Missouri Statewide DSM Market Potential Study

Final Report

Prepared for:
Missouri Public Service Commission
Jefferson City, Missouri

Prepared by

KEMA, Inc.
Burlington, Massachusetts

March 4, 2011

Table of Contents

Table of Contents

Table of Contents

Table of Contents

List of Figures:

Table of Contents

Table of Contents

Table of Contents

List of Tables:

Table of Contents

Table of Contents

Table of Contents

List of Appendices:

1. Executive Summary

This study assessed the electric and natural gas DSM (demand side management) potential for the residential, commercial, and industrial sectors in the state of Missouri. The study was commissioned by the Missouri Public Service Commission (PSC), supported by the Missouri Department of Natural Resources. The goal of this study was to determine the levels of DSM savings available in the state of Missouri, the costs associated with procuring these savings, and whether the measures delivering the savings are cost effective. This study provides energy-efficiency and demand-response potential estimates for the period from 2011-2030, with the primary focus on the 2011-2020 period.

1.1 Scope and Approach

In this study, three types of energy-efficiency potential were estimated:

- **Technical potential,** defined as the *complete* penetration of all measures analyzed in applications where they were deemed *technically* feasible from an *engineering* perspective
- **Economic potential,** defined as the *technical potential* of those energy-efficiency measures that are cost-effective when compared to supply-side alternatives
- **Achievable program potential,** the amount of savings that would occur in response to specific program funding and measure incentive levels.

In addition, naturally occurring energy-efficiency impacts were estimated. These are savings that result from normal market forces. These values were necessary to calculate the adjusted baseline described in Sections 4.2.5 and 4.3.5. Achievable program potential reflects savings that are projected beyond those that would occur naturally in the absence of any market intervention.

The method used for estimating potential is a “bottom-up” approach in which energy-efficiency costs and savings are assessed at the customer-segment and energy-efficiency measure level. For cost-effective measures (based on the total resource cost, or TRC, test), program savings potential was estimated as a function of measure economics, rebate levels, and program marketing and education efforts. The modeling approach was implemented using KEMA’s DSM ASSYST™ model. This model allows for efficient integration of large quantities of measure, building, and economic data to determine energy-efficiency potential.

For this study two scenarios were developed at the specific direction of the PSC based on measure payback levels. These are characterized as follows:

* **One-year Payback -** In this scenario we assume customer incentives are provided such that all cost-effective measures have a payback period of one year. For measures that have payback periods of one year or less without incentives, no incentives are provided, but they may be supported through marketing, educational, and other program efforts.

* **Three-year Payback** - In this scenario we assume customer incentives are provided such that all cost-effective measures have a payback period of three years. For measures that have payback periods of three years or less without incentives, no incentives are provided, but they may be supported through marketing, educational, and other program efforts.

A third scenario is described in Appendix A.

The assessment addressed measures and processes that are commercially available with proven savings and customer acceptance. We excluded a general modeling of emerging technologies and behavioral-conservation approaches. These additional components show promise for future DSM program impacts, but projections of their savings potentials have much more uncertainty than those of more standard measures. Nor did the study address incremental improvements in energy efficiency due to the ongoing evolution and improvement of technologies. These improvements will lead to increased energy-efficiency potential, over time. Also, the study did not address the ongoing tightening of equipment and building standards, which will in turn lead to a decrease in energy-efficiency potential, over time.

To estimate demand response (DR) impacts, we reviewed impacts from the Federal Energy Regulatory Commission's (FERC) *2009 National Assessment of Demand Response Potential*[1] (NADR) for the State of Missouri and customized the results to the state of Missouri, utilizing information developed by the KEMA team from Missouri-specific sources.

1.2 Results

We report overall results of the DSM potential study in this section. Cumulative results for the period from 2011 to 2020 are shown. Our analysis covered a twenty-year period, and the results of this analysis are included in Appendix H. In our experience the further into the future projections go, on any topic, the greater the uncertainty. For the purposes of policy, actions that

[1] *A National Assessment of Demand Response Potential*, Staff Report, Federal Energy Regulatory Commission, prepared by The Brattle Group, Freeman, Sullivan & Co., and Global Energy Partners, LLC, June 2009.

will be taken in the near term, and comparison to other studies and past results, we find that the ten-year timeframe is most useful, and credible.

Our analysis is conservative, in that we did not include savings from technologies or program efforts that are not currently in existence. Neither did we include predictions on savings from behavioral or societal shifts. For example residential comparative usage feedback programs, such as those provided by OPOWER, a residential consumer information program found to have verified savings in limited test periods on the order of 1-3% per year, are not included in the analysis, nor are policy initiatives such as an aggressive carbon emission reduction program on the national level. The measures included in our analysis are those where we have very high confidence in the savings estimates, based on documented results from existing programs, reliable evaluation, or other credible sources.

1.2.1 Electric Potential Overview

Table 1-1 and Table 1-2 below summarize the results for the electricity.

Table 1-1
Electric Energy Savings Potential Overview

Sector	2020 Fixed Efficiency Base Energy Use (GWH)	Ten Year Cumulative Potential - GWh			
		Technical Potential	Economic Potential	Three Year Payback Achievable Potential - Net*	One Year Payback Achievable Potential - Net*
Residential Existing	39,460	17,578	11,805		
Residential New	2,074	372	372		
Subtotal	41,534	17,949	12,176	1,313	2,910
Savings % of Base		**43%**	**29%**	**3%**	**7%**
Commercial Existing	28,959	10,263	7,211		
Commercial New	3,484	1,286	1,286		
Subtotal	32,444	11,549	8,496	1,125	1,980
Savings % of Base		**36%**	**26%**	**4%**	**6%**
Industrial	18,586	3,174	2,686	627	1,248
Savings % of Base		**17%**	**14%**	**3%**	**7%**
Total	92,564	32,672	23,359	3,066	6,138
Savings % of Base		**35%**	**25%**	**3%**	**7%**

*Percent savings for net achievable potential savings are calculated relative to the adjusted baseline (see Section 4.2.5).

Table 1-2
Electric Demand Savings Potential Overview

Sector	2020 Fixed Efficiency Base Demand (MW)	Ten Year Cumulative Potential - MW			
		Technical Potential	Economic Potential	Three Year Payback Achievable Potential - Net*	One Year Payback Achievable Potential - Net*
Residential Existing	9,938	4,582	3,593		
Residential New	404	72	72		
Subtotal	10,342	4,654	3,665	641	1,437
Savings % of Base		**45%**	**35%**	**6%**	**14%**
Commercial Existing	5,057	1,674	970		
Commercial New	486	180	180		
Subtotal	5,542	1,854	1,150	172	305
Savings % of Base		**33%**	**21%**	**3%**	**6%**
Industrial	2,313	350	348	63	126
Savings % of Base		**15%**	**15%**	**3%**	**5%**
Total	18,197	6,858	5,163	876	1,868
Savings % of Base		**38%**	**28%**	**5%**	**10%**

*Percent savings for net achievable potential savings are calculated relative to the adjusted baseline (see Section 4.2.5).

Demand savings from demand response programs presented separately and are not incorporated in the tables above.

1.2.2 Gas Potential Overview

KEMA analyzed the potential energy savings for natural gas using the same scenarios as electricity. Table 1-3 summarizes the results of this analysis.

Table 1-3
Natural Gas Energy Savings Potential Overview

Sector	2020 Fixed Efficiency Base Energy Use - Dekatherms	Ten Year Cumulative Potential - Dekatherms			
		Technical Potential	Economic Potential	Three Year Payback Achievable Potential - Net*	One Year Payback Achievable Potential - Net*
Residential Existing	99,868,466	59,222,439	27,350,596		
Residential New	17,227,081	3,333,059	3,333,059		
Subtotal	117,095,547	62,555,498	30,683,655	2,920,823	6,503,323
Savings % of Base		**53%**	**26%**	**3%**	**6%**
Commercial Existing	62,107,492	22,706,674	16,751,696		
Commercial New	7,504,701	2,752,166	2,198,437		
Subtotal	69,612,193	25,458,840	18,950,133	957,893	3,600,522
Savings % of Base		**37%**	**27%**	**1%**	**5%**
Industrial	67,097,602	9,032,250	8,535,630	454,927	1,292,675
Savings % of Base		**13%**	**13%**	**1%**	**2%**
Total	253,805,342	97,046,588	58,169,418	4,333,644	11,396,521
Savings % of Base		**38%**	**23%**	**2%**	**5%**

*Percent savings for net achievable potential savings are calculated relative to the adjusted baseline (see Section 4.3.5).

1.2.3 Demand Response Potential Overview

The demand response potential was developed using the NADR model as noted above. NADR develops potential under four scenarios, described below.

- Business-as-usual (BAU): BAU assumes current programs and tariffs are held constant;
- Expanded BAU (EBAU): EBAU assumes participation rates are increased to equal the 75th percentile of ranked participation rates of similar programs.

- Achievable Participation (AP): AP assumes advanced metering infrastructure (AMI) is universally deployed, and dynamic pricing is the opt-out default tariff.
- Full Participation (FP): EP assumes that dynamic pricing and the acceptance of enabling technology is mandatory. This scenario quantifies the maximum cost-effective DR potential, absent any regulatory and market barriers.

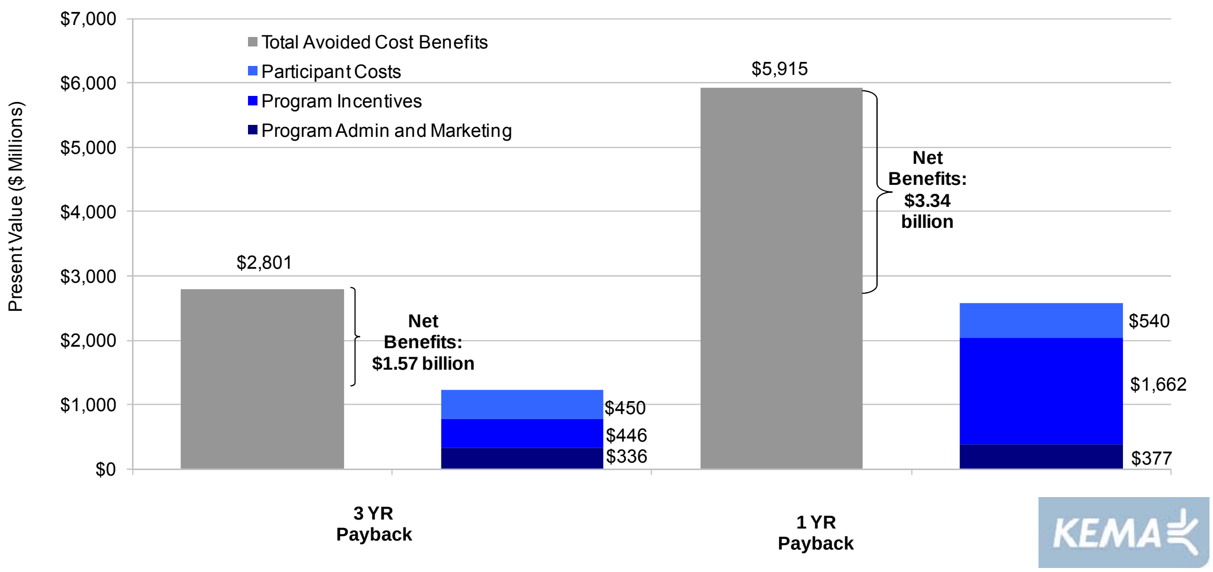
Table 1-4 summarizes the results of the NADR model across all four scenarios.

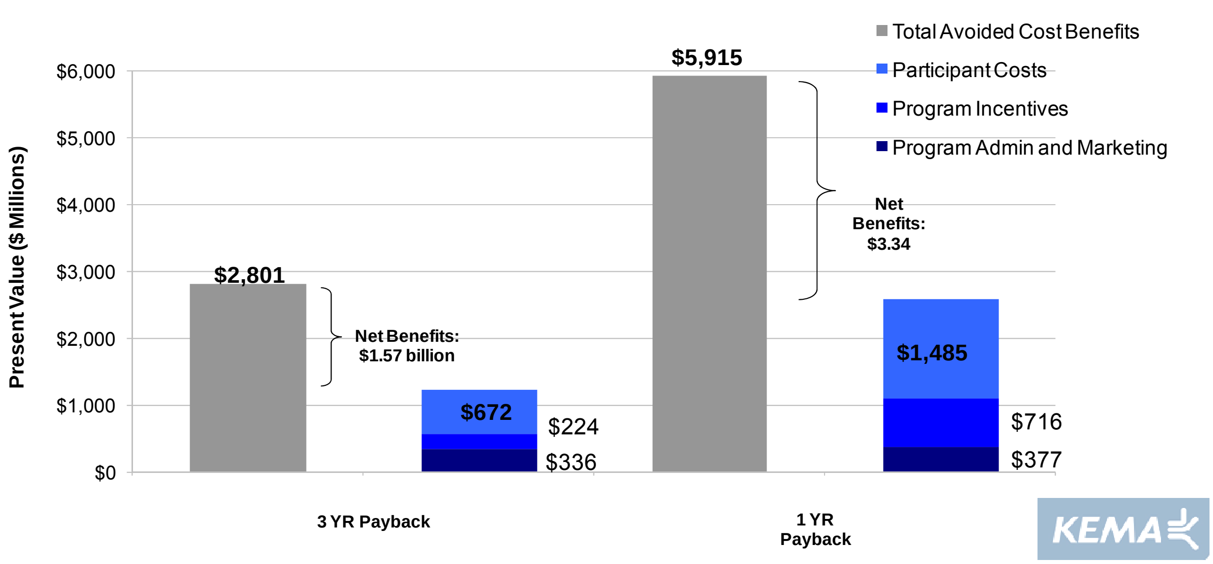
Table 1-4
NADR Demand Response Potential Summary

Program mechanism	2010	2015	2020	2025	2030
	MW	MW	MW	MW	MW
BAU					
Pricing With Enabling Technology	0	0	0	0	0
Pricing Without Enabling Technology	0	0	0	0	0
Automated or Direct Control DR	63	63	63	63	63
Interruptible Tariffs	219	219	219	219	219
Other DR	0	0	0	0	0
TOTAL	**282**	**282**	**282**	**282**	**282**
Expanded BAU					
Pricing With Enabling Technology	0	0	0	0	0
Pricing Without Enabling Technology	0	31	46	62	85
Automated or Direct Control DR	336	839	850	864	875
Interruptible Tariffs	326	647	677	713	752
Other DR	26	316	328	343	358
TOTAL	**688**	**1833**	**1900**	**1982**	**2070**
Achievable Participation					
Pricing With Enabling Technology	0	660	1255	1294	1335
Pricing Without Enabling Technology	0	353	674	697	722
Automated or Direct Control DR	336	521	241	247	252
Interruptible Tariffs	326	647	677	713	752
Other DR	26	218	134	142	149
TOTAL	**688**	**2399**	**2982**	**3093**	**3210**
Full Participation Potential					
Pricing With Enabling Technology	0	1599	3045	3142	3243
Pricing Without Enabling Technology	0	139	268	281	296
Automated or Direct Control DR	336	409	63	63	63
Interruptible Tariffs	326	647	677	713	752
Other DR	26	149	0	0	0
TOTAL	**688**	**2942**	**4052**	**4200**	**4353**

Figure 1-1 depicts costs and benefits under each program funding scenario from 2011~~2010~~ to 2020 for electric energy efficiency.

Figure 1-1
Benefits and Costs of Electric Efficiency Savings—2011-2020*

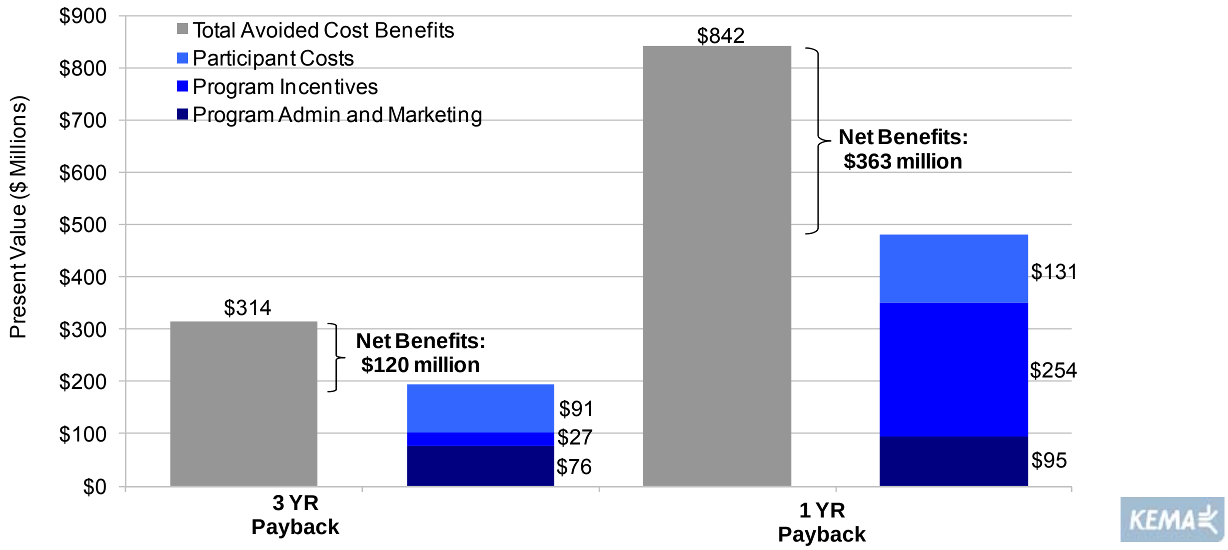


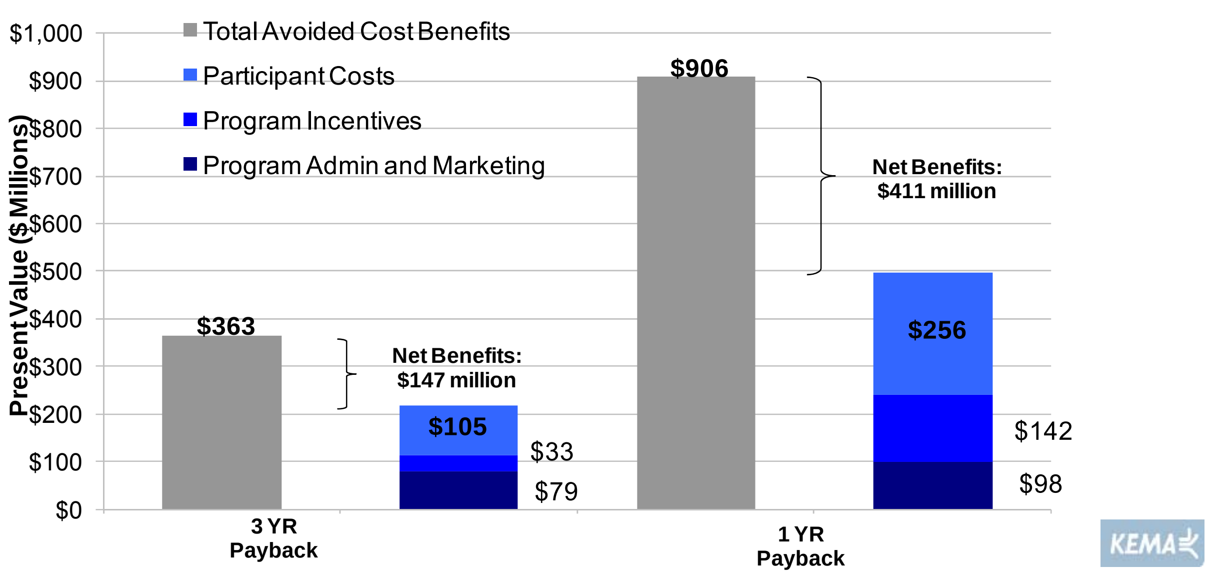


* Present value of benefits and costs over normalized 20-year measure lives; nominal discount rate is 7.8 percent, inflation rate is 2.5 percent.

Figure 1-2 shows the same sets of results for natural gas. For both electricity and natural gas, both of the program funding scenarios are cost-effective based on the TRC (total resource cost) test, which was the test used in this study to determine program cost-effectiveness.

Figure 1-2
Benefits and Costs of Natural-Gas Efficiency Savings—2011-2020* -





* Present value of benefits and costs over normalized 20-year measure lives; nominal discount rate is 7.8 percent, inflation rate is 2.5 percent.

The tables below provide a snapshot summary of the estimated programmatic savings, costs, and benefits for both scenarios.

Table 1-5 Summary of Achievable Electric Potential Results – 2011 - 2020

Result - Programs	3 YR Payback	1 YR Payback
Gross Energy Savings - GWh	5,447	8,519
Gross Peak Demand Savings - MW	1,282	2,274
Net Energy Savings - GWh	3,066	6,138
Net Peak Demand Savings - MW	876	1,868
Program Costs - Real, $ Million		
Administration	$195	$244
Marketing	$224	$224
Incentives	$563	$2,035
Total	$982	$2,504
PV Avoided Costs	$2,801	$5,915
PV Annual Program Costs (Adm/Mkt)	$336	$377
PV Net Measure Costs	$896	$2,201
Net Benefits	$1,568	$3,336
TRC Ratio	2.27	2.29

Table 1-6
Summary of Achievable Natural Gas Potential Results—2011-2020

Result - Programs	3 YR Payback	1 YR Payback
Gross Energy Savings - Therms (Millions)	103.6	177.6
Net Energy Savings - Therms (Millions)	43.3	114.0
Program Costs - Real, $ Million		
Administration	$61	$84
Marketing	$34	$34
Incentives	$33	$314
Total	$127	$431
PV Avoided Costs	$314	$842
PV Annual Program Costs (Adm/Mkt)	$76	$95
PV Net Measure Costs	$118	$385
Net Benefits	$120	$363
TRC Ratio	1.62	1.76

Result - Programs	3 YR Payback	1 YR Payback
Gross Energy Savings - Therms (Millions)	103.6	177.6
Net Energy Savings - Therms (Millions)	43.3	114.0
Program Costs - Real, $ Million		
Administration	$61	$84
Marketing	$34	$34
Incentives	$33	$314
Total	$127	$431
PV Avoided Costs	$314	$842
PV Annual Program Costs (Adm/Mkt)	$76	$95
PV Net Measure Costs	$118	$385
Net Benefits	$120	$363
TRC Ratio	1.62	1.76

The scenarios analyzed show benefit cost ratios increasing for both energy sources as the investment increases.

1.2.4 Uncertainty of Results

We want to caution the reader that there is inherent uncertainty in the results presented in this report because they are forecasts of what could happen in the future. Our estimates of technical and economic potential have the lowest degree of uncertainty. These are estimates that account for savings, costs, and current saturations of DSM measures but do not factor in human behavior.

The achievable program estimates do take into account behavior, as our modeling efforts try to predict program participation levels while factoring in measure awareness and economics, as well as barriers to measure uptake. Hence, the uncertainty in our achievable potential estimates is greater.

1.3 Conclusions

As the results of this study indicate, there is a significant amount of energy efficiency potential remaining in the state of Missouri. For electricity, the residential and commercial sectors provide the largest sources of potential savings.

Key residential end uses, in terms of potentials, include cooling, lighting, and refrigeration. Whole-building new construction measures are also a source of large potential savings. It may be necessary to offer fairly large incentives to capture the largest amounts of residential electricity savings potential. Plug loads, home entertainment equipment, and home office equipment also provide a significant of energy savings potential, but use of customer incentives for measures in these end uses does not appear to be the way to go as there is usually very little cost differential between standard-efficiency and high-efficiency equipment. Customer education and upstream activities are probably more useful approaches to increase the availability and purchases of more efficient electronic equipment.

In the commercial sector, lighting and cooling continue to provide the largest sources of electric energy efficiency potential. Data center and server measures also appear to be a growing source of potential energy savings.

Demand response programs will continue to be a large source of peak demand savings.

The residential sector is by far the largest source of natural-gas savings potential. The key residential end-uses are space heating and water heating, and key measures include high efficiency water heaters, furnaces and boilers as well as building shell measures such as insulation and weatherization. Residential new construction measures also provide a large source of potential natural-gas savings. Similar to the electric findings, it may take fairly large incentives to capture high levels of residential gas potential.

Emerging technologies will play an increasing role in the energy efficiency portfolio as traditional measures reach high market saturation levels. It will be useful for Missouri to run pilot programs to test both the technical effectiveness and the market acceptance of emerging technologies before rolling out full scale programs.

2. Introduction

2.1 Overview

The study will:

1. Help determine how much electric and natural-gas technical, economic, achievable (market), and naturally occurring potential exists within the State of Missouri
2. Assist in establishing mechanisms by which the State can continuously evaluate opportunities for cost-effective DSM, including but not limited to financial modeling.

KEMA, Inc. (KEMA) was retained to conduct this demand-side management (DSM) market potential study. The study provides estimates of potential electricity and peak-demand savings and natural-gas savings from DSM measures in Missouri.

The scope of this study includes new and existing residential and nonresidential buildings, as well as industrial process savings. The study covers a 20-year period spanning 2011-2030. Given the near- to mid-term focus, the base study was restricted to DSM measures that are presently commercially available. A number of measures were evaluated as emerging technologies, for example LED lighting. While commercially available, these products are characterized by limited availability, low consumer awareness, uncertainty about average energy savings, and high current costs that have the potential to drop significantly with market adoption. Unit energy savings and cost inputs for these measures are near-term (2-3 year) forecasts, based on current trends.

Data for the study come from a number of different secondary sources that include internal Missouri utility studies and data, as well as a variety of information from third parties and significant, if not uniformly successful, efforts to collect data from Missouri stakeholders.

2.2 Study Approach

This study involved identification and development of baseline end-use and measure data and development of estimates of future energy-efficiency impacts under varying levels of program effort. Information from secondary sources was used to aid in development of the baseline and measure data.

The market characterization allowed us to identify the types and approximate sizes of the various market segments that are the most likely sources of DSM potential in Missouri. These characteristics then served as inputs to a modeling process that incorporated Missouri energy-cost parameters and specific energy-efficiency measure characteristics (such as costs, savings, and existing penetration estimates) to provide more detailed potential estimates.

To aid in the analysis, we utilized the KEMA DSM ASSYST™ model. This model provides a thorough, clear, and transparent documentation database, as well as an extremely efficient data processing system for estimating technical, economic, and achievable potential. We estimated technical, economic, and achievable program potential for the residential, commercial, and industrial sectors, with a focus on energy-efficiency impacts over the next 10 years.

To estimate demand response (DR) impacts, we reviewed impacts from the Federal Energy Regulatory Commission's *2009 National Assessment of Demand Response Potential*[2] for the State of Missouri and customized the results to the state of Missouri, utilizing information on Missouri's peak demand relative to the Colorado peak demand and information on current programs being run by Xcel Energy.

2.3 Layout of the Report

Section 3 discusses the methodology and concepts used to develop the technical, economic, and achievable potential estimates. Section 4 provides market characterization results developed for the study and describes the baselines used in the report. Section 5 discusses the results of the electric energy-efficiency potential analysis by sector and over time. Section 6 presents similar results for gas energy-efficiency potential. Section 7 presents demand-response potential results.

The report incorporates the following appendices:

- Appendix A: Achievable potential developed under an alternative scenario.
- Appendix B: Questions and comments submitted by stakeholders subsequent to the January 20, 2011 presentation of draft results and KEMA's responses.
- Appendix C: Economic Inputs—Provides avoided cost, electric rate, discount rate, and inflation rate assumptions used for the study.
- Appendix D: Building and TOU Factor Inputs—Shows the base household counts, square footage estimates for commercial building types, and base energy use by

[2] *A National Assessment of Demand Response Potential*, Staff Report, Federal Energy Regulatory Commission, prepared by The Brattle Group, Freeman, Sullivan & Co., and Global Energy Partners, LLC, June 2009

industrial segment. This appendix also includes time-of-use factors by sector and end-use.

- Appendix E: Measure Inputs—Lists the measures included in the analysis with the costs, estimated savings, applicability, and estimated current saturation factors.
- Appendix F: Technical and Economic Non-Additive Measure Level Results—Shows energy-efficiency potential for each measure independent of any other measure.
- Appendix G: Supply-Curve Data—Shows the data behind the energy supply curves provided in Section 5 of the report.
- Appendix H: Achievable Program Potential—Provides the detailed forecasts for the achievable potential scenarios over the full analysis horizon.
- Appendix I: Detailed Methodology and Model Description— Provides greater detail on the concepts introduced in Section 3, below.
- Appendix J: Measure Descriptions—Describes the measures included in the study.

3. Methods and Scenarios

This section provides a brief overview of the concepts, methods, and scenarios used to conduct this study. Additional methodological details are provided in Appendix I.

3.1 Characterizing the Energy-Efficiency Resource

Energy efficiency has been characterized for some time now as an alternative to energy supply options, such as conventional power plants that produce electricity from fossil or nuclear fuels. In the early 1980s, researchers developed and popularized the use of a conservation supply-curve paradigm to characterize the potential costs and benefits of energy conservation and efficiency. Under this framework, technologies or practices that reduced energy use through efficiency were characterized as “liberating ‘supply’ for other energy demands” and could therefore be thought of as a resource and plotted on an energy supply curve. The energy-efficiency resource paradigm argued simply that the more energy efficiency or “nega-watts” produced, the fewer new plants would be needed to meet end-users’ power demands.

3.1.1 Defining Energy-Efficiency Potential

Energy-efficiency potential studies were popular throughout the utility industry from the late 1980s through the mid-1990s. This period coincided with the advent of what was called least-cost or integrated resource planning (IRP). Energy-efficiency potential studies became one of the primary means of characterizing the resource availability and value of energy efficiency within the overall resource planning process.

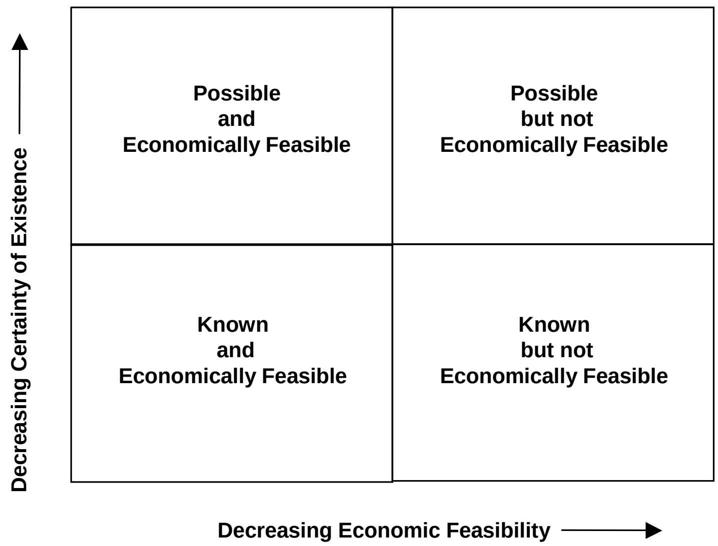
Like any resource, there are a number of ways in which the energy-efficiency resource can be estimated and characterized. Definitions of energy-efficiency potential are similar to definitions of potential developed for finite fossil-fuel resources, like coal, oil, and natural gas. For example, fossil-fuel resources are typically characterized along two primary dimensions: the degree of geological certainty with which resources may be found and the likelihood that extraction of the resource will be economic. This relationship is shown conceptually in Figure 3-1.

Somewhat analogously, this energy-efficiency potential study defines several different *types* of energy-efficiency *potential*, namely, technical, economic, achievable program, and naturally occurring. These potentials are shown conceptually in Figure 3-2 and described below.

- **Technical potential** is defined in this study as the *complete* penetration of all measures analyzed in applications where they were deemed *technically* feasible from an *engineering* perspective.

Figure 3-1

Conceptual Framework for Estimates of Fossil Fuel Resources

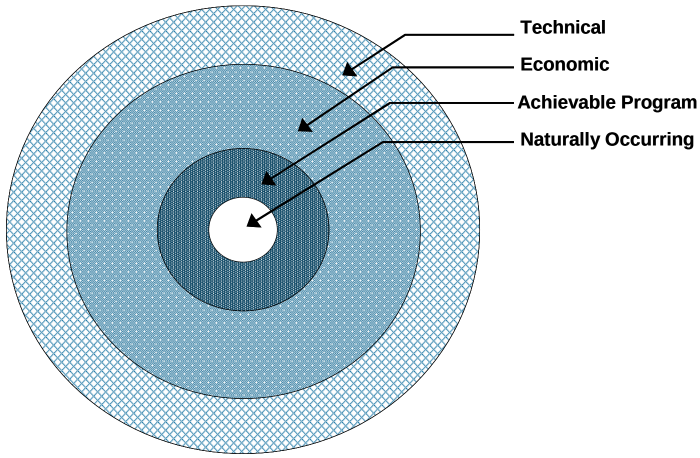


- **Economic potential** refers to the *technical potential* of those energy conservation measures that are cost effective when compared to supply-side alternatives.

- **Achievable program potential** refers to the amount of savings that would occur in response to specific program funding and measure incentive levels. Savings associated with program potential are savings that are projected beyond those that would occur naturally in the absence of any market intervention.

- **Naturally occurring potential** refers to the amount of savings estimated to occur as a result of normal market forces; that is, in the absence of any utility or governmental intervention.

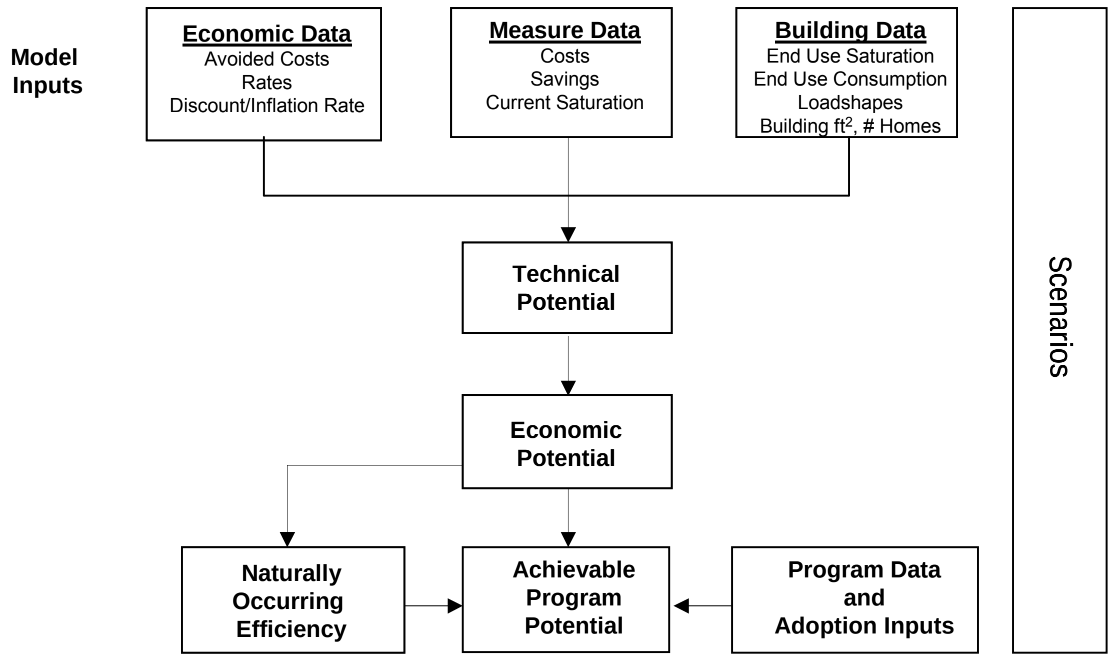
Figure 3-2
Conceptual Relationship among Energy-Efficiency Potential Definitions



3.2 Summary of Analytical Steps Used in this Study

The crux of this study involves carrying out a number of basic analytical steps to produce estimates of the energy-efficiency potentials introduced above. The basic analytical steps for this study are shown in relation to one another in Figure 3-3. The bulk of the analytical process for this study was carried out in a model developed by KEMA for conducting energy-efficiency potential studies. Details on the steps employed and analyses conducted are described in Appendix A. The model used, DSM ASSYST™, is a Microsoft Excel®-based model that integrates technology-specific engineering and customer behavior data with utility market saturation data, load shapes, rate projections, and marginal costs into an easily updated data management system.

Figure 3-3
Conceptual Overview of Study Process



The key steps implemented in this study are:

Step 1: Develop Initial Input Data

- Develop a list of energy-efficiency measure opportunities to include in scope. In this step, an initial draft measure list was developed and circulated by the PSC to stakeholders for comments. The final measure list was developed after consideration of the comments.
- Gather and develop technical data (costs and savings) on efficient measure opportunities. Data on measures were gathered from a variety of sources. Measure descriptions are provided in Appendix J, and detail on measure inputs is provided in Appendix E.
- Gather, analyze, and develop information on building characteristics, including total square footage or total number of households, energy consumption and intensity by end use, end-use consumption load patterns by time of day and year (i.e., load shapes), market shares of key electric consuming equipment, and market shares of

energy-efficiency technologies and practices. Section 4 of this report describes the market characterization data and baselines developed for this study.

- Collect data on economic parameters: avoided costs, electricity rates, discount rates, and inflation rate. These inputs are provided in Appendix C of this report.

Step 2: Estimate Technical Potential and Develop Supply Curves

- Match and integrate data on efficient measures to data on existing building characteristics to produce estimates of technical potential and energy-efficiency supply curves.

Step 3: Estimate Economic Potential

- Match and integrate measure and building data with economic assumptions to produce indicators of costs from different viewpoints (e.g., societal and consumer).
- Estimate total economic potential.

Step 4: Estimate Achievable Program and Naturally Occurring Potentials

- Screen initial measures for inclusion in the program analysis. This screening may take into account factors such as cost effectiveness, potential market size, non-energy benefits, market barriers, and potentially adverse effects associated with a measure. For this study, measures were screened using the total-resource-cost test, while considering only electric or natural gas avoided-cost benefits.
- Gather and develop estimates of program costs (e.g., for administration and marketing) and historic program savings.
- Develop estimates of customer adoption of energy-efficiency measures as a function of the economic attractiveness of the measures, barriers to their adoption, and the effects of program intervention.
- Estimate achievable program and naturally occurring potentials.

Step 5: Scenario Analyses

- Recalculate potentials under alternate program scenarios.

3.3 Scenario Analysis

Scenario analysis is a tool commonly used to structure the uncertainty and examine the robustness of projected outcomes to changes in key underlying assumptions. This section describes the alternative scenarios under which demand-side management (DSM) potential was estimated in this study. We developed two scenarios of DSM potential at the direction of the PSC.

The cost components of program funding that may vary under each scenario include:

Marketing and Education Expenditures

- Customers must be aware of efficiency measures and their associated benefits in order to adopt those measures. In our analysis, program marketing expenditures are converted to increases in awareness. Thus, under higher levels of marketing expenditures, higher levels of awareness are achieved.

Incentives and Direct Implementation Expenditures

- The higher the percentage of measure costs paid by the program, the higher the participants' benefit-cost ratios and, consequently, the number of measure adoptions.

Administration Expenditures

- Purely administrative costs, though necessary and important to the program process, do not directly lead to adoptions; however, they have been included in program funding because they are an input to program benefit-cost tests.

For each analysis, two program-funding scenarios were considered: a three year payback incentive scenario and a one year payback scenario. These scenarios are discussed below.

In both scenarios, a number of measures were modeled without financial incentives. These include office equipment power-management enabling, industrial operations and maintenance (O&M) measures, and Energy Star office equipment and consumer electronics for the residential sector. Because these measures are very cost effective, it was deemed that provision of an incentive would primarily benefit free riders.

Note that for the low-income segment, all scenarios reflect 100 percent incentives (as a percent of incremental measure cost). Program effort was adjusted across scenarios such that low-income program potentials roughly track other residential program potentials.

3.3.1 One-year Payback Scenario

In the one-year payback scenario, base incentive levels are set to a one-year payback. Program administration budgets are set at moderately aggressive amounts, roughly corresponding to program support levels. In this case measures that had a less than one year natural (i.e. without intervention) payback were modeled without incentives.

3.3.2 Three-year Payback Scenario

In the three-year payback scenario, base incentive levels are set to a Three year payback. Program administration budgets are set at modest amounts, roughly corresponding to minimum program support levels. In this case measure that had a less than three year natural payback modeled without incentives.

4. Market Characterization and Baseline Development

4.1 Overview

Estimating the potential for energy-efficiency improvements requires a comparison of the energy impacts of standard-efficiency technologies with those of alternative high-efficiency equipment. This, in turn, dictates a relatively detailed understanding of the energy characteristics of the marketplace. Market characterization data that were required for each studied market segment includes:

- Total count of energy-consuming units (floor space of commercial buildings, number of residential dwellings, and the base kWh consumption of industrial facilities)
- Annual energy consumption for each end use studied (both in terms of total consumption in GWh and normalized for intensity on a per-unit basis (e.g., kWh/ft2)
- End-use load shapes (that describe the amount of energy used or power demand over certain times of the day and days of the year)
- The saturation of electric end uses (e.g., the fraction of total commercial floor space with electric air conditioning)
- The market share of each base equipment type for example, the fraction of total commercial floor space served by 4-foot fluorescent lighting fixtures)
- Market share for each energy-efficiency measure in scope (for example, the fraction of total commercial floor space already served by CFLs).

Data for the market characterization analysis comes from a number of sources including market characterization studies conducted by Missouri utilities, the Department of Energy's Energy Information Administration, the Federal Energy Regulatory Commission, federal and state government databases, Bureau of the Census, evaluations of Missouri efficiency programs, and a recent appliance saturation survey. Market data sources vary by sector and are described further below.

4.2 Electricity Market Characterization

To develop Missouri statewide electricity use by sector, we started with breakouts from the Energy Information Administration's State Energy Data System (EIA's SEDS, found at http://www.eia.doe.gov/states/seds.html). Table 4-1 shows the SEDS electricity use by sector for 2008, with subtotals for the commercial and industrial (C&I) sectors combined.

Table 4-1

SEDS 2008 Electricity Consumption Data

		Electricity GWh
Residential consumption		35,390
Commercial consumption		31,118
Industrial consumption		17,850
	Subtotal C&I	*48,968*
Total		84,358

It is our understanding that the SEDS sector breakouts are determined by assigning rate classes to one sector or another in their entirety. Utilities typically have a residential rate class that applies to residential customers, so this approach should result in accurate estimates for the residential sector. However, because commercial and industrial rates are typically broken out by customer demand rather than by sector, we did not want to rely on SEDS for the commercial and industrial breakouts. Instead, while we relied on SEDS for overall C&I consumption, we looked for other data to break out energy use between the sectors.

We found that Ameren, KCP&L and KCP&L/GMO each had detailed commercial and industrial electricity market characterizations, which were provided to us through the PSC. These three utilities represent a majority of Missouri's electricity consumption. While we had concerns extrapolating the data to Missouri as a whole, we felt this approach was more reliable than SEDS' rate-class approach. In the absence of detailed sector breakouts from Empire and the state's publicly owned utilities, we believe this is the best approach. Table 4-2 shows the adjusted electricity consumption by sector.

Table 4-2

Adjusted SEDS Electricity Use Data for the Commercial and Industrial Sectors (2008)

		GWh
Commercial consumption		28,577
Industrial consumption		20,391
	Subtotal C&I	48,968

Sector consumptions were adjusted further as discussed below to create our base year (2011) consumption estimate.

Peak demand estimates were calibrated to a forecast of Missouri's peak demand for 2011 from the Federal Energy Regulatory Commission's National Assessment of Demand Response

Potential, which estimates peak for the residential, commercial and industrial sectors at 16,922 MW. To break out peak demand by sector, we used energy use estimates by building type and end-use (discussed below), and load shape data from the IOUs.

4.2.1 Residential Electricity Market Characterization

4.2.1.1 Residential Building Types

The residential customer class in Missouri was disaggregated into four building types for our analysis:

- Single family (SF)
- Multifamily (MF)
- Single family low income (SF LI)
- Multifamily low income (MF LI)

While low income is not really a "building type," it represents a customer segment that is frequently targeted with specialized programs. It is therefore useful to split these customers out in the modeling.

We prefer to break out energy use by building type using a billing data analysis, but because this is a statewide analysis involving a large number of utilities, billing data was not available. Instead, we turned to a variety of sources of secondary sources. The EIA's most recent estimate of the total number of residential electricity customers in Missouri is 2,686,746. The total number of low income households (683,461) was taken from the "LIHEAP [Low Income Home Energy Assistance Program] Home Energy Notebook for Fiscal Year 2008." This approach may understate the total number of low income households, as the figure is an average of the 2006 through 2008 state-level estimates. The ratio of low income single family and low income multifamily households was approximated using the American Community Survey 2009 dataset accessed through the Missouri Census Data Center's Data Extraction Web Utility "Dexter," which allowed us to disaggregate Missouri into 41 regions. To inflate the energy consumption and customer counts from 2008 to 2011, ten year average growth rates of Missouri's residential electricity and natural gas consumption and customer base from various EIA datasets were applied to the above quoted figures to arrive at the values used for this study, shown in Table 4-3. Table 4-4 shows the final residential customer counts by customer class.

Table 4-3
Residential Electric Base Year and Forecast Data

	2008 Base	Source	Forecast 2011
Electric Customers	2,686,746	EIA 2008	2,789,874
Electric Consumption (MWh)	35,389,941	EIA 2008	38,554,849
Accounts Eligible for LIHEAP	683,461	2008 LIHEAP	700,840

Table 4-4
Number of Residential Customers by Class (2011)

	SF	MF	SF-LI	MF-LI	Total
Electric	1,659,427	429,606	542,690	158,151	2,789,874

4.2.1.2 Residential Energy Consumption Survey Data

Energy consumption data and equipment saturations for the residential sector were taken from the EIA's Residential Energy Consumption Survey (RECS). The survey collects data on housing characteristics and energy consumption for more than 4,000 homes across the country.

Each home in the RECS dataset includes information about its location by census region and census divisions. Missouri falls into the "Midwest" region and the southeastern corner of the "West North Central" census division. As can be seen from the EIA maps below, these census divisions span disparate climate zones. To analyze weather sensitive end uses such as HVAC and water heating and capture both geographic and climate variations, we sorted the RECS microdata by census divisions, heating degree days (HDD) and cooling degree days (CDD). To approximate the climate in Missouri, microdata within divisions 3, 4, and 6 with the characteristics of climate zone 3 (less than 2,000 CDD and between 4,000 and 5,499 HDD) were selected for analysis. This dataset spans Missouri, Kansas, Kentucky, and the southern ends of Illinois and Indiana. For non-weather sensitive measures, we used data from the West North Central census division.

Figure 4-1
United States Census Regions and Divisions

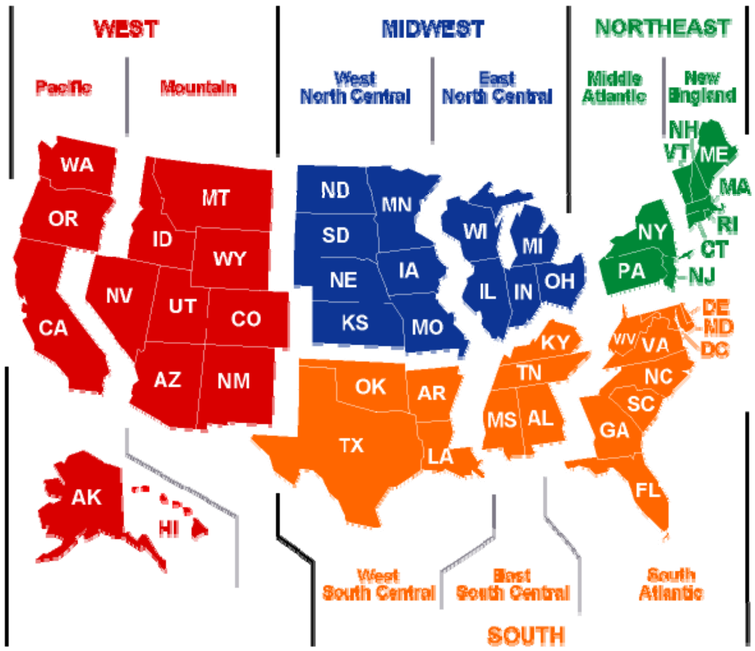
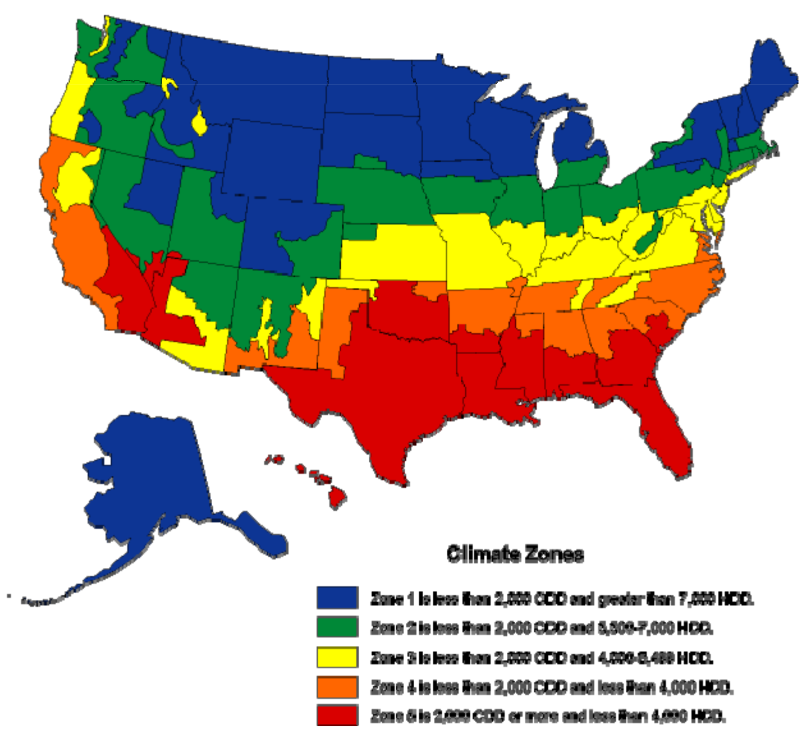


Figure 4-2
United States Climate Zones



4.2.1.3 Residential Electric End use Saturations

Residential electric saturation were calculated based on RLW 2006, the 2010 Ameren UE “Demand Side Management Market Potential Study” by Global Energy Partners, and the Energy Information Administration’s most recent Residential Energy Consumption Survey (RECS) microdata from 2005.

Table 4-5
Residential Electric End-Use Saturation

	SF	MF	SF LI	MF LI	Sources & Notes
10.7 SEER Split-System Air Conditioner	74.0%	73.1%	74.0%	73.1%	Ameren 2010 and RLW 2006 - 85% percentage of respondents with CAC.
Early Replace 10 SEER Split-Sys AC	13.1%	15.5%	13.1%	15.5%	Ameren 2010 and RLW 2006 - 15% respondents with CAC.
Room Air Conditioner - EER 9.7	5.1%	7.7%	5.1%	7.7%	Ameren 2010 and RLW 2006 - 85% percentage of respondents with RAC.
Early Replacement RAC- EER 9.0	0.9%	1.4%	0.9%	1.4%	Ameren 2010 and RLW 2006 - 15% of respondents with RAC.
Dehumidifier (EF =1.20)	27%	13%	27.0%	13.0%	Ameren 2010 --> all respondents with dehumidifier
Furnace Fans	87.0%	87.0%	87.0%	87.0%	RLW 2006
Resistance Space Heating	3.9%	3.9%	3.9%	3.9%	RLW 2006
Electric Furnace	15.0%	15.0%	15.0%	15.0%	RLW 2006
Ltg 60-Watt incandescent, 1.8 hr/day	100.0%	100.0%	100.0%	100.0%	RLW 2006
Lighting 15 Watt CFL, 1.8 hours/day	100.0%	100.0%	100.0%	100.0%	RLW 2006
Lighting Fluorescent Tube, 1.8 hrs/day	100.0%	100.0%	100.0%	100.0%	RLW 2006
Ltg: HID, Halogen, Fluor, 1.8 hrs/day	100.0%	100.0%	100.0%	100.0%	RLW 2006
Refrigerator	85.0%	85.0%	85.0%	85.0%	RLW 2006
Early Replacement Refrigerator	15.0%	15.0%	15.0%	15.0%	RLW 2006
Second Refrigerator	32.7%	12.0%	16.4%	6.0%	RLW 2006 for SF, Ameren 2010 for MF; LI estimated based on Ameren 2010
Freezer	45.9%	16.8%	38.3%	10.5%	RLW 2006 for SF, ratio to derive MF taken from SF/MF secondary fridge ownership --> 85% respondents with freezer; ; LI from ratios of SF LI/ SF and MF LI/ MF from RECS CZ 3, Division 3, 4 & 6
Early Replacement Freezer	8.1%	3.0%	8.1%	3.0%	RLW 2006 for SF, ratio to MF taken from SF/MF secondary fridge ownership -->15% respondents with freezer
40 gal. Water Heating (EF=0.88)	24.6%	33.4%	26.8%	28.9%	SF based on RLW 2006, assuming SF/MF ratio from Ameren, minus 5% from both for ER; LI from ratios of SF LI/ SF and MF LI/ MF from RECS CZ 3, Division 3, 4 & 6
Early Replacement Water Heating to Heat Pump Water Heater	1.3%	1.8%	1.4%	1.5%	SF based on RLW 2006, assuming SF/MF ratio from Ameren 2010, 5% from both for ER; LI from ratios of SF LI/ SF and MF LI/ MF from RECS CZ 3, Division 3, 4 & 6
Clothes washer (MEF=1.26)	98.0%	68.0%	98.0%	68.0%	Ameren 2010
Clothes Dryer (EF=3.01)	87.7%	63.8%	79.7%	57.8%	SF from RLW 2006, MF derived from ratio of SF/MF from Ameren 2010; LI from ratios of SF LI/ SF and MF LI/ MF from RECS CZ 3, Division 3, 4 & 6
Dishwasher (EF=0.65)	77.0%	75.0%	52.9%	31.5%	SF and MF from Ameren 2010, multiplied by the % of electric WH; LI from ratios of SF LI/ SF and MF LI/ MF from RECS CZ 3, Division 3, 4 & 6
Single Speed Pool Pump (RET)	0.4%	0.4%	0.0%	0.0%	RLW 2006; LI assumed to be 10%
Two Speed Pool Pump (1.5 hp) (ROB)	0.4%	0.4%	0.0%	0.0%	RLW 2006; LI assumed to be 10%
Plasma Screen TV	11.0%	8.0%	1.1%	0.8%	Ameren 2010 for SF/MF, assumption for LI
LCD Screen TV	42.0%	35.0%	4.2%	3.5%	Ameren 2010 for SF/MF, assumption for LI
Other TV	87.0%	78.0%	87.0%	78.0%	Ameren 2010 for SF/MF, assumption for LI
Laptop Computer	46.0%	56.0%	46.0%	56.0%	Ameren 2010
Desktop Computer	47.0%	35.0%	47.0%	35.0%	Ameren 2010
Cooking	81.4%	81.4%	81.4%	81.4%	RECS microdata, CZ 3 in Division 3, 4 & 6
Miscellaneous	100.0%	100.0%	100.0%	100.0%	By definition

4.2.1.4 Residential Electricity Energy Intensities

Residential sector end-use energy intensities are shown in Table 4-6. These were estimated from a variety of sources, as noted in the table.

Table 4-6

Residential Electric End-Use Energy Intensities (kWh/home with the installed measure)

	SF	MF	SF LI	MF LI	Sources & Notes
10.7 SEER Split-System Air Conditioner	3,161	2,253	3,161	2,253	ENERGYSTAR Calculator - SEER 10.7 (RLW 2006); St. Louis, MO; weighted average of 2.5 and 3 ton EUI for SF (RLW 2006 average tonnage is 2.84 ton), ratio of SF/MF floorspace for MF from Ameren 2010 Volume 3 Appendix B. Calibrated.
Early Replace 10 SEER Split-Sys AC	4,092	2,916	4,092	2,916	ENERGYSTAR Calculator- 3 ton for SF 2.5 ton for MF. 10 SEER, used ENERGYSTAR calculator for St. Louis, MO; Calibrated.
Room Air Conditioner - EER 9.7	2,008	2,579	1,947	1,621	ENERGYSTAR Calculator, 9.7 EER, St. Louis, MO; Units/ home from RECS microdata, CZ3 in Division 3, 4 & 6 Calibrated.
Early Replacement RAC-EER 9.0	2,163	2,779	2,097	1,747	ENERGYSTAR Calculator, 9.0 EER, St. Louis, MO; Units/ home from RECS microdata, CZ3 in Division 3, 4 & 6 Calibrated.
Dehumidifier (EF =1.20)	1,064	1,064	1,064	1,064	ENERGYSTAR Calculator- 35-45 pints, 1.2 EF
Furnace Fans	1,106	1,106	1,106	1,106	Assumed 350 watts, 1997 full load heating hours and 1178 cooling hours (ENERGYSTAR Calculator ASHP); Calibrated.
Resistance Space Heating	16,654	11,304	19,944	8,563	RECS microdata, CZ 3 in Division 3, 4 & 6. Note that LBNL "Home Energy Saver" gave preliminary heating estimates of 18,230 kWh/ yr for baseboard heat, using SF housing characteristics from Ameren 2010 Vol 3 Appendix B, St. Louis. Calibrated.
Electric Furnace	13,155	9,345	10,516	7,079	RECS microdata, CZ 3 in Division 3, 4 & 6. Note that LBNL "Home Energy Saver" gave preliminary heating estimates of 18,553 kWh/ yr for electric furnace heat, using SF housing characteristics from Ameren 2010 Vol 3 Appendix B, St. Louis. Calibrated.
Lighting 60-Watt incandescent, 1.8 hr/day	1,528	860	1,528	860	Hours of use (1.8 hrs/day) from CA Upstream Lighting Evaluation Program; lamps/HH and average watts/bulb from RLW 2006, updated to account for Ameren's findings that CFL and Halogen penetration has increased; incandescent is 37.22 bulbs/HH (63%) and 62.5 watts. MF diminished to account for Ameren's findings that MF averages 27/48 as many bulbs/HH as SF
Lighting 15 Watt CFL, 1.8 hours/day	172	97	172	97	Hours of use (1.8 hrs/day) from CA Upstream Lighting Evaluation Program; lamps/HH and average watts/bulb from RLW 2006, updated to account for Ameren's findings that CFL and Halogen penetration has increased; CFLs average 12.44 bulbs/HH (21%) and 21 watts. MF diminished to account for Ameren's findings that MF averages 27/48 as many bulbs/HH as SF
Lighting Fluorescent Tube, 1.8 hrs/day	83	46	83	46	Hours of use (1.8 hrs/day) from CA Upstream Lighting Evaluation Program; lamps/HH and average watts/bulb from RLW 2006, updated to account for Ameren's findings that CFL and Halogen penetration has increased; Fluorescent is 21.05W and 5.97 bulbs/home. MF diminished to account for Ameren's findings that MF averages 27/48 as many bulbs/HH as SF
Lighting HID, Halogen, 1.8 hrs/day	116	65	116	65	Hours of use (1.8 hrs/day) from CA Upstream Lighting Evaluation Program; lamps/HH and average watts/bulb from RLW 2006, updated to account for Ameren's findings that CFL and Halogen penetration has increased; Halogen is 45.6W and 3.55 bulbs/home; HID is 251.9W and 0.06 bulbs/home. MF diminished to account for Ameren's findings that MF averages 27/48 as many bulbs/HH as SF

Table 4-6

Residential Electric End-Use Energy Intensities (kWh/home with the installed measure)

	SF	MF	SF LI	MF LI	Sources & Notes
Refrigerator	719	719	719	719	RLW 2006, multiplied by fridges/home, taking into account fridges for recycling
Early Replacement Refrigerator	719	719	719	719	RLW 2006, multiplied by fridges/home, taking into account fridges for recycling
Second Refrigerator	791	791	791	791	RLW 2006
Freezer	549	549	549	549	RLW 2006
Early Replacement Freezer	549	549	549	549	RLW 2006
	4,516	3,447	4,516	3,447	DOE/LBNL Water Heater calculator; EF .89 (RLW 2006); gallons per day based on 21.78 gallons daily recovery load per person (PG&E 2007) multiplied by average people/ home 2.7 for SF and 1.9 for MF (Ameren 2010).
40 gal. Water Heating (EF=0.88)	4,516	3,447	4,516	3,447	DOE Water calculator; EF .89 (RLW 2006); gallons per day based on 21.78 gallons daily recovery load per person (PG&E 2007) multiplied by average people/ home 2.7 for SF and 1.9 for MF (Ameren 2010).
Early Replacement Water Heating to Heat Pump Water Heater	81	81	81	81	ENERGYSTAR Calculator- Energy used with beyond water heating
Clothes washer (MEF=1.26)	969	583	776	583	Assumptions from [http://www.energy.ca.gov/2008publications/CEC-400-2008-013/CEC-400-2008-013-D.PDF] (653); [http://www.calmac.org/events/Final_DEER_Presentation_-_Complete_.ppt#347,29,Non-Weather Sensitive Measures; LBNL:Residential Measures; [http://enduse.lbl.gov/SharedData/standards/resstds.DOC]. Based on 416 cycles/yr SF and 250 cycles/yr MF; SF LI is average of SF and MF
Clothes Dryer (EF=3.01)	791	791	791	791	ENERGYSTAR Calculator
Dishwasher (EF=0.65)	162	162	162	162	Used CEC HERS EUI, then divided by 3.25 to account for less run time in MO than CA
Single Speed Pool Pump (RET)	822	822	822	822	Using pump affinity law: [http://clubp.info/media/1.Pool%20Pump%20Energy%20Savings%20Calculator.xls], then divided by 3.25 to account for less run time in MO
Two Speed Pool Pump (1.5 hp) (ROB)	357	357	357	357	Calculated from LBNL 4/2008 UEC for all TV types
Plasma Screen TV	931	1,118	946	946	Calculated from LBNL 4/2008 UEC for all TV types
LCD Screen TV	450	500	460	460	Calculated from LBNL 4/2008 UEC for all TV types
Other TV	127	111	118	118	LBNL4/2007 UEC, adjusted by average number of laptops per home
Laptop Computer	192	168	170	170	LBNL4/2007 UEC, adjusted by average number of desktops/home
Desktop Computer	730	572	685	1,129	CA HERS Topic Report 2008 - [http://www.energy.ca.gov/2008publications/CEC-400-2008-013/CEC-400-2008-013-D.PDF]
Cooking	316	316	316	316	Assumed 10%, calibrated to intensity targets
Miscellaneous	1,535	1,141	1,430	1,035	ENERGYSTAR Calculator - SEER 10.7 (RLW 2006); St. Louis, MO; weighted average of 2.5 and 3 ton EUI for SF (RLW 2006 average tonnage is 2.84 ton), ratio of SF/MF floorspace for MF from Ameren 2010 Volume 3 Appendix B
Whole House	14,880	11,064	13,861	10,035	

4.2.1.5 Residential Electricity Use

The following tables and figures show the number of households by building type and energy consumption by building type and end-use for electricity. Energy use is calculated by multiplying together the saturations, EUIs, and number of households.

Table 4-7
Residential Electric Housing Stock and Energy Use by Building Type and End-Use

	SF	MF	SF LI	MF LI	Total
Households	1,659,427	429,606	542,690	158,151	2,789,874
Energy Consumption (MWh)					
10.7 SEER Split-System Air Conditioner	3,879,609	707,423	1,268,765	260,423	6,116,221
Early Replace 10 SEER Split-Sys AC	886,155	193,902	289,803	71,381	1,441,241
Room Air Conditioner - EER 9.7	169,907	84,762	53,878	19,613	328,159
Early Replacement RAC- EER 9.0	32,305	16,116	10,244	3,729	62,394
Dehumidifier (EF =1.20)	476,720	59,423	155,904	21,875	713,923
Furnace Fans	1,596,403	413,290	522,078	152,144	2,683,915
Resistance Space Heating	1,067,291	187,536	417,980	52,299	1,725,106
Electric Furnace	3,265,414	600,567	853,684	167,470	4,887,135
Ltg 60-Watt incandescent, 1.8 hr/day	2,535,853	369,283	829,311	135,944	3,870,390
Lighting 20 Watt CFL, 1.8 hours/day	284,824	41,477	93,147	15,269	434,718
Lighting Fluorescent Tube, 1.8 hrs/day	137,009	19,952	44,807	7,345	209,113
Ltg: HID, Halogen 1.8 hrs/day	193,185	28,133	63,178	10,356	294,853
Refrigerator	1,013,454	262,371	331,434	96,587	1,703,846
Early Replacement Refrigerator	178,845	46,301	58,488	17,045	300,679
Second Refrigerator	3,879,609	707,423	1,268,765	260,423	6,116,221
Freezer	886,155	193,902	289,803	71,381	1,441,241
Early Replacement Freezer	169,907	84,762	53,878	19,613	328,159
40 gal. Water Heating (EF=0.88)	429,440	40,799	70,221	7,510	547,969
Early Replacement Water Heating to Heat Pump Water Heater	418,465	39,756	114,132	9,083	581,436
Clothes washer (MEF=1.26)	73,847	7,016	24,150	2,583	107,596
Clothes Dryer (EF=3.01)	1,844,903	493,972	656,806	157,821	3,153,503
Dishwasher (EF=0.65)	97,100	25,999	34,569	8,306	165,974
Single Speed Pool Pump (RET)	131,237	23,575	42,919	8,679	206,410
Two Speed Pool Pump (1.5 hp) (ROB)	1,410,203	159,611	335,707	53,282	1,958,803
Plasma Screen TV	206,997	52,197	46,536	8,059	313,789
LCD Screen TV	5,246	1,358	0	0	6,604
Other TV	2,280	590	0	0	2,870
Laptop Computer	169,942	38,407	5,648	1,197	215,194
Desktop Computer	313,318	75,106	10,474	2,544	401,442
Cooking	182,989	37,028	55,854	14,593	290,464
Miscellaneous	146,511	40,528	42,484	15,072	244,596
Total	24,692,201	4,753,258	7,522,328	1,587,062	38,554,849

Figure 4-3
Residential Electricity Use by End Use

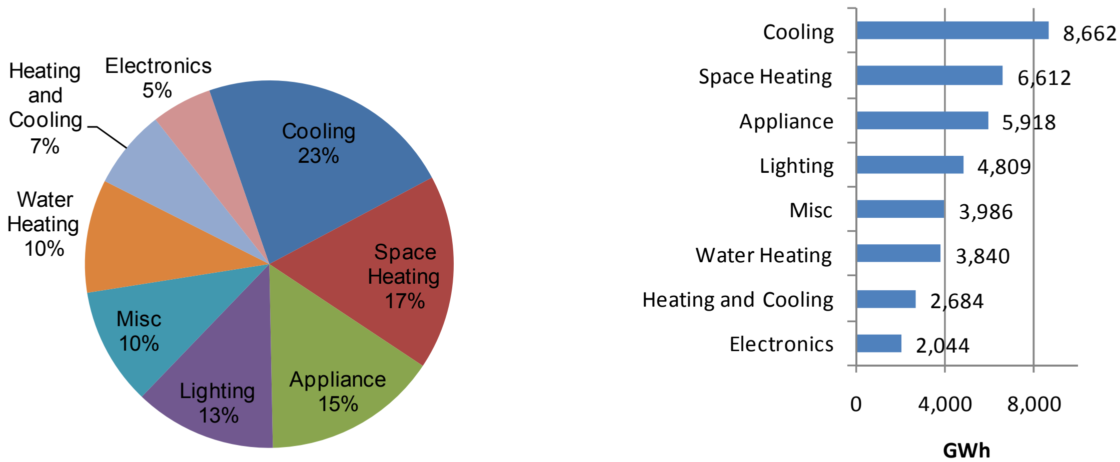
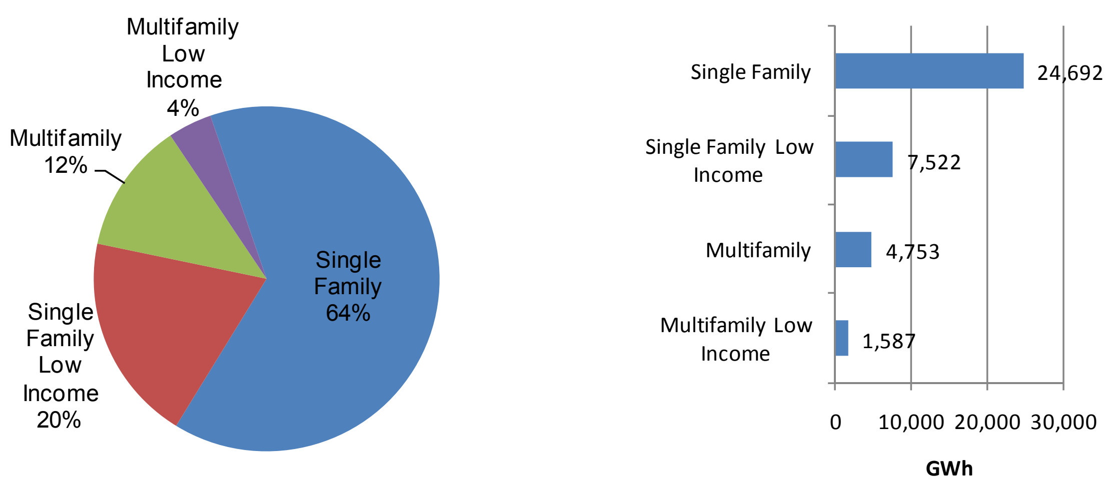


Figure 4-4
Residential Electricity Use by Building Type



4.2.1.6 Residential Peak Demand

Residential load shape data from KEMA's end-use databases was utilized to allocate annual energy usage to time-of-use (TOU) periods. Peak period usage, developed on a sector-specific and end-use basis, were calibrated across all sectors to equal the Missouri summer peak. Residential peak demand was estimated to be 9,710 MW. The following table shows the contribution to residential peak demand by building type and end use.

Figure 4-5
Residential Peak Demand by Building Type and Sector (MW)

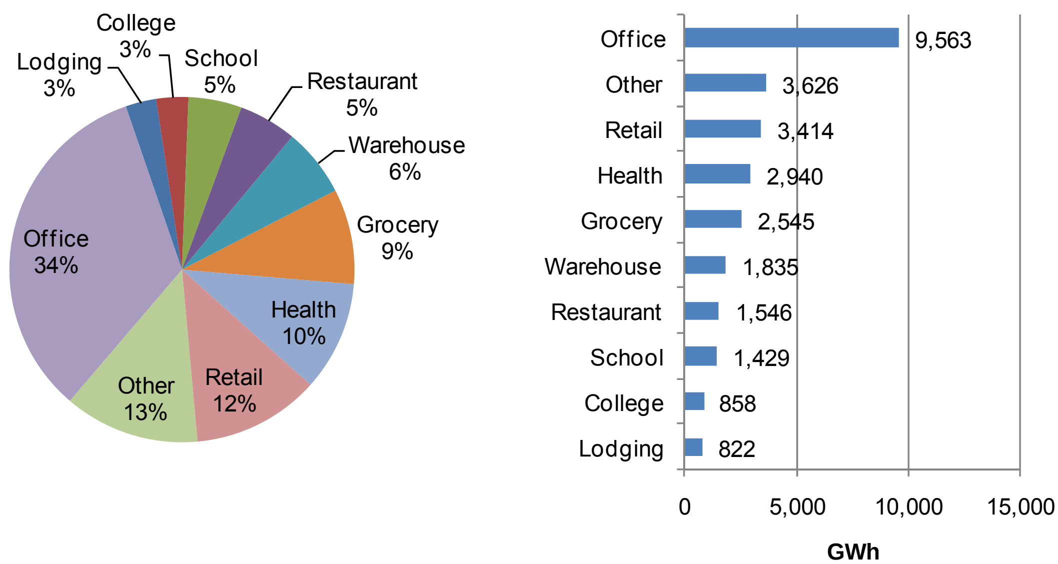
Peak demand estimates	SF	MF	SF LI	MF LI	Total
10.7 SEER Split-System Air Conditioner	3,477	634	1,137	233	5,482
Early Replacement 10 SEER Split-System AC	794	174	260	64	1,292
EER 9.7 Room Air Conditioner	152	76	48	18	294
Early Replacement Room Air Conditioner- EER 9.0 to CEE Tier 1 EER 11.3	29	14	9	3	56
Dehumidifier (35-45 pints/day; EF = 1.20)	38	5	12	2	56
Furnace Fans (Retrofit)	482	125	158	46	811
Resistance Space Heating (Electric)	0	0	0	0	0
Electric Furnace	0	0	0	0	0
Lighting 60 Watt Incandescent, 1.8 hours per day	165	24	54	9	253
Lighting 15 Watt CFL, 1.8 hours per day	19	3	6	1	28
Lighting Fluorescent Tube, 1.8 hrs/day	9	1	3	0	14
Lighting HID, Halogen, Fluorescent, 1.8 hrs per day	13	2	4	1	19
Refrigerator	97	25	32	9	163
Early Replacement Refrigerator	17	4	6	2	29
Second Refrigerator	41	4	7	1	52
Freezer	41	4	11	1	57
Early Replacement Freezer	7	1	2	0	10
40 gal. Water Heating (EF=0.90)	132	35	47	11	226
Early Replacement Water Heating to Heat Pump Water Heater	7	2	2	1	12
Clotheswasher (MEF=1.26)	13	2	4	1	20
Clothes Dryer (EF=.46)	130	15	31	5	181
Dishwasher (EF=0.58)	22	5	5	1	33
Single Speed Pool Pump to Variable RET	0	0	0	0	1
Two Speed Pool Pump to Variable ROB	0	0	0	0	0
Plasma Screen TV	15	3	1	0	19
LCD TV	28	7	1	0	36
Other TV	17	3	5	1	26
Laptop Computer	12	3	3	1	19
Desktop Computer	45	7	14	5	70
Cooking	82	21	27	8	137
Miscellaneous	201	39	61	13	313
House Practices	4,808	926	1,465	309	7,508
Total	6,084	1,239	1,950	437	9,710

4.2.2 Commercial Electricity Market Characterization

4.2.2.1 Commercial Building Types

For the commercial electricity breakdown, we turned to the market characterization studies performed by Ameren, KCP&L and KCP&L-GMO. The sales data by building type for the three utilities was combined and the resulting distribution of commercial electricity use by building type was applied to total Missouri consumption, developed as discussed above. Figure 4-6 shows the breakdown of commercial electricity use by building type.

Figure 4-6
Commercial Electricity Use by Building Type



4.2.2.2 Commercial Electric End-use Saturations

For the commercial sector electricity saturations, we again turned to the market characterization studies done for Ameren, KCP&L and KCP&L-GMO. Each study broke out energy use by major end-use (lighting, cooling, etc.). These end-use splits were weighted and used as the basis for the base measure saturations.

Because some end-uses have several base measures, we needed to break out the end-use saturations developed from the utility studies into the detailed base measures. To do this, we turned to detailed on-site data from a recent Rhode Island study (no Missouri data was found to inform these splits at the necessary level of detail). This allowed us to break up the overall cooling saturation, for example, into chillers and DX systems. During the EUI calibration process, discussed below, some saturations were modified so that energy intensities and end-use intensities would balance.

For some measures, the utility data was not available or useable (for example, outdoor lighting could not be disaggregated from indoor lighting). We turned to the U.S. DOE's Commercial Building Energy Consumption Survey (CBECS) for some measures that fell outside the definitions of the utility studies, and used saturations from previous studies for outdoor lighting. Exit signs and miscellaneous were assumed to have 100 percent saturation.

Commercial end-use saturations are shown in Table 4-8.

Table 4-8
Commercial Saturations for Electric Base Measures

	Office	Restaurant	Retail	Grocery	Warehouse	School	College	Health	Lodging	Other
Lighting 4 Lamp 4' T12	5.96%	8.0%	3.69%	0.00%	9.50%	0.00%	0.60%	0.46%	0.00%	3.41%
Lighting 2 Lamp 4' T12	9.94%	3.00%	7.48%	12.00%	6.04%	0.00%	0.98%	1.75%	1.90%	2.28%
Lighting 2 Lamp 8' T12	4.77%	8.00%	5.06%	50.39%	3.31%	0.00%	0.00%	0.00%	0.00%	0.97%
Lighting Incand-CFL Screw-in	15.80%	70.00%	9.70%	15.00%	0.47%	3.33%	0.63%	5.63%	4.73%	32.77%
Lighting CFL-LED Screw-in	5.48%	1.00%	0.47%	0.00%	0.79%	0.20%	0.01%	8.82%	8.70%	5.24%
Lighting Incand-CFL Hardwire	7.13%	7.00%	2.82%	3.00%	0.04%	0.22%	3.64%	15.50%	23.65%	7.20%
Lighting CFL-LED Hardwire	19.65%	1.00%	0.22%	0.51%	0.06%	0.14%	6.09%	25.33%	61.01%	5.71%
Lighting High Bay	0.65%	0.00%	8.22%	7.09%	6.00%	11.21%	2.75%	0.31%	0.00%	14.66%
Lighting 4 Lamp 4' T8	12.64%	1.00%	16.93%	0.00%	13.51%	30.05%	34.30%	39.57%	0.00%	18.89%
Lighting 2 Lamp 4' T8	18.28%	1.00%	35.85%	12.00%	3.93%	24.89%	48.74%	49.93%	0.00%	8.59%
Lighting Exit Signs	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Outdoor Lighting	67.00%	100.00%	81.50%	47.28%	88.72%	79.19%	100.00%	96.73%	100.00%	88.40%
Street Lighting										100.00%
Chillers	35.42%	4.55%	12.31%	0.00%	7.17%	21.36%	74.74%	76.68%	27.92%	14.57%
DX Packaged Systems	57.19%	88.17%	73.81%	94.29%	72.81%	62.64%	9.26%	18.01%	67.94%	69.92%
Ventilation Motors 5 hp	85.96%	72.75%	73.25%	49.25%	68.33%	77.68%	100.00%	47.74%	100.00%	83.57%
Ventilation Motors 15 hp	5.52%	12.09%	8.97%	0.00%	0.00%	42.03%	37.11%	14.33%	0.00%	12.15%
Ventilation Motors 40 hp	20.20%	0.00%	13.64%	0.00%	5.70%	0.00%	22.29%	0.00%	0.00%	52.04%
Non-commercial refrigerators	67.29%	44.01%	53.11%	43.40%	49.04%	60.32%	73.12%	89.74%	61.09%	60.04%
Refrigeration System	67.82%	87.69%	70.06%	96.67%	67.13%	86.43%	97.23%	96.55%	86.10%	63.53%
Desktop PC	91.03%	72.75%	84.39%	66.98%	68.10%	93.00%	37.11%	94.91%	96.41%	79.14%
Monitor, 17" CRT	38.85%	31.45%	54.86%	37.43%	71.20%	69.18%	37.11%	42.19%	4.90%	63.53%
Monitor, 17" LCD	16.74%	46.96%	12.77%	61.73%	15.55%	84.00%	37.11%	24.80%	63.47%	22.82%
Copier	94.22%	14.22%	58.98%	45.73%	68.10%	85.66%	93.00%	94.91%	42.36%	49.16%
Laser Printer	94.22%	72.60%	85.82%	87.64%	68.10%	93.00%	93.00%	94.91%	86.05%	65.72%
Data Centers	0.72%	0.10%	0.03%	0.13%	0.18%	0.31%	1.28%	1.10%	0.07%	0.11%
Water Heating	36.08%	21.17%	35.19%	8.09%	30.88%	27.00%	27.00%	9.20%	8.04%	34.66%
Vending Machines	62.30%	25.04%	48.54%	53.64%	51.98%	71.69%	96.62%	95.93%	84.03%	36.91%
Convection Oven	0.00%	67.93%	12.77%	38.58%	0.00%	84.00%	84.00%	0.00%	63.47%	22.82%
Fryer	1.43%	21.41%	0.00%	38.58%	0.00%	0.00%	0.00%	0.00%	0.00%	22.82%
Steamer	1.43%	38.11%	0.00%	61.73%	0.00%	0.00%	0.00%	24.80%	0.00%	22.82%
Hot Food Holding Cabinets	1.43%	67.93%	6.45%	50.97%	0.00%	65.45%	65.45%	24.80%	49.75%	22.82%
Heating	20.93%	17.00%	19.55%	11.63%	14.94%	9.00%	9.00%	6.08%	56.59%	22.77%
Miscellaneous	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

4.2.2.3 Commercial Electric Energy Intensity

The Ameren, KCP&L and KCP&L-GMO studies provided both energy intensities (energy per total building square foot) and end-use energy intensities (EUI, defined as energy use per end-use square foot) only for electricity. As with saturations, these were provided for major end-uses (such as lighting) rather than at the detailed base-measure level required for ASSYST. We therefore started with EUIs from a recent Colorado study, then adjusted within each major end-use category to match the Missouri data. Once that was done, we calculated the overall energy intensity by building type implied by the EUIs and saturation we had just developed. A second calibration was applied to bring the overall energy intensity in line with that found by the utility studies. We compared the results to the California Commercial End-Use Survey (CEUS) as a cross-check, and found, as expected, that energy use by non-weather-sensitive measures (such as lighting and cooking) were similar, while weather sensitive measures such as cooling and heating were higher in Missouri, which has more extreme weather than mild California.

Table 4-9

Commercial Electric EUIs (kWh/end-use square foot)

	Office	Restaurant	Retail	Grocery	Warehouse	School	College	Health	Lodging	Other
Lighting 4 Lamp 4' T12	2.9	2.3	3.5	8.3	2.9	4.6	4.2	3.6	2.1	1.1
Lighting 2 Lamp 4' T12	2.8	2.0	3.4	8.2	3.5	4.9	4.2	3.1	2.0	0.8
Lighting 2 Lamp 8' T12	2.8	2.0	3.4	8.2	3.5	4.9	4.2	3.1	2.0	0.8
Lighting Incand-CFL Screw-in	11.2	8.1	13.4	32.6	14.1	19.6	16.6	12.2	8.0	3.3
Lighting CFL-LED Screw-in	3.1	2.2	3.7	8.9	3.9	5.4	4.5	3.3	2.2	0.9
Lighting Incand-CFL Hardwire	11.2	8.1	13.4	32.6	14.1	19.6	16.6	12.2	8.0	3.3
Lighting CFL-LED Hardwire	3.1	2.2	3.7	8.9	3.9	5.4	4.5	3.3	2.2	0.9
High Bay Lighting	2.1	1.5	2.5	6.1	2.7	3.7	3.1	2.3	1.5	0.6
Lighting 4 Lamp 4' T8	1.9	1.4	2.2	5.5	2.4	3.3	2.8	2.0	1.3	0.6
Lighting 2 Lamp 4' T8	1.9	1.4	2.2	5.5	2.4	3.3	2.8	2.0	1.3	0.6
Exit Signs	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outdoor lighting	1.1	2.9	1.0	1.7	0.4	0.8	0.2	0.3	0.5	0.6
Street Lighting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0
Chillers	2.9	5.3	2.3	5.9	2.5	1.5	2.1	3.1	0.9	1.1
DX Packaged Systems	4.9	9.1	4.0	10.2	4.3	2.5	3.6	5.3	1.6	1.9
Ventilation Motors 5 hp	1.1	3.1	0.9	7.8	0.7	0.8	0.6	3.9	0.7	0.4
Ventilation Motors 15 hp	1.0	2.9	0.8	7.2	0.6	0.7	0.5	3.6	0.7	0.4
Ventilation Motors 40 hp	1.0	2.8	0.8	7.1	0.6	0.7	0.5	3.5	0.7	0.4
Non-commercial refrigerators	0.1	0.3	0.1	0.0	0.0	0.2	0.0	0.1	0.2	0.0
Refrigeration System	0.1	10.3	0.3	26.4	1.3	0.4	0.5	0.3	0.4	0.2
Desktop PC	1.28	0.14	0.31	0.17	0.09	0.33	0.07	0.39	0.06	0.50
Monitor, 17" CRT	1.12	0.12	0.27	0.15	0.08	0.29	0.06	0.34	0.05	0.44
Monitor, 17" LCD	0.2807	0.0303	0.0673	0.0375	0.0200	0.0715	0.0154	0.0859	0.0122	0.1101
Copier	0.42	0.09	0.20	0.32	0.04	0.07	0.01	0.25	0.03	0.26
Laser Printer	0.82	0.22	0.40	0.20	0.07	0.20	0.05	0.44	0.07	0.41
Data Centers	236	266	282	407	26	95	75	118	195	116
Water Heating	0.5	5.8	0.8	5.5	0.4	0.4	0.4	1.3	3.2	0.5
Vending Machines	0.2	0.2	0.1	0.4	0.2	0.4	0.4	0.1	0.2	0.1
Convection Oven	0.0	0.7	0.2	1.3	0.0	0.0	0.0	0.0	0.0	0.1
Fryer	0.1	19.2	0.0	11.2	0.0	0.0	0.0	0.0	0.0	0.5
Steamer	0.1	6.6	0.0	4.3	0.0	0.0	0.0	0.4	0.0	0.3
Hot Food Holding Cabinets	0.0	1.1	0.6	1.5	0.0	0.0	0.0	0.1	0.1	0.1
Heating	5.5	6.4	4.3	9.5	1.0	6.4	6.4	7.0	2.4	2.3
Miscellaneous	4.1	4.5	2.4	5.0	0.6	0.4	0.4	8.9	2.9	2.2
Overall Energy Intensity (kWh/total sq ft)	20.56	45.06	13.41	67.90	7.53	9.41	9.43	24.10	11.90	9.91

4.2.2.4 Commercial Electric Floorspace

Floorspace was calculated for electricity customers based on the saturations, EUIs and usage by building type already developed. Data on floorspace is poor, and we have typically found this data to be the least reliable of the inputs to the ASSYST market characterization analysis. We therefore relied on the other data, and derived the floorspace that makes the other inputs balance in the final calibration step.

Floorspace is shown with energy consumption in Table 4-10.

4.2.2.5 Commercial Electricity Consumption

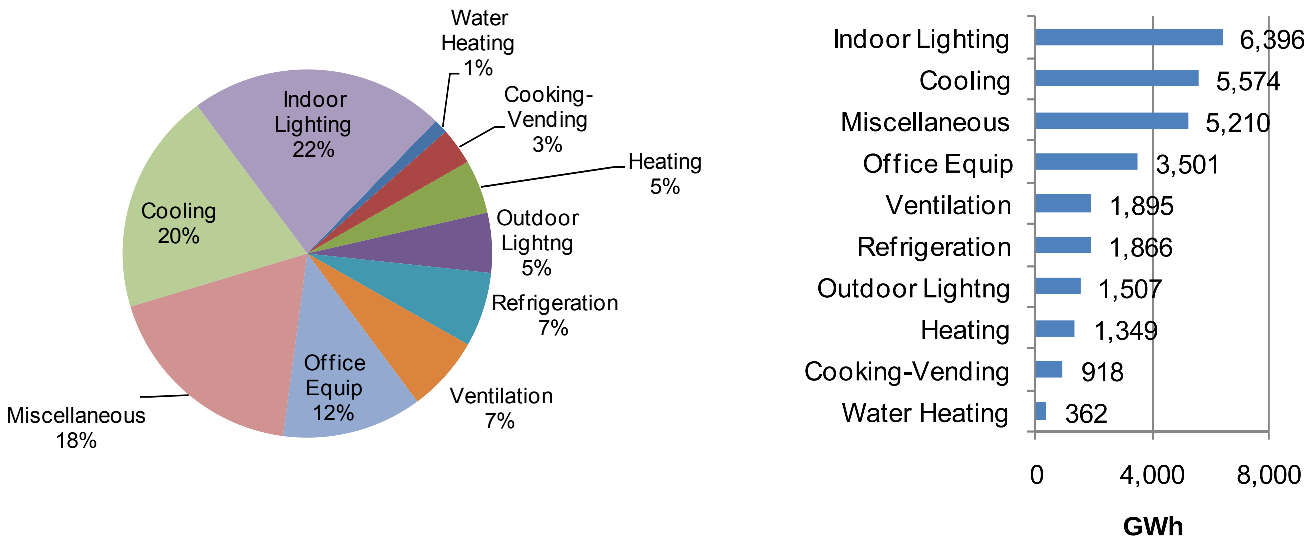
Table 4-10 shows commercial floorspace by building type and electricity consumption by end-use and building type. Figure 4-7 summarizes energy consumption by end-use.

Table 4-10

Commercial Floorspace (thousand sq ft) and Electricity Consumption (MWh) by Building Type and End Use

	Office	Restaurant	Retail	Grocery	Warehouse	School	College	Health	Lodging	Other	Total
Floorspace (thousand sq ft)	464,984	34,314	254,315	37,486	243,553	152,484	91,054	122,011	69,170	365,445	1,824,503
Energy Consumption (MWh)											
Lighting 4 Lamp 4' T12	81,024	6,254	33,065	0	66,871	0	2,321	2,025	0	13,188	204,747
Lighting 2 Lamp 4' T12	129,801	2,088	64,052	36,790	52,001	0	3,694	6,527	2,644	7,007	304,605
Lighting 2 Lamp 8' T12	62,352	5,569	43,294	154,487	28,493	0	0	0	0	2,984	297,180
Lighting Incand-CFL Screw-in	822,708	194,275	331,099	183,338	16,259	99,252	9,559	83,544	26,172	401,081	2,167,286
Lighting CFL-LED Screw-in	78,036	759	4,366	0	7,421	1,608	33	35,818	13,181	17,534	158,756
Lighting Incand-CFL Hardwire	371,605	19,427	96,185	36,668	1,210	6,680	54,937	230,186	130,860	88,082	1,035,840
Lighting CFL-LED Hardwire	280,000	759	2,013	1,715	552	1,133	25,160	102,928	92,390	19,118	525,770
High Bay Lighting	6,353	0	52,799	16,308	38,784	62,879	7,804	859	0	33,766	219,551
Lighting 4 Lamp 4' T8	110,057	464	96,635	0	77,599	149,848	86,620	98,248	0	38,662	658,134
Lighting 2 Lamp 4' T8	159,200	464	204,679	24,527	22,566	124,134	123,083	123,982	0	17,578	800,212
Exit Signs	6,927	1,993	3,695	414	940	1,606	2,055	3,315	1,723	1,131	23,799
Outdoor lighting	356,153	99,093	208,288	29,364	79,310	101,898	17,835	36,016	32,648	194,983	1,155,587
Street Lighting	0	0	0	0	0	0	0	0	0	351,323	351,323
Chillers	470,227	8,246	72,505	0	43,170	47,637	142,432	286,426	17,955	59,541	1,148,139
DX Packaged Systems	1,315,914	276,802	753,488	359,605	760,003	242,083	30,571	116,593	75,725	495,145	4,425,930
Ventilation Motors 5 hp	441,565	77,656	164,295	143,842	111,227	90,382	52,378	224,583	49,986	126,038	1,481,952
Ventilation Motors 15 hp	26,266	11,963	18,655	0	0	45,329	18,018	62,482	0	16,993	199,706
Ventilation Motors 40 hp	94,603	0	27,899	0	8,464	0	10,642	0	0	71,542	213,150
Non-commercial refrigerators	25,114	5,278	9,498	561	1,847	14,230	594	13,910	10,531	9,017	90,582
Refrigeration System	24,741	310,720	52,616	956,136	211,857	58,963	43,112	38,545	25,118	53,877	1,775,684
Desktop PC	541,511	3,446	65,779	4,292	15,144	46,196	2,367	45,338	3,720	145,178	872,970
Monitor, 17" CRT	202,878	1,308	37,538	2,105	13,898	30,162	2,078	17,689	166	102,295	410,117
Monitor, 17" LCD	21,852	488	2,184	868	759	9,156	519	2,600	537	9,186	48,149
Copier	184,766	417	30,707	5,492	5,820	9,472	1,183	28,643	789	47,036	314,326
Laser Printer	359,477	5,538	88,367	6,634	10,973	28,755	3,952	51,232	4,017	99,213	658,158
Data Centers	792,982	9,430	18,017	19,406	11,163	44,935	87,599	158,570	9,833	44,845	1,196,780
Water Heating	77,117	42,085	70,270	16,807	32,973	18,298	10,927	14,701	17,969	60,465	361,612
Vending Machines	64,130	1,678	9,643	8,797	26,615	49,039	32,780	7,910	9,496	15,535	225,622
Convection Oven	0	15,797	6,458	18,242	0	2,282	0	0	1,163	4,444	48,387
Fryer	760	140,677	0	162,452	0	0	0	0	0	39,578	343,467
Steamer	467	86,451	0	99,833	0	0	0	10,826	0	24,322	221,899
Hot Food Holding Cabinets	134	24,727	10,109	28,555	0	3,573	0	3,096	1,821	6,957	78,971
Heating	538,504	37,296	212,864	41,489	35,199	88,441	52,812	52,117	95,629	194,734	1,349,085
Miscellaneous	1,913,422	155,200	620,438	186,614	152,795	56,419	33,690	1,082,007	198,927	810,470	5,209,982
Total	9,560,644	1,546,351	3,411,501	2,545,340	1,833,911	1,434,391	858,757	2,940,716	823,000	3,622,847	28,577,458

Figure 4-7
Commercial Electricity Consumption by End Use



4.2.2.6 Commercial Peak Demand

Commercial load shape data from KEMA's end-use databases was utilized to allocate annual energy usage to time-of-use (TOU) periods. Peak period usage, developed on a sector-specific and end-use basis, was calibrated across all sectors to equal the Missouri summer peak. Commercial peak demand was estimated to be 4,991 MW. The table below shows the contribution to commercial peak demand by building type and end use.

Table 4-11
Commercial Peak Demand by Building Type and End Use (MW)

	Office	Restaurant	Retail	Grocery	Warehouse	School	College	Health	Lodging	Other	Total
Lighting 4 Lamp 4' T12	10.1	0.8	4.0	0.0	7.9	0.0	0.3	0.2	0.0	1.5	24.8
Lighting 2 Lamp 4' T12	16.1	0.3	7.7	3.7	6.1	0.0	0.5	0.7	0.2	0.8	36.2
Lighting 2 Lamp 8' T12	7.8	0.7	5.2	15.7	3.4	0.0	0.0	0.0	0.0	0.3	33.1
Lighting Incand-CFL Screw-in	102.3	25.5	39.9	18.6	1.9	9.1	1.4	8.5	2.5	45.6	255.2
Lighting CFL-LED Screw-in	9.7	0.1	0.5	0.0	0.9	0.1	0.0	3.6	1.2	2.0	18.2
Lighting Incand-CFL Hardwire	46.2	2.6	11.6	3.7	0.1	0.6	7.8	23.4	12.3	10.0	118.3
Lighting CFL-LED Hardwire	34.8	0.1	0.2	0.2	0.1	0.1	3.6	10.4	8.7	2.2	60.4
High Bay Lighting	0.8	0.0	6.4	1.7	4.6	5.7	1.1	0.1	0.0	3.8	24.2
Lighting 4 Lamp 4' T8	13.7	0.1	11.7	0.0	9.2	13.7	12.2	10.0	0.0	4.4	74.9
Lighting 2 Lamp 4' T8	19.8	0.1	24.7	2.5	2.7	11.3	17.4	12.6	0.0	2.0	93.0
Exit Signs	1.1	0.3	0.6	0.1	0.1	0.3	0.3	0.5	0.3	0.2	3.8
Outdoor lighting	3.3	4.4	9.1	0.5	0.7	2.7	0.0	0.2	0.2	10.1	31.1
Street Lighting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.1	18.1
Chillers	215.3	3.2	37.6	0.0	26.3	15.3	54.5	100.5	6.8	30.6	490.1
DX Packaged Systems	602.6	108.4	391.0	149.4	462.4	77.7	11.7	40.9	28.5	254.2	2,126.8
Ventilation Motors 5 hp	84.7	12.6	28.9	19.4	21.7	11.0	9.2	28.6	6.7	22.9	245.7
Ventilation Motors 15 hp	5.0	1.9	3.3	0.0	0.0	5.5	3.2	8.0	0.0	3.1	30.0
Ventilation Motors 40 hp	18.1	0.0	4.9	0.0	1.6	0.0	1.9	0.0	0.0	13.0	39.6
Non-commercial refrigerators	2.6	0.6	1.1	0.1	0.3	1.5	0.1	1.5	1.1	1.0	9.7
Refrigeration System	2.6	34.4	5.9	114.2	29.9	6.0	4.8	4.1	2.7	6.0	210.7
Desktop PC	50.1	0.4	7.8	0.5	1.7	2.7	0.3	4.3	0.4	14.8	83.0
Monitor, 17" CRT	18.8	0.2	4.5	0.3	1.5	1.7	0.2	1.7	0.0	10.5	39.4
Monitor, 17" LCD	2.0	0.1	0.3	0.1	0.1	0.5	0.1	0.2	0.1	0.9	4.4
Copier	17.1	0.1	3.7	0.7	0.6	0.5	0.1	2.7	0.1	4.8	30.4
Laser Printer	33.3	0.7	10.5	0.8	1.2	1.7	0.5	4.9	0.4	10.1	64.0
Data Centers	73.4	1.2	2.1	2.3	1.2	2.6	10.4	15.0	1.0	4.6	114.0
Water Heating	6.9	4.8	7.5	1.8	3.4	1.0	1.4	1.3	1.6	6.0	35.7
Vending Machines	6.2	0.2	1.1	0.9	3.3	2.9	4.1	0.7	1.0	1.7	22.4
Convection Oven	0.0	2.2	0.8	1.7	0.0	0.1	0.0	0.0	0.2	0.5	5.4
Fryer	0.1	19.2	0.0	15.1	0.0	0.0	0.0	0.0	0.0	4.4	38.7
Steamer	0.0	11.8	0.0	9.3	0.0	0.0	0.0	1.4	0.0	2.7	25.2
Hot Food Holding Cabinets	0.0	3.4	1.2	2.6	0.0	0.2	0.0	0.4	0.2	0.8	8.8
Heating	24.6	0.1	1.0	0.0	0.0	1.2	3.0	1.9	1.8	3.4	36.9
Miscellaneous	185.8	20.3	73.9	19.8	19.2	3.4	4.2	100.4	21.4	90.3	538.7
Total	1,614.9	260.7	708.8	385.4	612.2	179.2	154.3	388.7	99.5	587.3	4,991.0

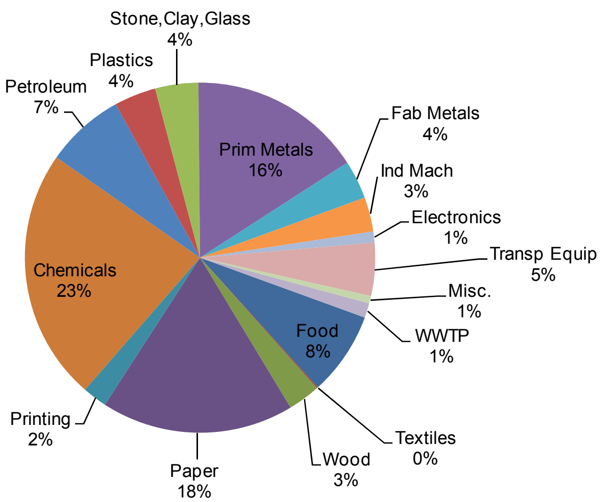
4.2.3 Industrial Electricity Market Characterization

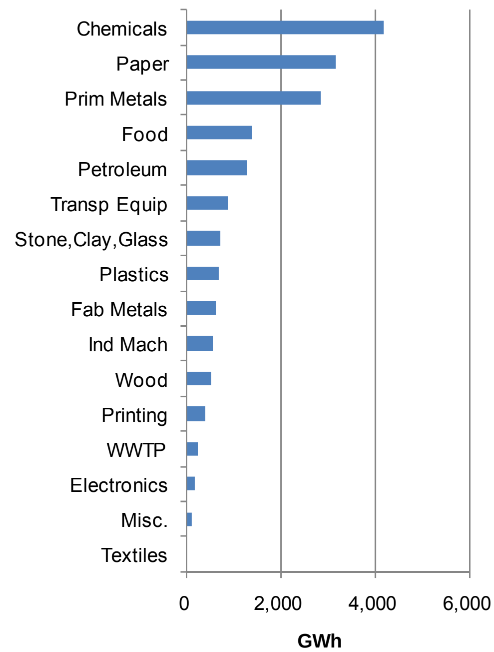
4.2.3.1 Industrial Building Types

We used a different approach on the industrial side. The available data on energy use by industry was not very detailed. The Ameren potential study treated all industries together to protect the confidentiality of Ameren's largest customers. The KCP&L and KCP&L-GMO studies broke out a limited number of industries (for example, printing and petroleum), while presenting all manufacturing industries together. Since we wanted to break out 16 different industries, this data was inadequate, although it acted as a cross-check against numbers developed through other methods. As noted above, the distribution of industries varies greatly by region, making it impossible to apply distributions from other studies as we did with commercial gas.

We adopted an approach based on employment data by industry. The Bureau of the Census' 2007 Economic Census provides state-level employment by NAICS code, which we combined with energy use per employee by industry from the Department of Energy's Manufacturing Energy Consumption Survey to estimate distributions of electricity and gas use by industry for Missouri. These were then normalized to the consumption estimates developed above. The following figures show the breakdown of electricity and natural gas by industry.

Figure 4-8
Industrial Sector Electricity Consumption by Industry





4.2.3.2 Industrial Sector Electric End Use Consumption

Energy use was disaggregated into end-use consumption percentages based mainly on the Department of Energy's Manufacturing Energy Consumption Survey (MECS). Where possible, the most current end-use by industry splits were used. A minority of end use splits were withheld in the 2006 MECS due to sampling errors, and were informed by applying ratios derived from 2002 MECS end-use data. Further disaggregation of the motor end uses (into pumps, fans, drives, and compressed air) by industry were based on the 1998 study "United States Industrial Electric Motor Systems Market Opportunities Assessment." Water and wastewater treatment plant electric end-use splits are not included in MECS and were based on a number of surveys conducted during the course of KEMA's potential studies for Xcel Energy (Colorado) in 2004 and Rhode Island in 2010.

Table 4-12 shows, for each industry, the fraction of energy used by each end use. Figure 4-9 summarized industrial energy use by end use. Table 4-13 shown the full breakdown of industrial energy use by end-use and industry.

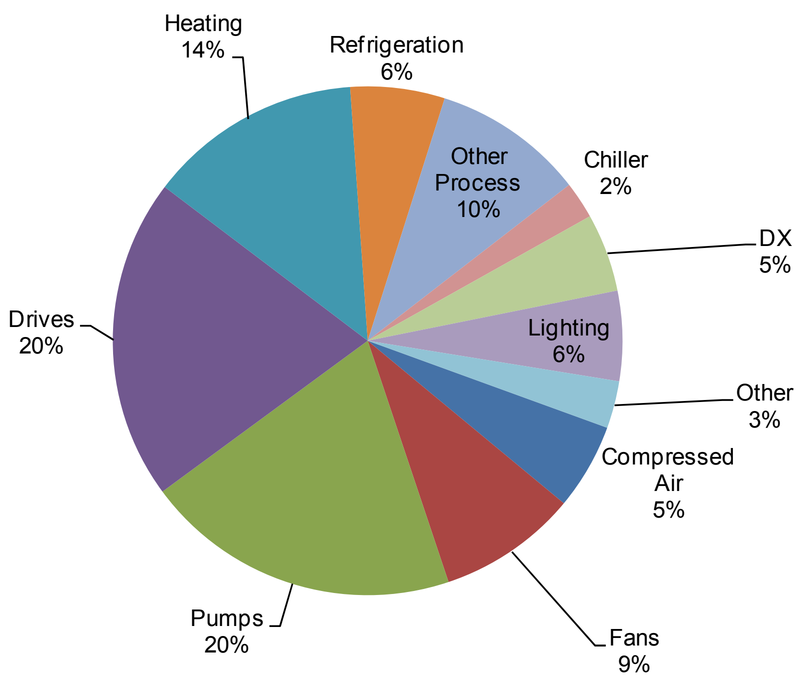
Table 4-12

Industrial Electric End-Use Consumption Splits (fraction of energy)

	Proc Heat	Proc Cool	Pumps	Fans	Comp Air	Proc Drives	Proc Other	HVAC	Lighting	Other	Boiler Use	CHP Proc	Total
Food	0.06	0.26	0.15	0.08	0.08	0.14	0.01	0.08	0.07	0.04	0.03	0.00	1.00
Textiles	0.10	0.12	0.09	0.07	0.04	0.30	0.01	0.14	0.10	0.03	0.01	0.00	1.00
Wood	0.07	0.01	0.11	0.09	0.05	0.41	0.01	0.07	0.08	0.09	0.02	0.00	1.00
Paper	0.04	0.02	0.24	0.15	0.04	0.32	0.02	0.04	0.04	0.02	0.07	0.00	1.00
Printing	0.03	0.06	0.09	0.07	0.04	0.32	0.01	0.19	0.12	0.07	0.01	0.00	1.00
Chemicals	0.05	0.08	0.26	0.06	0.03	0.21	0.14	0.06	0.04	0.03	0.04	0.00	1.00
Petroleum	0.04	0.05	0.49	0.07	0.12	0.13	0.01	0.04	0.02	0.01	0.01	0.00	1.00
Plastics	0.15	0.09	0.09	0.07	0.04	0.31	0.02	0.11	0.09	0.04	0.01	0.00	1.00
Stone,Clay,Glass	0.22	0.03	0.18	0.14	0.06	0.20	0.03	0.06	0.05	0.03	0.00	0.00	1.00
Prim Metals	0.28	0.01	0.10	0.08	0.03	0.11	0.31	0.03	0.03	0.01	0.00	0.00	1.00
Fab Metals	0.20	0.04	0.09	0.07	0.12	0.22	0.05	0.10	0.09	0.03	0.00	0.00	1.00
Ind Mach	0.07	0.03	0.07	0.05	0.14	0.18	0.02	0.22	0.15	0.06	0.00	0.00	1.00
Electronics	0.15	0.09	0.04	0.03	0.10	0.09	0.08	0.24	0.12	0.07	0.01	0.00	1.00
Transp Equip	0.14	0.06	0.07	0.05	0.12	0.12	0.03	0.19	0.15	0.05	0.01	0.00	1.00
Misc.	0.10	0.06	0.04	0.03	0.09	0.16	0.02	0.25	0.17	0.08	0.00	0.00	1.00
WWTP	0.01	0.00	0.62	0.30	0.00	0.00	0.00	0.02	0.04	0.00	0.00	0.00	1.00

Sources: DOE 2006 & 2003 MECS, KEMA 1998 Motors Assessment

Figure 4-9
Industrial Electricity Consumption by End Use



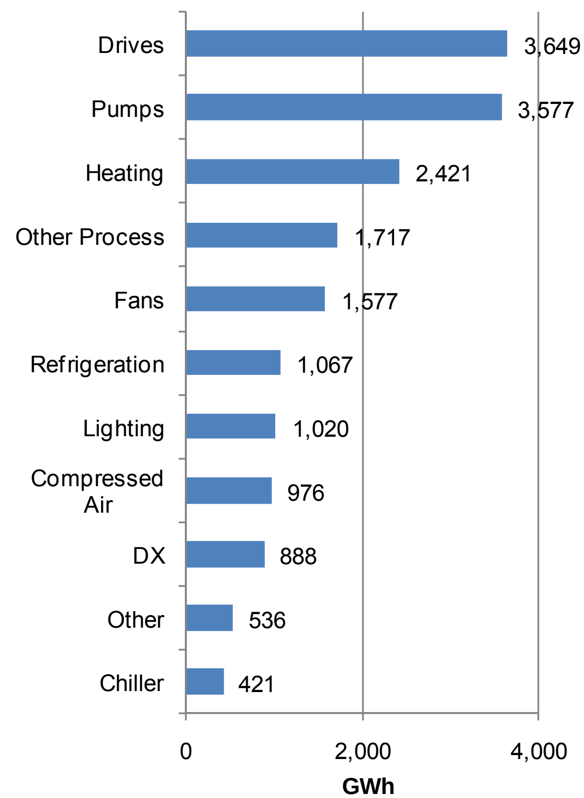


Table 4-13
Industrial Electricity Consumption by Industry and End Use (MWh)

	Compressed Air	Fans	Pumps	Drives	Heating	Refrig-eration	Other Process	Chiller	DX	Lighting	Other	Total
Food	104,793	114,696	201,829	193,927	113,119	357,270	13,761	14,928	101,526	101,576	58,345	1,375,767
Textiles	685	1,297	1,736	5,939	2,043	2,276	291	1,424	1,225	2,040	590	19,546
Wood	24,224	45,853	60,128	216,288	49,563	7,170	4,296	19,106	16,438	45,029	45,783	533,878
Paper	113,718	461,764	768,459	1,009,679	369,567	50,098	65,759	17,571	119,504	124,817	71,940	3,172,875
Printing	14,599	27,633	36,236	130,345	14,627	23,770	3,099	40,530	34,870	48,655	28,666	403,030
Chemicals	106,083	269,088	1,091,877	871,949	386,494	332,581	598,147	31,422	213,708	152,677	107,625	4,161,652
Petroleum	160,135	96,081	640,539	170,810	65,453	70,431	7,251	5,937	40,382	30,302	14,567	1,301,887
Plastics	24,251	45,903	60,194	216,525	110,184	62,045	11,670	39,811	34,252	59,098	26,467	690,399
Stone,Clay,Glass	42,157	99,069	125,769	142,632	155,528	19,165	23,608	5,692	38,715	36,649	21,513	710,497
Prim Metals	91,302	214,560	272,385	308,906	818,433	26,046	899,308	12,318	83,776	98,484	34,095	2,859,613
Fab Metals	74,991	41,769	54,772	138,733	126,362	22,282	30,193	34,103	29,340	59,443	20,933	632,921
Ind Mach	81,529	29,520	38,710	103,810	39,617	15,923	14,086	67,783	58,317	82,455	35,387	567,135
Electronics	18,320	5,551	7,280	15,572	27,705	15,713	14,091	23,228	19,984	21,035	13,160	181,639
Transp Equip	107,556	48,153	63,144	103,715	126,984	54,728	29,564	89,959	77,396	127,758	46,820	875,778
Misc.	11,036	4,099	5,375	20,032	12,552	7,329	1,890	16,391	14,102	20,648	10,113	123,566
WWTP	600	71,826	148,817	0	2,998	600	0	692	4,704	9,581	0	239,817
Total	975,977	1,576,863	3,577,249	3,648,861	2,421,229	1,067,426	1,717,014	420,894	888,237	1,020,246	536,004	17,850,000

4.2.3.3 Industrial Peak Demand

Industrial load shape data from KEMA's end-use databases were utilized to allocate annual energy usage to Missouri's peak electricity use periods. Given limited information on industrial end use load shapes, typical whole-facility shapes were applied to each end use. Peak period usage, developed on a sector-specific and end-use basis, was calibrated to equal Missouri's summer peak. Peak demands for the process cooling/refrigeration and HVAC end uses were adjusted upward to account for temperature sensitivity on peak days. Industrial peak demand was estimated to be 2,221 MW. Table 4-14 shows the contribution to peak by industry and end-use.

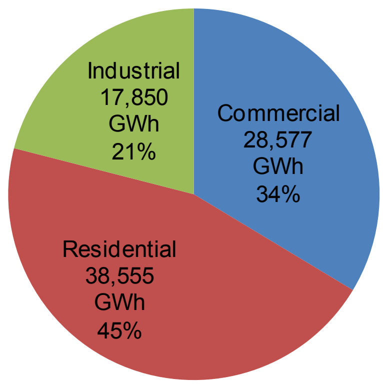
Table 4-14
Industrial Peak Demand by Industry and End Use – MW – 2011

Peak demand estimates	Proc Heat	Proc Cool	Pumps	Fans	Comp Air	Proc Drives	Proc Other	HVAC	Lighting	Other	Boiler Use	CHP Proc	Total
Food	9.5	51.7	24.4	13.8	12.6	23.4	1.7	16.9	12.3	7.0	4.2	0.0	177.5
Textiles	0.8	1.1	0.7	0.5	0.3	2.5	0.1	1.3	0.8	0.2	0.1	0.0	8.5
Lumber	5.7	1.3	8.9	6.8	3.6	32.1	0.6	6.3	6.7	6.8	1.7	0.0	80.6
Paper	10.7	4.8	61.4	36.9	9.1	80.7	5.3	13.1	10.0	5.8	18.9	0.0	256.6
Printing	1.5	3.7	4.7	3.6	1.9	17.1	0.4	11.9	6.4	3.8	0.4	0.0	55.4
Chemicals	23.6	45.4	124.2	30.6	12.1	99.2	68.1	33.5	17.4	12.2	20.3	0.0	486.7
Petroleum	5.5	9.6	72.9	10.9	18.2	19.4	0.8	6.3	3.4	1.7	2.0	0.0	150.8
Plastics	14.5	10.3	8.3	6.3	3.3	29.8	1.6	12.2	8.1	3.6	0.6	0.0	98.9
Stone-clay-glass	17.2	2.6	14.0	11.1	4.7	15.9	2.6	6.0	4.1	2.4	0.2	0.0	80.8
Primary Metals	115.5	4.5	38.8	30.6	13.0	44.0	128.2	16.4	14.0	4.9	1.2	0.0	411.2
Fab Metals	17.1	3.7	7.6	5.8	10.4	19.2	4.2	10.5	8.2	2.9	0.3	0.0	89.9
Ind Machinery	8.5	4.2	8.6	6.5	18.0	23.0	3.1	33.5	18.3	7.8	0.3	0.0	131.8
Electronics	3.4	2.4	0.9	0.7	2.3	2.0	1.8	6.6	2.7	1.7	0.2	0.0	24.5
Transp Equip	16.3	9.0	8.7	6.6	14.8	14.2	4.1	27.6	17.5	6.4	1.2	0.0	126.4
Misc	1.4	1.0	0.6	0.5	1.2	2.3	0.2	4.1	2.3	1.1	0.0	0.0	14.8
WWT	0.3	0.1	16.8	8.1	0.1	0.0	0.0	0.7	1.1	0.0	0.0	0.0	27.1
Total	251.5	155.4	401.6	179.4	125.7	424.9	222.8	207.0	133.3	68.4	51.5	0.0	2,221.3

4.2.4 2011 Electricity Consumption and Peak Demand Summary

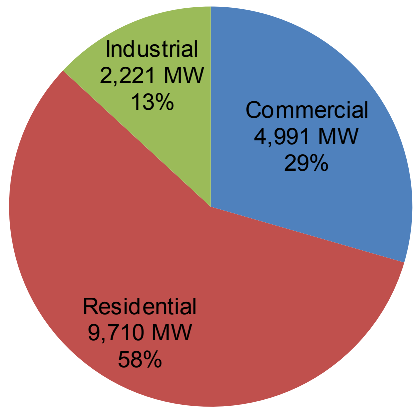
Total energy use in 2011 was estimated to be 84,982 GWh. Figure 4-10 shows how 2011 energy use breaks out by sector.

Figure 4-10
2011 Initial Energy Use by Sector (excluding line losses)



Total peak demand in 2011 was estimated to be 16,922 MW. Figure 4-11 shows 2011 peak demand by sector.

Figure 4-11
2011 Initial Peak Demand (excluding line losses)



4.2.5 Additional Electricity Baselines Used in this Report

The discussion in this section has focused on the 2011 baselines that serve as inputs to the model. These estimates serve to allocate energy use and peak demand among sectors, building types and end-uses, a necessary first step in setting up the ASSYST model. These estimates are based on sales, and do not include line losses.

Elsewhere in the report, we use estimates of base energy use that are output from the model, which are adjusted to include line losses.

We also calculate a 2020 fixed efficiency baseline that takes into account new construction and decay of the existing building stock over ten years. We do this to give new construction savings potential its proper weight. If 2011 results were presented, it would include only one year's worth of new construction, which would be dwarfed by savings for existing buildings. However, over time, new construction is very significant, and presenting 2020 results captures this. The following equation shows how the 2020 fixed efficiency baseline is calculated.

$$E_{2020} = E^{e}_{2011} \cdot (1 - D)^{10} + E^{n}_{2011} \cdot 10$$

Where E_{2020} is total energy use in 2020, E_{2011}^{e} is energy use for existing buildings in 2011, E_{2011}^{n} is energy use for new buildings constructed in 2011, and D is the rate of decay for the existing building stock. Note that the model assumes that the quantity of new building stock constructed is the same for each year of the forecast.

At the request of the PSC, we have also created an adjusted 2020 baseline that takes into account the effect of naturally occurring energy savings. Naturally occurring savings are an output of the model's achievable potential calculations. The adjusted 2020 baseline is calculated by subtracting the naturally occurring savings estimated by the model from the 2020 fixed efficiency baseline. Note that naturally occurring savings may occur within a program as free ridership, so this baseline is only appropriate to use for discussions of net program savings, not gross program savings.

The following table summarizes the two baselines used to present results in this report, compared to the 2011 energy use characterization developed above.

Table 4-15
Comparison of Electricity Use Baselines Used in this Report (GWh)

Sector	2011 Market Characterization GWh	2011 Baseline GWh*	2020 Fixed Efficiency Baseline GWh*	2020 Adjusted Baseline GWh
Residential	38,555	41,488	41,534	40,885
Commercial	28,577	30,644	32,444	31,316
Industrial	17,850	18,586	18,586	18,112
Total	84,982	90,718	92,564	90,313

*Includes line losses

Table 4-16
Comparison of Peak Demand Baselines Used in this Report (MW)

Sector	2011 Market Characterization MW	2011 Baseline MW*	2020 Fixed Efficiency Baseline MW*	2020 Adjusted Baseline MW*
Residential	9,710	10,437	10,342	10,131
Commercial	4,991	5,338	5,542	5,402
Industrial	2,221	2,313	2,313	2,269
Total	16,922	18,088	18,197	17,802

*Includes line losses

4.3 Natural Gas Market Characterization

To develop Missouri statewide natural gas use by sector, we started with breakouts from the Energy Information Administration's State Energy Data System (EIA's SEDS, found at http://www.eia.doe.gov/states/seds.html). Table 4-17 shows the SEDS data by sector, with subtotals for the commercial and industrial (C&I) sectors combined. Consumption is further broken out into sales and transport, a distinction which may be important for program design. For this study, we have been directed to consider both natural gas sales and transport for savings potential.

Table 4-17
SEDS 2008 Natural Gas Energy Consumption Data

	Sales Trillion Btu	Transport Trillion Btu	Total Trillion Btu
Residential consumption	114.6	0	114.6
Commercial consumption	50.6	14.7	65.3
Industrial consumption	9.3	57.8	67.1
Subtotal C&I	*59.9*	72.5	*132.4*
Total	174.5	72.5	247.0

It is our understanding that the SEDS sector breakouts are determined by assigning rate classes to one sector or another in their entirety. Utilities typically have a residential rate class that applies to residential customers, so this approach should result in accurate estimates for the residential sector. Commercial and industrial rates are typically broken out by customer demand rather than by sector, so we looked for other information to either corroborate the SEDS splits or inform new sector splits. Unfortunately, none of Missouri's natural gas utilities had market characterization studies of the sort that were available for the electric sector. The variation between energy use profiles in different utilities, combined with the variation in industrial customers between utilities, regions, and states, limited our ability to leverage data from other studies. In the absence of a better approach, we adopted the SEDS splits for natural gas unaltered.

The SEDS 2008 data were adjusted as discussed below to develop the 2011 initial baseline for the study.

4.3.1 Residential Natural Gas Market Characterization

4.3.1.1 Residential Building Types

The natural gas analysis used the same residential customer classes as the electric analysis.

The total number of residential natural gas customers was given by EIA's SEDS (2008) as 1,352,015, or 50.32% of electricity customers. These customers were disaggregated into the four customer classes using the same methodology applied to electric customers. Table 4-18 shows base year (2008) and forecast consumption and customer counts. Table 4-19 shows number of customers by customer class.

Table 4-18
Residential Natural Gas Base Year and Forecast Data

	Baseline	Source	Forecast 2011
Natural Gas Customers	1,352,015	SEDS 2008	1,365,701
Natural Gas Consumption (Dth)	114,600,000	SEDS 2008	105,001,999

Table 4-19
Number of Residential Natural Gas Customers by Class (2011)

	Single Family	Multifamily	Single Family—Low Income	Multifamily—Low Income	Total
Number of Natural Gas Customers	954,605	72,294	312,188	26,614	1,365,701

4.3.1.2 Residential Natural Gas End-use Saturations

The residential gas saturation estimates (the percentages of homes with the base measure installed) were calculated based on the 2006 "Missouri Statewide Residential Lighting and Appliance Efficiency Saturation Study" by KEMA (formerly RLW Analytics) and RECS 2005 microdata.

Table 4-20
Residential Natural Gas End-Use Saturations

	SF	MF	SF LI	MF LI	
Furnace	0.765	0.765	0.765	0.765	RLW 2006
Boiler	0.008	0.008	0.008	0.008	RLW 2006
Room Heat	0.020	0.020	0.020	0.020	RLW 2006
Water Heating	0.765	0.765	0.765	0.765	RLW 2006
Clothes Dryer	0.119	0.119	0.119	0.119	RLW 2006
Cooking	0.356	0.344	0.456	0.391	RECS microdata, Region 2
Other	0.047	0.015	0.025	0.010	RECS microdata, Region 2

4.3.1.3 Residential Natural Gas Energy Intensities

Residential gas end-use energy intensities were taken from RECS microdata. For weather-sensitive measures we used data from climate zone 3 in census divisions 3, 4 and 6. For non-weather sensitive measures, we used the West North Central census division.

Table 4-21
Residential Natural Gas Energy Intensity (Dth/household)

	SF	MF	SF LI	MF LI	
Furnace	64	61	63	75	RECS microdata, CZ 3 in Division 3, 4 & 6, calibrated
Boiler	113	56	117	63	RECS microdata, CZ 3 in Division 3, 4 & 7, calibrated
Room Heat	57	22	89	22	RECS microdata, CZ 3 in Division 3, 4 & 8
Water Heating	31	15	28	23	RECS microdata, CZ 3 in Division 3, 4 & 8
Clothes Dryer	10	10	4	4	RECS microdata, West North Central Midwest
Cooking	6	5	5	6	RECS microdata, West North Central Midwest
Other	14	14	1	1	RECS microdata, West North Central Midwest
Total (kBtu/sq ft)	79	62	75	79	

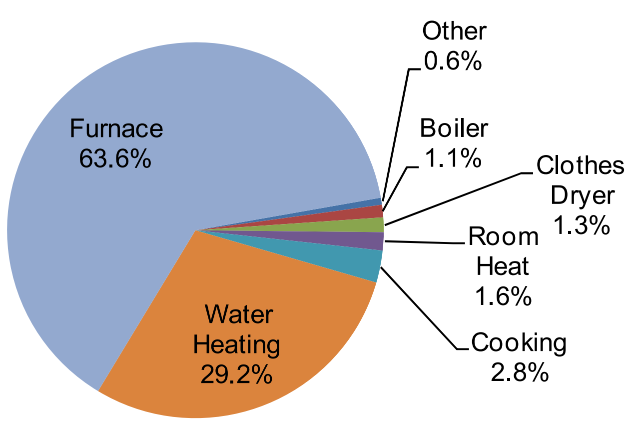
4.3.1.4 Residential Natural Gas Use

Table 4-22 shows the number of households by building type, and energy consumption by building type and end-use. Energy use is calculated by multiplying together the saturations, EUIs, and number of households. Figure 4-12 summarizes natural gas use by end-use, and Figure 4-13 summarizes use by customer class.

Table 4-22
Residential Natural Gas Housing Stock and Energy Use by Building Type and End-Use

	Single Family	Multifamily	Single Family Low Income	Multifamily Low Income	Total
Homes	954,605	72,294	312,188	26,614	1,339,087
Energy Consumption (Dth)					
Furnace	46,763,523	3,365,559	15,094,423	1,531,530	66,755,034
Boiler	810,546	30,471	274,277	12,582	1,127,876
Room Heat	1,063,396	31,503	541,141	11,597	1,647,637
Water Heating	22,683,594	840,943	6,612,519	477,979	30,615,036
Clothes Dryer	1,086,837	82,308	146,601	12,498	1,328,245
Cooking	2,006,944	125,108	696,707	64,328	2,893,088
Other	609,495	15,222	10,022	343	635,083
Total	75,024,336	4,491,115	23,375,690	2,110,858	105,001,999

Figure 4-12
Residential Natural Gas Use by End Use



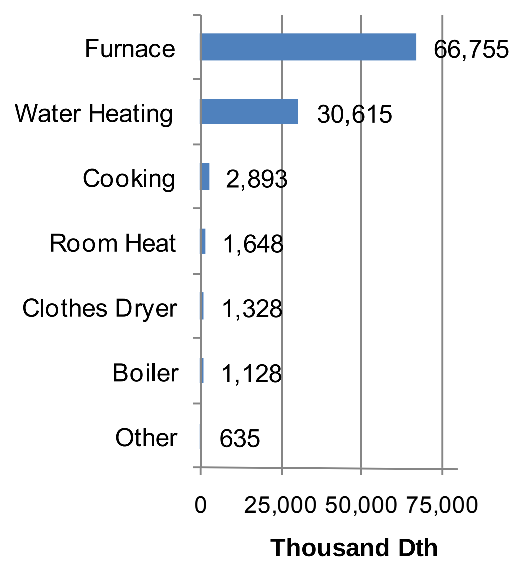
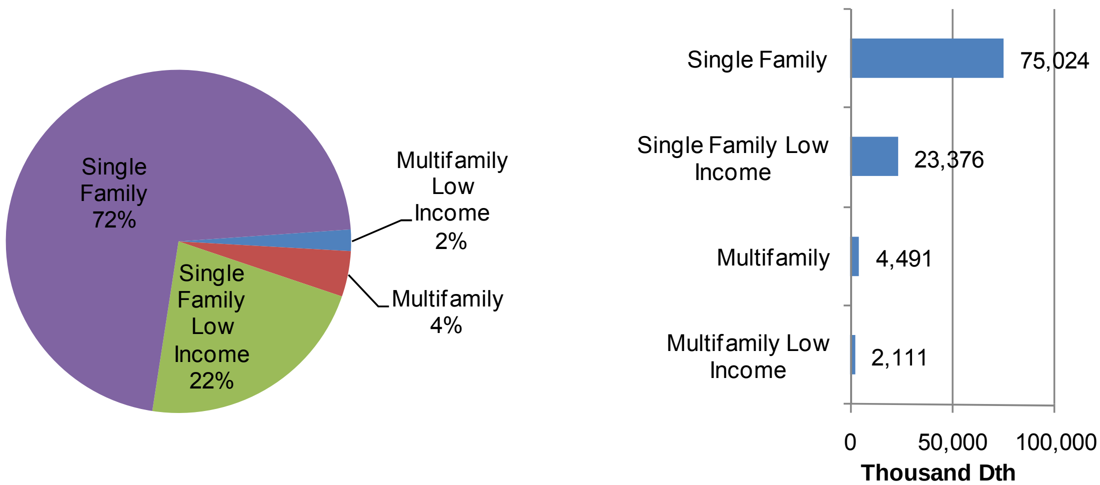


Figure 4-13
Residential Natural Gas Use by Building Type

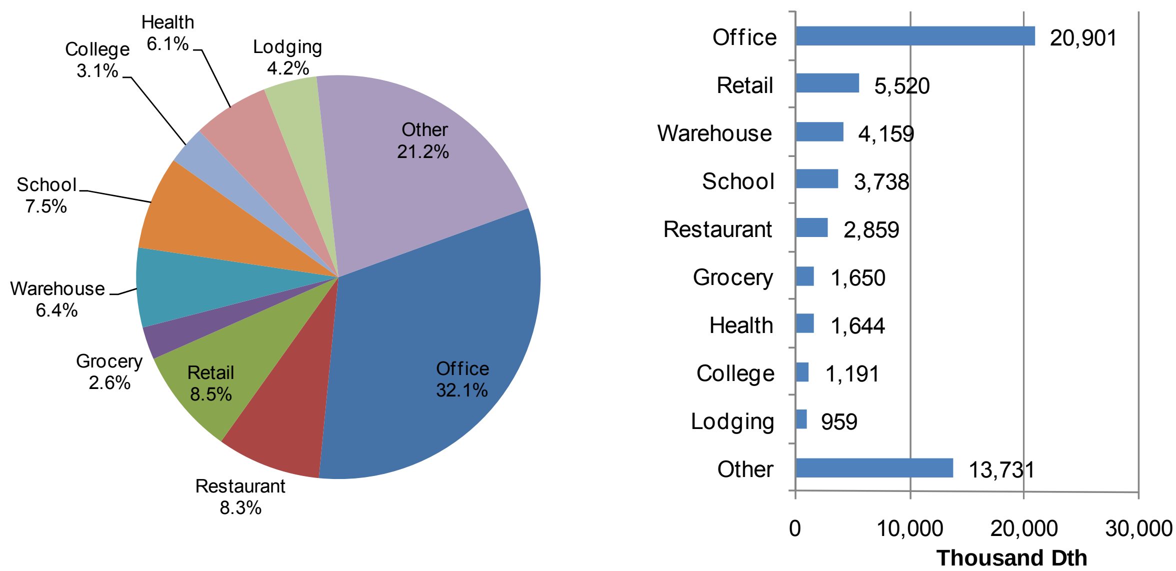


4.3.2 Commercial Natural Gas Market Characterization

4.3.2.1 Commercial Natural Gas Use by Building Type

Unlike the electricity sector, no gas market analyses were available through any of Missouri's gas utilities, nor did we have access to billing data. We therefore looked to other recent gas studies KEMA did for which we had access to utility billing data by NAICS (North American Industry Classification System) code. We have found the distribution of energy use across building types to be very similar across different regions. We took the energy use distribution by building type for Xcel Energy's Colorado service territory and for the state of Connecticut and reweighted them to reflect the distribution of floorspace by building type in Missouri (for example, if offices represented 36 percent of Xcel's floorspace compared to 24 percent of Missouri floorspace, we scaled back Xcel's office energy use by a third before calculating the distribution of energy use). The distributions for Xcel and Connecticut were averaged and applied to Missouri commercial natural gas use, developed as discussed above. The following chart shows commercial natural gas use by building type.

Figure 4-14
Commercial Natural Gas Use by Building Type



4.3.2.2 Commercial Natural Gas End-use Saturations

We relied on the U.S. DOE Commercial Building Energy Consumption Survey (CBECS) for end use saturation estimates of natural gas equipment.

Table 4-23
Commercial Natural Gas End-Use Saturations

End Use	Office	Restaurant	Retail	Grocery	Warehouse	School	College	Health	Lodging	Other
Heating	71%	74%	74%	98%	88%	79%	89%	83%	39%	82%
Water Heating - high standby applications	51%	79%	57%	75%	55%	77%	85%	80%	94%	69%
Water Heating - low standby applications	51%	79%	57%	75%	55%	77%	85%	80%	94%	69%
Cooking - Fryer	21%	88%	0%	66%	0%	48%	0%	34%	36%	6%
Cooking - Steamer	0%	17%	0%	33%	0%	69%	0%	80%	36%	1%
Cooking - Convection Oven	31%	31%	28%	33%	0%	69%	0%	80%	36%	16%
Cooking - Griddle	21%	73%	0%	0%	0%	42%	0%	34%	36%	8%
Cooking - Range	23%	87%	0%	0%	0%	2%	0%	67%	36%	29%
Other	0%	6%	0%	0%	11%	6%	10%	10%	6%	1%

4.3.2.3 Commercial Natural Gas Energy Intensity

We began with California Commercial End-Use Survey data as a starting point for natural gas EUI estimates. These values were adjusted to account for Missouri's climate differences.

Table 4-24
Commercial Natural Gas EUIs (kBtu/end use sq ft)

End Use	Office	Restaurant	Retail	Grocery	Warehouse	School	College	Health	Lodging	Other
Heating	63.3	15.1	28.9	28.5	18.8	33.6	15.0	14.8	35.6	21.6
Water Heating - high standby applications	9.0	22.4	4.8	20.8	2.0	0.0	0.0	0.0	0.0	33.0
Water Heating - low standby applications	0.0	28.1	0.0	0.0	0.0	10.2	11.8	24.5	28.7	0.0
Cooking – Fryer	0.60	68.88	3.28	8.09	2.80	0.62	1.36	1.54	3.38	1.50
Cooking - Steamer	0.35	40.19	1.92	4.72	1.63	0.36	0.79	0.90	1.97	0.87
Cooking - Convection Oven	0.09	10.39	0.50	1.22	0.42	0.09	0.20	0.23	0.51	0.23
Cooking - Griddle	0.24	27.45	1.31	3.22	1.12	0.25	0.54	0.61	1.35	0.60
Cooking - Range	0.30	34.95	1.67	4.11	1.42	0.31	0.69	0.78	1.71	0.76
Other	27.8	43.5	12.1	10.0	11.3	3.7	11.0	21.1	3.8	75.3

4.3.2.4 Commercial Natural Gas Floor space

As discussed in the electricity market characterization section, we have typically found floorspace data to be the least reliable of the inputs to the ASSYST market characterization analysis. However, unlike the electricity analysis, there was too much uncertainty in EUIs to use floorspace as a calibration factor. We therefore used the floorspace determined for the electric analysis as a starting point, and scaled it back 10 percent to account for electric-only customers. With floorspace estimated in this manner, we were then able to calibrate the weather-sensitive EUIs so that overall energy use balanced with our sector totals.

Floorspace is shown with energy consumption in the tables below.

4.3.2.5 Commercial Energy Consumption

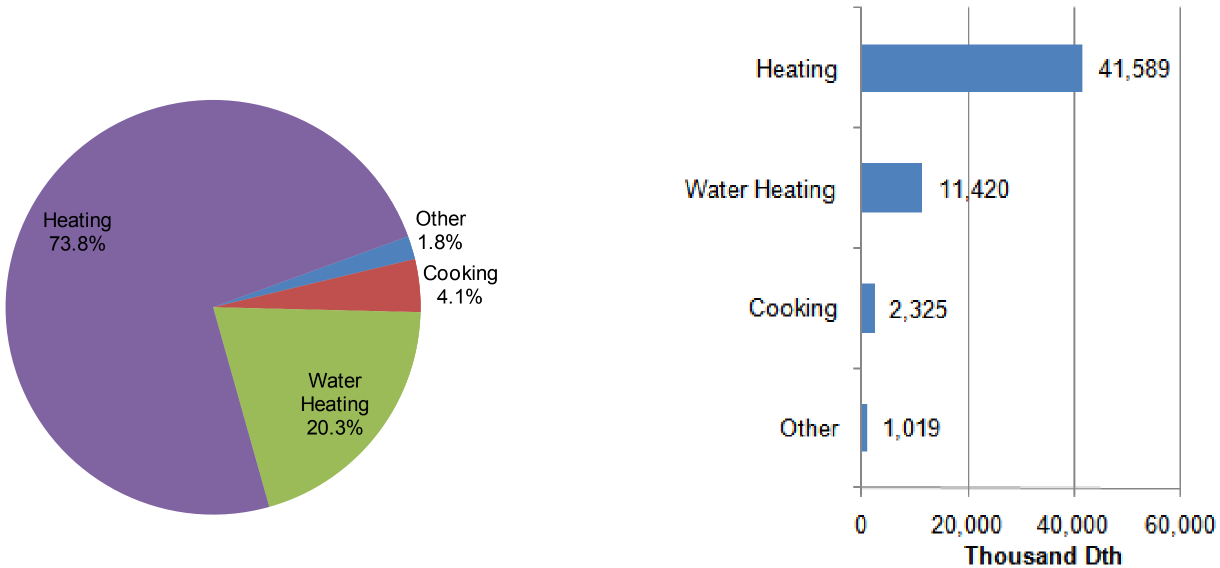
The following tables and figures show commercial natural gas floorspace by building type and energy consumption by end-use and building type for natural gas.

Table 4-25

Commercial Natural Gas Floorspace (thousand sq ft) and Energy Consumption (Dekatherms) by Building Type and End Use

	Office	Restaurant	Retail	Grocery	Warehouse	School	College	Health	Lodging	Other	Total
Floorspace (thous. sq ft)	419,996	30,994	229,709	33,859	219,988	137,731	82,245	110,206	62,478	330,087	1,657,294
Energy Consumption											
Heating	18,922,398	346,383	4,893,472	945,341	3,641,947	3,665,033	1,096,377	1,356,424	869,235	5,851,945	41,588,553
Water Heating - high standby applications	1,926,495	548,317	626,249	524,678	247,409	0	0	0	0	7,546,465	11,419,613
Water Heating - low standby applications	0	688,221	0	0	0	1,081,958	821,900	2,162,181	1,691,178	0	6,445,438
Cooking – Fryer	52,244	1,886,336	0	179,877	0	41,268	0	57,543	75,909	31,504	2,324,682
Cooking - Steamer	0	205,823	0	52,479	0	34,260	0	78,828	44,292	1,593	417,276
Cooking - Convection Oven	11,575	101,297	31,554	13,565	0	8,917	0	20,375	11,449	11,966	210,698
Cooking - Griddle	20,817	624,552	0	0	0	14,264	0	22,928	30,246	14,998	727,805
Cooking - Range	29,343	947,529	0	0	0	653	0	57,839	38,514	72,784	1,146,662
Other	0	78,240	0	0	269,826	31,608	94,565	229,741	13,902	301,390	1,019,274
Total	20,962,871	5,426,698	5,551,275	1,715,940	4,159,182	4,877,961	2,012,842	3,985,860	2,774,726	13,832,645	65,300,000

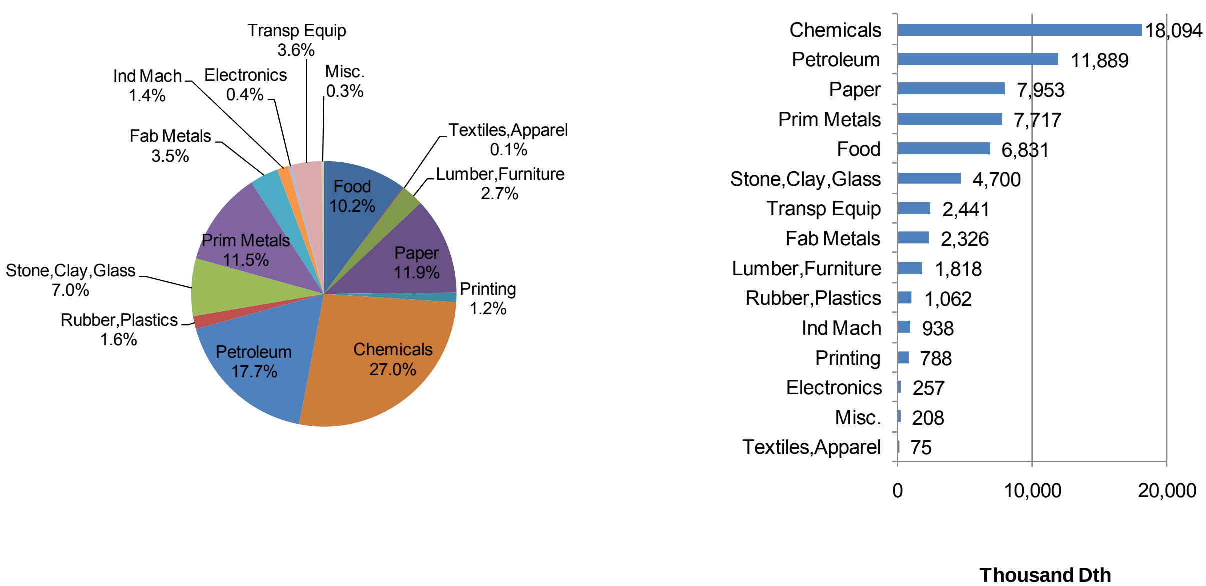
Figure 4-15
Commercial Natural Gas Consumption by End Use



4.3.3 Industrial Natural Gas Market Characterization

The distribution of industries varies greatly by region, making it impossible to apply distributions from other studies as we did with commercial gas. We adopted an approach based on employment data by industry. The Bureau of the Census' 2007 Economic Census provides state-level employment by NAICS code, which we combined with energy use per employee by industry from the Department of Energy's Manufacturing Energy Consumption Survey to estimate distributions natural gas use by industry for Missouri. These were then normalized to the consumption estimates developed above. The following figures show the breakdown of natural gas by industry.

Figure 4-16
Industrial Sector Natural Gas Use by Industry



4.3.3.1 Industrial Sector End Use Consumption

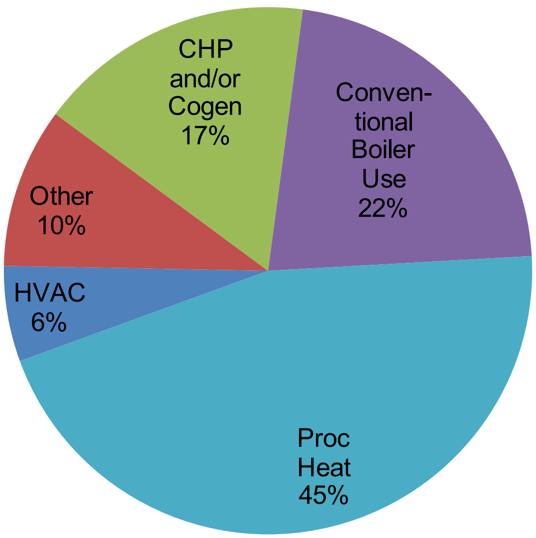
Energy use was disaggregated into end-use consumption percentages based mainly on the Department of Energy's Manufacturing Energy Consumption Survey (MECS). Where possible, the most current end-use by industry splits were used. A minority of end use splits were withheld in the 2006 version due to sampling errors, and were informed by applying ratios derived from 2002 MECS end-use data.

Table 4-26
Industrial Natural Gas End-Use Shares

Industry	Proc Heat	HVAC	Conventional Boiler Use	CHP and/or Cogen	Other	Total
Food	0.31	0.05	0.52	0.04	0.07	1.00
Textiles,Apparel	0.30	0.06	0.35	0.12	0.17	1.00
Lumber,Furniture	0.53	0.13	0.16	0.00	0.18	1.00
Paper	0.26	0.03	0.25	0.33	0.13	1.00
Printing	0.66	0.18	0.13	0.00	0.03	1.00
Chemicals	0.28	0.02	0.28	0.32	0.11	1.00
Petroleum	0.59	0.01	0.14	0.19	0.07	1.00
Rubber,Plastics	0.25	0.19	0.45	0.00	0.10	1.00
Stone,Clay,Glass	0.78	0.04	0.04	0.00	0.14	1.00
Prim Metals	0.78	0.07	0.05	0.05	0.05	1.00
Fab Metals	0.64	0.15	0.15	0.01	0.06	1.00
Ind Mach	0.29	0.37	0.20	0.05	0.10	1.00
Electronics	0.30	0.29	0.31	0.00	0.10	1.00
Transp Equip	0.30	0.34	0.15	0.02	0.19	1.00
Misc.	0.24	0.48	0.16	0.00	0.12	1.00

Source: DOE 2002 and 2006 MECS

Figure 4-17
Industrial Natural Gas Consumption by End Use



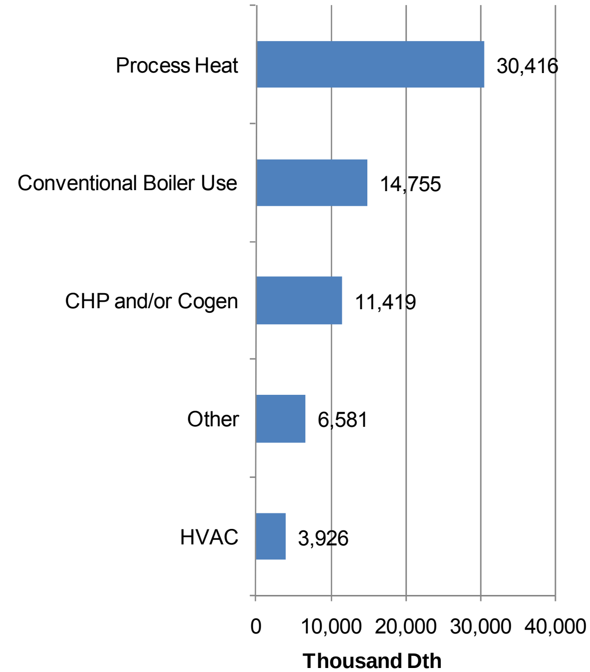


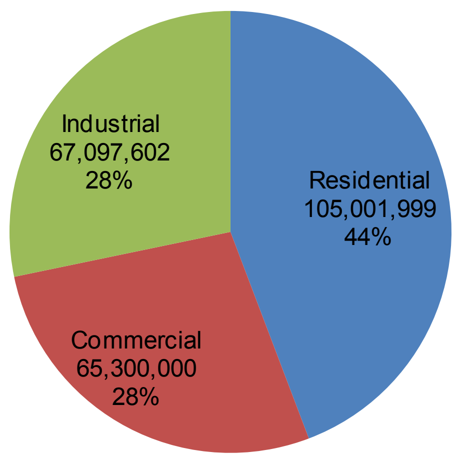
Table 4-27
Industrial Natural Gas Consumption by Industry and End Use (thousand Dth)

Industry	Proc Heat	HVAC	Conventional Boiler Use	CHP and/or Cogen	Other	Total
Food	2,149	343	3,582	301	457	6,831
Textiles, Apparel	23	4	26	9	12	75
Lumber, Furniture	964	236	291	7	320	1,818
Paper	2,070	224	2,018	2,639	1,001	7,953
Printing	518	145	104	0	21	788
Chemicals	5,034	294	4,981	5,729	2,056	18,094
Petroleum	7,061	101	1,672	2,248	807	11,889
Rubber, Plastics	266	206	480	2	110	1,062
Stone, Clay, Glass	3,657	179	211	11	643	4,700
Prim Metals	6,046	503	394	367	408	7,717
Fab Metals	1,491	338	338	20	139	2,326
Ind Mach	275	343	183	46	92	938
Electronics	76	73	79	1	27	257
Transp Equip	736	837	363	40	464	2,441
Misc.	50	100	33	0	25	208
Total	30,416	3,926	14,755	11,419	6,581	67,098

4.3.4 2011 Natural Gas Consumption Summary

Total natural gas energy use in 2011 was estimated to be 237,399,601 Dth. Figure 4-18 shows the how 2011 energy use breaks out by sector.

Figure 4-18
2011 Natural Gas Energy Use by Sector (Dth)



4.3.5 Additional Natural Gas Baselines Used in this Report

The discussion in this section has focused on the 2011 initial energy use characterization. The inputs developed in this analysis serve to allocate energy use and peak demand among sectors, building types and end-uses, a necessary first step in setting up the ASSYST model. These estimates are based on sales.

Elsewhere in the report, we use estimates of base energy use that are output from the model. From these model outputs, we calculate a 2020 fixed efficiency baseline that takes into account new construction and decay of the existing building stock over ten years. We do this to give new construction savings potential its proper weight. If 2011 results were presented, it would include only one year's worth of new construction, which would be dwarfed by savings for existing buildings. However, over time, new construction is very significant, and presenting 2020 results captures this. The following equation shows how the 2020 fixed efficiency baseline is calculated.

$$E_{2020} = E^{e}_{2011} \cdot (1 - D)^{10} + E^{n}_{2011} \cdot 10$$

Where E_{2020} is total energy use in 2020, $E^{e}_{2011}$is energy use for existing buildings in 2011, E^{n}_{2011} is energy use for new buildings constructed in 2011, and D is the rate of decay for the existing building stock. Note that the model assumes that the quantity of new building stock constructed is the same for each year of the forecast.

At the request of the PSC, we have also created an adjusted 2020 baseline that takes into account the effect of naturally occurring energy savings. Naturally occurring savings are an output of the model's achievable potential calculations. The adjusted 2020 baseline is calculated by subtracting the naturally occurring savings estimated by the model from the 2020 fixed efficiency baseline. Note that naturally occurring savings may occur within a program as free ridership, so this baseline is only appropriate to use for discussions of net program savings, not gross program savings.

The following table summarizes the two baselines used to present results in this report, compared to the 2011 energy use characterization developed above.

Table 4-28

Comparison of Natural Gas Use Baselines Used in this Report (Dth)

Sector	2011 Input Baseline	2020 Fixed Efficiency Baseline	2020 Adjusted Baseline
Residential	105,001,999	117,095,547	112,511,101
Commercial	65,300,000	69,612,193	68,578,050
Industrial	67,097,602	67,097,602	66,353,313
Total	237,399,601	253,805,342	247,442,463

5. Electric Energy-Efficiency Potential Results

In this section, we present estimates of electric energy-efficiency potential. First, we present technical and economic potential results for all electric measures considered in the study. Next, we present estimates of achievable program potential under three different scenarios.

5.1 Technical and Economic Potential

Estimates of overall energy-efficiency technical and economic potential are discussed in section 5.1.1. More detail on these potentials is presented in section 5.1.2. Section 5.1.3 presents the results of high and low avoided cost scenarios. Energy-efficiency supply curves are shown in section 5.1.4.

5.1.1 Overall Technical and Economic Potential

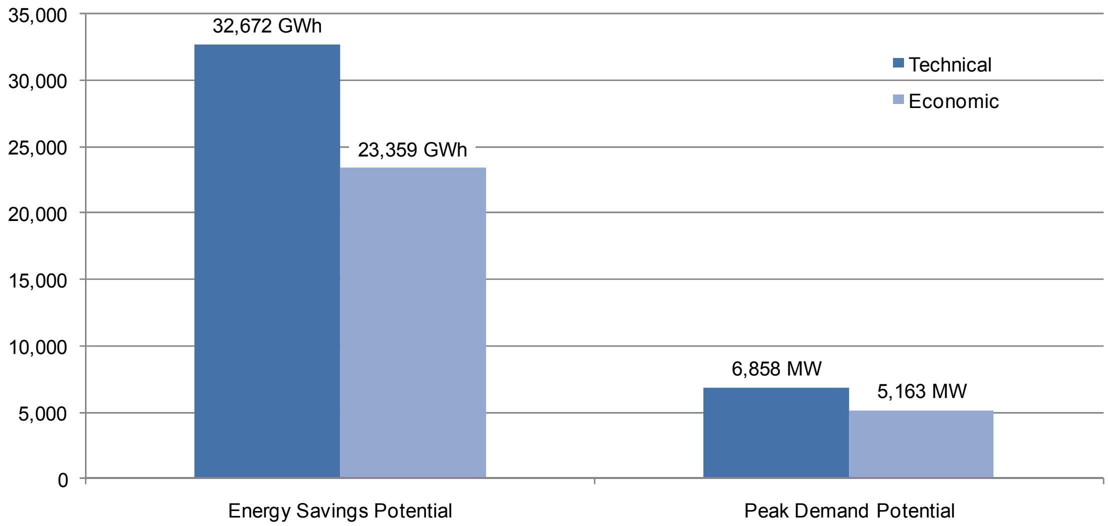
Figure 5-1 presents our overall estimates of total technical and economic potential for electrical energy and peak-demand savings for Missouri. Technical potential represents the sum of all savings from all of the measures deemed applicable and technically feasible. Economic potential is based on efficiency measures that are cost-effective, as determined by the total resource cost (TRC) test—a benefit-cost test that compares the value of avoided energy production and power-plant construction to the costs of energy-efficiency measures and program activities necessary to deliver them. The values of both energy savings and peak-demand reductions are incorporated in the TRC test.

- Energy Savings. Technical potential is estimated at about 32,672 GWh per year, and economic potential at 23,359 GWh per year by 2020 (about 35 and 25 percent of base 2020 usage, respectively).

- Peak-Demand Savings. Technical potential is estimated at about 6,858 MW, and economic potential at 5,163 MW by 2020 (about 38 and 28 percent of base 2020 demand, respectively).

Note that the technical and economic potentials include the effect of CFLs, although federal lighting standards may preempt much of the CFL potential that might otherwise be achieved through programs.

Figure 5-1
Estimated Electric Technical and Economic Potential 2020



5.1.2 Technical and Economic Potential Detail

In this subsection, we explore technical and economic potential in more detail, looking at potentials by sector and by end use.

5.1.2.1 Potentials by Sector

Figure 5-2 and Figure 5-3 show estimates of technical and economic energy (GWh) and demand (MW) savings potential by sector.

Figure 5-3 shows how the three sectors contribute to base energy use and peak demand, technical energy and demand savings, and economic energy and demand savings. On the energy side, the residential sector contribution to potential is greater than its contribution to base energy use, while industrial contributes less to potential, and commercial is roughly proportional. On the peak demand side, residential similarly contributes more to potential than to base use, with both commercial and industrial contributing less to potential than to base use.

Figure 5-2
Technical and Economic Potential (2020)
Energy Savings by Sector—GWh per Year

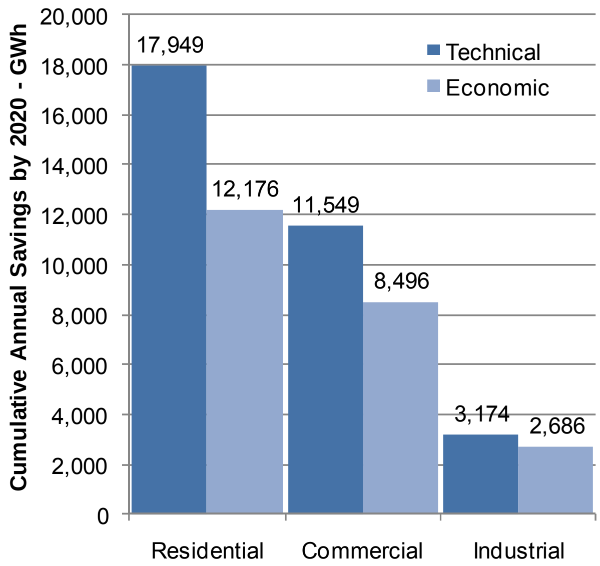


Figure 5-3
Technical and Economic Potential (2020)
Demand Savings by Sector—MW

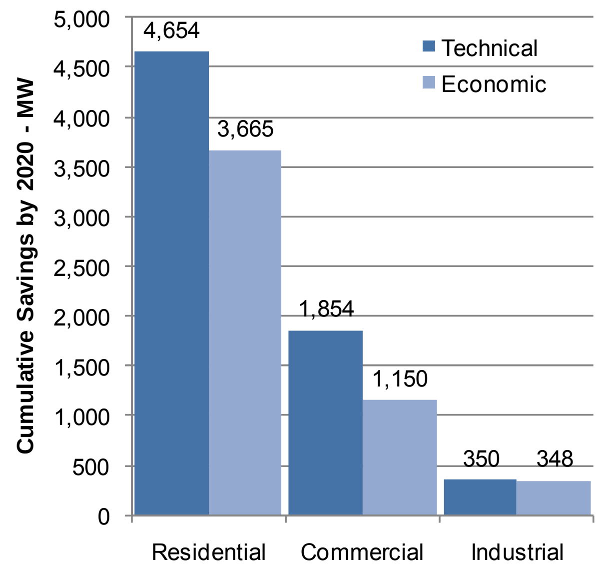


Figure 5-4

Shares of Base Energy Use and Peak Demand, Technical and Economic Energy and Peak Demand Potential by Sector

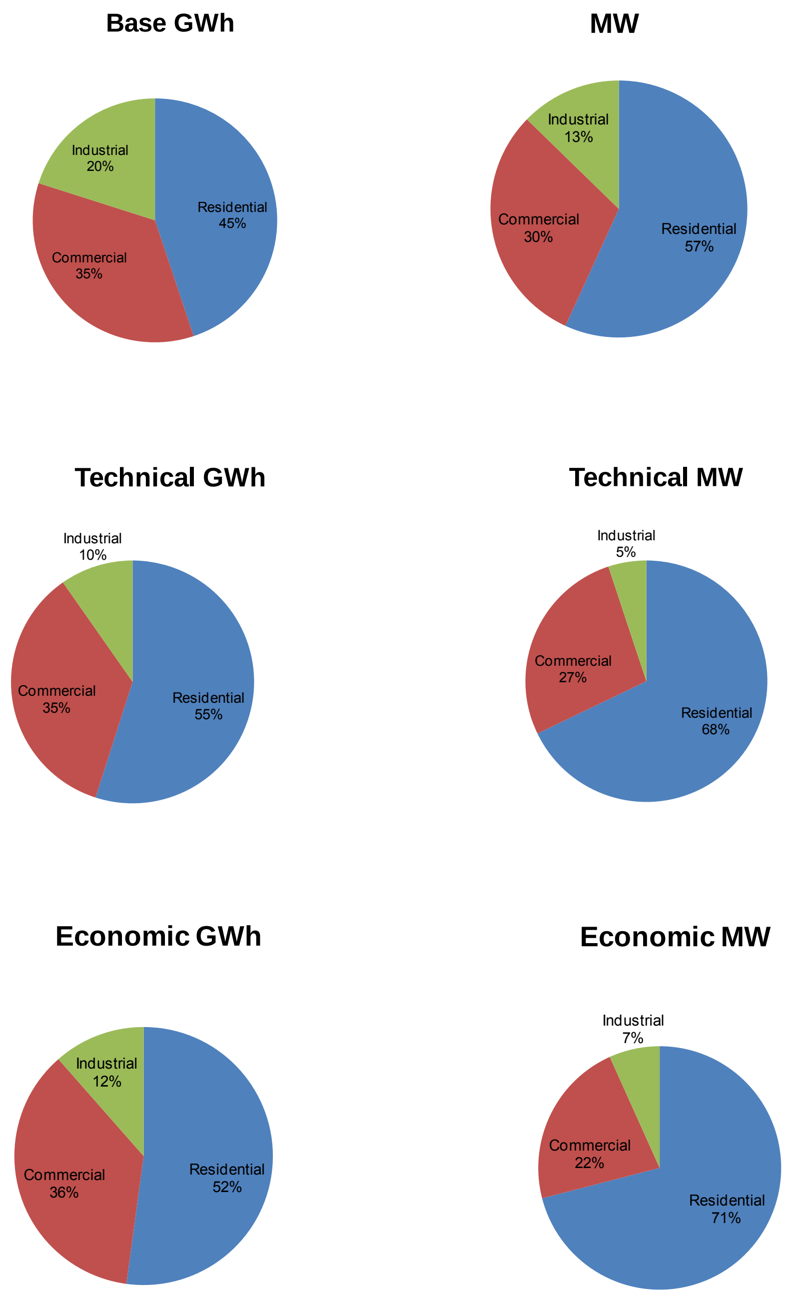


Figure 5-5 and Figure 5-6 show the same potentials as a percentage of 2020 base energy and base peak demand. The residential sector has the highest energy savings potential in relation to base energy use, followed by the commercial sector. The estimated savings fraction is lowest for the industrial sector at around 17 percent for technical and 14 percent for economic savings. A similar pattern holds for peak demand.

Figure 5-5
Technical and Economic Potential (2020)
Percentage of Fixed Efficiency Base Energy Use

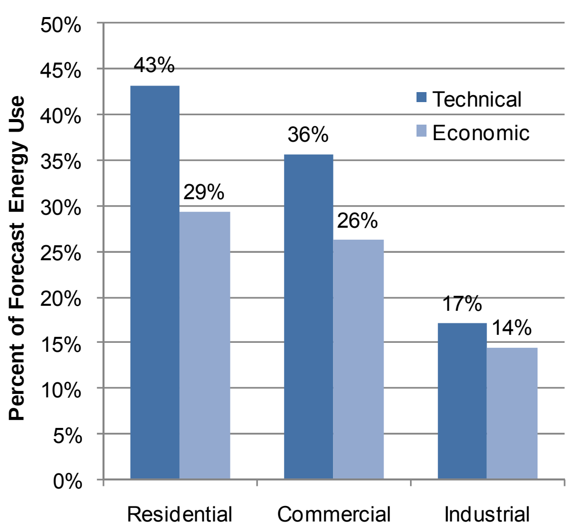
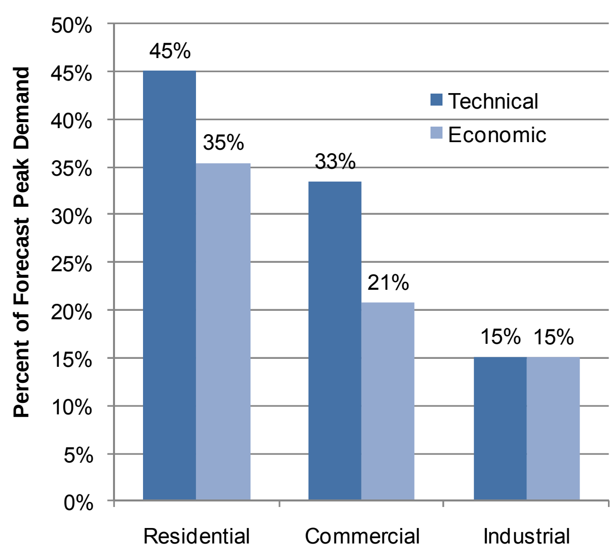


Figure 5-6
Technical and Economic Potential (2020)
Percentage of Fixed Efficiency Base Peak Demand



5.1.2.2 Potentials by Building Type

Figure 5-7 and Figure 5-8 show the potentials in the residential sector by building type. Single-family homes account for about 85 percent of the potential, and low-income homes account for about 24 percent of the potential.

Figure 5-7
Residential Energy-Savings Potential by Building Type (2020)

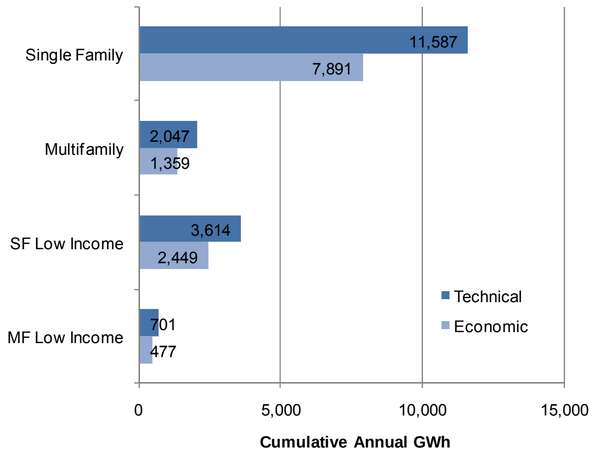


Figure 5-8
Residential Demand-Savings Potential by Building Type (2020)

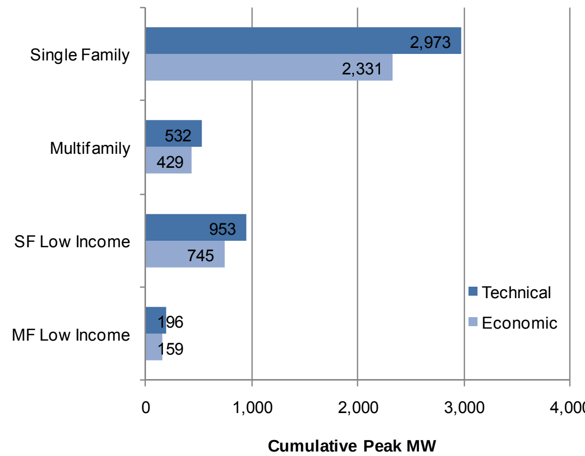


Figure 5-9 and Figure 5-10 show the building-type breakdown of commercial potential. Offices account for about 36 percent of the economic energy potential, followed by grocery, retail, and miscellaneous commercial buildings.

Figure 5-9
Commercial Economic Energy-Savings Potential by Building Type (2020)

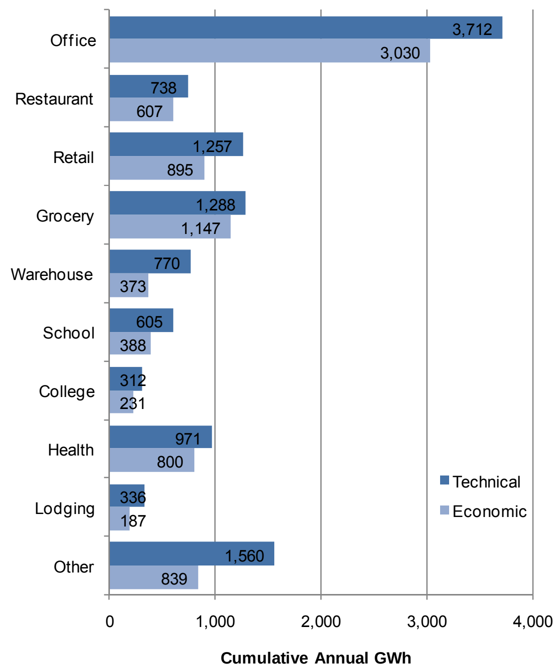


Figure 5-10
Commercial Economic Demand-Savings Potential by Building Type (2020)

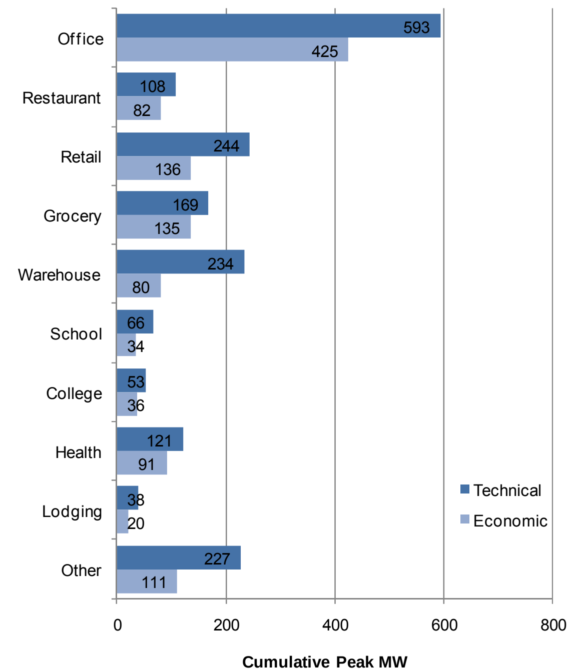


Figure 5-11 and Figure 5-12 show the business-type breakdown of industrial potential. Key industries in terms of economic potential include chemicals, paper, food processing, and primary metals.

Figure 5-11
Industrial Economic Energy-Savings Potential by Business Type (2020)

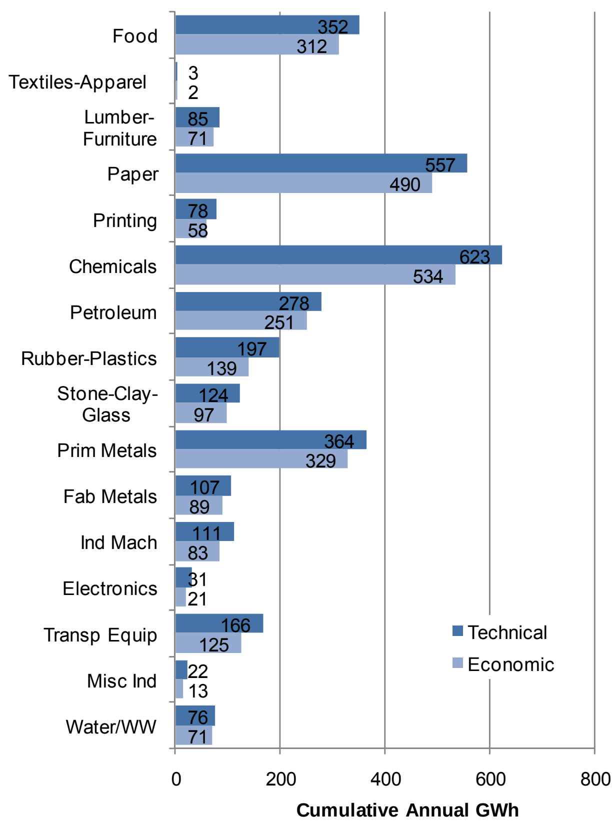
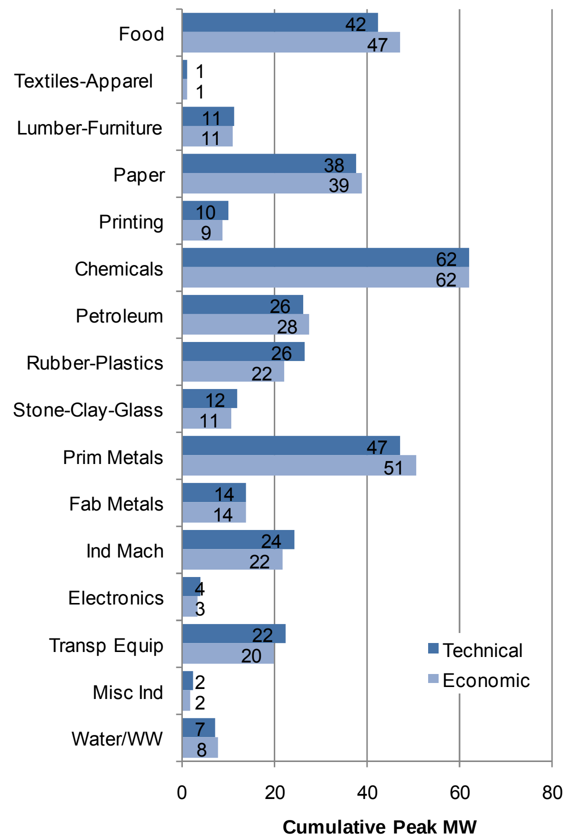


Figure 5-12
Industrial Economic Demand-Savings Potential by Business Type (2020)



5.1.2.3 Potentials by End Use

Figure 5-13 and Figure 5-14 show the end-use breakdown of technical and economic potential in the residential sector. Energy economic potential is split fairly evenly among the lighting and cooling end uses, followed by space heating and furnace fans. Water heating ranks high in technical, but not in economic energy potential. Cooling accounts for most of the peak-demand savings potential, since very little lighting is used on warm summer afternoons.

Figure 5-13
Residential Economic Energy-Savings Potential by End Use (2020)

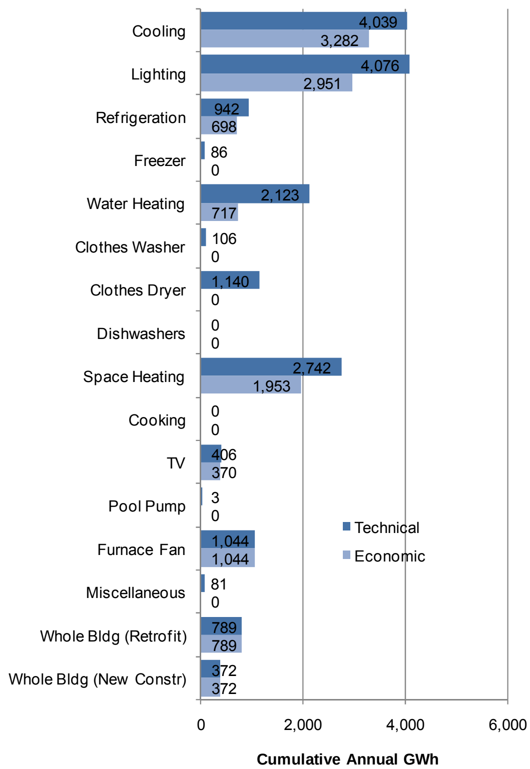


Figure 5-14
Residential Economic Demand-Savings Potential by End Use (2020)

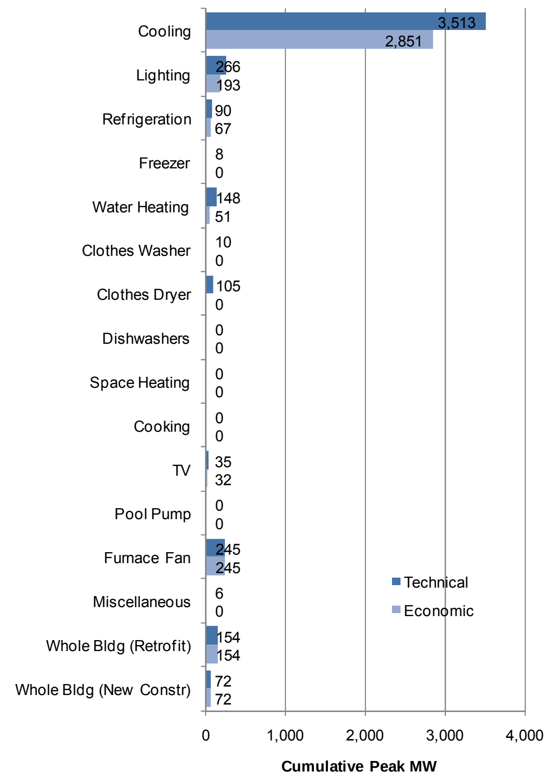


Figure 5-15 and Figure 5-16 show the end-use breakdown of commercial potential. Energy savings potential is highest for indoor lighting. In technical potential, lighting is followed by cooling and whole buildings (new construction). For economic potential, lighting is followed by whole buildings, then cooling. Cooling accounts for most of the peak-demand savings potential, followed by indoor lighting.

Figure 5-15
Commercial Economic Energy Savings Potential by End Use (2020)

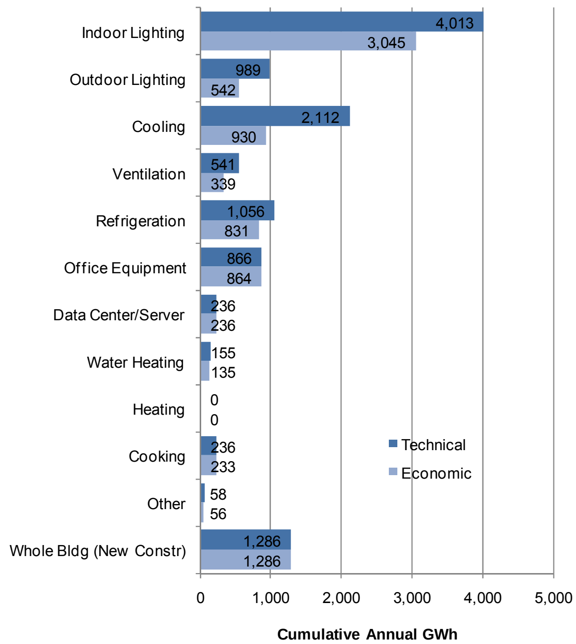


Figure 5-16
Commercial Economic Demand Savings Potential by End Use (2020)

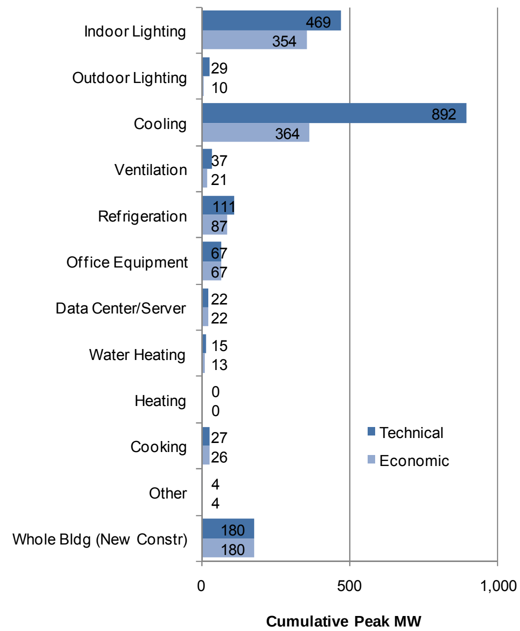


Figure 5-17 and Figure 5-18 show the end-use breakdown of industrial potential. Pumping-system measures provide the largest source of economic potential, followed by fans, drives, and compressed air.

Figure 5-17
Industrial Economic Energy-Savings Potential by End Use (2020)

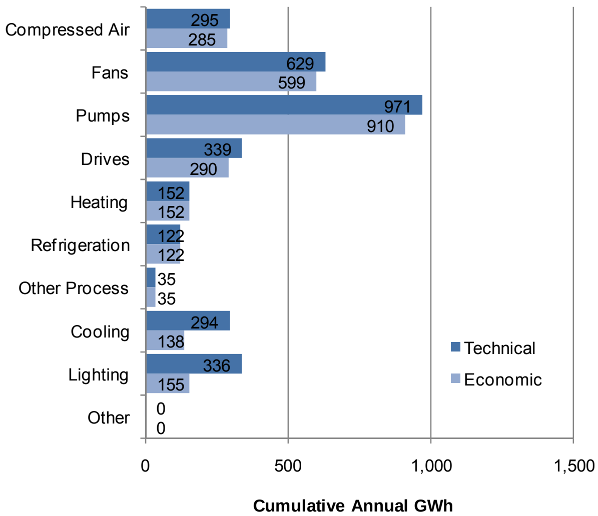
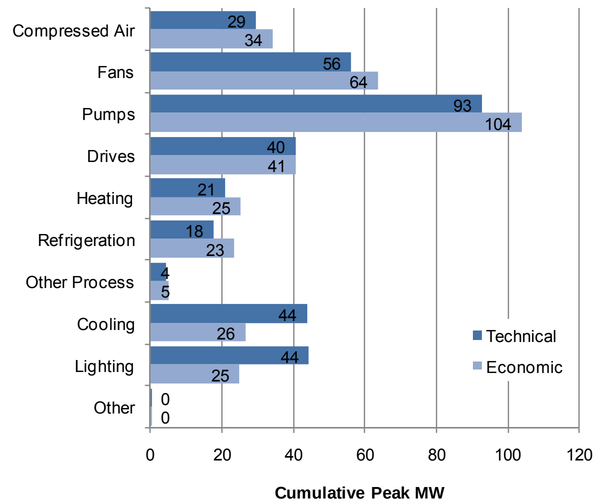


Figure 5-18
Industrial Economic Demand-Savings Potential by End Use (2020)



5.1.3 Avoided Cost Scenarios

We examined two alternative avoided cost scenarios in addition to the base scenario. For the low avoided cost scenario, we reduced avoided costs by 20 percent in each year of the forecast. For the high scenario, we increased costs by 50 percent. Figure 5-19 shows technical and economic potential for the three scenarios (technical potential is the same for all three scenarios). In Table 5-1, we compare the three scenarios in terms of percent of sales, percent of technical, and relative to the economic potential of the base avoided cost scenario. The low avoided cost scenario results in economic savings that are 5 percent lower for energy and 3~~4~~ percent lower for peak demand compared to the base avoided cost scenario. The high avoided cost scenario results in savings that are 10~~6~~ percent higher for energy and 4~~3~~ percent higher for peak demand.

Figure 5-19
Estimated Electricity Technical and Economic Potential for Alternative Avoided Cost Scenarios, 2020

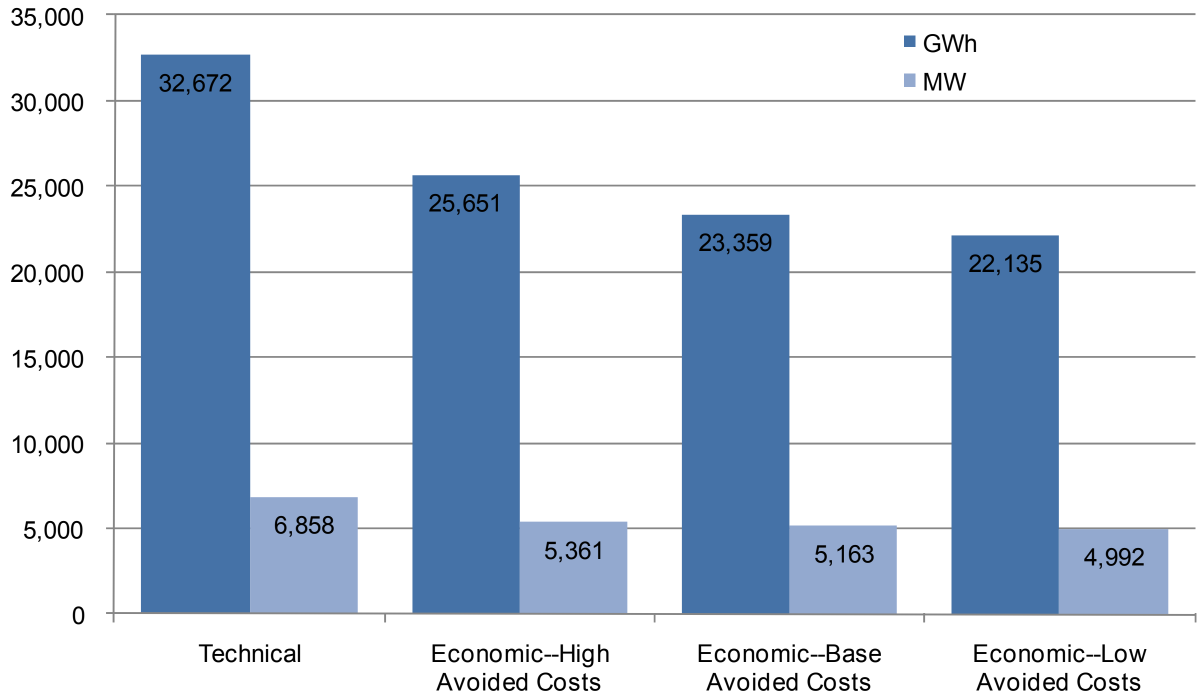


Table 5-1
Comparison of Estimated Electricity Technical and Economic Potential for Alternative Avoided Cost Scenarios, 2020

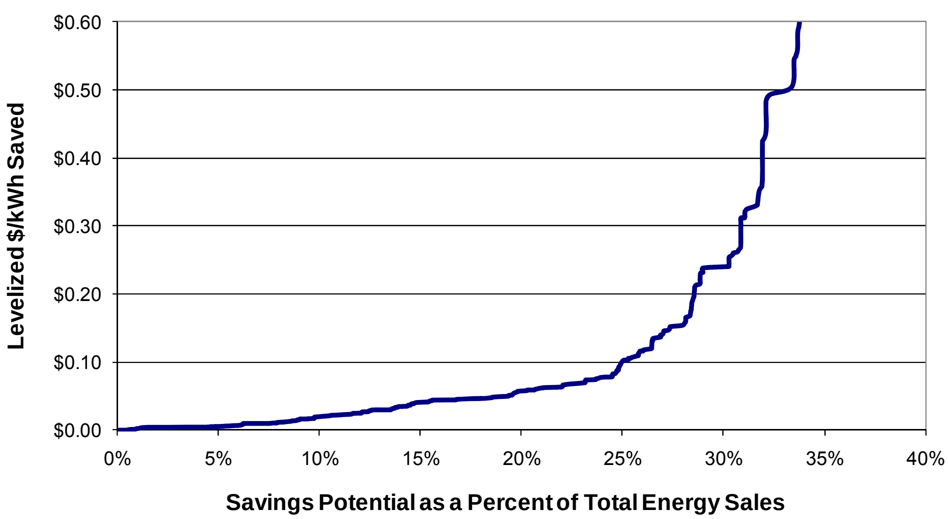
	Base	Technical	Economic--High Avoided Costs	Economic--Base Avoided Costs	Economic--Low Avoided Costs
Energy					
GWh	92,564	32,672	25,651	23,359	22,135
% of fixed efficiency base energy use		35%	28%	25%	24%
% of Technical			79%	71%	68%
% of Economic--Base Avoided Costs			110%	100%	95%
Peak Demand					
MW	18,197	6,858	5,361	5,163	4,992
% of fixed efficiency base demand		38%	29%	28%	27%
% of Technical			78%	75%	73%
% of Economic--Base Avoided Costs			104%	100%	97%

5.1.4 Energy-Efficiency Supply Curves

A common way to illustrate the amount of energy savings per dollar spent is to construct an energy-efficiency supply curve. A supply curve typically is depicted on two axes: one captures the cost per unit of saved energy (e.g., levelized $/kWh saved), and the other shows energy savings at each level of cost. Measures are sorted on a least-cost basis, and total savings are calculated incrementally with respect to measures that precede them. The costs of the measures are levelized over the life of the savings achieved.

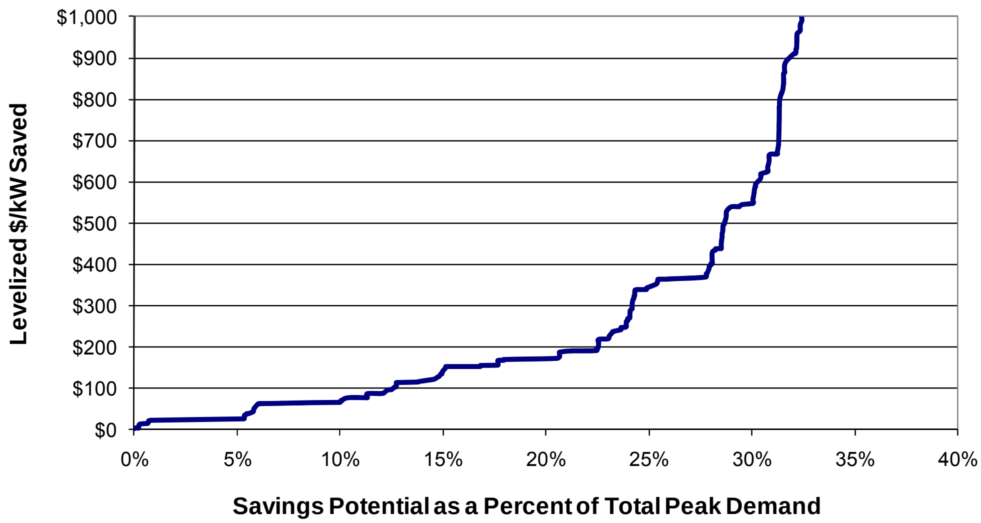
Figure 5-20 and Figure 5-21 present the supply curves constructed for this study for electric energy-efficiency and peak-demand efficiency, respectively. Each curve represents savings as a percentage of total energy or peak demand. These curves show that energy savings of about 17 percent are available at under $0.05 per kWh, and peak demand savings of about 13 percent are available at under $100 per MW. Savings potentials and levelized costs for the individual measures that comprise the supply curves are provided in Appendix G.

Figure 5-20
Electric Energy Supply Curve*



*Levelized cost per kWh saved is calculated using a 7.8 percent nominal discount rate.

Figure 5-21
Peak-Demand Supply Curve*



*Levelized cost per kW saved is calculated using a 7.8 percent nominal discount rate.

5.2 Achievable (Program) Potential

In contrast to technical and economic potential estimates, achievable potential estimates take into account market and other factors that affect the adoption of efficiency measures. Our method of estimating measure adoption takes into account market barriers and reflects actual consumer- and business-implicit discount rates. This section presents results for achievable potential for the scenarios described in section 3.3 Scenario Analysis, first at the summary level and then by sector. More detail on the estimates of achievable program potential is presented in Appendix H.

5.2.1 Markets within the Scenarios

For each electric scenario we modeled achievable potential by market. We used the following markets:

Table 5-2
Market Definitions

Customer Sector	Building type	Market	Measures
Residential	Existing	Replace on Burnout	All except CFLs
Residential	Existing	Retrofit	All except CFLs
Residential	Existing	Retrofit	CFLs –Until 2014
Residential	New	New Construction	All
Commercial	Existing	Replace on Burnout	All except CFLs
Commercial	Existing	Retrofit	All except CFLs
Commercial	Existing	Retrofit	CFLs- Until 2014
Commercial	New	New Construction	All
Industrial	Existing	Replace on Burnout	All
Industrial	Existing	Retrofit	All

Each the sum of the achievable potential for each scenario is built up from the potential for each of these markets.

5.2.2 Overall results

Figure 5-22 and Figure 5-23 show our estimates of achievable potential savings over time. As shown in Figure 5-22, by 2020, cumulative *net*[3] energy savings are projected to be 3,066 GWh under the three year payback scenario and 6,138 GWh under the one year payback scenario. Figure 5-23 depicts projected net peak-demand savings under the same scenarios, 876 MW and 1,868 MW respectively.

[3] Throughout this section, *net* refers to savings beyond those estimated to be naturally occurring; that is, from customer adoptions that would occur in the absence of any programs or standards.

Figure 5-22 Achievable Electric Energy-Savings: All Sectors

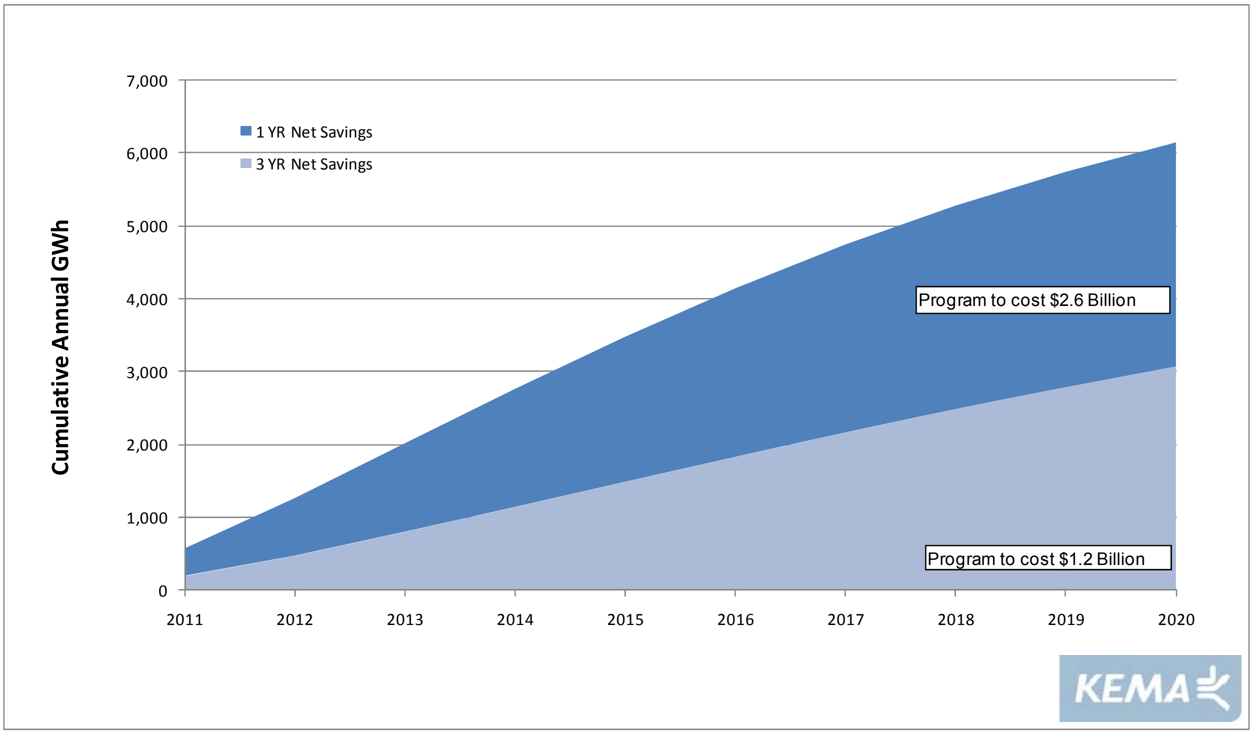


Figure 5-23 Achievable Peak-Demand Savings: All Sectors

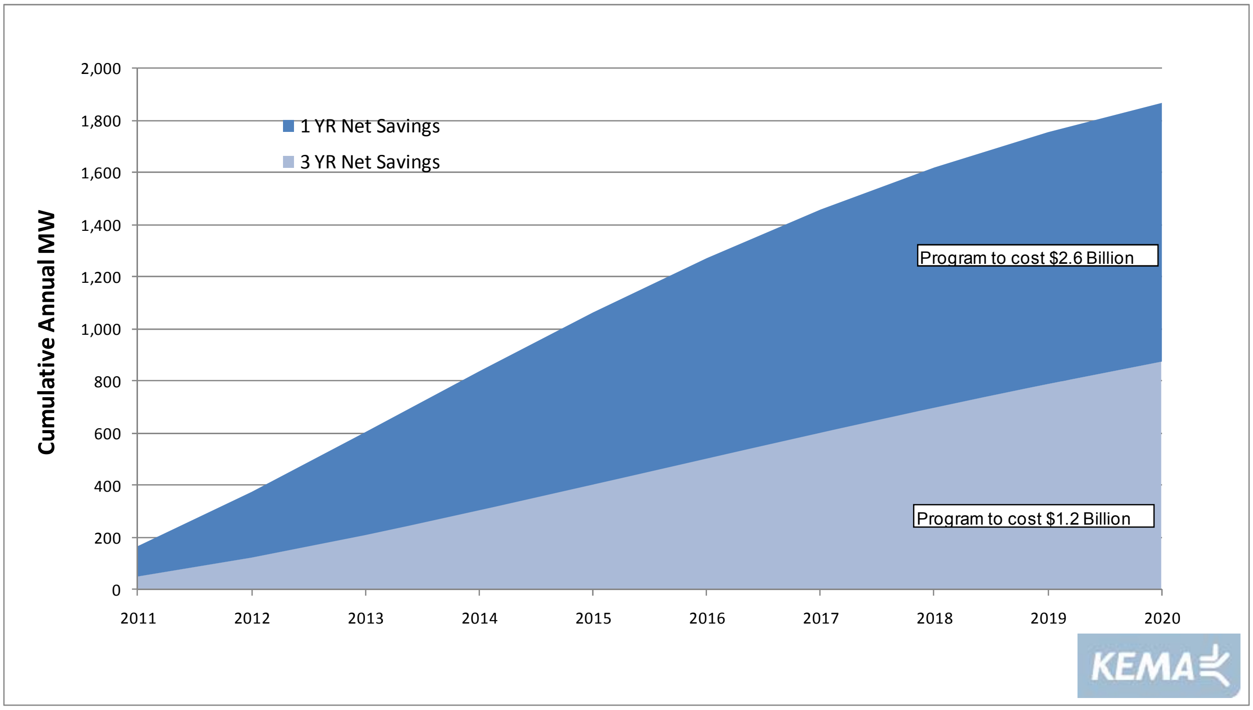
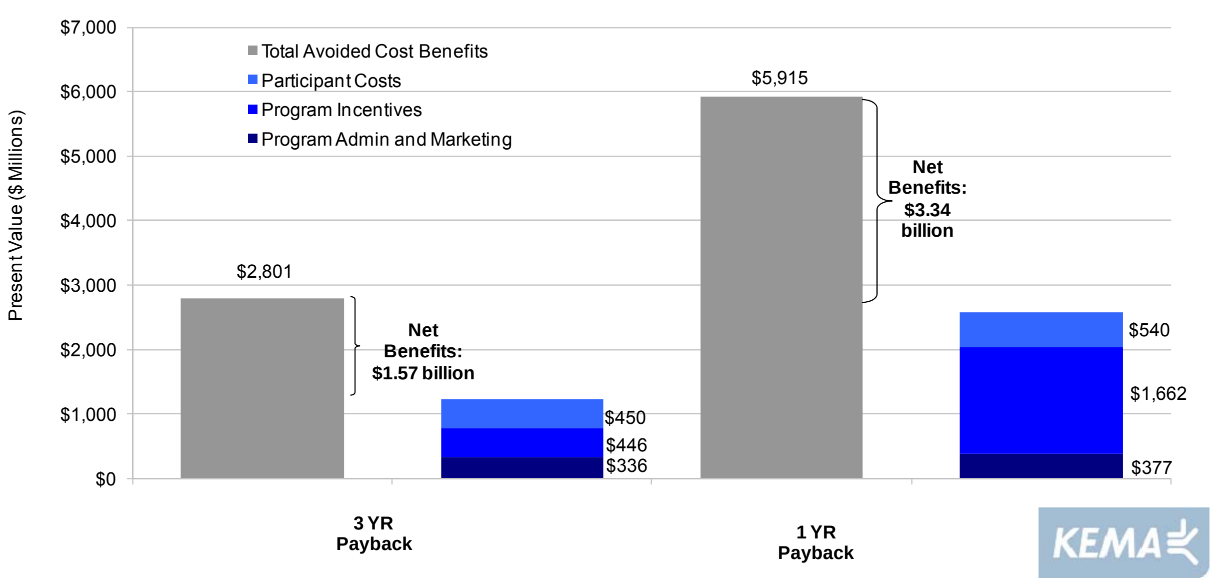
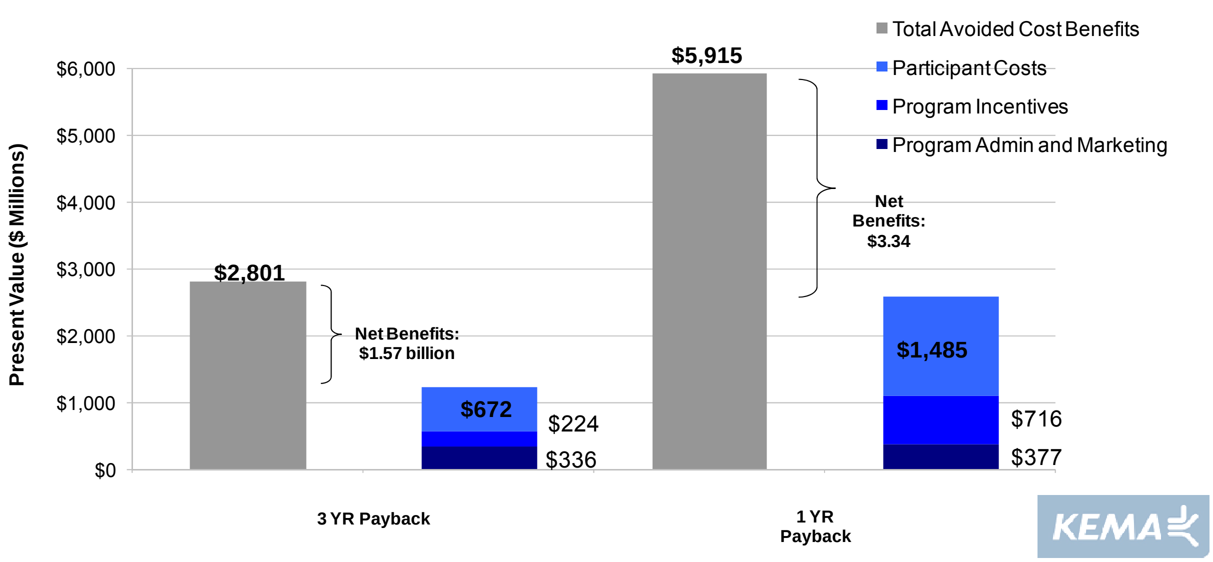


Figure 5-24 depicts costs and benefits under each funding scenario from 2011 to 2020, which are also shown in Table 5-3. The bottom line is that the net present value, the present value of all the benefits less the present value of all the costs, developed by the three year payback incentive scenario is $1.5 million and the one year payback scenario develops $3.3 million.

Figure 5-24
Benefits and Costs of Energy-Efficiency Savings—2011-2020*





* Present value of benefits and costs over normalized 20-year measure lives; nominal discount rate is 7.8 percent, inflation rate is 2.5 percent.

All of the funding scenarios are cost-effective based on the TRC test, which is the test used in this study to determine program cost-effectiveness. The TRC benefit-cost ratios are 2.27 for the three year payback scenario and 2.29 for the one year payback scenario. That program cost-effectiveness increases with increasing program effort indicates that program effort under all scenarios has not reached the point of diminishing returns. Key results of our efficiency scenario forecasts from 2011~~2010~~ to 2020 are summarized in Table 5-3 .

Table 5-3
Summary of Both Scenarios

Result - Programs	3 YR Payback	1 YR Payback
Gross Energy Savings - GWh	5,447	8,519
Gross Peak Demand Savings - MW	1,282	2,274
Net Energy Savings - GWh	3,066	6,138
Net Peak Demand Savings - MW	876	1,868
Program Costs - Real, $ Million		
Administration	$195	$244
Marketing	$224	$224
Incentives	$563	$2,035
Total	$982	$2,504
PV Avoided Costs	$2,801	$5,915
PV Annual Program Costs (Adm/Mkt)	$336	$377
PV Net Measure Costs	$896	$2,201
Net Benefits	$1,568	$3,336
TRC Ratio	2.27	2.29

5.2.3 Summary of the 3 Year Payback Scenario

This section presents the summary of the 3 year payback for incentives scenario. Overall budgets are lower than the other scenarios. This is also the least cost effective electric scenario.

Table 5-4
Summary of the Electric Three Year Payback Scenario

Result - Programs	Program Scenario: 2011 - 2020			
	Residential	Commercial	Industrial	All Programs
Gross Energy Savings - GWh	2,058	2,287	1,101	5,447
Gross Peak Demand Savings - MW	858	316	108	1,282
Net Energy Savings - GWh	1313	1125	627	3,066
Net Peak Demand Savings - MW	641	172	63	876
Program Costs - Real, $ Million				
Administration	$94	$44	$57	$195
Marketing	$67	$102	$55	$224
Incentives	$319	$196	$48	$563
Total	$481	$341	$161	$982
PV Avoided Costs	$1,562	$838	$401	$2,801
PV Annual Program Costs (Adm/Mkt)	$129	$117	$90	$336
PV Net Measure Costs	$482	$293	$121	$896
Net Benefits	$951	$428	$190	$1,568
TRC Ratio	2.56	2.04	1.90	2.27

Figure 5-25 and Figure 5-26 present energy and demand savings overtime for this scenario.

Figure 5-25: Electric Energy Savings in the Three Year Payback Scenario

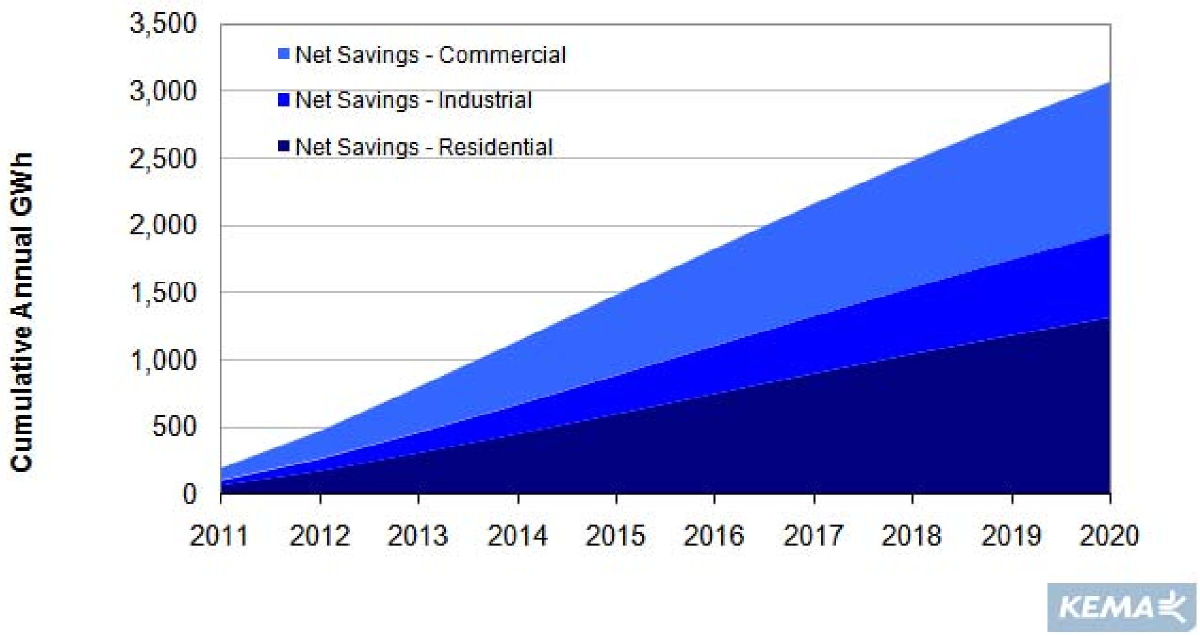


Figure 5-26: Electric Demand Savings in the Three Year Payback Scenario

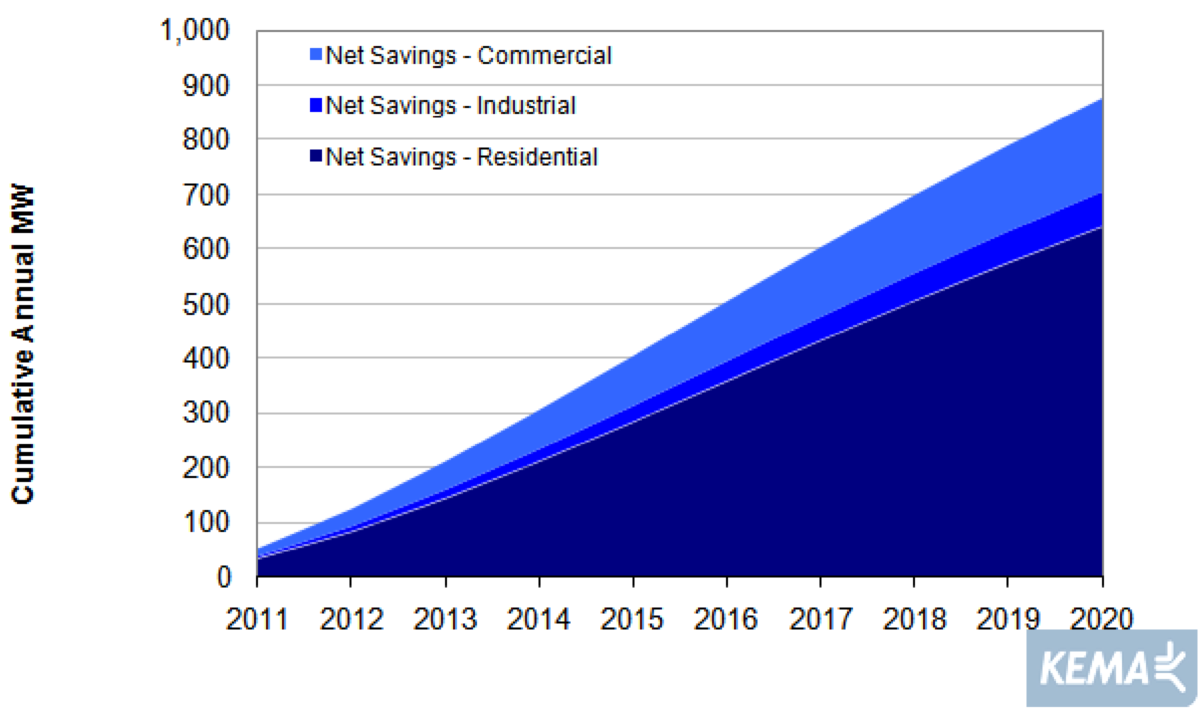
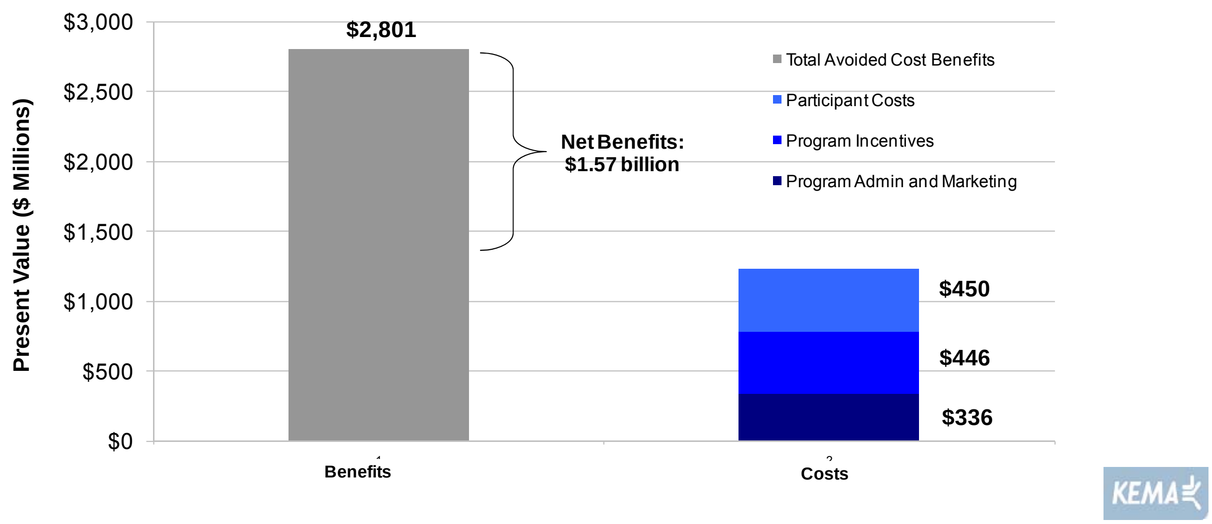
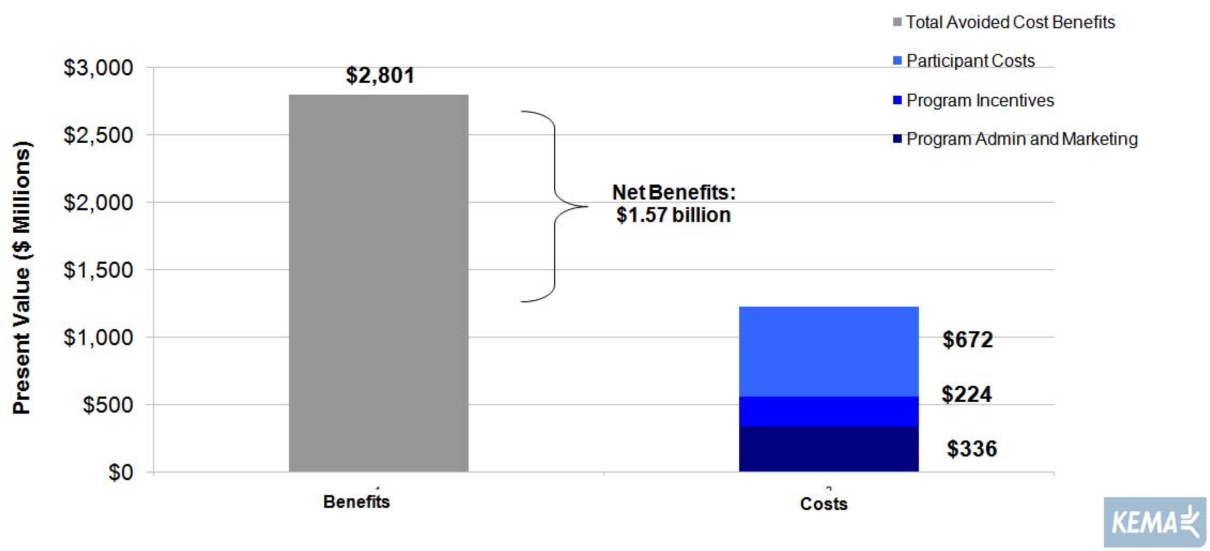


Figure 5-27 presents a summary of the cost effectiveness of this scenario.

Figure 5-27
Overall Benefit Cost Chart – Electric Three Year Payback Scenario





5.2.4 Summary of the 1 Year Payback Scenario

This section presents a summary of the one year payback for incentives scenario. Table 5-5 presents a summary of this scenario.

Table 5-5
Summary Table for the Electric One Year Payback Scenario

Result - Programs	Program Scenario: 2011 - 2020			
	Residential	Commercial	Industrial	All Programs
Gross Energy Savings - GWh	3,655	3,142	1,722	8,519
Gross Peak Demand Savings - MW	1,654	450	170	2,274
Net Energy Savings - GWh	2910	1980	1,248	6,138
Net Peak Demand Savings - MW	1437	305	126	1,868
Program Costs - Real, $ Million				
Administration	$137	$48	$59	$244
Marketing	$67	$102	$55	$224
Incentives	$1,199	$606	$231	$2,035
Total	$1,403	$755	$345	$2,504
PV Avoided Costs	$3,580	$1,503	$831	$5,915
PV Annual Program Costs (Adm/Mkt)	$164	$121	$93	$377
PV Net Measure Costs	$1,271	$636	$294	$2,201
Net Benefits	$2,146	$746	$444	$3,336
TRC Ratio	2.50	1.99	2.15	2.29

This figure presents the energy savings for the one year payback scenario. Savings are presented for both net savings and for free riders. Demand savings are presented in Figure 5-28.

Figure 5-28: Electric Energy Savings for the 1 Year Payback Scenario

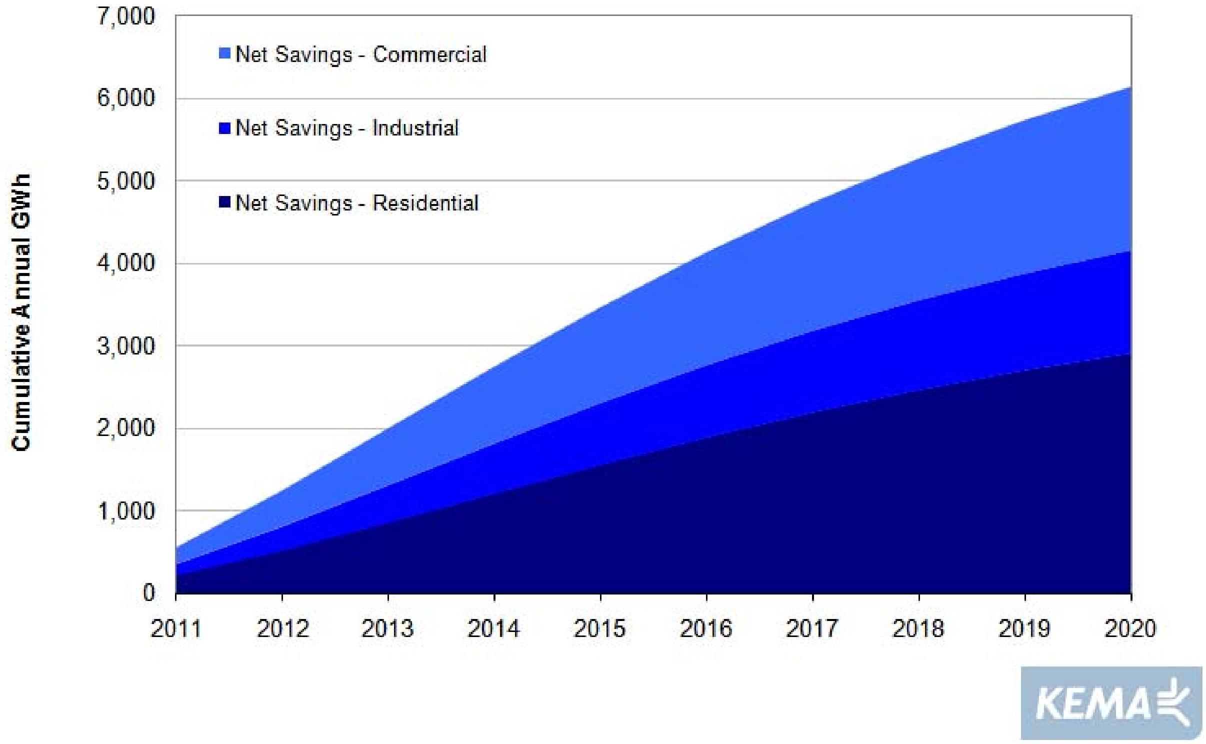


Figure 5-29: Electric Demand Savings for the 1 Year Payback Scenario

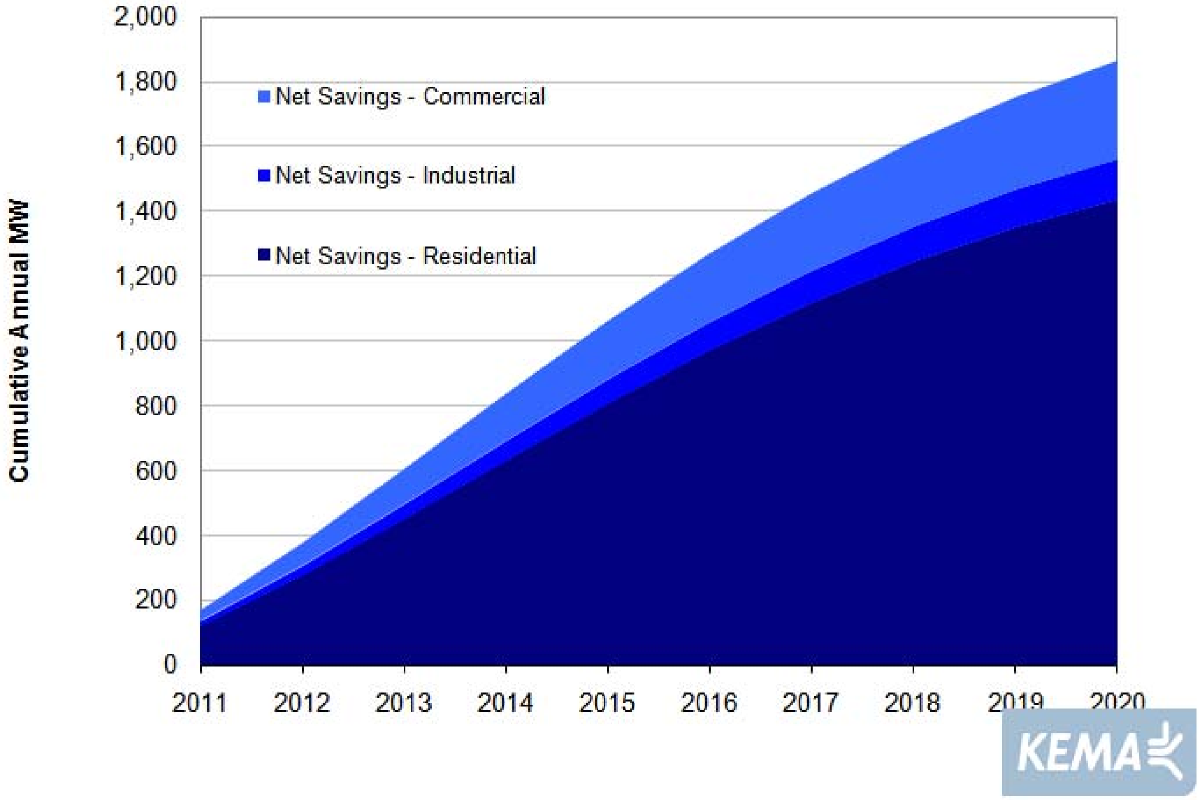
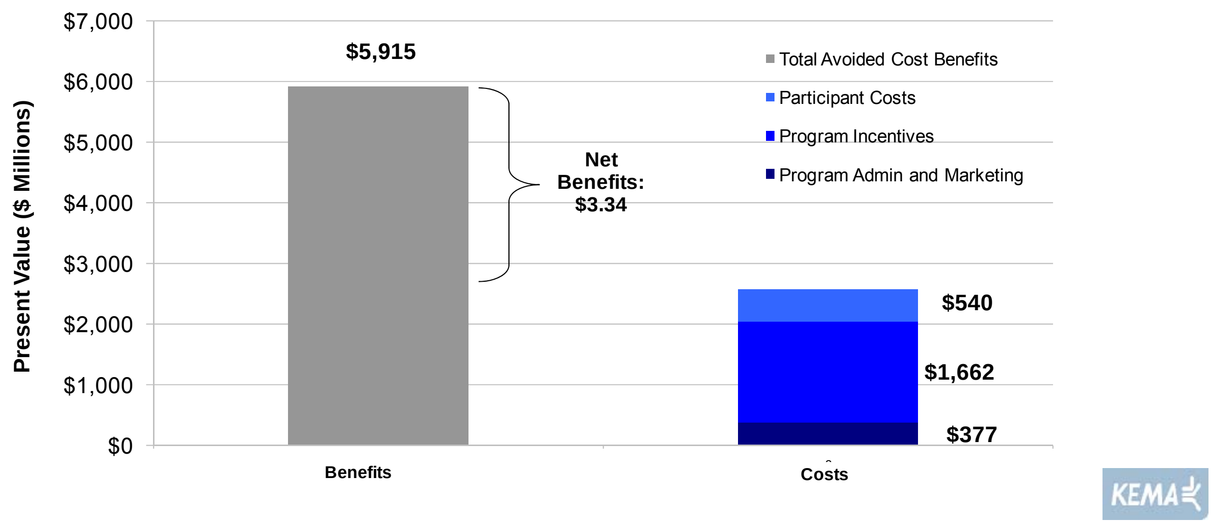
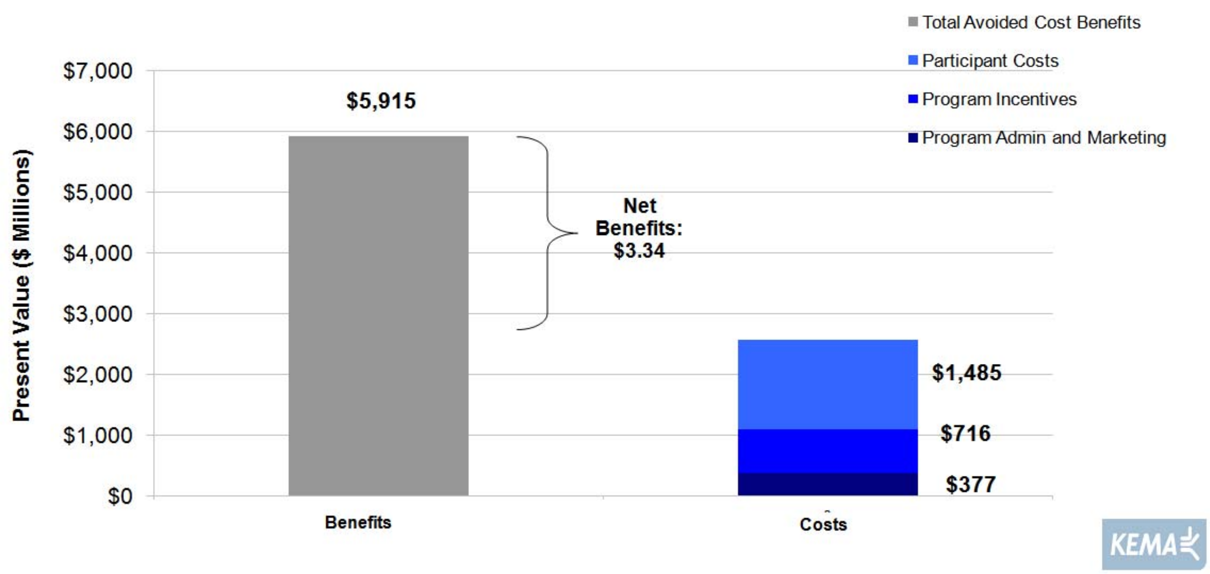


Figure 5-30 below presents the overall cost effectiveness of this scenario.

Figure 5-30
Overall Benefit Cost Chart – Electric 1 Year Payback Scenario





5.2.5 Comparison of approach and result to Ameren Study

In this sub-section we compare approaches and results of this study to those of a recently completed DSM potential study completed by Ameren. The key areas addressed are the market characterization, the estimation of technical and economic potential, and the estimation of achievable potential.

5.2.5.1 Market Characterization

The baseline estimates include both a base year energy consumption analysis and a baseline forecast.

Base-Year Energy Consumption.

Both the KEMA study and the Ameren study develop base-year energy consumption by sector and end use. The Ameren study relied on customer surveys, prototype energy analysis, and secondary sources for their analysis. The KEMA study relied on all secondary-source data. A comparison of base-year energy results would be of limited value since both studies target different service territories, with a different sectoral/building-type mix.

Baseline Forecast

Global Energy Partners's LoadMAP tool was utilized to develop Ameren's baseline forecast. "This forecast embodies assumptions about customer growth, electricity prices, technology trends, and the impacts of codes and standards."[4] The Ameren reports do not provide much detail on how the LoadMAP model works, but a high-level description of the model is provided in Volume 3 of the study.[5]

---

[4] AmerenUE Demand Side Management (DSM) Market Potential Study Volume 1: Executive Summary, Global Energy Partners, LLC, January 2010, page ES-24.
[5] AmerenUE Demand Side Management (DSM) Market Potential Study Volume 3: Analysis of Energy-Efficiency Potential, Global Energy Partners, LLC, January 2010, pages 2-3 through 2-5.

KEMA's baseline forecast is a frozen efficiency forecast that assumes energy use per consuming unit (such as households for residential and square footage for commercial) and per end use is held constant at base-year levels throughout the forecast horizon. The growth in baseline energy use is just a function of customer growth.

The Ameren baseline forecast appears to be an integral part of their study, and the estimates of energy efficiency potential. It is designed to address codes and standards and naturally occurring energy efficiency. The KEMA forecast is much simpler and is mainly used as a benchmark for understanding the relative magnitude of energy efficiency improvements. (KEMA's development of naturally occurring energy efficiency and codes and standards affects are carried out in our achievable potential analysis.)

Table 5-6 compares growth rates for the Ameren and KEMA baseline forecasts. Both sets of estimates show minimal growth in the 2010-2020 timeframe.

Table 5-6
Comparison of Baseline Electricity Usage

Study	2010	2011	2020	Average Annual Growth Rate
Ameren	38,847		40,248	0.35%
KEMA		90,718	92,564	0.22%

5.2.5.2 Technical and Economic Potential Calculations

Both the KEMA and Ameren studies use a bottom-up approach to estimate technical and economic potential. Both studies utilize measure cost, savings, applicability, feasibility, and measure lifetimes to assess these potentials, using what appear to be similar algorithms. However, KEMA's definition of technical and economic potential differs from Ameren's.

KEMA begins with current energy use and calculates what current energy use would be if all the measures under consideration (for technical) or all the cost-effective measures under consideration (for economic) were instantaneously put into place. The calculation is extended to forecast years by adding customer growth and the potentials associated with new construction energy efficiency. In these calculations, KEMA does not take into consideration stock turnover and that replace-on-burnout measures will only gradually penetrate the market as existing equipment is retired (note that KEMA does take this significant factor into account in estimating achievable potential). KEMA's approach uses current measures with current cost effectiveness in these calculations. Economic potential therefore does not include measures that are not cost effective now but may become cost effective in the future. Both technical and economic potential do include savings that may be achieved through standards or through naturally occurring energy efficiency. KEMA's definition of technical and economic potential is consistent with industry standards.[6]

Ameren's approach is different. Ameren's technical and economic potentials are not instantaneous; they take into account stock turnover and a gradual penetration of replace-on-burnout measures. Ameren also models incremental costs for at least some equipment types as falling over time, resulting in some measures not cost effective in 2011 becoming cost effective later in the study's time horizon.

These differences make it difficult to compare KEMA and Ameren's technical and economic potentials. The 2011 estimates differ because KEMA includes the impact of replace-on-burnout measures and Ameren does not, resulting in KEMA having much higher potential. Solving this problem requires looking forward, at 2020 or 2030 numbers, by which time most of the stock of most equipment types has turned over. However, by 2030, Ameren's assumptions about the improved cost effectiveness of some measures makes the Ameren potential significantly higher than KEMA's for some end-uses.

Another difference between the two studies lies in the costs that are utilized for cost effectiveness screening. Both studies utilize the total resource cost (TRC) test for screening, but the Ameren study includes program cost adders in their analysis, while the KEMA study utilizes only incremental measure costs. KEMA later adds in program costs in the achievable potential analysis for calculating program cost effectiveness. KEMA does not allocate program costs to measures in the initial economic screening because these costs are not generally

---

[6] For example see: National Action Plan for Energy Efficiency (2007). Guide for Conducting Energy Effi ciency Potential Studies. Prepared by Philip Mosenthal and Jeffrey Loiter, Optimal Energy, Inc. <www.epa.gov/eeactionplan>, page 2-4.

incurred at the measure level, but rather at the program levels, and assignment of these costs would be arbitrary. Overall, this factor may lead to a somewhat lower estimate of economic potential in the Ameren study (other things being equal), but we expect this difference to be small as it would only affect a handful of measures where TRC ratios are near 1.0.

Finally, it appears that both studies treat the effects of codes and standards differently in the technical and economic potential calculations. The Ameren approach seems to address effects of codes and standards as part of the baseline forecast and excludes savings from technologies affected by codes and standards from the technical and economic potentials. The KEMA study includes in technical and economic potential technologies that get affected by codes and standards, but then factors these effects out as part of the achievable potential analysis. Table 5-7 compares 2020 technical and economic potentials as a percent of base energy usage, although we recognize that this comparison has limited value due to differences in how both baseline and potentials are calculated, as noted above.

Table 5-7
Comparison of Technical and Economic Potential as a Percent of Baseline Usage – 2020

Study	Technical	Economic
Ameren	28%	14%
KEMA	35%	25%

Note that the KEMA technical and economic potentials for CFL are respectively about 5.7% and 5.2% of baseline usage in 2020. This result may explain a significant portion of the difference between the Ameren and KEMA estimates.

5.2.5.3 Achievable Potential Calculations

The KEMA and Ameren studies utilized very different approaches to estimate achievable potential. The KEMA approach estimates naturally occurring and achievable program potential as a function of measure availability (utilizing a stock-adjustment process to determine how much of a measure is available in a given year), customer awareness of the measure, measure economics, and barriers to installing the measure.[7] The model provides estimates of what would happen in the absence of programs, which is defined as naturally occurring energy efficiency. The model also provides estimates of savings attributable to the program efforts, both in terms of marketing/education efforts and financial incentives.

The KEMA model estimates the effects of program marketing expenditures on increased customer awareness of measures, which leads to one level of program savings. In addition the model, through the use of penetration curves that translate measure cost effectiveness ratios into measure penetration rates, provides estimates of increased measure uptake (over naturally occurring measure uptake) that result from payment of financial incentives.

For the 1-year and 3-year payback scenarios, measure-specific incentives were developed to drive measure paybacks to the 1-year and 3-year points. No incentives were assumed for measures that already had payback lower than the 1-year or 3-year payback criteria without an incentive. This approach was taken in order to estimate, as accurately as possible, what incentive levels and associated program penetration would occur if, in fact, programs were designed to meet the 1-year and 3-year payback criteria.

To be as consistent with the Ameren study as possible for these scenarios, beginning customer awareness of measures was set at 25%, and sufficient marketing/education expenditures were input into the model to increase awareness into the 80% range over a 10-year period. In addition, measure penetration curves were adjusted to take into account stated penetration rates developed as part of the Ameren market research.

In the KEMA model, all savings, incentive levels, and program costs are internally consistent, and program effects flow directly from measure-specific estimates of how customers are likely to behave at given incentive levels. For example, program effects for the 3-year payback incentive are relatively low compared to naturally occurring effects. The reason for this result is that incentive rates are low or zero for many measures in this scenario because the paybacks already approach or are at the 3-year payback cutoff. The low incentives will not be sufficient to induce many new customers to purchase energy efficiency, but will only serve to reward customers who would have done it anyway with a financial bonus.

[7] The KEMA approach is described in Section I.1.3 of Appendix I.

The Ameren approach for estimating achievable potential appears to be mainly driven by informed assumption[8]. First, measure awareness was assumed to grow from 25% in 2010 to 85% by 2019, but it was not clear from the documentation if or how this increase in awareness was tied to program marketing/education expenditures.

Second, initial program “take rates” were developed from the study’s market research and were assumed to grow at 1% per year over the forecast horizon. These take rates reflect the fraction of informed customers that would purchase a measure under the assumed financial circumstances (1-year, 3-year, and 5-year paybacks). Ameren indicates that their savings are “net” savings, but their documentation does not describe how the take rates, which are estimated for the total customer population, are translated into net effects. For example, the market research indicates that 37% of residential customers were likely to purchase energy efficient light bulbs at a three-year payback.[9] However, since payback periods for CFLs are already at 3-years or less for most likely residential installations, there would be no need to provide incentives for this measure and most of the savings would be naturally occurring savings under the 3-year payback scenario. However, it appears that Ameren applies the estimated take rate (37%) for this measure and simply calls it net savings, with the explanation that naturally occurring savings are picked up in the baseline forecast.

Third, it appears that incentive amounts were based on program experience in other regions of the country and were only generally tied to the customer payback criteria that were used to define the various scenarios.

The Ameren report provided incentive levels in Appendix A of Volume 4 of their report. It contains incentives as a fixed dollar amount and also displays a field labeled “% of equipment cost covered by Ameren” which also appears to be fixed by measure (33% for residential sector measures, 25% for commercial sector measures with a few exceptions at 33%, and 50% for industrial sector measures). The tables in this file are all labeled “RAP.” Similar information for Ameren’s “MAP” scenario was not available.

[8] See AmerenUE Demand Side Management (DSM) Market Potential Study Volume 4: Program Analysis, Global Energy Partners, LLC, January 2010, pages 2-1 through 2-9 for a discussion of the program analysis methodology.
[9] See AmerenUE Demand Side Management (DSM) Market Potential Study Volume 2: Market Research, Global Energy Partners, LLC, January 2010, Chapter 4, page 14.

In light of wide variation in incentive levels KEMA developed for the one-year payback and three-year year payback scenarios, incorporated as Attachment B to KEMA's February 7,2011 response to questions and in Appendix B of this report, and the fixed levels presented by Ameren, we could not determine how Ameren matched the estimated incentive levels to the assumed payback criteria.)

Overall, the KEMA and Ameren studies approach achievable potential estimation from different perspectives. KEMA builds up program savings potentials based on penetration curves, measure cost effectiveness, program expenditures, and incentives tied to the measure specific payback criteria that define each scenario. The Ameren approach appears to utilize infomrmed assumptions, in part supported by their market research, to develop estimates of program savings potentials, and then applies judgment and experience with related programs to develop program costs that are consistent with the level of program savings that have been developed.

Both studies utilize reasonable approaches for estimating achievable program potential. However, we do not think Ameren has provided enough documentation of their take-rate approach to support their claim that their achievable savings estimates represent net savings.

It appears that the 1-year and 3-year payback scenarios developed under each study attempt to get at similar levels of program effort. However, the differences in approach limit the ability to do a direct comparison.

Table 5-8 compares 2020 cumulative net achievable potentials as a percent of base energy usage, although we recognize that this comparison has limited value due to differences in how both baseline and potentials are calculated, as noted above.

Table 5-8 Comparison of Net Achievable Potential as Percentage of Baseline Usage – 2020

Study	1-Year Payback Scenario	3-Year Payback Scenario
Ameren	9.8%	6.5%
KEMA	6.8%	3.4%

The KEMA estimates show a lower savings penetration rate than the Ameren estimates, if in fact the Ameren estimates truly reflect net savings. (See comments above.) Note that KEMA's gross achievable potential estimates are 10% of base usage for the 1-year payback scenario and 7% of base usage for the 3-year payback scenario, which are similar to the Ameren "net" savings.

Table 5-9, below provides a comparison of total program costs per first year kWh saved. This table shows that Ameren estimates lower costs per net first year kWh saved than does KEMA. We think there are at least three possible reasons for this difference: (1) Ameren's estimates do not incorporate as much free-ridership as KEMA's estimates, and thus the costs don't reflect the need for as much rebate expenditures for customers who wouldn't contribute to net savings; (2) Ameren's incentive rates, by measure, are different that KEMA's, and this could affect the amount of incentive expenditures; and (3) the Ameren estimates may reflect lower expenditures on marketing and administration than the KEMA estimates.

Table 5-9
Comparison of Cost per First Year kWh Saved – Cumulative Savings and Costs to 2020[10]

Study	1-Year Payback Scenario	3-Year Payback Scenario
Ameren	$0.22	$0.16
KEMA	$0.41	$0.32

[10] See AmerenUE Demand Side Management (DSM) Market Potential Study Volume 2: Market Research, Global Energy Partners, LLC, January 2010, Chapter 5, Table 5-7 and Figure 5-5 for data that were used to develop cost per kWh shown in Table 4.

6. Natural-Gas Energy-Efficiency Potential Results

In this section, we present estimates of natural-gas energy-efficiency potential. First, we present technical and economic potential results for all electric measures considered in the study. Next, we present estimates of achievable program potential under different program funding scenarios.

6.1 Technical and Economic Potential

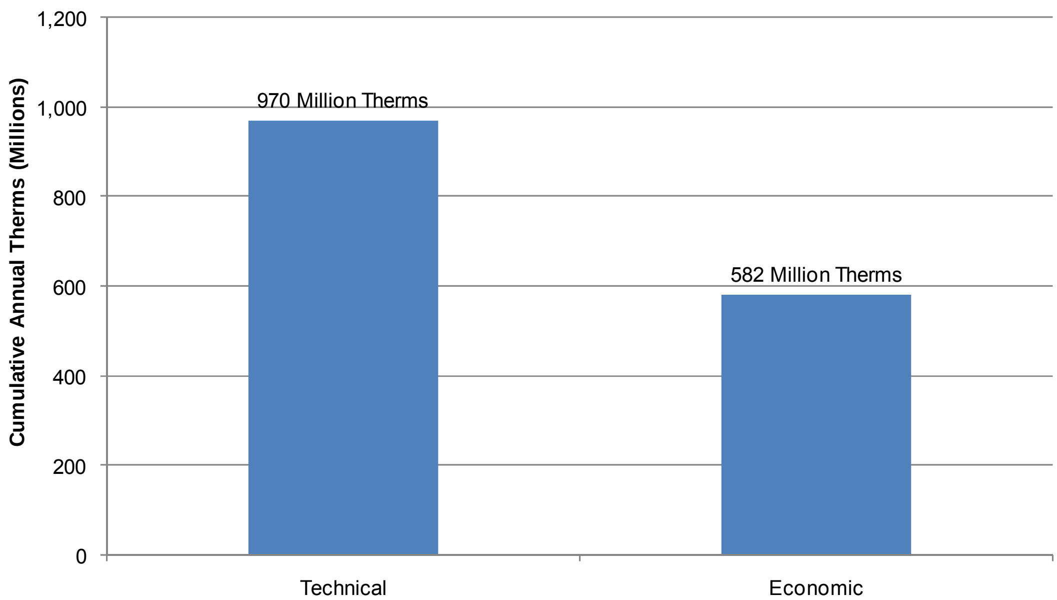
Estimates of overall energy-efficiency technical and economic potential are discussed in section 6.1.1. More detail on these potentials is presented in section 6.1.2. Section 6.1.3 presents the results of alternative avoided cost scenarios considered for the analysis. Energy-efficiency supply curves are shown in Section 6.1.4.

6.1.1 Overall Technical and Economic Potential

Figure 6-1 presents our overall estimates of total technical and economic potential for natural gas energy savings for Missouri. Technical potential represents the sum of all savings from all of the measures deemed applicable and technically feasible. Economic potential is based on efficiency measures that are cost-effective, as determined by the total resource cost (TRC) test—a benefit-cost test that compares the value of avoided energy production and delivery to the costs of energy-efficiency measures and program activities necessary to deliver them.

- Energy Savings. Technical potential is estimated at about 970 million therms per year and economic potential at 582 million therms per year by 2020 (about 38~~37~~ and 23~~24~~ percent of base 2020 usage, respectively).

Figure 6-1
Estimated Natural-Gas Technical and Economic Potential, 2020



6.1.2 Technical and Economic Potential Detail

In this subsection, we explore technical and economic potential in more detail, looking at potentials by sector and by end use.

6.1.2.1 Potentials by Sector

Figure 6-2 shows estimates of technical and economic energy-savings potential by sector. Figure 6-3 shows the same potentials as a percentage of 2020 base energy use.

As shown in Figure 6-3, the residential sector has by far the highest technical savings potential in relation to base energy use, but when looking at economic potential, residential and commercial have similar potentials relative to base energy use.

Figure 6-2
Technical and Economic Potential (2020)
Energy Savings by Sector
Millions of Therms per Year

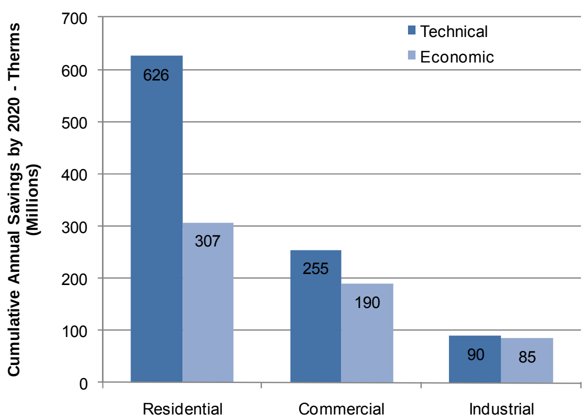


Figure 6-3
Technical and Economic Potential (2020)
Percentage of Base Energy Use

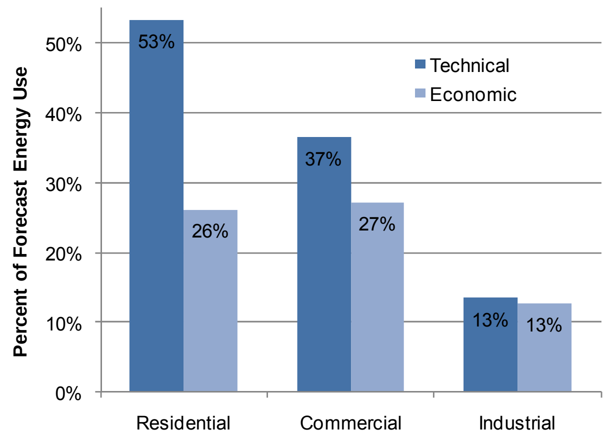
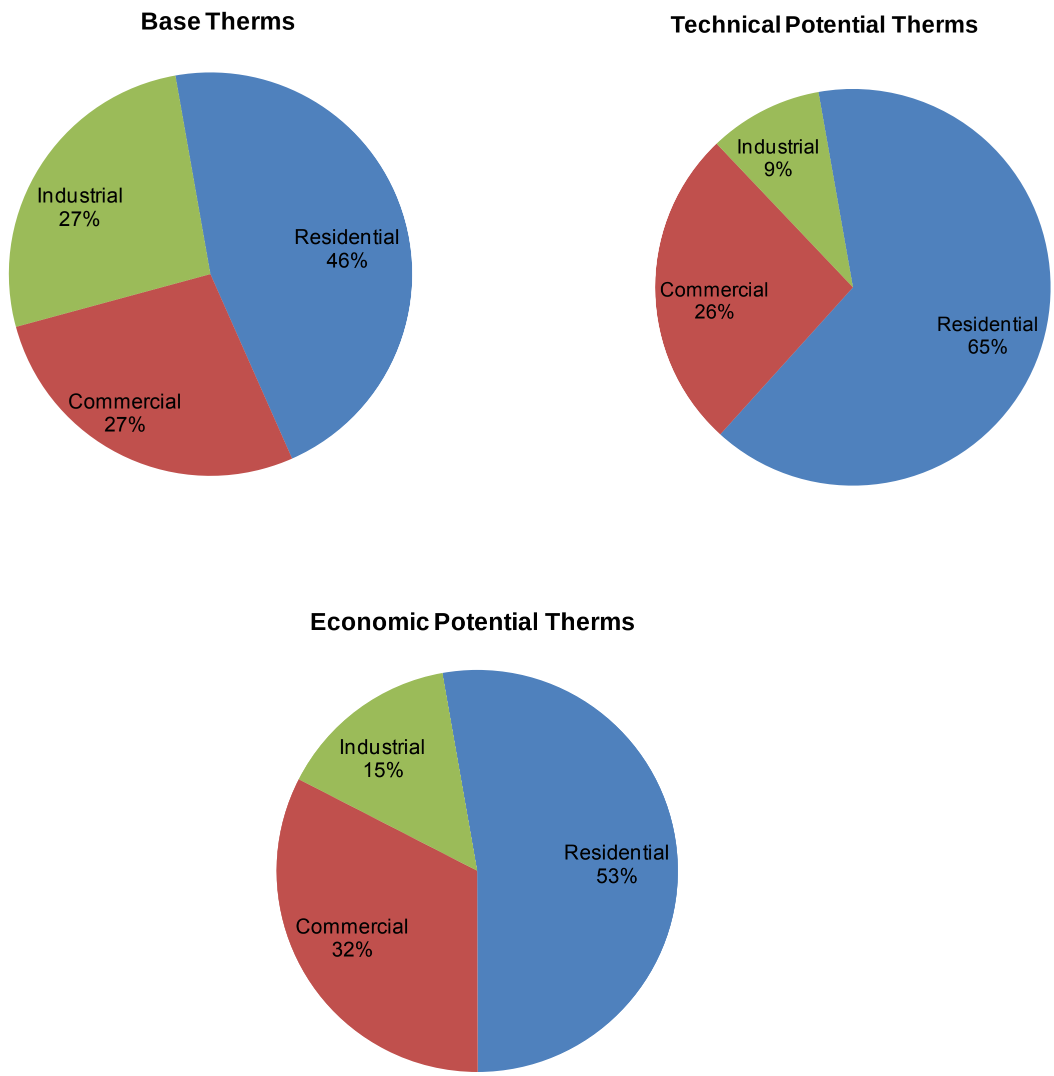


Figure 6-4 shows the relative contribution of the three sectors to base energy use, technical potential and economic potential. The residential sector represents the largest share of base energy, and an even larger share of potential savings. The commercial sectors contribution to technical savings is similar to~~the same as~~ its share of base use (26 and 27 percent, respectively),~~,~~ but its contribution to economic potential is higher, 33~~32 percent compared to 27~~ percent. Industrial's share of potential is smaller than its share of overall base use.

Figure 6-4
Shares of Base Energy Use, Technical and Economic Energy Potential by Sector



6.1.2.2 Potentials by Building Type

Figure 6-5 shows the technical and economic potentials in the residential sector by building type. Single-family homes account for more than 90% of the potential (including single-family low income), and low-income homes account for about 25~~27~~ percent of the potential.

Figure 6-6 shows the building-type breakdown of commercial potential. Offices account for 40 percent of the economic potential, followed by “other” commercial buildings.

Figure 6-5
Residential Energy-Savings Potential by Building Type (2020)

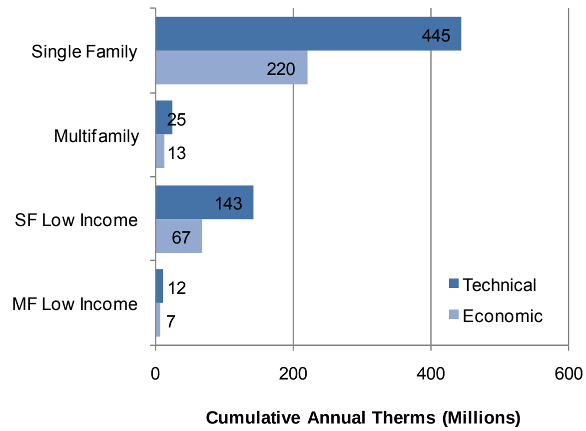


Figure 6-6
Commercial Energy-Savings Potential by Building Type (2020)

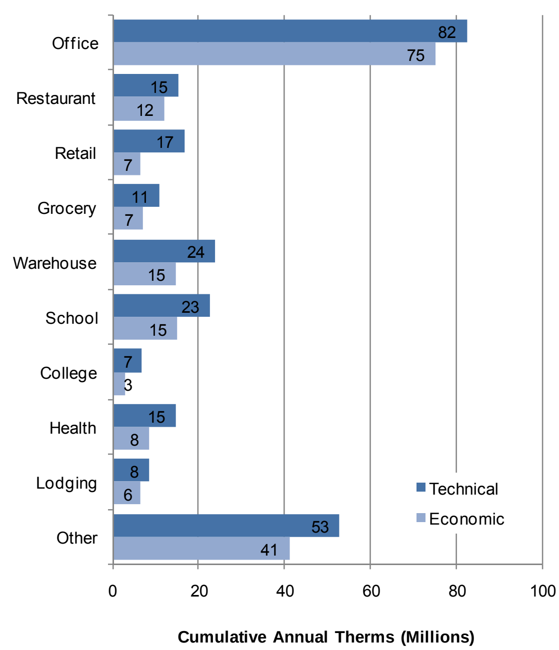
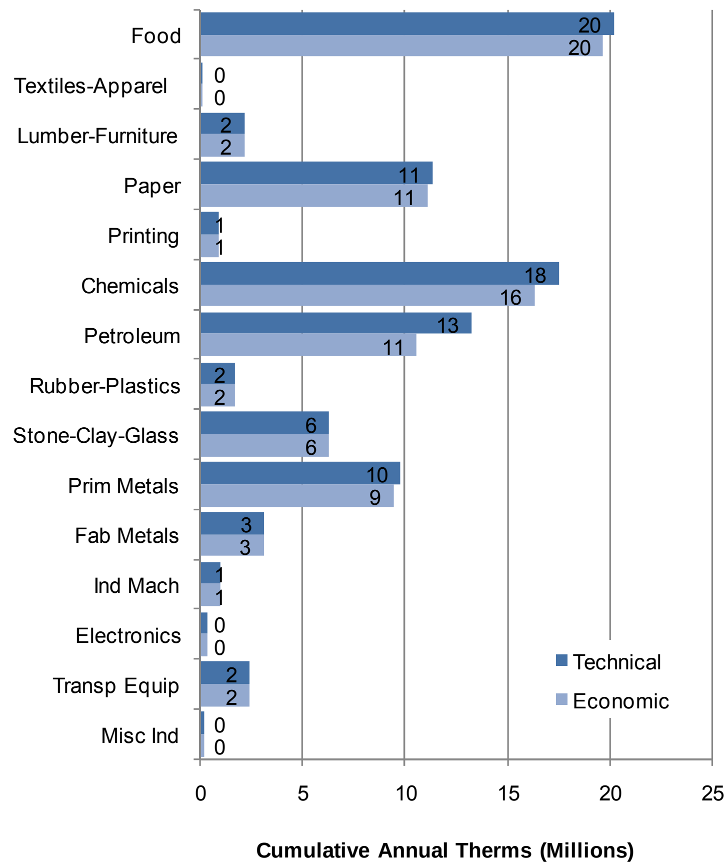


Figure 6-7 shows the business-type breakdown of industrial potential. Key industries in terms of economic potential include food, chemicals, petroleum, paper, and primary metals.

Figure 6-7
Industrial Energy-Savings Potential by Business Type (2020)



6.1.2.3 Potentials by End-Use

Figure 6-8 shows the end-use breakdown of technical and economic potential in the residential sector. Energy-savings potential comes predominantly from space heating and water heating. The whole-building - new construction component also consists mainly of space-heating and water-heating measures. The whole-building – retrofit end use consists of a single behavioral conservation measure.

Figure 6-8
Residential Economic Energy-Savings Potential by End Use (2020)

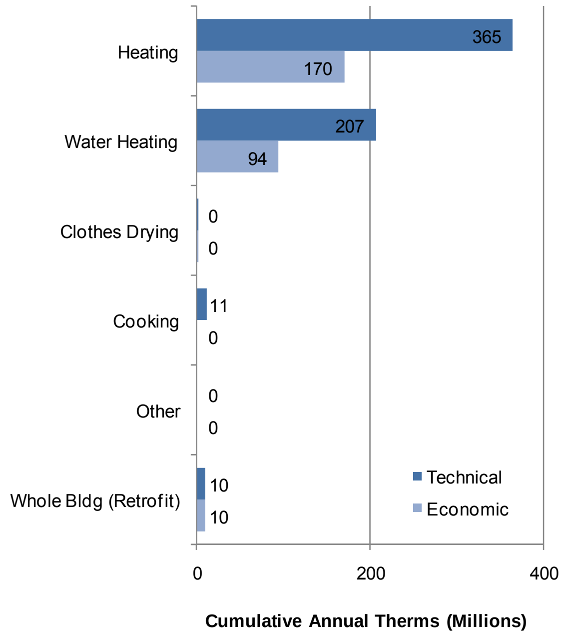


Figure 6-9 shows the end-use breakdown of commercial potential. Space heating is the largest contributor to potentials, followed by water heating and cooking.

Figure 6-9
Commercial Economic Energy-Savings Potential by End Use (2020)

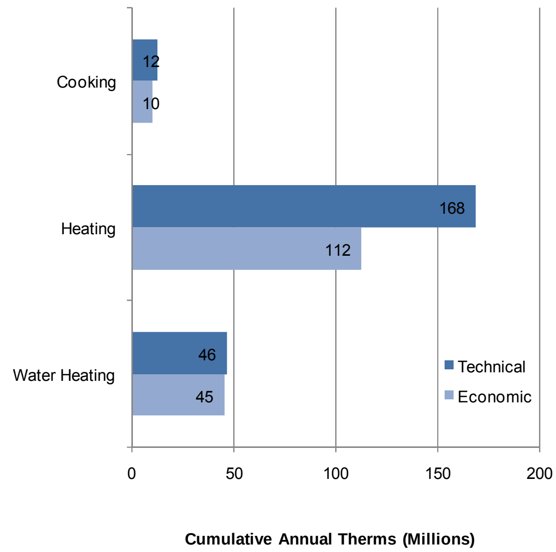
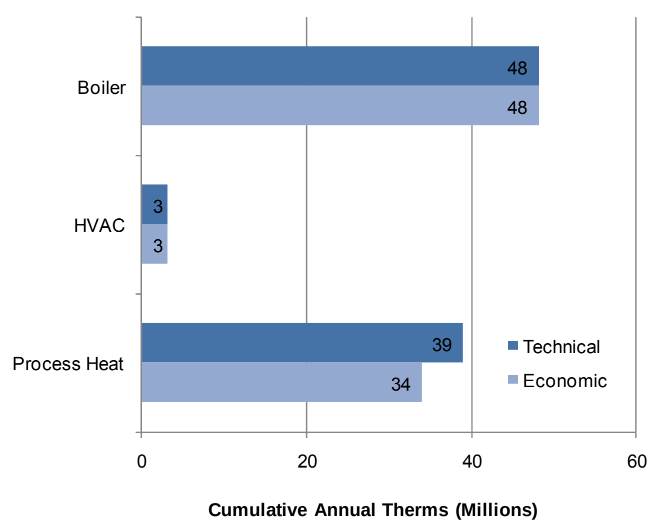


Figure 6-10 shows the end-use breakdown of industrial potential. Boilers have the highest technical and economic saving, followed by process heating. HVAC contributes only a small share to the totals.

Figure 6-10
Industrial Economic Energy-Savings Potential by End Use (2020)



6.1.3 Avoided Cost Scenarios

We examined two alternative avoided cost scenarios in addition to the base scenario. For the low avoided cost scenario, we reduced avoided costs by 20 percent in each year of the forecast. For the high scenario, we increased costs by 50 percent. Figure 6-11 shows technical and economic potential for the three scenarios (technical potential is the same for all three scenarios). In Table 6-1, we compare the three scenarios in terms of percent of sales, percent of technical, and relative to the economic potential of the base avoided cost scenario. The low avoided cost forecast results in economic savings that are 16~~13~~ percent lower than the base avoided cost forecast, while the high avoided costs result in savings that are 27~~19~~ percent higher.

Figure 6-11
Estimated Natural-Gas Technical and Economic Potential for Alternative Avoided Cost Scenarios, 2020

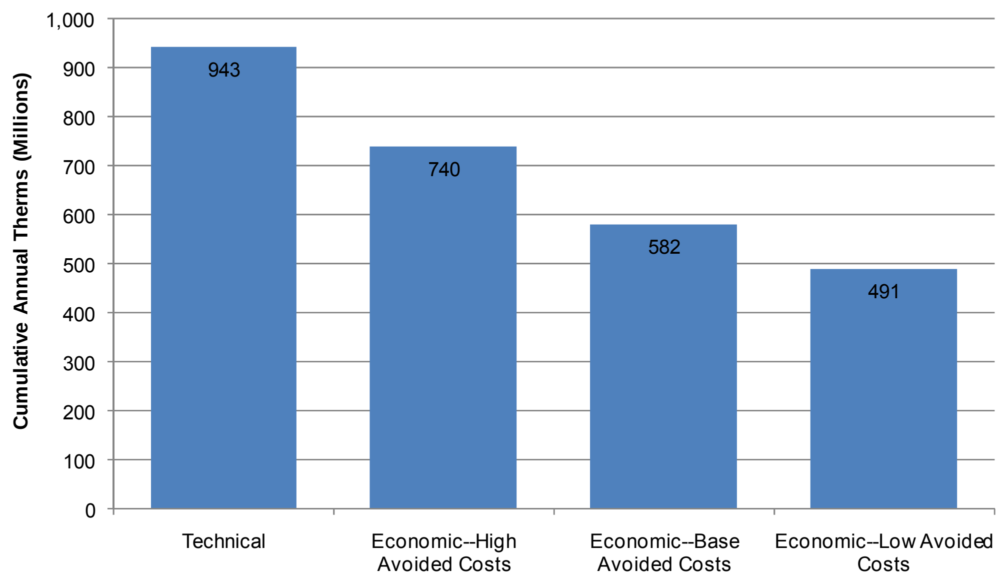


Table 6-1
Comparison of Estimated Natural-Gas Technical and Economic Potential for Alternative Avoided Cost Scenarios, 2020

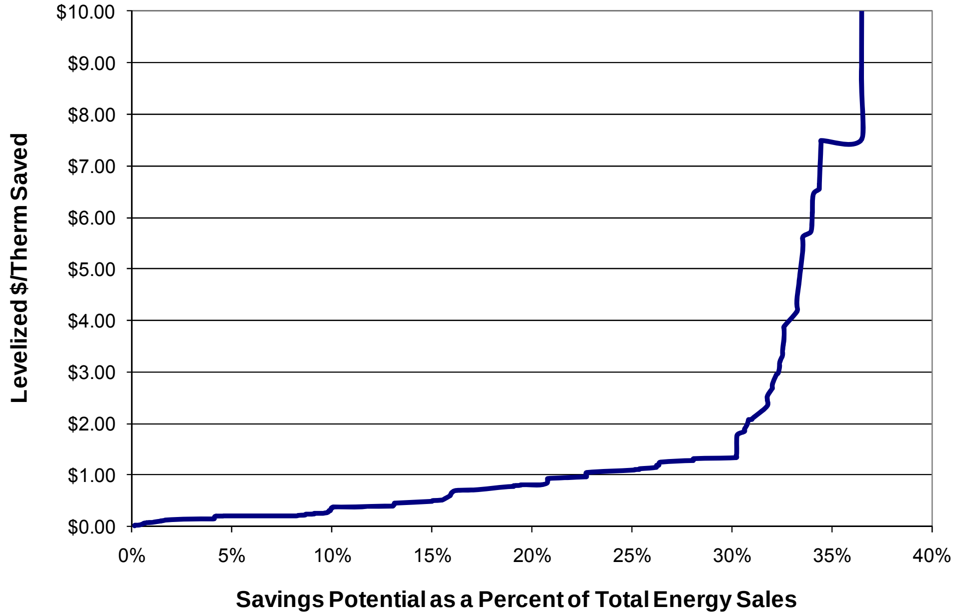
	Sales	Technical Potential	Economic--High Avoided Costs	Economic--Base Avoided Costs	Economic--Low Avoided Costs
Million Therms	2,463	943	740	582	491
% of consumption		38%	30%	24%	20%
% of Technical			78%	62%	52%
% of Economic--Base Avoided Costs			127%	100%	84%

6.1.4 Energy-Efficiency Supply Curves

A common way to illustrate the amount of energy savings per dollar spent is to construct an energy-efficiency supply curve. A supply curve typically is depicted on two axes: one captures the cost per unit of saved energy (e.g., levelized $/therm saved), and the other shows energy savings at each level of cost. Measures are sorted on a least-cost basis, and total savings are calculated incrementally with respect to measures that preceded them. The costs of the measures are levelized over the life of the savings achieved.

Figure 6-12 presents the supply curve constructed for this study for natural gas. The curve represents savings as a percentage of total energy or peak demand. It shows that energy savings of almost 23 percent are available at under $1.00 per therm. Savings potentials and levelized costs for the individual measures that comprise the supply curve are provided in Appendix G.

Figure 6-12
Natural-Gas Supply Curve*



*Levelized cost per kWh saved is calculated using a 7.76 percent nominal discount rate.

6.2 Achievable (Program) Potential

In contrast to technical and economic potential estimates, achievable potential estimates take into account market and other factors that affect the adoption of efficiency measures. We estimate measure adoption while taking into account market barriers and actual consumer- and business-implicit discount rates. This section presents results for achievable potential, first at the summary level and then by scenarios as describe in section 3.3 .

6.2.1 Markets within the Scenarios

For each gas scenario we modeled achievable potential by market. We used the following markets:

Table 6-2

Natural Gas Markets and Measures

Customer Sector	Building type	Market	Measures
Residential	Existing	Replace on Burnout	All
Residential	Existing	Retrofit	All
Residential	New	New Construction	All
Commercial	Existing	Replace on Burnout	All
Commercial	Existing	Retrofit	All
Commercial	New	New Construction	All
Industrial	Existing	Replace on Burnout	All
Industrial	Existing	Retrofit	All

Each scenario is build up from these markets.

Achievable potential refers to the amount of savings that would occur in response to one or more specific program interventions. *Net* savings associated with program potential are savings that are projected beyond those that would occur naturally in the absence of any market intervention. Because achievable potential depends on the type and degree of intervention applied, we developed, similar to the electric analysis, potential estimates under two scenarios We estimated program energy savings under each scenario for the 2011-2020 time period. Figure 6-13 shows our estimates of achievable potential savings over time.

Figure 6-13
Achievable Energy Savings: All Sectors

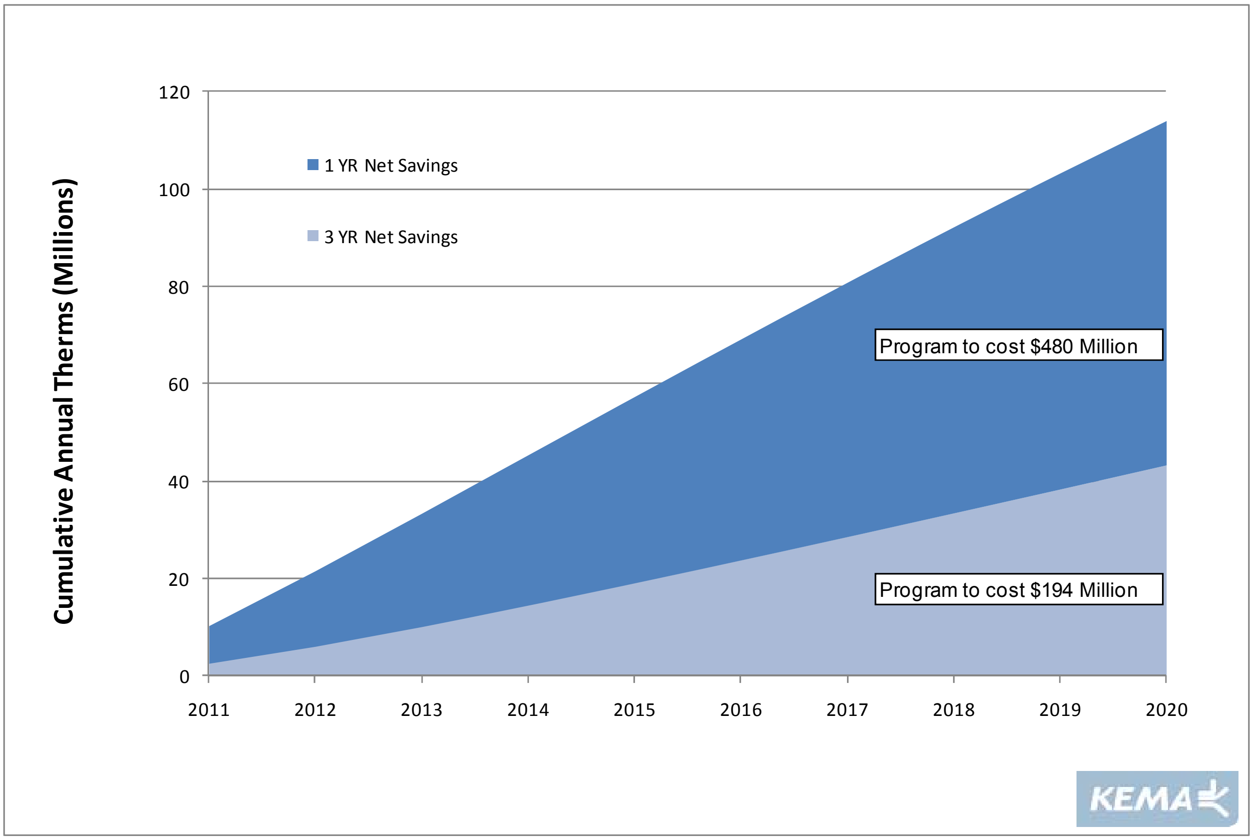
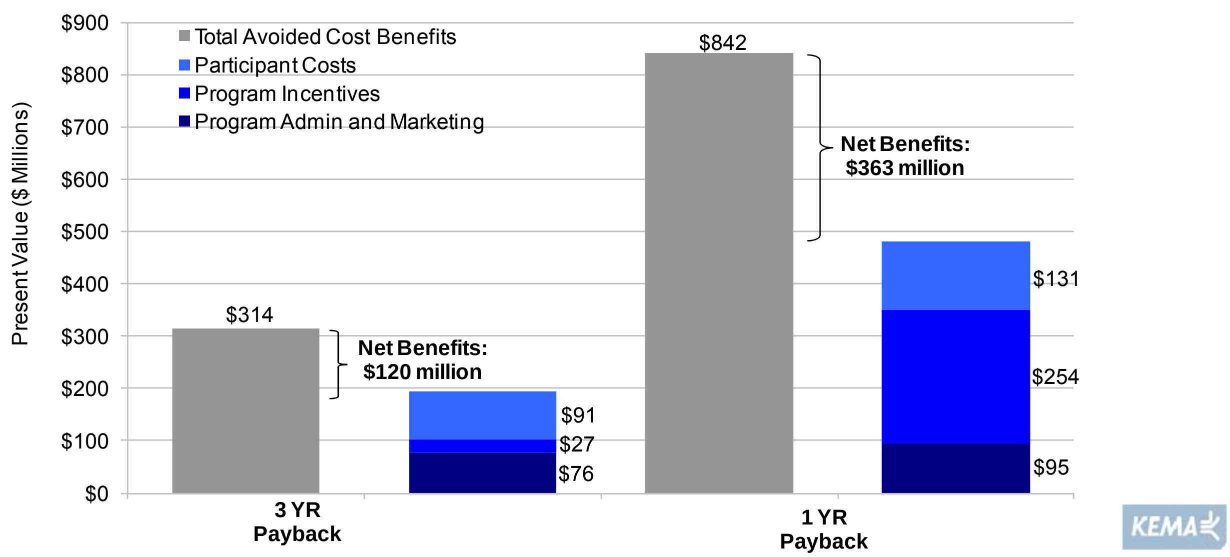
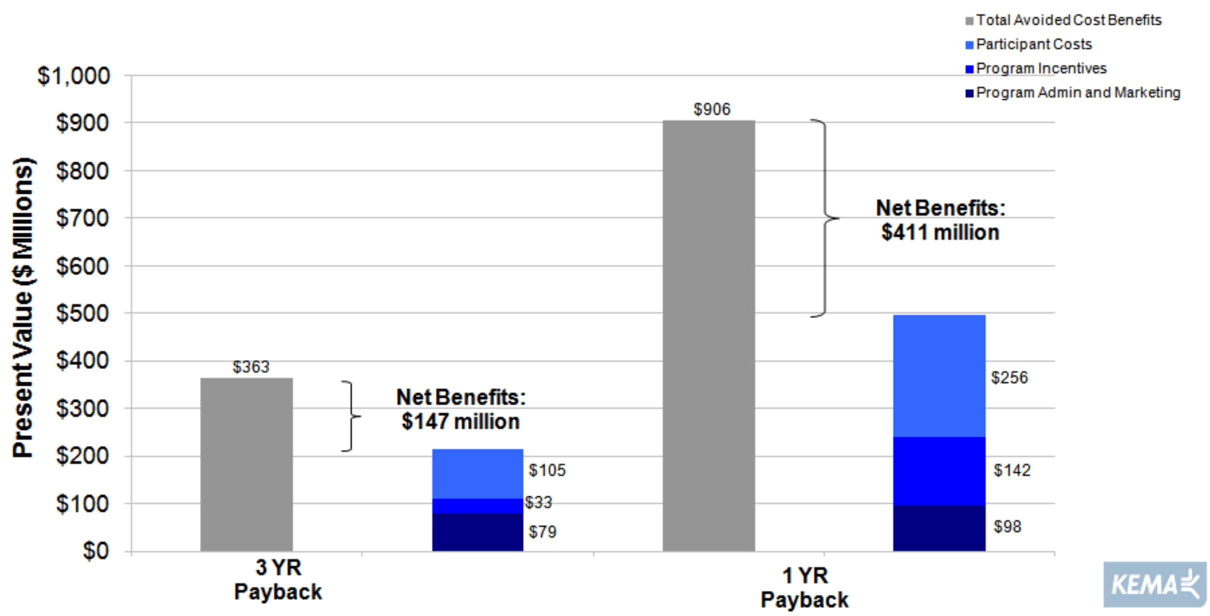


Figure 6-14 depicts costs and benefits under each scenario from 2011 to 2020.

Figure 6-14
Benefits and Costs of Energy-Efficiency Savings—2011-2020*





* Present value of benefits and costs over normalized 20-year measure lives; nominal discount rate is 7.7 percent, inflation rate is 1.5 percent.

All of the funding scenarios are cost-effective based on the TRC test, which is the test used in this study to determine program cost-effectiveness. The TRC benefit-cost ratios are 1.7 for the three year payback scenario and 1.8 for the one year payback scenario. As will the analysis in the electric sector, the point of diminishing returns was not passed by scenarios in this analysis. Key results of our efficiency scenario forecasts from 2011 to 2020 are summarized in Table 6-3.

Table 6-3
Summary of Achievable Potential Results—2011-2020

Result - Programs	3 YR Payback	1 YR Payback
Gross Energy Savings - Therms (Millions)	103.6	177.6
Net Energy Savings - Therms (Millions)	43.3	114.0
Program Costs - Real, $ Million		
Administration	$61	$84
Marketing	$34	$34
Incentives	$33	$314
Total	$127	$431
PV Avoided Costs	$314	$842
PV Annual Program Costs (Adm/Mkt)	$76	$95
PV Net Measure Costs	$118	$385
Net Benefits	$120	$363
TRC Ratio	1.62	1.76

Result - Programs	3 YR Payback	1 YR Payback
Gross Energy Savings - Therms (Millions)	103.6	177.6
Net Energy Savings - Therms (Millions)	43.3	114.0
Program Costs - Real, $ Million		
Administration	$61	$84
Marketing	$34	$34
Incentives	$33	$314
Total	$127	$431
PV Avoided Costs	$314	$842
PV Annual Program Costs (Adm/Mkt)	$76	$95
PV Net Measure Costs	$118	$385
Net Benefits	$120	$363
TRC Ratio	1.62	1.76

6.3 Breakdown of Achievable Potential

6.3.1 Summary of the 3 Year Payback Scenario

This section presents the summary of the 3 year payback for incentives scenario.

Table 6-4
Summary Table for the Gas 3 Year Payback Scenario

Result - Programs	Program Scenario: 2011 - 2020 Residential	Commercial	Industrial	All Programs
Gross Energy Savings - Therms (Millions)	71.64	19.92	11.99	103.55
Net Energy Savings Therms (Millions)	29.21	9.58	4.55	43.34
Program Costs - Real, $				
Administration	$42	$14	$5	$61
Marketing	$10	$17	$6	$34
Incentives	$21	$12	$0.5	$33
Total	$73	$43	$11	$127
PV Avoided Costs	$212	$70	$32	$314
PV Annual Program Costs (Adm/Mkt)	$42	$25	$9	$76
PV Net Measure Costs	$90	$22	$5	$118
Net Benefits	$80	$23	$18	$120
TRC Ratio	1.60	1.48	2.28	1.62

Result - Programs	Program Scenario: 2011 - 2020 Residential	Commercial	Industrial	All Programs
Gross Energy Savings - Therms (Millions)	71.64	19.92	11.99	103.55
Net Energy Savings - Therms (Millions)	29.21	9.58	4.55	43.34
Program Costs - Real, $				
Administration	$42	$14	$5	$61
Marketing	$10	$17	$6	$34
Incentives	$21	$12	$0	$33
Total	$73	$43	$11	$127
PV Avoided Costs	$212	$70	$32	$314
PV Annual Program Costs (Adm/Mkt)	$42	$25	$9	$76
PV Net Measure Costs	$90	$22	$5	$118
Net Benefits	$80	$23	$18	$120
TRC Ratio	1.60	1.48	2.28	1.62

Figure 6-15 presents energy savings over time for this scenario.

Figure 6-15
Gas Energy Savings for the 3 Year Payback Scenario

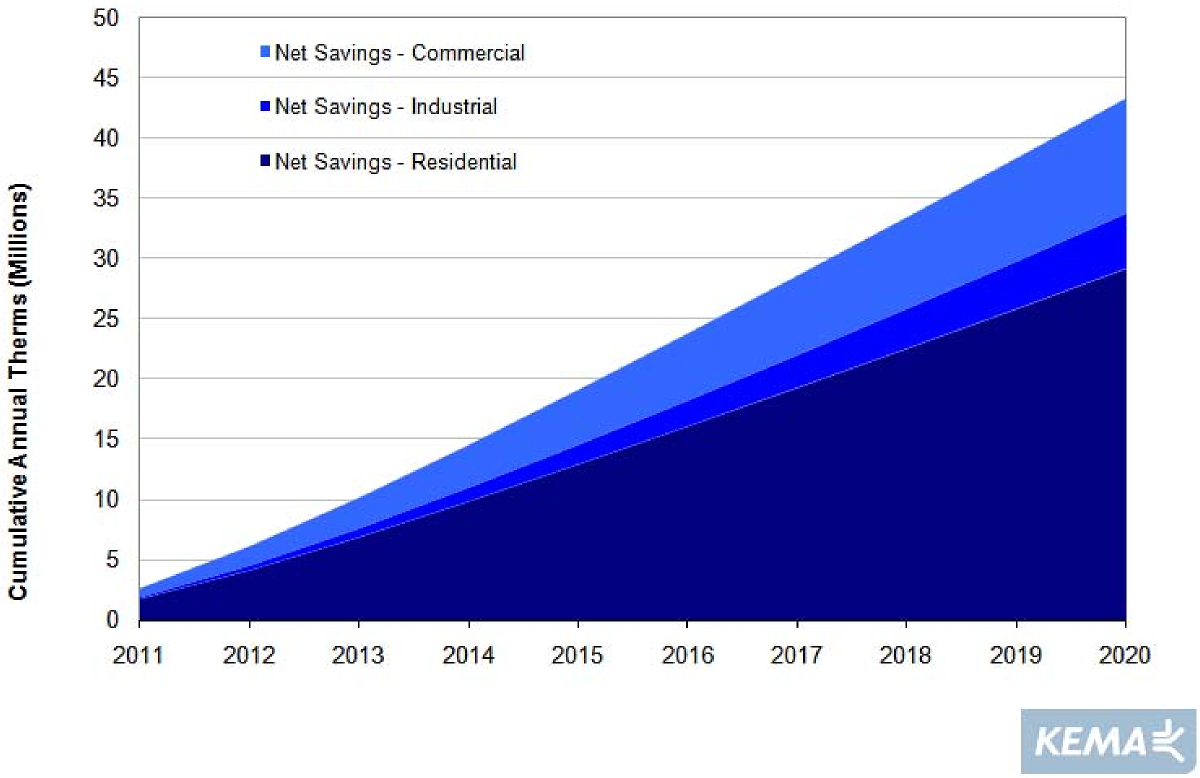
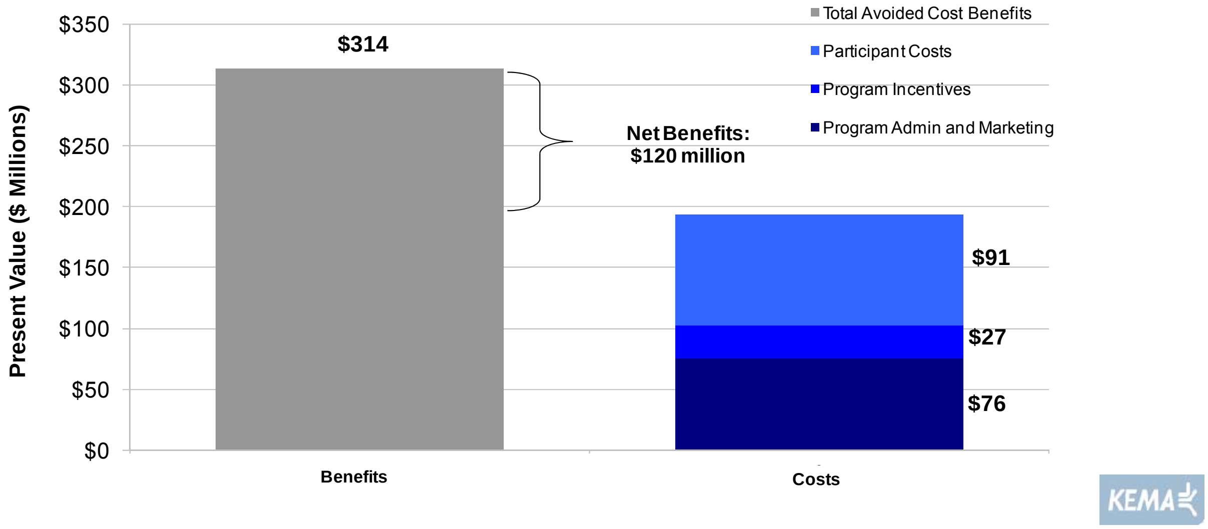
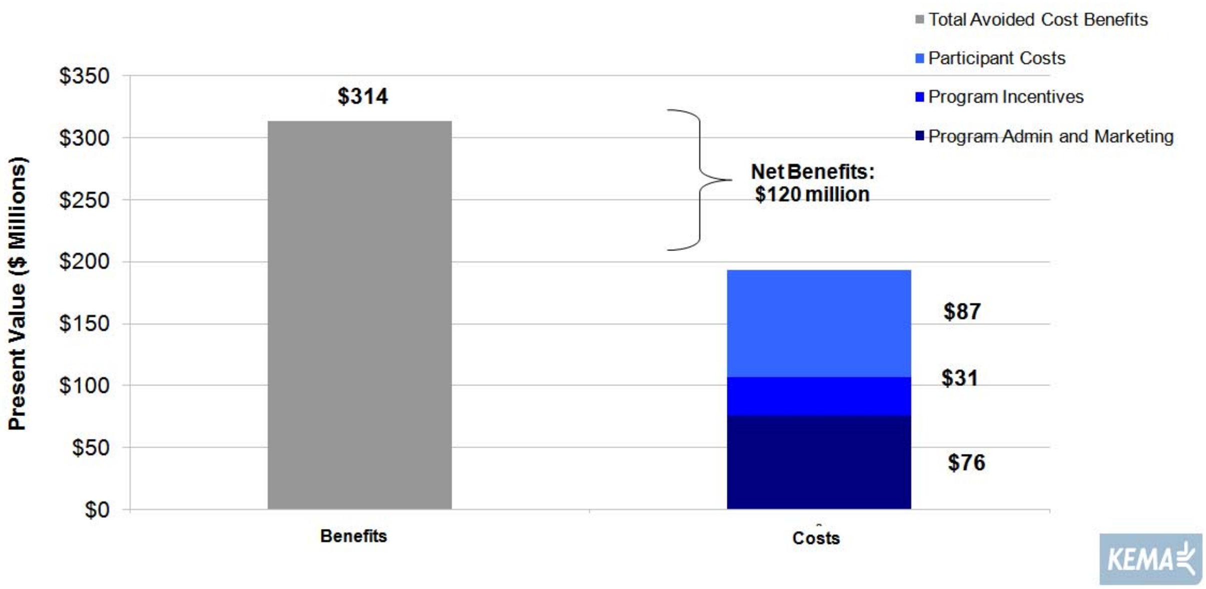


Figure 6-16 presents a summary of the cost effectiveness of this scenario.

Figure 6-16
Overall Benefit Cost Chart –Gas 3 Year Payback Incentives





6.3.2 Summary of the 1 Year Payback Scenario

This section presents a summary of the one year payback for incentives scenario. ~~Table 6-5 presents a summary.~~

Table 6-5
Summary Table for the Gas 1 Year Payback Scenario

Result - Programs	Program Scenario: 2011 - 2020			
	Residential	Commercial	Industrial	All Programs
Gross Energy Savings - Therms	111	46	20	178
Cumulative Net Energy Savings - Therms	65	36	13	114
Program Costs - Real, $ Million				
Administration	$58	$20	$6	$84
Marketing	$10	$17	$6	$34
Incentives	$215	$84	$14	$314
Total	$284	$121	$26	$431
PV Avoided Costs	$482	$267	$94	$842
PV Annual Program Costs (Adm/Mkt)	$55	$30	$10	$95
PV Net Measure Costs	$270	$95	$20	$385
Net Benefits	$157	$141	$65	$363
TRC Ratio	1.48	2.13	3.19	1.76

Figure 6-17~~This figure~~ presents the energy savings for the one year payback scenario.

Figure 6-17
Gas Energy Savings for the 1 Year Payback Scenario

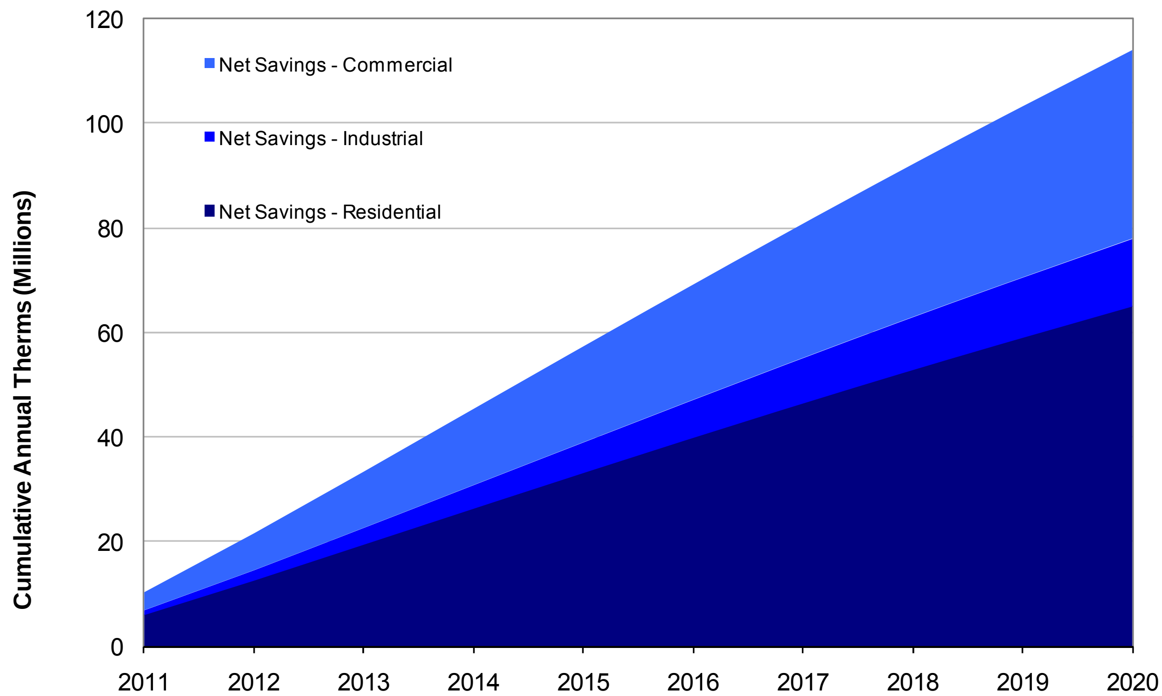
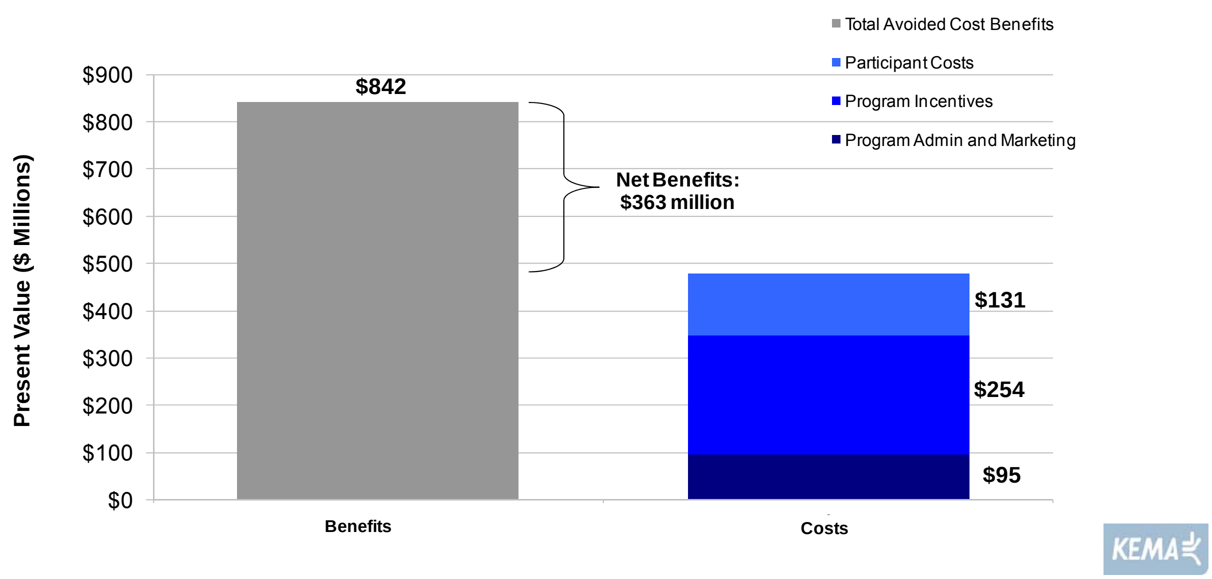
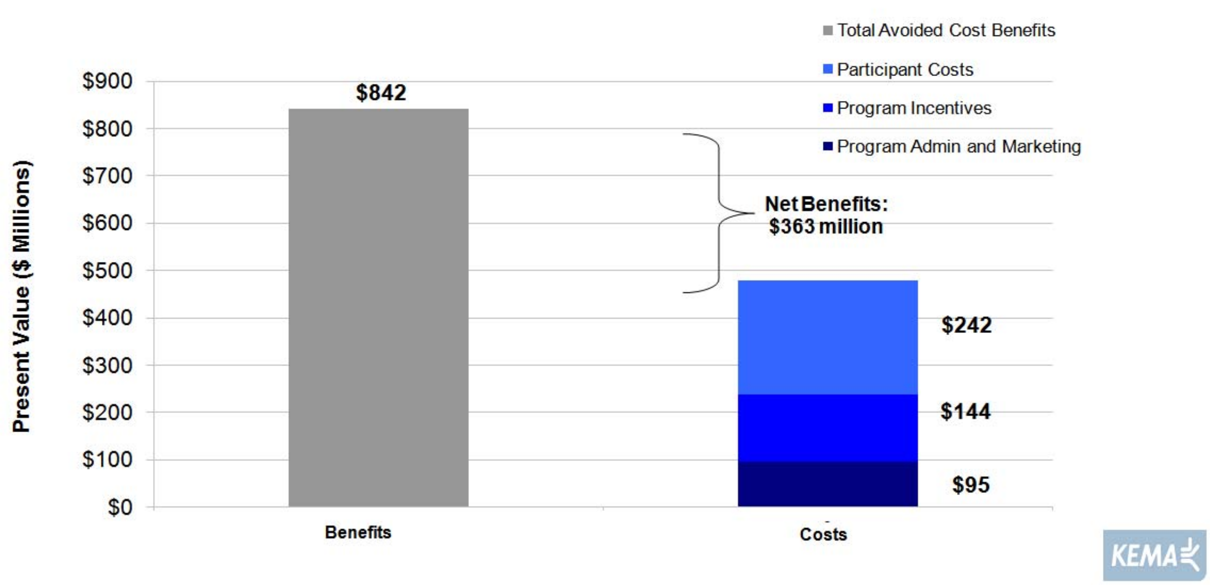


Figure 6-18 below presents the overall cost effectiveness of this scenario.

Figure 6-18
Cost Effectiveness of 1 Year Payback Scenario





7. Demand Response Potential Results

7.1 Methodology

KEMA developed an estimate of demand response potential for the State of Missouri using the Federal Energy Regulatory Commission's (FERC's) 2009 National Assessment of Demand Response (NADR) models with specific inputs for the State of Missouri. The NADR model was used to evaluate Missouri demand response potential through 2030. The default inputs for the model were confirmed or adjusted based on information developed during the data collection phase of the project, e.g. advanced meter penetrations.

The national study and model implemented a bottom-up approach to estimate DR resources. DR Participation estimates were developed as a percentage of the total customers in each Customer Segment. The four Customer Segments are:

- Residential,
- Small nonresidential,
- Medium nonresidential, and
- Large nonresidential.

The model has the capability of estimating participation in five DR program categories:

- Direct load control,
- Interruptible rates,
- Dynamic pricing with enabling technologies,
- Dynamic pricing without enabling technologies, and
- Other DR programs such as demand bidding.

Participation estimates were developed for four different scenarios:

- Business-as-usual (BAU): BAU assumes current programs and tariffs are held constant;.

- Expanded BAU (EBAU): BAU assumes participation rates are increased to equal the 75th percentile of ranked participation rates of similar programs.

- Achievable Participation (AP): AP assumes advanced metering infrastructure (AMI) is universally deployed, and dynamic pricing is the opt-out default tariff.

- Full Participation (FP): EP assumes that dynamic pricing and the acceptance of enabling technology is mandatory. This scenario quantifies the maximum cost-effective DR potential, absent any regulatory and market barriers.

The NADR model evaluated demand response for the period 2009 through 2019. An evaluation of Missouri DR participation for the period 2010 - 2030 was developed by using the FERC 2009 - 2019 Missouri specific data, adding AMI meter additions identified in this study to the 2010 and 2010 meter totals and developing assumptions consistent with the findings of our research concerning customer, system peak and meter deployment growth for the 2020 - 2030 period. The model was extended through 2030 by projecting the rate of increase in customers, system peak megawatts and AMI meter installations growth from the 2018 to 2019 growth rate.

7.2 FERC Model

The NADR model assumes that demand response (DR) programs are triggered during periods of peak demand. The model output is an estimate of the volume of energy curtailed during a peak demand period. The model is not applicable for estimating the volume of energy that can be curtailed for other purposes such as: avoiding grid congestion, delaying transmission or distribution system capital expenditures, or supporting grid reliability during emergencies.

The model develops an estimate of the quantity of energy curtailed from the following inputs:

- An estimate of the average energy use during peak periods assuming no demand response. The model assumes peak demand will occur 15 hours per year.
- An estimate of the change in energy consumption when a DR program is triggered.
- An estimate of the number of customers participating in the DR program

7.3 Customer Types modeled

The results in this report are based on Missouri specific data embedded in the FERC model. The model divides retail customers into four segments based on common metering and tariff thresholds.

- Residential: includes all residential customers.
- Small commercial and industrial: commercial and industrial customers with summer peak demand less than 20 kilowatts (kW).

- Medium commercial and industrial: commercial and industrial customers with summer peak demand between 20 and 200 kW.
- Large commercial and industrial: demand greater than 200 kW.

7.4 DR Programs Modeled

The FERC analysis[11] assumes five Demand Response (DR) types:

- Dynamic pricing without enabling technology
- Dynamic pricing with enabling technology
- Direct Load Control
- Interruptible tariffs
- “Other”, such as capacity/demand bidding and ISO sponsored programs

Dynamic Pricing (DP) refers to the groups of programs that offer time-varying electricity prices on either a day-ahead or real-time basis. The prices change in response to heavy demand, higher than average costs, and reliability conditions. For the purposes of this model, FERC does not include Time-of-Use (TOU) pricing.

- **DP without enabling technologies** assumes that customers will voluntarily respond to higher on-peak prices by reducing or shifting demand to lower priced off-peak prices. Examples include critical peak pricing and rebates for reducing demand during peaks. The FERC model assumes that Advanced Meter Infrastructures (AMI), including “smart meters”, and associated Meter Data Management Systems (MDMS) must be in place. These meters have the capability of measuring customer usage over short period such as 15 minutes.

- **DP with enabling technology** adds devices installed on customer equipment that can automatically reduce consumption during high priced hours. The model assumes that residential and small and medium commercial customers will have programmable communicating thermostats installed on air conditioners. Large commercial and

[11] (FERC, 2009a, Page2)

industrial customers are assumed to have automated demand response systems that coordinate the reduction of consumption within the facility

Direct Load Control (DLC) refers to devices installed on customer equipment that are directly controlled by the utility. For the model, residential customers are assumed to have DLC installed only on air conditioners. Non-residential DCL includes air conditioning load and, depending on the State, may include other forms such as irrigation load.

Interruptible Tariff programs, in the FERC model, require customers to reduce consumption to a pre-determined level or specific amount and only during system reliability problems. The programs are generally not available for residential and small commercial customers.

Other DR programs include capacity bidding, demand bidding, aggregator offerings and demand response bid into capacity markets. The program may be triggered by price or reliability. These programs are targeted toward medium and large commercial and large industrial customers.

7.5 Deployment Scenarios

The FERC model analyzes four scenarios.

- Business-As-Usual (BAU)
- Enhanced Business-As-Usual (EBAU)
- Achievable Participation (AP)
- Full Participation (FP)

Business-as-Usual is a measure of existing and planned demand response potential. It serves as a starting point against the other programs can be measured.

Expanded BAU is an estimate of demand response if the current mix of programs achieves "best practices" levels of participation and a modest amount of DR from pricing programs and AMI deployment.

Achievable Participation is an estimate of DR if AMI is universally deployed, DR pricing is the default tariff, and other programs are available for customers who decide to opt-out of dynamic pricing, Full Participation is an estimate of the total amount of cost-effective demand response given there are no regulatory or market barriers and all customers participate. It represents the upper limit on DR given the assumptions and conditions inherent in the model.

Below is a summary of the key differences in the scenario assumptions. For the purposes of this model, full deployment of AMI is assumed to occur by 2019.

Table 7-1

Key Differences in Scenario Assumptions[12]

Assumption	Business-as-Usual	Expanded BAU	Achievable Participation	Full Participation
AMI deployment	Partial Deployment	Partial deployment	Full deployment	Full deployment
Dynamic pricing participation (of eligible)	Today's level	Voluntary (opt-in); 5%	Default (opt-out); 60% to 75%	Universal (mandatory); 100%
Eligible customers offered enabling tech	None	None	95%	100%
Eligible customers accepting enabling tech	None	None	60%	100%
Basis for non-pricing participation rate	Today's level	"Best practices" estimate	"Best practices" estimate	"Best practices" estimate

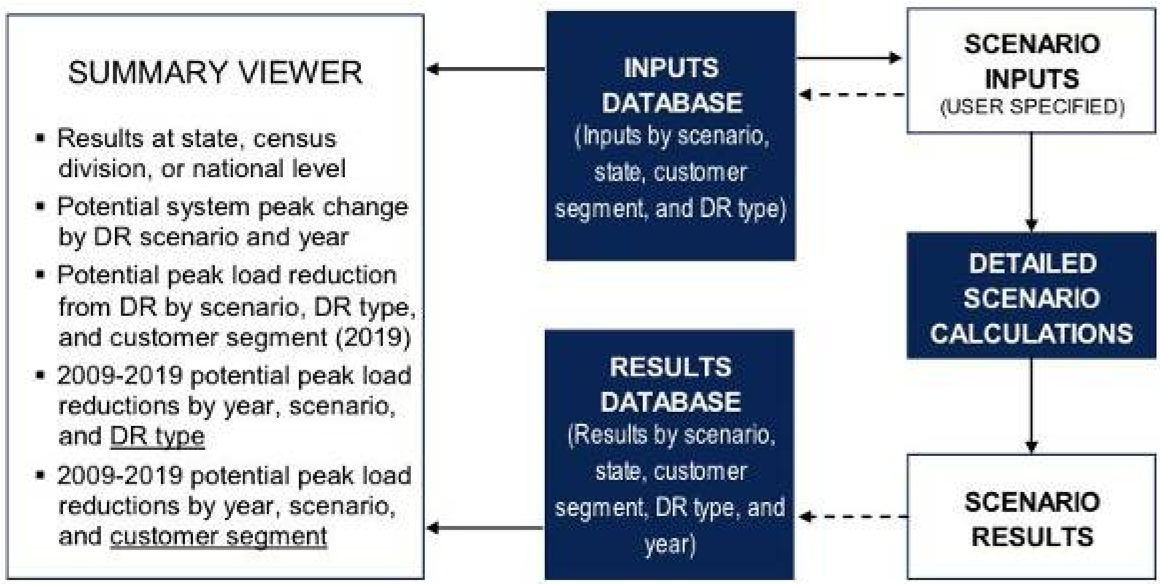
7.6 Model Architecture

The model[13] is an Excel spreadsheet that takes State specific inputs and runs them through a series of scenarios and outputs the results to a summary page. Scenario inputs are stored in the Inputs Database. The Scenario Results Database stores the output from the Detailed Scenario Calculations. Below is a general schematic of the model followed by a summary description of the modeling process.

[12] (Ferc, 2009b, Page24)

[13] (FERC, 2009a, Page4)

Figure 7-1
FERC Model Architecture[14]



Scenario Inputs. Region specific customer, peak load, AMI and demand response program information is collected in the Inputs Data sheet.

Scenario Results. Input data is feed in to the model (Detailed Scenario Calculations) calculates DR potential and a Scenario Results Database produced.

Summary Viewer summarizes and displays the information from both the inputs and results database

7.7 Scenario Calculations

Number of Participants in Each Scenario. The number of participants in each DR program is determined by identifying the number of customers eligible to participate in a DR program and assumed participation rates. The number of eligible customers is determined by the customer type and appliance/equipment targeted for reduction. For residential customers, customers with

[14] (FERC, 2009a, Page4)

air conditioning were considered eligible. Of those eligible customers, participation rates were determined based on the market penetration of existing DR programs. Except for dynamic pricing, the participation level is set at the percentage participation reached by one quarter of existing program.

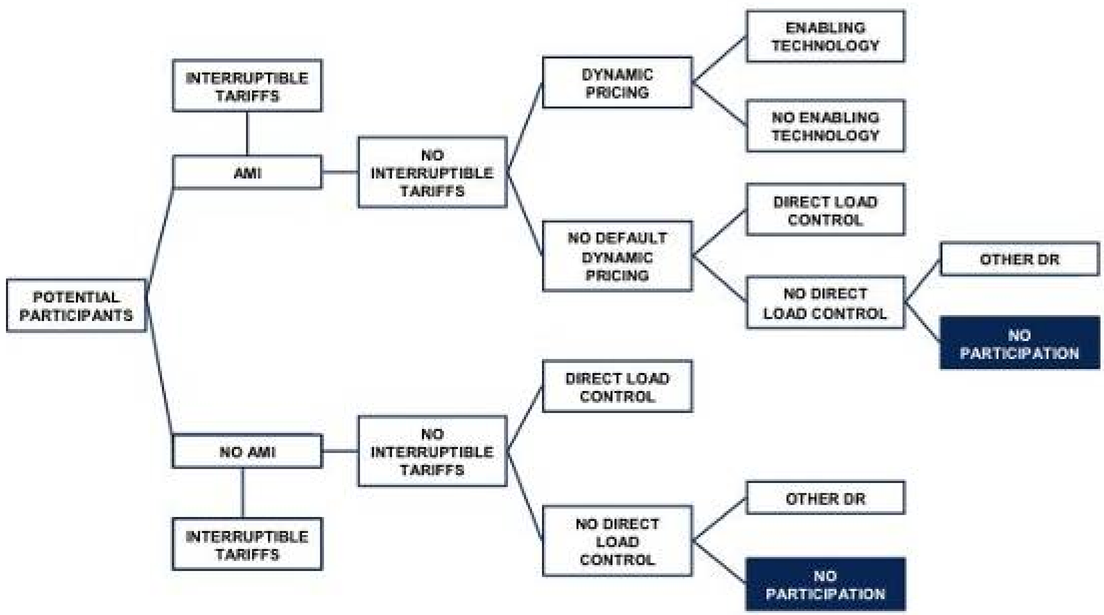
Participation Hierarchy. To prevent double-counting of participants, a hierarchy was established. As shown in Figure 2.3, initially all customers are separated based on the installation of AMI. Customers with interruptible tariffs are assumed not to participate in other DR programs. Customers with AMI traverse the upper path and customers without AMI traverse the lower path.

The next level for customers with AMI is dynamic pricing. Customers with a dynamic pricing tariff may have enabling technology (i.e. programmable thermostats on air conditioners). For customers not on a dynamic pricing tariff, the options are direct load control, other programs (such as demand bidding or ISO/RTO administered program) or no participation.

Customers with AMI, the lower path, have a similar matrix except they are not eligible for a dynamic pricing tariff.

FERC assumes that dynamic pricing options have limited overhead costs particularly if all customers are placed on a dynamic pricing tariff and must take action to op-out out of the tariff. FERC also assumes that dynamic pricing options are not dependent on enabling technologies.

Figure 7-2
Customer Participation Hierarchy Employed in the FERC Model[15]



7.8 Example of Full Participation

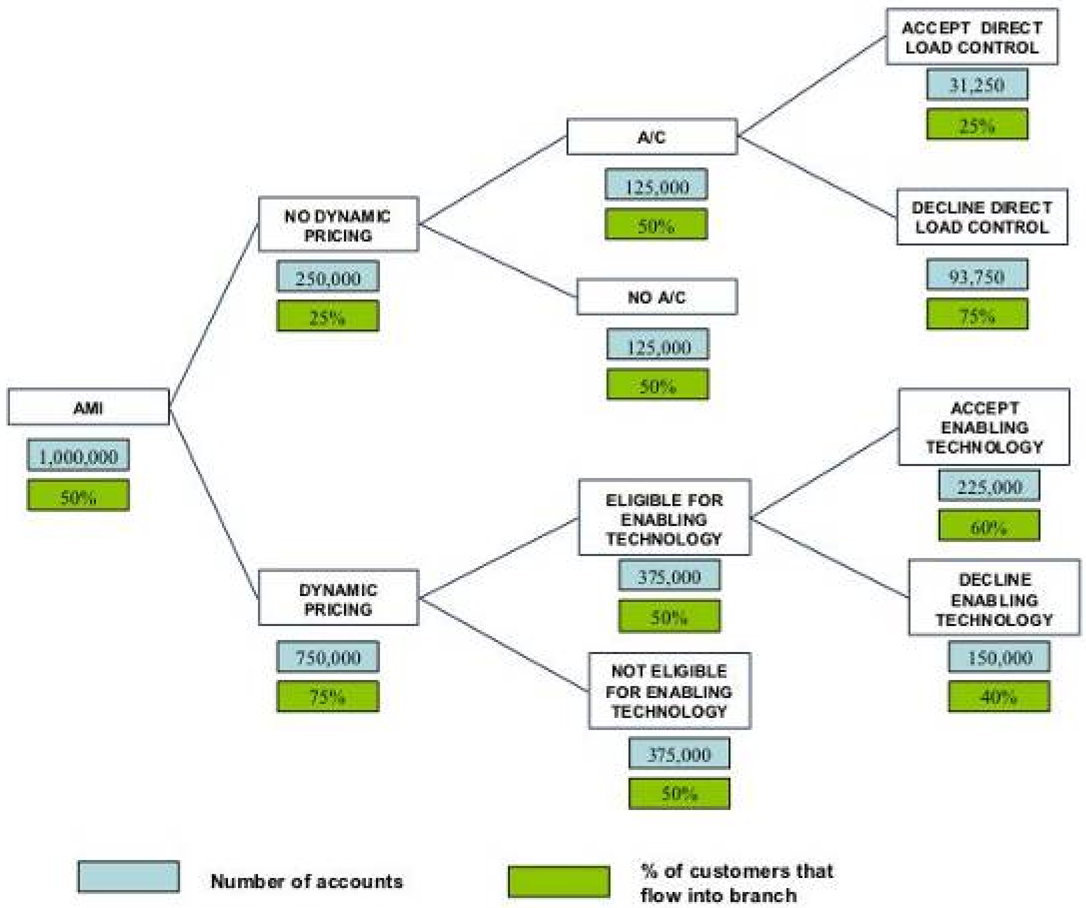
To assist in envisioning the assumed size of the customer pool for each option, FERC provides an example of the hierarchy for residential customers. The example assumes that all residential customers have smart meters and are placed on a dynamic tariff rate. The assumption is that 25% will opt-out of the tariff. Of those remaining, 50% will have air conditioners. 60% of the dynamic rate customers with air conditioners will accept free enabling technology or programmable communicating thermostats (PCT) for their air conditioners.

The model assumes that customers with enabling technology are more likely to curtail and will curtail to a greater extent than customers without enabling technology. Customers without air conditioners are not eligible for enabling technology and are not expected to curtail to the same extent of those with air conditioning. Of the customers with air conditioners that declined to install PCT an achievable penetration rate for direct load control is expected. The result is that

15 (FERC, 2009a, Page10)

of the 1,000,000 customer with AMI and dynamic pricing, 225,000 (23%) will choose DR using enabling technology.

Figure 7-3
An Example of Enabling Technology and Participation Rates[16]



7.9 Using FERC Full Participation Estimate for Missouri

The FERC model results for 2019 were reviewed to identify Missouri specific assumptions and results. FERC assumes a 45% penetration of AMI meters (Ferc, 2009b Page80), 87.5% saturation of residential central air conditioning and 14.8% (Ferc, 2009b Page 238). As noted in

16 (FERC, 2009a,Page11)

Table 7-2 below, FERC estimated the number of residential customer to be 2,815,113. Assuming the FERC dynamic tariff opt-out rate of 25% applies to Missouri, below is the estimate of the number of residential participants in the dynamic pricing program.

Table 7-2
FERC Residential Customer Matrix

Matrix Step	Residential Customers
Total 2019 Residential Customers	2,815,113
Customers with AMI (45%)	1,266,801
Customers Accepting Dynamic Pricing Tariff (75%)	950,101
Customers Eligible for Enabling Technology with Central Air Conditioning (87.5%)	831,338
Customers Accepting Enabling Technologies (60%)	498,803
Customer Declining Enabling Technologies (40%)	332,535

In the Full Participation scenario 18% of the total 2019 Missouri residential customers are projected to adopt dynamic pricing using enabling technology.

7.10 Missouri Model Run

Missouri Data Adjustments

During the data collection phase of the project, data was collected on the deployment of advanced meters by utilities in Missouri.

- Elster and Webster Electric Coop - 15,500 smart meters July - December 2010[17]
- SEMO Coop - 16,000 smart meters[18]
- City of Fulton - 5,000 meters - [19]
- Kansas City Power & Light - 14,000 Commercial and Residential[20]

[17] Elster EnergyAxis(R) AMI to replace entire meter base for electric co-op in Missouri
[18] seMissourian.com: Local News: SEMO Electric installs new 'smart' meter system (08/25/10)
[19] SmartGrid.gov: City of Fulton, Missouri Smart Grid Project
[20] SmartGrid.gov: Kansas City Power & Light Company Smart Grid Demonstration Project

Based on the total number of customers the additional meters installations were 1.9% for residential and 0.5% for small commercial customers. This information was added to the model for the years 2010 and 2011. These meters are assumed to be incorporated in the FERC assumption for Missouri of 7.5% for 2012

Extending FERC Model includes Missouri data through 2019. To extend the analysis through 2030 required estimating three sets of inputs:

- Number of Customers
- System Peak Load
- Number of AMI Meters Installed.

7.11 Number of Customers

The estimates were made by assuming the growth rates between 2018 and 2019 continued through 2030. Below are tables of the FERC included data through 2019 and the calculated extensions through 2030 assuming a growth rate of 0.46% for residential customers and 1.07% for commercial and industrial customers.

Table 7-3
Customer Population Growth Rates.

		Commercial & Industrial		
CUSTOMER POPULATION INPUTS	**Residential**	**Small**	**Medium**	**Large**
Growth Rate for years 2020-2030	**0.48%**	**1.07%**	**1.07%**	**1.07%**
Starting Customer Population	**2,670,172**	**347,394**	**25,739**	**4,651**
2009	**2,683,034**	**351,098**	**26,013**	**4,700**
2010	2,695,958	354,841	26,291	4,750
2011	2,708,944	358,624	26,571	4,801
2012	2,721,993	362,448	26,854	4,852
2013	2,735,105	366,312	27,140	4,904
2014	2,748,280	370,218	27,430	4,956
2015	2,761,518	374,165	27,722	5,009
2016	2,774,820	378,154	28,018	5,063
2017	2,788,187	382,186	28,317	5,117
2018	2,801,617	386,260	28,618	5,171
2019	2,815,113	390,378	28,924	5,226
2020	*2,828,673*	*394,540*	*29,232*	*5,282*
2021	*2,842,299*	*398,747*	*29,544*	*5,338*
2022	*2,855,990*	*402,998*	*29,859*	*5,395*
2023	*2,869,747*	*407,295*	*30,177*	*5,453*
2024	*2,883,571*	*411,637*	*30,499*	*5,511*
2025	*2,897,461*	*416,026*	*30,824*	*5,570*
2026	*2,911,418*	*420,461*	*31,152*	*5,629*
2027	*2,925,442*	*424,944*	*31,485*	*5,689*
2028	*2,939,534*	*429,475*	*31,820*	*5,750*
2029	*2,953,693*	*434,054*	*32,159*	*5,811*
2030	*2,967,921*	*438,681*	*32,502*	*5,873*

7.12 System Peak

System peak values for 2020 through 2030 were estimated assuming the growth rate was constant and equal to the rate of growth between 2018 and 2019. The growth rate between 2018 and 2019 was calculated to be 1.68%. That rate was applied to estimate the peak demand growth between 2020 and 2030. The peak demand for those years is included in Tables 7-4 through 7-7.

7.13 Number of AMI Meters

In the FERC model, the level of demand reduction is partly driven by the number of AMI meters installed. The BAU and EAU scenarios assume a slower rate of AMI deployment than the AP and FP scenarios. For the BAU and EBAU scenarios, the rate of deployment for 2018 to 2019 was assumed to continue through 2030. That rate was calculated to be 5.72%. The FERC model assumes full deployment of AMI meters by 2019. This rate was extended through 2030. The assumed penetration of AMI for each of the scenarios is shown in Tables 7-4 through 7-7.

Table 7-4
BAU Data Inputs for System Peak and AMI Meters

BAU	System Peak	Advanced Metering Infrastructure Deployment			
	Forecast		Commercial & Industrial		
YEARLY SYSTEM PEAK AND AMI DEPLOYMENT INPUTS	**(MW)**	**Residential**	**Small**	**Medium**	**Large**
2009	17,739	0.0%	0.0%	0.0%	0.0%
2010	18,102	**1.9%**	**0.5%**	0.0%	0.0%
2011	18,424	**1.9%**	**0.5%**	0.0%	0.0%
2012	18,728	**7.5%**	**7.5%**	**7.5%**	**7.5%**
2013	19,053	**15.0%**	**15.0%**	**15.0%**	**15.0%**
2014	19,408	**24.0%**	**24.0%**	**24.0%**	**24.0%**
2015	19,755	**33.0%**	**33.0%**	**33.0%**	**33.0%**
2016	20,090	**36.4%**	**36.4%**	**36.4%**	**36.4%**
2017	20,434	**40.0%**	**40.0%**	**40.0%**	**40.0%**
2018	20,783	**42.6%**	**42.6%**	**42.6%**	**42.6%**
2019	21,139	**45.2%**	**45.2%**	**45.2%**	**45.2%**
2020	*21,495*	*47.8%*	*47.8%*	*47.8%*	*47.8%*
2021	*21,857*	*50.5%*	*50.5%*	*50.5%*	*50.5%*
2022	*22,224*	*53.4%*	*53.4%*	*53.4%*	*53.4%*
2023	*22,598*	*56.5%*	*56.5%*	*56.5%*	*56.5%*
2024	*22,978*	*59.7%*	*59.7%*	*59.7%*	*59.7%*
2025	*23,365*	*63.1%*	*63.1%*	*63.1%*	*63.1%*
2026	*23,758*	*66.7%*	*66.7%*	*66.7%*	*66.7%*
2027	*24,158*	*70.5%*	*70.5%*	*70.5%*	*70.5%*
2028	*24,565*	*74.6%*	*74.6%*	*74.6%*	*74.6%*
2029	*24,978*	*78.8%*	*78.8%*	*78.8%*	*78.8%*
2030	*25,398*	*83.3%*	*83.3%*	*83.3%*	*83.3%*
Assume 2018 to 2019 growth rate	**0.0168**	**0.0572**	**0.05721**	**0.0572**	**0.0572**

Table 7-5
Enhanced BAU Data Inputs for System Peak and AMI Meters

Expanded BAU	**System Peak Forecast**	**Advanced Metering Infrastructure Deployment**			
			Commercial & Industrial		
YEARLY SYSTEM PEAK AND AMI DEPLOYMENT INPUTS	**(MW)**	**Residential**	**Small**	**Medium**	**Large**
2009	17,739	0.0%	0.0%	0.0%	0.0%
2010	18,102	**1.9%**	**0.5%**	0.0%	0.0%
2011	18,424	**1.9%**	**0.5%**	0.0%	0.0%
2012	18,728	**7.5%**	**7.5%**	**7.5%**	**7.5%**
2013	19,053	**15.0%**	**15.0%**	**15.0%**	**15.0%**
2014	19,408	**24.0%**	**24.0%**	**24.0%**	**24.0%**
2015	19,755	**33.0%**	**33.0%**	**33.0%**	**33.0%**
2016	20,090	**36.4%**	**36.4%**	**36.4%**	**36.4%**
2017	20,434	**40.0%**	**40.0%**	**40.0%**	**40.0%**
2018	20,783	**42.6%**	**42.6%**	**42.6%**	**42.6%**
2019	21,139	**45.2%**	**45.2%**	**45.2%**	**45.2%**
2020	*21,495*	*47.8%*	*47.8%*	*47.8%*	*47.8%*
2021	*21,857*	*50.5%*	*50.5%*	*50.5%*	*50.5%*
2022	*22,224*	*53.4%*	*53.4%*	*53.4%*	*53.4%*
2023	*22,598*	*56.5%*	*56.5%*	*56.5%*	*56.5%*
2024	*22,978*	*59.7%*	*59.7%*	*59.7%*	*59.7%*
2025	*23,365*	*63.1%*	*63.1%*	*63.1%*	*63.1%*
2026	*23,758*	*66.7%*	*66.7%*	*66.7%*	*66.7%*
2027	*24,158*	*70.5%*	*70.5%*	*70.5%*	*70.5%*
2028	*24,565*	*74.6%*	*74.6%*	*74.6%*	*74.6%*
2029	*24,978*	*78.8%*	*78.8%*	*78.8%*	*78.8%*
2030	*25,398*	*83.3%*	*83.3%*	*83.3%*	*83.3%*
Assume 2018 to 2019 growth rate	**0.0168**	**0.0572**	**0.0572**	**0.0572**	**0.0572**

Table 7-6
Achievable Participation Data Inputs for System Peak and AMI Meters

Achievable Participation	System Peak Forecast	Advanced Metering Infrastructure Deployment			
			Commercial & Industrial		
YEARLY SYSTEM PEAK AND AMI DEPLOYMENT INPUTS	**(MW)**	**Residential**	**Small**	**Medium**	**Large**
2009	17,739	0.0%	0.0%	0.0%	0.0%
2010	18,102	**1.9%**	**0.5%**	0.0%	0.0%
2011	18,424	**1.9%**	**0.5%**	0.0%	0.0%
2012	18,728	**11.2%**	**11.2%**	**11.2%**	**11.2%**
2013	19,053	**22.4%**	**22.4%**	**22.4%**	**22.4%**
2014	19,408	**38.1%**	**38.1%**	**38.1%**	**38.1%**
2015	19,755	**53.8%**	**53.8%**	**53.8%**	**53.8%**
2016	20,090	**63.6%**	**63.6%**	**63.6%**	**63.6%**
2017	20,434	**76.7%**	**76.7%**	**76.7%**	**76.7%**
2018	20,783	**88.4%**	**88.4%**	**88.4%**	**88.4%**
2019	21,139	**100.0%**	**100.0%**	**100.0%**	**100.0%**
2020	*21,495*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2021	*21,857*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2022	*22,224*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2023	*22,598*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2024	*22,978*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2025	*23,365*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2026	*23,758*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2027	*24,158*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2028	*24,565*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2029	*24,978*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2030	*25,398*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
Assumed 2018 to 2019 growth rate	**0.0168**				

Table 7-7
Full Participation Data Inputs for System Peak and AMI Meters

Full Participation	System Peak Forecast	Advanced Metering Infrastructure Deployment	Commercial & Industrial		
YEARLY SYSTEM PEAK AND AMI DEPLOYMENT INPUTS	**(MW)**	**Residential**	**Small**	**Medium**	**Large**
2009	17,739	0.0%	0.0%	0.0%	0.0%
2010	18,102	**1.9%**	**0.5%**	0.0%	0.0%
2011	18,424	**1.9%**	**0.5%**	0.0%	0.0%
2012	18,728	11.2%	11.2%	11.2%	11.2%
2013	19,053	22.4%	22.4%	22.4%	22.4%
2014	19,408	38.1%	38.1%	38.1%	38.1%
2015	19,755	53.8%	53.8%	53.8%	53.8%
2016	20,090	63.6%	63.6%	63.6%	63.6%
2017	20,434	76.7%	76.7%	76.7%	76.7%
2018	20,783	88.4%	88.4%	88.4%	88.4%
2019	21,139	100.0%	100.0%	100.0%	100.0%
2020	*21,495*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2021	*21,857*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2022	*22,224*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2023	*22,598*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2024	*22,978*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2025	*23,365*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2026	*23,758*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2027	*24,158*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2028	*24,565*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2029	*24,978*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
2030	*25,398*	*100.0%*	*100.0%*	*100.0%*	*100.0%*
Assume 2018 to 2019 growth rate	**0.0168**				

7.14 Study Results

The FERC model was run in two parts. The default Missouri data for years 2009 through 2019 was augmented with the additional AMI information and then solved. A new model sheet was created and populated with the 2020 through 2030 estimated data and solved. The five year results are provided in Tables 7-8 and 7-9.

Table 7-8 provides a summary of demand reduction by scenario in both megawatts reduced and percentage of peak demand. Under the BAU scenario, the model predicts a reduction of one percent in peak demand is estimated. The Expanded BAU scenario predicts that peak demand savings will increase to 8% when participation in Missouri is modeled at 75% of best practices across all other jurisdictions. Under the Achievable and Full Potential scenarios the model predicts peak demand reductions of 13% and 17% respectively in 2030.

Table 7-8

Model Results for Missouri, Years 2009 Through 2030

Year	System Peak (without DR)	Business As Usual	Expanded BAU	Achievable Participation	Full Participation
MW Reduction					
2010	18,102	17,820	17,414	17,414	17,414
2015	19,755	19,473	17,921	17,356	16,812
2020	21,495	21,213	19,595	18,513	17,443
2025	23,365	23,083	21,383	20,272	19,166
2030	25,398	25,116	23,328	22,188	21,045
Percentage Reduction					
2010	18,102	2%	2%	2%	2%
2015	19,755	1%	2%	12%	12%
2020	21,495	1%	9%	14%	19%
2025	23,365	1%	8%	13%	18%
2030	25,398	1%	8%	13%	17%

Disaggregation of the saving achieved by program and mechanism is shown in Table 7-9 below. The model estimates that demand reductions in the BAU scenario will be driven by customers under interruptible tariffs. The Expanded BAU scenario estimates that the major drivers for peak demand reduction will be interruptible tariff and direct load control programs. Both Achievable and Full Participation scenarios are heavily driven by customer participation in dynamic pricing with and without enabling technologies over direct load control with interruptible tariff customers continuing to participate at Expanded BAU rates.

Table 7-9
Summary Demand Response Results

Program mechanism	2010 MW	2015 MW	2020 MW	2025 MW	2030 MW
BAU					
Pricing With Enabling Technology	0	0	0	0	0
Pricing Without Enabling Technology	0	0	0	0	0
Automated or Direct Control DR	63	63	63	63	63
Interruptible Tariffs	219	219	219	219	219
Other DR	0	0	0	0	0
TOTAL	**282**	**282**	**282**	**282**	**282**
Expanded BAU					
Pricing With Enabling Technology	0	0	0	0	0
Pricing Without Enabling Technology	0	31	46	62	85
Automated or Direct Control DR	336	839	850	864	875
Interruptible Tariffs	326	647	677	713	752
Other DR	26	316	328	343	358
TOTAL	**688**	**1833**	**1900**	**1982**	**2070**
Achievable Participation					
Pricing With Enabling Technology	0	660	1255	1294	1335
Pricing Without Enabling Technology	0	353	674	697	722
Automated or Direct Control DR	336	521	241	247	252
Interruptible Tariffs	326	647	677	713	752
Other DR	26	218	134	142	149
TOTAL	**688**	**2399**	**2982**	**3093**	**3210**
Full Participation Potential					
Pricing With Enabling Technology	0	1599	3045	3142	3243
Pricing Without Enabling Technology	0	139	268	281	296
Automated or Direct Control DR	336	409	63	63	63
Interruptible Tariffs	326	647	677	713	752
Other DR	26	149	0	0	0
TOTAL	**688**	**2942**	**4052**	**4200**	**4353**

7.15 Cost-effectiveness Overview

The FERC assessment focuses on programs that reduce consumption during periods of high demand. These programs are modeled to reduce demand between 2 and 6 PM on the 15 peak days per year. Some stakeholders may consider untenable the significant deployment of time and resources to manage demand for 60 hours. If managing transmission congestion and system reliability during emergencies are included in the overall analysis of demand response programs, then the DR program has an opportunity to provide Missouri customers with benefits throughout the year.

Nonetheless, a review of Missouri data showed that a direct load control provided more benefit for the same enabling technology cost. FERC performed a cost effectiveness analysis for each State (Ferc, 2009b, Page 238). They estimated the cost of enabling technology. Table D-15 from the report shows the cost of a programmable control thermostat (PCT) to be equivalent to a direct load control switch. Below is the table reproduced for residential, and C&I customers.

Table 7-10

Existing Technology Equipment Costs (from FERC 2009b, Table D-15)

Customer	Dynamic Pricing		Direct Load Control	
Type	Equipment	Unit Cost	Equipment	Unit Cost
Residential	PCT	$200	Switch	$200
Small C&I	PCT	$350	Switch	$350
Medium C&I	PCT	$1,050	Auto-DR	$1,050
Large C&I	Auto-DR[21]	$13,500	Not Applicable	Not Applicable

The analysis also estimated the cost benefit compared to the avoided cost of a gas-fired combustion turbine-generator. The assessment assumed that a demand response option with enabling technology is cost effective if the benefit-cost ration was one or higher. The larger the number, the greater the economic benefit. For Missouri, the results were as shown below:

[21] Auto-DR is a communications infrastructure to provide DR program participants electronic, internet-based price and reliability signals that are linked to the facility energy management control systems (EMCS) or related building and automated process control systems.

Table 7-11

Benefit Cost Ratio for Missouri DR Programs (from FERC 2009b,Tables D-16 and D-17)

Customer Type	Dynamic Pricing with Enabling Technology	Direct Load Control
Residential	1.24	4.18
Small C&I	1.27	4.78
Medium C&I	3.41	4.78
Large C&I	2.21	Not Applicable

7.16 References

FERC, "National Demand Response Potential Model Guide," 2009a, pp. 1-31.

FERC, "A National Assessment of Demand Response Potential," 2009b, pp. 1-254.