Public

AmerenUE

Integrated Resource Plan

4 CSR 240-22.050

Demand-Side Resource Analysis

February 2008

4 CSR 240-22.050 (1) (A)

Identification of End-Use Measures. The analysis of demand-side resources shall begin with the development of a menu of energy efficiency and energy management measures that provide broad coverage of—

All major customer classes, including at least residential, commercial, industrial and interruptible;

The analysis began by compiling measure information from several industry sources, primarily the Database for Energy Efficient Resources (DEER). DEER is a publicly funded and available database of measures and is maintained by the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC).

The majority of the residential sector measures were from the 2006 Missouri Statewide Residential Lighting and Appliance Efficiency Saturation Study, Final Report, November 15, 2006, prepared by RLW Analytics. Other residential and commercial measures were from the EPA ENERGY STAR Qualified Products list. (http://www.energystar.gov/index.cfm?fuseaction=find_a_product)

Measure information for non-residential motors was from DEER and PG&E Workpapers, filed on August 31, 2006 with the CPUC. Additional information for food service measures was from the PG&E Food Service Technology Center (http://www.fishnick.com).

Industrial process measures were developed based on KEMA's California Industrial Existing Construction Energy Efficiency Potential Study, Calmac Study ID: PGE0252.01, May 2006.

Demand response measure information was based on AmerenUE Residential TOU Pilot Study, Load Research Analysis - 2005 Program Results, June 2006, prepared by RLW Analytics. Additional information was taken from California's CPP (Critical Peak Pricing) Pilot programs from 2003-5.

The full list of measures considered can be found in 4 CSR 240-22.050_Appendix A, pages 2.1 to 2.13, in the column "Efficient Technology". Additional detail is provided in the "Efficient Efficiency Definition", "Base Technology", and "Base Efficiency Definition" columns.

4 CSR 240-22.050 (1) (B)

All significant decision-makers, including at least those who choose building design features and thermal integrity levels, equipment and appliance efficiency levels, and utilization levels of the energy-using capital stock;

The list of measures includes in 4 CSR 240-22.050_Appendix A, pages 2.1 to 2.13 is intended to be comprehensive with respect to possible decision makers, recognizing that the measures per se are not typically classified with respect to decision-maker. Rather, decision makers typically are relevant at the program level, when programs are designed to motivate those who make decisions regarding building design and construction, the choice of thermal integrity level, and the choice of appliance and equipment and equipment efficiency level. The measures listed in 4 CSR 240-22.050_Appendix A, pages 2.1 to 2.13 include those pertaining to:

- New building construction
    - Measure ID numbers 145-147, 345
- Thermal integrity levels
    - Measure ID numbers 38-76, 113-124, 141-144, 158-159, 201-213, 245-257, 276-288, 659-661
- Equipment and appliance efficiency levels
    - Measure ID numbers 33-37, 77-92, 125-140, 148-157, 160-187, 214-218, 302-309, 335-344, 346-613, 618-620, 622, 634-635, 637-638, 643-646, 662-777
- Utilization levels of energy-using capital stock
    - Measure ID numbers 1-32, 93-112, 188-200, 219-244, 258-275, 289-301, 310-334, 614-617, 621, 623-633, 636, 639-642, 647-658, 778-857, and 858-865.

4 CSR 240-22.050 (1) (C)

All major end uses, including at least lighting, refrigeration, space cooling, space heating, water heating and motive power; and

The initial set of measures covered the following end uses within these sectors:

- Residential
    - Lighting
    - Space Heating (including thermal integrity measures)
    - Space Cooling (including thermal integrity measures)
    - Refrigeration
    - Water Heating
    - Dishwashing
    - Clothes Washing
    - Domestic Hot Water

- Commercial
    - HVAC (Heating, Ventilation and Air Conditioning)
    - Lighting – interior and exterior
    - Motors
    - Cooking
    - Refrigeration
    - Domestic Hot Water

- Industrial
    - HVAC (Heating, Ventilation and Air Conditioning)
    - Lighting – interior and exterior
    - Motors
    - Process (multiple SIC codes)

4 CSR 240-22.050 (1) (D)

Renewable energy sources and energy technologies that substitute for electricity at the point of use.

To fulfill this section of the rule Alternative Energy Systems Consulting, Inc. (AESC) was hired to do the research and analysis to determine the cost and availability of a wide range of technologies that can, "… substitute for electricity at the point of use."

AESC completed their research and final report on November 30, 2007. Their report and documentation are included as 4 CSR 240-22.050_Appendix C. In summary, AESC's screening identified Farm Anaerobic Digestion (Farm AD) as the candidate technology for an incentive program within AmerenUE's service territory. All other DG technologies, including energy storage, were found to be too costly to provide reasonable incentives to improve their customer economics.
The conclusions from their study.

- Farm AD systems are the best DG candidate for an incentive program within AmerenUE's service territory.
- The market potential for Farm AD systems within AmerenUE's service territory 5.2 MW, most of which is at swine farms.
- The best program design is a capacity based lump sum incentive paid upon project completion and startup.
- An incentive of approximately $1,665/kW will make the levelized cost of electricity from Farm AD equal to retail grid electric purchases. Farm AD systems have additional benefits of odor and run-off control.
- A survey of DG program costs shows that administrative costs can vary from 2% to 24%. In this study we assume a base 10% administrative cost with a $100,000 first year start up costs and a minimum $20,000 annual cost. This results in a total program cost of $9 million and an administrative cost of nearly $1 million over the life of the program, 20 years.

AESC's recommendations are –

- Analyze the cost of the Farm AD capacity and determine if it is cost effective versus other demand-side management (DSM) and supply-side options.
- If Farm AD is found to be cost effective, develop incentive program details, including marketing and outreach as well as program materials and assign responsibility for implementation of the program.
- Regardless of the cost effectiveness of Farm AD, monitor its progress as well as the performance and economics of –

  - Small run of the river hydroelectric
  - Onsite Wind Turbine Technology
  - Natural Gas Reciprocation ICE CHP

- Additional DG technologies that warrant tracking because of their potential for improved economics and green house gas mitigation.
  - Solar Dish Stirling technology
  - High temperature Molten Carbonate and Solid Oxide fuel cells
  - Advanced photovoltaics such as multi-junction and dye sensitized cells

AmerenUE will continue to study anaerobic digestor technology as well as other promising renewable energy DG technologies for possible pilot project applications in the AmerenUE service territory. In addition, we will research local zoning issues that may impact the ability to pursue DG technology applications at specific sites.

4 CSR 240-22.050 (2)

Calculation of Avoided Costs. The utility shall develop estimates of the cost savings that can be obtained by substituting demand-side resources for existing and new supply-side resources. These avoided cost estimates, expressed in nominal dollars, shall be used for cost-effectiveness screening and ranking of end-use measures and demand-side programs.

As an alternative to the procedure outlined in subsections (A) – (D), AmerenUE may use a forecast of the market cost of power, including any regulatory capacity cost, for the calculation of avoided capacity and running costs. If AmerenUE chooses the market cost of power approach, any reference to avoided new generation (or avoided generation, or avoided capacity, or avoided generation capacity, or avoided peaking capacity, or avoided energy, or avoided running cost) in section 22.050(2) shall be deemed to refer to the market cost of power. If this alternative method is employed, AmerenUE shall adjust this market price to account for transmission and distribution avoided costs as well as probable environmental costs pursuant to 4 CSR 240-22.040(2)(B).

In addition, AmerenUE shall describe its method for (1) grouping hourly forecasted prices into avoided cost periods to reflect significant differences in the seasonal and/or hourly variation in prices, and (2) for allocating regulatory capacity costs to these periods.

Forecasts of the market cost of power were derived from CRA International's MRN-NEEM model projections of wholesale electricity prices. The integrated MRN-NEEM modeling framework described in Appendix B furnishes electricity prices by load block and year for the Eastern Missouri (EMO) region encompassing AmerenUE's service territory. To reiterate, these electricity prices incorporate all macroeconomic feedback effects that would result from economy-wide policies such as the carbon abatement branches in the probability tree.[1] In the electric sector particularly, electricity demand will decrease in response to higher power prices, and in turn influence the final equilibrium price for electricity. This equilibrium price represents the marginal cost of supplying an incremental megawatt-hour (MWh) of electricity in each region and in each load block for each year. It accounts for (1) the dispatch costs of existing resources and potential new additions,[2] (2) planned maintenance and forced outages at generating units in the region, (3) compliance with all environmental regulations, and (4) a dynamic transmission system that allows for imports and exports between regions.

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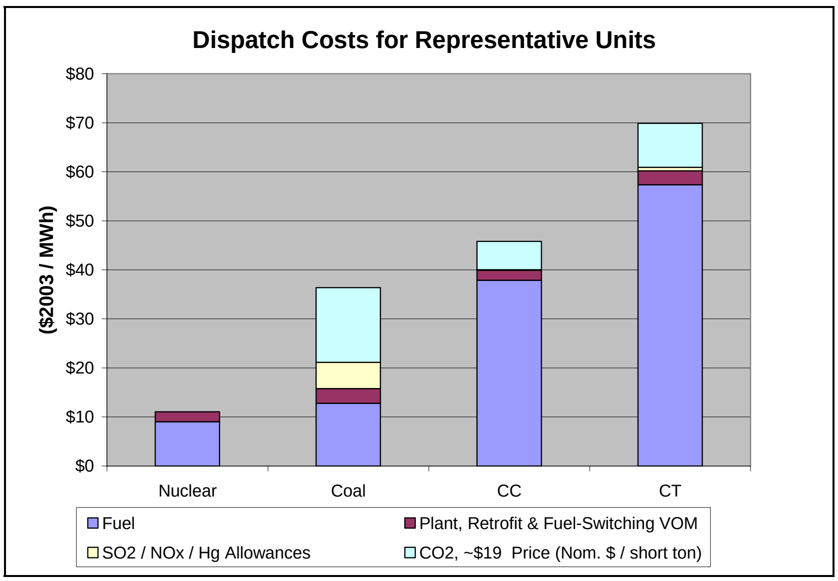
[1] Higher electricity prices will raise production costs throughout the economy, but especially in sectors that use electricity-intensive production processes. As all sectors adjust their production processes to be optimized under post-policy prices, there are changes in demand for labor, materials and commodities, capital, and different types of fuels and primary energy sources.

[2] The dispatch cost signifies the cost of supplying electricity, which includes (1) fixed and variable operating costs for all units, (2) fuel costs, (3) capital investments in new plants and retrofits at new and existing facilities, and (4) the cost of moving power between regions (wheeling charges).

Figure 1 details the composition of dispatch, or variable, costs for four representative unit types in the NEEM model. The relative variable costs of different capacity types determine the merit order of dispatch and, in turn, the supply curve in each load block, region, and year. They include fuel costs; plant, retrofit, and fuel-switching variable O&M (VOM) costs; SO_2, NO_X, and Hg emissions costs; and any prevailing CO_2 abatement costs. Those unit types with the lowest variable costs will constitute the bottom of the supply curve and serve base load demand. As given below, available nuclear capacity in a particular region often sits at this point on the curve.[3] As one moves up the supply curve, the variable costs of the capacity being dispatched get progressively higher. Figure 1 shows that coal generators generally have lower variable costs than gas-fired CC units and peaking gas-fired CT units, in that order, largely due to differences in fuel costs. Also of note are the appreciable effects an aggressive CO_2 policy[4] could have on the dispatch costs of coal- and gas-fired capacity. At most times of the year, the demand in any particular load block in Missouri will intersect the supply curve at a price level in the vicinity of coal and CC variable costs. Since coal contains much more CO_2 than natural gas, a price on CO_2 emissions closes the gap between coal and CC variable costs. Depending upon the shape of the supply curve and where demand falls, a CO_2 price could thus change what unit type represents the incremental MWh of generation, which, as previously described, establishes the wholesale electricity price.

Figure 1: Composition of Dispatch Costs for Representative Units in NEEM



[3] The variable costs of hydroelectric generating facilities is even less than those for nuclear units, so, in regions where those resources exist, hydroelectric capacity will precede nuclear in the merit order.

[4] The CO_2 costs in Figure 1: Composition of Dispatch Costs for Representative Units in NEEM

are consistent with what a representative unit would face in 2015 in the high CO_2 price scenarios, which set a 2012 CO_2 price equal to $15/short ton that then rises 5% annually in real terms.

Having sorted all available capacity in a NEEM region by dispatch costs, the model assesses where the so-constructed supply curve intersects with the demand in that load block and year. The MRN-NEEM modeling framework produces demand levels in each year and load block that do indeed reflect macroeconomic responses to electricity policies, but that are not stratified by end-user type in the way supply is structured by generation type. As such, Figures 2 and 3 represent demand in a typical peak and off-peak load blocks, respectively, by vertical lines. Where each perfectly inelastic demand curve crosses the supply curve sets the equilibrium wholesale electricity prices, P^*_{peak} and $P^*_{off\text{-}peak}$.

Figure 2: Determination of Electricity Prices in a Peak Load Block.

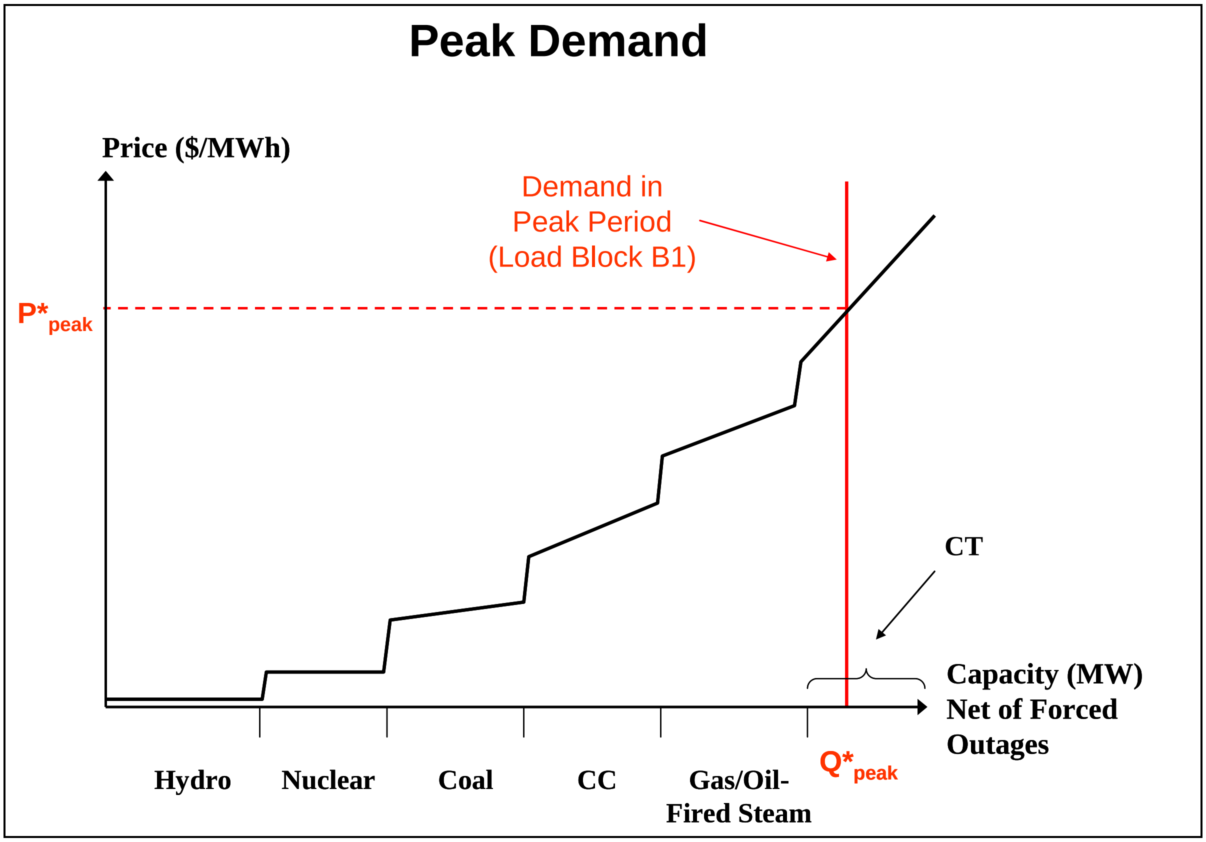
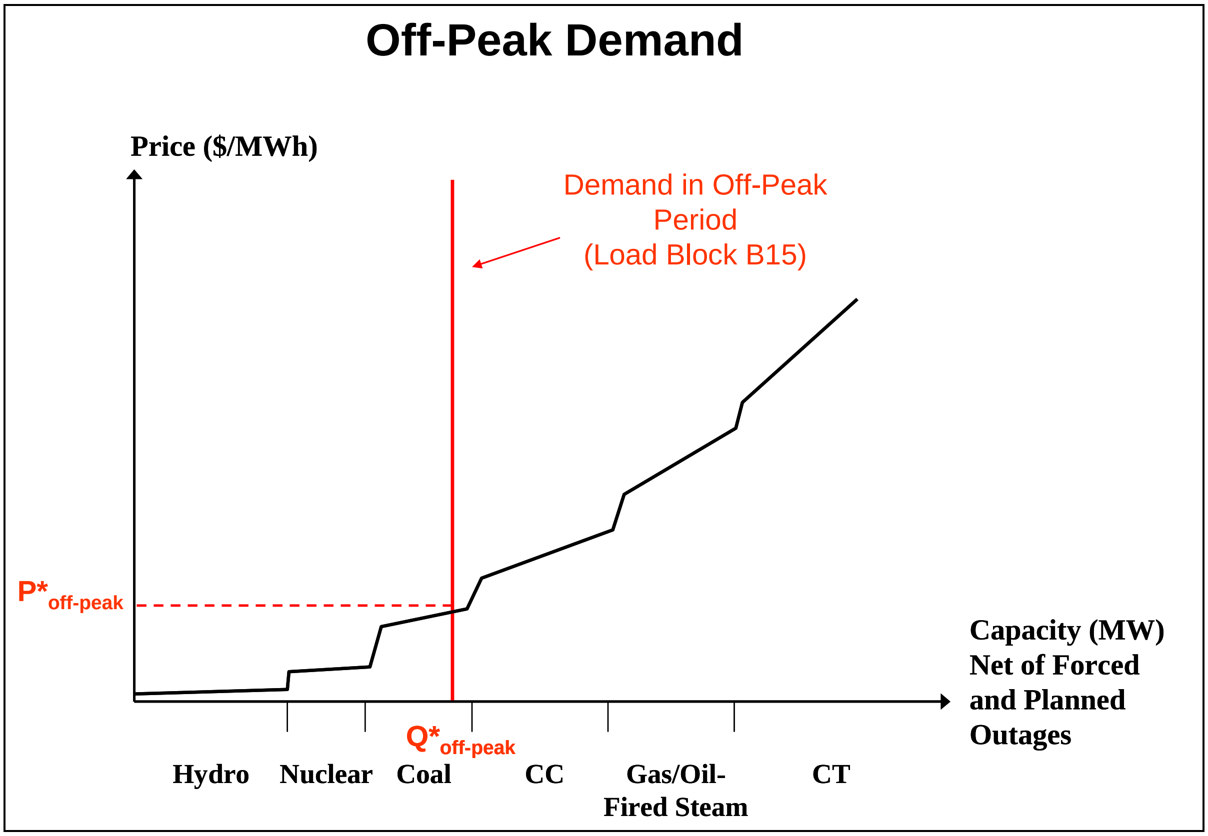
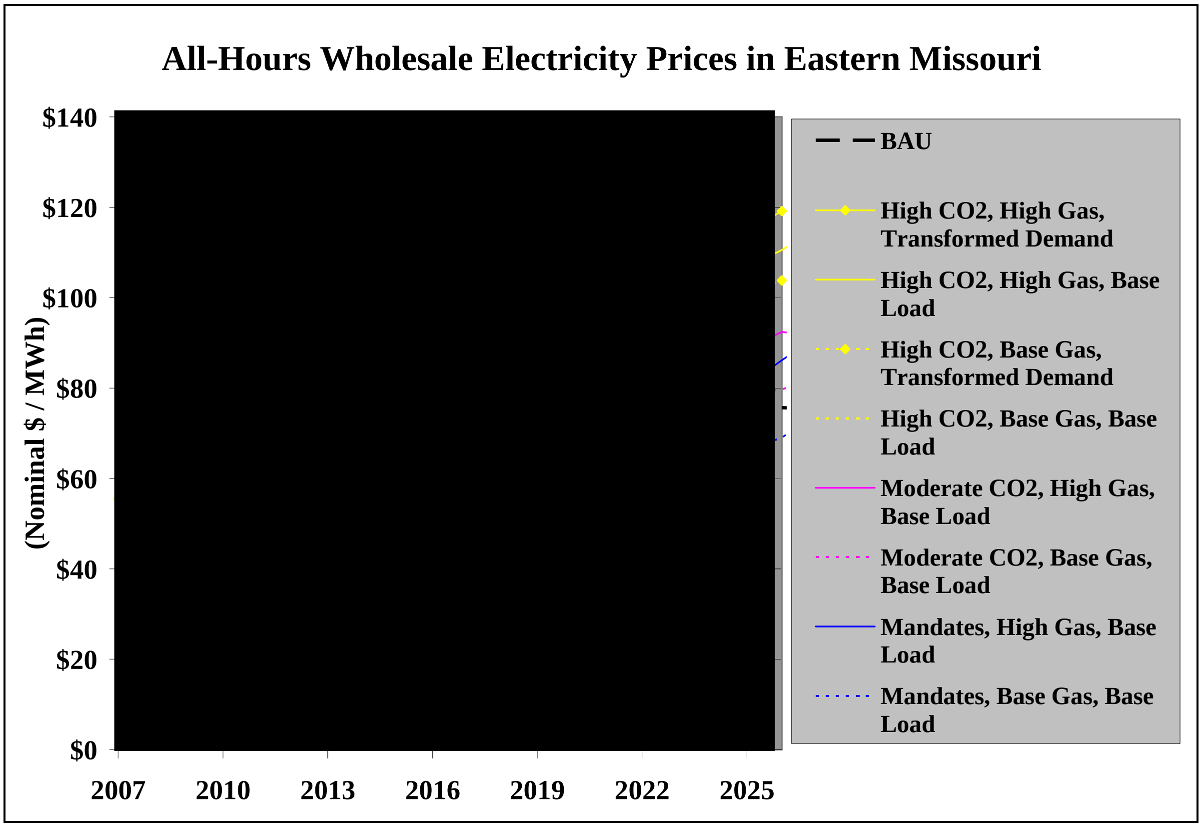


Figure 3: Determination of Electricity Prices in an Off-Peak Load Block.



The graphical depictions above delineate the dynamics of electricity pricing in the NEEM model. First, demand in an off-peak period is predictably less than demand in an on-peak period, which shifts the inelastic demand curve to the left towards capacity with less expensive dispatch. As such, P^*_{peak} is greater than $P^*_{off\text{-}peak}$. Second, NEEM optimally chooses the shoulder, off-peak load blocks for nuclear and coal capacity to undergo planned maintenance. With less inexpensively dispatched capacity available, the steps in the supply curve corresponding to those unit types shrink. This shortening of the supply curve partially mitigates the difference in off-peak and on-peak prices. Third, the supply curve is not a continuous function, and instead is stratified by the unique variable costs of each generation technology. In turn, incremental changes in demand induced by the macroeconomic ripple effects of CO_2 emissions reductions can result in the intersection point jumping from a lower step (*e.g.*, coal) on the curve to a starkly higher step (*e.g.*, gas-fired CC). In this way, the MRN-NEEM model derives wholesale electricity prices in each year for each load block and NEEM region. Figure 4: MRN-NEEM All-Hours Wholesale Electricity Prices in Eastern Missouri presents all-hours wholesale electricity prices in Eastern Missouri consistent with the MRN-NEEM methodology delineated above.

Figure 4: MRN-NEEM All-Hours Wholesale Electricity Prices in Eastern Missouri.



The construction of candidate resource plans on a deterministic basis requires the use of a model more local in scope at both the system and regional level.[5] For this phase of the IRP, AmerenUE used MIDAS, which is a chronological model in which new build decisions are determined on a year-to-year basis. This model requires electricity prices on an hourly basis for the entirety of the planning horizon. Since NEEM outputs power prices in each region by load block, the question then becomes how to translate these prices into an hourly template for each year from 2007 through 2026. Of all the inputs at AmerenUE's disposal, MIDAS power prices from the Southern MAIN (SMAIN) region most highly correlated with MIDAS demand projections. Thus, since MIDAS load forecasts ultimately shape least-cost options for new capacity portfolios, annual MIDAS SMAIN power prices from a BAU forecast determined the mapping of NEEM-outputted electricity prices by load block to equivalent hourly prices.

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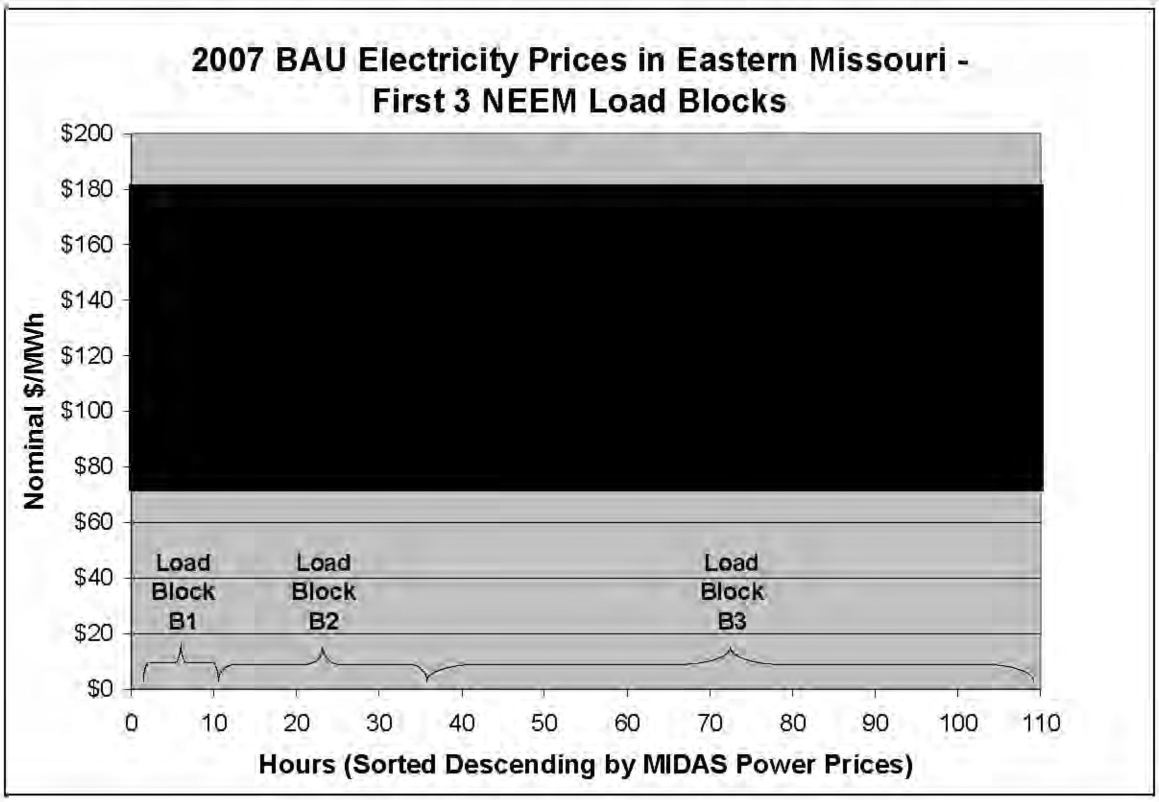
[5] As detailed in the waiver request to 4 CSR 240-22.070, AmerenUE separated the development of the scenarios and associated integrated modeling of those scenarios into its own step (*i.e.*, Step 1 of Figure 1in 4 CSR 240-050_Appendix B) that will precede the development of candidate resource plans on a deterministic basis (*i.e.*, Step 2 of Figure 1 in 4 CSR 240-050_Appendix B). Note, however, that results from the national-scale MRN-NEEM modeling will be used as inputs into the more local, system-specific modeling analysis.

Using these MIDAS SMAIN power prices, AmerenUE rank-ordered each hour within each season (per the month-to-season mapping described in the MRN-NEEM documentation) for every year from 2007 through 2026. Then, each hour in each year was assigned to one of the 20 corresponding NEEM load blocks. For example, if, in 2007, the ten summer hours with the highest MIDAS SMAIN power prices (which are a proxy for MIDAS demand) are the hours starting at 2:00 PM on each day from July 1 through July 10, then the power price in the EMO region for those hours will all be the 2007 NEEM power price in load block B1 for the EMO region.

Further adjustments were then made to the power prices in the very peak and low-load off-peak summer hours to achieve a level of granularity similar to the set of MIDAS prices and actual market prices. Since NEEM assumes a fully-functioning, competitive electricity market, it might underestimate power prices in the highest-demand hours if there is compelling evidence of a scarcity adder. As such, adjusting the prices in these hours upward more accurately accounts for costs AmerenUE might face if it is forced to purchase electricity from another generator in the region. Conversely, NEEM could overestimate prices in the extremely low-demand off-peak summer hours if something other than the true marginal cost of dispatching an additional MWh is setting the market price.

To accomplish a greater spread reflective of actual power prices in these time periods, the difference between the 2007 BAU MIDAS hourly price and the analogous NEEM load-block price was used to adjust NEEM prices upward in load blocks B1 (10 highest-demand hours from MIDAS BAU yearly forecasts) and B2 (next 25 highest-demand hours), and downward in load block B10 (the 1,262 lowest-demand hours in the summer season). Figure 5 juxtaposes the final 2007 BAU adjusted electricity prices, given by the dotted red line, with the unadjusted NEEM and MIDAS price paths. The hours on the horizontal axis have been sorted from highest to lowest in terms of the 2007 MIDAS base case demand levels, and encompass the first three load blocks in NEEM. Note how NEEM, given by the solid blue curve, only outputs three distinct price levels for these 110 hours. The dotted red line, which follows the MIDAS curve in the first two load blocks and then the NEEM curve in the third load block, represents the final adjusted electricity prices used in the selection of resource plans. The delta, *d*, between the MIDAS and NEEM curves represents the adder applied *across all other scenarios and all IRP years* to B1 and B2 wholesale electricity prices. Similarly, the adjustment in load block B10 adhered to the same procedure outlined above, except that the “adder” in these 1,262 hours was negative.

Figure 5: Adjustment to NEEM Electricity Prices in Load Blocks B1 and B2.



As referenced in the waiver request to 4 CSR 240-22.050 (2), a complete forecast of the market cost of power includes regulatory capacity costs due to units meeting reserve margin requirements. In each model year, MRN-NEEM sets capacity costs by determining the payments necessary to make whole investments in the marginal MW of required capacity. In more detail, the "investment" signifies the sum of annualized capital expenditures and fixed operations and maintenance (O&M) costs, and the "marginal" unit denotes the last incremental capacity addition required to meet reserve margin requirements. Usually, and particularly in Eastern Missouri, this marginal unit is a gas-fired peaking plant, whose low up-front capital costs provide for quicker construction but whose high variable costs place it last in the merit order. Having identified the marginal unit, MRN-NEEM then assesses whether the unit was ever dispatched. If so, the revenues earned in the energy-only market are subtracted from the aforementioned fixed costs to determine the capacity price that makes the unit "whole." That is, the capacity price produced by MRN-NEEM, in dollars per kilowatt-year (kW-yr), equals the difference between fixed costs and energy revenues for the marginal peaking unit in each reserve margin region.

For resource planning purposes, however, these annual capacity prices are not appropriate in two important respects. First, the capacity prices produced by MRN-NEEM are not intended to indicate year-to-year fluctuations, but instead a long-term stream of payments whose present value is at least as great as the fixed investment costs of the marginal unit. As such, CRA levelized the stream of capacity payments over the modeling horizon at a discount rate of 5%. Moreover, due to the very fact that this levelized capacity payment is long-term in nature, it is not particularly reflective of actual market conditions right now. AmerenUE management deemed that MRN-NEEM capacity prices on the order of [redacted] kW-year signify a capacity shortage situation, but nevertheless do not project a possible need for new base load capacity in their system until 2014. In 2007, AmerenUE engaged in a capacity market transaction at a price of [redacted] kW-year. As an actual market transaction between a willing buyer and a willing seller, AmerenUE and CRA concurred that it was the most rational 2007 capacity price to use in resource plan selection, while levelized MRN-NEEM capacity prices were more appropriate from 2014 onward. The capacity prices in the intervening years from 2008 through 2013 were computed by taking a linear interpolation between the short-term market transaction and the long-term MRN-NEEM projections.

Secondly, as a load duration curve model with only 20 load blocks to segregate peak and off-peak demand periods, NEEM does not fully simulate the peakiness in demand characteristic of competitive markets. By not capturing those few hours in a year where electricity prices are more likely to support the economic dispatch of gas peaking units, NEEM overstates capacity prices. For example, NEEM assigns the 10 hours in the summer season with the highest demand in the ECAR region to load block B1. Consequently, the wholesale electricity prices in these 10 highest-demand summer hours are all identical in NEEM, despite the fact that there may be a wide divergence in the actual demand levels, and in turn electricity prices, within that 10-hour load block.[6] Therefore, in extremely "peaky" periods, NEEM underestimates potential energy payments to those marginal gas peaking units. In such hours of extremely peaky demand, it is reasonable to expect that these energy revenues chip away at the capacity price required for the peaker to recover its fixed costs.

To derive a data-based energy margin for peaking units in the AmerenUE territory, operational data from 2005 and 2006 Continuous Emissions Monitoring Systems (CEMS) records was pulled (using Global Energy's Energy Velocity Suite) for recently built (post-2003) gas-turbine units located in the Midwest ISO. Pertinent data included generation, total generating hours, and fuel and variable O&M costs. In total, there were 7 such plants (and 22 units) that satisfied these criteria. For the price nodes assigned to each of these 22 peaking units, real-time hourly locational marginal prices (LMPs) were pulled for the months from June through September in 2005 and 2006. Lacking reasonable hourly dispatch prices for specific units, a critical assumption to our analysis was that these peakers would only operate in the highest-price hours of the year. Furthermore, given that a unit generated in X hours of the year, energy revenues (per MWh) would simply be the average electricity price over the year's X highest electricity prices. The energy margin for each peaker, then, is given by:

$$\begin{aligned} &\textit{Energy Margin } (\$/MWh) = \textit{Average of } X \textit{ highest LMP Prices } (\$/MWh) - \\ &\qquad\qquad\qquad\qquad\qquad\qquad \textit{Average Dispatch Costs } (\$/MWh), \end{aligned}$$

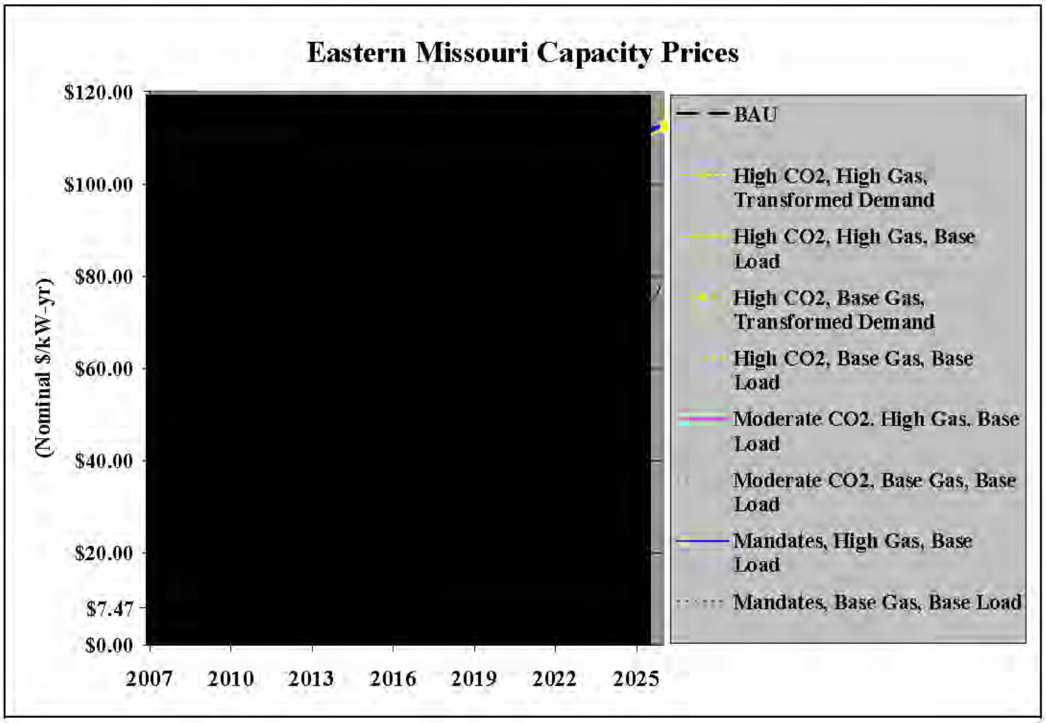
where X ranged from 3 to 1,821 generating hours, and average dispatch costs were equal to the sum of fuel and variable O&M costs divided by generation. The energy margin computed as

[6] In fact, it was this very phenomenon that motivated the adjustment to electricity prices in load blocks B1 and B2, as given in
Figure 5: **Adjustment to NEEM Electricity Prices in Load Blocks B1 and B2.**

above was then restated as the total margin per kW of capacity by first multiplying by generation and then dividing by the summer capacity.

In all, 17 of the 44 data points resulted in negative energy margins. This could be due to several factors: one, that all such units were generating at least 500 hours, indicating that they may have been serving some base load demand; two, that these MISO peakers have fixed price contracts which lock prices different than real time LMPs; and, three, that these units are receiving ancillary services, spinning reserve, or various other payments outside of the real time spot market. Only considering the other 27 "energy-profitable" units, the average energy margin in 2005 and 2006 is [redacted]kW (in 2006 dollars). This margin is subtracted from the levelized MRN-NEEM capacity price to arrive at capacity payments more consistent with historical experience. As discussed previously, AmerenUE linearly grew an actual 2007 capacity market transaction priced at [redacted]kW-year to these levelized energy revenue-adjusted capacity payments in the post-2014 timeframe. Figure 6 graphically portrays the capacity prices for each of the nine scenarios in accordance with the above methodology.[7]

Figure 6: Capacity Prices in Eastern Missouri (Nominal $/kW-yr).



[7] See Table 1 in 4 CSR 240-22.050_Appendix B for a data table of the Eastern Missouri capacity prices used in IRP strategy selection.

4 CSR 240-22.050 (3) (A)

Cost-Effectiveness Screening of End-Use Measures. The utility shall evaluate the cost effectiveness of each end-use measure identified pursuant to section (1) using the probable environmental benefits test. All costs and benefits shall be expressed in nominal dollars.

> **(A) The utility shall develop estimates of the end-use measure demand reduction for each demand period and energy savings per installation for each avoided cost period on a normal-weather basis. If the utility can show that subannual load impact estimates are not required to capture the potential benefits of an end-use measure, annual estimates of demand and energy savings may be used for cost-effectiveness screening.**

Measures are distinguished by the sensitivity of their savings impacts to weather. For measures that are not weather-sensitive, annual energy savings and coincident peak demand impacts were taken from established industry sources, primary the DEER database. Annual energy savings were then disaggregated to the avoided cost period using hourly load shapes developed by and purchased from Itron as part of its *eShapes* service. The eShapes load duration curves include normalized values for each hour of the year for each major end-use.

$$\textit{annual energy savings} \;*\; \left[\begin{array}{lcl} \textit{fraction of annual energy in hour 1} & = & \textit{energy saved in hour 1} \\ \textit{fraction of energy in hour i} & = & \textit{energy saved in hour i} \\ \textit{fraction of energy in hour 8760} & = & \textit{energy saved in hour 8760} \end{array}\right.$$

The energy and demand impacts of weather-sensitive measures were estimated using the DOE-2 building simulation model. The first step in the simulation process was to develop a representative set of building prototypes. These were:

- Residential sector
    - Gas space heating with central air conditioning
    - Electric baseboard resistance heating with central air conditioning
    - Electric heating and cooling with a heat pump.
- Commercial sector
    - Education
    - Food Sales
    - Food Service
    - Health Care
    - Lodging
    - Office – Large
    - Office – Small
    - Retail
    - Warehouse
- Industrial sector

Each of these building types was characterized by a series of inputs pertaining to building shell (floor area, wall area, insulation levels, window and door area and type, construction, orientation, etc) and system (HVAC type and efficiency, duct efficiency, control system, etc.). These characteristics were based on the construction of a typical existing building in the AmerenUE service territory. Each building prototype was then benchmarked in its baseline configuration against AmerenUE-specific or regional building type consumption data, where available.

The building prototype characteristics can be found in 4 CSR 240-22.050_Appendix A, pages 7.1 to 7.9.

Once the prototypes were benchmarked, the impact of each of the weather-sensitive measures was simulated using normal weather data for the AmerenUE service territory. This consisted of 30 year weather data for the following representative geographic locations:

1. St. Louis, MO
2. Columbia, MO
3. Kansas City, MO
4. Memphis, TN

The results of the parametric measure simulations were then subtracted from the baseline buildings' performance and averaged across the four climate zones to yield the hourly energy savings and coincident peak hour reduction per measure. The hourly energy savings were aggregated to match the avoided cost periods.

Per measure annual energy and demand savings are shown in the "Annual kWh Savings" and "Coincident Peak Savings" columns in 4 CSR 240-22.050_Appendix A, pages 2.14 to 2.26.

The normalized load shapes (the percentage of energy savings per avoided cost period) are shown in 4 CSR 240-22.050_Appendix A, pages 4.1 to 4.18.

4 CSR 240-22.050 (3) (B)

Benefits per installation of each end-use measure in each avoided cost period shall be calculated as the demand reduction multiplied by the levelized avoided demand cost plus the energy savings multiplied by the levelized avoided energy cost.

1. Avoided costs in each avoided cost period shall be levelized over the planning horizon using the utility discount rate.

2. Annualized benefits shall be calculated as the sum of the levelized benefits over all avoided cost periods.

Although disaggregation of load impacts is necessary to capture the value of time-varying avoided costs, the use of hourly disaggregation for all calculations creates a significant data management challenge. The next step in the analysis, therefore, was to re-aggregate load and avoided costs data into more manageable data sets that still reflected the time-varying value of avoided energy consumption and demand. 36 hourly buckets were defined (peak, off-peak and weekend-holiday periods for each month). Each hourly load and avoided cost value was sorted into one of these buckets to yield 36 avoided cost values per year cost and 36 energy consumption values per year per end use measure.

The 36 annual avoided cost values were multiplied by the per unit energy savings in each of the 36 corresponding periods to yield a measure-specific annual avoided cost stream over a 20 year period. The net present value of this stream over the life of a given measure is equivalent to the calculation of a levelized avoided cost. This value was then multiplied by the annual energy savings to arrive at the kWh value of the benefits per installation.

For the kW value of the benefits per installation, the coincident peak demand reduction for each measure was multiplied by the annual avoided capacity cost.

The kW value was then added to the kWh value to determine the total benefits per installation. These values are shown in the “Utility Avoided Costs” column in 4 CSR 240-22.050_Appendix A, pages 2.14 to 2.26.

The average annual avoided cost per period, for the BAU and CO2 scenarios, is shown in 4 CSR 240-22.050_Appendix A, pages 5.1 to 5.2.

The measure-specific avoided cost stream is shown in 4 CSR 240-22.050_Appendix A, pages 6.1 to 6.9 for the BAU Scenario, and pages 6.10 to 6.18 for the CO2 Scenario.

4 CSR 240-22.050 (3) (C)

Annualized costs per installation for each end-use measure shall be calculated as the sum of the following components:

1. Incremental costs of implementing the measure (regardless of who pays these costs) levelized over the life of the measure using the utility discount rate;
2. Incremental annual operation and maintenance costs (regardless of who pays these costs) levelized over the life of the measure using the utility discount rate; and
3. Any probable environmental impact mitigation costs due to implementation of the end-use measure that are borne by either the utility or the customer.

The incremental measure costs for each measure are shown in the “Total Incremental Cost” column in 4 CSR 240-22.050_Appendix A, pages 2.14 to 2.26. The incremental costs are treated as a single upfront cost that includes equipment and labor. Incremental operation and maintenance (O&M) costs also are included when applicable. The measure economic screening compares a single value for the sum of incremental measure installation and O&M costs, with the present value of the stream of avoided costs yielding an arithmetically identical result to annualized measure costs:

$$\frac{LevelizedBenefits}{LevelizedCosts} = \frac{NPVBenefits}{NPVCosts}$$

4 CSR 240-22.050 (3) (D)

Annualized costs for end-use measures shall not include either utility marketing and delivery costs for demand-side programs or lost revenues due to measure-induced reductions in energy sales or billing demands between rate cases.

The incremental measure costs, as shown in Appendix 4 CSR_240-22.050, pages 2.14 to 2.26, do not include utility marketing and delivery costs or lost revenues.

4 CSR 240-22.050 (3) (E)

Annualized benefits minus annualized costs per installation must be positive or the ratio of annualized benefits to annualized costs must be greater than one (1) for an end-use measure to pass the screening test. The utility may relax this criterion for measures that are judged to have potential benefits which are not captured by the estimated load impacts or avoided costs.

Given the uncertainties associated with the estimates of measure-level costs and savings, a loose economic screen was applied such that if a measure achieved a ratio of benefits-to-costs of 0.91 or higher, it was considered to have passed the measure screening. The results of the measure screening are shown in the "PEB (TRC) Test" column in 4 CSR 240-22.050_Appendix A, pages 2.14 to 2.26.

4 CSR 240-22.050 (3) (F)

End-use measures that pass the probable environmental benefits test must be included in at least one (1) potential demand-side program.
or,
If AmerenUE does not include each end-use measure that passes the probable environmental benefits test in at least one potential demand-side program, it shall provide an explanation as to why that measure was not appropriate for inclusion.

All measures that had a benefit-cost ratio equal to or greater than 0.91 were included in measure bundles that formed the basis for program design and screening. 4 CSR 240-22.050_Appendix A, pages 2.14 to 2.26 of show the results of the probable environmental benefits test for each measures, and **Error! Reference source not found.** and **Error! Reference source not found.** presented under 4 CSR 240-22.050 (6) (C) below show how the measures passing the screening were allocated to programs. In some cases, measures that did not screen as cost-effective were included in programs. Most measures were screened by building type. For example, a commercial lighting fixture configuration was screened for all commercial types. In addition, basic measures were screened in a variety of configurations. For example, replacement of T-12 lamps with T-8 lamps was represented by a variety of combinations of lamp length and number of lamps per fixture. In many cases, a basic measure might be cost-effective in one or more configurations for one or more buildings, but not cost-effective in others. From a program design perspective it is not feasible to exclude certain building types from participation in a program offering that measure. Therefore, if a measure screened as cost-effective in configurations and building types representing a market that could sustain a program, those measures in all building types were included in the program.

4 CSR 240-22.050 (3) (G)

For each end-use measure that passes the probable environmental benefits test, the utility also shall perform the utility benefits test for informational purposes. This calculation shall include the cost components identified in paragraphs (3)(C)1. and 2.

The utility test was performed for all measures. At the measure level, the numerator for the utility benefits test, as defined here, and for the probable environmental benefits test are essentially equivalent. The utility test results are shown in the "UCT" column in 4 CSR 240-22.050_Appendix A, pages 2.14 to 2.26. Note that in many cases the utility test benefit cost ratio will be indeterminate (listed as 0.00) since the denominator will be zero, i.e. utility costs (incentives and administrative costs) will be zero.

4 CSR 240-22.050 (4)

AmerenUE shall prepare an estimate of the achievable potential of programs screened as cost-effective under 4 CSR 240-22.050 (7). Achievable potential is understood to be equivalent to the incremental and cumulative demand reduction and energy savings described in Section 22.050 (7)(A). An estimate of achievable potential shall be prepared for multiple portfolios of programs, where at least one portfolio represents a very aggressive approach to encouraging program participation.

This estimate of achievable potential has been completed and is represented by the annual and cumulative energy and demand reductions estimated for the Aggressive Portfolio of demand-side measures. These results are contained in 4 CSR 240-22.050_Appendix A, pages 3.61 to 3.108. The results are represented graphically below.

Figure 1: Achievable Potential – Energy (kWh).

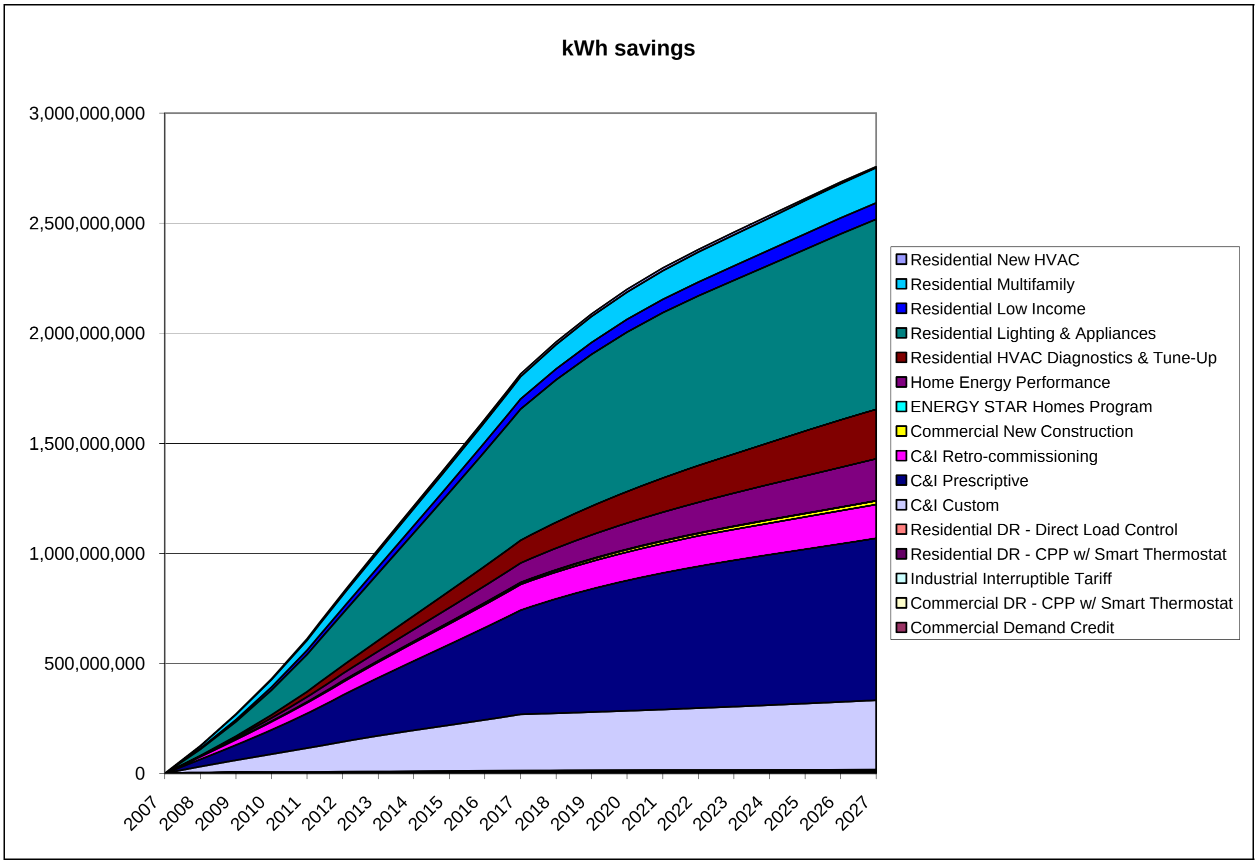
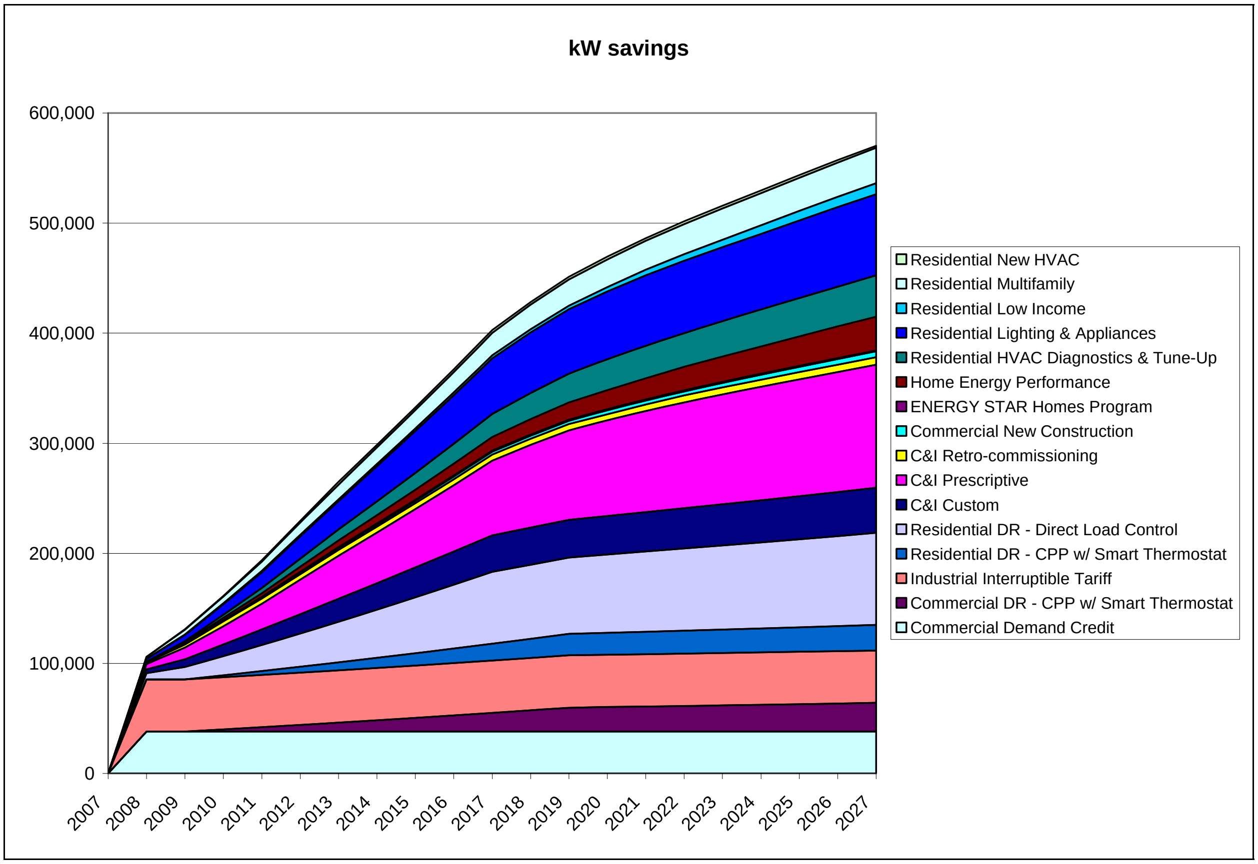


Figure 2: Achievable Potential – Demand (kW).



4 CSR 240-22.050 (5)

The utility shall conduct market research studies, customer surveys, pilot demand-side programs, test marketing programs and other activities as necessary to estimate the technical potential of end-use measures and to develop the information necessary to design and implement cost-effective demand-side programs. These research activities shall be designed to provide a solid foundation of information about how and by whom energy-related decisions are made and about the most appropriate and cost-effective methods of influencing these decisions in favor of greater long-run energy efficiency.

A variety of existing secondary market research was employed in the development of the demand-side analysis. This research included:

- Evaluations of AmerenUE's Building Operator Certification (4 CSR 240-22.050_Appendix E), Change A Light Rebate (4 CSR 240-22.050_Appendix F), Commercial Energy Audit and Energy Efficiency Rebate (4 CSR 240-22.050_Appendix G), LEED Incentive Grant (4 CSR 240-22.050_Appendix H) and Refrigerator Recycling and rebate programs (4 CSR 240-22.050_Appendix J) prepared by Opinion Dynamics Corporation.
- The 2006 Missouri Statewide Residential Lighting and Appliance Efficiency Saturation Study prepared by RLW Analytics.
- The Midwest Residential market Assessment and DSM Potential Study commissioned by the Midwest Energy Efficiency Alliance.
- An overview of Utility Load Control Programs prepared by Chartwell.
- A summary of the 2006 Electric Utility Residential Customer Satisfaction Study prepared by J.D. Power and Associates.
- Highlights of EEI member and Non-member Residential/Commercial/Industrial Efficiency and Demand Response Programs for 2006 prepared by the Edison Electric Institute.

In addition, a wide variety of secondary data sources were consulted in the development of the measure data. Principal among these was the Database for Energy Efficiency Resources (DEER), available online from the California Energy Commission. Additional measure data were taken from an "Internal Memo Report – Potential Analyses" prepared for the Missouri Utility Collaborative by RLW Analytics.

No primary market research was conducted as part of this plan. However, several areas of need have been identified. These include:

- An improved understanding of the peak impacts of a variety of weather-sensitive measures. For example, there is some uncertainty regarding the relationship between energy savings produced by upgrades to central air conditioners (both operating improvements and installation of new air conditioners) and coincident peak impacts. There also is uncertainty associated with the peak impacts of various building thermal integrity measures such as air sealing and insulation. This understanding could be improved by sub-metering and billing analysis studies.

- An improved understanding of market baseline conditions. Although the 2006 Missouri Statewide Residential Lighting and Appliance Efficiency Saturation Study provides valuable residential sector baseline data, comparable data were not available for the commercial and industrial sectors. Data pertaining to electricity use by building type and end-use within building type would be useful, as would an assessment of the current saturations of key commercial energy efficiency measures.

4 CSR 240-22.050 (6) (A)

The utility shall develop a set of potential demand-side programs that are designed to deliver an appropriate selection of end-use measures to each market segment. The demand-side program planning and design process shall include at least the following activities and elements:

Identify market segments that are numerous and diverse enough to provide relatively complete coverage of the classes and decision-makers identified in subsections (1)(A) and (B), and that are specifically defined to reflect the primary market imperfections that are common to the members of the market segment;

The program types examined and the market segments to which they are aimed are described in the Table 1:

Major Segment	Sub-Segments
Residential	
Lighting and Appliances	▪ Primary sub-segments: End-use customers and retailers. Manufacturers if program scale is sufficient. ▪ Primary market barriers are customer lack of information regarding product availability and cost-effective and higher first cost. Primary point of leverage is at point of sale.
New Construction	▪ Primary sub-segments: Builders and home energy raters. Home-buyers are secondary target ▪ Primary market barriers: Lack or awareness of brand value; Lack of home rating infrastructure.
Retrofit	▪ Primary sub-segments: Home owners/landlords; Home performance contractors. ▪ Primary market barriers: Lack of awareness of “house as a system”; Lack of information regarding providers of services; First cost.
New Central AC	▪ Primary sub-segments: HVAC dealers/installers. ▪ Primary market barriers: Lack of knowledge of proper installation techniques; Lack of knowledge of value proposition
Central AC Diagnostics	▪ Primary sub-segments: HVAC dealers/installers; Home owners; Small commercial customers. ▪ Primary market barriers: Lack of knowledge of proper diagnostic techniques; Lack of credible diagnostics infrastructure; Customer cost.
Low Income	▪ Primary sub-segments: End user customers; Landlords. ▪ Primary market barriers: Measure cost.
Multi-Family	▪ Primary sub-segments: Property owners/managers. ▪ Primary market barriers: First cost; Lack of awareness and staff resources.
Direct Load	▪ Primary sub-segments: Home owners

Control	▪ Primary market barriers: No inherent incentive to reduce peak loads given average cost pricing.
Critical Peak Pricing	▪ Primary sub-segments: Home owners ▪ Primary market barriers: No inherent incentive to reduce peak loads given average cost pricing.
Commercial and Industrial	
Prescriptive Incentive	▪ Primary sub-segments: Property/energy managers for all C&I building types; Trade allies (suppliers of equipment and services) ▪ Primary market barriers: High RoR requirements; Lack of knowledge about efficient technologies.
Custom Incentive	▪ Primary sub-segments: All C&I building types; Trade allies (suppliers of equipment and services) ▪ Primary market barriers: High RoR requirements; Lack of knowledge about efficient technologies.
Retro-Commissioning	▪ Primary sub-segments: Property/energy managers for all building types, but most likely participants include health care, education, government and commercial real estate. ▪ Primary market barriers: Lack of awareness of proper operation of current buildings; Lack of resources to devote to energy operations improvements.
New Construction	▪ Primary sub-segments: Architects and designers; Property owners. ▪ Primary market barriers: First cost for design and construction.
Interruptible	▪ Primary sub-segments: Owners/managers of large facilities ▪ Primary market barriers: No inherent motivation to reduce peak demand under average cost pricing; Cost of service disruptions.
Demand Credit	▪ Primary sub-segments: Owners/managers of large facilities ▪ Primary market barriers: No inherent motivation to reduce peak demand under average cost pricing; Cost of service disruptions.

Table 1: DSM Programs and Corresponding Market Segments

4 CSR 240-22.050 (6) (B)

Analyze the interactions between end-use measures (for example, more efficient lighting reduces the savings related to efficiency gains in cooling equipment because efficient lighting reduces intrinsic heat gain;

The interactions between measures were analyzed in two ways. First, factors representing the interactive effects associated with lighting measures were taken from the DEER database referenced in the measures documentation. These energy and demand interactive effects factors were multiplied by estimated lighting measure savings to estimate the net effect of the measure on thermal loads.

Second, the interactive effects of thermal measures and other appliances were simulated using the DOE-2 building energy simulation model. For example, different building types and shell characteristics have differential effects on cooling loads. A new efficient central air conditioner will produce different energy and demand savings in a prototypical gas-heated home than in a prototypical home heated using electric resistance. In addition, some appliances such as dishwashers exhaust heat within a conditioned space increasing the cooling load and reducing the heating load. More efficient appliances have reduced thermal discharge producing cooling savings in gas-heated homes and heating and cooling savings in electrically-heated homes.

It is not possible to comprehensively account for all possible interactive effects, since these will depend on the combinations of measures actually installed by program participants and the order in which measures are installed. For example, while installation of efficient commercial lighting measures will reduce cooling loads (accounted for in the interactive factors described above), the impact of reduced cooling load on the savings associated with a more efficient cooling systems only exists in those cases in which both lighting are first installed in the same building. However, it is not possible to estimate what fraction of program participants will install this specific combination of measures. To assume that efficient cooling systems will only be installed in buildings that have installed efficient lighting will lead to under-estimates of cooling savings given that it is unlikely that all cooling loads will have been reduced.

These measure interactive effects were estimated during the measure screening process and were accounted for in the cost-effectiveness analysis of the measures.

4 CSR 240-22.050 (6) (C)

Assemble menus of end-use measures that are appropriate to the shared characteristics of each market segment and cost-effective as measured by the screening test;

Measures that screened as cost-effective were then bundled into program types. A program type is a represented by a specific market segment, and high-level incentive, intervention and delivery strategies. The generic program types employed were drawn from a review of best practice program information drawn from publications of the American Council for an Energy Efficient Economy (Accessible at http://www.aceee.org/utility/exemplary_programs/index.htm), the Consortium for Energy Efficiency (www.cee.org), and the Energy Trust of Oregon (Accessible at http://www.energytrust.org/library/reports/Best_Practices/index.html?link_programs_reports_lin1Page=3) as well as from the Best Practices web site operated for the California Public Utilities Commission (Accessible at http://www.eebestpractices.com/index.asp), and from ICF International's own internal review of program operated by program administrators across the country. Below are the program mappings by sector.

Residential Program	Efficient Technology
ENERGY STAR Homes Program	ENERGY STAR Home (New)
Home Energy Performance	Ceiling Insulation (R-30)
	Ceiling Insulation (R-38)
	Faucet Aerators (Existing)
	Hot Water Insulation (Existing)
	Hot Water Pipe Insulation (Existing)
	Infiltration = 0.35 ACH
	Low Flow Shower Heads (Existing)
	R-11 Wall Insulation
Residential HVAC Diagnostics & Tune-Up	Central AC (Correct charge, Existing)
	Duct Leakage 5%
	Increase blower speed
	Increase duct sizes or add new ducts
Residential Lighting & Appliances	Compact fluorescent lamp (CFL)
	ENERGY STAR Ceiling Fan
	ENERGY STAR De-humidifier (Existing)
	ENERGY STAR Dishwasher (Existing)
	ENERGY STAR Freezer (Existing)
	ENERGY STAR Window AC (10.8 EER, Existing)
Residential Low Income	Ceiling Insulation (R-30)
	Compact fluorescent lamp (CFL)
	Doors R-4 (Existing)
	Low-E Windows (Existing)
	Programmable Thermostat (Existing)
	R-11 Wall Insulation
	Standard Refrigerator (Existing) - NAECA
Residential Multifamily	1 4' T8 32 watt lamps with electronic ballast and reflector
	1 8' T8 59 watt lamps with electronic ballast and reflector
	2 4' Super T8 28 watt lamps with electronic ballast
	2 4' T8 32 watt lamps with electronic ballast
	2 4' T8 32 watt lamps with electronic ballast with dimming system
	2 4' T8 32 watt lamps with electronic ballast with occupancy sensors
	2 8' Super T8 59 watt lamps with electronic ballast
	2 8' T8 59 watt lamps with electronic ballast with occupancy sensors
	Central AC (Correct charge, Existing)
	Electroluminescent Exit Sign (New)
	Electroluminescent Exit Sign Retrofit Kit
	Increase blower speed
	Infiltration = 0.35 ACH
	Integral CFL, screw-in
	LED Exit Sign (new)
	LED Exit Sign (retrofit kit)
	Modular CFL, pin based
	Occupancy sensor - Assume control 3 2-lamp fixtures w/T8 34W EL Ballast
	R-11 Wall Insulation
Residential New HVAC	ENERGY STAR Central AC (14 SEER, Existing)
	Size AC units to 100% of Manual J
Residential DR - CPP w/ Smart Thermostat	Critical peak pricing - CPP events with smart thermostat
Residential DR - Direct Load Control	Direct load control - air conditioner

Table 2: Residential Program Mapping

Business Program	Efficient Technology
C&I Prescriptive	250W PS Metal Halide
	50W Metal Halide
	1 4' T8 32 watt lamps with electronic ballast and reflector
	1 8' T8 59 watt lamps with electronic ballast and reflector
	100W Metal Halide
	175W PS Metal Halide
	180W LPS
	2 4' Super T8 28 watt lamps with electronic ballast
	2 4' T8 32 watt lamps with electronic ballast
	2 4' T8 32 watt lamps with electronic ballast with dimming system
	2 4' T8 32 watt lamps with electronic ballast with occupancy sensors
	2 8' Super T8 59 watt lamps with electronic ballast
	2 8' T8 59 watt lamps with electronic ballast with occupancy sensors
	200W HPS
	Addition of a LT subcooler to an air-cooled multiplex
	Addition of LT and MT subcoolers to an air-cooled multiplex
	Chiller Efficiency
	Connectionless Steamer, Efficient use = 0.5 kW/hour
	Electroluminescent Exit Sign (New)
	Electroluminescent Exit Sign Retrofit Kit
	Eliminate anti-sweat heaters from doors
	Hot Food Holding Cabinet, Efficient use = 0.43 kW/hour
	Install automatic door closer on walk-in cooler doors
	Install automatic door closer on walk-in freezer doors
	Integral CFL, screw-in
	LED Exit Sign (new)
	LED Exit Sign (retrofit kit)
	Modular CFL, pin based
	Occupancy sensor - Assume control 3 2-lamp fixtures w/T8 34W EL Ballast
	Packaged Unit Efficiency
	Premium Efficiency Motor
	Replace multiplex air-cooled condenser with evaporative condenser
	Scheduled AHU
	Substitute high efficiency motors for standard efficiency
	Upgrade from 53 Btu/Watt @ 10°F TD to 85 Btu/Watt
	Variable CW Pump
	Variable HW Pump
	VAV
C&I Retro-commissioning	Adds an 85°F holdback valve, active only when needed
	Air-cooled multiplex system w/extensive refrigeration equipment maintenance, normal setpoints
	Ambient following SCT setpoint, 70°F minimum
	Ambient following SCT setpoint, 70°F minimum, variable-spd condenser fan
	Cleaned Coil
	Cycle fan off with thermostat; duty cycle occasionally when off
	Extensive refrigeration equipment maintenance
	Floating SCT controlled to 70°F
	Floating SST control on LT and MT suction groups
	Optimized OA
	Reduce design SCT by ~5°F and improve efficiency
	Scheduled AHU
	Turn off fixture lights when store closed, between 12am and 6am
	Wetbulb following SCT setpoint, 70°F minimum
	Wetbulb following SCT setpoint, 70°F minimum, variable-spd condenser fan
Commercial New Construction	New Construction Building - with upgrades
C&I Custom	Industrial process measures
Commercial Demand Credit	Commercial Demand Credit
Commercial DR - CPP w/ Smart Thermostat	Critical peak pricing - CPP events with smart thermostat
Industrial Interruptible Tariff	Industrial Interruptible Tariff

Table 3: Business Program Mapping

4 CSR 240-22.050 (6) (D)

Include a delivery strategy that outlines the anticipated approach to promotion and delivery of the programs to the target market segment. This delivery strategy shall include basic information regarding marketing and implementation strategy as an element of program design and will outline approach, channels, and incentive, outreach and administrative processes. The strategies should be detailed enough to provide the Company and the parties with a sense of the proposed approaches as a basis for estimating program costs.

Such a delivery strategy has been prepared for each program type listed above in the form of a program template. These templates were provided to stakeholders, and stakeholder comments were incorporated as appropriate. These templates are included in Appendix_4 CSR 240-22.070(9) DSM Implementation Plan.

4 CSR 240-22.050 (7) (A)

Cost-Effectiveness Screening of Demand-Side Programs. The utility shall evaluate the cost-effectiveness of each potential demand side program developed pursuant to section (6) using the total resource cost test. The utility cost test shall also be performed for purposes of comparison. All costs and benefits shall be expressed in nominal dollars. The following procedure shall be used to perform these tests:

> **The utility shall estimate the incremental and cumulative number of program participants and end-use measure installations due to the program and the incremental and cumulative demand reduction and energy savings due to the program in each avoided cost period in each year of the planning horizon.**

Estimated incremental and cumulative program participants, end-use measure installations, and demand reductions and energy savings were estimated using a ICF International's Energy Efficiency Potential Model (EEPM). This model contains all of the measure information described earlier and performs calculations to estimate participation levels and end-use measure installations and, in turn, to estimate energy and demand impacts.

The process begins by establishing the eligible population of measures that can be replaced by more efficient measures. This "gross" population is then reduced by a series of factors shown below to account for the relevance of the measure, technical feasibility of measure replacement, the fraction of the total number of eligible baseline measures that are not yet efficient (based on the definition of the efficient measure), and the annual replacement eligibility which represents the fraction of the baseline stock that is assumed to turn over each year.

Total Sector Units (eg, # of Homes)	Relevance (eg, % of Homes with CAC)	# Technology Units per Sector Unit (eg, Bulbs per Home)	Technical Applicability (%)	Not Yet Adopted (%)	Annual Replacement Eligibility (%)	Total Applicable Technology Units

Total Sector Units * Relevance * # Technology Units per Sector Unit * Technical Applicability (%) * Not Yet Adopted (%) * Annual Replacement Eligibility (%) = Total Applicable Technology Units

The manner in which efficiency measures are defined in the primary source for the measure data determines whether what will be counted as a participant or a measure. For example, most residential measures are defined in terms of a specific piece of equipment in a home, for example, a central air conditioner or number of lighting sockets. Some commercial measures, however, are expressed in terms of savings per square foot (insulation) or tons of cooling (commercial HVAC). This definition carries through to the final estimates of energy and demand savings. Therefore, it is not possible in all cases to define a participant as a customer. In some cases, the participant effectively is a total number of square feet of building space or tons of cooling. While, conceptually, these units could be converted to numbers of buildings, to do so would require much more detailed data on commercial building stock than was available for this plan.

For measures for which savings were calculated on a whole building basis, building stock information from AmerenUE was used. For many of the commercial lighting measures, for which savings were calculated on a per fixture basis, commercial lighting load was disaggregated by building type and technology type. The building type shares were taken from AmerenUE customer data. Since technology type shares were not available for the AmerenUE territory, these figures were estimated using Lawrence Berkeley National Laboratory's (LBNL) Lighting Market Sourcebook for the US. For other commercial measures, estimates were made based on AmerenUE end use load data.

Industrial process measures represent the most difficult set of measures to assess given the enormous variety of applications, processes and technologies. Consistent data are difficult to obtain. For the industrial analysis conducted here, ICF relied primarily on California's Industrial Existing Construction Energy Efficiency Potential Study, developed by KEMA. The data for the measures examined in that study are all defined with respect to 1 kWh of energy use. Thus, the savings attributable to an efficient measure are expressed as a percentage reduction from 1 kWh of electricity consumed. For these measures, the total sector units would be equal to the total industrial load.

The data required for the calculation shown above generally are difficult to obtain and few utilities have primary data for these variables. Table 1 describes the sources used for each variable.

Variable	Source
Total Sector Units	Ameren 2005 IRP, EIA Form 861
Relevance	Missouri Statewide Residential Lighting and Appliance Saturation Study (RLW), California Industrial Existing Construction Energy Efficiency Potential Study (KEMA)
Technology Units per Sector Unit	Generally assumed as equal to 1
Technical Applicability	ICF's previous EEPM studies
Not Yet Adopted (%)	Missouri Statewide Residential Lighting and Appliance Saturation Study (RLW), California Industrial Existing Construction Energy Efficiency Potential Study (KEMA)
Annual Replacement Eligibility	Typically defined as the inverse of the measure life

Table 1: Sources of Measure Data

The assumptions used for these variables are shown in 4 CSR 240-22.050_Appendix A, pages 2.14 to 2.26.

Once the number of measures eligible for replacement in a given year is estimated, participation is calculated in a four-step process. First, the economics of a given measure are estimated from the Participant's perspective by calculating a pre-rebate payback period. Second, a desired payback period is selected, and the EEPM calculates the level of incentive required to bring the payback down to this level. Table 2 shows the desired payback period inputs (in years) for each portfolio.

Payback Acceptance	Portfolios 1,2	Portfolio 3
Residential	2.00	1.00
Commercial	2.00	1.50
Industrial	2.00	1.50

Table 2: Summary of Portfolio Payback Periods (Years)

A minimum incentive is established at 25% of the measure incremental cost and a maximum is set at 75% for most measures. In the case of measures included in the Low Income Program, the maximum is set at 80%, to reflect an average participant cost based on income level. Given these thresholds, it is possible that the post-rebate payback period could be lower than the target (if a measure is close to meeting the payback threshold, the 25% minimum incentive level will push the payback below the threshold). Similarly, even at the maximum incentive level, measures with relatively long paybacks might not meet the payback threshold.

Third, EEPM calculates a Payback Factor (PF) using a payback function that determines a measure's maximum market share based on the post-rebate payback. The payback function is an exponential function, such that the lower the payback, the greater the share of the market captured.

The functional form of the payback function is shown below:

$$PF = a * e \wedge (- b * x)$$

where the following variables represent:

a = sector specific parameter
b = sector specific parameter
x = post-rebate payback period

The sector specific parameters were estimated from a survey of residential and non-residential customers' payback preferences for participation in energy efficiency programs. The results were then used to estimate the Payback Factor for each energy efficiency measure. Fourth, EEPM calculates annual adoption of these measures using an adoption function that relates annual participation to an initial year's adoption rate, a maximum fraction of the market that a measure or program is assumed to achieve, and an annual growth rate.

The variables used in the adoption function are:

- Payback Acceptance Factor (PAF) - refers to the theoretical participation limit as applied to a program.
- Growth Rate (r) – determines how quickly the payback factor is reached, similar to an adoptive influence factor.
- Program Length - refers to the number of years a program would be run in order to approach the payback factor. Participation would not necessarily equal the payback factor over the Program Length period; this would occur over a longer term.

The measure PF from the payback function is then multiplied by the program PAF to get S_{max}, the Maximum Share of Installations. S_{max} is then divided by Program Length to get S_o, the initial year's adoption rate. These parameters are then entered into the S-curve equation to estimate participation in each year. The functional form of the adoption equation is shown below:

$$P_t = \frac{S_o * S_{max}}{S_o + (S_{max} - S_o) * e \wedge (-r * t)}$$

where P_t represents Participation in Year t.

The theoretical basis for the adoption function used in EEPM is well-established. The function generates the typical S-shaped curve characteristic of technology adoption. The actual shape of the curve, generated by the equation's parameters is subject to uncertainty. Very little consistent time-series or cross-sectional efficiency measure adoption data exist to enable a statistically valid estimate of key model parameters.

Given this uncertainty, the projections made by the model were compared where possible with actual program participation data from other utilities. This comparison was limited for the same reasons that statistically valid estimates of model parameters is elusive; there simply are very few published sources of data that enable one to gauge program participation over time as a function of program incentive levels, which we assume to be the primary driver of participation. Therefore, not only were comparisons made with available program performance data from other utilities, the estimated aggregate performance of the portfolio was compared with what other utilities had estimated to be total relative savings from their portfolios over time.

Data pertaining to estimated annual incremental measure installations, cumulative measure installations and annual kWh reductions associated with those installations are shown in 4 CSR 240-22.050_Appendix A, pages 3.13 to 3.108.

A.1

Initial estimates of demand-side program load impacts shall be based on the best available information from in-house research, vendors, consultants, industry research groups, national laboratories or other credible sources.

The estimates of the load impacts of the measure were estimated using the best available data; these data are described in the documentation of the measures analysis. Generally, the specific data values for measure load impacts are sound. As described earlier, non-weather-sensitive measure load impacts can be found in several credible sources, although some disagreement remains among practitioners regarding variables such as hours of operation and peak coincidence for different measures. Similarly the measure-level load impacts for weather-sensitive measures were estimated using standard practice (DOE-2 building energy simulation). However, even these estimates can be improved with actual in-field measurement data that can be used to calibrate model estimates. This is particularly the case with certain HVAC measures such as central air conditioning, where questions remain regarding the peak impacts of newer, high-efficiency technologies.

A.2
As the load-impact measurements required by subsection (9)(B) become available, these results shall be used in the ongoing development and screening of demand side programs and in the development of alternative resource plans;

Section (9)(B) pertains to required ongoing program impact evaluations. As programs are implemented and impact evaluation results become available, those results will be incorporated into subsequent analyses of energy efficiency and demand response measures and programs.

4 CSR 240-22.050 (7) (B)

In each year of the planning horizon, the benefits of each demand-side program shall be calculated as the cumulative demand reduction multiplied by the avoided demand cost plus the cumulative energy savings multiplied by the avoided energy cost, summed over the avoided cost periods within each year. These calculations shall be performed using the avoided probable environmental costs developed pursuant to section (2);

For each year of the analysis, the incremental number of participants (expressed as numbers of measures) was estimated. These estimates were multiplied by the per unit electricity and system coincident peak reductions to yield the annual incremental electricity and peak demand savings. The per measure avoided electricity and peak demand avoided costs also were multiplied by the annual incremental number of measures to yield the total avoided cost of the measure.

The estimates of annual incremental savings and avoided costs were added over years such that the cumulative savings in any year were equal to the savings realized by measures adopted in that year plus the annual savings realized from measures adopted in prior years taking into account measure lifetimes.

The analysis assumes that when adopted measures reach the end of their estimated lives, their impacts are “retired”. For example, compact fluorescent lamps (CFLs) are assumed to have a lifetime of nine years. The annual energy and peak demand impacts will be carried within the calculations for nine years and in the tenth year, the impacts will be subtracted. The assumption underlying this calculation is that customers are not “transformed” by their participation in the program. Once they are incented to install a measure they will not re-install that measure without an incentive when the measure expires. Undoubtedly, some customers will replace burned-out CFLs with new CFLs even without an incentive. However, across all measure categories, there simply are not sufficient data to support an assumption that efficient technologies will be replaced with efficient technologies absent program intervention. This effect of this assumption is most noticeable with CFLs since these measures make up a significant share of the total number of measures and measure savings projected over the planning period. However, other measures such as air conditioner maintenance, some lighting control technologies and some household appliances also have lifetimes that are significantly shorter than the planning period.

The calculations of annual avoided cost savings were made using avoided costs that assume a carbon tax and therefore incorporate probable environmental costs.

4 CSR 240-22.050 (7) (C)

Utility Cost Test. In each year of the planning horizon, the costs of each demand side program shall be calculated as the sum of all utility incentive payments plus utility costs to administer, deliver and evaluate each demand-side program. For purposes of this test, demand-side program costs shall not include lost revenues or costs paid by participants in demand-side programs;

The Utility Cost Test (UCT) as defined in the Rule was calculated for each program. The calculations included estimated/assumed program costs, including incentives, but did not include either lost revenues or participant costs.

Program	UCT
C&I Custom	2.94
C&I Prescriptive	2.44
C&I Retro-commissioning	6.78
Commercial Demand Credit	1.08
Commercial DR - CPP w/ Smart Thermostat	1.51
Commercial New Construction	1.35
ENERGY STAR Homes Program	1.18
Home Energy Performance	3.19
Industrial Interruptible Tariff	0.36
Residential DR - CPP w/ Smart Thermostat	1.30
Residential DR - Direct Load Control	1.78
Residential HVAC Diagnostics & Tune-Up	1.92
Residential Lighting & Appliances	3.99
Residential Low Income	1.00
Residential Multifamily	3.26
Residential New HVAC	2.13
Total Portfolio	**2.04**

Table 3: Utility Cost Test Results

4 CSR 240-22.050 (7) (D)

Total Resource Cost Test. In each year of the planning horizon, the costs of each demand-side program shall be calculated as the sum of all incremental costs of end-use measures that are implemented due to the program (including both utility and participant contributions) plus utility costs to administer, deliver and evaluate each demand-side program. For purposes of this test, demand-side program costs shall not include lost revenues or utility incentive payments to customers;

The Total Resource Cost (TRC) Test as defined in the Rule was calculated for each program. The calculations included estimated/assumed program administrative costs plus full measure incremental costs. Because measure incentives are always less than or equal to the measure incremental cost, the sum of participant and utility contributions never exceeds the measure incremental costs for energy efficiency programs.[1] Thus, the test as calculated excluded measure incentives. The test calculations did not include incentive payments to customers or lost revenues.

[1] This is not the case for all demand response programs. For example, the interruptible program has a very low incremental cost; essentially there are no measure costs. However, there is a utility incentive. This incentive is not counted in the TRC, but does result in the uncommon result of the program passing the TRC test but not the UCT.

Program	TRC
C&I Custom	2.23
C&I Prescriptive	1.89
C&I Retro-commissioning	3.17
Commercial Demand Credit	1.56
Commercial DR - CPP w/ Smart Thermostat	1.60
Commercial New Construction	1.14
ENERGY STAR Homes Program	1.00
Home Energy Performance	2.39
Industrial Interruptible Tariff	1.59
Residential DR - CPP w/ Smart Thermostat	1.37
Residential DR - Direct Load Control	1.93
Residential HVAC Diagnostics & Tune-Up	1.55
Residential Lighting & Appliances	2.29
Residential Low Income	0.88
Residential Multifamily	2.63
Residential New HVAC	1.71
Total Portfolio	**1.71**

Table 4: Total Resource Cost Test Results

4 CSR 240-22.050 (7) (E)

The present value of program benefits minus the present value of program costs over the planning horizon must be positive or the ratio of annualized benefits to annualized costs must be greater than one (1) for a demand-side program to pass the utility cost test or the total resource cost test. The utility may relax this criterion for programs that are judged to have potential benefits that are not captured by the estimated load impacts or avoided costs.

Most programs passed both the TRC test and UCT with few exceptions. As shown above, the Low Income Program fails the TRC test and barely passes the UCT. This is largely because this is configured as a comprehensive home performance program including a number of measures that are not cost-effective, e.g. window replacements. Because this program is intended to reach an otherwise hard-to-reach and at-risk market, the program was included in the all demand-side portfolios despite the results of the cost-effectiveness tests.

4 CSR 240-22.050 (7) (F)

Potential demand-side programs that pass the total resource cost test shall be considered as candidate resource options and must be included in at least one (1) alternative resource plan developed pursuant to 4 CSR 240-22.060(3).

Each of the programs listed above, including the Low Income Program, was included in two demand-side portfolios passed to the resource integration stage. The two portfolios differed with respect to the assumed level of participation and thus costs and energy and demand impacts.

4 CSR 240-22.050 (8)

For each demand-side program that passes the total resource cost test, the utility shall develop time-differentiated load impact estimates over the planning horizon at the level of detail required by the supply system simulation model that is used in the integrated resource analysis required by 4 CSR 240-22.060(4).

The model used to prepare the integration analysis requires estimates of monthly electricity and peak demand reductions. The results of the demand-side analysis were disaggregated into monthly energy and peak demand values. This was done by returning to the individual measures included in each program and aggregating detailed hourly impacts to the monthly level. For weather-sensitive measures, the initial simulation results already included hourly energy savings and demand reductions. The hourly energy savings simply were summed over the hours per month. The peak demand reduction was determined by matching the hourly peak demand reduction from the simulation to the hour of the monthly system peak demand.

Estimating non-weather-sensitive measure monthly energy and peak demand values was slightly more complicated. The Itron load shapes used to disaggregate annual energy savings into hourly values (described in the measures documentation) provided estimates of hourly energy. The usage at the hour of the monthly system peak was then compared to the usage at the hour of the annual system peak. The resulting ratio was then multiplied by the system peak demand reduction to determine each month's peak demand reduction.

For the Demand Response measures and programs, the system peak demand impacts were allocated fully for July, the month in which the system peak demand occurs. For the other summer (peak) months, the ratio of these months' peak demand savings to July's peak demand savings were calculated. These factors were calculated at about 77%, 88%, and 54% for June, August, and September, respectively.

All energy efficiency measures have some annual coincident peak demand impact, although certain measures such as residential CFLs have very low peak coincidence. However, the contribution of various measures to other monthly peaks can be quite different. For example, the residential CFL annual peak coincidence is low because the annual peak occurs during the summer and during daylight hours when few residential lights would be on. However, the coincidence is much higher (up to 5 times higher) during the winter months. The Company's monthly peaks occur in the late afternoon when a much higher proportion of residential CFLs would be expected to be in use. Driven primarily by this residential lighting effect, the monthly peak reduction impacts by the end of the forecast period are highest in the winter months. CFL use is projected to grow considerably, while demand response impacts (felt only during summer months) do not grow at nearly the same rate. Thus, the maximum peak impact shifts from the summer to the winter by later years of the analysis.

The monthly and system peak demand reductions, as well as the estimated monthly coincidence factors for a single 15 watt CFL (replacing a 60 watt incandescent lamp) are shown below:

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Demand reduction - watts	45	45	45	45	45	45	45	45	45	45	45	45
Ratio of monthly peak to system peak	5.04	8.33	6.17	1.83	1.17	1.46	1.00	1.56	1.71	1.94	4.12	7.53
Peak demand reduction - watts	18.38	30.38	22.49	6.68	4.27	5.33	3.65	5.70	6.24	7.09	15.03	27.45
Estimated coincidence factor	40.8%	67.5%	50.0%	14.9%	9.5%	11.8%	8.1%	12.7%	13.9%	15.8%	33.4%	61.0%

Table 1: Estimated Monthly & System Peak Demand Reductions (15 watt CFL)

4 CSR 240-22.050 (9)

Evaluation of Demand-Side Programs. AmerenUE shall develop process and impact evaluation strategies for all demand side-side programs that are included in the preferred resource plan. These strategies shall outline the proposed approach to the impact and process evaluation for the programs. Parts (A), (B) and (C) of the rule shall be considered advisory for purposes of developing these broad strategies. AmerenUE shall develop evaluation plans consistent with 4 CSR 240-22.050 (9) after final programs have been selected and detailed implementation plans have been prepared.

Such high-level evaluation strategies have been developed as part of each program design template which can be found in Section 4 of Appendix_4 CSR 240-22.070(9)-DSM Implementation Plan. These templates were shared with stakeholders in September 2007. In addition, an over-arching portfolio evaluation strategy was developed and described in section 5 of 4 CSR 240-22.070(9)_Appendix - DSM Implementation Plan.

4 CSR 240-22.050 (10)

Demand-side programs and load-building programs shall be separately designed and administered, and all costs shall be separately classified so as to permit a clear distinction between demand-side program costs and the costs of load-building programs. The costs of demand-side resource development that also serve other functions shall be allocated between the functions served.

No load building programs were examined as part of the demand-side analysis.

4 CSR 240-22.050 (11) (A)

Reporting Requirements. To demonstrate compliance with the provisions of this rule, and pursuant to the requirements of 4 CSR 240-22.080, the utility shall prepare a report that contains at least the following information:

A list of the end-use measures developed for initial screening pursuant to the requirements of section (1) of this rule;

The list of measures developed for screening is in 4 CSR 240-22.050_Appendix A, pages 2.1 to 2.13.

4 CSR 240-22.050 (11) (B)

The estimated load impacts, annualized costs per installation and the results of the probable environmental benefits test for each end-use measure identified pursuant to section (1);

The estimated load impacts, annualized costs per installation and the results of the probable environmental benefits test for each end-use measure identified pursuant to section (1) are shown in 4 CSR 240-22.050_Appendix A, pages 2.14 to 2.26.

4 CSR 240-22.050 (11) (C)

The results of AmerenUE benefits test for each end-use measure that passes the probable environmental benefits test.

The results of the utility benefits test are presented in 4 CSR 240-22.050_Appendix A, pages 2.14 to 2.26 (same as above). Note that the results of the test are equivalent to the Probable Environmental Benefits Test at the measure level given that all measures and programs have been evaluated using an avoided cost forecasts that includes an assumed cost for compliance with CO_2 emission legislation.

4 CSR 240-22.050 (11) (D) 1-2

If AmerenUE chooses the forecast of market cost of power alternative for 4 CSR 240-22.050 (2)(C), the following is substituted for this portion of the rule:

Documentation of the methods and assumptions used to develop the avoided cost estimates developed pursuant to section (2) including

1. **A description of the assumptions and procedures used for avoided capacity costs including regulatory capacity, transmission and distribution facilities;**
2. **A description of the assumptions and procedure used to calculate the market cost of power;**

See the response to section **Error! Reference source not found.** for a description of the assumptions and procedures used for capacity costs and the market cost of power.

4 CSR 240-22.050 (11) (E)

Copies of completed market research studies, pilot programs, test marketing programs and other studies as required by section (5) of this rule and descriptions of those studies that are planned or in progress and the scheduled completion dates;

No studies were conducted specifically to support this filing. The demand-side analysis did rely on recently completed pilot program evaluations for some measure and program data. These studies include:

- *2006 Missouri Statewide Residential Lighting And Appliance Efficiency Saturation Study Final Report*, November 15, 2006, A Joint Study for the Utility Collaborative: AmerenUE, Kansas City Power & Light, Aquila, Independence Power & Light, Empire District Electric Co., City Utilities Of Springfield, Columbia Water & Light, Prepared By RLW Analytics

- *Midwest Residential Market Assessment And DSM Potential Study*, Commissioned by Midwest Energy Efficiency Alliance, and sponsored by Xcel Energy, March 2006.

- *AmerenUE Residential TOU Pilot Study Load Research Analysis – 2005 Program Results*, Prepared by RLW Analytics, June 2006, submitted as 4 CSR 240-22.050_Appendix D.

- *Evaluation Of AmerenUE's Builder Operator Certification Program*, Prepared by Opinion Dynamics Corporation, in partnership with GDS Associates, June 2007, submitted as 4 CSR 240-22.050_APPENDIX E

- *Evaluation of AmerenUE's Change a Light Rebate Program*, Prepared by Opinion Dynamics Corporation in partnership with GDS Associates, June 2007, submitted as 4 CSR 240-22.050_Appendix F.

- *Evaluation Of AmerenUE's Commercial Energy Audit And Energy Efficiency Improvement Rebate Program*, Prepared by Opinion Dynamics Corporation, in partnership with GDS Associates, June 2007, submitted as 4 CSR 240-22.050_Appendix G.

- *Evaluation of AmerenUE's LEED™ Incentive Grant Program*, Prepared by Opinion Dynamics Corporation, in partnership with GDS Associates, June 2007, submitted as 4 CSR 240-22.050_Appendix H.

- *Evaluation of AmerenUE's Online Energy Information and Analysis Program*, Prepared by Opinion Dynamics Corporation, in partnership with GDS Associates, June 2007, submitted as 4 CSR 240-22.050_Appendix I.

- *Evaluation of AmerenUE's Refrigerator Recycling and Rebate Program*, Prepared by Opinion Dynamics Corporation, in partnership with GDS Associates, June 2007, submitted as 4 CSR 240-22.050_Appendix J.

4 CSR 240-22.050 (11) (F)

A description of each market segment identified pursuant to subsection (6)(A);

Please see the response to Requirement 4 CSR 240-22.050 (6)(A) above. Also see 4 CSR 240-22.070(9)_Appendix - DSM Implementation Plan for a more complete description of the program design process and the resulting program designs.

4 CSR 240-22.050 (11) (G)

A description of each demand-side program developed for initial screening pursuant to section (6) of this rule;

Please see 4 CSR 240-22.070(9)_Appendix - DSM Implementation Plan for a more complete description of each program. Table 1 summarizes the program descriptions.

ENERGY STAR New Homes	The program would target builders with a package of training, technical and marketing assistance and incentives for construction of ENERGY STAR homes (homes with a HERS score of 86 or higher). The Program would also provide supplemental incentives for savings measures not otherwise included in the builders' design or construction process (e.g. the ENERGY STAR Advanced Lighting Package, and duct sealing). To the extent that gas utilities offer similar programs in the service territory, close coordination/harmonization of program design and delivery is critical to avoid market confusion.
Residential Home Energy Performance	Home Energy Performance is a home diagnostic and improvement program that, as it establishes itself, can evolve into a more comprehensive ENERGY STAR Home Performance program focused on developing a local home performance industry. This initial implementation phase focuses on resource acquisition. An implementation contractor will be retained to market energy home improvement services, based on provision of a range of specific measure incentives, including a number of direct install measures (e.g. CFLs and faucet aerators.) The contractor will provide an energy audit, and will arrange for installation of insulation measures as warranted by the audit. In addition, as warranted, the contractor will coordinate with the HVAC Diagnostics and Tune-Up program to deliver those program services as warranted. During the initial implementation period, the implementation contractor will work to identify and train local firms that can provide comprehensive diagnostic and improvement services. Close coordination with the Earthways Center's St. Louis Home Performance with ENERGY STAR initiative will be key.
Residential HVAC Diagnostics	Some estimates show that as many as 78% of central AC units are improperly charged and up to 70% have improper airflow, both of which can lead to significant performance degradation. In concept the program is simple; HVAC contractors are trained to use one of several tools used to check refrigerant charge and airflow over the system's coils. Based on a quick analysis based on the inputs provided by the technician, the tool provides recommended charge and airflow. The technician then makes the necessary modifications. Typically, incentives are paid to the HVAC contractor per job. The contractor has the option of passing the incentive through to the consumer in the form of a lower fee for the service, or retaining the incentive; the choice depends on the contractor's marketing strategy. The key to the program is HVAC technical training and access to the tools used to diagnose system performance. The tool most cited in the best practice literature is CheckMe! More a process than a specific tool, the CheckMe! approach uses certified technicians to take a series of readings from operating air conditioners. These readings are phoned in to a central office where they are run through a computer analysis, producing a diagnosis as to performance and recommended actions. After the charge and airflow have been corrected, the technician takes another set of readings, calls them in and has the result verified. This process helps ensure not only that the proper diagnosis is performed, but also that the technician correctly sets refrigerant charge and airflow. The CheckMe! Process has been quite successful where applied; between 1998 and 2002 the program produced 46 MW in evaluated peak reduction. Honeywell offers a competing product and service known as HVAC Service Assistant that is designed to diagnose residential and small commercial HVAC performance on-the-spot, with the capability to upload the results to the web. This service is offered through Honeywell and does not provide the same independent check as the CheckMe! Program. KCP&L currently employs CheckMe! As the basis for a similar program.

Residential Lighting and Appliances	Given the initial size of the program, scale is insufficient to generate significant manufacturer or major retailer participation (such as through in store instant rebates or product price buy-downs. The primary delivery strategy will be direct consumer rebates, supported by outreach to retailers (special in-store events, etc). Essential elements of the program will include: • Account management—build relationships with retailers and manufacturers • Field services—provide retailer support for promotions, merchandising, and networking between retailers and manufacturers • Training—educate retail staff on the benefits of ENERGY STAR products • Co-op promotions and advertising –leverage existing funds for advertising and promoting products. Funds will be cost-shared up to a maximum amount. • Consumer incentives—provided to offset the purchase price • Manufacturer incentives—buy-downs to assist manufacturers' retail penetration primarily in the case of CFLs as part of the national Change-a-Light promotion. • In-store promotions—leverage existing retailer promotions • Marketing—develop and provide POP, advertising, in-store educational materials Retail sales staff incentives to promote and sell ENERGY STAR products (only would apply to larger appliances).
Residential Low Income	The Company would work with participating partners or agencies to qualify low-income customers for the program. The program would consist of the following measures: • Window replacement • Outside and storm door installation or replacement • Attic and wall insulation • ENERGY STAR refrigerator and freezer replacement • ENERGY STAR gas furnace replacement • CFL installations • Programmable thermostat installation Customers who have participated in the program would be eligible for a special rate based on reduced energy use.
Residential Multifamily	The program would provide installation of measures in tenant spaces related to central AC unit diagnostics and tune-up. It would also provide significant incentives for replacement of standard efficiency common area lighting and incandescent and fluorescent exit signs with LED exit signs. More expensive or complex measures (windows, replacement of roof-top AC units would be subject to an energy analyses to validate cost-effectiveness and set incentive levels. The incentives for these measures would be calculated in a fashion similar to the C&I Custom Incentive program, although the threshold payment period would be set at 1 year, recognizing that this is market that is harder to reach than the C&I market. The program would include limited technical services such as walk-through audits to determine approximate measure
Residential New HVAC	Many new central air conditioning units are under- or more commonly, over-sized resulting in frequent cycling and inefficient operation of the unit. Proper sizing of the units typically is accomplished using Manual J, the residential central AC sizing protocol developed by the Air Conditioning Contractors of America (ACCA) that uses detailed heat load calculations. Even where HVAC contractors use Manual J they can improperly apply the protocol. This program would target training at HVAC installers in the proper use of the Manual J and would provide modest incentives for proper application of the protocol.
Residential Direct Load Control	92% of the Company's residential customers have a Central AC system. These systems typically account for half of home's summer peak demand. Under this program, the Company provides for free equipment and installation of a smart thermostat that uses a one-way paging strategy. During summer peak periods, the Company activates the thermostats resulting in cycling of the Central AC unit. Customers can be paid an incentive in return for giving the Company the option to cycle their air conditioner. This program resembles the CPP program with Smart Control. The Company benefits through reduced peak power purchases and increased electric system reliability. Customers can benefit through reduced energy bills and an additional incentive.
Residential CPP with Smart Technology	This program combines a critical peak pricing tariff with a customer control architecture that enables customers to select control regimes in response to prices and/or enables the Company to control devices based on customers' specified control regimes. The specific technology employed may be similar to that used for the Company's pilot residential CPP program, or a more sophisticated system offered by demand response vendors. Customers enroll in a CPP tariff. The Company or its contractor

	provides for installation of the customer control equipment at no cost to the customer. Depending on the nature of the system, the customer will then set an equipment control regime based on the tariff's pricing periods. Again, depending on the specific structure of the system, during summer critical peak periods, the Company will activate control of specific equipment with limited customer override options. The Company benefits through reduced peak power purchases and increased electric system reliability. Customers can benefit by shifting use from on-peak and critical peak periods to off and mid-peak periods; however they do not receive an additional incentive beyond whatever equipment is provided.
C&I Custom Incentive	The Program will provide financial assistance to customers to support implementation of high-efficiency opportunities which are available at the time of new equipment purchases, facility modernization, and industrial process improvement. The incentives will be customized based on estimated energy savings subject to a cap. The cap can be single tier (e.g. $/kWh of first year savings) or can be multi-tiered with caps based on maximum incentive per kWh, minimum payback (e.g. buy-down to a 2 year payback), and maximum share of project cost. The advantage of a single tier cap is that customers and allies are better able to estimate the level of incentive in project evaluations. This is typical how standard offer programs operate. A multi-tiered cap is appropriate if there are concerns that the program would be overpaying for projects or attracting too high a level of free riders It is often assumed that C&I customers typically will make an investment without incentive if the payback is below two years. We have found this not to be the case consistently, particularly with projects that entail significant perceived risk. Initially, the program will be offered without extensive technical support (detailed audits, co-funding of studies, etc). The program logic model assumes that most projects will be initiated by trade allies and more sophisticated customers with in-house energy management who, as part of the project assessment, will prepare such studies (generally consistent with recent program experience for We Energies). Should program volume lag expectations, the Company reserves the right to provide financial support for project studies or independent review of projects to confirm savings, recognizing that extensive technical support can significantly impact program cost-effectiveness. The program will include internal review of all custom incentive applications to verify savings calculations and the program will reserve the right to site-verify data prior to approval. The primary delivery channel for custom projects will be trade allies/energy service companies, and Company account representatives. Outreach to trade allies to explain project eligibility and the incentive structure is critical. Again, depending on project volume, the Company will consider a supplemental ally incentive to stimulate project development. The key to the success of a custom incentive program is minimizing program application complexity and a straightforward incentive structure. If the final program design is too complex, allies will by-pass the program in favor of the prescriptive incentive program.
C&I Prescriptive Incentive	The program will provide rebates for energy-efficient products that are readily available in the marketplace and with savings opportunities for a large number of customers. The program will target measures for which energy savings can be reliably deemed, or calculated using simple threshold criteria. Rebates will be fixed per measure. Examples of measures in the first category are premium efficiency motors, vending machine sensors, and many lighting measures. Variable frequency drives, air compressors, basic refrigeration measures are examples of measures where a simple calculation may be required. In either case, the rebate is pre-set rather than calculated based on the specific project. A principal objective of this program element is to provide an expedited, simple solution for customers interested in purchasing efficient technologies that can produce verifiable savings.
C&I Retro-Commissioning	This program is intended to help building owners and managers determine the energy performance of buildings, to identify major opportunities for improving that performance through re-optimization of existing systems and replacement of under-performing equipment, and to provide financial support in some cases for taking recommended actions. To ensure savings persistence, program process involves establishment of a tracking system in the post-implementation M&V stage. The program would provide several related sets of services including initial qualification based on benchmarking or quick facility assessments, more detailed facility assessments intended to identify opportunities for systems improvements, development of a retro-commissioning plan, training, direct installation of low-cost measures and verification of plan implementation and incentive fulfillment.
C&I New Construction	The New Construction Program will promote energy efficiency through a comprehensive effort to influence building design practices. To secure these opportunities it is necessary to overcome barriers such as resistance in the design community to adopt new ideas, increased first cost for efficient options and tendency to design for worst-case conditions rather than efficiency over the range of expected operating conditions. The program will endeavor to overcome these and other barriers through education and outreach to building owners, design professionals, building contractors and other trade

	allies to introduce efficiency concepts, design facilitation, technical assistance, support for the LEED rating system, and incentives for efficient designs and measure implementation. The Company has participated in the Ameren/USGBC – St. Louis Chapter LEED Incentive Grant Program that has provided grants of up to $30,000 for projects designed and built to LEED standards (the size of the project grants has been linked to the level of LEED certification). Under this new program, the LEED certification grant will be retained, but expanded to include additional training and technical assistance and actual measure incentives. The program will work with building owners/managers, design professionals, trade allies, contractors and the USGBC – St. Louis Regional Chapter to design and construct high performance buildings that provide improved energy efficiency, strong environmental performance, systems performance and comfort. This will be accomplished through an integrated design process that results in improved efficiency in the building envelope, lighting, HVAC and other energy and resource consuming systems. At this stage in the program design process the program is envisioned as having two tracks. The first retains the features of the original LEED Incentive Grant Program. The initial design grant for LEED-designed buildings and the post-certification grants will continue to be available. The second track incorporates a more focused approach to specific energy efficiency improvements and itself includes two tracks. 1. Systems track – technical assistance and incentives are provided for construction that incorporates efficient systems (lighting, daylighting, HVAC, etc). This track could be based on an approach such as the Advanced Buildings concept developed by the New Buildings Institute. Advanced Buildings is a suite of design manuals, performance guidelines and training designed to increase market place knowledge and improve design and construction practices. 2. Comprehensive or whole building track – technical assistance and incentives are provided for buildings constructed based on whole-building energy simulation and achievement of whole-building performance targets. A key element for success in a new construction program is securing the involvement of the professional design community. This will be a major activity in both program approaches. The program will employ targeted marketing, training and education offerings, lunch and learn presentations, individual contact and outreach through professional organizations to engage design professionals. The program will also offer design and implementation incentives to encourage program participation. To encourage participation of the design community and to offset the costs of considering multiple design options a multi-tier incentive will be offered to the project design teams. The LEED grants are intended to provide an incentive to invest additional design resources. An implementation incentive based on the incremental costs of the efficiency measures will be offered to the building owner to help overcome the first cost barrier.
Commercial CPP with Smart Technology	This program combines a critical peak pricing tariff with a customer control architecture that enables customers to select control regimes in response to prices and/or enables the Company to control devices based on customers' specified control regimes. The specific technology employed may be similar to that used for the Company's pilot residential CPP program, or a more sophisticated system offered by demand response vendors. Customers enroll in a CPP tariff. The Company or its contractor provides for installation of the customer control equipment at no cost to the customer. Depending on the nature of the system, the customer will then set an equipment control regime based on the tariff's pricing periods. Again, depending on the specific structure of the system, during summer critical peak periods, the Company will activate control of specific equipment with limited customer override options. The Company benefits through reduced peak power purchases and increased electric system reliability. Customers can benefit by shifting use from on-peak and critical peak periods to off and mid-peak periods; however they do not receive an additional incentive beyond whatever equipment is provided.
Commercial and Industrial Demand Credit	Commercial and industrial customers willing to curtail their service by the Company at times of peak demand enroll in the Program by signing a curtailment service contract and providing an action plan for complying with the rider. The contract will specify that during curtailment events in which the customer participates, the customer must reduce demand to level specified by the customer or incur a penalty for not reducing demand. The Company will provide participating customers with an automated fax and email, on the day prior to or the day of a curtailment event. Customers will receive a per-event incentive payment in the form of a bill credit for reducing demand to the contractually-specified level during a curtailment event. Unlike the proposed Interruptible Program, customers receive payments only for demand reductions during events.
C&I Interruptible Tariff	Commercial and industrial customers willing to have their service interrupted by the Company at times

	of peak demand enroll in the Program by signing an interruptible service contract with a fixed term (e.g. one, three and/or five years). Curtailment/interruption can be for either reliability or economic reasons. Customers will be allowed to buy-through a curtailment called for economic reasons. The customer incentive will be graduated based on the contract length, with higher incentives under longer contracts. The contract will specify that during program "events" (which could be defined by reliability or economic conditions), the customer must have their service interrupted or reduce demand to a specified level, or incur a penalty for not reducing demand. The Company will provide participating customers with an automated phone call or email, with at least four hours advance notice prior to an event. Interruptions will be limited to one event per day for a duration of between two and eight hours, ands 10 events in total per season, with maximum of 80 interruptible hours per seasons. The season is defined as the months June – September.

Table 1: Summary of DSM Program Descriptions

4 CSR 240-22.050 (11) (H)

A tabulation of the incremental and cumulative number of participants, load impacts, utility costs and program participant costs in each year of the planning horizon for each demand-side program developed pursuant to section (6) of this rule;

These tabulations, noted as:

- Installations
- Cumulative Installations
- Net kWh Savings
- Net kW Savings
- Incentive Costs, and
- Administrative Costs,

are in 4 CSR 240-22.050_Appendix A, pages 3.13 to 3.156.

4 CSR 240-22.050 (11) (I)

The results of the utility cost test and the total resource cost test for each demand-side program developed pursuant to section (6) of this rule; and

Program	TRC	UCT
C&I Custom	2.23	2.94
C&I Prescriptive	1.89	2.44
C&I Retro-commissioning	3.17	6.78
Commercial Demand Credit	1.56	1.08
Commercial DR - CPP w/ Smart Thermostat	1.60	1.51
Commercial New Construction	1.14	1.35
ENERGY STAR Homes Program	1.00	1.18
Home Energy Performance	2.39	3.19
Industrial Interruptible Tariff	1.59	0.36
Residential DR - CPP w/ Smart Thermostat	1.37	1.30
Residential DR - Direct Load Control	1.93	1.78
Residential HVAC Diagnostics & Tune-Up	1.55	1.92
Residential Lighting & Appliances	2.29	3.99
Residential Low Income	0.88	1.00
Residential Multifamily	2.63	3.26
Residential New HVAC	1.71	2.13
Total Portfolio	**1.71**	**2.04**

Table 2: TRC and UCT Results (Program & Portfolio)

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A description of the process and impact evaluation plans for demand-side programs that are included in the preferred resource plan as required by section (9) of this rule and the results of any such evaluations that have been completed since the utility's last scheduled filing pursuant to 4 CSR 240-22.080.

Evaluation strategies can be found in 4 CSR 240-22.070(9)_Appendix-DSM Implementation Plan. Program-specific strategies can be found in Section 4 of that document within each program template. Section 5 of that document contains a discussion of overall portfolio and program evaluation strategy. Certainly, actual program evaluations should be based on more detailed evaluation plans, including data collection and analysis methodologies consistent with the appropriate IPMVP option. However, these detailed plans cannot reasonably be developed until final program designs have been prepared.