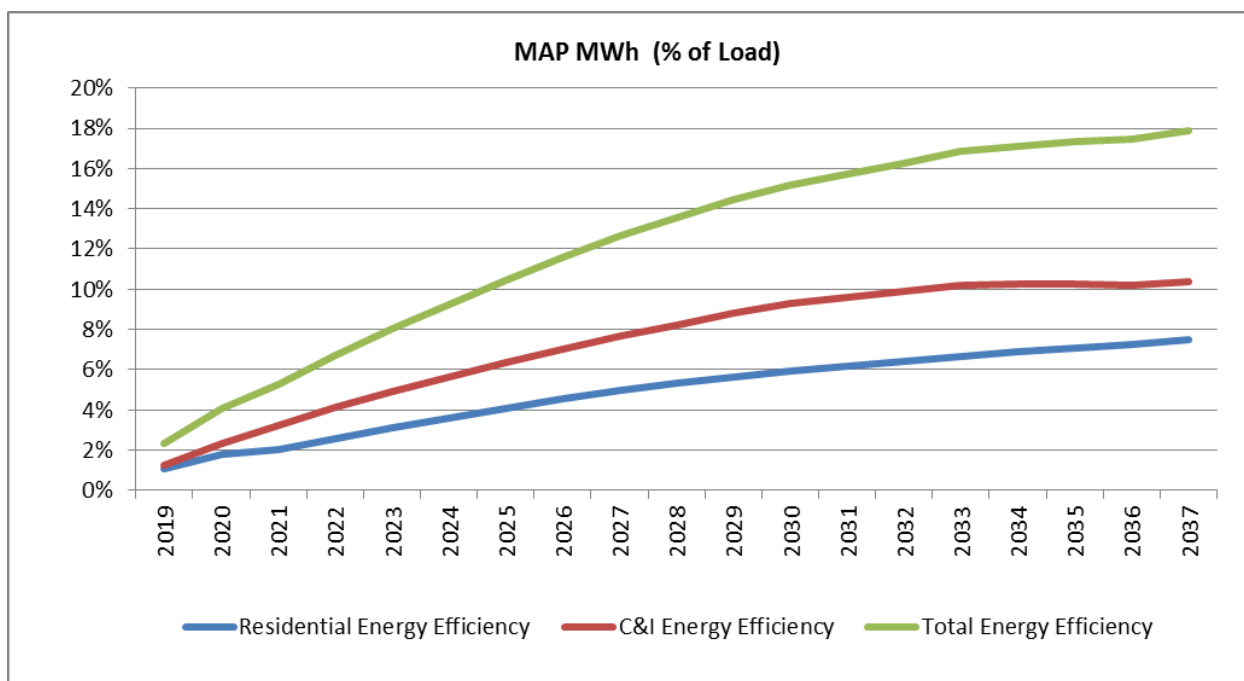
<sup>9</sup> 4 CSR 240-22.050(3)(G)5B

effective energy efficiency measures from a program in order to make the program cost effective. For this reason, program potential is usually less than the measure level potential. Below are the energy efficiency program RAP and MAP potentials across the 20 year planning horizon for the residential and commercial/industrial (C&I) sectors.

**Figure 8.3 Summary of Cumulative Annual RAP Energy Efficiency Energy Savings**



**Figure 8.4 Summary of Cumulative Annual MAP Energy Efficiency Energy Savings**



As Ameren Missouri analyzed the results of the 2016 DSM Potential Study data, there were two modifications to the raw results in order to align it with the current MEEIA structure in Missouri and extend the data for the IRP planning horizon. Those changes included the following:<sup>10</sup>

1. Ameren Missouri used the energy savings potential from the 2016 DSM Potential Study without modification but applied the Ameren Missouri coincident peak factors as approved in the MEEIA 2016-2018 filing in order to determine the associated coincident peak demand savings.
2. Ameren Missouri used a simple regression analysis over the last few years of the 2016 DSM Potential Study to extend the savings and cost estimates by one year to match the IRP planning horizon through 2037.

Historically, Ameren Missouri has used the potential study results for energy efficiency and modified them where appropriate to create a cost effective portfolio design for its MEEIA implementation plan. Alternatively for its next implementation plan, Ameren Missouri has used the 2016 DSM Potential Study results as an initial basis for its targets in an RFP. The resulting proposals from implementation contractors will then be used by Ameren Missouri to initiate a collaborative dialogue with interested stakeholders to define the demand-side portfolio, budgets, and targets for its next MEEIA plan.

Another notable change is that this RFP is being issued for a 6-year implementation cycle unlike the first two MEEIA cycles which offered a 3-year cycle each. Moving toward a longer program cycle enhances the structure to better enable continuity of a base set of programs and allow more time and energy to focus on new programs, new technologies, and overall improvement opportunities.<sup>11</sup> In past experience, by the time a new program cycle is through the “start-up” phase, planning for the next cycle has to begin and there is little time to incorporate improvement opportunities from the current cycle into the planning process, as the first year results are still being finalized. A longer cycle will provide more opportunity to manage the programs and understand what is or is not working well, so those considerations can be better implemented in the future.

#### 8.2.1.5 Portfolio Descriptions<sup>12</sup>

Ameren Missouri examined a number of possible DSM portfolios to be used for the IRP resource plan analysis phase. The DSM portfolios considered are shown below, along with a brief description of portfolio features.

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<sup>10</sup> 4 CSR 240-22.050(1)(D)

<sup>11</sup> 4 CSR 240-22.050(1)(D)

<sup>12</sup> 4 CSR 240-22.050(6)(A)



### **RAP Portfolio**

The RAP portfolio represents a level of DSM programs that are based on the RAP measure level savings which were identified within the 2016 DSM Potential Study. The RAP portfolio of programs represents estimates of energy efficiency and demand response program potential based on realistic program implementation assumptions, such as: industry-standard incentive levels, customer acceptance barriers, etc.

### **MAP Portfolio**

The (MAP portfolio represents the most aggressive level of DSM programs that could be delivered by Ameren Missouri and are based on the MAP measure level savings which were identified within the 2016 DSM Potential Study. MAP represents estimates of energy efficiency and demand response potential that are based on the most optimistic program implementation assumptions, such as: boosted utility budgets, higher incentive levels, high customer acceptance, cutting edge delivery methods, etc.

### **Mid Portfolio**

This aggressive portfolio, for energy efficiency, is designed to be a set of programs that will deliver a level of savings half-way between the RAP portfolio and the MAP portfolio. This portfolio was developed to determine the potential merit, if any, of delivering DSM programs at a level that is between RAP and MAP. For energy efficiency both the energy and program cost were an average of RAP and MAP, while in the case of demand response, a separate mid-portfolio was constructed with the help of GDS Associates. For demand response the mid portfolio was constructed using a blend of MAP and RAP programs, with more focus on direct load control programs, to arrive at a demand savings level near the average of MAP and RAP. GDS then reconstructed the cost for this mid portfolio based upon the specific program hierarchy and cost effectiveness of each program.

#### **8.2.1.6 Portfolio Impacts and Costs<sup>13</sup>**

Each of the portfolios described above achieves various levels of savings (energy and demand) in each year of the planning horizon at projected annual costs. Below are charts showing the costs and savings of each portfolio used as the basis for analysis of alternative resource plans.

Figure 8.5 shows the projected annual budget for each of the energy efficiency portfolios that were developed.

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<sup>13</sup> 4 CSR 240-22.050(3)(G)1

Figure 8.5 Portfolio Energy Efficiency Spending

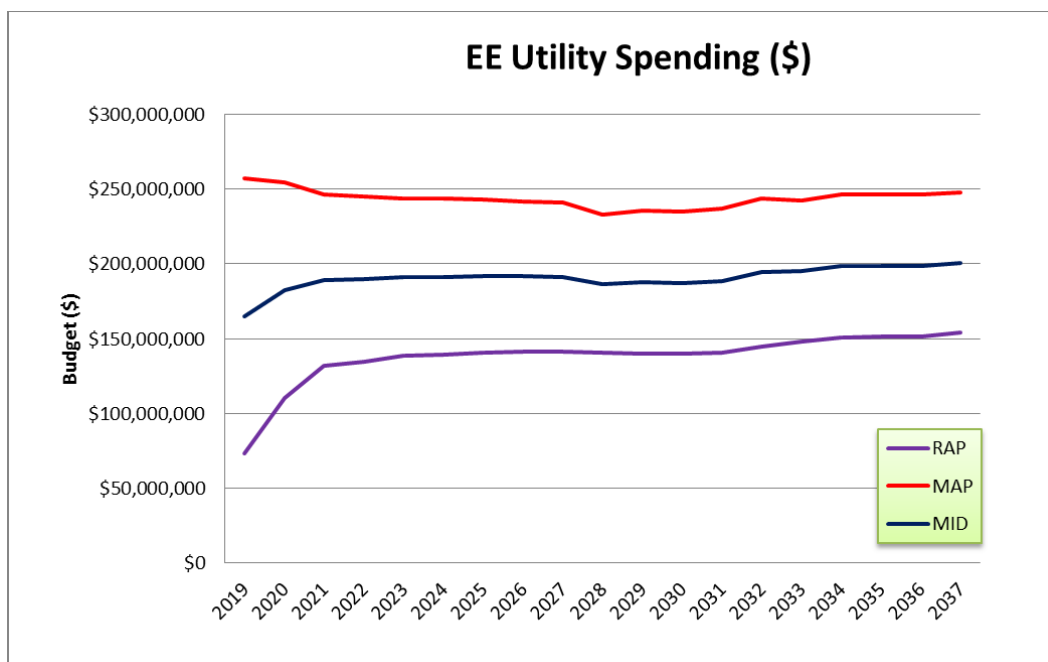


Figure 8.6 shows the projected annual budget for each of the demand response portfolios that were developed. Note that the MAP portfolio budget is lower than the MID portfolio budget from 2021 through 2022 and again from 2031 through 2032 because the MID is reliant on direct load control devices (which have a 10-year useful life) while the MAP portfolio assumes lower acquisition cost pricing programs.

Figure 8.6 Portfolio Demand Response Spending

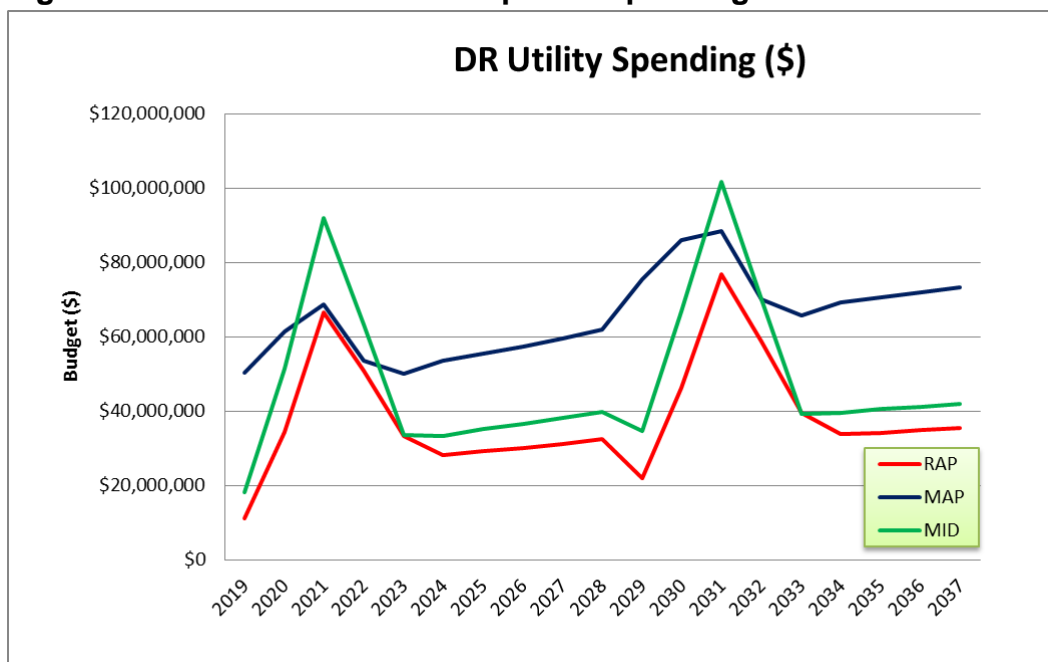
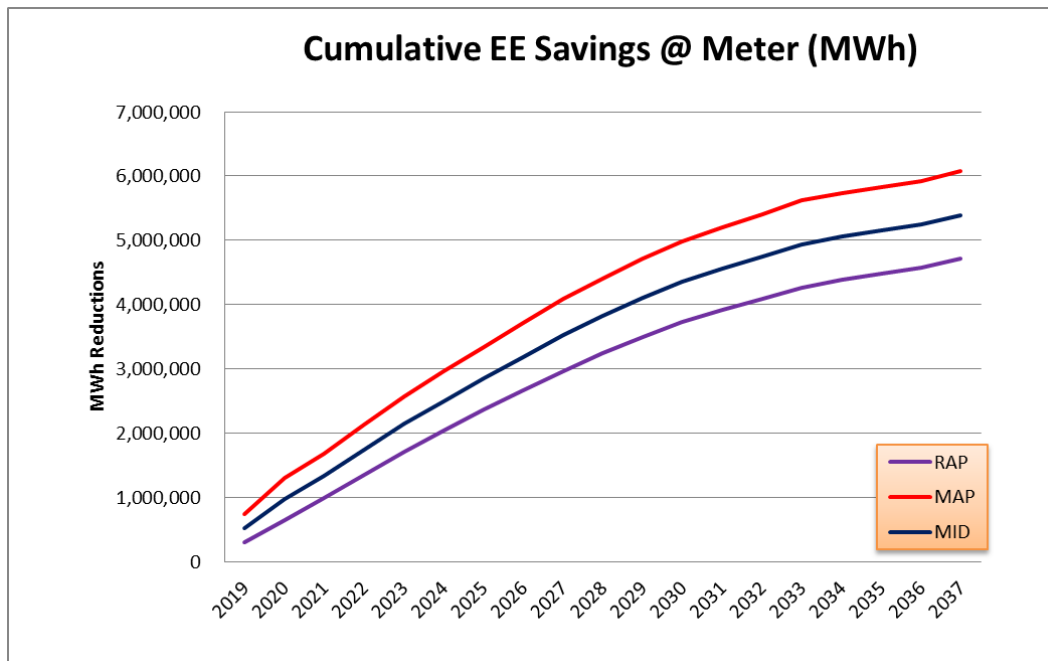
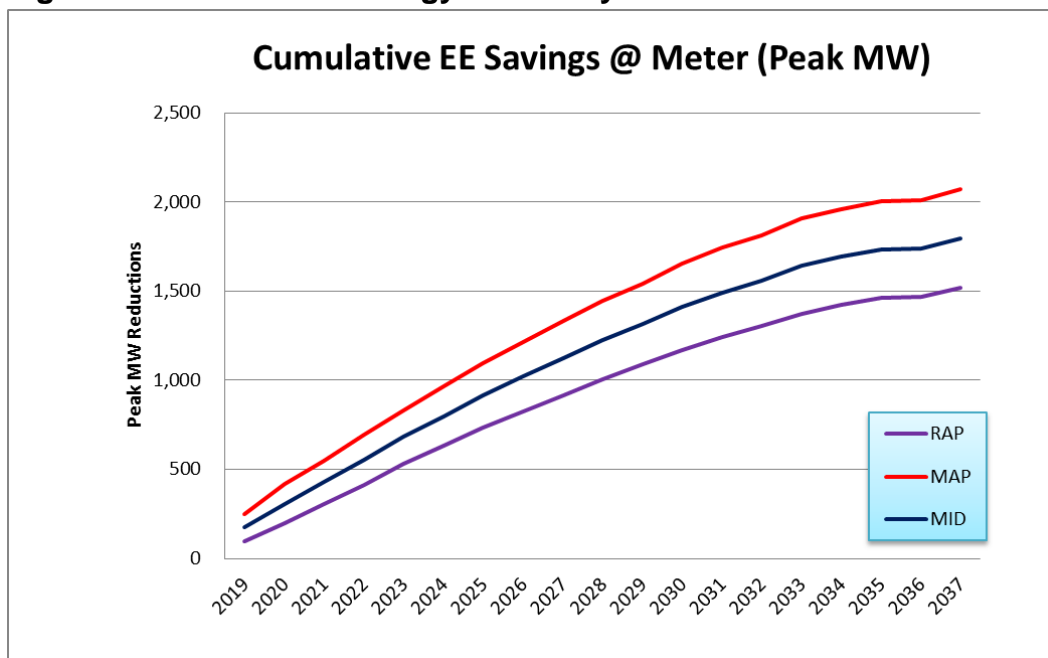


Figure 8.7 and Figure 8.8 show the projected annual cumulative energy and peak demand savings, respectively, for each of the energy efficiency portfolios that were developed:

**Figure 8.7 Cumulative Energy Efficiency Savings<sup>14</sup>**



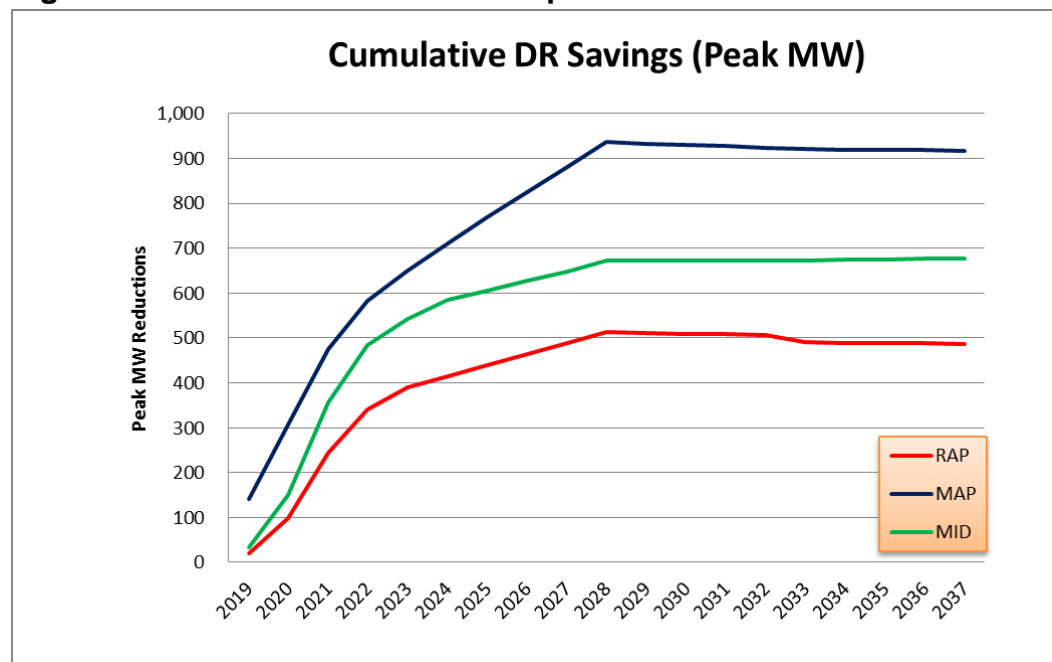
**Figure 8.8 Cumulative Energy Efficiency Peak Load Reductions**



<sup>14</sup> 4 CSR 240-22.050(6)(B)

Figure 8.9 shows the projected annual cumulative demand savings for each of the demand response portfolios that were developed.

**Figure 8.9 Cumulative Demand Response Peak Load Reductions**



## 8.3 Evaluation Measurement and Verification (EM&V)

### 8.3.1 Existing EM&V Model

Separate evaluators are currently under contract for the Residential and Business portfolios. The evaluators provide an annual independent review of the gross and net program impacts. They also provide process evaluations including reviews of databases and marketing materials, conduct implementer interviews, and measure customer satisfaction with programs.

The Commission has hired an Auditor to assess and report on the work of Ameren Missouri's independent EM&V contractors. The Commission Auditor monitors EM&V planning, implementation, and analysis of the EM&V contractors and ultimately files a report each year with its findings.

The evaluators submit their draft annual process and impact evaluation reports to stakeholders and the Commission Auditor for review and comment 60 days after the completion of each program year and their final annual process and impact evaluation reports 135 days after the completion of each program year.

### 8.3.2 Proposed EM&V Model

#### 8.3.2.1 Evaluation Contractor Role

For the MEEIA (2019 – 2024) cycle, a competitive procurement process will take place to ensure that the most qualified evaluation contractor(s) is hired prior to the start of the programs in order to understand the program details and ensure adequate data requirements are implemented. Missouri has historically allocated 5% of portfolio resources to EM&V to ensure a balanced approach is utilized to estimate net savings.

Evaluation contractors enhance implementation efforts in several ways. Evaluators contribute meaningfully to operational efforts, having done so in the past for program design roundtable discussions, design of customer forms and materials, data tracking system setup, and program delivery modifications. The evaluation contractor also works with the Commission Auditor to assure that best practices are being followed and the accuracy of the evaluated results are being maximized.

#### 8.3.2.2 Evaluation Plan

The Evaluation Plans are detailed work plans that fulfill the evaluation objectives and identify the activities that will be undertaken in each program year.

The EM&V plans described within this section should be considered a preliminary planning document and subject to change based upon program design changes incorporated by the implementation team. The evaluation plans for each DSM program will be developed during the first quarter of 2019. Each evaluation plan will be composed of annual work plans which support the overall program cycle. As programs and markets evolve each year, the evaluation methods may need to change to ensure the evaluation method(s) being used continue to be appropriate. Findings from process evaluations and market assessments can help identify when to reassess impact evaluation methods. This will give the evaluation team the same type flexibility as the implementation teams to make appropriate modifications to respond to program and market condition changes. Interested stakeholders will be engaged with the development and review of the overall EM&V plans prior to its implementation and be informed as modifications are made throughout the program cycle.

#### 8.3.2.3 Impact Evaluations<sup>15</sup>

One of the most important aspects of evaluation is the measurement of savings achieved, or impact evaluation results. Ameren Missouri has developed, in coordination with the evaluation contractor(s), the necessary methods to estimate load impacts of the energy efficiency programs offered by the Company. The impact evaluation estimates

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<sup>15</sup> 4 CSR 240-22.070(8)(B); 4 CSR 240-22.050(7)

of gross program savings may include engineering analysis and formulas, building simulation models, meter data, statistical models and billing analysis.

For the low income program, the evaluation will also include an analysis of how the program affects bill payments, arrearages, and disconnections.

#### 8.3.2.4 Process Evaluations<sup>16</sup>

Ameren Missouri's evaluators are tasked to identify appropriate process evaluation goals, procedures, and practices. These evaluations focus more on program design and delivery, market segments, and other societal factors that affect the program's performance.

Process evaluations use program implementer/contractor interviews, customer and trade-ally surveys and review of program materials to inform the process evaluation. Stakeholder and retailer interviews provide details on program design, database review, staffing levels, training, implementation, marketing to retailers and trade allies, retailer and trade ally satisfaction, marketing to consumers, products, payments and invoicing, communications, tracking and market feedback. Program data reviews provide further information on program design and implementation processes.

#### 8.3.2.5 Data Collection<sup>17</sup>

Thus far, Ameren Missouri has been engaged with the evaluation contractors to develop and implement the necessary protocols, methodologies, and technology to gather the appropriate data necessary to facilitate effective evaluation. As programs mature and the market begins to transform, it is important for Ameren Missouri to continue to have open lines of communication with both the evaluation teams and the implementation teams. A centralized data tracking system is being utilized by the implementation contractors to track program metrics for use by the evaluators in the EM&V process.

#### 8.3.2.6 Internal Verification and Quality Control

The evaluation contractor has responsibility for verification of installation and estimation of energy savings for purposes of independent evaluation. Besides coordinating independent EM&V, Ameren Missouri requires implementation contractors to develop and implement internal Quality Assurance and Quality Control (QA/QC), inspection, and due diligence procedures. These procedures will vary by program and are necessary to assure customer eligibility, completion of installations, and the reasonableness and

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<sup>16</sup> 4 CSR 240-22.070(8)(A); 4 CSR 240-22.050(7)

<sup>17</sup> 4 CSR 240-22.070(8)(C); 4 CSR 240-22.050(7)

accuracy of savings upon which incentives have been based. Evaluators also review these QA/QC procedures.

### **8.3.2.7 Annual EM&V Reporting**

The evaluation contractors will prepare annual draft and final impact and process evaluation reports. The reports will include ex-ante gross, ex-post gross and ex-post net energy savings and demand reduction for each of the programs and residential and non-residential portfolios. The reports will also include a summary of the process evaluation and will identify specific detail regarding the impact methodologies and results as well as key findings, conclusions and recommendations. Based on the annual report results, Ameren Missouri will complete the cost effectiveness analysis at the program and portfolio level.

## **8.4 Outreach, Marketing and Communications<sup>18</sup>**

Developing and executing a comprehensive marketing communications plan is essential to reaching the residential and business energy efficiency goals. Executing a mix of marketing simultaneously with a consistent message creates repetitive exposure which drives recognition and as a result drives participation. In addition, a multi-media plan enables Ameren Missouri to reach its diverse customer base.

The most opportunistic means to market the business energy efficiency programs is through Trade Allies, Program Business Development staff and key customer facing employees such as Key Account Executives and Customer Service Advisors. Trade Allies are experts in energy efficient technology, understanding market conditions, and are whom customers go-to when seeking energy efficient products and services. They are the primary channel for marketing and outreach. The marketing efforts for the business portfolio are also a combination of internal and external activities.

## **8.5 The Planning Process**

### **8.5.1 Cost-Effectiveness Defined**

Cost effectiveness of Ameren Missouri DSM measures, programs, and portfolios was calculated using the total resource cost (TRC) test, the utility cost test (UCT), the participant cost test (PCT), and the ratepayer impact measure (RIM) test.<sup>19</sup> In each year of the planning horizon, the benefits of each demand-side program are calculated as the cumulative energy and demand impact multiplied by all applicable avoided costs,

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<sup>18</sup> 4 CSR 240-22.050(3)(E)

<sup>19</sup> 4 CSR 240-22.050(5)(E); 4 CSR 240-22.050(5)(F); 4 CSR 240-22.050(5)(G); 4 CSR 240-22.050(3)(I)

and then summed into net present values for the timeframe considered.<sup>20</sup> The definitions of the tests are outlined below:

**The Total Resource Cost (TRC)** test measures benefits and costs from the perspective of the utility and society as a whole. The benefits are the net present value of the energy and capacity saved by the measures. The costs are the net present value of all costs to implement those measures. These costs include program administrative costs and full incremental costs (both utility and participant contributions), but no incentive payments that offset incremental costs to customers and no lost revenues.<sup>21</sup> The full incremental costs include single upfront costs and operational & maintenance costs where applicable.<sup>22</sup> Programs passing the TRC test (that is, having a B/C ratio greater than 1.0) result in a decrease in the total cost of energy services to electric ratepayers.<sup>23</sup>

**The Utility Cost Test (UCT)** measures the costs and benefits from the perspective of the utility administering the program.<sup>24</sup> As such, this test is characterized as the revenue requirement test. Benefits are the net present value of the avoided energy and capacity costs resulting from the implementation of the measures. Costs are the administrative, marketing and evaluation costs resulting from program implementation along with the costs of incentives but do not include lost revenues.<sup>25</sup> Programs passing the UCT result in overall net benefits to the utility, thus making the program worthwhile from a utility cost accounting perspective.<sup>26</sup>

**The Participant Cost Test (PCT)** measures the benefits and costs from the perspective of program participants, or customers, as a whole. Benefits are the net present value savings that participating customers receive on their electric bills as a result of the implementation of the energy efficiency and demand response measures plus incentives received by the customer. Costs are the customer's up-front net capital costs to install the measures. If the customer receives some form of a rebate incentive, then those costs are considered as a credit to the customer and are added to the customer's total benefits.<sup>27</sup>

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<sup>20</sup> 4 CSR 240-22.050(5)(A);

<sup>21</sup> 4 CSR 240-22.050(5)(B)2; 4 CSR 240-22.050(5)(B)3

<sup>22</sup> 4 CSR 240-22.050(5)(B)1

<sup>23</sup> 4 CSR 240-22.050(5)(D)

<sup>24</sup> 4 CSR 240-22.050(5)(C)

<sup>25</sup> 4 CSR 240-22.050(5)(C)1; 4 CSR 240-22.050(5)(C)2&3

<sup>26</sup> 4 CSR 240-22.050(5)(D)

<sup>27</sup> 4 CSR 240-22.050(5)(F)



**The Ratepayer Impact Measure (RIM)** test measures the difference between the change in total revenues paid to a utility and the change in total costs to a utility resulting from the energy efficiency and demand response programs. If a change in the revenues is larger or smaller than the change in total costs (revenue requirements), then the rate levels may have to change as a result of the program.<sup>28</sup>

### 8.5.2 Interactive Effects<sup>29</sup>

Interactive effects, both energy and demand, were assessed by Ameren Missouri's contractor for the 2016 DSM Potential Study. Note that the potential study actually consisted of energy efficiency, distributed generation, combined heat and power, and demand response.

Capturing the energy efficiency interactive effects of applicable measures required examining many instances where multiple measures affect a single end use both positively and negatively. To avoid overestimation of total savings, the assessment of cumulative impacts accounts for the interaction among the various end uses. This was accomplished by establishing a base level model that incorporated many non-related measures and identifying the savings achieved by stacking the incremental measure within an additional modeling run, with a comparison of the base and modified runs to arrive at the implemented measure impact on energy consumption.

Ameren Missouri's contractor for the potential study developed the effects of interaction between the programs/resources identified within each study using a program stacking order with preference given to energy efficiency and behavior programs, followed by demand response and distributed generation and combined heat and power.

## 8.6 Demand-Side Rate Potential<sup>30</sup>

### 8.6.1 Introduction

The structure of retail rates has the potential to influence the manner in which customers choose to use electric energy services. As such, rate design may contribute to the achievement of demand side goals that impact the total load served by the utility and therefore influence the amount and type of supply side resources needed. In addition to recognizing the ability of rate design to further demand side goals, it is important to ground the discussion of the topic with other important and well-established considerations. Rate designs traditionally have been evaluated based on the extent to

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<sup>28</sup> 4 CSR 240-22.050(5)(F)

<sup>29</sup> 4 CSR 240-22.050(3)(G)2

<sup>30</sup> 4 CSR 240-22.050(4); Demand-Side Rates is discussed further in chapter 8 of the 2016 DSM Potential Study

which they reflect the cost of serving customers and therefore promote equity between them (i.e. costs are borne by the cost causer with no unintentional subsidization) and provide economically efficient price signals<sup>31</sup>. Additional long-recognized rate design priorities include simplicity in customer understanding and utility administration, stability of resulting customer bills and utility revenues, and adequacy in producing the intended revenues. The potential benefits of a particular rate design in achieving demand side goals must always be assessed in conjunction with its positive or negative contributions toward these other important objectives. With that context and awareness, Ameren Missouri has evaluated a number of rate designs for their potential impacts on resource planning. For this purpose, Ameren Missouri engaged GDS Associates to screen various rate options and develop estimates of the potential energy and demand savings that may be associated with these rate options. As discussed further below, Ameren Missouri engaged in additional analysis of one specific rate design, inclining block rates, beyond the work done by GDS in order to incorporate new information associated with recent studies and papers on the topic. Additionally, while not incorporated in any potential analysis, Ameren Missouri will provide information about an emerging rate design issue with potentially significant demand-side implications – residential demand charges.

### 8.6.2 Approach<sup>32</sup>

GDS Associates compiled a list of candidate rate structures for analysis – this list included interruptible rates for large commercial and industrial customers, time of use rates (TOU) with and without enabling technology for residential and small commercial and industrial customers, Critical Peak Pricing (CPP) across all customer segments with and without enabling technology, end-use specific TOU rates for charging applications such as electric vehicles across all customer segments, and residential inclining block rates (IBR)<sup>33</sup>. GDS then reviewed numerous offerings by other utilities<sup>34</sup> and relevant studies of such rate options to develop projected take rates (number of participants), implementation costs<sup>35</sup>, and participant load reductions to develop estimates for each year of the planning horizon of RAP and MAP for each rate design option<sup>36</sup>. Specific sources and values for the take rate and load reduction estimates are detailed in Chapter 8 and Appendix D of the Ameren Missouri 2016 DSM Potential Study authored by GDS<sup>37</sup> and attached to this chapter of the IRP as Appendix A. Application of these

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<sup>31</sup> Promoting economic efficiency is not the same as promoting energy efficiency. Economic efficiency refers generally to a condition where resources are allocated in a manner designed to produce optimal welfare, not lowest consumption.

<sup>32</sup> 4 CSR 240-22.050(2)

<sup>33</sup> 4 CSR 240-22.050(4)(B); 4 CSR 240-22.050(4)(F)

<sup>34</sup> 4 CSR 240-22.050(4)(A)

<sup>35</sup> 4 CSR 240-22.050(4)(D)5

<sup>36</sup> 4 CSR 240-22.050(4)(D)1&4; 4 CSR 240-22.050(4)(E)

<sup>37</sup> 4 CSR 240-22.050(4)(D); 4 CSR 240-22.050(4)(G)

take rates and per participant load reductions to actual Ameren Missouri customer usage and usage forecast information allowed GDS to estimate the potential energy and demand reductions associated with each candidate rate design. Specific care was taken in this estimation process to impose a hierarchy of rate design and demand response programs from which to allow impacts such that no double-counting of the same savings could take place<sup>38</sup>. Results of this analysis for all rate designs and customer classes found to be cost effective by GDS are reported below in terms of peak demand MW reduction potential by year, with one exception. It is necessary to revisit the concept of inclining block rates to describe additional relevant analysis undertaken by Ameren Missouri subsequent to the completion of the 2016 DSM Potential Study, so potential estimates<sup>39</sup> for inclining block rates are omitted in Tables 8.2 through 8.7 below.

**Table 8.2 Cumulative Annual Residential Program MAP Summer MW Savings by Program**

DR Program	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Critical Peak Pricing Rate with Enabling Technology	45	88	126	389	377
Critical Peak Pricing Rate without Enabling Technology	23	45	64	197	191
Plug-In Electric Vehicle Charging Stations Off Peak	1	2	2	9	17

**Table 8.3 Cumulative Annual Residential Program RAP Summer MW Savings by Program**

DR Program	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Critical Peak Pricing Rate with Enabling Technology	1	10	35	160	155
Critical Peak Pricing Rate without Enabling Technology	0	5	15	64	62
Plug-In Electric Vehicle Charging Stations Off Peak	0	0	1	4	11

<sup>38</sup> 4 CSR 240-22.050(4)(D)2&3

<sup>39</sup> Energy savings not shown due to the fact that all demand side rates reflected in programs are focused on demand savings and produce negligible total energy savings.

**Table 8.4 Cumulative Annual Program MAP Commercial Summer MW Savings by Program**

DR Program	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Critical Peak Pricing Rate with Enabling Technology	27	50	63	172	166
Critical Peak Pricing Rate without Enabling Technology	17	32	44	123	118
Plug-In Electric Vehicle Charging Stations Off Peak	0	0	0	2	4

**Table 8.5 Cumulative Annual Program RAP Commercial Summer MW Savings by Program**

DR Program	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Critical Peak Pricing Rate with Enabling Technology	1	6	19	88	86
Critical Peak Pricing Rate without Enabling Technology	0	3	11	46	45

**Table 8.6 Cumulative Annual Program MAP Industrial Summer MW Savings by Program**

DR Program	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Critical Peak Pricing Rate with Enabling Technology	1	2	2	6	6
Critical Peak Pricing Rate without Enabling Technology	4	7	9	24	22

**Table 8.7 Cumulative Annual Program RAP Industrial Summer MW Savings by Program**

DR Program	2019 Potential (MW)	2020 Potential (MW)	2021 Potential (MW)	2028 Potential (MW)	2036 Potential (MW)
Critical Peak Pricing Rate with Enabling Technology	0	0	1	3	3
Critical Peak Pricing Rate without Enabling Technology	0	1	2	8	7

The ability of each type of demand side rate program to be explicitly counted by Midcontinent Independent System Operator (MISO) as an energy, capacity, or ancillary services market resource is greatly dependent upon the specifics of the program

design<sup>40</sup>. Generally, time of use rates, including end use specific time of use rates such as special rates for off-peak electric vehicle charging, would not explicitly qualify to directly participate in capacity markets. However, to the extent that load consumption (i.e. vehicle charging) behavior changes materialized in a manner that was captured in the utility's peak demand forecasting, the peak load obligation that the utility is required to procure capacity for may be reduced. Hence there would potentially still be avoided capacity value ascribable to the program. Other programs, such as Critical Peak Pricing and Interruptible rates, would likely be attributed capacity value directly if designed to meet the following criteria:

1. Include provisions for mandatory curtailment
2. Aggregate to achieve greater than 100 kW of load reduction
3. Respond on no more than 12 hours' notice
4. Demonstrate they can achieve targeted load reduction
5. Able to maintain reduction for 4 hours
6. Able respond at least 5 times during the MISO summer period

Such programs must meet further criteria to register in MISO as a Demand Response Resource in order to participate in energy or ancillary services programs. Some interruptible program designs would likely qualify, whereas critical peak pricing programs may not.

### 8.6.3 Inclining Block Rates







The term inclining block rates refers to a rate structure where customers pay a lower rate for some initial level of usage, but a higher rate for incremental usage above a predefined threshold. For a number of years there has been general interest from many jurisdictions and utility stakeholders in the purported ability of inclining block rates to promote energy conservation, and several jurisdictions have implemented such rate structures. In its 2014 IRP, the Company provided results of a study performed by The Brattle Group that suggested that inclining block rates applied to residential customers' usage had the potential to promote a noteworthy amount of energy and demand savings. The 2016 DSM Potential Study results were informed largely by that Brattle work commissioned for the 2014 IRP. That study was itself premised on work done by Brattle principal Ahmad Faruqui, which is well known in the industry from the 2008 article published by Dr. Faruqui titled "Inclining Towards Efficiency". The premise of this article/study is that customers make usage decisions informed by their awareness of the marginal rate for incremental consumption. As such, it was assumed that raising the marginal rate by employing an inclining block structure where incremental usage faced

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<sup>40</sup> 4 CSR 240-22.050(4)(F)

a higher price would ultimately cause customers to make decisions to consume less energy. Brattle's analysis for Ameren Missouri relied on secondary estimates of price elasticity derived from other studies. Price elasticity is a measure of customers' tendency to increase or decrease consumption of a good in response to changes in its price. However, many such published price elasticity studies are not well-suited to differentiating the impact of marginal prices (the price of the next kWh consumed) on consumption from the impact of average prices (the combination of all prices experienced – i.e. customer charge, first block energy charge, second block energy charge - that make up the total bill to the customer). To explain the distinction further, consider the two likely ways that customers could be informed regarding electricity prices. Customers could either review utility tariffs and familiarize themselves with the rates and apply them to their understanding of their consumption, or they could simply observe the changes in their total bill over time and draw inferences about the underlying rates. But these two methods will potentially lead to significantly different outcomes. Consider how three different customers would experience a change from a flat rate to an inclining block rate. Assume a simple hypothetical incumbent rate structure with a monthly customer charge of \$10/month and a flat energy charge of \$0.10/kWh (for ease of math in the example). Now assume the residential rate structure is changed to include an inclining block rate with a block threshold of 750 kWh, with a first block energy charge of \$0.08/kWh and a second block energy charge of \$0.12/kWh. Next assume that three hypothetical customers have usage in a given month of 600, 1,000, and 2,000 kWh respectively. See the impacts of the change of rate design on each customer's marginal price and total bill in Table 8.8 below.

**Table 8.8 Inclining Block Rate Impacts**

	Usage	Flat Rate Bill	Inclining Block Rate Bill	Block in Which Marginal Usage Occurs	Impact of Inclining Block Rate Structure on Marginal Rate	Impact of Inclining Block Rate Structure on Total Bill
<b>Customer 1</b>	600	\$70	\$58	1		
<b>Customer 2</b>	1,000	\$110	\$100	2		
<b>Customer 3</b>	2,000	\$210	\$220	2		

Note that, if customers are aware of the rate structure and genuinely respond to changes in the marginal price, the two customers whose usage exceeds the block threshold of 750 kWh receive a higher marginal rate under the inclining block structure, which suggests a stronger price signal to conserve will be present under that rate design for those customers. However, because Customer 1 uses less than the block threshold, the inclining block rate structure lowers her marginal rate, sending a price signal to be less focused on conservation than did the flat rate, which may ultimately lead to increased consumption for such situated customers. So even under the assumption that consumers understand utility prices and respond to them with a high level of engagement, the move to an inclining block rate sends a mixed signal, with some customers recognizing a reduction in their marginal rate.

However, it is probable that most customers are not engaged at the level required to know what their marginal electric rate is or when their monthly usage cross the threshold where it changes under a blocked rate structure. For these customers, their reaction to the rate design change will be informed by what they experience on their bill (i.e., if their bill goes up, they perceive higher prices and vice versa). Now note that two out of the three hypothetical customers in Figure 8.8 see a *bill decrease* under the rate design change relative to the flat rate, including one customer that faces a *higher marginal rate* under inclining blocks. The goal of the higher marginal rate included in the IBR structure is potentially confounded by the reality of a lower bill for this customer under the new rate structure. Hence, the hypothesis that customers respond to rates based on the impact they have on their bills (i.e., customers respond to average price rather than marginal) suggests an even more conflicting price signal than the marginal rate perspective. Clearly the impact of inclining block rates is more complex and nuanced than a cursory review of them would suggest.

To that end, it is instructive to review some recent additions to the academic literature on the subject. As discussed previously, most studies of price elasticity are not well-suited to answering the question posed by inclining block rates regarding whether customers respond to marginal or average price. This information is necessary to determine how customer 2, who uses 1,000 kWh per month in the example in the previous paragraph, will respond to the rate change. However, a 2014 paper capitalizing on a unique circumstance in Southern California over a multi-year period tackled this very interesting question in a unique and effective way. The study titled “Do Consumers Respond to Marginal or Average Price? Evidence from Nonlinear Electricity Pricing” by Koichiro Ito and published in the American Economic Review focuses on the electricity crisis experienced in Southern California at the beginning of the last decade. Dr. Ito observed customer behavior during the years 1999-2007, a span that saw both significant rate increases and rate design changes being phased in over time. The study

also capitalized on a particular part of the San Diego metropolitan area where the service territories of two different electric utilities share a border in a relatively homogeneous area of the city. The study's author was able to take the opportunity to observe what amounted to a natural experiment, where the conditions for a scientific study were created by natural circumstances. The author used an innovative statistical methodology to test the question in the paper's title. Dr. Ito's conclusion:

*"The evidence strongly suggests that consumers respond to average price and do not respond to marginal or expected price. I show that this suboptimizing behavior makes nonlinear pricing **unsuccessful in achieving its policy goal of energy conservation** and substantially changes the efficiency cost of nonlinear pricing."* (emphasis supplied)

This finding has important implications for inclining block rates, which did not go unnoticed by Dr. Faruqui of Brattle, whose original analysis of inclining block rates was reflected in past Ameren Missouri IRPs as described previously. Dr. Faruqui subsequently co-authored a new article building on Dr. Ito's work titled "The Paradox of Inclining Block Rates". In this article, Dr. Faruqui et al discuss the implications of the conclusion that customers respond more to their average price than their marginal price, and go on to describe alternate methodologies for estimating class level load impacts of inclining block rates from those he used in the original Ameren Missouri analysis. By analyzing the impact of *each customer's* individual marginal and average price, and applying elasticity relationships to usage at the customer level, a more realistic impact of inclining block rates can be inferred. Ameren Missouri has undertaken such an analysis and developed revised expectations for the impacts of inclining block residential rates.

When re-analyzed with customer level detail, and with sensitivity to the marginal versus average price questions, inclining block rates appear to have considerably less energy and demand savings potential than previously reported, as in the 2014 IRP and the 2016 DSM Potential Study. Ameren Missouri ran a customer by customer analysis, assuming a range of pricing differentials between tiers in the inclining block rate, a range for the elasticity of customer usage, and also employing both a marginal price perspective (i.e. each customer's usage change was premised on application of the elasticity to the customer's marginal rate, which depends on the relationship of their specific usage to the block threshold) and an average price perspective (i.e. each customer's usage change was premised on application of the elasticity to the change experienced in that customer's bill when changing from application of a flat rate to an inclining block rate). The results of the study are summarized in Table 8.9 below:



Table 8.9 Inclining Block Rate Analysis

Summer Inclining Block - Marginal Rate Approach			
	5% Block Pricing Differential	10% Block Pricing Differential	20% Block Pricing Differential
Assumed Elasticity	% Change in Load	% Change in Load	% Change in Load
<b>0.1</b>	-0.23%	-0.44%	-0.85%
<b>0.15</b>	-0.34%	-0.66%	-1.27%
<b>0.2</b>	-0.46%	-0.88%	-1.70%
<b>0.25</b>	-0.57%	-1.10%	-2.12%

Summer Inclining Block - Average Rate Approach			
	5% Block Pricing Differential	10% Block Pricing Differential	20% Block Pricing Differential
Assumed Elasticity	% Change in Load	% Change in Load	% Change in Load
<b>0.1</b>	-0.02%	-0.03%	-0.06%
<b>0.15</b>	-0.03%	-0.04%	-0.08%
<b>0.2</b>	-0.04%	-0.06%	-0.11%
<b>0.25</b>	-0.05%	-0.07%	<b>-0.14%</b>

Because, as discussed in the Ito paper, customers tend to respond much more significantly to average pricing than marginal, the values in the second table represent the most likely customer usage impacts and load reduction potential that would be associated with a move to an inclining block rate. As such the 0.14% load reduction (shown in bold in the table above) is a more realistic impact to use to develop expectations for inclining block rates than the 4.4% value in the previous Ameren Missouri potential studies. The relatively negligible expected net impact of inclining block rates, along with relatively poor performance of such rates on the other rate design priorities discussed in the introduction of this section resulted in Ameren Missouri not passing the IBR structure on for further analysis and integration in the IRP. Inclining block rates are simply not a good candidate for implementation from Ameren Missouri's perspective.

### 8.6.4 Residential Demand Charges

Another rate design that was not incorporated into the 2016 DSM Potential Study, but that is receiving an increasing level of interest across the industry, is residential demand charges. Demand charges are a common rate structure utilized for large commercial and industrial customers. Such charges are applied to some measure of the maximum demand that customers place on the system over a defined period of time. This can be viewed as aligning the customer's bill more accurately with costs that the customer imposes on the system, because many types of utility costs are incurred when constructing adequate capacity to meet customer peak demand. An additional benefit of demand charges beyond the alignment of customer bills with the cost of serving them is associated with the fact that, if customers do respond to the price signal represented by a demand charge, that response is more likely to be targeted to times that reduce peak demand and can produce capacity, and therefore long-run cost, savings. There are still relatively few utilities that offer residential demand charges, although there have been increasing numbers of new proposals for such rates in recent years. That said, there is still relatively little data on the effects of residential demand charges. Those studies that do exist, however, show the potential for significant peak demand savings<sup>41</sup>. While Ameren Missouri has not estimated its own demand savings potential for implementation of demand charges, it is a rate design option that appears to have considerable potential to help achieve demand side goals in a manner that furthers other important rate design criteria as well. Residential demand charges are not reflected in the demand side rates potential below, but warrant monitoring as they are deployed at utilities across the country for future consideration in Ameren Missouri rate making and resource planning discussions.

### 8.6.5 Implementation

The timing of implementation of demand side rates that exhibit load reduction potential and also score favorably on other rate design criteria may still be influenced by other factors, such as technological advancements that impact the cost and/feasibility of implementing such rates.<sup>42</sup> For example, investments in Advanced Metering Infrastructure (AMI) have the potential to greatly reduce the cost associated with rate options that require time differentiated usage measurements, such as TOU, CPP, and residential demand rates. As such, the Company's plans to implement any demand side rates are tied closely with its plans regarding AMI, which are described in Chapter 7 of this IRP.

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<sup>41</sup> "Rolling Out Residential Demand Charges", Ryan Hledik, The Brattle Group, Slide 7 [http://www.brattle.com/system/publications/pdfs/000/005/170/original/Rolling\\_Out\\_Residential\\_Demand\\_Charges\\_Hledik\\_EUCI.pdf?1431628444](http://www.brattle.com/system/publications/pdfs/000/005/170/original/Rolling_Out_Residential_Demand_Charges_Hledik_EUCI.pdf?1431628444)

<sup>42</sup> 4 CSR 240-22.050(4)(C); 4 CSR 240-22.050(3)(D)

That said, agreement reached in the Company's last rate case (ER-2016-0179) has charted a path forward for one rate option that the Commission has expressed specific interest in – residential Time of Use Rates. The Commission has in fact designated TOU as a Special Contemporary Issue to be addressed in this IRP.<sup>43</sup> Pursuant to the stipulation and agreement that resolved the case, Ameren Missouri agreed to publicize its existing residential time of use, as well as file a proposed amendment to its residential Time-of-Use rates in its next general rate case with the following goals: to shift usage to off-peak hours during all months of the year; to be structured to allow interested customers to opt-in; to be compatible with existing Automated Meter Reading (AMR) technology; and to encourage off-peak electric vehicle charging. While making the updated offering compatible with AMR meters may provide some limitations to the extent of new options and enhancements the Company can provide, the Company will be working on an enhanced rate to meet the terms of the agreement. If and when the Company is able to roll out AMI metering, Ameren Missouri plans to develop additional TOU rate options or enhancements and promote TOU rates more broadly to its residential customer base.

## 8.7 DSM Potential Uncertainty

### 8.7.1 Risk and Uncertainty Analysis

Ameren Missouri categorized the uncertainty in its DSM potential estimates into two broad categories to help inform the risk assessment of the DSM potential. The first category involved looking at various factors that impact both the energy savings potential and the accompanying costs of the DSM programs in a favorable or unfavorable manner. These uncertainties are inherent in the assumptions necessary to develop point estimates for future DSM load and budget impacts. The second category, described further below, assumes the estimated DSM load impacts are achievable but the costs to obtain the savings are uncertain.

The first category of uncertainty analysis, as described above, was analyzed for both RAP and MAP scenarios.<sup>44</sup> The 2016 DSM Potential Study developed scenario analyses for utility attribution, take rates, and avoided costs. Ameren Missouri used those scenario analyses as a primary input into its uncertainty analysis by comparing the net present value of the energy and program costs scenarios to the base case for each to determine a percentage variation from the base for both a favorable and unfavorable state.

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<sup>43</sup> EO-2017-0073 1.Q

<sup>44</sup> 4 CSR 240-22.050(6)(C)1 through 2

Ameren Missouri included two additional uncertain factors in assessing the DSM potential uncertainty; large customer opt-out and unforeseen new technologies. For the opt-out uncertainty, the unfavorable scenario was derived by using data from the most recent (Nov. 2016) Ameren Missouri Energy Efficiency Investment Charge (EEIC) rider filing<sup>45</sup> to emulate a scenario in which the entire Large Primary Service rate class chose not to participate in Ameren Missouri's energy efficiency programs, which equated to a 23% opt-out rate. When combining this with the Base assumption in the 2016 DSM Potential Study and inclusion of the Residential rate class, the impact on total potential was a 6.0% reduction to the base scenario. As a favorable opt-out scenario, the lowest opt-out rate experienced (8.93% from 2013) was used. When combining this value with the base scenario and the inclusion of the residential rate class, the impact on total potential was a 2.0% increase. It was also assumed that costs scale proportionately.

New technology can be a very broad and complex scenario because it is difficult to measure the impact of unknown technologies 10-20 years into the future. Given past experience with CFL and LED technologies, it is known this impact can be significant yet impactful new developments may be rare occurrences. A simplified assumption was made that the impact of new technologies on total potential could be 10% higher than the base case with no additional cost.<sup>46</sup>

Even though combined heat and power (CHP) was analyzed in the 2016 DSM Potential Study, it has only been passed onto further resource planning analysis as a subcomponent of DSM potential uncertainty because there is significant uncertainty about how or if CHP fits under MEEIA and the economic value of CHP continues to decline as avoided costs drop.<sup>47</sup> The load impacts and costs are direct estimates from the 2016 DSM Potential Study.

The 2016 DSM Potential Study analyzed scenarios as independent uncertainties and the additional uncertain factors described above were also analyzed as independent uncertainties. However, for the risk analysis of various alternative resource plans, an overall risk assessment that incorporates these individual uncertainties is required. It is impractical to try to assess the various interactive codependences of the individual uncertainties so as a simplification, Ameren Missouri developed subjective weights for the various independent uncertainties which results in an overall weighted risk assessment. The individual uncertainties, associated favorable and unfavorable ranges, subjective weights, and overall uncertainty ranges are presented in Tables 8.10 and 8.11 below for both load and budget impacts.

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<sup>45</sup> ER-2017-0149

<sup>46</sup> 4 CSR 240-22.050(1)(E); 4 CSR 240-22.050(4)(C); EO-2017-0073 1.A(1)

<sup>47</sup> EO-2017-0073 1.A(3)

Table 8.10 Uncertainty Scalars – Load Impacts

<b>RAP - Energy Efficiency Load Impacts</b>						
	Unfavorable	Base	Favorable	Weight	Unfavorable	Favorable
<b>Attribution</b>	-49.7%	0.0%	14.8%	15.0%	-7.46%	2.22%
<b>Take rate</b>	-26.0%	0.0%	22.8%	15.0%	-3.90%	3.42%
<b>Avoided costs</b>	-16.0%	0.0%	5.9%	40.0%	-6.42%	2.34%
<b>Opt-out</b>	-6.0%	0.0%	2.0%	8.0%	-0.48%	0.16%
<b>New tech.</b>	0.0%	0.0%	10.0%	20.0%	0.00%	2.00%
<b>CHP</b>	0.0%	0.0%	34.6%	2.0%	0.00%	0.69%
				<b>100.0%</b>	<b>-18.3%</b>	<b>10.8%</b>

<b>MAP - Energy Efficiency Load Impacts</b>						
	Unfavorable	Base	Favorable	Weight	Unfavorable	Favorable
<b>Attribution</b>	-49.7%	0.0%	14.8%	15.0%	-7.46%	2.22%
<b>Take rate</b>	-26.0%	0.0%	22.8%	15.0%	-3.90%	3.42%
<b>Avoided costs</b>	-16.0%	0.0%	5.9%	40.0%	-6.42%	2.34%
<b>Opt-out</b>	-6.0%	0.0%	2.0%	8.0%	-0.48%	0.16%
<b>New tech.</b>	0.0%	0.0%	10.0%	20.0%	0.00%	2.00%
<b>CHP</b>	0.0%	0.0%	26.5%	2.0%	0.00%	0.53%
				<b>100.0%</b>	<b>-18.3%</b>	<b>10.7%</b>

<b>RAP/MAP/MID - Demand Response Load Impacts</b>						
	Unfavorable	Base	Favorable	Weight	Unfavorable	Favorable
<b>Take rate</b>	-9.0%	0.0%	8.2%	25.0%	-2.2%	2.0%
<b>Avoided costs</b>	-29.8%	0.0%	7.5%	55.0%	-16.4%	4.1%
<b>New tech.</b>	0.0%	0.0%	10.0%	20.0%	0.0%	2.0%
				<b>100.0%</b>	<b>-18.6%</b>	<b>8.2%</b>

\*As described in the Portfolio descriptions (Chapter 8.2.1.5) earlier in this report demand response had its own MID scenario that was not a simple average of RAP & MAP, therefore the sensitivities apply to each scenario for demand response (MAP, RAP and MID). In the case of energy efficiency the MID scenario is the average of the RAP and MAP scenarios.

Table 8.11 Uncertainty Scalars – Budget Impacts

<b>RAP - Energy Efficiency Budget Impacts</b>						
	Unfavorable	Base	Favorable	Weight	Unfavorable	Favorable
<b>Attribution</b>	-7.1%	0.0%	2.1%	15.0%	-1.1%	0.3%
<b>Take rate</b>	-26.1%	0.0%	23.4%	15.0%	-3.9%	3.5%
<b>Avoided costs</b>	-27.3%	0.0%	31.7%	40.0%	-10.9%	12.7%
<b>Opt-out</b>	-6.0%	0.0%	2.0%	8.0%	-0.5%	0.2%
<b>New tech.</b>	0.0%	0.0%	0.0%	20.0%	0.0%	0.0%
<b>CHP</b>	0.0%	0.0%	46.6%	2.0%	0.0%	0.9%
<b>Total Impact</b>				<b>100.0%</b>	<b>-16.4%</b>	<b>17.6%</b>

<b>MAP - Energy Efficiency Budget Impacts</b>						
	Unfavorable	Base	Favorable	Weight	Unfavorable	Favorable
<b>Attribution</b>	-7.1%	0.0%	2.1%	15.0%	-1.1%	0.3%
<b>Take rate</b>	-26.1%	0.0%	23.4%	15.0%	-3.9%	3.5%
<b>Avoided costs</b>	-27.3%	0.0%	31.7%	40.0%	-10.9%	12.7%
<b>Opt-out</b>	-6.0%	0.0%	2.0%	8.0%	-0.5%	0.2%
<b>New tech.</b>	0.0%	0.0%	0.0%	20.0%	0.0%	0.0%
<b>CHP</b>	0.0%	0.0%	33.9%	2.0%	0.0%	0.7%
<b>Total Impact</b>				<b>100.0%</b>	<b>-16.4%</b>	<b>17.3%</b>

<b>RAP/MAP/MID - Demand Response Budget Impacts</b>						
	Unfavorable	Base	Favorable	Weight	Unfavorable	Favorable
<b>Take rate</b>	12.3%	0.0%	32.0%	25.0%	3.1%	8.0%
<b>Avoided costs</b>	29.7%	0.0%	5.8%	55.0%	16.4%	3.2%
<b>New tech</b>	0.0%	0.0%	0.0%	20.0%	0.0%	0.0%
<b>Total Impact</b>				<b>100.0%</b>	<b>19.4%</b>	<b>11.2%</b>

\*As described in the Portfolio descriptions (Chapter 8.2.1.5) earlier in this report demand response had its own MID scenario that was not a simple average of RAP & MAP, therefore the sensitivities apply to each scenario for demand response (MAP, RAP and MID). In the case of EE the MID scenario is the average of the RAP and MAP scenarios.

Another similar component analyzed is the participant cost impact, which is likely a direct correlation of the program budget impacts in the RAP scenario. If the programs increase in cost, it is assumed that the participant cost impact will follow in a similar fashion. Because the MAP scenarios within the 2016 DSM Potential Study apply

incentives at 100% of the measure cost there is no impact to participant costs in this case. For demand response programs there is generally no participant cost because any equipment necessary for these programs is generally provided at no cost to the customers. See the participant cost impacts in Table 8.12 below:

**Table 8.12 Uncertainty Scalars – Participant Cost Impacts**

<b>RAP - Energy Efficiency Participant Cost Impacts</b>						
	Unfavorable	Base	Favorable	Weight	Unfavorable	Favorable
<b>Attribution</b>	-7.1%	0.0%	2.1%	15.0%	-1.1%	0.3%
<b>Take rate</b>	-26.1%	0.0%	23.4%	15.0%	-3.9%	3.5%
<b>Avoided costs</b>	-27.3%	0.0%	31.7%	40.0%	-10.9%	12.7%
<b>Opt-out</b>	-6.0%	0.0%	2.0%	8.0%	-0.5%	0.2%
<b>New tech.</b>	0.0%	0.0%	0.0%	20.0%	0.0%	0.0%
<b>CHP</b>	0.0%	0.0%	46.6%	2.0%	0.0%	0.9%
<b>Total Impact</b>				<b>100.0%</b>	<b>-16.4%</b>	<b>17.6%</b>

<b>MAP - Energy Efficiency Participant Cost Impacts</b>						
	Unfavorable	Base	Favorable	Weight	Unfavorable	Favorable
<b>Attribution</b>	0.0%	0.0%	0.0%	15.0%	0.0%	0.0%
<b>Take rate</b>	0.0%	0.0%	0.0%	15.0%	0.0%	0.0%
<b>Avoided costs</b>	0.0%	0.0%	0.0%	40.0%	0.0%	0.0%
<b>Opt-out</b>	0.0%	0.0%	0.0%	8.0%	0.0%	0.0%
<b>New tech.</b>	0.0%	0.0%	0.0%	20.0%	0.0%	0.0%
<b>CHP</b>	0.0%	0.0%	0.0%	2.0%	0.0%	0.0%
<b>Total Impact</b>				<b>100.0%</b>	<b>0.0%</b>	<b>0.0%</b>

<b>RAP/MAP/MID - Demand Response Participant Cost Impacts</b>						
	Unfavorable	Base	Favorable	Weight	Unfavorable	Favorable
<b>Take rate</b>	0.0%	0.0%	0.0%	25.0%	0.0%	0.0%
<b>Avoided costs</b>	0.0%	0.0%	0.0%	55.0%	0.0%	0.0%
<b>New tech</b>	0.0%	0.0%	0.0%	20.0%	0.0%	0.0%
<b>Total Impact</b>				<b>100.0%</b>	<b>0.0%</b>	<b>0.0%</b>

As mentioned above, the second uncertainty category assumes the estimated DSM load impacts are achievable but the cost to obtain the savings is uncertain. To assess the cost uncertainty, the Project Cost Uncertainty Grid in Table 8.13 below was used. The grid below demonstrates that as the cost estimate quality increases and the maturity of the technology increases then the uncertainty decreases; and vice versa.

**Table 8.13 Project Cost Uncertainty Grid**

Estimate Class	Degree of Project Definition (% complete)	Established Standard (Low to High)	Maturing (Low to High)	Evolving (Low to High)	Emerging (Low to High)
Class 5	0% to 2%	-20% to +30%	-25 to +45%	-30% to +75%	-35% to +120%
Class 4	1% to 15%	-15% to +20%	-20% to +35%	-25% to +55%	-30% to +90%
Class 3	10% to 40%	-10% to +10%	-15% to +25%	-20 to +45%	-25 to +70%
Class 2	30% to 75%	-5% to +5%	-10% to +15%	-15% to +35%	-20% to +55%
Class 1	65% to 100%	-3% to +3%	-5% to +8%	-10% to +17%	-15% to +40%

Ameren Missouri determined the combination of quality of cost estimate and maturity of technology for both its energy efficiency and demand response base case estimates. The resulting cost uncertainty ranges for the second category of DSM potential uncertainty are summarized in Table 8.14 below. The energy efficiency cost estimates cover the entire 20 year planning horizon; therefore, the overall degree of project definition was determined to be a Class 4 because there is significant uncertainty about how the programs will evolve over the planning horizon. The demand response costs estimates also cover the full planning horizon but the program designs are not expected to evolve as much as energy efficiency. Both energy efficiency and demand response were determined to be “maturing” for purposes of project costs uncertainty because there is significant uncertainty about the future cost of new and existing technologies.

**Table 8.14 Project Cost Uncertainty Results**

Portfolio	Unfavorable	Base	Favorable	Estimate Quality/Maturity
EE-RAP	35%	0%	-20%	Class 4 / Maturing
EE-MAP	35%	0%	-20%	Class 4 / Maturing
DR-RAP	25%	0%	-15%	class 3 / Maturing
DR-MAP	25%	0%	-15%	class 3 / Maturing



## 8.8 Other Special Contemporary Issues

### 8.8.1 Distributed Generation & Combined Heat & Power <sup>48</sup>

Ameren Missouri's 2016 DSM Potential Study also included an assessment of the various categories of distributed generation (DG), and CHP potentials for the residential, commercial, and industrial sectors. Ameren Missouri expects most microgrid formations to include CHP and/or solar power; therefore, it is assumed that the potential estimations for CHP and solar already include the potential related to the formation of microgrids without an explicit forecast to quantify this segment.

### 8.8.2 Utility Rates/Standards for DG Development <sup>49</sup>

The State of Missouri has three primary policies that have customer-owned distributed energy resources (DER) impacts including: compliance with PURPA standards regarding qualifying facilities (QF), the Missouri Net Metering and Easy Connection Act (Net Metering) and the Missouri Renewable Energy Standard (RES).

Overall, the combination of Net Metering and RES has had the greatest impact on customers both in terms of number of customers installing DER and total capacity installed with over 3,800 customers participating to install over 54 MW of net metered capacity through the end of 2016. Ameren Missouri's net metering and solar rebate tariffs and administrative processes are consistent with the Commission's rules and are also well supported on Ameren.com with tools and information to aid customers and developers, including an online application that was launched in 2017. In total, the documentation and customer resources that support net metering (and solar rebates) strongly support the State of Missouri's policies with respect to Net Metering DER.

Ameren Missouri's QF tariff outlines the technical requirements for interconnecting a QF project to the Ameren Missouri system as well as the rate to be paid for QF energy delivered to the Ameren Missouri transmission or distribution system.

- **Interconnection:** For QFs connecting to the transmission system, MISO interconnection procedures apply. The process and documents used for a QF to connect to the Ameren Missouri distribution system are modeled after and similar to MISO's procedures.
- **QF Energy Rates:** In 2015 and again in 2017, Ameren Missouri adjusted the QF rates using the same core methodology that is used in its general rate cases for the determination of normalized market prices used in establishing net off-system sales revenue and in the production cost models used to dispatch generating

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<sup>48</sup> EO-2017-0073 1.A(3)

<sup>49</sup> EO-2017-0073 1.O

units. This has resulted in QF rates that are slightly higher than the marginal cost approach that was used prior to the development of the MISO market.

In File No. ER-2016-0179, the Commission approved Rider SSR as a new tariff. The tariff was developed in cooperation with the Commission Staff, Division of Energy and others in order to provide non-renewable DER customers with supplemental and standby service at rates that are cost based. The development began following File No. ER-2014-0258 as a result of Division of Energy's concern, in that case, that the structure of Rider E – Supplementary Service was not cost based and created barriers to DER. While there are many factors that influence the economic viability of DER, being cost based, Rider SSR will provide appropriate price signals for future DER development.

### 8.8.3 DER Deployment <sup>50</sup>

Ameren Missouri is actively supporting, preparing for and participating in increased deployment of DER. In recent years, Ameren Missouri installed solar DER at its headquarters and brought the O'Fallon Energy Center online. In addition, as an outcome of the Renewable Energy Standard Rate Cap Case (File No. ET-2014-0085), Ameren Missouri agreed to make more total solar rebate funds available than would have occurred absent the settlement.

Presently, Ameren Missouri has active initiatives that will increase DER including Community Solar (File No. EA-2016-0207) and Solar Partnership (File No. EA-2016-0208). The Community Solar program will allow a material number of customers that are unable or unwilling to install their own solar DER but are interested in procuring solar power, to do so from a solar DER owned by Ameren Missouri. Solar Partnership will increase the amount of solar DER available to all Ameren Missouri customers in a cost effective manner.

Additionally, Ameren Missouri is actively exploring opportunities to establish microgrid pilot project(s) with a customer(s) that would include various types of DER, energy storage and load management.

In terms of customer-installed DER, Ameren Missouri has simplified the QF interconnection process for certain large renewable projects that do not qualify for net metering but which are not designed to deliver energy to the Ameren Missouri distribution system (i.e. a large solar project connected to a much larger load). Such projects have minimal impacts to the Ameren Missouri system and, therefore, do not require any interconnection studies. As a result, the interconnection process and

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<sup>50</sup> EO-2017-0073 1.R

agreement are very closely aligned with Net Metering and administered by the same Ameren Missouri personnel. This capitalizes on familiarity with the net metering process and also streamlines the process to the benefit of customers, developers and Ameren Missouri alike.

#### 8.8.4 Potential Benefits of Co-delivery of DSM programs<sup>51</sup>

As part of the 2017 and 2018 energy efficiency program years Ameren Missouri is beginning to co-deliver on several measures within the Multifamily Low-Income and Energy Efficiency School Kits Programs with other natural gas utilities. Combining efforts and budgets on delivery can benefit the electric utility cost effectiveness of programs and measures that may otherwise be borderline cost-effective. Although this can be important for specific programs and measures, the co-delivered portion of the budget for this 2 year period is just over 1% of the MEEIA portfolio budget or just over 3% of the residential portfolio budget for this 2 year period. For the programs themselves, this amounts to roughly 21% of the 2 year budget for the Multifamily Low-Income and Efficient Kits programs combined. At first glance co-delivery appears to provide significant cost savings to customers but in fact the total cost to customers is very similar, as co-delivery generally shifts the program cost from one utility to another. In this manner the electric utility pays for electric measure cost and the gas utility pays for gas measure cost. One hindrance to co-delivery is the large amount of administrative coordination required between utilities with potential conflicting goals, budgets, contracts, schedules, and data requirements. The large amount of effort becomes magnified due to the fact that the DSM programs may change in scale or scope in the next program cycle for one or both utilities involved, which can add unforeseen complexities.

These same core benefits and complexities exist when attempting to co-deliver with water utilities, but the potential savings diminishes as the quantity of measures or potential applications become more limited. Co-delivery of natural gas savings includes end-use equipment options for customers such as faucet aerators and low-flow shower heads that generate hot water savings. These same measures can create water savings by reducing the number of gallons used; however, the vast majority of the customer savings would be generated by heating fewer gallons of water

A common factor between utility programs is a wide range of contractors that are commonly the sales force to market DSM programs. Continued effort in training and creating synergies with this sales force across utility programs may be a cost effective and efficient approach, bypassing some of the barriers across utility DSM portfolios.



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<sup>51</sup> 4 CSR 240-22.050(3)(F); EO-2017-0073 1.I

Table 8.15 below provides a high level analysis of program options including co-delivery, statewide DSM programs, and upstream programs. In the analysis, Statewide Programs are depicted with a low feasibility as the DSM framework is very utility specific. Not only would programs be difficult to offer across regulated utilities, but the mix of cooperative and municipal utilities would also layer into the complexity, making it near impossible to make a uniform DSM effort.

Co-delivered programs are feasible for reasons mentioned above but similar to statewide programs, the cost savings nor benefit gains are significant drivers that push these models to a high priority level due to their complex nature. Statewide program implementation would also be less feasible because municipal and cooperative utilities are not regulated under the same structure as the investor-owned utilities. In addition, there is a large geographic difference in the investor-owned utility service territories which would tend to minimize any potential benefits of co-delivery. Upstream programs maybe an efficient way to reach a large amount of customers but come with the added challenge of program attribution and concerns with free ridership and program leakage. There are instances where upstream programs are attractive but careful consideration must be taken on a case-by-case basis.

**Table 8.15 Cumulative Energy Efficiency Savings**

Program Type	Feasibility	Cost	Benefits
Statewide Programs		---Neutral---	---Neutral---
Joint Programs (co-delivery)		---Neutral---	---Neutral---
Upstream Programs*	---Neutral---	--Neutral--	--Neutral--

\* Upstream program opportunities may vary widely depending on the structure and measures being offered.

### 8.8.5 DSM Opportunities for Providing Customer Financing<sup>52</sup>

#### 8.8.5.1 Customer Financing

Ameren Missouri is motivated to increase customer participation in energy efficiency programs and up-front costs to customer are a barrier to participation. There are a number of financing options currently available to Missouri customers who are interested in improving their home or buildings' energy efficiency. These include but are not limited to:

##### **Fannie Mae Green Initiative**

<https://www.fanniemae.com/multifamily/green-initiative>

This loan program provides owners of multifamily properties (rental or cooperative properties with 5 or more units) with valuable green financing solutions and tools to make smart energy and water-saving property improvements. Its green financing programs include Green Rewards, Green Preservation Plus, and the Green Building Certification Pricing Break, all of which are eligible for a 10 basis points (0.1%) reduction in the all-in interest rate. Over the life of a 10-year, \$10 million loan this could result in a savings of \$95,000 or more in interest. All Fannie Mae green loans are securitized as Green Mortgage Backed Securities (Green MBS).

##### **FHA Energy Efficiency Mortgages**

<https://www.allregs.com/tpl/main.aspx>

The Energy Efficient Mortgage (EEM) program allows the Mortgagee to offer financing for cost-effective energy efficient improvements to an existing property at the time of purchase or re-financing, or for upgrades above the established residential building code for new construction. Cost-effective refers to the costs of the improvements that are less than the present value of the energy saved over the estimated useful life of those improvements.

Eligible property types include:

1. New construction properties (one- to four-units);
2. Existing construction properties (one- to four-units);
3. Condominiums (one unit); or
4. Manufactured housing

##### **Missouri Energy Loan Program**

<https://energy.mo.gov/energy/communities/assistance-programs/energy-loan-program>

The Missouri Division of Energy provides loans to public schools (K-12), public/private colleges and universities, city/county governments, public owned airport facilities

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<sup>52</sup> EO-2017-0073 1.G; 4 CSR 240-22.050(3)(E)

(municipal, county, regional, and international), public water and wastewater treatment facilities, and public/private not-for-profit hospitals to help reduce energy costs through the Energy Loan Program. This loan financing may be used for various energy-saving investments, including projects such as upgrading insulation, lighting systems, heating and cooling systems, windows and other items that affect your energy use.

### **Veterans Administration Energy-Efficient Mortgage Program**

<https://www.benefits.va.gov/WARMS/docs/admin26/handbook/ChapterLendersHanbookChapter7.pdf>

The Veteran's Administration (VA) Energy Efficient Mortgage (EEM) is available to qualified military personnel, reservists and veterans for energy improvements when purchasing an existing home. The VA EEM caps energy improvements at \$3,000–\$6,000. More information about VA EEMs can be obtained from the website for the U.S. Department of Veteran's Affairs or by calling (800) 827-1000. Chapter 7 of VA Pamphlet 26-7 (Revised) (PDF, 1.5MB) contains lender guidance on the VA EEM.

### **Conventional Energy Efficient Mortgages**

Conventional Energy Efficient Mortgages (EEMs) increase the purchasing power of buying an energy efficient home by allowing the lender to increase the borrower's income by a dollar amount equal to the estimated energy savings. While Freddie Mac does not offer EEMS, they do allow underwriting flexibilities for energy efficient improvements with all of their offerings. Consumers can find out more by discussing this with their mortgage lender.

#### **8.8.5.2 Ameren Missouri's Current Focus**

Despite the variety of public and private financing options available to Missouri customers for financing; access to capital for making energy efficiency improvements and energy efficiency equipment purchases is frequently cited as a barrier to program participation. Ameren Missouri is currently engaged in two key projects in this area.

### **On-Bill Financing Pilot**

The Company will use approximately \$900,000 of the MEEIA 2 R&D budget to implement and evaluate the effectiveness of on-bill financing (OBF) of residential portfolio measures. This pilot is to be available to customers beginning in 2018 through February 28, 2019.

### **PAYS Feasibility Study**

The second project will use no more than \$25,000 to hire an independent third-party consultant to perform a feasibility study of the Pay As You Save (PAYS) financing model. The PAYS feasibility study will be completed by June 2018.

The PAYS feasibility study tasks will include the following, at a minimum:

- Provide measure level information for each participating utility. Determine which measures have adequate kWh savings to meet the PAYS requirements:
  - Loan repayment must be 20% below the new monthly energy savings.
  - Loan pay-off must be 20% sooner than the effective useful life.
  - Include the utility investment costs to set up the PAYS infrastructure, and operate the program.
- The future of demand side rates is under consideration. To acknowledge potential changes and provide sensitivity analysis of financing feasibility at various demand side rates; \$/kWh.
- Quantify the volume of participation required for PAYS to be cost-effective.
- Identify any regulatory or legal barriers to offering the PAYS model (i.e. tying the loan to the customer meter).
- Provide information on other financing solutions that would be competing with PAYS. (OBF, PACE) and how they compare.
- Include opportunities for Missouri DSM stakeholders to review the assumptions and provide comments for consideration.

#### 8.8.6 DSM Opt-out Considerations<sup>53</sup>

Some commercial and industrial customers consider opting-out of DSM programs, when they do not recognize the energy savings opportunity and associated financial value. Through a recent MEEIA stakeholder collaborative process, Ameren Missouri has implemented an energy benchmarking awareness pilot utilizing the EPA Portfolio Manager Application tool. The pilot is designed to educate businesses on how the EPA Portfolio Manager can be used to determine how efficient their energy usage is compared to their peers and how MEEIA program incentives can move them to higher efficient equipment, saving long term energy and costs.

Prior to the Commission's 2017 approval of the "Cycle 2 Transition Plan for Certain Long-Lead Projects Under the MEEIA Cycle 2 Program" Stipulation and Agreement, large customers with long time horizons for planning and design have opted-out and have moved ahead with lower efficient equipment. With the new continuity Transition Plan, business customers now can have assurance that incentives offered will be available at time of project completion, which allows them to design a project with higher efficient equipment utilizing current MEEIA Cycle incentives and eliminates a consideration for opt-out.

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<sup>53</sup> EO-2017-0073 1.J



### 8.8.7 Electric Vehicles<sup>54</sup>

The 2016 DSM Market Potential Study included off-peak pricing programs for Plug-in Electric Vehicles (PEV's) in all three demand response scenarios, (MAP, RAP and Mid) used in the development of the preferred resource plans. Ameren Missouri load forecasts include three scenarios of PEV adoption (see Other Forecasting Considerations in Chapter 3). While continuing to explore options to stimulate investment in PEV charging infrastructure and reduce the barrier to PEV adoption by customers, Ameren Missouri is aware that there will be opportunities to educate customers and potentially offer cost-effective programs to affect customer charging behavior. This offering can increase system operational flexibility and utilization efficiency. However, the 2016 DSM Potential Study does not identify any cost-effective program options in the near term future but Ameren Missouri will continue to seek viable program options as PEV penetration increases and technology improvements increase available options to deploy cost-effective programs.

### 8.8.8 Conservation Voltage Reduction<sup>55</sup>

Conservation Voltage Reduction (CVR) is a reduction of voltage along a distribution feeder for the purpose of reducing electric power demand and energy. By reducing the voltage along the feeder a few percentage points, but keeping the delivery voltage in the acceptable range of 114-126 volts, demand and energy are reduced while still providing adequate voltage for customers. In addition, losses in lines and transformers are slightly reduced under the lower-voltage condition.

The CVR concept involves modification of the load-tap-changing (LTC) transformer or distribution circuit voltage regulators' mid-band set points to minimize losses and manage voltage levels within an acceptable range over the whole circuit. Capacitors are installed along lines using real time feedback to regulate voltage. Demand, therefore energy, is reduced by actively managing the distribution circuit's voltage level at a lower than maximum level while still maintaining the voltage level within the acceptable range. For a CVR project to be effective in Missouri, smart meters need be in place to record voltage levels along the distribution circuit. CVR requires communication both up and downstream from the meters, to the substations and from substations up to where they are being monitored. With smart meters in place and monitoring the system, CVR can save money and energy for both Ameren Missouri and its customers.

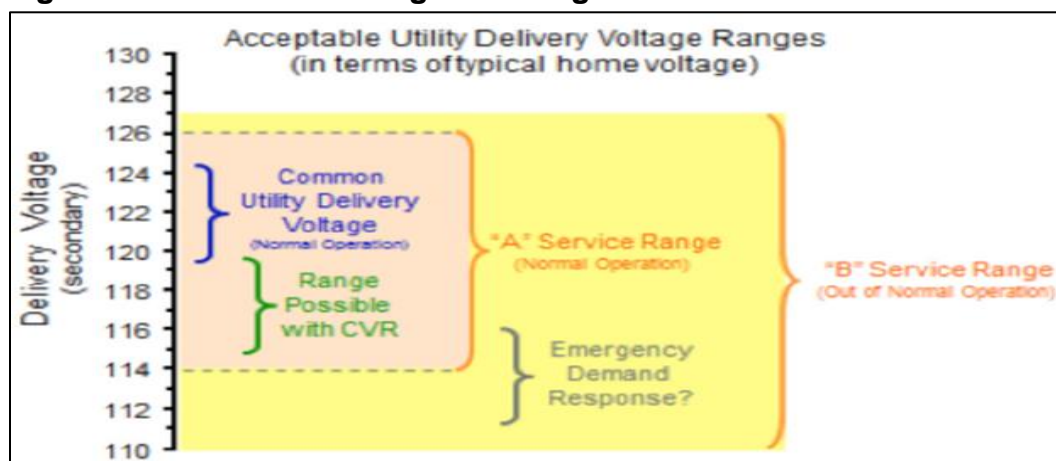
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<sup>54</sup> EO-2017-0073 1.K

<sup>55</sup> EO-2017-0073 1.L

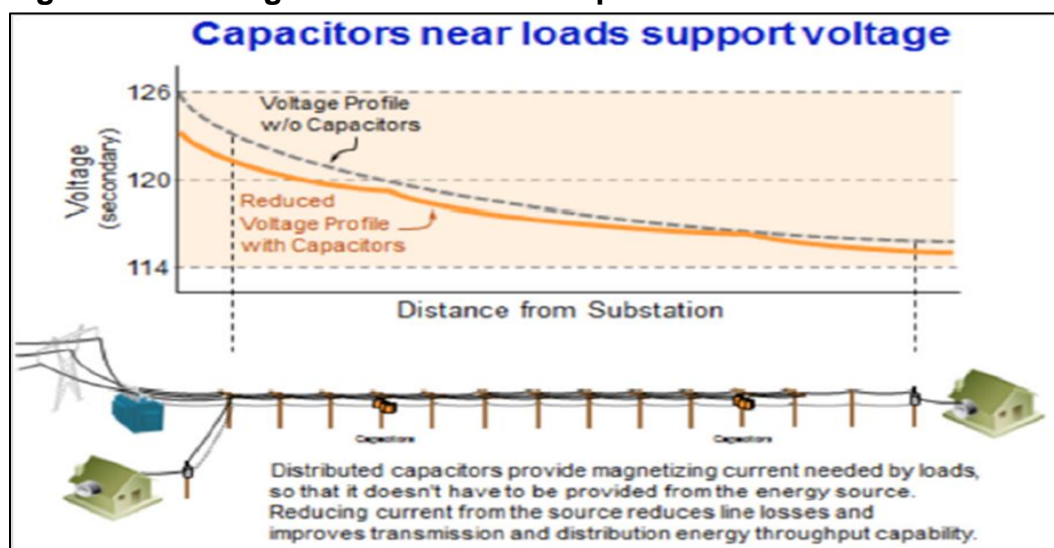


Figure 8.10 Potential Change in Voltage



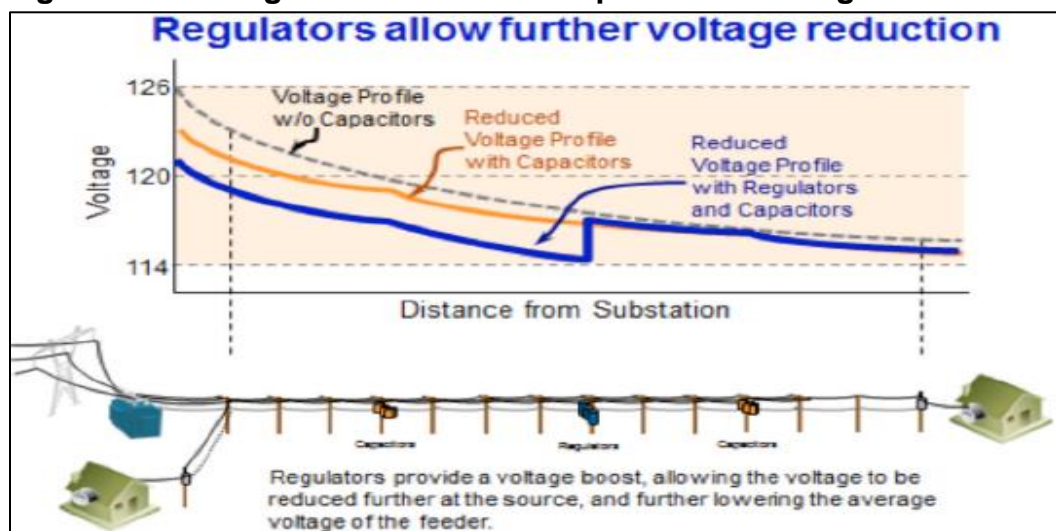
With properly-sized capacitors in place, the voltage at the substation can be reduced slightly, reducing the average delivery voltage along the line. The voltage reduction is not uniform, and is usually greatest near the substation, as the voltage closer to the end of the line is typically near the bottom of the acceptable delivery voltage range.

Figure 8.11 Voltage Reduction from Capacitors

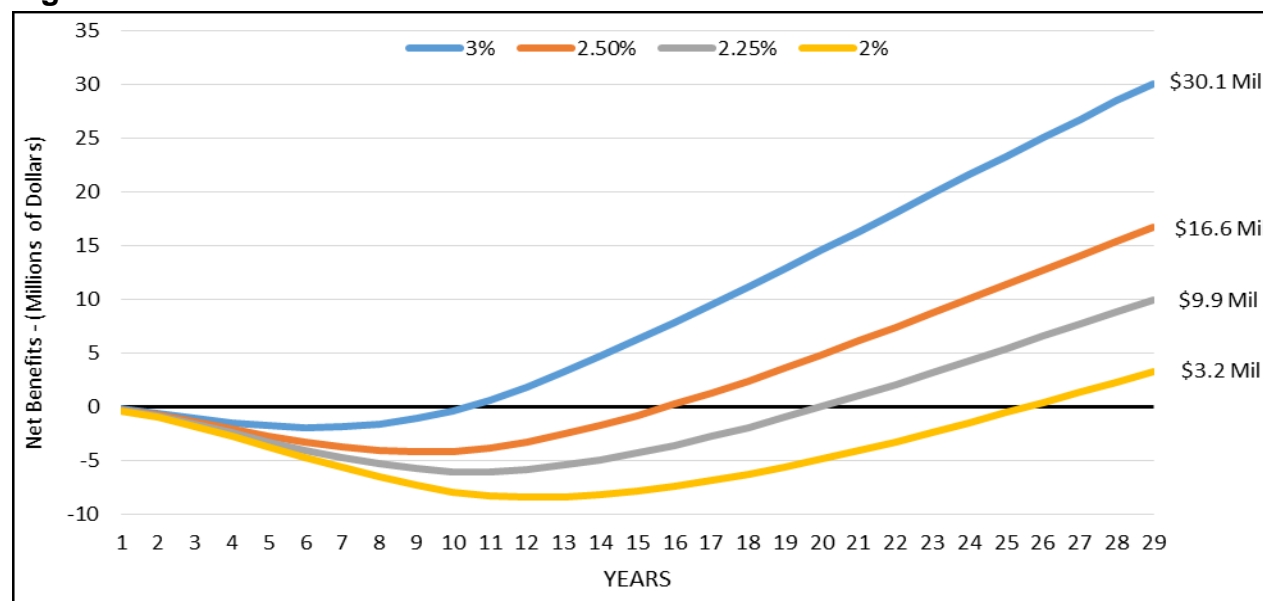


Voltage regulators provide an in-line voltage boost at the point where they are installed on the distribution line. Regulators effectively allow distribution lines to be extended further distances than would otherwise be possible by keeping the end of line voltage from falling below the acceptable delivery voltage range. While maintaining adequate end-of-line voltage is in general the primary function of the voltage regulators, in concert with capacitors and control systems, they can play an important role in allowing the average voltage of the entire distribution circuit to be reduced for energy conservation purposes.

Figure 8.12 Voltage Reduction from Capacitors and Regulators



Based on other CVR programs around the country for which data is available we estimate that the cost of implementing CVR is roughly \$150,000 per circuit. The savings ranges from .05% - 3% with an industry average around 2% of voltage reduced. There are a range of factors that affect the actual voltage reduction including but not limited to; load mix on each circuit and distance from substations. For the purpose of this screening-level analysis, individual circuit characteristics were not evaluated. Based on system average numbers, each of Ameren Missouri's circuit's supports about 12,500 MWh and 2.5 MW. To estimate the amount of potential savings, it was assumed that 10% of the total circuits would be good candidates; that is, circuits at primary voltage and where higher than average savings can be achieved. It was further assumed that each circuit would require \$150,000 of capital investment to account for upgrades including, capacitors, voltage regulators, line voltage monitors and substation metering devices. To model CVR as a program, it was assumed that all of the promising circuits would be upgraded evenly over a ten year period. The chart below shows the annual cumulative net present value of the net benefits of the CVR analysis. Because the savings per circuit is a critical factor, several savings values were analyzed to demonstrate the differences.

**Figure 8.13 CVR Cumulative NPV of Net Benefits**

It is clear that the energy savings per circuit is a critical determination of cost effectiveness. At 2.5% the breakeven point is year 15, while at 3% the breakeven point is year 10. An important factor to making CVR successful for Ameren Missouri is choosing those circuits that provide the most reduction. Table 8.16 below summarizes key information about the CVR scenarios analyzed as reflected in the graph above.

**Table 8.16 Conservation Voltage Reduction Scenarios**

Category	2.00%	2.50%	3.00%
NPV Cost	\$50,437,980	\$50,437,979	\$50,437,980
NPV MWh	693,410	866,762	1,040,115
LCOE (Levelized Cost of Energy)	\$72.74	\$58.19	\$48.49
NPV Benefits	\$53,679,938	\$67,099,922	\$80,519,907
Net Benefits	\$3,241,958	\$16,661,943	\$30,081,927
Cost Effectiveness Ratio	1.06	1.33	1.60
Ongoing Energy Savings (MWh)	69,852	87,315	104,778
Ongoing Demand Savings (MW)	14.3	17.9	21.5

CVR has potential savings and benefits for both Ameren Missouri and its customers. It would be beneficial to study which circuits have the potential to yield the best benefits once there are smart meters in place. Unfortunately, there is not a simple criterion to determine which circuits would yield the greatest savings and it will require detailed analysis by experienced experts. Once that circuit analysis is done further study would be possible to more precisely gauge cost effectiveness.

## 8.9 Compliance References

4 CSR 240-22.050(1)(A)1 through 3 .....	1
4 CSR 240-22.050(1)(C) .....	5
4 CSR 240-22.050(1)(D) .....	4, 8
4 CSR 240-22.050(1)(E) .....	28
4 CSR 240-22.050(2) .....	5, 18
4 CSR 240-22.050(3)(A) .....	4
4 CSR 240-22.050(3)(B) .....	1
4 CSR 240-22.050(3)(D) .....	26
4 CSR 240-22.050(3)(E) .....	15, 37
4 CSR 240-22.050(3)(F) .....	35
4 CSR 240-22.050(3)(G)1 .....	9
4 CSR 240-22.050(3)(G)2 .....	17
4 CSR 240-22.050(3)(G)5B .....	6
4 CSR 240-22.050(3)(I) .....	15
4 CSR 240-22.050(4) .....	17
4 CSR 240-22.050(4)(A) .....	18
4 CSR 240-22.050(4)(B) .....	18
4 CSR 240-22.050(4)(C) .....	26, 28
4 CSR 240-22.050(4)(D) .....	18
4 CSR 240-22.050(4)(D)1&4 .....	18
4 CSR 240-22.050(4)(D)2&3 .....	19
4 CSR 240-22.050(4)(D)5 .....	18
4 CSR 240-22.050(4)(E) .....	18
4 CSR 240-22.050(4)(F) .....	18, 21
4 CSR 240-22.050(4)(G) .....	18
4 CSR 240-22.050(5)(A) .....	16
4 CSR 240-22.050(5)(A)1 through 3 .....	3
4 CSR 240-22.050(5)(B)1 .....	16
4 CSR 240-22.050(5)(B)2 .....	16
4 CSR 240-22.050(5)(B)3 .....	16
4 CSR 240-22.050(5)(C) .....	16
4 CSR 240-22.050(5)(C)1 .....	16
4 CSR 240-22.050(5)(C)2&3 .....	16
4 CSR 240-22.050(5)(D) .....	16
4 CSR 240-22.050(5)(E) .....	15
4 CSR 240-22.050(5)(F) .....	15, 16, 17
4 CSR 240-22.050(5)(G) .....	15
4 CSR 240-22.050(6)(A) .....	8
4 CSR 240-22.050(6)(B) .....	11
4 CSR 240-22.050(6)(C)1 through 2 .....	27
4 CSR 240-22.050(6)(C)2 .....	3
4 CSR 240-22.050(7) .....	13, 14
4 CSR 240-22.070(8)(A) .....	14
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