

8. Demand-Side Resources

Highlights

- Ameren Missouri completed a comprehensive Demand Side Management (DSM) Market Potential Study (MPS) in April 2026. The study identified and developed four portfolios for inclusion in the IRP. This includes the Maximum Achievable Potential (MAP), the Realistic Achievable Potential (RAP), the Less than RAP (LTR or LRAP), and the Less than RAP plus 25% (LTR+25 or LRAP+25) portfolios. LTR explores the reduced portfolio potential including only approved measures in MEEIA Cycle 4, while LTR+25 demonstrates the benefit of a program 25% closer to RAP than the current MEEIA 4 levels.
 - MAP identified nearly 4.4 million MWh and just over 1.8 Summer GW (1.2 Winter GW) of cost-effective DSM potential available to customers by 2046
 - RAP identified nearly 2.7 million MWh and just over 1.3 Summer GW (832 Winter MW)
 - LTR (MEEIA 4 levels) captures 965 thousand MWh and 755 Summer MW (505 MW Winter)
 - LTR+25 increases the potential beyond MEEIA 4 levels to 1.35 million MWh and 932 Summer MW (585 MW Winter)
- Key components of the analysis include:
 - Methodologies to account for the interactive effects of DSM measures, segregate results by residential and business sectors, and calibrate first year results to existing program delivery
 - Incorporated seasonal avoided costs and coincident factors to examine potential for each season
 - A Distributed Energy Resource potential (Combined Heat & Power and Solar Photovoltaic) study, including a sensitivity analysis of increased transmission and distribution avoided costs representing locational value
 - A comprehensive scenario analysis across all sectors used to inform the load and cost risk-adjusted analysis of DSM portfolios
- All values presented herein are at the meter

8.1 Key Takeaways from DSM Potential Study

The primary purpose of this chapter is to document the demand-side resources considered within this IRP and describe the role these resources can play in meeting Ameren Missouri's future energy, capacity, and reliability needs. In addition to presenting the results of the 2026 DSM Market Potential Study (2026 MPS), this chapter examines how energy efficiency, demand response, and distributed energy resources can help improve customer affordability while addressing uncertainty associated with future load growth, resource development timelines, seasonal capacity needs, and changing customer energy requirements. Demand-side resources are evaluated alongside traditional supply-side resources due to their ability to provide scalable, cost-effective, and deployable solutions that support resource adequacy while reducing customer costs.

The DSM portfolios passed on for further integrated analysis are based on the robust and comprehensive analysis completed as part of the 2026 MPS.¹ Each DSM portfolio includes the total resource potential from four sectors (residential & business energy efficiency, demand response, and distributed energy resources (DER)). The potential from these sectors is combined into three different portfolios for further analysis.² These portfolios are defined as follows:

- **Maximum Achievable Potential (MAP):** Represents the maximum amount of cost-effective DSM that would be expected, assuming incentives that cover the full incremental cost of qualifying measures.
- **Realistic Achievable Potential (RAP):** Represents all cost-effective DSM that would be expected, based on forecast incentive levels and customer willingness to participate, as identified through primary market research conducted in 2025.
- **Less Than Realistic Achievable Potential (LTR):** Is a subset up the RAP scenario but only includes measures and funding levels that are part of the approved MEEIA 4 portfolio.
- **Less Than Realistic Achievable Potential +25:** Is also a subset of the RAP scenario, but includes an uplift in spending compared to the LTR scenario, whereby 25% of the difference in annual budget between RAP and LTR is included and used to focus on measures with lower costs per MW saved (i.e. targets the most cost-effective end-uses that are in the RAP scenario but not the LRAP scenario).

Figures 8.1 - 8.5 provide the results of the MAP, RAP, LTR, and LTR +25 portfolios with respect to energy and demand potential. Across all four sectors studied, the MAP portfolio identified nearly 4.4 million MWh and just over 1.2 GW (Winter) of cumulative annual potential by 2046, while the program RAP portfolio identified nearly 2.7 million MWh and 832 MW (Winter) of cumulative annual potential by 2046.

Recent regional planning developments have increased attention to seasonal capacity requirements, particularly winter reliability. Because demand-side resources can influence all seasonal peak conditions, they provide a flexible planning option capable of supporting evolving seasonal resource adequacy requirements. As future planning reserve constructs continue to evolve, maintaining a diverse portfolio of demand-side resources would provide additional resilience against uncertainty in future reliability requirements.

¹ 20 CSR 4240-22.050(1); The 2026 MPS was released in April 2026 and included as Appendix A to this chapter. The 2026 MPS also includes a complete regulatory compliance checklist as Appendix H. This Chapter includes relevant rule references. The interested reader should also refer to the more detailed Market Potential Study and Appendix H.

² 20 CSR 4240-22.050(6)(A)

Total potential in each sector was developed after a careful assessment of baseline market conditions for residential and business customers across relevant dimensions of housing type and income level. This included an assessment of the penetration and saturation of the type and efficiency level of various end use technologies already in use within Ameren Missouri's service territory. Baseline market research conducted in 2025 was also used to estimate customers' willingness to participate and adopt future technologies at various future incentive levels.

Results for the first year of the study (2027) were calibrated to consider historic program achievement. This creates consistency between future potential and actual program delivery. As a final check, the MAP and RAP results from the 2026 MPS were benchmarked against ten comparable peer utility programs. That analysis confirmed that these values are consistent with standard industry expectations.

Figure 8.1: DSM Portfolio, Cumulative Annual Energy Potential (MWh)

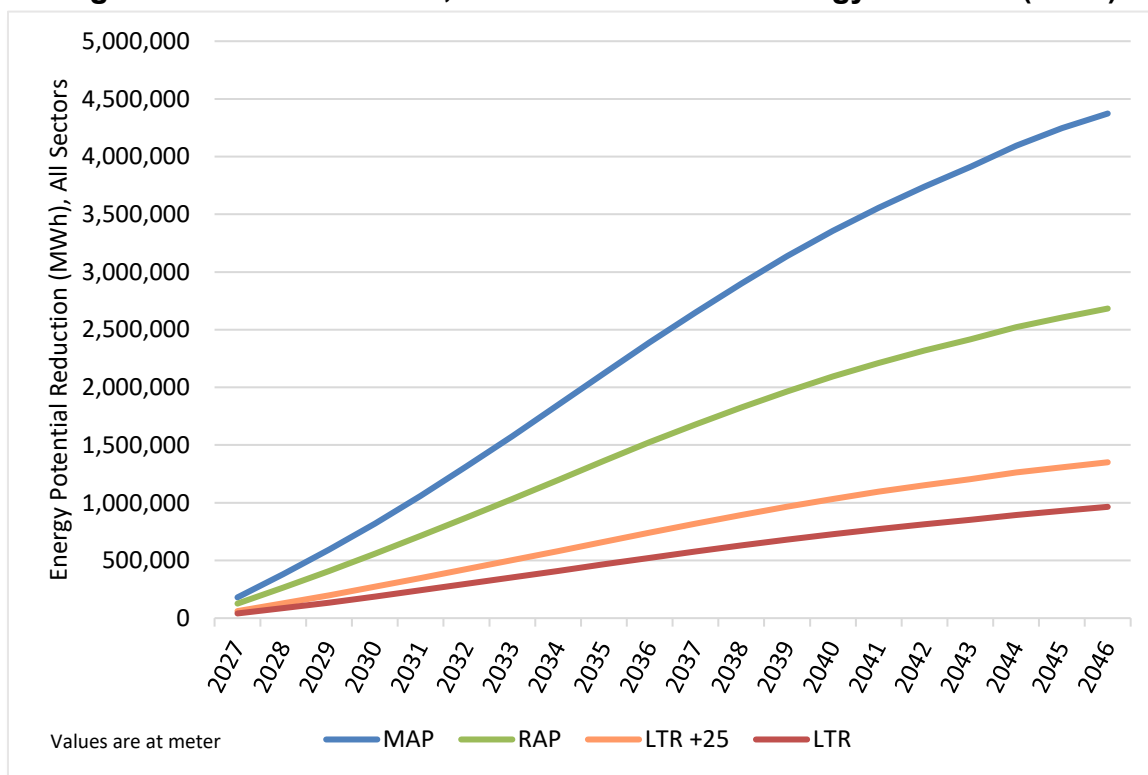


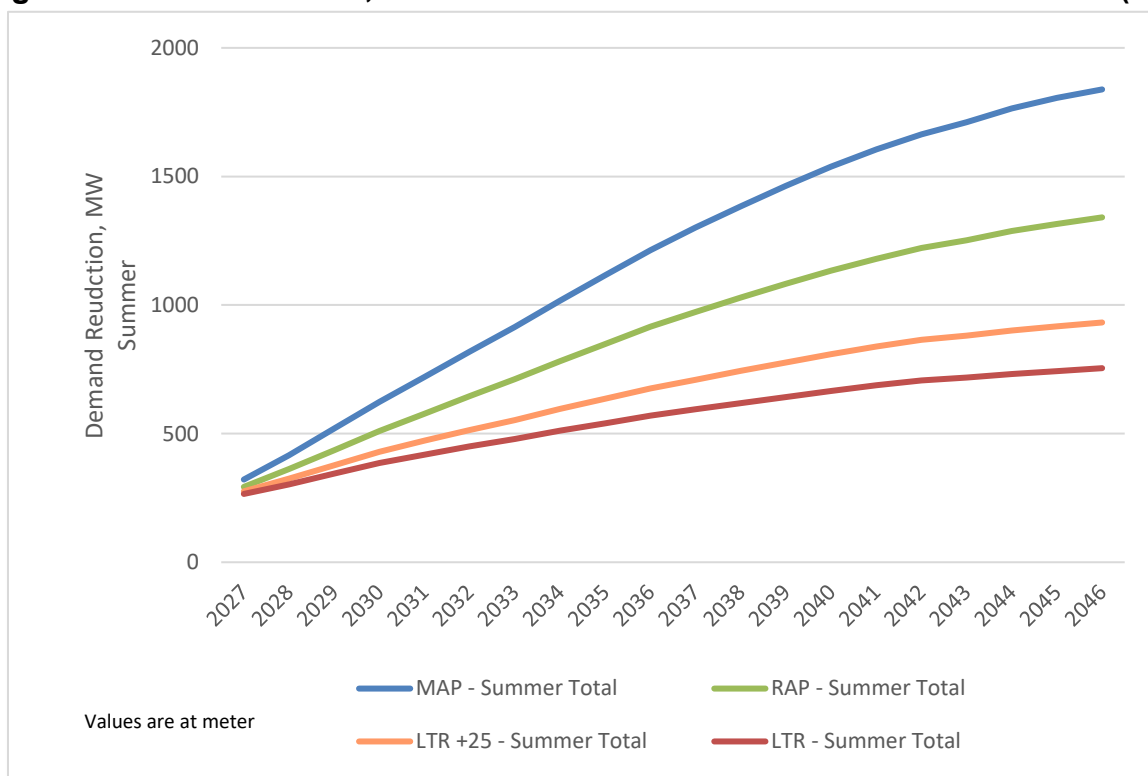
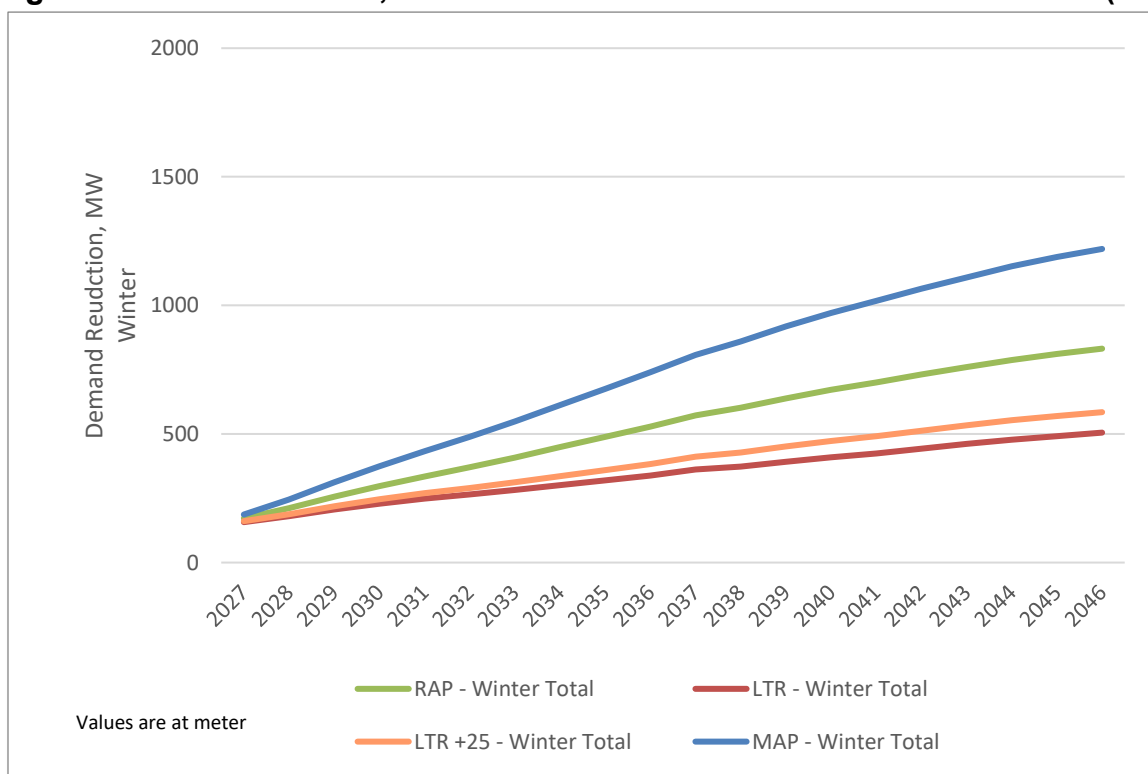
Figure 8.2: DSM Portfolio, Cumulative Annual Summer Demand Reduction (MW)**Figure 8.3: DSM Portfolio, Cumulative Annual Winter Demand Reduction (MW)**

Figure 8.4: DSM Portfolio, Cumulative Annual Spring Demand Reduction (MW)

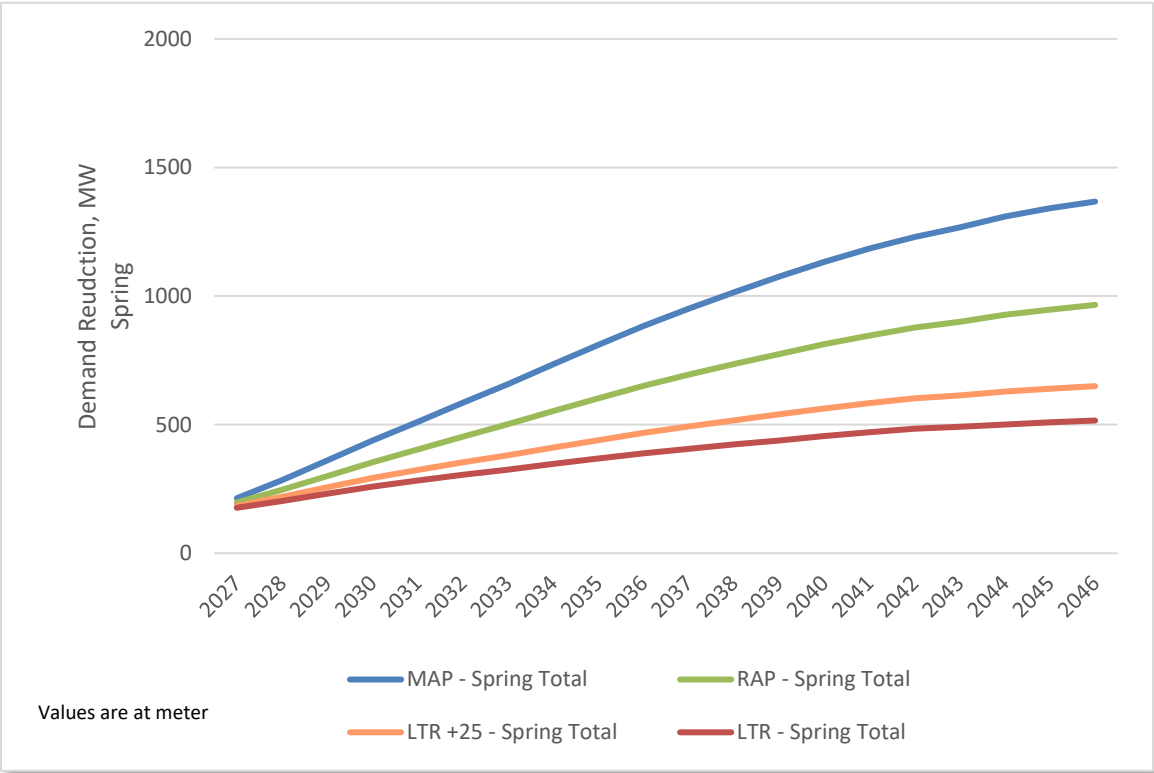
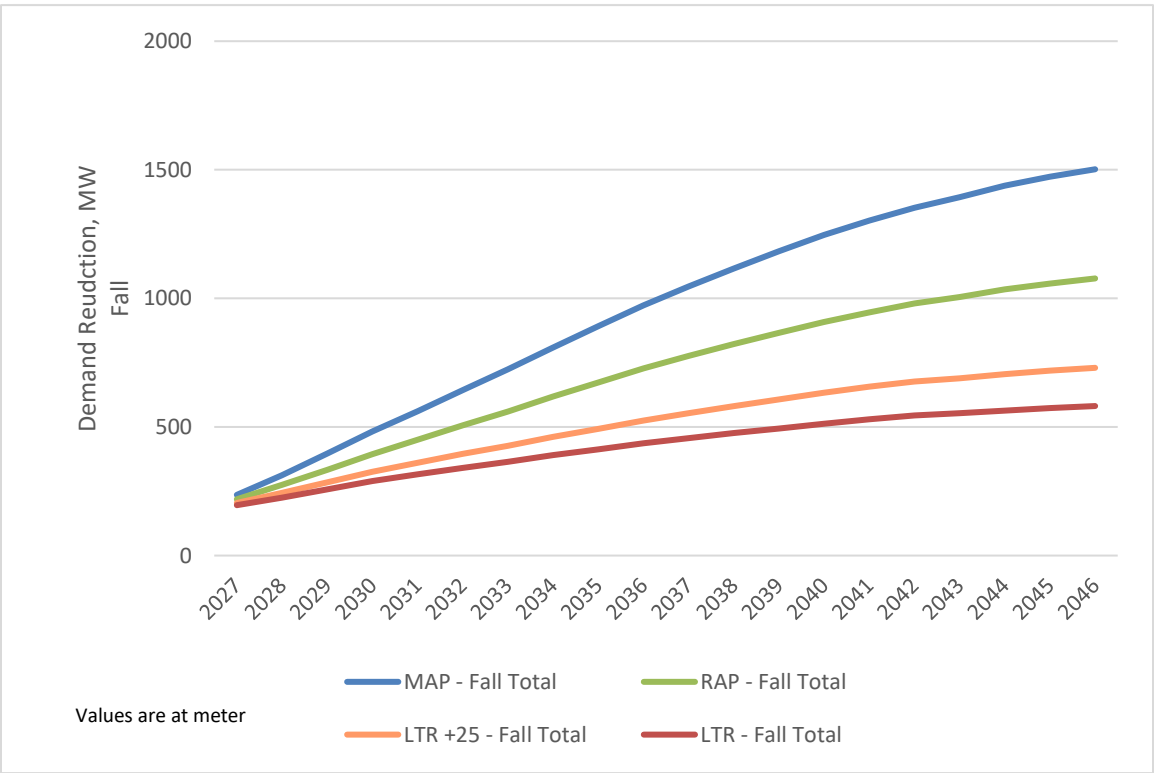


Figure 8.5: DSM Portfolio, Cumulative Annual Fall Demand Reduction (MW)



To visualize potential future scenarios, a comprehensive load and cost risk adjusted analysis was developed for each of the DSM portfolios presented above. The 2026 MPS developed sector specific scenarios for each sector studied, designed to account for future uncertainty in economic conditions, weather, technology development, avoided costs, attribution levels, customer adoption given various financial and non-financial barriers, and key policy goals related to implementation design. These scenarios were used to develop a probability weighted average high and low case for load and cost for the MAP, RAP, LTR, and LTR +25 portfolios.

8.1.1 Demand-Side Resources and Resource Adequacy

As Ameren Missouri evaluates future resource needs, demand-side resources will continue to provide an important planning option in an environment characterized by uncertainty. Forecasts of customer demand and economic growth necessarily reflect a range of possible outcomes, particularly as electrification, data centers, manufacturing development, and other emerging trends create the potential for significant changes in future load growth. In this environment, energy efficiency, demand response, and distributed energy resources can complement traditional supply-side investments by reducing demand, shifting load during constrained periods, and providing a valuable hedge against uncertainty as system needs evolve.

Demand-side resources possess several characteristics that make them valuable within a diverse resource portfolio. They can often be deployed incrementally, scaled over time, and adjusted as customer needs, market conditions, and resource adequacy requirements become clearer. This provides valuable optionality while reducing exposure to risks associated with long development timelines, permitting requirements, fuel price volatility, and interconnection constraints. In many cases, these resources can also be implemented more quickly than large generation or transmission projects, allowing them to support near-term reliability needs while preserving flexibility for future planning decisions.

Demand-side resources are also becoming increasingly important from a resource adequacy and reliability perspective. Across the industry, utilities, regulators, and regional transmission organizations are placing greater emphasis on seasonal reliability and ensuring sufficient capacity is available during periods of greatest system stress. Demand-side resources can support these objectives by reducing seasonal peaks, shifting customer load away from constrained hours, and improving system flexibility during critical conditions. Demand response, in particular, offers growing opportunities to support reliability while preserving customer choice and comfort.

Maintaining continuity of DSM investment is therefore important not only for preserving customer benefits and program performance, but also for sustaining the trade ally networks, implementation infrastructure, customer awareness, and organizational

expertise necessary to respond effectively to future capacity and reliability needs. As Ameren Missouri continues to evaluate future resource portfolios, demand-side resources should remain an important component of a diverse and adaptable strategy designed to meet customer needs while maintaining reliability and affordability.

8.2 Review of Past and Current MEEIA Plans

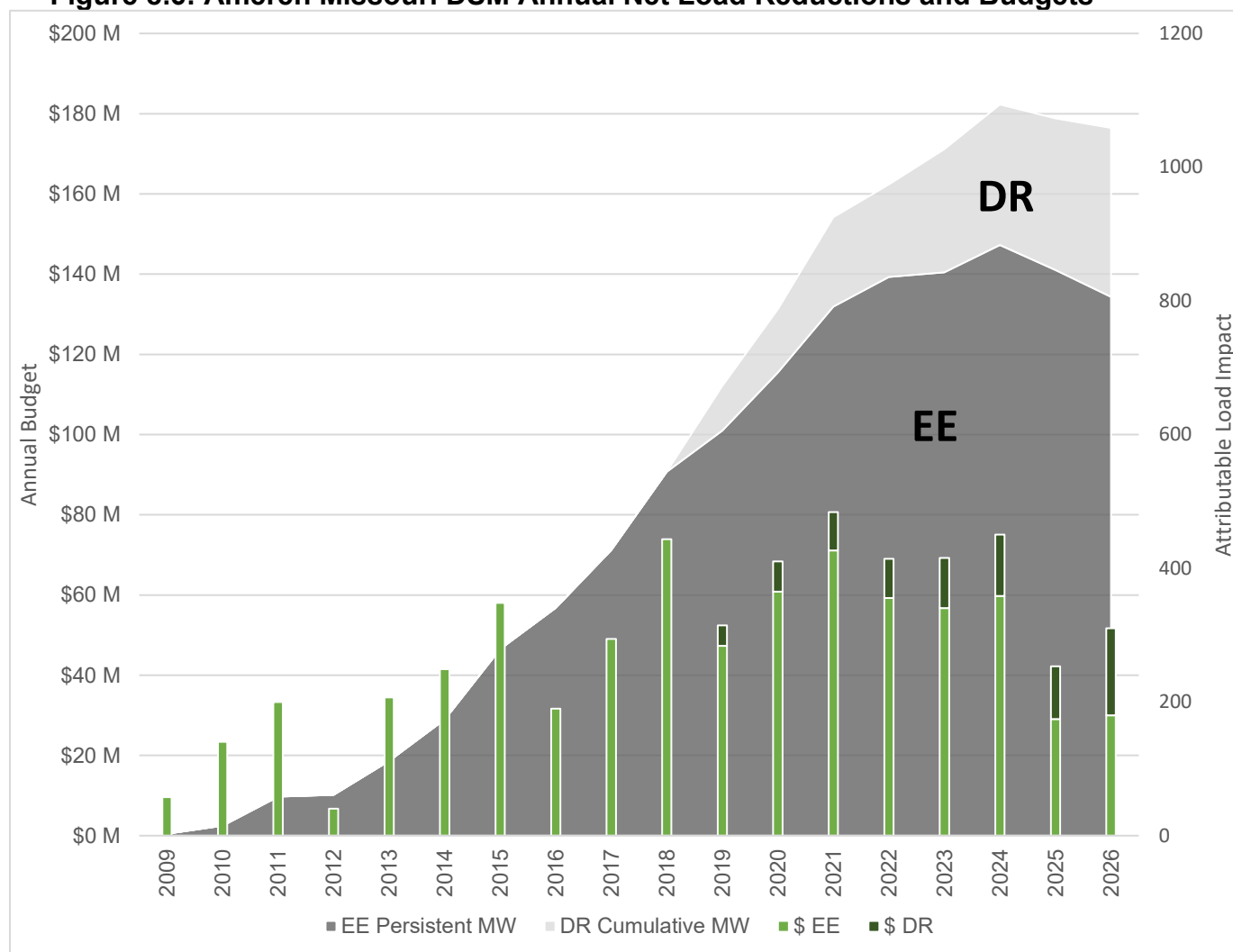
Ameren Missouri continues to operate using its DSM planning, implementation, and evaluation performance leadership which have operated successfully since 2009.

Ameren Missouri has achieved consistent success regardless of the relative size and budget for energy efficiency and demand response portfolios. Figure 8.6 shows the cumulative annual energy savings and associated budgets from 2009 through 2024, with a forecast of program goals for 2025 and 2026.

In addition to showing a simple view of DSM budgets and net load reductions, the trends shown in the figure below also demonstrate the negative impact of losing program continuity between cycles. The deep valleys in budgets and savings seen in 2012, 2016, and 2019 are largely due to these years serving as a "bridge" year between cycle shut down and ramp up. When there is uncertainty around the future of program funding, projects may fall out of the forecasts. Ramping up programs is labor intensive and frequent delays, both to customer projects and operational integrations, are common.

Beyond the direct impact on annual energy and demand savings, continuity of DSM investment supports the long-term infrastructure necessary for successful program delivery. Trade ally networks, implementation contractors, customer awareness, program delivery systems, evaluation infrastructure, and organizational expertise require sustained investment to remain effective. Disruptions in program continuity can erode these capabilities and increase future implementation costs and timelines. Maintaining continuity therefore preserves both current program performance and the Company's ability to scale demand-side resources in response to future reliability and capacity needs.

Figure 8.6 demonstrates the effects of Ameren Missouri's commitment to continuous demand side management programs. Energy efficiency measures' savings and demand reductions are sustained throughout the expected life of the equipment installed. The persistent, additive nature of energy efficiency's effect on peak system load is evident and a significant cumulative effect of the portfolio (while not pictured, a further large benefit of the EE programs is the avoided energy usage, resulting in total persistent energy savings in 2025 of nearly 2,900 GWh annually). Emerging in 2019, demand response has played an increasingly valuable role in the Company's ability to ensure reliability during system peaks. The load reductions from the demand response resource necessitates continued engagement and incentives.

Figure 8.6: Ameren Missouri DSM Annual Net Load Reductions and Budgets

Note: 2009 to 2024 values represent actual evaluated (net) values from annual EM&V reports. 2025 and 2026 values represent net as filed values approved as part of program filings. EE values integrate the average useful life of measures, only counting avoided load during a measure's expected life.

The most recent approved portfolio, MEEIA 4, represents a shift in the State of Missouri's regulatory posture towards customer-funded, cost-effective, utility sponsored DSM programs. Ameren's Missouri original 6-year MEEIA filing aligned with the Realistic Achievable Potential (RAP) highlighted in the 2023 Market Potential Study and incorporated into the 2023 IRP. Ultimately the portfolio approved reduced the budget for many aspects of EE and will result in lower persistent energy and demand savings and was reflected in the Company's 2025 Preferred Resource Plan (PRP) update.

8.3 IRP DSM Portfolios

This section of Chapter 8 begins with an overview of the 2026 MPS. The overview is followed by the methodology used to develop the DSM portfolios, including a discussion of key design elements and differences with the prior study, before providing a more detailed presentation of results for total resource potential, including the results of benchmarking to other external studies.

8.3.1 Overview

The purpose of the 2026 Market Potential Study is to assess potential energy and demand savings from energy efficiency, demand response, and distributed energy resources across multiple sectors of the economy.

Ameren Missouri held a series of workshops to review methodologies and assumptions, analyze market data, and review draft and final results. To accomplish this task, Ameren Missouri commissioned GDS Associates (GDS) to serve as the lead author of the study. GDS also completed the 2016, 2020, and 2023 MPS, which allows for a baseline level of consistency and comparison across studies.

GDS partnered with subject matter experts to assist with sections of key interest. Brightline Group provided technical expertise and modeling of emerging distributed energy resources while Opinion Dynamics provided expertise in conducting the market research. Together, these partners form the “GDS Team.”

The 2026 Market Potential Study was composed of four distinct areas of study:

- Residential and business sector market-rate energy efficiency,
- Demand response peak load reduction potential,
- Distributed Energy Resource (DER) potential, and
- Sensitivity and scenario analysis.

It should be noted that although these distinct areas are investigated separately, the overall effect is aggregated for the purposes of integration into the IRP and reported here as such. The 2026 MPS reviewed the period from 2027 to 2046. Obtaining market potential data lays the critical groundwork for setting budget and energy savings targets for the MEEIA portfolio.

8.3.2 Key Methodologies and Assumptions

For each sector studied, the MPS first assessed the technical potential. The technical potential represents the theoretical upper bound on savings and reflects total potential regardless of cost-effectiveness. Technical potential is then screened against the TRC to estimate all economic potential. In a final step, the economic potential is further

categorized as the MAP³ and RAP⁴ described above. MAP and RAP are based on expected customer adoption rates and willingness to participate, given relevant incremental costs, utility incentives assumed to be available to the customer, and the presence (or lack thereof) of other financial and non-financial barriers.⁵ In the 2026 MPS Ameren Missouri examined two more scenarios meant to simulate programs executed at less than RAP (LTR) levels commensurate with budget levels approved in MEEIA 4 as well as a portfolio 25% closer to RAP levels (LTR +25).

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 net to gross impacts. Program-level potential reflects how measures are combined and offered to customers. Because cost-effectiveness is most appropriately evaluated at the program level, it may be reasonable to include some measures that are not independently cost-effective if they enhance customer participation, expand customer choice, and support the overall cost-effectiveness and performance of the program portfolio⁶.

8.3.2.1 Overall Approach

For the residential, demand response, and DER sectors, GDS relied on a bottom-up approach to estimate potential. GDS relied on market research to first characterize the eligible equipment stock that could be replaced by a more efficient measure and the relative potential savings per measure against that baseline equipment. This defines the technical potential. Next, measures were screened for cost effectiveness and then assessed relative to expected customer adoption. Total potential represents the sum of all measures for the relevant populations of interest. In contrast, GDS relied on a top-down approach when estimating potential in the business sector. GDS first estimated measure level savings and costs using a bottom-up modeling approach and then applied all cost-effective measure savings to all applicable shares of electric energy load.

As a starting point, GDS reviewed the Ameren Missouri load forecast to generate the necessary inputs for the analysis. The study modified the Ameren forecast to create an adjusted baseline forecast to account for various impacts⁷ such as:

- Current DSM impacts
- Naturally occurring efficiency savings
- Adjustment for large C&I opt-out customers

³ 20 CSR 4240-22.050(2); 20 CSR 4240-22.050(3)(G)5B; 20 CSR 4240-22.020(40)

⁴ 20 CSR 4240-22.050(3)(G)5B; 20 CSR 4240-22.020(49); 20 CSR 4240-22.050(2)

⁵ 20 CSR 4240-22.050(2); 20 CSR 4240-22.050(3)(B); 20 CSR 4240-22.050(3)(G)5B

⁶ 20 CSR 4240-20.094(4)(I); 20 CSR 4240-22.050(5)(B)

⁷ 20 CSR 4240-22.030; 20 CSR 4240-22.050(3)(G)1; 20 CSR 4240-22.050(3)(G)2

- Reclassification of load

For additional details regarding Ameren Missouri's load forecasting system as well as each of these adjustments, see sections 3.1 through 3.2 of the 2026 MPS.

8.3.2.2 Cost-Effectiveness Defined

Cost effectiveness of Ameren Missouri DSM measures, programs, and portfolios was calculated using the TRC test,⁸ the utility cost test (UCT), the participant cost test (PCT), and the ratepayer impact measure (RIM) test.⁹ 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, and then summed into net present values for the timeframe considered.¹⁰ The definitions of the tests are outlined below:

The Total Resource Cost 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.¹¹ The full incremental costs include single upfront costs and operational & maintenance costs where applicable.¹² 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.¹³

The Utility Cost Test measures the costs and benefits from the perspective of the utility administering the program.¹⁴ 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.¹⁵ Programs passing the UCT result in overall net benefits to the utility, thus making the program worthwhile from a utility cost accounting perspective.¹⁶

⁸ 20 CSR 4240-22.050(5)(B)

⁹ 20 CSR 4240-22.050(5)(E); 20 CSR 4240-22.050(5)(F); 20 CSR 4240-22.050(5)(G); 20 CSR 4240-22.050(3)(I)

¹⁰ 20 CSR 4240-22.050(5)(A)

¹¹ 20 CSR 4240-22.050(5)(B)1; 20 CSR 4240-22.050(5)(B)3

¹² 20 CSR 4240-22.050(3)(G)5A-F; 20 CSR 4240-22.050(5)(B)1

¹³ 20 CSR 4240-22.050(5)(D)

¹⁴ 20 CSR 4240-22.050(5)(C)

¹⁵ 20 CSR 4240-22.050(5)(C)1; 20 CSR 4240-22.050(5)(C)2 and 3

¹⁶ 20 CSR 4240-22.050(5)(C); 20 CSR 4240-22.050(5)(D)

The Participant Cost Test 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.¹⁷

The Ratepayer Impact Measure 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.¹⁸

8.3.2.3 Market Adoption Rates

Market adoption rate estimates were developed using primary market research conducted within the Ameren Missouri service territory, which characterized building and equipment attributes as well as customer behavior. The primary objective of this research was to develop measure- and program-specific adoption curves to support the estimation of achievable potential. Adoption rates were derived from a structured survey-based methodology that incorporated: (1) customer willingness to participate (WTP) under varying incentive levels, including scenarios ranging from no incentive to full cost coverage; (2) adjustments for the magnitude of financial and non-financial barriers to adoption or participation; and (3) adjustments for customer awareness of Ameren Missouri energy efficiency programs and high-efficiency technologies. These components were combined to produce final adoption scores used in the achievable potential analysis.

8.3.2.4 Development of DSM Applicable Measure Lists

DSM potential is derived from individual measures available within each sector. The study's sector-level measure lists were developed through various resources. The initial measure list was primarily informed by Ameren Missouri's most recent Deemed Savings Table and Technical Reference Manual, as approved in the most recent MEEIA Cycle 4 application. Consideration of additional measures can be attributed to current Ameren Missouri program offerings, prior Ameren Missouri and other regional potential

¹⁷ 20 CSR 4240-22.050(3)(G)5C;20 CSR 4240-22.050(5)(F)

¹⁸ 20 CSR 4240-22.050(5)(F)

assessments and program offerings, other regional technical reference manuals, and commercially viable emerging technologies.¹⁹

Measures were screened to ensure relevance and appropriateness for inclusion in the analysis. This screening considered factors such as market applicability, baseline assumptions, customer acceptance, and the presence of financial and non-financial barriers identified through primary research. Measures that were no longer applicable, had limited savings potential, or faced significant adoption challenges were excluded. Stakeholder input, prior evaluation findings, and program experience were also used to inform this process. The final study included 183 residential and 170 business energy efficiency measures. A total of 2,891 different measure permutations were performed for this study to help inform future program planning and align with existing offerings. Each permutation was screened for cost-effectiveness according to the TRC test.

GDS estimated relevant costs for each measure, as defined by each cost effectiveness test.²⁰ Costs for each measure include either incremental or full costs, depending on program design and implementation. GDS estimated measure costs from Ameren Missouri program planning databases and evaluation reports, other state technical resource manuals, secondary sources and industry databases, and other program evaluation reports. Administrative costs for each measure were developed based on a review of historical evaluated costs and/or budgets for past portfolios. RAP scenarios assume an incentive as a percent of the incremental measure cost, consistent with past program delivery, with the remainder of the incremental cost borne by the participant. In contrast, the MAP assumes an incentive equal to 100 percent of the incremental cost.

Finally, measure savings were adjusted to account for interactive effects across end uses to avoid double counting. For example, HVAC measures installed at the same time as building shell measures would be expected to operate at fewer effective full load hours. A structured application order was used in the analysis, generally prioritizing new equipment measures, followed by retrofit measures and then behavioral measures, to ensure that overlapping impacts were appropriately captured in the final DSM potential estimates.²¹

8.3.3 DSM Potential under MAP, RAP, LTR and LTR +25²²

By combining 2025 market research with the detailed assessment of potential DSM measures described above, GDS estimated all cost-effective potential in each year from 2027 through 2046. This cost-effective potential was used to define the MAP and RAP portfolios. The potential of the RAP portfolio was then modified to only consider measures

¹⁹ 20 CSR 4240-22.050(3); 20 CSR 4240-22.050(3)(A); 20 CSR 4240-22.050(3)(B); 20 CSR 4240-22.050(3)(C)

²⁰ 20 CSR 4240-22.050(3)(G)5A-F

²¹ 20 CSR 4240-22.050(3)(G)2

²² 20 CSR 4240-22.050(6)(A)

and budget levels currently available through the MEEIA 4 portfolio to identify the cost-effective potential of LTR. Finally one more portfolio (LTR +25) explored the potential of increasing MEEIA 4 levels 25% towards RAP.

Table 8.1 provides the portfolio MAP, RAP, LTR, and LTR +25 cumulative annual demand reduction potential and budget by sector for select years. Table 8.2 shows the additional energy avoidance benefit (at no additional cost) associated with implementing the portfolio. Tables 8.3 - 8.4 show the relative impact of the savings compared to the baseline forecast. Figures 8.7 - 8.23 provide a more detailed representation of the seasonal peak reduction and energy reduction MAP, RAP, LTR, and LTR +25 potential across the 20-year planning horizon for the whole portfolio.²³ Figure 8.24 provides the MAP and RAP potential for demand response. LTR and LTR +25 assume the same level of DR potential as RAP. Additionally, it is assumed that there is no DER potential in the LTR and LTR +25 portfolios. Collectively, these totals represent the MAP, RAP, LTR and LTR +25 DSM cases included in the 2026 IRP.

²³ 20 CSR 4240-22.050(3)(G); 20 CSR 4240-22.050(3)(I); Section 4.1.8.1 of the Potential Study describes development of the program potential through the application of net-to-gross factors. Measure net-to-gross ratios were based on the most recent evaluation findings for Ameren Missouri at the individual measure level.

Table 8.1: MAP, RAP, LTR, and LTR +25 Coincident Peak Reduction Potential (MW) and Implementation Budget (NPV \$Million)

Potential and Sector	2027				2029				2034				2039				2046				Implementation Budget (+20yr NPV 2027 \$millions *base yr'27)
MAP	Summer	Winter	Spring	Fall	Summer	Winter	Spring	Fall	Summer	Winter	Spring	Fall	Summer	Winter	Spring	Fall	Summer	Winter	Spring	Fall	
EE Residential	21.1	12.2	15.7	17.5	75.9	44.6	56.4	62.8	269.5	168.5	200.7	223.1	484.1	341.2	361.8	401.6	695.9	526.6	520.6	577.7	\$ 1,429
EE C&I	35.9	18.7	27.5	30.3	114.9	59.1	88.3	97.1	334.7	165.9	257.2	282.9	510.2	246.4	391.9	431.4	595.2	287.6	457.1	503.5	\$ 911
DR Residential	70.8	48.2	35.3	39.2	83.3	60.4	44.9	49.8	115.6	88.2	67.1	74.4	143.7	112.0	86.1	95.4	172.2	136.7	105.3	116.8	\$ 266
DR C&I	192.8	106.7	134.4	148.0	242.1	144.8	167.6	183.9	282.8	174.7	195.3	214.2	290.6	183.7	200.8	220.2	294.1	187.6	203.3	223.0	\$ 244
DER	1.0	1.0	1.0	1.0	3.5	3.5	3.5	3.5	14.2	14.2	14.2	14.2	34.6	34.6	34.6	34.6	81.0	81.0	81.0	81.0	\$ 141
Total (seasonal)	321.6	186.8	214.0	236.0	519.7	312.3	360.7	397.1	1,016.8	611.4	734.5	808.8	1,463.3	918.0	1,075.3	1,183.3	1,838.5	1,219.4	1,367.3	1,502.0	\$ 2,991
RAP	Summer	Winter	Spring	Fall	Summer	Winter	Spring	Fall	Summer	Winter	Spring	Fall	Summer	Winter	Spring	Fall	Summer	Winter	Spring	Fall	
EE Residential	15.6	7.4	11.5	12.9	55.9	27.1	41.1	46.1	201.4	103.9	148.4	166.1	365.0	214.4	269.7	301.5	516.7	338.8	382.5	427.3	\$ 711
EE C&I	26.2	13.9	20.0	22.1	82.8	43.6	63.2	69.8	215.6	109.8	164.7	181.8	305.1	151.3	233.5	257.6	356.0	175.8	272.6	300.8	\$ 309
DR Residential	63.0	46.9	34.4	38.2	77.4	56.6	42.3	46.9	111.5	79.0	60.9	67.6	141.6	98.9	77.4	85.9	174.6	120.9	95.5	105.9	\$ 195
DR C&I	187.4	103.0	130.8	144.0	216.7	125.8	150.5	165.4	243.6	145.6	168.9	185.5	249.6	153.1	173.1	190.1	256.1	158.7	177.6	195.1	\$ 194
DER	0.8	0.8	0.8	0.8	2.8	2.8	2.8	2.8	10.1	10.1	10.1	10.1	21.0	21.0	21.0	21.0	37.5	37.5	37.5	37.5	\$ 51
Total (seasonal)	293.1	172.2	197.5	218.0	435.6	255.8	299.9	331.0	782.2	448.5	553.1	611.1	1,082.2	638.6	774.6	856.0	1,341.0	831.7	965.7	1,066.5	\$ 1,459
LTR +25	Summer	Winter	Spring	Fall	Summer	Winter	Spring	Fall	Summer	Winter	Spring	Fall	Summer	Winter	Spring	Fall	Summer	Winter	Spring	Fall	
EE Residential	10.0	4.8	7.4	8.2	35.6	17.2	26.2	29.4	131.4	65.8	96.8	108.3	238.3	137.6	175.9	196.7	332.4	232.3	245.8	274.6	\$ 550
EE C&I	15.6	6.2	12.0	13.2	47.8	19.2	36.9	40.5	109.4	45.3	84.6	92.7	146.7	61.4	113.4	124.4	169.2	72.9	130.7	143.5	\$ 155
DR Residential	63.0	46.9	34.4	38.2	77.4	56.6	42.3	46.9	111.5	79.0	60.9	67.6	141.6	98.9	77.4	85.9	174.6	120.9	95.5	105.9	\$ 195
DR C&I	187.4	103.0	130.8	144.0	216.7	125.8	150.5	165.4	243.6	145.6	168.9	185.5	249.6	153.1	173.1	190.1	256.1	158.7	177.6	195.1	\$ 194
DER	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	\$ -
Total (seasonal)	275.9	161.0	184.6	203.6	377.6	218.7	256.0	282.2	595.9	335.8	411.2	454.0	776.2	451.0	539.8	597.0	932.3	584.8	649.7	719.1	\$ 1,093
LTR	Summer	Winter	Spring	Fall	Summer	Winter	Spring	Fall	Summer	Winter	Spring	Fall	Summer	Winter	Spring	Fall	Summer	Winter	Spring	Fall	
EE Residential	8.0	3.9	5.9	6.6	28.4	13.6	20.9	23.4	104.3	51.5	76.8	86.0	185.3	107.1	136.7	152.8	253.2	187.9	187.2	209.0	\$ 487
EE C&I	9.2	4.4	7.3	7.9	30.4	14.5	24.3	26.0	87.1	42.4	69.3	74.4	123.6	62.0	97.9	105.6	139.4	73.6	110.2	119.3	\$ 99
DR Residential	63.0	46.9	34.4	38.2	77.4	56.6	42.3	46.9	111.5	79.0	60.9	67.6	141.6	98.9	77.4	85.9	174.6	120.9	95.5	105.9	\$ 195
DR C&I	187.4	103.0	130.8	144.0	216.7	125.8	150.5	165.4	243.6	145.6	168.9	185.5	249.6	153.1	173.1	190.1	256.1	158.7	177.6	195.1	\$ 194
DER	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	\$ -
Total (seasonal)	267.6	158.2	178.4	196.6	353.0	210.4	238.1	261.8	546.5	318.6	375.9	413.5	700.1	421.1	485.1	534.4	823.3	541.0	570.5	629.3	\$ 974

Values are at meter

Table 8.2: MAP, RAP, LTR, and LTR +25 Energy Reduction Potential (MWh)

Potential and Sector	2027	2029	2034	2039	2046	Implementation Budget (+20yr NPV 2027 \$millions *base yr'27)
MAP						
EE Residential	53,424	191,379	706,199	1,373,572	2,062,485	\$1,429
EE C&I	119,985	378,867	1,047,014	1,536,202	1,777,654	\$911
DER	6,539	23,051	93,337	227,937	533,104	\$141
Total	179,948	593,298	1,846,550	3,137,711	4,373,243	\$2,480

RAP						
EE Residential	35,236	124,643	464,983	911,959	1,378,413	\$711
EE C&I	85,608	265,988	665,753	915,526	1,057,711	\$309
DER	5,367	18,351	66,635	138,038	246,985	\$51
Total	126,211	408,982	1,197,371	1,965,524	2,683,109	\$1,070

LTR +25						
EE Residential	22,502	63,111	232,997	447,491	696,054	\$550
EE C&I	38,573	119,557	283,965	385,270	453,110	\$155
DER						\$0
Total	61,075	182,668	516,962	832,761	1,149,163	\$704

LTR						
EE Residential	17,946	63,111	232,997	447,491	696,054	\$487
EE C&I	22,895	71,414	176,037	233,174	268,533	\$99
DER						\$0
Total	40,842	134,525	409,034	680,666	964,587	\$586

Values are at meter

Table 8.3: MAP, RAP, LTR, and LTR +25 Coincident Summer Peak Reduction (MW) Potential Percent of Forecasted Load

Potential and Sector	2027	2029	2034	2039	2046
MAP					
EE Residential	0.30%	1.05%	3.65%	6.43%	8.48%
EE C&I	0.50%	1.59%	4.53%	6.78%	7.25%
DR Residential	1.00%	1.15%	1.57%	1.91%	2.10%
DR C&I	2.71%	3.35%	3.83%	3.86%	3.58%
DER	0.01%	0.05%	0.19%	0.46%	0.99%
Total	4.52%	7.19%	13.77%	19.43%	22.39%

RAP					
EE Residential	0.22%	0.77%	2.73%	4.85%	6.29%
EE C&I	0.37%	1.15%	2.92%	4.05%	4.34%
DR Residential	0.89%	1.07%	1.51%	1.88%	2.13%
DR C&I	2.64%	3.00%	3.30%	3.31%	3.12%
DER	0.01%	0.04%	0.14%	0.28%	0.46%
Total	4.12%	6.03%	10.60%	14.37%	16.33%

LTR +25					
EE Residential	0.14%	0.49%	1.78%	3.17%	4.05%
EE C&I	0.22%	0.66%	1.48%	1.95%	2.06%
DR Residential	0.89%	1.07%	1.51%	1.88%	2.13%
DR C&I	2.64%	3.00%	3.30%	3.31%	3.12%
DER	N/A	N/A	N/A	N/A	N/A
Total	3.88%	5.22%	8.07%	10.31%	11.36%

LTR					
EE Residential	0.11%	0.39%	1.41%	2.46%	3.08%
EE C&I	0.10%	0.31%	0.70%	0.87%	0.86%
DR Residential	0.89%	1.07%	1.51%	1.88%	2.13%
DR C&I	2.64%	3.00%	3.30%	3.31%	3.12%
DER	N/A	N/A	N/A	N/A	N/A
Total	3.74%	4.77%	6.93%	8.52%	9.19%

Values are at meter

**Table 8.4: MAP, RAP, LTR, and LTR +25 Energy Reduction Potential (MWh)
Percent of Forecasted Load**

Potential and Sector	2027	2029	2034	2039	2046
MAP					
EE Residential	0.17%	0.61%	2.20%	4.08%	5.81%
EE C&I	0.39%	1.22%	3.26%	4.56%	5.01%
DR	N/A	N/A	N/A	N/A	N/A
DER	0.02%	0.07%	0.29%	0.68%	1.50%
Total	0.59%	1.91%	5.74%	9.32%	12.32%

RAP					
EE Residential	0.11%	0.40%	1.45%	2.71%	3.88%
EE C&I	0.28%	0.85%	2.07%	2.72%	2.98%
DR	N/A	N/A	N/A	N/A	N/A
DER	0.02%	0.06%	0.21%	0.41%	0.70%
Total	0.41%	1.31%	3.72%	5.84%	7.56%

LTR +25					
EE Residential	0.07%	0.26%	0.92%	1.73%	2.53%
EE C&I	0.13%	0.38%	0.88%	1.14%	1.28%
DR	N/A	N/A	N/A	N/A	N/A
DER	N/A	N/A	N/A	N/A	N/A
Total	0.20%	0.64%	1.81%	2.87%	3.80%

LTR					
EE Residential	0.06%	0.20%	0.72%	1.33%	1.96%
EE C&I	0.07%	0.23%	0.55%	0.69%	0.76%
DR	N/A	N/A	N/A	N/A	N/A
DER	N/A	N/A	N/A	N/A	N/A
Total	0.13%	0.43%	1.27%	2.02%	2.72%

Values are at meter

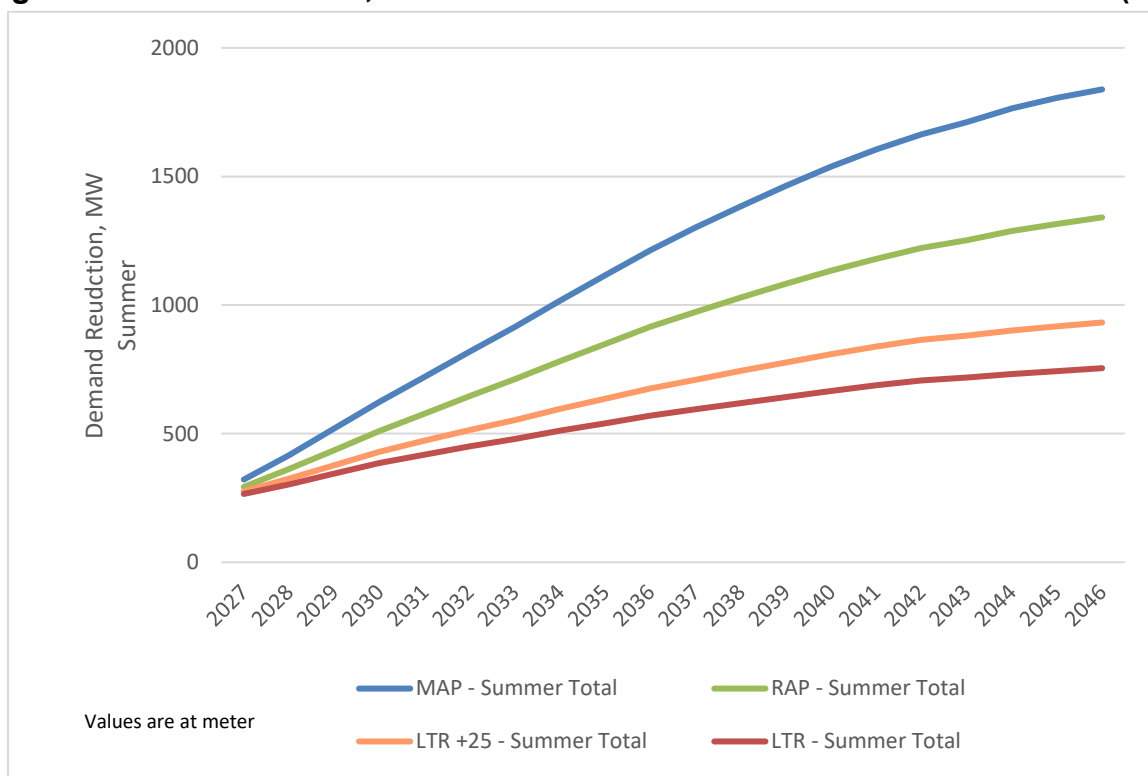
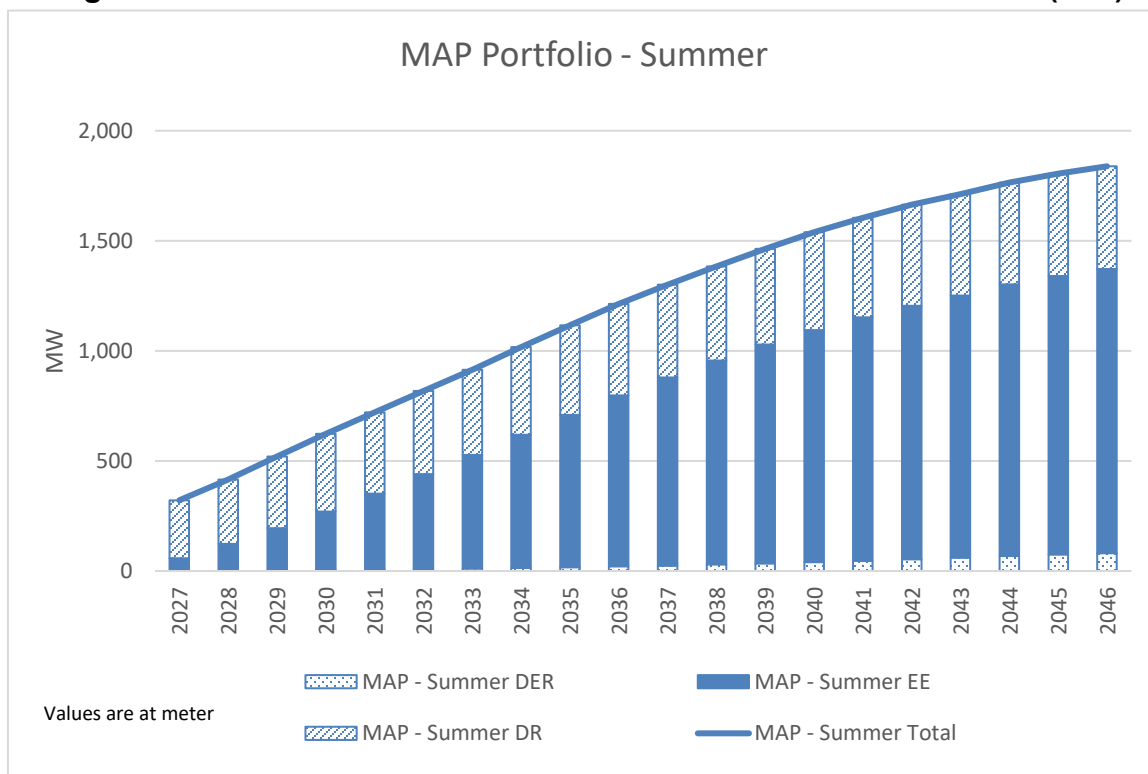
Figure 8.7: DSM Portfolio, Cumulative Annual Summer Demand Reduction (MW)**Figure 8.8: MAP Coincident Summer Peak Reduction Breakdown (MW)**

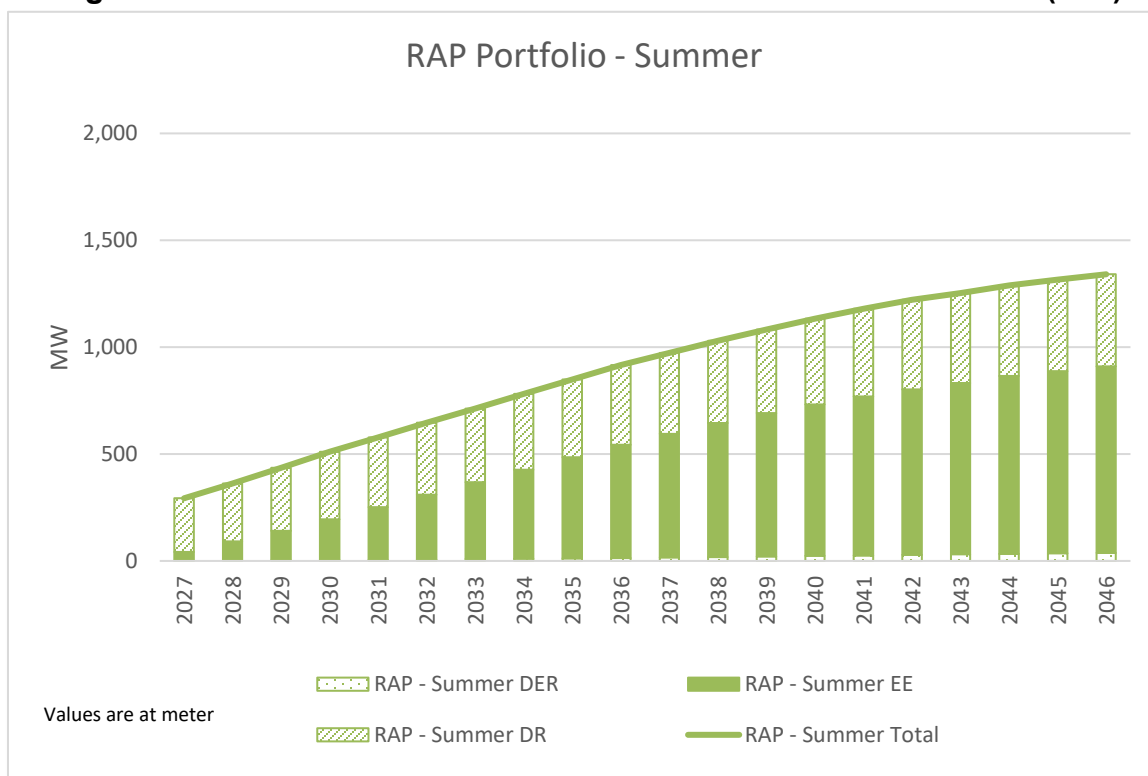
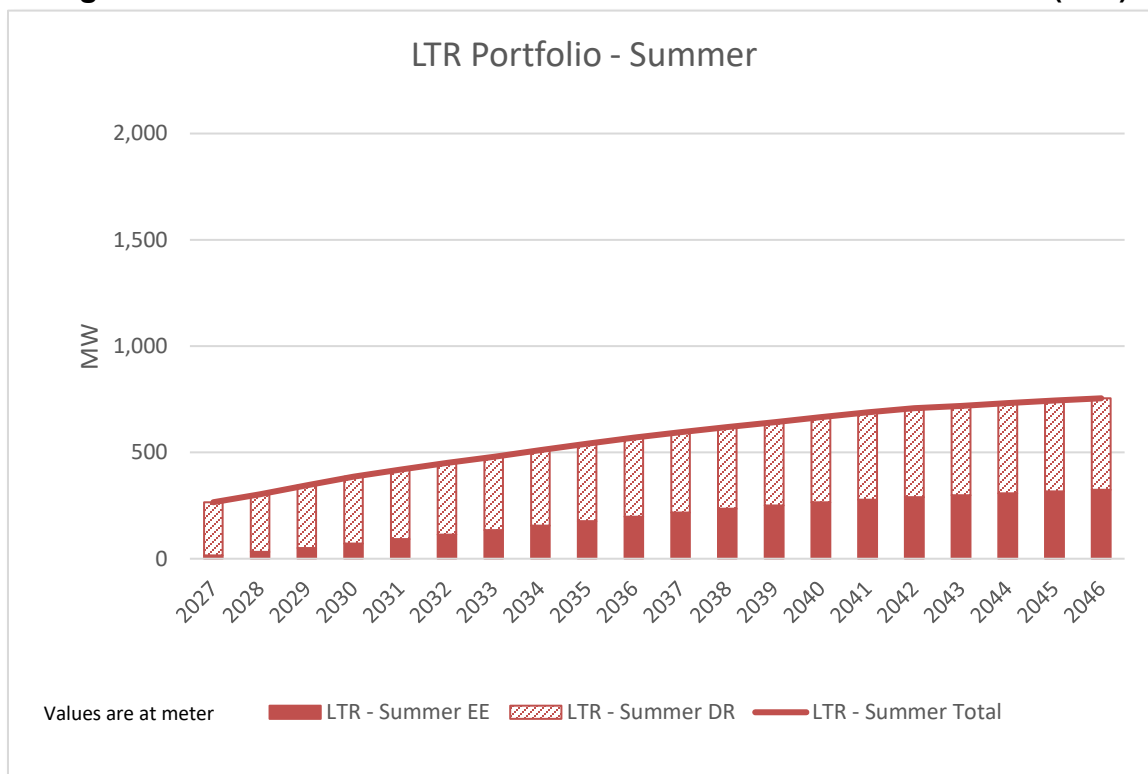
Figure 8.9: RAP Coincident Summer Peak Reduction Breakdown (MW)**Figure 8.10: LTR Coincident Summer Peak Reduction Breakdown (MW)**

Figure 8.11: LTR +25 Coincident Summer Peak Reduction Breakdown (MW)

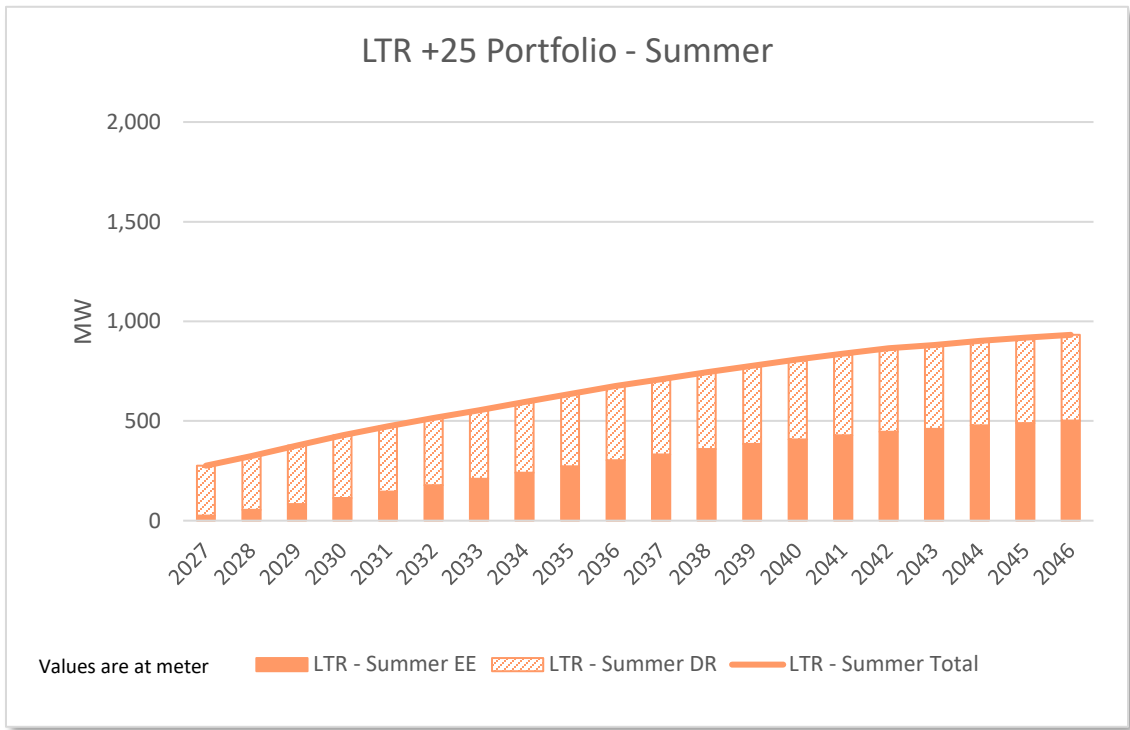


Figure 8.12: DSM Portfolio, Cumulative Annual Winter Demand Reduction (MW)

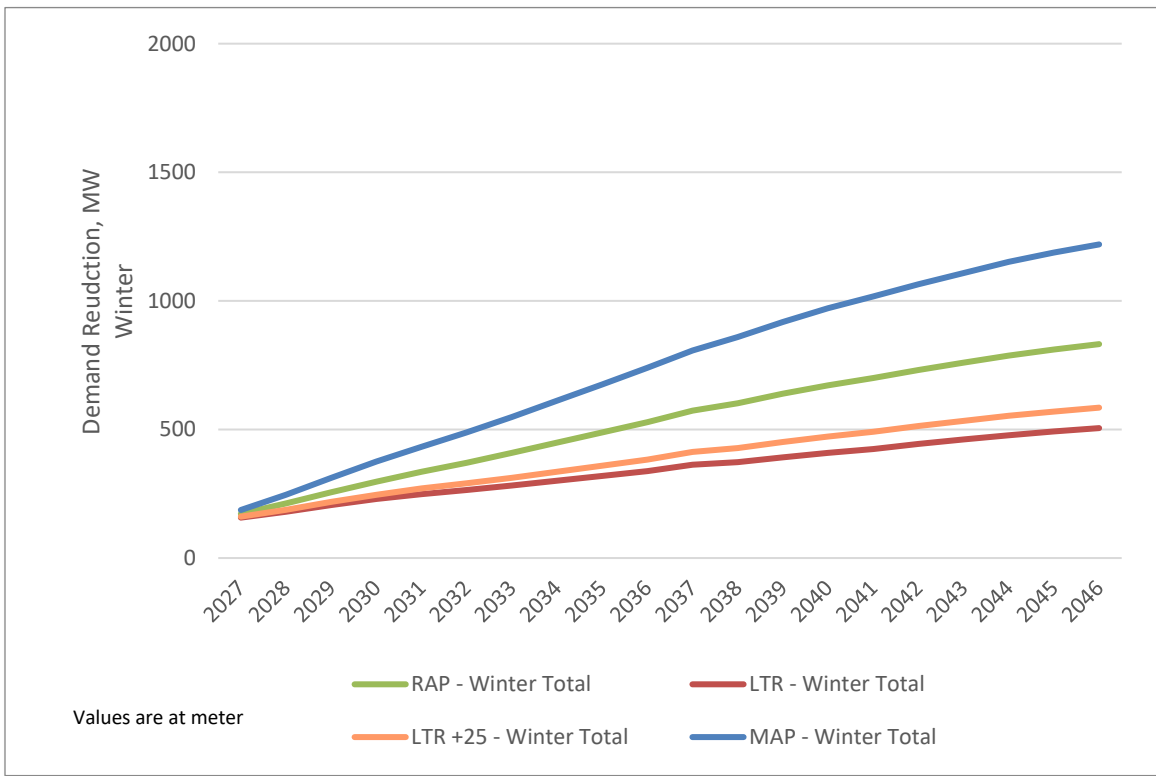


Figure 8.13: MAP Coincident Winter Peak Reduction Breakdown (MW)

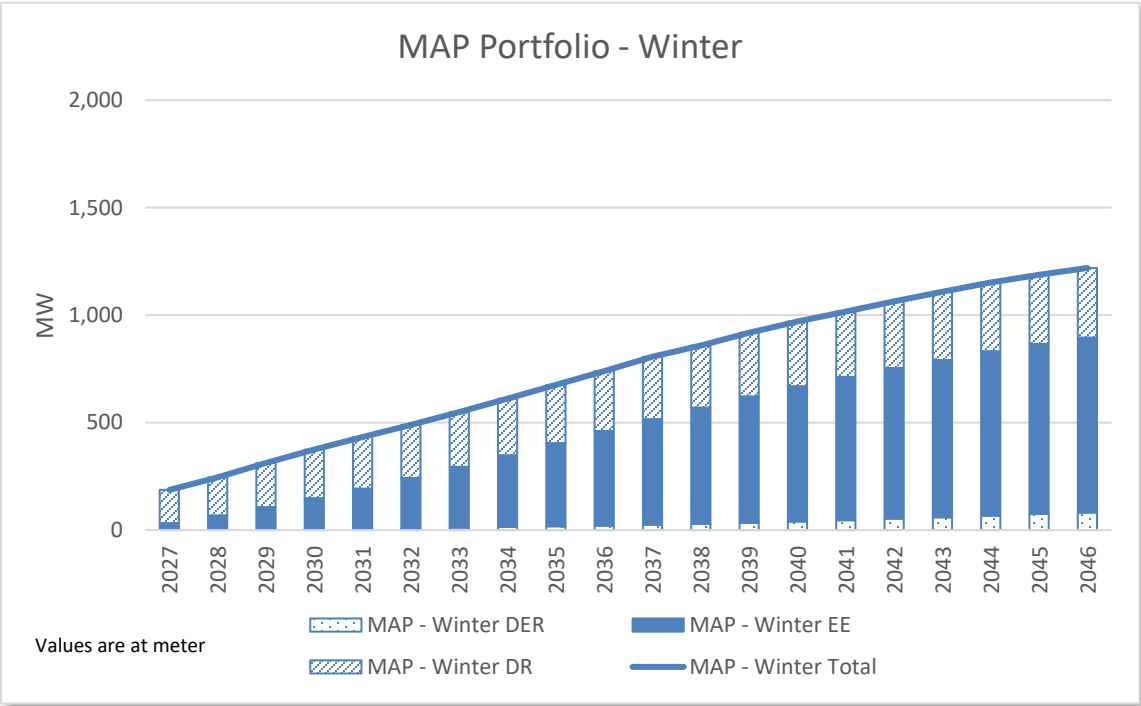


Figure 8.14: RAP Coincident Winter Peak Reduction Breakdown (MW)

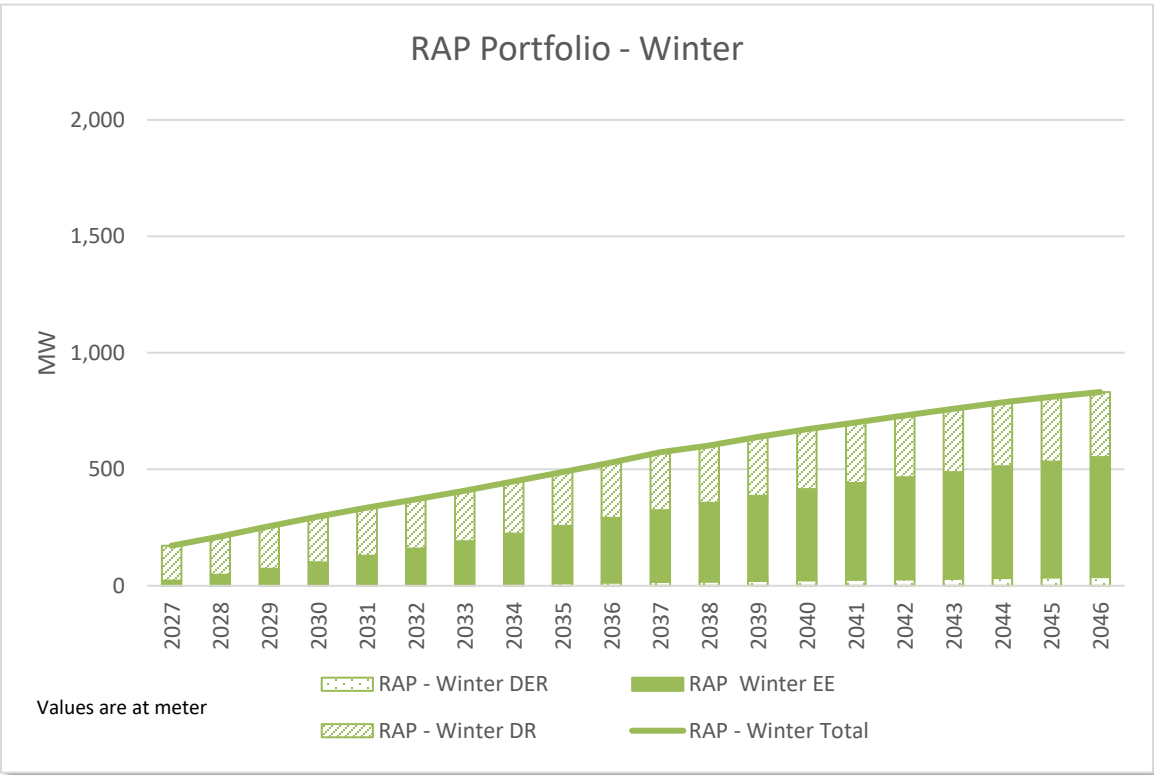


Figure 8.15: LTR Coincident Winter Peak Reduction Breakdown (MW)

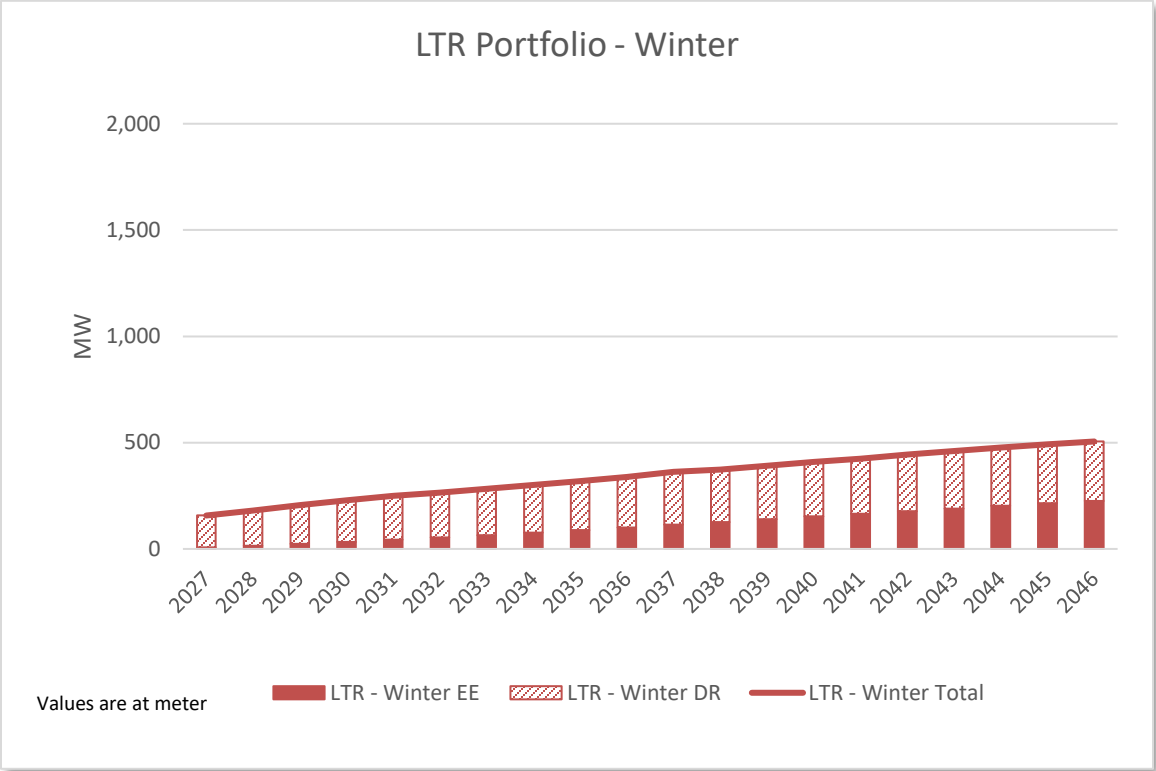


Figure 8.16: LTR +25 Coincident Winter Peak Reduction Breakdown (MW)

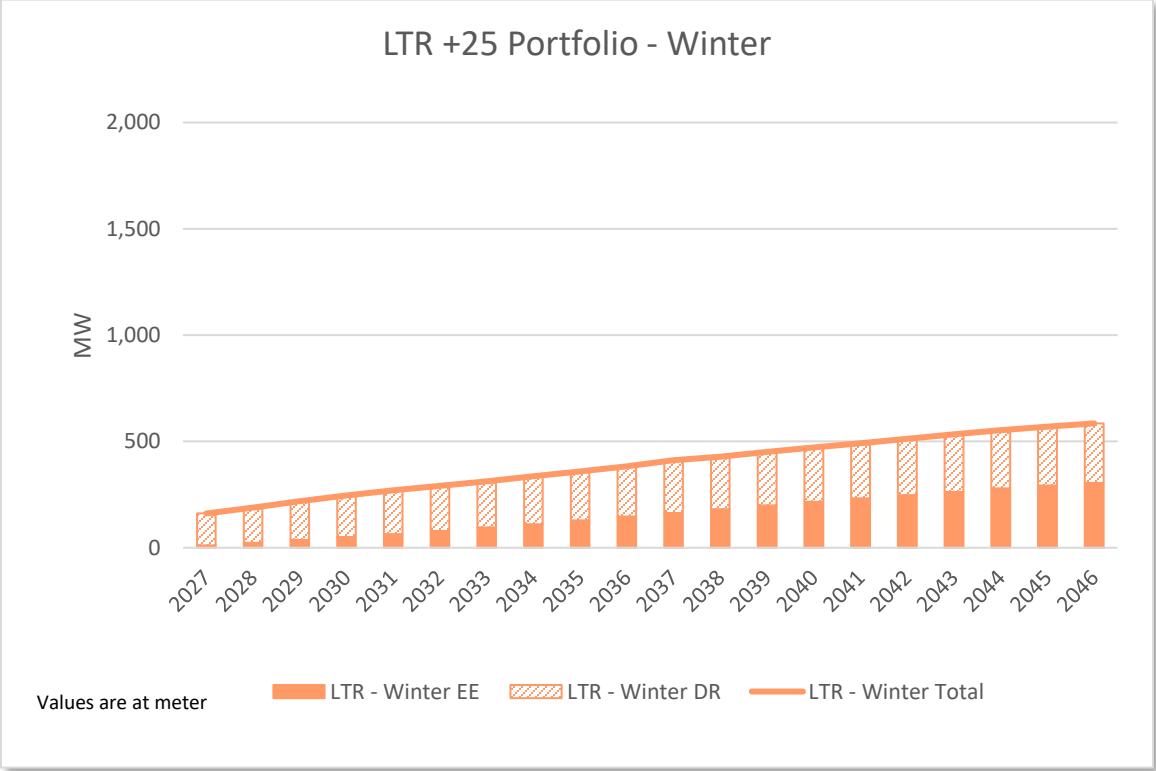


Figure 8.17: DSM Portfolio, Cumulative Annual Spring Demand Reduction (MW)

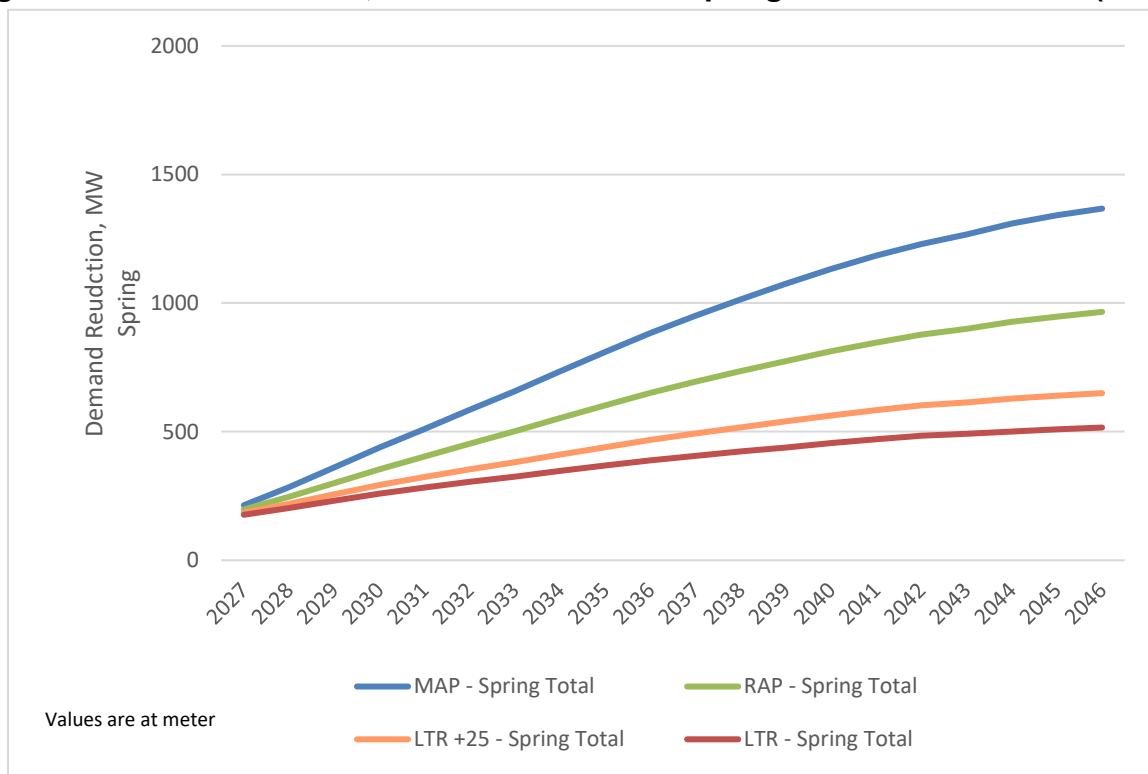


Figure 8.18: MAP Coincident Spring Peak Reduction Breakdown (MW)

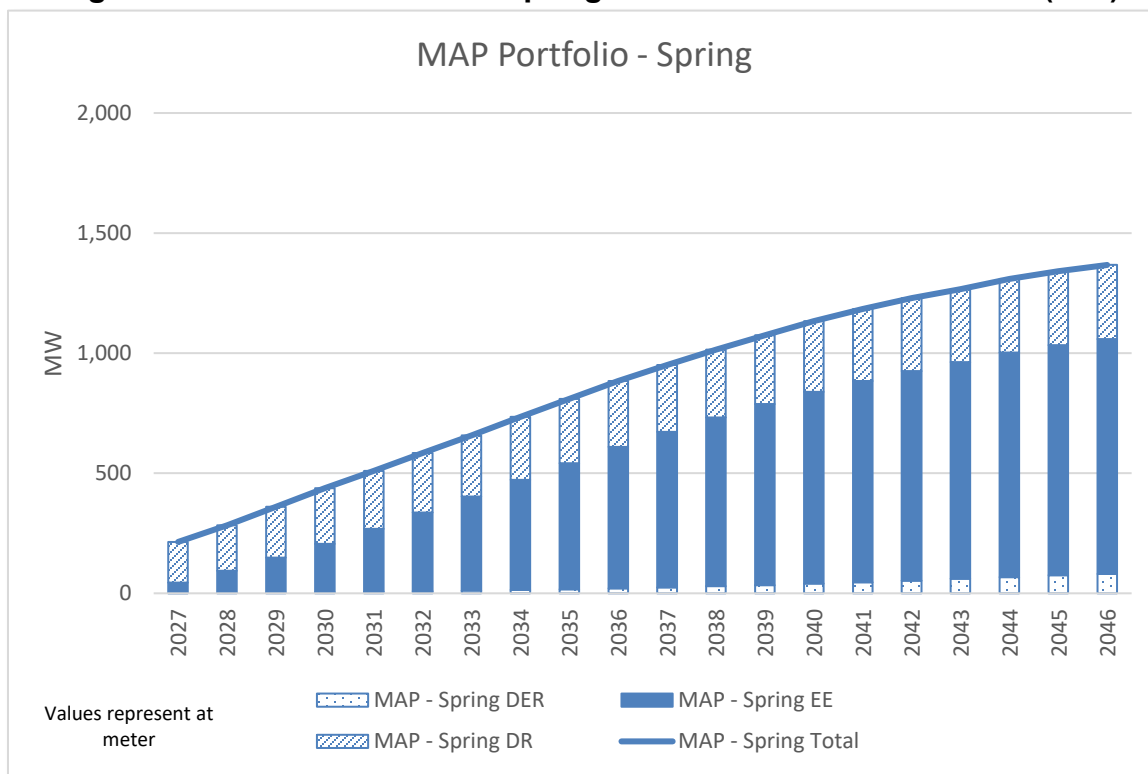


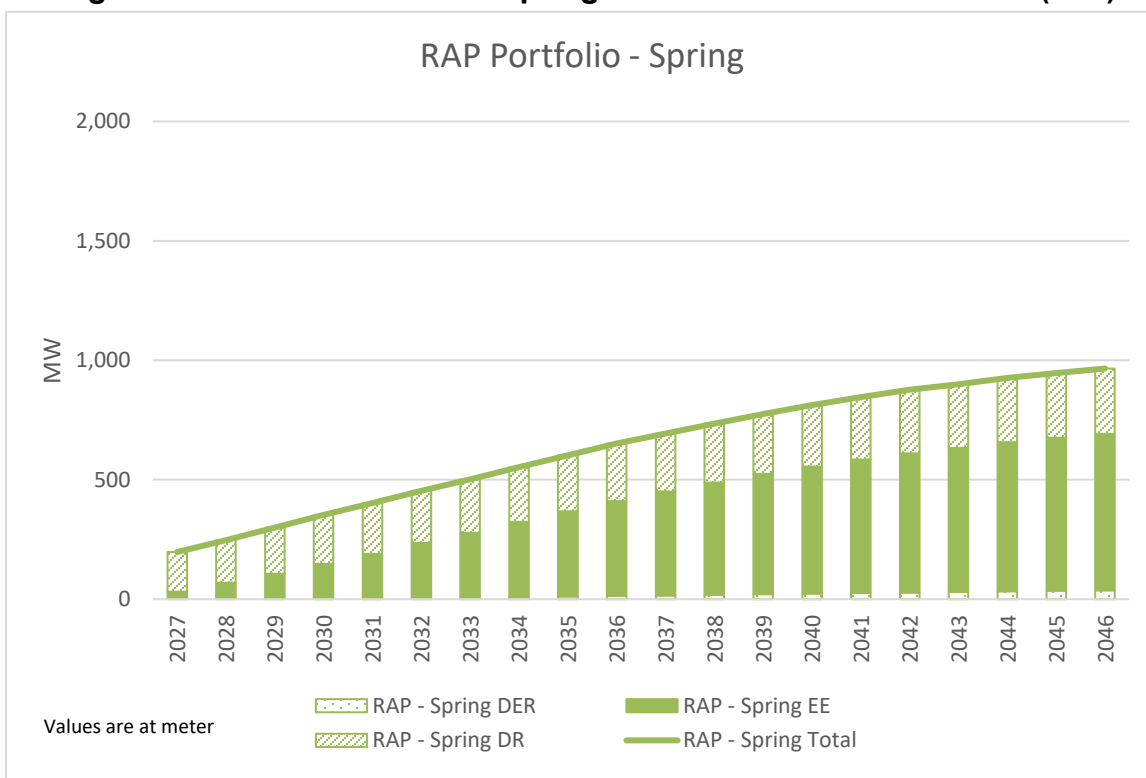
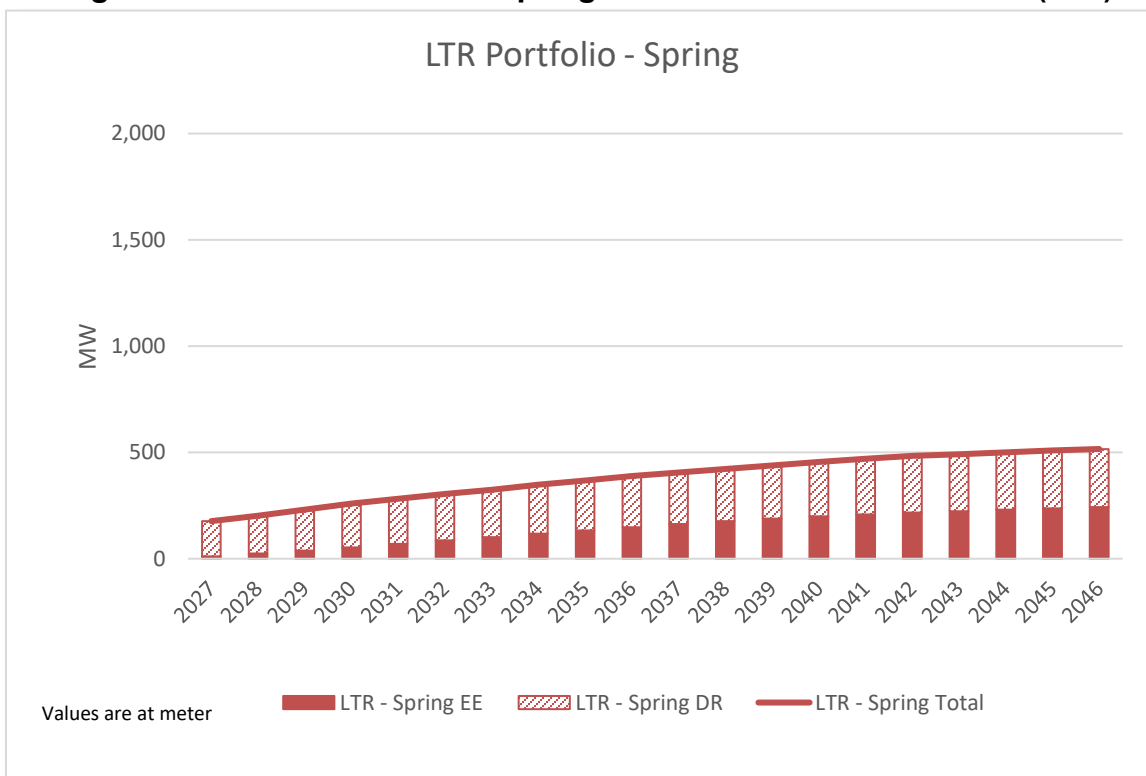
Figure 8.19: RAP Coincident Spring Peak Reduction Breakdown (MW)**Figure 8.20: LTR Coincident Spring Peak Reduction Breakdown (MW)**

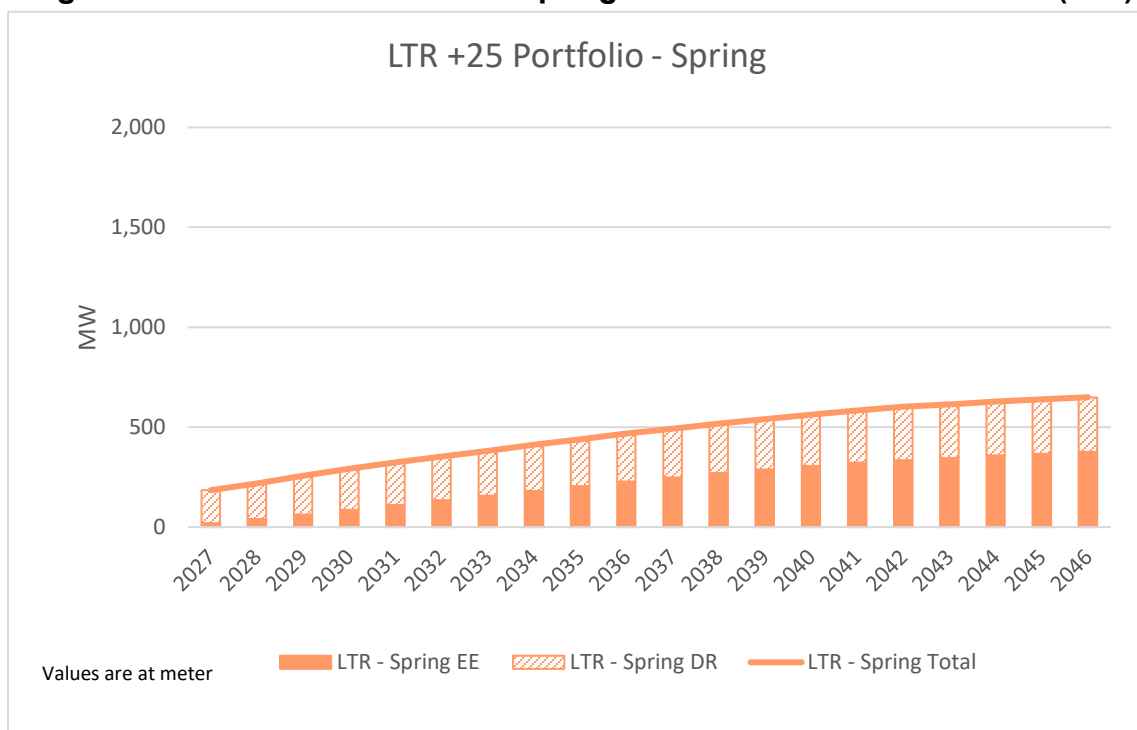
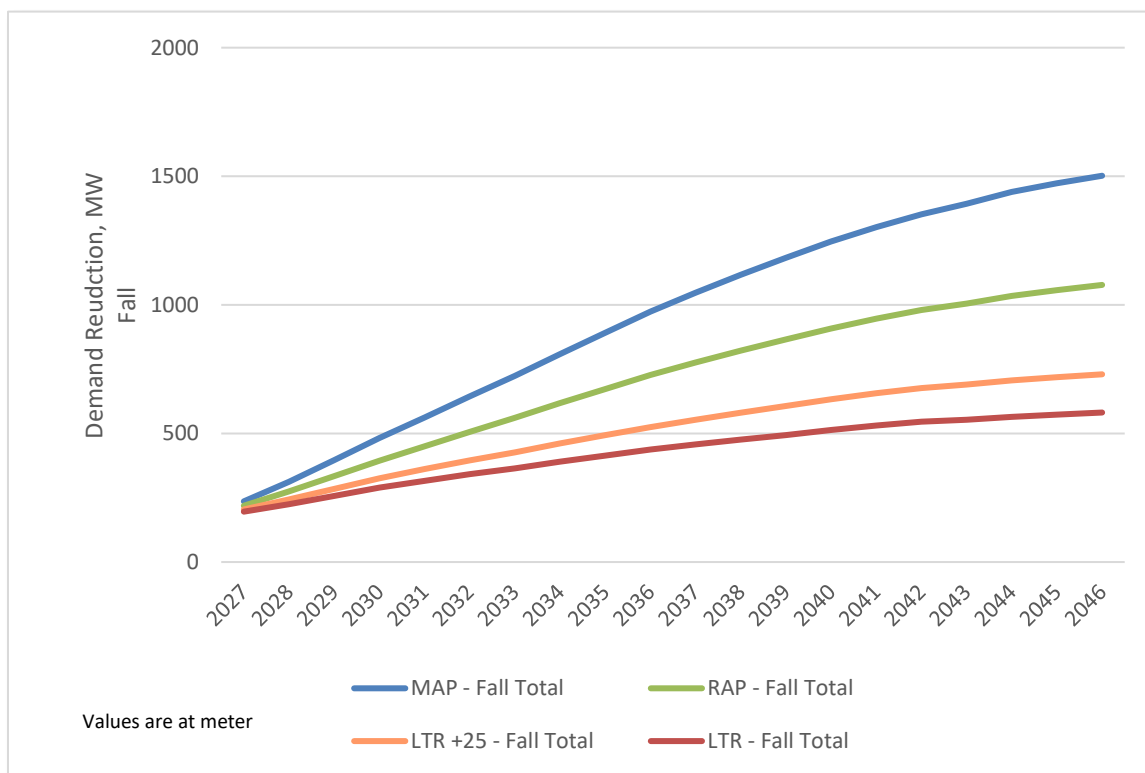
Figure 8.21: LTR+25 Coincident Spring Peak Reduction Breakdown (MW)**Figure 8.22: DSM Portfolio, Cumulative Annual Fall Demand Reduction (MW)**

Figure 8.23: MAP Coincident Fall Peak Reduction Breakdown (MW)

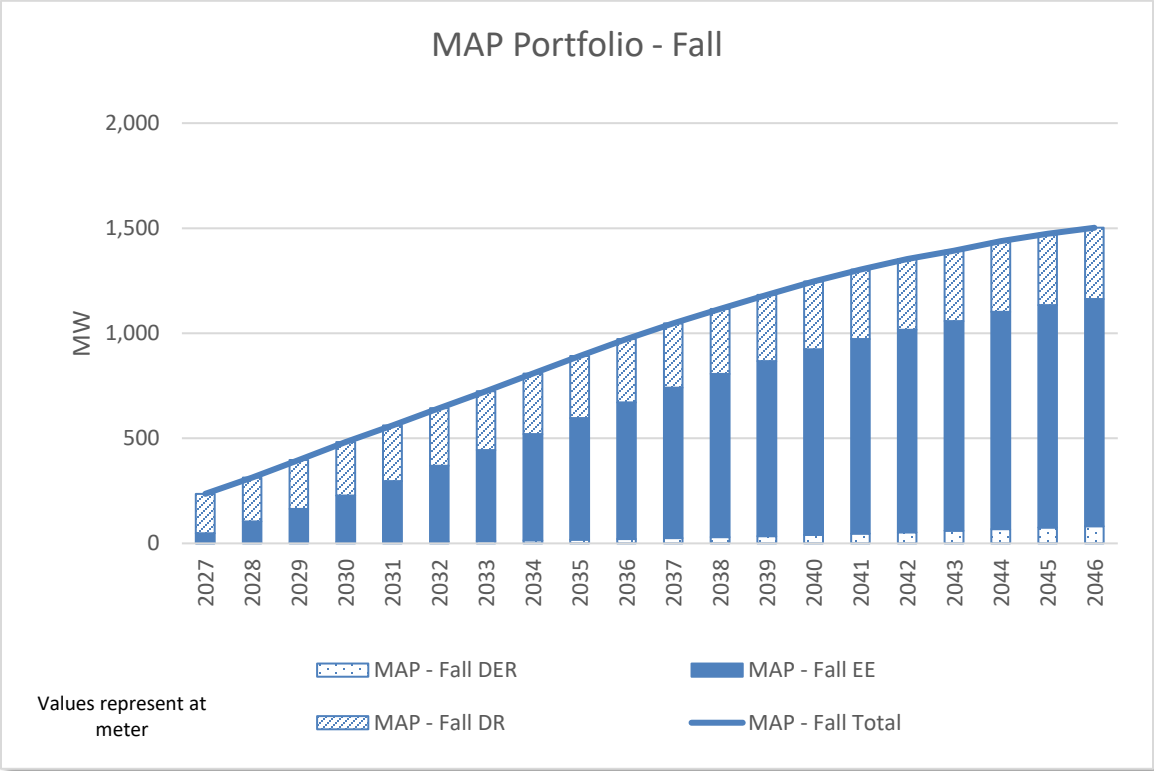


Figure 8.24: RAP Coincident Fall Peak Reduction Breakdown (MW)

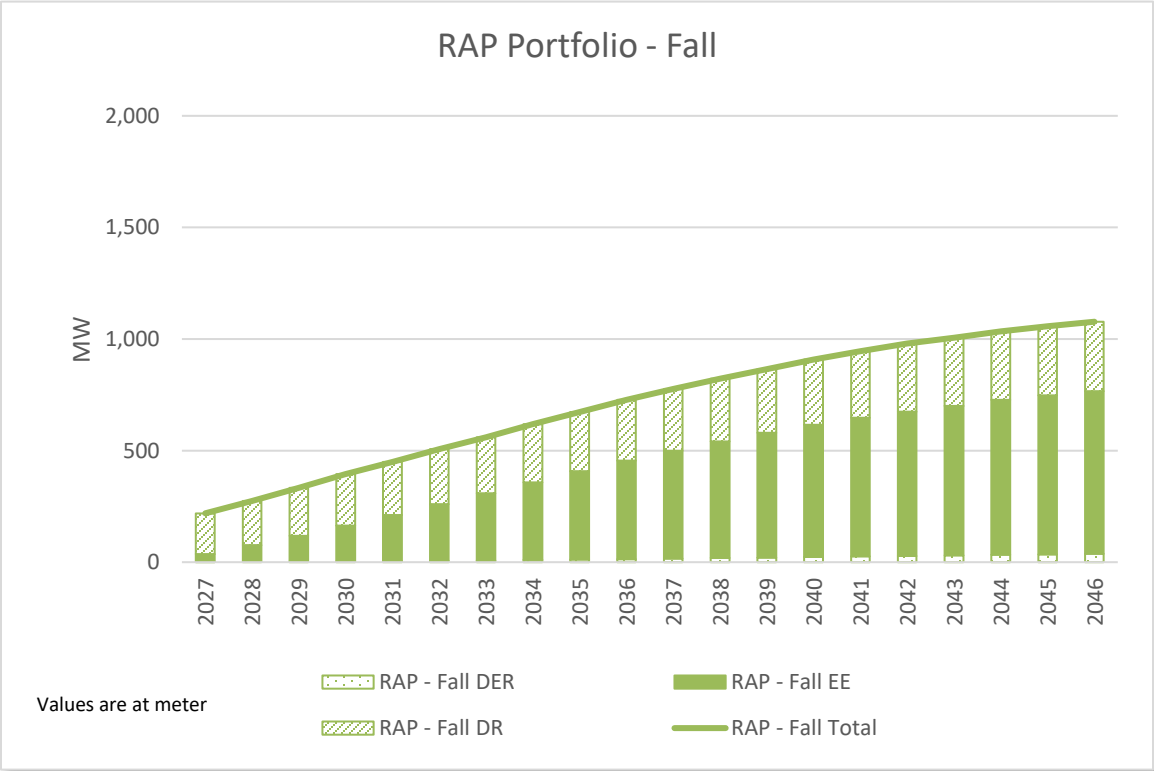


Figure 8.25: LTR Coincident Fall Peak Reduction Breakdown (MW)

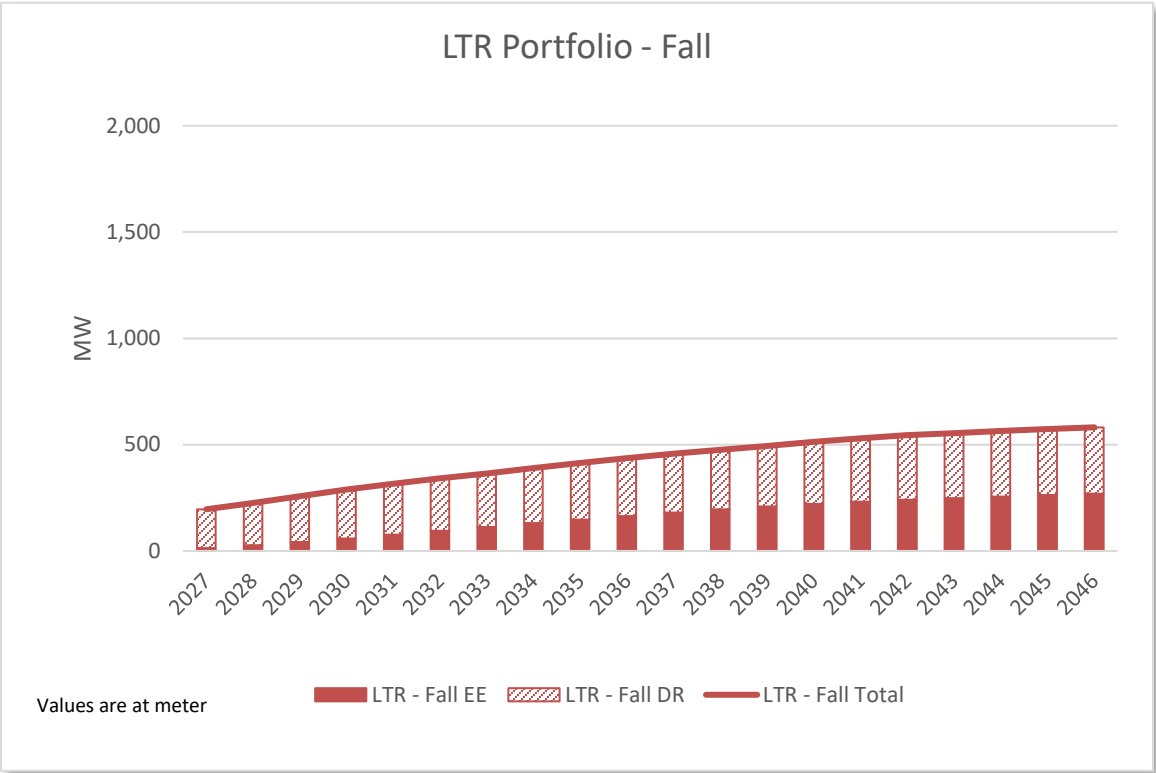


Figure 8.26: LTR +25 Coincident Fall Peak Reduction Breakdown (MW)

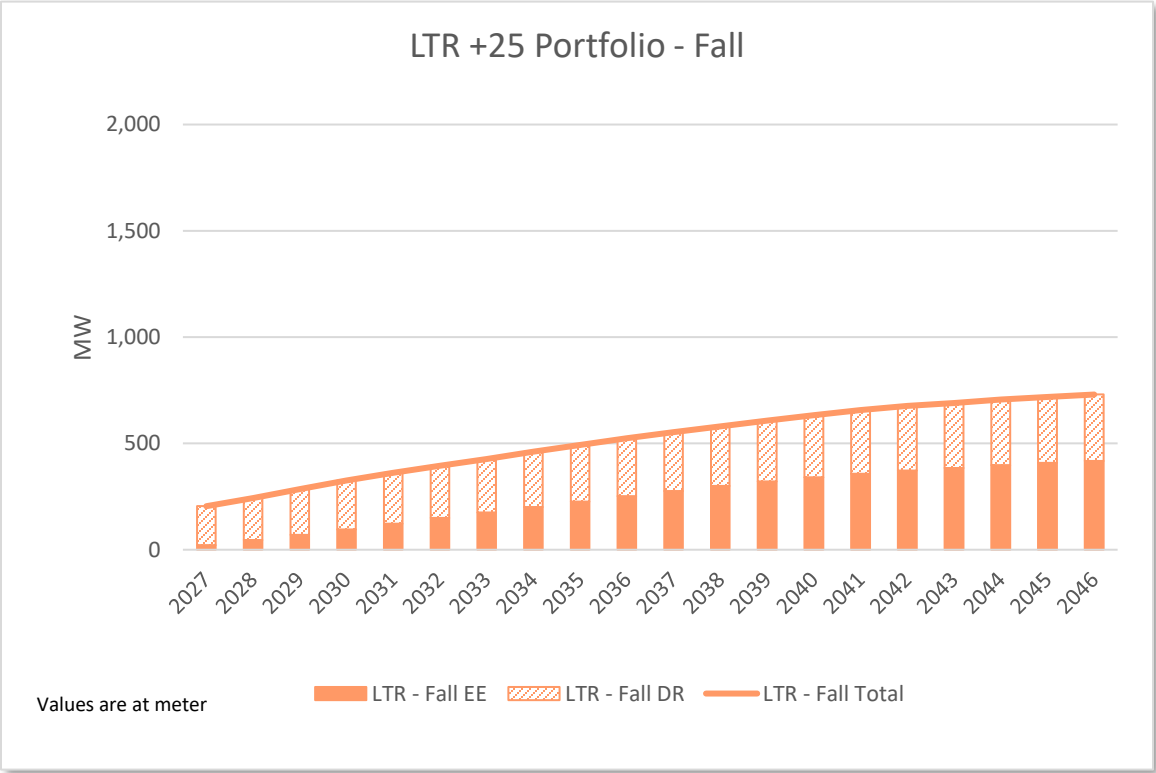
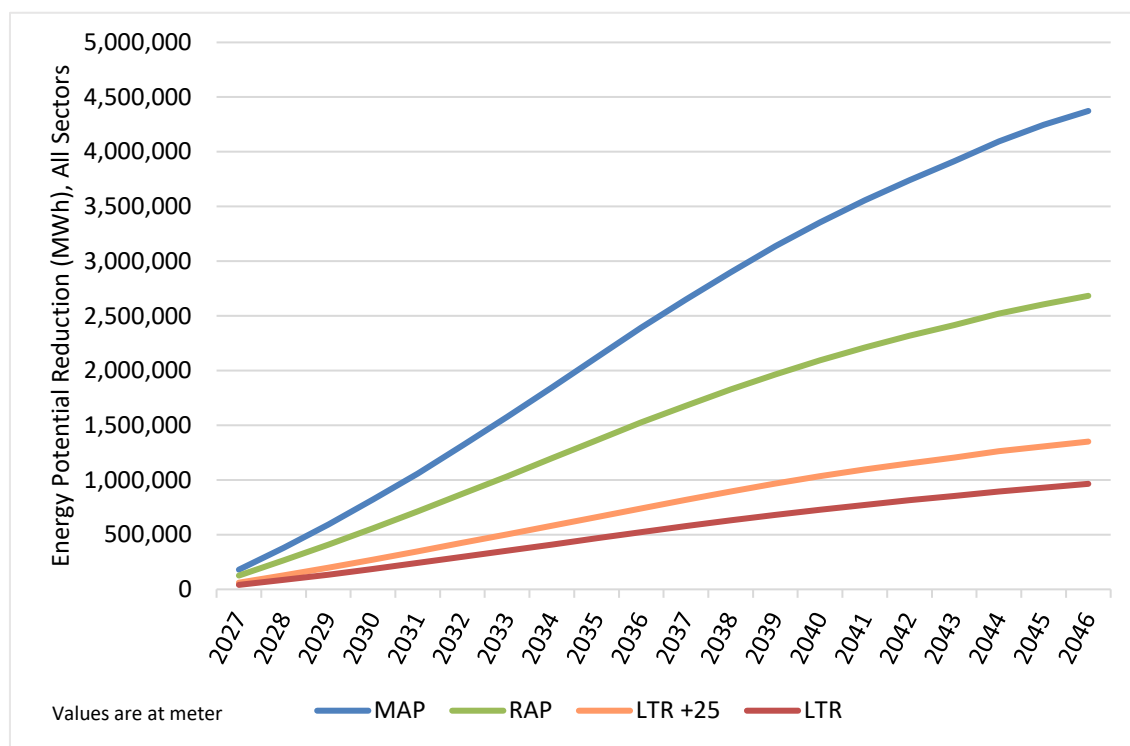
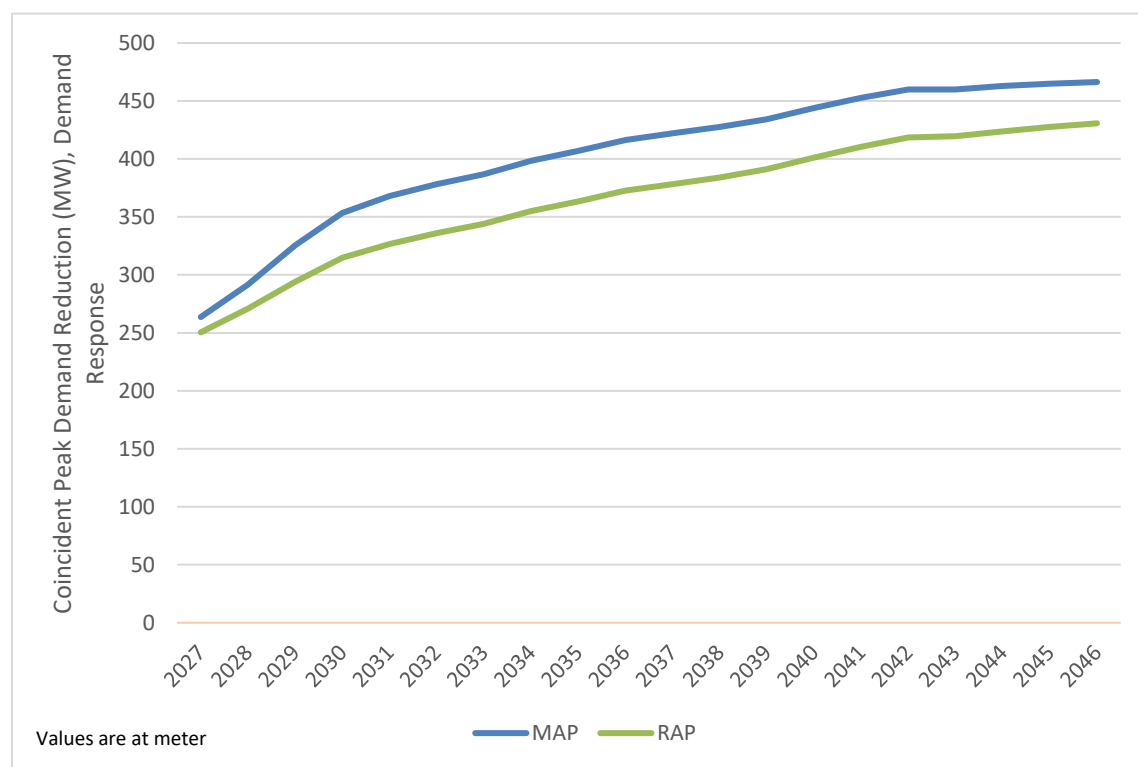


Figure 8.27: DSM Portfolio, Cumulative Annual Energy Potential (MWh)**Figure 8.28: Cumulative Annual Demand Response Savings (MW)**

8.3.3.2 External Benchmarking of Market Potential

As part of the review process, the energy efficiency and demand response MAP and RAP estimates presented above were benchmarked against other potential studies. This comparison was performed on a "peer" group of like utilities in neighboring states.²⁴

There is a broader industry shift away from traditional long-term (10–20 year) technical and economic potential studies toward shorter, program-focused analyses that emphasize achievable savings over utility planning horizons, typically 4–6 years. This evolution, along with differences in study methodologies, reporting conventions, and policy frameworks, limits direct comparability across studies; therefore, the benchmarking approach emphasized recent studies from comparable and neighboring utilities with sufficient transparency and focused on aligning similar achievable savings scenarios (e.g., MAP and RAP) to provide a more consistent and meaningful basis for comparison.

Table 8.5: Peer Benchmarking

Study / Year	Years in Study	Program Achievable Scenario Focus	Scenario Total Annual Impact (% of energy sales)	B/C Test
Ameren Missouri / 2026 ²⁵	20	2027-2032	0.2% LTR ²⁶ 0.7% RAP	TRC
Ameren Illinois / 2024 ²⁷	20	2026-2029	0.5%	TRC
Arkansas Statewide / 2025	6	2027-2032	1.0%	TRC
ComEd (IL) / 2024	20	2026-2029	1.0%	TRC
AES-Indiana (IN) / 2025	19	2027-2032	1.1%	UCT
Focus on Energy (WI) / 2025	6	2027-2032	0.7%	TRC
Iowa Statewide / 2022	5	2024-2028	0.4%	SCT
Michigan Statewide / 2025	20	2026-2029	2.2%	UCT
Pennsylvania Statewide (PA) / 2024	5	2026-2030	0.4%	TRC
Eversource (MO) / 2023	20	2024-2029	0.3%	TRC

²⁴ See section 7.3 of the 2026 MPS for a detailed discussion of benchmarking against peer utilities.

²⁵ Ameren Missouri's study covers 20 years. For purposes of making comparisons to the other studies, GDS selected a six-year period in which to compare average annual impacts. The Scenario Total Annual Impacts reflects the portfolio level of impact of energy efficiency from the "less than RAP" scenario on eligible energy sales, averaged over the six-year period.

²⁶ The "less than RAP" (LTR) scenario limits measures to those in the Ameren Missouri approved MEEIA plan. The RAP scenario includes those savings and additional cost-effective savings beyond the LTR scenario. Both are relevant for making comparisons to other studies.

²⁷ In the Illinois study (including ComEd), electrification provides a portion of the electric potential. Electric utilities are able to claim a policy-limited amount within their portfolio, with savings calculated on an equivalent MWh basis as derived from therm savings at the site level.

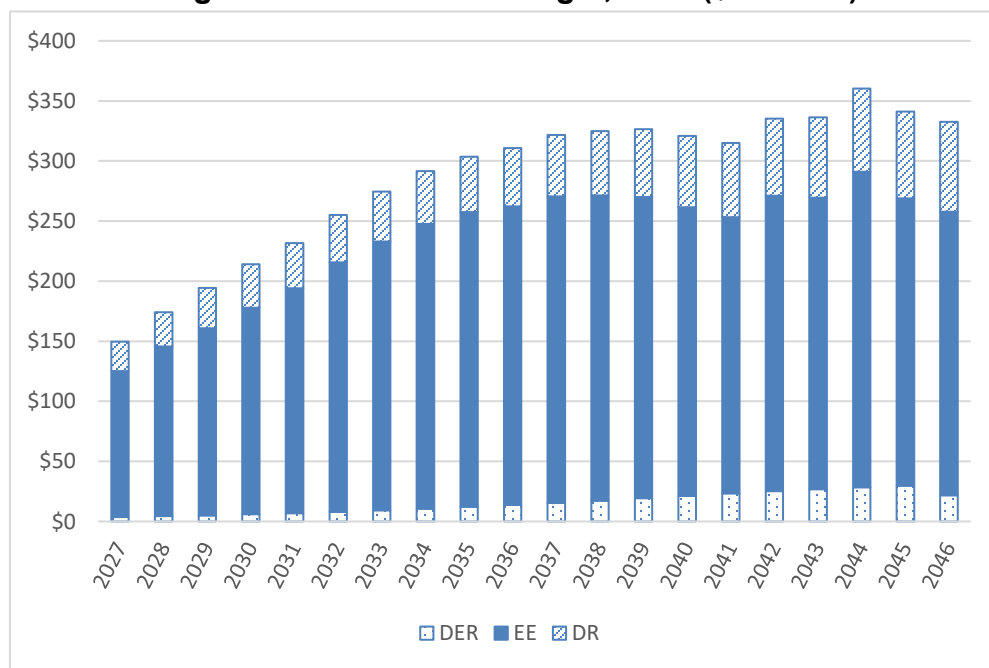
8.3.4 Portfolio MAP, RAP, LTR, LTR +25 Costs²⁸

As described above, the study assessed both incentive and non-incentive costs. MAP and RAP differ primarily in the level of incentives offered to customers. Under a MAP scenario, incentives are assumed to cover the full incremental cost of the measure. In contrast, the RAP, LTR, and LTR +25 scenarios assume that incentives are available for a portion of the incremental costs, based on historical program implementation. The greater incentive in the MAP case drives greater adoption of potential (as illustrated above) and also results in a greater total budget.

Incremental measure costs and utility incentives were held constant in nominal dollars, based on a review of external TRM data. This implies that the incremental cost of energy efficiency measures will narrow, in real terms, over the study period. In contrast, the study assumes that administrative costs will increase at half of the forecasted inflation rate, reflecting potential operational efficiency gains offsetting cost of living and labor adjustments.

Figure 8.29 shows the projected annual budget for the MAP portfolio, Figure 8.30 shows the projected annual budget for the RAP portfolio and Figures 8.31 & 8.32 show the projected annual budget for the LTR and LTR +25 portfolios. All costs are expressed in nominal terms.

Figure 8.29: Portfolio Budget, MAP (\$Millions)



²⁸ 20 CSR 4240-22.050(3)(G)4; 20 CSR 4240-22.050(3)(G)5A-F

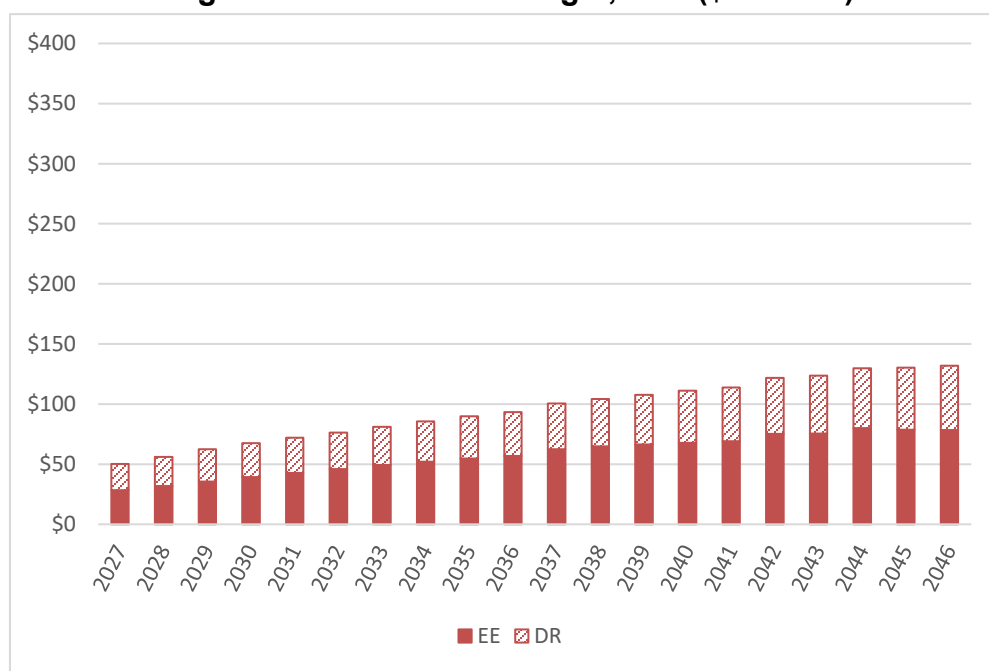
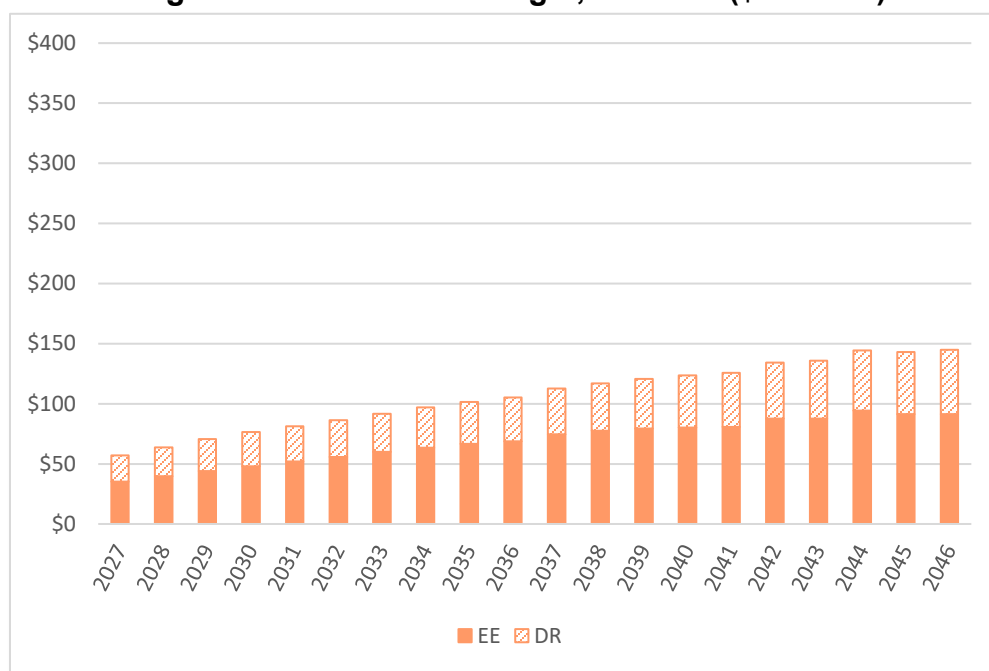
Figure 8.30: Portfolio Budget, RAP (\$Millions)**Figure 8.31: Portfolio Budget, LTR (\$Millions)**

Figure 8.32: Portfolio Budget, LTR +25 (\$Millions)

8.4 DSM Potential Uncertainty

8.4.1 Risk and Uncertainty Analysis²⁹

In addition to the development of a base case for program MAP/RAP/LTR/LTR +25 potential, sensitivity analyses were performed surrounding several key assumptions in the study. The final set of sensitivities were ultimately the product of stakeholder discussions. In general, candidates for the sensitivity analysis were related to two overarching themes, factors which concern uncertainty of customer participation and/or cost-effectiveness.³⁰ These themes 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 uncertainty analysis was analyzed for MAP, RAP, LTR, and LTR +25 scenarios.³¹ The 2026 MPS developed a robust scenario analysis, covering a wide array of potential factors and uncertainties. Some scenarios assess both a higher and lower impact, while other scenarios assess uncertainty in only one direction. Scenarios for the residential and business sectors include:

²⁹ 20 CSR 4240-22.050(6)(C)

³⁰ 20 CSR 4240-22.050(6)(C); 20 CSR 4240-22.050(6)(C)1; 20 CSR 4240-22.050(6)(C)2

³¹ 20 CSR 4240-22.050(6)(C)1 through 2

- **Avoided Costs (EE, DR, DER):** Avoided costs represent the primary benefit within the TRC, and higher/lower avoided costs will lead to greater/lesser potential. Included four sensitivities for a) an increase in avoided energy and capacity costs of +35%/-25% and b) change in T&D costs by 200%/\$0, with no change in avoided energy and capacity and c) 2026 IRP vintage energy and capacity costs, with no change to avoided T&D costs to analyze impacts compared to results with using the avoided costs available at study inception and finally d) a change in T&D costs by 500% for just the DER program as a proxy for potential locational value.
- **Prolonged Economic Downturn (EE, DR):** Economic factors were held constant in the load forecast resulting in a negative impact on future energy sales. Adoption rates were reduced to reflect concern over financial barriers a) Residential: 17% decrease to forecast and adoption levels; b) Commercial: 5% decrease to forecast and adoption levels; c) Industrial: 2% decrease to forecast and adoption levels.
- **Net-to-gross (NTG) Uncertainty (EE):** The NTG ratio identifies the fraction of program participants who would not have purchased the energy efficient measures in the absence of a program. For the Program RAP reference case, the NTG ratios assigned to each measure/end-use/program were based on the latest evaluated DSM programs for MEEIA Cycle 3. However, changes to DSM measure mixes, costs, savings, program delivery methods, market forces, and other factors can significantly impact future NTG ratios +15%/-30%.
- **High Touch Marketing (EE, DR):** Assume additional marketing raises program awareness and reduces non-financial barriers to adoption³².
- **Large Customer Opt-Out (EE, DER):** Estimates potential, both including and excluding all eligible opt-out customers in the analysis, for both a higher and lower estimate of business potential.
- **Volatile Weather (EE):** Impact of increasing Heating Degree Days (+25%) and Cooling Degree Days (+25%), impacting measure savings and cost-effectiveness.
- **Improved Technology Savings/Costs (EE):** Assume a 35% decrease in emerging technology/high tier equipment costs and incentives over the study horizon. For all other measures, reduced costs between 5%-20% based on current energy efficiency saturation assumptions.
- **HVAC Program Mapping (EE):** Enhances the adoption of HVAC measures in the early years of the study by re-mapping many of these measures from the PAYS program delivery channel to a more traditional HVAC program whereby contractors

³² 20 CSR 4240-22.070(8); 20 CSR 4240-22.050(7)

provide incentives to customers to purchase and install high efficiency heat pumps and air conditioners.

- **Additional Demand Response Rate Options (DR):** Includes rate programs not already included in the Base Case analysis.

Ameren Missouri used these 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.

Demand response was evaluated against a subset of these sensitivities but also included a specific scenario accounting for additional program options rate options with enabling technology and other emerging DR programs. It should be noted that although these subsectors are examined separately, their respective uncertainty probabilities are factored in with the overall section measuring the impact on savings and cost.

The Distributed Energy Resource analysis also differs from the main EE/DR uncertainty analysis. For DER, the study team examined sensitivities for both Combined Heat and Power and Photovoltaics. Sensitivities include higher and lower avoided energy costs, multiple sensitivities of higher and lower avoided Transmission and Distribution costs, reflecting locational value of DER, and inclusion of opt-out customers.

Also consistent with the prior study, the 2026 MPS analyzed scenarios as independent uncertainties. An overall risk assessment that incorporates these individual uncertainties is required for the risk analysis of various alternative resource plans. It is impractical to try to assess the various interactive codependences of the individual uncertainties so as a simplification, Ameren Missouri again developed subjective weights for each scenario and combined these weights into an overall weighted risk assessment. Tables 8.6 - 8.9 provide the MAP, RAP, LTR and LTR +25 sensitivities with high and low results for budget and energy (MWh).

Table 8.6: MAP Portfolio Sensitivities, Energy Reduction (MWh) & Budget

Sensitivity Scenario	20-yr MWh	20-yr Budget (\$ Millions)
Base Program MAP	3,844,193	\$4,396
Avoided Cost #1		
<i>High</i>	3,976,305	\$4,886
<i>Low</i>	3,699,788	\$4,020
Avoided Cost #2		
<i>High</i>	3,905,135	\$4,600
<i>Low</i>	3,798,434	\$4,264
Avoided Cost #3	3,750,608	\$4,167
Prolonged Downturn	3,292,379	\$3,692
NTG Attribution		
<i>High</i>	4,474,590	\$4,498
<i>Low</i>	2,628,087	\$4,219
High-Touch Marketing	3,844,193	\$4,673
Opt-Out		
<i>High</i>	4,445,937	\$4,902
<i>Low</i>	3,721,855	\$4,288
Volatile Weather	4,417,032	\$4,974
Technology Cost	4,288,210	\$4,741
HVAC Program Mapping	3,819,048	\$4,105

Table 8.7: RAP Portfolio Sensitivities, Energy Reduction (MWh) & Budget

Sensitivity Scenario	20-yr MWh	20-yr Budget (\$ Millions)
Base Program RAP	2,436,124	\$1,964
Avoided Cost #1		
<i>High</i>	2,504,050	\$2,091
<i>Low</i>	2,344,604	\$1,895
Avoided Cost #2		
<i>High</i>	2,456,817	\$1,989
<i>Low</i>	2,409,750	\$1,964
Avoided Cost #3	2,365,931	\$1,951
Prolonged Downturn	2,127,831	\$1,652
NTG Attribution		
<i>High</i>	2,859,301	\$2,039
<i>Low</i>	1,639,040	\$1,831
High-Touch Marketing	2,731,668	\$2,383
Opt-Out		
<i>High</i>	2,793,587	\$2,136
<i>Low</i>	2,363,573	\$1,928
Volatile Weather	2,802,923	\$2,168
Technology Cost	3,004,892	\$2,766
HVAC Program Mapping	2,364,032	\$1,598

Table 8.8: LTR Portfolio Sensitivities, Energy Reduction (MWh) & Budget

Sensitivity Scenario	20-yr MWh	20-yr Budget (\$ Millions)
Base Program RAP	964,587	\$1,155
Avoided Cost #1		
<i>High</i>	952,855	\$1,093
<i>Low</i>	981,131	\$1,219
Avoided Cost #2		
<i>High</i>	952,897	\$1,094
<i>Low</i>	979,588	\$1,224
Avoided Cost #3	953,143	\$1,093
Prolonged Downturn	809,277	\$947
NTG Attribution		
<i>High</i>	1,135,094	\$1,215
<i>Low</i>	646,932	\$1,055
High-Touch Marketing	1,101,626	\$1,396
Opt-Out		
<i>High</i>	1,045,660	\$1,205
<i>Low</i>	947,961	\$1,144
Volatile Weather	1,103,235	\$1,147
Technology Cost	1,125,658	\$940
HVAC Program Mapping	893,110	\$790

Table 8.9: LTR +25 Portfolio Sensitivities, Energy Reduction (MWh) and Budget

Sensitivity Scenario	20-yr MWh	20-yr Budget (\$ Millions)
Base Program MAP	1,350,758	\$1,379
Avoided Cost #1		
<i>High</i>	1,365,589	\$1,369
<i>Low</i>	1,329,258	\$1,405
Avoided Cost #2		
<i>High</i>	1,351,738	\$1,342
<i>Low</i>	1,345,768	\$1,426
Avoided Cost #3	1,329,301	\$1,330
Prolonged Downturn	1,149,530	\$1,142
NTG Attribution		
<i>High</i>	1,590,200	\$1,444
<i>Low</i>	904,167	\$1,268
High-Touch Marketing	1,526,347	\$1,666
Opt-Out		
<i>High</i>	1,496,250	\$1,460
<i>Low</i>	1,320,928	\$1,361
Volatile Weather	1,556,254	\$1,426
Technology Cost	1,617,113	\$1,450
HVAC Program Mapping	1,279,106	\$1,013

8.4.2 Managing Uncertainty During Implementation

Ameren Missouri manages uncertainty regarding program implementation through multiple channels and processes. Two important processes include the annual EM&V and continuous efforts regarding ongoing outreach, marketing, and communication.

8.4.2.1 Evaluation, Measurement, and Verification

Ameren Missouri continues to work with the independent evaluation contractor to apply national best practices to the EM&V of its programs. A single evaluator is typically under contract for the Residential and Business portfolios. As part of MEEIA 4, the Commission hired the independent evaluator to assess and report on the work of Ameren Missouri's MEEIA portfolio, to be overseen by the Commission Staff (in addition to the MEEIA portfolios from other Missouri Investor-Owned Utilities).

A key purpose of EM&V is to help drive continuous improvement in programs to the benefit of customers. In this sense, EM&V is best thought of as the first and continuous step in the implementation plan and cycle, as opposed to the last step. In this manner, EM&V helps identify necessary program changes on an annual basis, partly in response to any identified uncertainties that arise within a given program year. Given any level of DSM budget and resources, Ameren Missouri and its stakeholders decide how much of that budget to invest in implementation of programs and how much to invest in EM&V.

There are two main components to any effective evaluation: process and impact. To complete these important studies, Ameren Missouri and Commission Staff coordinate with the evaluation contractor to develop and implement the necessary protocols, methodologies, and technology to gather the appropriate data necessary for review.³³

Process evaluations provide a detailed, holistic assessment of how programs are being delivered relative to the underlying program theory logic regarding how utility interaction in the market will drive meaningful change. Process evaluations provide important insights into the relationships and interactions between Ameren Missouri program staff, implementation administrators, trade ally and contractor networks, and the customer. Process evaluations identify any necessary program changes to ensure an efficient and effective delivery of services.³⁴

The impact evaluation helps measure and verify energy and demand savings.³⁵ Within the impact evaluation, savings are classified as ex ante gross (original forecast), the ex post gross (based on the mix of measures actually installed), and the ex post net savings (the fraction of ex post gross savings that would not have occurred but for the utility investment). Ameren Missouri has developed, in coordination with the evaluation and implementation contractors, the necessary methods to estimate load impacts of the

³³ 20 CSR 4240-22.070(8); 20 CSR 4240-22.050(7)

³⁴ 20 CSR 4240-22.070(8)(A); 20 CSR 4240-22.050(7)

³⁵ 20 CSR 4240-22.050(8)(B)

energy efficiency programs offered by the Company. The impact evaluation estimates of gross program savings typically include engineering analysis and formulas, building simulation models, meter data, statistical models, and billing analysis. For low-income programs, the evaluation also includes an analysis of how the program affects bill payments, arrearages, and disconnections.

Ex post net savings are necessary to evaluate the total cost effectiveness of programs. However, net savings represent only one input, and only one source of uncertainty, in a cost-effective analysis. Net savings for many programs can be determined through detailed and resource intensive participant surveys, with the total outreach designed to meet given confidence and precision levels. Participant surveys are used to develop a net to gross ratio, or the fraction of savings that are attributable to the utility program. This can be based on the impact program rebates and/or information from the program on the availability of tax credits and other federal, state, or manufacturer rebates and the benefits of installing efficient equipment had on the customer's decision to install qualifying equipment. In addition to the actual program implementation, this ratio can vary year to year, based on the survey design and methodology employed, assumptions used to aggregate results, the attitudes and makeup of the sample population, and other methodological factors. Given the time and resources to develop these estimates, recent Ameren EM&V plans have "deemed" or carried forward net to gross factors for programs into future program years.

8.4.2.2 Outreach, Marketing and Communications³⁶

Developing and executing a comprehensive marketing communications plan is essential to reaching the residential and business energy efficiency goals and represents one of the key strategies used to help mitigate annual uncertainty in implementation plans. Executing a mix of broad and targeted marketing simultaneously with a consistent message creates repetitive exposure which drives awareness 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 Regional Account Executives. 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 a combination of internal and external activities.

Both the business and residential programs also leverage Trade Allies to communicate incentives to customers. Both broad and targeted multi-media advertisements are used

³⁶ 20 CSR 4240-22.050(3)(E)

to drive awareness of programs and incentives. Residential income eligible programs utilize a community approach by building partnerships with organizations that have already established communication and trust with the targeted customer segment.

To provide an array of avenues through which customers can take advantage of programs, Ameren Missouri employs multiple approaches. To name a few, traditional rebates (BizSavers), online discounts (Efficient Products) and direct installation (income-eligible, Peak Time Savings, Business Social Services) options all provide multiple access points to the same end use measures.

8.5 Additional Detail by Study Sector

This section provides additional detail on the Demand Response (DR) and DER study components of the 2026 MPS.

8.5.1 Foreseeable Demand Response Technologies, including Demand-Side Rate Potential³⁷

8.5.1.1 Overview

The deployment of AMI, smart thermostats, managed EV charging, and flexible rate designs create opportunities for demand response to serve an expanding role in system reliability and resource adequacy. The 2026 MPS identified an additional 86 MW (336 MW total) over the next 6 years of summer peak demand MW from measure implementation (base case). Over the next 20 years there is a base case potential of about an additional 170 MW. Peak demand reduction from rate sensitivities create the potential for 221 MW more. Over the 20 years, the other DR sensitivities had the potential to adjust the forecast down as low as 22 MW less and as high as 52 MW greater. The total DR potential identified in the 2026 MPS is driven by several factors, including the addition of new measures based on foreseeable technologies, additional rate offerings, and specific market research regarding likely customer adoption.³⁸

Within the 2026 MPS, demand response is defined consistently with applicable FERC rules as:³⁹

"[C]hanges in electric usage by demand-side resources from their normal consumption patterns in response to change the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized."

³⁷ 20 CSR 4240-22.050(1)(C); 20 CSR 4240-22.050(3); 20 CSR 4240-22.050(4)

³⁸ 20 CSR 4240-22.050(1)(E); 20 CSR 4240-22.050(1)(E)1; 20 CSR 4240-22.050(1)(E)2

³⁹ 20 CSR 4240-22.050(4)(F)

Under this broad definition, demand response creates a reduction in usage during coincident peak. This can be due to a reduction in overall load or due to the shifting of load to later periods.

Further, the Midcontinent Independent System Operator (MISO) defines demand response as the ability of a Market Participant to reduce its electric consumption in response to an instruction received from MISO. Market Participants can provide such demand response either with discretely interruptible or continuously controllable loads or with behind-the-meter generation. In short, resources must be dispatchable and measurable. Demand response rate options such as Time of Use (TOU) or Critical Peak Pricing (CPP) don't meet these requirements. However, these rates can provide value for Ameren Missouri if they lower their peak demand requirements. That reduction in peak load can translate into lower capacity requirements.

The study also explicitly accounted for the interactive effects of energy efficient measures and programs, demand response measures, and demand side rates. The study applied a hierarchical approach to ensure that savings were not duplicated between programs or for programs that seek to influence customers through similar channels.⁴⁰

8.5.1.2 Foreseeable Demand Response Measures and Technologies

Table 8.10 provides a brief description of the demand response program options considered and identifies the eligible customer segment for each demand response program that was considered in this study for base case analysis⁴¹. This includes direct load control, rate design, and aggregator options. The program option list largely follows the same categories included in the 2023 MPS.

Table 8.10: Demand Response Options, Base Case 2026 MPS

Demand Response Program Option	Program Description	Eligible Markets
DLC Thermostat	The system operator can remotely change the HVAC's thermostat set point during peak load conditions, lowering HVAC load.	Residential and C&I Customers ⁴²
DLC Water Heater Switch	The water heater is remotely shut off by the system operator for periods normally ranging from 2 to 8 hours.	Residential and C&I Customers

⁴⁰ 20 CSR 4240-22.050(4)(D)2; 20 CSR 4240-22.050(4)(D)3; 20 CSR 4240-22.050(3)(G)2

⁴¹ 20 CSR 4240-22.050(1)(C); 20 CSR 4240-22.050(3)(A); 20 CSR 4240-22.050(4)(B)

⁴² This program has large amount for potential for both residential and business customers. However, only the program for business customers is cost-effective based on the most currently available estimates of per customer load reduction. The residential program is not cost-effective based on the most currently available evaluation results. However, changes to future program guidelines could lead to the program becoming cost-effective.

Demand Response Program Option	Program Description	Eligible Markets
DLC Grid-Enabled Water Heaters	The grid-enabled water heater is equipped with a smart controller that allows the utility to remotely shut off the water heater for periods normally ranging from 2 to 4 hours.	Residential and C&I Customers
DLC Room Air Conditioning	The compressor of the room air conditioner is remotely shut off (cycled) by the system operator for periods that may range from 7 ½ to 15 minutes during every 30-minute period (i.e., 25%-50% duty cycle). Controlled via load control switch. Participants cannot override control.	Residential Customers
DLC Pool Pumps	The swimming pool pump is remotely shut off by the system operator for periods normally ranging from 2 to 4 hours.	Residential Customers
DLC Lighting	A portion of the lighting load (typically 25-33%) is remotely shut off by the system operator for periods normally ranging from 2 to 4 hours	C&I Customers
DLC Agricultural Irrigation	The irrigation pump is remotely shut off by the system operator for periods normally ranging from 2 to 4 hours.	Irrigated Farms
DLC Electric Vehicle	DLC of electric vehicles relies on communication (i.e., "dispatch") signals originating from a utility or aggregator and sent to a vehicle or charger to control charging in a predetermined manner. Can be events-based to control load during a limited number of events in a given time period (season or annually) or use continuous management to control load when the vehicle is connected to the charger.	Residential and C&I Customers
Time of Use Rates	A retail rate with different prices for usage during different blocks of time. Looked at Ameren Missouri's current four options: Evening/Morning Savers, Overnight Savers, Smart Savers, and Ultimate Savers.	Residential Customers

Demand Response Program Option	Program Description	Eligible Markets
Capacity Bidding ⁴³	Flexible bidding program offering qualified businesses payments for agreeing to reduce load when an event is called. Participants make monthly nominations and receive capacity payments based on the amount of capacity reduction nominated each month, plus energy payments based on actual kilowatt-hour (kWh) energy reduction when an event is called. The amount of capacity nomination can be adjusted on a monthly basis. The program can be Internet-based, providing ready access to program information and ease-of-use. Penalties occur if load nominations are not met. Not all load nominated is necessarily dispatched.	C&I Customers
Battery Storage ⁴⁴	Uses the battery to reduce a home or facility's demand during peak or DR event hours, without requiring the customer to curtail their power. Instead of turning off equipment, the battery discharges power to offset load—or shifts charging to off-peak periods—so the utility sees a drop in grid demand.	Residential and C&I Customers

8.5.1.3 Review of Demand Side Rate Sensitivities⁴⁵

Within the 2026 MPS, demand side rate options were assessed as an additional set of sensitivities to the base case described above. This included: Peak Time Rebate, Critical Peak Pricing, and Electric Vehicle TOU Rates.⁴⁶ The study further included additional TOU rate options for Business customers: Interruptible Rates, Thermal Storage Rates, and Golf Cart off-peak charging. Table 8.11 provides the MAP and RAP adoption levels for each customer sector, with and without enabling technology.⁴⁷ LTR and LTR +25 assume RAP level DR values.

⁴³ The Capacity Bidding program serves as a proxy for the examination of potential for third-party aggregators of retail customers (ARCs).

⁴⁴ The battery storage system was not found to be cost-effective via the TRC test.

⁴⁵ 20 CSR 4240-22.050(2); 20 CSR 4240-22.050(4)(A); 20 CSR 4240-22.050(4)(B)

⁴⁶ 20 CSR 4240-22.050(1)(C); 20 CSR 4240-22.050(4)(B); 20 CSR 4240-22.050(4)(D)

⁴⁷ 20 CSR 4240-22.050(4)(D); 20 CSR 4240-22.050(4)(D)(1); 20 CSR 4240-22.050(4)(D)(3); 20 CSR 4240-22.050(4)(D)(4); 20 CSR 4240-22.050(4)(D)(5)A through D; 20 CSR 4240-22.050(4)(G)

Table 8.11: Adoption Rates (MAP, RAP) by Rate Option with and without Enabling Technology

Sector	Program	Steady State MAP Adoption Rate	Steady State RAP Adoption Rate
Residential	Peak Time Rebate	20%	13%
	Critical Peak Pricing	20%	15%
	EV TOU Rate	28%	20%
C&I	TOU Rate	25%	16%
	Interruptible Rate	28%	19%
	Critical Peak Pricing	18%	15%
	TES Cooling Rate	2%	1%
	Golf Cart Charting Rate	25%	16%
	EV TOU Rate	28%	20%

TOU - Time of Use

8.5.1.4 Implementation of Demand Side Rates

The 2026 MPS considers the effort to install AMI meters to be complete. As such, the opportunity highlighted in the study is not limited by availability but rather a customer's willingness to participate.

To avoid double-counting potential and to account for the interactive effects between rates, the 2026 MPS assumed the hierarchy as shown in table 8.12.

Table 8.12: DR Hierarchy by Sector (including Rate Programs)

Order	Residential Hierarchy	C&I (SGS) Hierarchy	C&I (LGS+) Hierarchy
1	DLC & TOU	DLC	Capacity Bidding
2	PTR	TOU	Interruptible
3	CPP	CPP	CPP

TOU - Time of Use

CPP - Critical Peak Pricing

In total, the rate sensitivities identified an additional 116 MW of RAP potential for the Residential sector and an additional 105 MW of RAP potential for the Business sector.

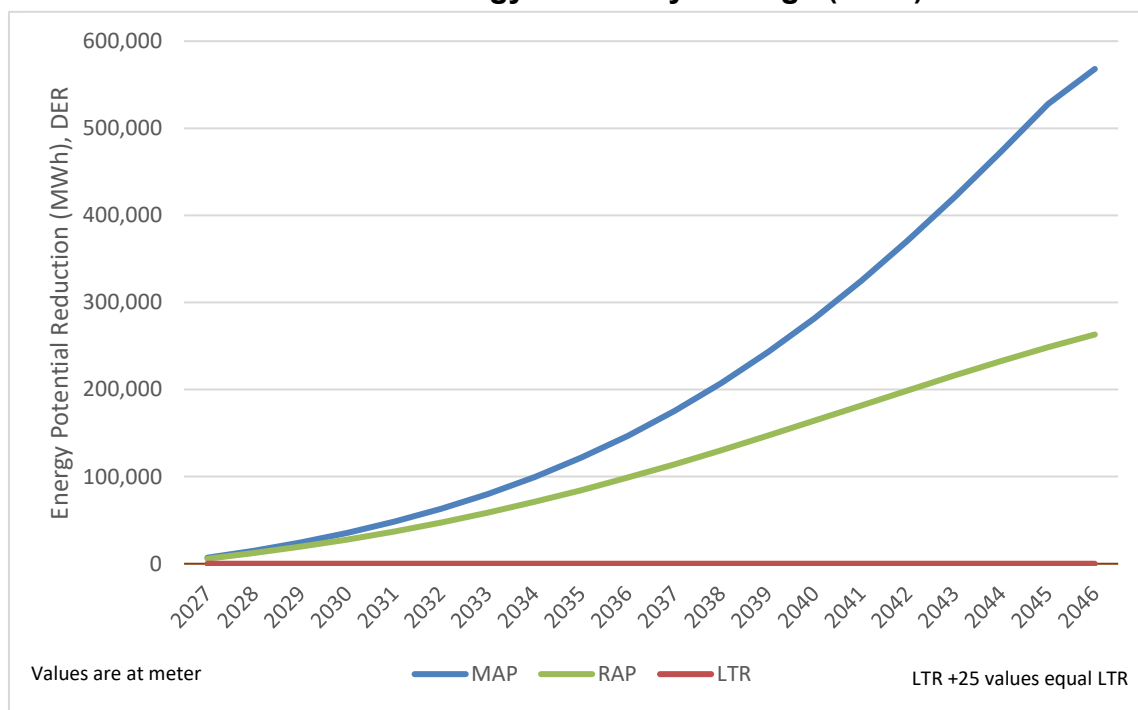
Future savings from DSM rates and rate design will depend significantly on the rate of customer adoption and the strength of the price signal. Note too, that the TOU rates implemented through the general rate review are not considered a MEEIA program, and therefore, potential savings are not developed through EM&V as described in Section 8.4.

8.5.2 Distributed Energy Resources Potential

The 2026 MPS focused on combined heat and power (CHP) and Solar Photovoltaics (PV) to analyze their potential under the current MEEIA cost-effectiveness framework to

provide the collective distributed energy resources (DER) MAP and RAP potential. DER has no potential in the LTR scenario because the approved MEEIA 4 portfolio included no DER component. The results, as shown in the figure below, indicate MWh potential for MAP just upwards of 533,000 and sitting at 247,000 for RAP by 2046.

Figure 8.33: Cumulative Annual MAP/RAP/LTR/LTR +25 Distributed Energy Resources Energy Efficiency Savings (MWh)



The 2026 MPS utilized a bottom-up approach to estimate distributed energy resource potential by:

- Characterized the applicable premises within each market sector, along with the premise-level energy consumption for average premise;
- Researched DER technology performance, including hourly profiles, along with installed and operating costs;
- Analysis of cost-effectiveness for each technology for each unique capacity and application;
- The TRC test, consistent with energy efficiency and demand response potential analysis along with the statute framework was applied to consider as a DSM resource on equal footing with energy efficiency and demand response. No additional benefits for reliability or resilience was included in the analysis;
- Forecasted achievable potential and program potential through application of customer adoption curve(s) for technologies that are cost-effective; and

- Considered sensitivities through alternative scenarios with different unique inputs.

A key conclusion of the DER analysis is that while significant technical potential exists, no technologies were cost effective as measured by the TRC under base case avoided costs. The lone exception to this is a single configuration of large CHP natural gas reciprocating turbine with capacity greater than 15 MW. Sensitivities included alternative cost effectiveness testing criteria for CHP. Despite the lack of cost effectiveness as measured by the existing MEEIA framework – TRC - both solar PV and CHP technologies were found to be cost effective using the PCT.

Similar to the 2023 MPS, the 2026 MPS highlighted that while technical potential for DER exists, deployment and installation will depend on multiple location- and customer-specific financial and non-financial criteria.

To this end, Ameren Missouri continues to operate voluntary renewable subscription programs for residential and business customers as alternatives to behind the meter resources. These programs allow interested customers to participate in the manner that works best for their unique needs, while also ensuring that Ameren Missouri can continue to provide the most cost-effective service to non-participating customers.⁴⁸ Additionally, the Business energy efficiency program continues to offer custom incentives to provide opportunity for cost-effective CHP projects to receive a rebate.

8.6 Future Role of Demand-Side Resources

Ultimately, demand-side resources provide value beyond reducing energy consumption and customer bills. Energy efficiency, demand response, and distributed energy resources can help reduce peak demand, support reliability during periods of system stress, and provide flexibility as future load growth becomes clearer. Because these resources can often be deployed incrementally and scaled over time, they offer important optionality in an environment shaped by electrification, data center development, manufacturing growth, and evolving resource adequacy requirements. Continued DSM investment also helps preserve customer awareness, trade ally networks, implementation infrastructure, and organizational expertise needed to respond effectively to future reliability and affordability challenges.

8.6.1 Integration with Resource Strategy Selection and Revenue Requirement Analysis

The DSM portfolios described in this chapter represent candidate demand-side resources available for selection as part of Ameren Missouri's integrated resource planning process. The MAP, RAP, LTR and LTR +25% portfolios, together with the associated sensitivity

⁴⁸ By definition, resources with a TRC below 1 and a PCT above 1 that reduce system load transfer or shift in costs from participants to non-participants.

analyses presented herein, are carried forward into the alternative resource plan development and analysis process discussed in Chapter 9. Within that analysis, DSM resources are evaluated alongside supply-side resource alternatives to assess their contribution toward meeting forecasted energy and capacity needs while balancing cost, reliability, risk, and other planning objectives. The alternative resource plans reflect varying levels of DSM deployment to enable analysis of the comparative economics and operational characteristics of available resource options.

The results of analysis of alternative resource plans that include various DSM portfolios, therefore, also serve as key inputs to the strategy selection process presented in Chapter 10. The energy savings, peak demand reductions, program implementation costs, and avoided energy, capacity, and transmission and distribution costs associated with DSM resources influence the projected revenue requirements of alternative resource plans. Accordingly, DSM resources are evaluated both on their individual cost-effectiveness characteristics and on the value they provide within the integrated portfolio of resources selected to serve customers.

8.7 Compliance References

20 CSR 4240-22.050(1)	2
20 CSR 4240-22.050(1)(D)	2
20 CSR 4240-22.050(1)(E)	40
20 CSR 4240-22.050(1)(E)1	40
20 CSR 4240-22.050(1)(E)2	40
20 CSR 4240-22.050(2)	43
20 CSR 4240-22.050(3)	13
20 CSR 4240-22.050(3)(A)	13
20 CSR 4240-22.050(3)(B)	13
20 CSR 4240-22.050(3)(D)	43
20 CSR 4240-22.050(3)(E)	39
20 CSR 4240-22.050(3)(G)	14
20 CSR 4240-22.050(3)(G)1	10
20 CSR 4240-22.050(3)(G)2	10, 13
20 CSR 4240-22.050(3)(G)5A-F	13
20 CSR 4240-22.050(3)(G)5B	10
20 CSR 4240-22.050(3)(G)5C	12
20 CSR 4240-22.050(3)(G)5D	13
20 CSR 4240-22.050(3)(H)	10
20 CSR 4240-22.050(3)(I)	11
20 CSR 4240-22.050(4)	40
20 CSR 4240-22.050(4)(A)	43
20 CSR 4240-22.050(4)(B)	43
20 CSR 4240-22.050(4)(C)	33
20 CSR 4240-22.050(4)(D)	43
20 CSR 4240-22.050(4)(D)(1)	43
20 CSR 4240-22.050(4)(D)(2)	41, 43
20 CSR 4240-22.050(4)(D)(3);	43
20 CSR 4240-22.050(4)(D)(4)	43
20 CSR 4240-22.050(4)(D)(5)A through D	43
20 CSR 4240-22.050(4)(E);	2
20 CSR 4240-22.050(4)(F)	40
20 CSR 4240-22.050(4)(G)	43
20 CSR 4240-22.050(5)(A)	11
20 CSR 4240-22.050(5)(B)	11
20 CSR 4240-22.050(5)(B)1	11
20 CSR 4240-22.050(5)(C)	11
20 CSR 4240-22.050(5)(C)1	11
20 CSR 4240-22.050(5)(C)2&3	11
20 CSR 4240-22.050(5)(D)	11
20 CSR 4240-22.050(5)(E)	11
20 CSR 4240-22.050(5)(F)	11, 12
20 CSR 4240-22.050(5)(G)	11
20 CSR 4240-22.050(6)(A)	13

20 CSR 4240-22.050(6)(C)	33
20 CSR 4240-22.050(6)(C)1	33
20 CSR 4240-22.050(6)(C)1 through 2	33
20 CSR 4240-22.050(6)(C)2	33
20 CSR 4240-22.050(7)	38
20 CSR 4240-22.070(8)(A)	38
20 CSR 4240-22.070(8)(B)	38