KANSAS CITY POWER & LIGHT 2016 DSM POTENTIAL STUDY

VOLUME 3:
POTENTIAL ANALYSIS
FINAL REPORT

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INTRODUCTION

Kansas City Power and Light Company (KCP&L) engaged the Applied Energy Group (AEG) Team to conduct this Demand Side Management (DSM) Market Potential Study. It evaluates various categories of electricity DSM resources in the residential, commercial, and industrial sectors of KCP&L's service territory in Kansas and Missouri for the years 2019-2037. The resource categories investigated are: Energy Efficiency, Demand Response, Demand-Side Rates, and Combined Heat & Power.

The key objectives of the study are to:

- Perform a comprehensive analysis that complies with the respective statutory requirements of the Missouri Public Service Commission and the Kansas Corporation Commission
- Develop annual electricity energy and peak demand potential estimates for the DSM resource categories by customer class for each KCP&L jurisdiction for the time period of 2019 to 2037
- Develop baseline projections of annual electricity use and peak demand for each KCP&L jurisdiction, accounting for future codes and standards, naturally occurring energy efficiency, opt-out customers, smart connected devices, and combined heat and power
- Identify a subset of economic and program potential that is applicable to low-income customers
- Conduct a reliable, accurate and useful residential appliance saturation survey and C&I end-use saturation survey
- Quantify potential program savings from the DSM initiatives at various levels of cost
- Support KCP&L's effort to offer programs to all customer market segments while achieving the ultimate goal of all cost-effective demand-side savings

The study assesses various tiers of potential including technical, economic, maximum achievable, and realistic achievable potential. The study developed updated baseline estimates with the latest information on federal, state, and local codes and standards for improving energy efficiency.

As part of the study, the AEG Team conducted primary market research to collect data for the KCP&L service territory, including: end-use equipment saturation data and customer demographics and firmographics. All models and assumptions include the results from these primary market research efforts.

KCP&L will use the results of this study in its DSM and IRP planning process to optimally implement programs across its four service territories: Kansas City Power & Light Missouri (KCP&L-MO), Kansas City Power & Light Kansas (KCP&L-KS), Greater Missouri Operations Missouri Public Service (GMO-MPS), and Greater Missouri Operations St. Joseph Light & Power (GMO-SJLP).

REPORT ORGANIZATION

This report is presented in five volumes:

- Volume 1, Executive Summary
- Volume 2, Market Research Report
- Volume 3, Potential Analysis
- Volume 4, Program Potential
- Volume 5, Appendices

This document is Volume 3: Potential Analysis.

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ENERGY EFFICIENCY POTENTIAL ANALYSIS

As a part of this DSM Market Potential Study, AEG conducted KCP&L's energy efficiency (EE) potential analysis to understand the energy and peak demand savings that could be achieved from energy efficiency measures and resources. To perform the analysis, AEG used a detailed, bottom-up approach beginning with the objectives described above. We then completed each of the steps listed below, all of which are described in more detail throughout the remainder of this chapter:

- Analysis Approach
- Data Development
- Market Characterization
- Baseline Projection
- EE Potential Results
- EE Potential Results by Sector
- Sensitivity Analysis

DEFINITIONS OF POTENTIAL

In this study, the energy efficiency potential estimates represent net savings[1] developed into several levels of potential. This report volume focuses on analysis at the measure-level, that is, before consideration of program delivery mechanisms, program costs, and the application of portfolio strategy and measure bundling. At the measure-level, we analyze four levels of potential: technical, economic, maximum achievable, and realistic achievable potential. Technical and economic potential are both theoretical limits to efficiency savings and would not be realizable in actual programs. Achievable potential embodies a set of assumptions about the decisions consumers make regarding the efficiency of the equipment they purchase, the maintenance activities they undertake, the controls they use for energy-consuming equipment, and the elements of building construction. These levels are described in more detail below.

- **Technical Potential (TP)** is the theoretical upper limit of energy efficiency potential, assuming that customers adopt all feasible measures regardless of cost or customer preference. At the time of existing equipment failure, customers replace their equipment with the most efficient option available. In new construction, customers and developers also choose the most efficient equipment option.
- **Economic Potential (EP)** represents the adoption of all ***cost-effective*** energy efficiency measures. Cost-effectiveness is measured by the total resource cost (TRC) test, which compares lifetime energy and capacity benefits to the costs of the delivering the measure. If the benefits outweigh the costs (the TRC ratio is equal to or greater than 1.0), a given measure is included in the economic potential. Customers are then assumed to purchase the most cost-effective option applicable to them at any decision juncture. Economic potential is still a hypothetical upper-boundary of savings potential as it represents only measures that are economic but does not yet consider customer acceptance and other factors.

[1] "Net" savings mean that the baseline forecast includes naturally occurring efficiency. In other words, the baseline assumes that energy efficiency levels reflect that some customers are already purchasing the more efficient option.

- **Maximum Achievable Potential (MAP)** estimates customer adoption of economic measures when delivered through DSM programs under ideal market, implementation, and customer preference conditions and an appropriate regulatory framework. Information channels are assumed to be well established and efficient for marketing, educating consumers, and coordinating with trade allies and delivery partners. Maximum Achievable Potential establishes a maximum target for the savings that an administrator can hope to achieve through its DSM programs and involves incentives that represent a substantial portion of measure costs combined with high administrative and marketing costs.
- **Realistic Achievable Potential (RAP)** reflects expected program participation given DSM programs under more typical market conditions and barriers to customer acceptance, non-ideal implementation channels, and constrained program budgets. The delivery environment in this analysis projects the current state of the DSM market in KCP&L's service territory and projects typical levels of expansion and increased awareness over time.

LoadMAP Model

For the measure-level energy efficiency potential analysis, AEG used its Load Management Analysis and Planning tool (LoadMAP™) version 4.0 to develop both the baseline projection and the estimates of potential. AEG developed LoadMAP in 2007 and has enhanced it over time, using it for more than 50 potential studies in the past five years. Built in Microsoft Excel®, the LoadMAP framework is both accessible and transparent and has the following key features.

- Embodies the basic principles of rigorous end-use models (such as EPRI's REEPS and COMMEND) but in a more simplified, accessible form.
- Includes stock-accounting algorithms that treat older, less efficient appliance/equipment stock separately from newer, more efficient equipment. Equipment is replaced according to the measure life and appliance vintage distributions defined by the user.
- Balances the competing needs of simplicity and robustness by incorporating important modeling details related to equipment saturations, efficiencies, vintage, and the like, where market data are available, and treats end uses separately to account for varying importance and availability of data resources.
- Isolates new construction from existing equipment and buildings and treats purchase decisions for new construction and existing buildings separately.
- Uses a simple logic for appliance and equipment decisions. Other models available for this purpose embody complex decision choice algorithms or diffusion assumptions, and the model parameters tend to be difficult to estimate or observe and sometimes produce anomalous results that require calibration or even overriding. The LoadMAP approach allows the user to drive the appliance and equipment choices year by year directly in the model. This flexible approach allows users to import the results from diffusion models or to input individual assumptions. The framework also facilitates sensitivity analysis.
- Includes appliance and equipment models customized by end use. For example, the logic for lighting is distinct from refrigerators and freezers.
- Can accommodate various levels of segmentation. Analysis can be performed at the sector level (e.g., total residential) or for customized segments within sectors (e.g., housing type, income level, or business type).

Consistent with the segmentation scheme and the market profiles we describe below, the LoadMAP model provides forecasts of baseline energy use by sector, segment, end use, and technology for existing and new buildings. It also provides forecasts of total energy use and energy-efficiency savings associated with the various types of potential.

Market Characterization Approach

In order to estimate the savings potential from energy-efficient measures, it is necessary to understand how much energy is used today and what equipment is currently being used.

Segmentation for Modeling Purposes

The characterization begins with a segmentation of KCP&L's electricity footprint to quantify energy use by sector, segment, end-use application, and the current set of technologies used. The segmentation scheme for this project is presented in Table 1-1.

Table 1-1 Overview of KCP&L Analysis Segmentation Scheme

Dimension	Segmentation Variables	Description
1	Sector	Residential, Commercial, and Industrial
2	Segment	**Residential**: Single Family and Multifamily, further separated by service territory and Low Income/Regular Income **Commercial**: Small Office, Large Office, Restaurant, Retail, Grocery, College, School, Healthcare, Lodging, Warehouse, Data Center, Miscellaneous **Industrial**: Food Production, Chemicals & Pharmaceuticals, Transportation Equipment, Electronic Equipment, Stone-clay-and-glass, Primary Metals, Rubber & Plastics, Other Industrial
3	Vintage	Existing and New Construction
4	End uses	Cooling, Heating, Lighting, Water heat, motors, etc. (as appropriate by sector)
5	Appliances/technologies	Lamp type, air conditioning equipment, motors by application, etc.
6	Equipment efficiency levels for new purchases	Baseline and higher-efficiency options as appropriate for each technology

With the segmentation scheme defined, we then performed a high-level market characterization of electricity sales in the base year (2015) to allocate sales to each customer segment. We used KCP&L billing and customer data, residential and non-residential customer surveys, and secondary sources to allocate energy use and customers to the various sectors and segments such that the total customer count, energy consumption, and peak demand matched the KCP&L system totals from the 2015 billing data. This information provided control totals at a sector level for calibrating the LoadMAP model to known data for the base year.

Market Profile

The next step was to develop market profiles for each sector, customer segment, end use, and technology. A market profile includes the following elements:

- **Market size** is a representation of the number of customers in the segment. For the residential sector, it is number of households. The commercial sector is floor space measured in square feet and the industrial sector is number of employees.
- **Saturations** define the fraction of homes, square feet, or employees with the various technologies (e.g., homes with electric space heating).
- **UEC (unit energy consumption) or EUI (energy-use index)** describes the amount of energy consumed annually by a specific technology in buildings that have the technology. The UECs are expressed in kWh per household for the residential sector and EUIs are expressed in kWh per square foot or employees for the commercial and industrial sectors.
- **Annual energy intensity** represents the average energy use for the technology across all homes, floor space, or employees in 2015. The residential sector intensity is computed as the product of the saturation and the UEC. The commercial and industrial sector intensity is computed as the product of the saturation and the EUI.
- **Annual usage** is the annual energy use by an end-use technology in the segment. It is the product of the market size and intensity and is quantified in GWh.

- **Summer and winter peak demand** for each technology are calculated using peak fractions of annual energy use developed using KCP&L's system peak data and AEG's EnergyShape end-use load shape library.

Baseline Projection Approach

The next step was to develop the baseline projection of annual electricity use, summer peak demand, and winter peak demand for 2015 through 2037 by customer segment and end use without new utility programs. The end-use projection includes the relatively certain impacts of known and adopted legislation, as well as codes and standards that will unfold over the study timeframe. All such legislation and mandates that were finalized as of January 31, 2016 are included in the baseline. The baseline projection is the foundation for the analysis and is the metric against which potential savings are measured.

Inputs to the baseline projection include:

- Current economic growth forecasts (i.e., customer growth, income growth)
- Electricity price forecasts
- Trends in fuel shares and equipment saturations
- Existing and approved changes to building codes and equipment standards
- Known and adopted legislation
- Naturally occurring efficiency improvements, which include purchases of high-efficiency equipment options by early adopters.

AEG also developed a baseline projection for summer and winter peak by applying the peak fractions from the energy market profiles to the annual energy forecast in each year.

With a base year of 2015, and a potential analysis beginning in 2019, we also made adjustments to the intervening years in 2016-2018 to account for anticipated DSM program activity. This will drive more efficiency in the baseline for those three years than would be expected in a non-program case. Therefore, we made high-level adjustments to embed activity levels and purchase decisions equivalent to realistic achievable potential case in Residential Lighting, Heating, Cooling; C&I Lighting; and C&I Strategic Energy Management and Retrocommissioning measures. These are the major areas of planned KCP&L program savings during these years and will provide for a more accurate starting point in the baseline projection for 2019.

EE Measure Analysis Approach

This section describes the framework for the energy efficiency measure analysis. The framework, shown in Figure 1-1, involves identifying a list of energy efficiency measures to include in the analysis, determining their applicability to each market sector and segment, fully characterizing each measure, and performing cost-effectiveness screening.

A comprehensive list of energy efficiency and demand response measures was developed for each customer sector, drawing upon KCP&L's current programs, AEG's measure database, and measure lists developed from previous studies. The list of measures covers all major types of end-use equipment, as well as devices and actions to reduce energy consumption. Special focus was given to including the latest available data on emerging technologies from AEG's in-depth research and participation in technical working groups all over the nation. This includes recent evolutions in LED lighting, heat pump technologies, smart thermostats, behavioral research, and smart control systems; all of which are included in this study.

Each measure was characterized with energy and demand savings, incremental cost, effective useful life, and other performance factors, drawing upon data from AEG's DEEM measure database and well-vetted national and regional sources. We performed an economic screening of each measure, which serves as the basis for developing the economic and achievable potential, utilizing the measure information along with KCP&L's avoided cost data.

Approach for Energy Efficiency Measure Assessment

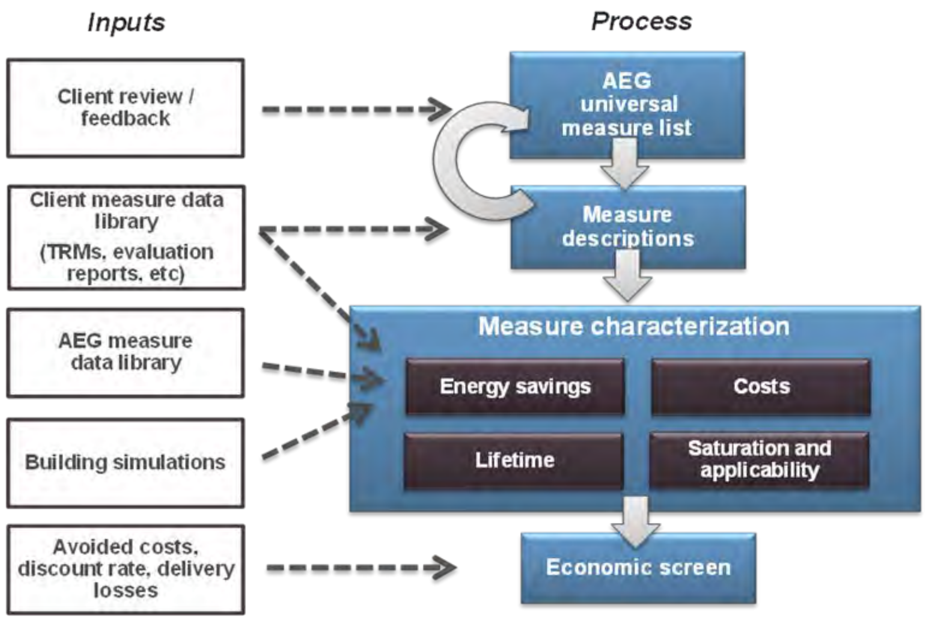

Figure 1-1 Approach for Energy Efficiency Measure Assessment

The selected measures are categorized into two types according to the LoadMAP taxonomy:

- **Equipment measures** are efficient energy-consuming pieces of equipment that save energy by providing the same service with a lower energy requirement than a standard unit. An example is an ENERGY STAR refrigerator that replaces a standard efficiency refrigerator. For equipment measures, many efficiency levels may be available for a given technology, ranging from the baseline unit (often determined by code or standard) up to the most efficient product commercially available. For instance, in the case of central air conditioners, this list begins with the current federal standard SEER 13 unit and spans a broad spectrum up to a maximum efficiency of a SEER 24 unit.
- **Non-equipment measures** save energy by reducing the need for delivered energy, but do not involve replacement or purchase of major end-use equipment (such as a refrigerator). An example would be a programmable thermostat that is pre-set to run heating and cooling systems only when people are home. Non-equipment measures can apply to more than one end use. For instance, wall insulation will affect the energy use of both space heating and cooling. Non-equipment measures typically fall into one of the following categories:
  - Building shell (windows, insulation, roofing material)
  - Equipment controls (thermostat, energy management system)
  - Equipment maintenance (cleaning filters, changing set-points)
  - Whole-building design (building orientation, passive solar lighting)
  - Commissioning and retro commissioning (monitoring of building energy systems)

Representative EE Measure Data Inputs

To provide an example of the measure data, Table 1-2 and Table 1-3 present examples of the detailed data inputs behind both equipment and non-equipment measures, respectively, for the case of residential central air conditioning (A/C) in single-family homes. Table 1-2 displays the various efficiency levels available as equipment measures, as well as the corresponding useful life, energy usage, and cost estimates. The columns labeled On Market and Off Market reflect equipment availability due to codes and standards or the entry of new products to the market.

Table 1-2 Example of Equipment Measures for Central A/C – Single Family Home, Existing

Efficiency Level	Useful Life	Equipment Cost	Base Year Energy Usage (kWh/yr)	On Market	Off Market
SEER 13.0	18	$1,022	2,162	2015	2037
SEER 14.0	18	$1,309	1,932	2015	2037
SEER 15.0	18	$1,597	1,984	2015	2037
SEER 16.0	18	$1,884	1,912	2015	2037
SEER 17.0	18	$2,172	1,849	2015	2037
SEER 18.0	18	$2,462	1,792	2015	2037
SEER 21.0	18	$3,216	1,655	2015	2037
SEER 24.0 Ductless, Var.Ref.Flow	18	$3,512	1,608	2015	2037

Table 1-3 lists some of the non-equipment measures applicable to Central A/C in an existing single-family home. All measures are evaluated for cost-effectiveness based on the lifetime benefits relative to the cost of the measure. The total savings and costs are calculated for each year of the study and depend on the base year saturation of the measure, the applicability[2] of the measure, and the savings as a percentage of the relevant energy end uses.

Table 1-3 Example of Non-Equipment Measure– Single Family Home, Existing

End Use	Measure	Saturation in 2015[3]	Applica-bility	Lifetime (yrs.)	Measure Installed Cost	Energy Savings (%)
Cooling	Insulation - Ceiling	49%	81%	25	$380	1%
Cooling	Ducting - Repair and Sealing	60%	75%	18	$453	4%
Cooling	Windows - High Eff/ENERGY STAR	26%	50%	25	$305	12%

Approach for Cost-effectiveness Screening of EE Measures

Only measures that are cost-effective were included in economic and achievable measure-level potential. Measures were first screened for cost-effectiveness within LoadMAP for inclusion in the economic and achievable potential scenarios. LoadMAP utilized the *Total Resource Cost Test* (TRC) test for measure-level cost-effectiveness screening (i.e., a TRC benefit-cost ratio of at least 1.0). The LoadMAP model performs this screening dynamically, taking into account changing savings and cost data over time. Thus, some measures pass the economic screen for some — but not all — years in the projection.

The TRC test is the primary method of assessing the cost-effectiveness of energy efficient measures that has been used across the United States for over twenty-five years. TRC measures the net costs and benefits of an energy efficiency program as a resource option based on the total costs of the measure, including both the participant's and the utility's costs. This test represents the combination of the effects of a program on both participating and non-participating customers.

Three other benefit-cost tests were calculated to analyze measure-level cost-effectiveness from different perspectives:

[2] The applicability factors take into account whether the measure is applicable to a particular building type and whether it is feasible to install the measure. For instance, attic fans are not applicable to homes where there is insufficient space in the attic or there is no attic at all.

[3] Note that saturation levels reflected for the base year change over time as more measures are adopted.

- *Participant Cost Test* quantifies the benefits and costs to the customer due to program participation.
- *Ratepayer Impact Measure Cost Test* measures what happens to a customer's rates due to changes in utility revenues and operating costs.
- *Utility Cost Test* measures the net costs of a measure as a resource option based on the costs incurred by the program administrator, excluding any net costs incurred by the participant.

It is important to note that the economic evaluation of every measure in the screen is conducted relative to a baseline condition. For instance, in order to determine the kilowatt-hour (kWh) savings potential of a measure, kWh consumption with the measure applied must be compared to the kWh consumption of a baseline condition. Also, if multiple equipment measures have B/C ratios greater than or equal to 1.0, the most efficient technology is selected by the economic screen.

Measures that are cost-effective within LoadMAP are included in the economic and achievable potential cases.

EE Potential

The approach we used to calculate the energy efficiency potential adheres to the approaches and conventions outlined in the National Action Plan for Energy-Efficiency (NAPEE) Guide for Conducting Potential Studies.[4] The NAPEE Guide represents the most credible and comprehensive industry practice for specifying energy efficiency potential.

The potential was estimated for the period from 2019 through 2037 to align with KCP&L's DSM regulatory schedule. This is the 20-year period that corresponds with KCP&L's next integrated resource plan.

The calculation of **Technical** and **Economic Potential** is a straightforward algorithm, phasing in the theoretical maximum efficiency units and screening them for cost-effective economics. To develop estimates for **Achievable Potential**, we develop market adoption rates for each measure in each year that specify the percentage of customers that will select the efficient, economic options.

Finally, we conducted a sensitivity analysis of key variables, including avoided costs, maximum opt-out rate for eligible large C&I customers in Missouri, and the effects of efficiency codes and standards on the baseline projection.

Data Development

This section details the data sources used in this study and describes how these sources were applied. In general, data was adapted to local conditions, for example, by using local sources for measure data and local weather for building simulations.

Data Sources

The data sources are organized into the following categories:

- Kansas City Power & Light Company data
- Energy efficiency measure data
- AEG's databases and analysis tools
- Other secondary data and reports

Kansas City Power & Light Company Data

Our highest priority data sources for this study were those that were specific to KCP&L.

[4] National Action Plan for Energy Efficiency (2007). *National Action Plan for Energy Efficiency Vision for 2025: Developing a Framework for Change*. www.epa.gov/eeactionplan.

- **KCP&L customer data:** KCP&L provided 2015 residential customer count and usage data as well as nonresidential billing data. The nonresidential billing data was (1) utilized to develop customer counts and energy use for the commercial and industrial segments and (2) SIC and NAICS information was analyzed to assist in development of the market segmentation.
- **Load forecasts:** KCP&L provided its most recent load and peak forecasts. KCP&L also provided an economic growth forecast by sector and electric load forecast by sector.
- **Economic information:** KCP&L provided a forecast of avoided costs, forecast of retail electricity rates by sector, discount rate, and line loss factor.
- **Additional Kansas City Power & Light program implementation and evaluation data**: KCP&L provided information about past and current DSM programs, including program descriptions, goals, and achievements to date.

Energy Efficiency Measure Data

Several sources of data were used to characterize the energy efficiency measures. We used the following national and well-vetted regional data sources and supplemented with AEG's data sources to fill in any gaps.

- **Appliance and Equipment Standards.** The study utilized data from the U.S. Department of Energy,[5] Energy Star[6] and the Consortium for Energy Efficiency[7] to determine baseline savings as well as efficient savings.
- **Illinois Technical Reference Manual.** Illinois Statewide Technical Reference Manual for Energy Efficiency, Version 5.0, effective June 1, 2016.
- **Northwest Power and Conservation Council workbooks.** To develop its Power Plan, the Council and its Regional Technical Forum maintain workbooks with detailed information about measures.

AEG Data

AEG maintains several databases and modeling tools that we use for forecasting and potential studies. Relevant data from these tools has been incorporated into the analysis and deliverables for this study.

- **AEG Energy Market Profiles**: For more than 10 years, AEG staff has maintained profiles of end-use consumption for the residential, commercial and industrial sectors. These profiles include market size, fuel shares, unit consumption estimates, and annual energy use, customer segment and end use for 10 regions in the United States. The Energy Information Administration surveys (RECS, CBECS and MECS) as well as state-level statistics and local customer research provide the foundation for these regional profiles.
- **Building Energy Simulation Tool (BEST)**. AEG's BEST is a derivative of the DOE 2.2 building simulation model, used to estimate base-year UECs and EUIs, as well as measure savings for the HVAC-related measures.
- **AEG's EnergyShape™:** This database of load shapes includes the following:
  - Residential – electric load shapes for ten regions, three housing types, 13 end uses
  - Nonresidential – electric load shapes for nine regions, 54 building types, ten end uses
- **AEG's Database of Energy Efficiency Measures (DEEM):** AEG maintains an extensive database of existing and emerging measures for our studies. Our database draws upon reliable sources including the California Database for Energy Efficient Resources (DEER), the EIA Technology

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[5] U.S. Department of Energy. Current Rulemakings and Notices. http://energy.gov/eere/buildings/current-rulemakings-and-notices

[6] Energy Star. Product Specifications and Partner Commitments Search. http://www.energystar.gov/products/spec/

[7] Consortium for Energy Efficiency. Program Resources. https://www.cee1.org/

Forecast Updates – Residential and Nonresidential Building Technologies – Reference Case, RS Means cost data, and Grainger Catalog Cost data.

- **Recent studies**. AEG has conducted numerous studies of EE potential in the last five years. We checked our input assumptions and analysis results against the results from these other studies, which include Ameren Illinois, Indianapolis Power & Light, NIPSCO, Indiana Michigan Power, PacifiCorp, and Vectren Energy. In addition, we used the information about impacts of building codes and appliance standards from recent reports for the Edison Electric Institute.[8]

Other Secondary Data

Finally, a variety of secondary data sources and reports were used for this study. The main sources are identified below.

- **Annual Energy Outlook**. The Annual Energy Outlook (AEO), conducted each year by the U.S. Energy Information Administration (EIA), presents yearly projections and analysis of energy topics. For this study, we used data from the 2015 AEO.
- **American Community Survey.** The US Census American Community Survey is an ongoing survey that provides data every year on household characteristics.
- **Local Weather Data:** Weather from NOAA's National Climatic Data Center for Kansas City was used as the basis for building simulations.
- **EPRI End-Use Models (REEPS and COMMEND)**. These models provide the energy-use elasticities we apply to electricity prices, household income, home size and heating and cooling.
- **Other relevant regional sources:** These include reports from the Consortium for Energy Efficiency, the EPA, and the American Council for an Energy-Efficient Economy.

Data Application

We now discuss how the data sources described above were used for each step of the study.

Data Application for Market Characterization

To construct the high-level market characterization of electricity use and households/floor space for the residential, commercial and industrial sectors, we used KCP&L billing data and secondary data.

- For the residential sector, AEG estimated the numbers of customers and the average energy use per customer for each segment based on KCP&L's 2015 residential sales data. Low income customers were identified from the American Community Survey and allocated to a housing type based upon KCP&L-specific data on customers that receive energy assistance.
- For the commercial and industrial sectors, AEG estimated sales by segment based on KCP&L 2015 customer billing data.

Data Application for Market Profiles

The specific data elements for the market profiles, together with the key data sources, are shown in Table 1-4. To develop the market profiles for each segment, we used the following approach:

1. Develop control totals for each segment. These include market size, segment-level annual electricity use, and annual intensity.
2. Utilize the results of AEG's Energy Market Profiles database to develop existing appliance saturations, appliance and equipment characteristics, and building characteristics. We also incorporated secondary sources to supplement and corroborate the data.

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[8] AEG staff has prepared three white papers on the topic of factors that affect U.S. electricity consumption, including appliance standards and building codes. Links to all three white papers are provided:
http://www.edisonfoundation.net/IEE/Documents/IEE_RohmundApplianceStandardsEfficiencyCodes1209.pdf
http://www.edisonfoundation.net/iee/Documents/IEE_CodesandStandardsAssessment_2010-2025_UPDATE.pdf.
http://www.edisonfoundation.net/iee/Documents/IEE_FactorsAffectingUSElecConsumption_Final.pdf

3. Ensure calibration to control totals for annual electricity sales in each sector and segment.
4. Compare and cross-check with other recent AEG studies.
5. Work with KCP&L staff to vet the data against their knowledge and experience.

Table 1-4 Data Applied for the Market Profiles

Model Inputs	Description	Key Sources
Market size	Base-year residential dwellings and commercial floor space, industrial employment	KCP&L billing data AEO 2015
Annual intensity	Residential: Annual use per household Commercial: Annual use per square foot Industrial: Annual use per employee	KCP&L billing data AEG's Energy Market Profiles AEO 2015 Other recent studies
Appliance/equipment saturations	Fraction of dwellings with an appliance/technology Percentage of commercial floor space/employment with technology	AEG's Energy Market Profiles Other recent studies
UEC/EUI for each end-use technology	UEC: Annual electricity use in homes and buildings that have the technology EUI: Annual electricity use per square foot/employee for a technology in floor space that has the technology	HVAC uses: BEST simulations using prototypes developed for KCP&L Engineering analysis AEG's DEEM Recent AEG studies AEO 2015
Appliance/equipment age distribution	Age distribution for each technology	AEG's DEEM Recent AEG studies
Efficiency options for each technology	List of available efficiency options and annual energy use for each technology	KCP&L DSM programs AEG's DEEM AEO 2015 Recent AEG studies
Peak factors	Share of technology energy use that occurs during the system peak hour	KCP&L system peak AEG's EnergyShape database

Data Application for Baseline Projection

Table 1-5 summarizes the LoadMAP model inputs required for the baseline projection. These inputs are required for each segment within each sector for existing dwellings/buildings as well as new construction.

Table 1-5 Data Needs for the Baseline Projection and Potential Estimates in LoadMAP

Model Inputs	Description	Key Sources
Customer growth forecasts	Forecasts of new construction in residential, commercial and industrial sectors	KCP&L load forecast AEO 2015 economic growth forecast
Equipment purchase shares for baseline projection	For each equipment/technology, purchase shares for each efficiency level; specified separately for existing equipment replacement and new construction	Shipments data from AEO AEO 2015 regional forecast assumptions[9] Appliance/efficiency standards analysis KCP&L DSM program and evaluation reports
Electricity prices	Forecast of average energy and capacity avoided costs and retail prices	KCP&L forecast

We implemented assumptions for known future equipment standards as of January 2016, as shown in Table 1-6 and Table 1-7 for the respective sectors. The assumptions tables here extend through 2025, after which all standards are assumed to hold steady.

Table 1-6 Residential Electric Equipment Standards[10]

<table>
<tr><th>End Use</th><th>Technology</th><th>2015</th><th>2016</th><th>2017</th><th>2018</th><th>2019</th><th>2020</th><th>2021</th><th>2022</th><th>2023</th><th>2024</th><th>2025</th></tr>
<tr><td rowspan="2">Cooling</td><td>Central AC</td><td colspan="11">SEER 13</td></tr>
<tr><td>Room AC</td><td colspan="11">EER 11.0</td></tr>
<tr><td>Cooling/Heating</td><td>Heat Pump</td><td colspan="11">SEER 14.0/HSPF 8.0</td></tr>
<tr><td rowspan="2">Water Heating</td><td>Water Heater (<=55 gallons)</td><td colspan="11">EF 0.95</td></tr>
<tr><td>Water Heater (>55 gallons)</td><td colspan="11">Heat Pump Water Heater</td></tr>
<tr><td rowspan="2">Lighting</td><td>Screw-in/Pin Lamps</td><td colspan="5">Advanced Incandescent (20 lumens/watt)</td><td colspan="6">Advanced Incandescent (45 lumens/watt)</td></tr>
<tr><td>Linear Fluorescent</td><td colspan="3">T8 (89 lumens/watt)</td><td colspan="8">T8 (92.5 lumens/watt)</td></tr>
<tr><td rowspan="4">Appliances</td><td>Refrigerator</td><td colspan="11">NAECA Standard</td></tr>
<tr><td>Freezer</td><td colspan="11">NAECA Standard</td></tr>
<tr><td>Clothes Washer</td><td colspan="3">1.29 IMEF top loader</td><td colspan="8">1.57 IMEF top loader</td></tr>
<tr><td>Clothes Dryer</td><td colspan="11">3.73 Combined EF</td></tr>
<tr><td>Miscellaneous</td><td>Furnace Fans</td><td colspan="4">Conventional</td><td colspan="7">40% more efficient</td></tr>
</table>

[9] We developed baseline purchase decisions using the Energy Information Agency's AEO 2015, which utilizes the National Energy Modeling System (NEMS) to produce a self-consistent supply and demand economic model. We calibrated equipment purchase options to match manufacturer shipment data for recent years and then held values constant for the study period. This removes any effects of naturally occurring conservation or effects of future programs that may be embedded in the AEO forecasts.

[10] The assumptions tables here extend through 2025, after which all standards are assumed to hold steady.

Table 1-7 Commercial and Industrial Electric Equipment Standards

Technology	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Chillers	2007 ASHRAE 90.1										
Roof Top Units	EER 11.0/11.2										
PTAC	EER 11.7		EER 11.9								
Heat Pump	EER 11.0/COP 3.3										
PTHP	EER 11.9/COP 3.3										
Ventilation	Constant Air Volume/Variable Air Volume										
Screw-in/Pin Lamps	Advanced Incandescent (20					Advanced Incandescent (45 lumens/watt)					
Linear Fluorescent	T8 (89 lumens/watt)			T8 (92.5 lumens/watt)							
High Intensity Discharge	EPACT 2005		Metal Halide Ballast Improvement								
Water Heater	EF 0.97										
Walk-in Refrigerator/Freezer	EISA 2007		10-38% more efficient								
Reach-in	EPACT 2005		40% more efficient								
Glass Door Display	EPACT 2005		12-28% more efficient								
Open Display Case	EPACT 2005		10-20% more efficient								
Ice maker	EPACT 2005			15% more efficient							
Pre-rinse Spray Valve	1.6 GPM				1.0 GPM						
Motors	EISA 2007	Expanded EISA 2007									

Energy Efficiency Measure Data Analysis

Table 1-8 details the energy-efficiency data inputs to the LoadMAP model. It describes each input and identifies the key sources used in the KCP&L analysis.

Table 1-8 Data Needs for the Measure Characterization in LoadMAP

Model Inputs	Description	Key Sources
Energy Impacts	The annual reduction in consumption attributable to each specific measure. Savings were developed as a percentage of the energy end use that the measure affects.	BEST AEG's DEEM AEO 2015 Other secondary sources
Peak Demand Impacts	Savings during the peak demand periods are specified for each electric measure. These impacts relate to the energy savings and depend on the extent to which each measure is coincident with the system peak.	BEST AEG's DEEM AEG EnergyShape
Costs	Equipment Measures: Includes the full cost of purchasing and installing the equipment on a per-unit basis. Non-equipment measures: Existing buildings – full installed cost. New Construction - the costs may be either the full cost of the measure, or as appropriate, it may be the incremental cost of upgrading from a standard level to a higher efficiency level.	AEG's DEEM AEO 2015 RS Means Other secondary sources
Measure Lifetimes	Estimates derived from the technical data and secondary data sources that support the measure demand and energy savings analysis.	AEG's DEEM AEO 2015 Other secondary sources
Applicability	Estimate of the percentage of dwellings in the residential sector, square feet in the commercial sector or employees in the industrial sector where the measure is applicable and where it is technically feasible to implement.	AEG's DEEM Other secondary sources
On Market and Off Market Availability	Expressed as years for equipment measures to reflect when the equipment technology is available or no longer available in the market.	AEG appliance standards and building codes analysis

Data Application for Cost Effectiveness Screening

To perform the cost-effectiveness screening, a number of economic assumptions were needed. All cost and benefit values were analyzed as real 2015 dollars. We used proprietary projections of avoided cost values provided by KCP&L and applied a discount rate provided by KCP&L in real dollars to all future cash flows. Avoided energy costs are the expected values derived from electricity price curves with low, mid, and high natural gas price assumptions as used in the Company's most recent integrated resource planning (IRP) update. Avoided capacity costs are the Company's most recent estimate of annual levelized capital cost for a new combustion turbine generator with the cost of a firm contract to supply natural gas to the plant. Note that the status of the Clean Power Plan is still in flux at the time of this analysis and therefore was not specifically considered. Reference case avoided costs do not include estimates of carbon emission costs, but the first sensitivity analysis does.

All impacts in this report are presented at the customer meter. Line losses were used to gross impacts up to the generator for the purposes of cost-effectiveness testing.

Achievable Potential Estimation

To estimate achievable potential, two sets of parameters are needed to represent customer decision making behavior with respect to energy-efficiency choices.

- **Technical diffusion curves for non-equipment measures**. Equipment measures are installed in our modeling process when existing units fail according to the stock accounting algorithms. Non-equipment measures do not have this natural periodicity, so rather than installing all available non-equipment measures in the first year of the projection (instantaneous potential), they are phased in according to adoption schedules over the timeline of the study that generally align with the diffusion of similar equipment measures.
- **Achievable adoption rates.** Customer adoption rates or take rates are applied to Economic potential to estimate two levels of Achievable Potential (Realistic and Maximum). These rates were developed based on program benchmarking, KCP&L program achievements in the near term, and market research and evaluation analyses conducted by AEG in the Midwest and around the nation. AEG mapped these adoption rates to all measures in the modeling universe.

  Note that in the study's reference case, the C&I take rates were adjusted downward to reflect the fact that large C&I customers in Missouri that have opted out are not eligible to participate in EE programs. The adoption rates were reduced by an amount proportional to the respective amount of base-year total energy in each C&I segment that had opted out as of the time of the study. This results in commercial adoption rates being adjusted downward by approximately 15% in Missouri, and corresponding industrial rates downward by approximately 40%. The associated achievable savings potential reflects the downward adjustment. Realistic and Maximum Achievable adoption rates for the Reference Case are presented in Volume 5, Appendices.

MARKET CHARACTERIZATION

In order to estimate the savings potential from energy-efficient measures, it is necessary to understand how much energy is used today and what equipment is currently being used.

ENERGY USE SUMMARY

Total electricity use for the residential, commercial, and industrial sectors for KCP&L in 2015 was 22,553 GWh. As shown in Figure 1-2 the commercial and residential sectors are nearly equal, with 39% and 38% of use respectively. Industrial is slightly smaller in terms of overall consumption, at 23%. In terms of peak demand, the total summer system peak in 2015 was 5,302 MW and winter peak was 4,250 MW. The residential sector has the highest contribution to peak. This is due to the high peak coincidence and healthy saturation of air conditioning equipment and electric heating.

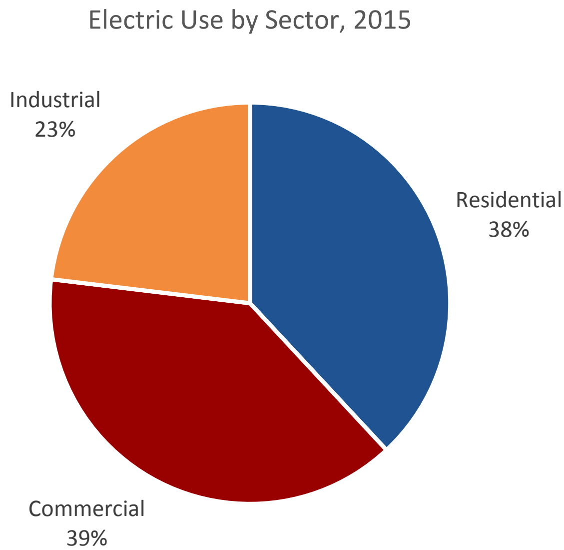

Figure 1-2 KCP&L Electricity Use by Sector, 2015

Table 1-9 KCP&L Electricity Use by Sector, 2015

Sector	Annual Electricity Use (GWh)	% of Sales	Summer Peak Demand (MW)	Winter Peak Demand (MW)
Residential	8,585	38%	2,786	2,043
Commercial	8,760	39%	1,578	1,384
Industrial	5,208	23%	938	823
Total	**22,553**	**100%**	**5,302**	**4,250**

Residential Market Characterization

The total number of households and residential electricity sales for the service territory were obtained from KCP&L's customer database. The first step was to allocate total residential sector customers and sales into four segments within each of KCP&L's four territories. These segments are: Single Family, Multifamily, Single Family Low Income (LI), and Multifamily Low Income (LI). AEG adjusted the number of customers and usage in each segment based on KCP&L's billing data and all reported residential energy sales in 2015.[11] In 2015, there were 742,047 households in the KCP&L territory that used a total of 8,585 GWh with a summer peak demand of 2,786 MW. The average use per customer (or household) of 11,569 kWh is relatively close to the national average. AEG allocated these totals into a total of 16 segments, with separate segments for each territory, as shown in Table 1-10 below.

[11] Low income customers were identified through our market research surveys as those respondents with an annual household income of $30,000 or less. This is based on the eligibility for KCP&L's current Income-Eligible Weatherization Program, which is about 200% of the Federal Poverty Income Guideline for a family of two.

Table 1-10 KCP&L Residential Sector Control Totals

Segment	Households	Electricity Sales (GWh)	% of Total Usage	Avg. Use / Household (kWh)	Summer Peak Demand (MW)	Winter Peak Demand (MW)
KCP&L-KS - Single Family	131,919	2,011	23%	15,241	707	443
KCP&L-KS - Multifamily	36,770	310	4%	8,433	70	92
KCP&L-KS - Single Family LI	20,344	237	3%	11,649	85	54
KCP&L-KS - Multifamily LI	30,983	181	2%	5,849	42	54
KCP&L-MO - Single Family	125,094	1,580	18%	12,630	585	341
KCP&L-MO - Multifamily	48,095	346	4%	7,194	87	95
KCP&L-MO - Single Family LI	36,401	343	4%	9,424	130	73
KCP&L-MO - Multifamily LI	33,702	205	2%	6,083	53	59
GMO-MPS - Single Family	138,198	1,942	23%	14,053	613	465
GMO-MPS - Multifamily	14,845	95	1%	6,420	23	27
GMO-MPS - Single Family LI	43,406	493	6%	11,359	155	121
GMO-MPS - Multifamily LI	24,607	135	2%	5,480	32	40
GMO-SJLP - Single Family	30,475	442	5%	14,505	131	111
GMO-SJLP - Multifamily	6,946	64	1%	9,284	13	19
GMO-SJLP - Single Family LI	14,802	162	2%	10,916	52	39
GMO-SJLP - Multifamily LI	5,461	38	0%	7,019	8	11
Total	**742,047**	**8,585**	**100%**	**11,569**	**2,786**	**2,043**

Figure 1-3 shows the distribution of annual electricity use by segment.

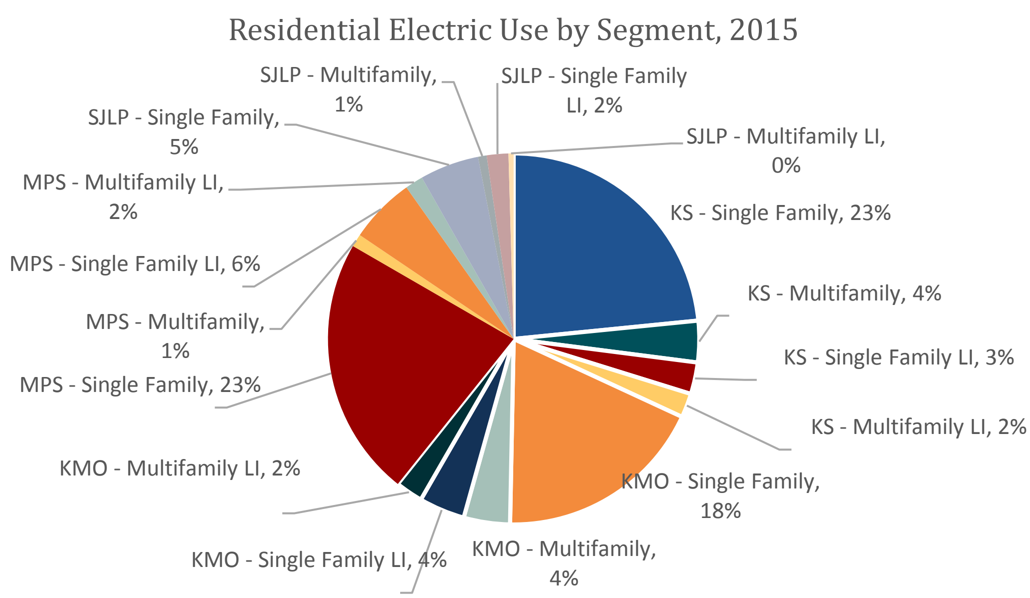

Figure 1-3 Residential Sector Electricity Use 2015

Three main electricity end uses – cooling, heating and appliances – together compose 65% of total residential electric use, as shown in Figure 1-4. Appliances include refrigerators, freezers, clothes dryers, dishwashers, and microwaves. The remainder of the energy falls into the electronics, lighting, water heating, and miscellaneous categories. Miscellaneous is used as a catch-all category for things such as furnace fans, pool pumps, and other "plug" loads not explicitly specified such as coffee makers, hair dryers, power tools, etc.

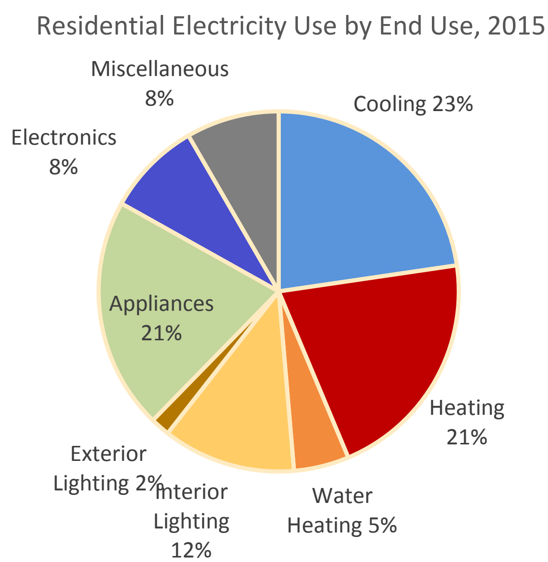

Figure 1-4 Residential Electricity Use by End Use, 2015

Figure 1-5 presents the electricity intensities by end use and housing type. Single family homes use more energy than multifamily homes, and consequently have more available potential. Households designated as low income homes use slightly less energy than homes not in that category. There is also variance across KCP&L's territories, as electric heating and water heating are more prevalent some areas than others.

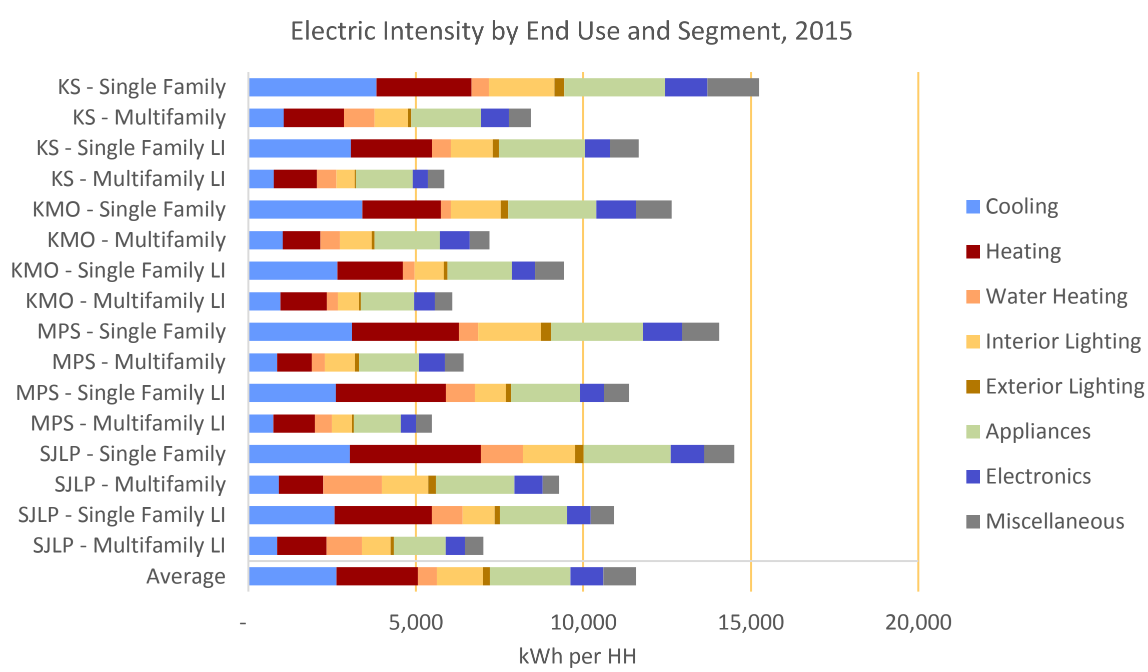

Figure 1-5 Residential Sector Electric Intensity by End use and Segment

Market profiles, the distribution of end-use technologies and average use for those technologies across the population, are the foundation for development of the baseline projection and the potential estimates. The average market profile for the residential sector as a whole is presented in Table 1-11 below. Segment-specific market profiles are presented in Volume 5, Appendices.

Table 1-11 Residential Average Market Profile

End Use	Technology	Saturation	UEC (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	81.7%	2,881	2,353	1,745.8
Cooling	Room AC	7.4%	1,154	85	63.4
Cooling	Air-Source Heat Pump	5.4%	3,038	163	121.0
Cooling	Geothermal Heat Pump	0.9%	2,642	23	17.1
Heating	Electric Room Heat	3.7%	3,307	121	89.7
Heating	Electric Furnace	28.7%	6,549	1,879	1,394.5
Heating	Air-Source Heat Pump	5.4%	7,505	403	298.9
Heating	Geothermal Heat Pump	0.9%	3,065	27	19.8
Water Heating	Water Heater <= 55 Gal	18.3%	2,990	547	406.2
Water Heating	Water Heater > 55 Gal	0.8%	3,256	26	19.4
Interior Lighting	General Service Screw-In	100.0%	1,004	1,004	745.2
Interior Lighting	Linear Lighting	100.0%	85	85	63.3
Interior Lighting	Exempted Screw-In	100.0%	290	290	215.6
Exterior Lighting	Screw-in	100.0%	201	201	149.5
Appliances	Clothes Washer	85.3%	84	71	52.9
Appliances	Clothes Dryer	77.0%	741	570	423.2
Appliances	Dishwasher	77.3%	384	297	220.7
Appliances	Refrigerator	99.8%	714	712	528.6
Appliances	Freezer	27.7%	571	158	117.3
Appliances	Second Refrigerator	27.2%	835	228	168.8
Appliances	Stove/Oven	55.3%	451	249	185.0
Appliances	Microwave	98.4%	122	120	89.4
Electronics	Personal Computers	51.7%	166	86	63.9
Electronics	Monitor	47.7%	70	34	24.9
Electronics	Laptops	96.4%	44	42	31.4
Electronics	TVs	239.2%	150	359	266.4
Electronics	Printer/Fax/Copier	72.5%	59	42	31.5
Electronics	Set top Boxes/DVRs	130.7%	104	136	100.7
Electronics	Devices and Gadgets	287.9%	100	287	213.2
Miscellaneous	Electric Vehicles	0.8%	3,527	30	22.0
Miscellaneous	Pool Pump	2.2%	1,350	29	21.7
Miscellaneous	Pool Heater	2.2%	1,356	29	21.8
Miscellaneous	Hot Tub/Spa	3.4%	1,974	67	49.4
Miscellaneous	Furnace Fan	76.6%	555	426	315.8
Miscellaneous	Well pump	2.0%	554	11	8.1
Miscellaneous	Miscellaneous	100.0%	375	375	278.4
Total				**11,569**	**8,584.6**

COMMERCIAL MARKET CHARACTERIZATION

The first step in developing the commercial market profile was to allocate total commercial customers and sales into eleven segments, shown in Table 1-12. The total electric energy consumed by commercial customers in KCP&L's service area in 2015 was 8,760 GWh. The average intensity of use was 15.3 kWh/square foot. With fewer survey completions than the residential sector and less anticipated heterogeneity among customers, we modeled the non-residential customers as a whole and make territory-specific calculations using pro-rata shares.

A Note on Opt Out Customers

Missouri regulations allow large C&I customers that meet size and eligibility requirements to opt out of energy efficiency programs. For purposes of this study, we maintain all customers in the baseline control totals and market characterization, but identify the portion of opt out load which allows us to remove them downstream from program participation as appropriate in the achievable potential cases. The removal and adjustment was done on a per-segment basis, using KCP&L's list of opt out customers.

Table 1-12 Commercial Control Totals

Segment	Electricity Sales (GWh)	% of Total Usage	Avg. Use / Square Foot (kWh/SqFt)	Summer Peak Demand (MW)	Winter Peak Demand (MW)
Small Office	778	8.9%	13.1	102	143
Large Office	488	5.6%	14.5	64	76
Restaurant	576	6.6%	38.6	80	81
Retail	638	7.3%	12.8	105	96
Grocery	470	5.4%	54.8	60	49
School	842	9.6%	12.8	297	92
College	646	7.4%	17.5	116	110
Healthcare	1,138	13.0%	20.4	132	239
Lodging	298	3.4%	17.2	30	36
Data Center	1,103	12.6%	112.7	160	152
Warehouse	529	6.0%	9.7	216	73
Miscellaneous	1,253	14.3%	7.5	218	238
Total	**8,760**	**100.0%**	**15.3**	**1,578**	**1,384**

Figure 1-6 and Figure 1-7 show the breakdown of commercial electric use by segment and by end use, respectively. The bulk of commercial use is in HVAC (38% combined) and lighting (31%). Other end uses are highly variable and generally dominant in a certain type of business, such as refrigeration in the grocery segment, or office equipment in large offices and data centers.

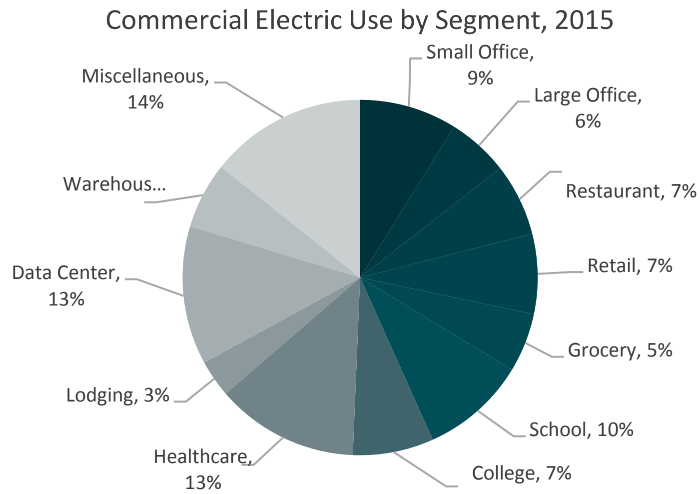

Figure 1-6 Commercial Energy Use by Segment

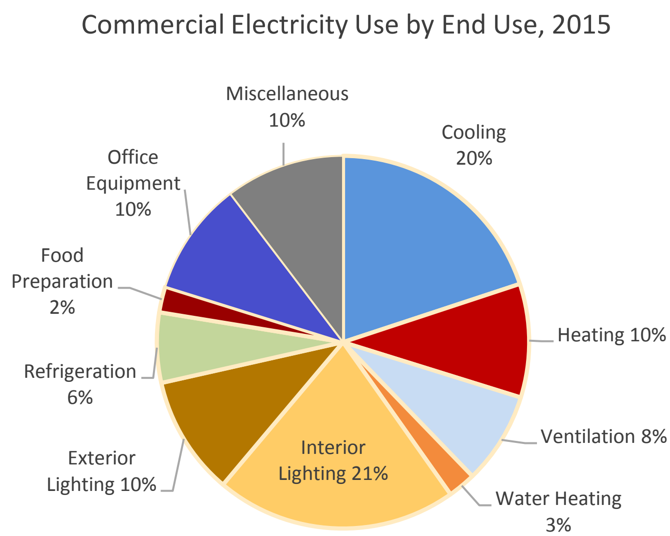

Figure 1-7 Commercial Energy Use by End Use

The miscellaneous building segment is the largest segment in terms of total square feet of building space in the KCP&L service territory, however, the grocery, restaurant and data center segments are highest in terms of electricity use per square feet due to the concentration of high-intensity end uses in those segments, as shown in Figure 1-8.

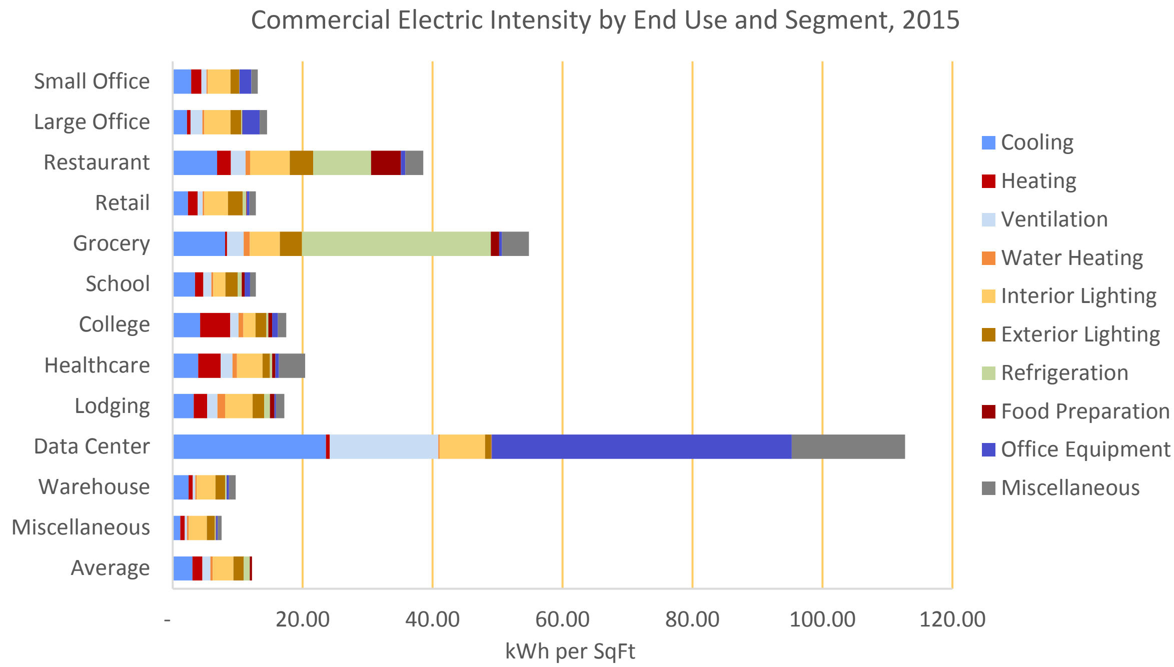

Figure 1-8 Commercial Electric Intensity

The average market profile for the commercial sector is presented in Table 1-13. Segment-specific market profiles are presented in Volume 5, Appendices.

Table 1-13 Average Commercial Market Profile

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/SqFt)	Usage (GWh)
Cooling	Air-Cooled Chiller	4.0%	4.37	0.18	101.1
Cooling	Water-Cooled Chiller	12.4%	6.54	0.81	465.9
Cooling	RTU	52.9%	3.55	1.88	1,076.5
Cooling	Room AC	2.0%	4.27	0.08	48.6
Cooling	Air-Source Heat Pump	2.2%	4.13	0.09	52.8
Cooling	Geothermal Heat Pump	0.2%	1.43	0.00	1.8
Heating	Electric Furnace	22.7%	5.74	1.30	745.1
Heating	Electric Room Heat	2.5%	4.78	0.12	69.0
Heating	Air-Source Heat Pump	2.2%	3.69	0.08	47.1
Heating	Geothermal Heat Pump	0.2%	1.92	0.00	2.4
Ventilation	Ventilation	100.0%	1.22	1.22	698.5
Water Heating	Water Heater	38.4%	0.97	0.37	212.9
Interior Lighting	Screw-in	100.0%	0.59	0.59	340.4
Interior Lighting	High-Bay Fixtures	100.0%	1.24	1.24	711.7
Interior Lighting	Linear Lighting	100.0%	1.37	1.37	782.9
Exterior Lighting	Screw-in	100.0%	0.40	0.40	228.8
Exterior Lighting	Area Lighting	100.0%	0.86	0.86	490.5
Exterior Lighting	Linear Lighting	100.0%	0.33	0.33	186.6
Refrigeration	Walk-in Refrigerator/Freezer	13.9%	0.84	0.12	66.6
Refrigeration	Reach-in Refrigerator/Freezer	12.6%	0.28	0.04	20.1
Refrigeration	Glass Door Display	33.3%	0.38	0.13	72.2
Refrigeration	Open Display Case	5.4%	8.44	0.46	261.4
Refrigeration	Icemaker	46.8%	0.32	0.15	86.0
Refrigeration	Vending Machine	34.1%	0.14	0.05	26.5
Food Preparation	Range/Oven	37.1%	0.24	0.09	51.8
Food Preparation	Fryer	8.8%	0.36	0.03	18.0
Food Preparation	Dishwasher	18.5%	0.43	0.08	45.6
Food Preparation	Hot Food Container	14.0%	0.05	0.01	4.1
Food Preparation	Steamer	6.8%	0.25	0.02	9.7
Food Preparation	Griddle	11.0%	0.18	0.02	11.2
Food Preparation	Broiler	36.4%	0.27	0.10	56.1
Office Equipment	Desktop Computer	94.0%	0.53	0.49	283.0
Office Equipment	Laptop	80.0%	0.07	0.05	30.4
Office Equipment	Server	44.4%	1.82	0.81	464.5
Office Equipment	Monitor	75.2%	0.10	0.07	41.6
Office Equipment	Printer/Copier/Fax	94.0%	0.06	0.06	32.5
Office Equipment	POS Terminal	36.5%	0.05	0.02	9.7
Miscellaneous	Non-HVAC Motors	5.2%	0.56	0.03	16.7
Miscellaneous	Pool Pump	13.3%	0.03	0.00	2.1
Miscellaneous	Pool Heater	9.8%	0.04	0.00	2.2
Miscellaneous	Other Miscellaneous	100.0%	1.55	1.55	885.8
Total				**15.29**	**8,760.4**

INDUSTRIAL MARKET CHARACTERIZATION

The industrial sector contributed 5,208 GWh of sales in 2015, somewhat smaller than both the residential and commercial sectors. As is discussed in the commercial section above, several large C&I customers have opted out of KCP&L's energy efficiency programs. These customers and their usage are included in the base year market characterization and the control totals. AEG addresses the lack of opt out customer participation by adjusting the participation rates for the achievable potential cases.

Table 1-14 Industrial Control Totals

Segment	Electricity Sales (GWh)	% of Total Usage	Summer Peak Demand (MW)	Winter Peak Demand (MW)
Food Production	894	17%	128	146
Chemicals & Pharmaceuticals	755	14%	106	122
Transportation Equipment	498	10%	120	70
Electronic Equipment	484	9%	120	73
Stone, clay, glass	428	8%	57	70
Primary Metals	405	8%	48	68
Rubber & Plastics	262	5%	41	42
Other Industrial	1,482	28%	318	231
Total	**5,208**	**100%**	**938**	**823**

Figure 1-9 and Figure 1-10 show the breakdown of industrial electric use by segment and by end use, respectively. Motors are the largest overall end use for the industrial sector, accounting for 45% of energy use. Note that this end use includes a wide range of industrial equipment, such as air compressors and refrigeration compressors, pumps, conveyor motors, and fans. The process end use accounts for 26% of annual energy use, which includes heating, cooling, refrigeration, and electro-chemical processes.

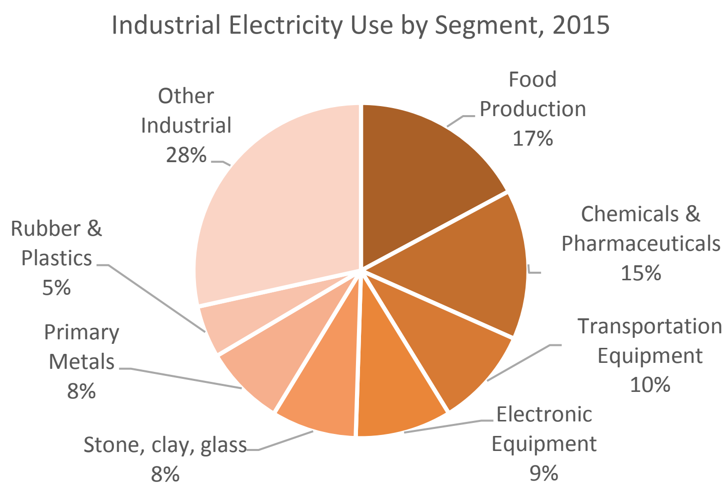

Figure 1-9 Industrial Electricity Use by Segment

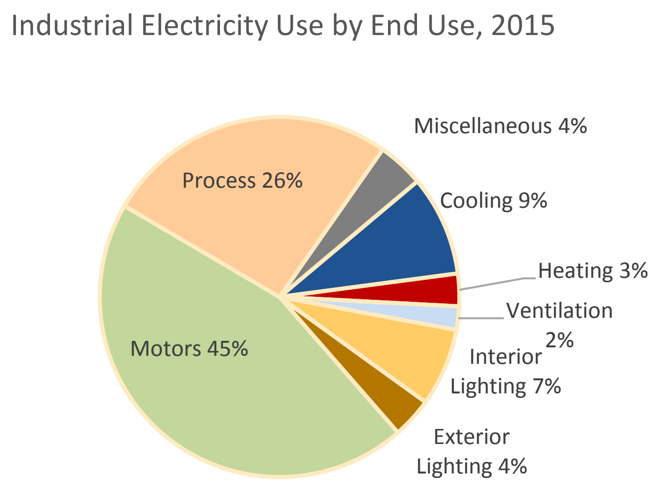

Figure 1-10 Industrial Energy Use by End Use

The average market profile for the industrial sector is presented in Table 1-15. Segment-specific market profiles are presented in Volume 5, Appendices.

Table 1-15 Average Industrial Market Profile

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Employee)	Usage (GWh)
Cooling	Air-Cooled Chiller	2.3%	8,885	203	27.9
Cooling	Water-Cooled Chiller	17.6%	8,245	1,449	198.6
Cooling	RTU	14.7%	11,618	1,704	233.5
Cooling	Air-Source Heat Pump	0.7%	9,709	72	9.9
Cooling	Geothermal Heat Pump	0.0%	7,198	1	0.1
Heating	Electric Furnace	2.5%	25,478	640	87.7
Heating	Electric Room Heat	0.3%	85,896	278	38.1
Heating	Air-Source Heat Pump	0.7%	25,804	191	26.2
Heating	Geothermal Heat Pump	0.0%	24,684	2	0.2
Ventilation	Ventilation	100.0%	799	799	109.5
Interior Lighting	Screw-in	100.0%	274	274	37.5
Interior Lighting	High-Bay Fixtures	100.0%	1,658	1,658	227.3
Interior Lighting	Linear Lighting	100.0%	726	726	99.5
Exterior Lighting	Screw-in	100.0%	341	341	46.7
Exterior Lighting	Area Lighting	100.0%	899	899	123.2
Exterior Lighting	Linear Lighting	100.0%	146	146	20.0
Motors	Pumps	100.0%	3,972	3,972	544.4
Motors	Fans & Blowers	100.0%	2,805	2,805	384.5
Motors	Compressed Air	100.0%	2,819	2,819	386.4
Motors	Material Handling	100.0%	6,778	6,778	929.1
Motors	Other Motors	100.0%	674	674	92.4
Process	Process Heating	100.0%	4,935	4,935	676.5
Process	Process Cooling	100.0%	1,813	1,813	248.5
Process	Process Refrigeration	100.0%	1,813	1,813	248.5
Process	Process Electrochemical	100.0%	829	829	113.6
Process	Process Other	100.0%	592	592	81.1
Miscellaneous	Miscellaneous	100.0%	1,584	1,584	217.2
Total				**37,995**	**5,208.1**

Baseline Projection

The next step was to develop the baseline projection of annual electricity use, summer peak demand, and winter peak demand for 2015 through 2037 by customer segment and end use without new utility programs. The end-use projection includes the relatively certain impacts of known and adopted legislation as well as codes and standards that will unfold over the study timeframe. All such legislation and mandates that were defined as of January 31, 2016 are included in the baseline. Note that the status of the Clean Power Plan was still in flux at the time of this analysis and therefore was not specifically considered. The baseline projection is the foundation for the analysis and is the metric against which potential savings are measured.

Inputs to the baseline projection include:

- Current economic growth forecasts (i.e., customer growth, income growth)
- Electricity price forecasts

- Trends in fuel shares and equipment saturations
- Existing and approved changes to building codes and equipment standards
- Known and adopted legislation
- Naturally occurring efficiency improvements, which include purchases of high-efficiency equipment options by early adopters

AEG also developed a baseline projection for summer and winter peak by applying the peak fractions from the energy market profiles to the annual energy forecast in each year.

Although it aligns closely, the baseline projection for this study is not KCP&L's official load forecast as presented in the Company's most recent 4 CSR 240-22 triennial compliance filing in 2015. Rather, it was developed within the potential modeling framework to serve as the metric against which DSM potentials are measured. Energy usage levels are generally within a few percentage points in any given year, but reasons why these baseline projections differ include: different economic outlook; changes in customer counts, usage, and growth expectations; elasticity modifications; and changes in federal forecasts and data sources.

The baseline projections for each sector are presented below, which include projections of annual use in GWh and summer peak demand in MW as well as a summary across all sectors. Overall for the KCP&L service territory the baseline projection increases 11% by 2037 with an approximate growth rate of 0.6% per year.

Baseline Summary Across All Sectors

Table 1-16 All Sector Baseline Projection for Selected Years (GWh)

	2015	2019	2020	2021	2030	2037	% Change '15-'37
Residential	8,585	9,082	9,069	9,053	9,416	10,041	0.6%
Commercial	8,760	8,870	8,866	8,876	9,471	10,171	0.8%
Industrial	5,208	5,352	5,354	5,349	5,444	5,566	0.2%
Total	**22,553**	**23,304**	**23,289**	**23,278**	**24,331**	**25,779**	**0.6%**

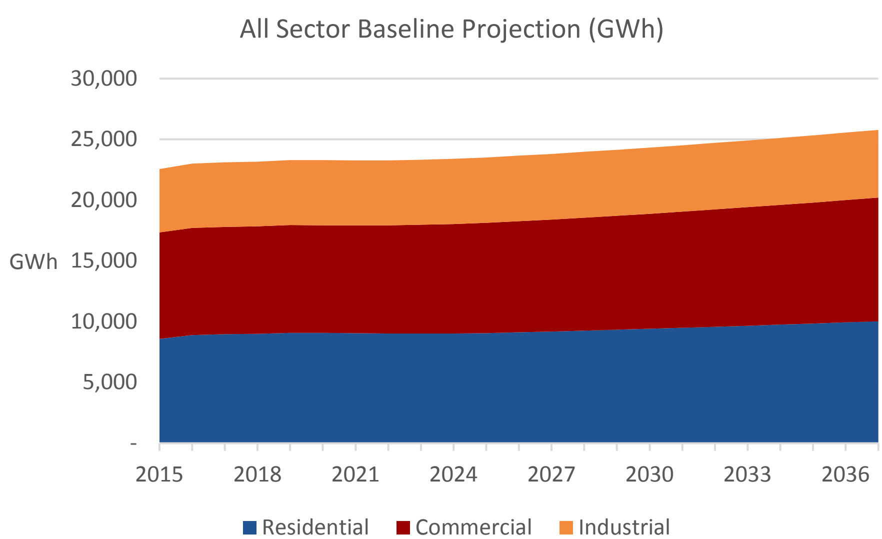

Figure 1-11 All Sector Baseline Projection (GWh)

Residential Baseline Projection

Table 1-17 and Figure 1-12 present the baseline projection for electricity at the end-use level for the residential sector. Overall, residential use increases from 8,585 GWh in 2015 to 10,041 GWh in 2037, an increase of 17%. This reflects a moderate customer growth forecast.

The baseline projection is in general alignment with KCP&L's residential load forecast. Specific observations include:

1. Lighting use decreases throughout the time period as the second tier of lighting standards from the Energy Independence and Security Act of 2007 (EISA) come into effect in 2020.
2. Appliance energy use experiences significant efficiency gains from new standards, but this is offset by customer growth.
3. Growth in use in electronics is substantial and reflects an increase in the number of devices per home in spite of the trend toward smaller and more mobile devices.
4. Growth in other miscellaneous use is also substantial. This end use grows consistently over time as new technologies and appliances are added to the market year after year. AEG incorporates future growth assumptions that are consistent with the Annual Energy Outlook.

Table 1-17 Residential Baseline Electricity Use by End Use, Selected Years (GWh)

End Use	2015	2019	2020	2021	2030	2037	% Change
Cooling	1,947	1,926	1,925	1,925	1,932	1,959	0.6%
Heating	1,803	2,184	2,210	2,235	2,431	2,556	41.7%
Water Heating	426	426	426	425	435	455	7.0%
Interior Lighting	1,024	955	888	819	562	561	-45.2%
Exterior Lighting	149	156	141	125	66	63	-58%
Appliances	1,786	1,868	1,885	1,901	2,028	2,108	18.0%
Electronics	732	760	765	771	846	922	25.9%
Miscellaneous	717	808	829	852	1,116	1,417	97.6%
Total	**8,585**	**9,082**	**9,069**	**9,053**	**9,416**	**10,041**	**17.0%**

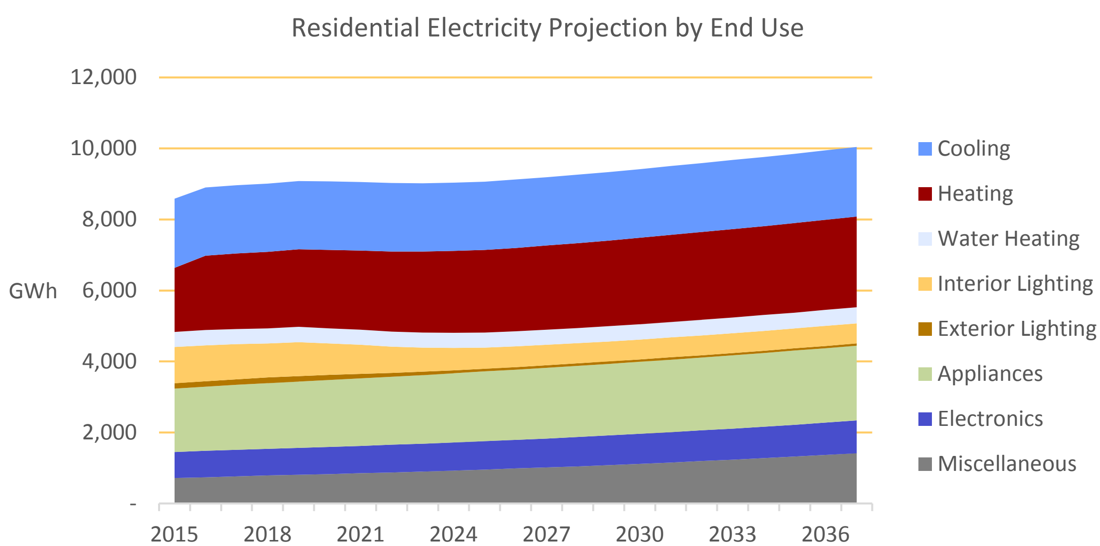

Figure 1-12 Residential Baseline Electricity Projection by End Use

Figure 1-13 presents the intensity projection in kWh per household by end use for the residential sector. There is modest growth in the overall baseline projection, however intensity per household only increases from 11,569 kWh to 11,977 kWh over the time horizon, a 3.5% increase.

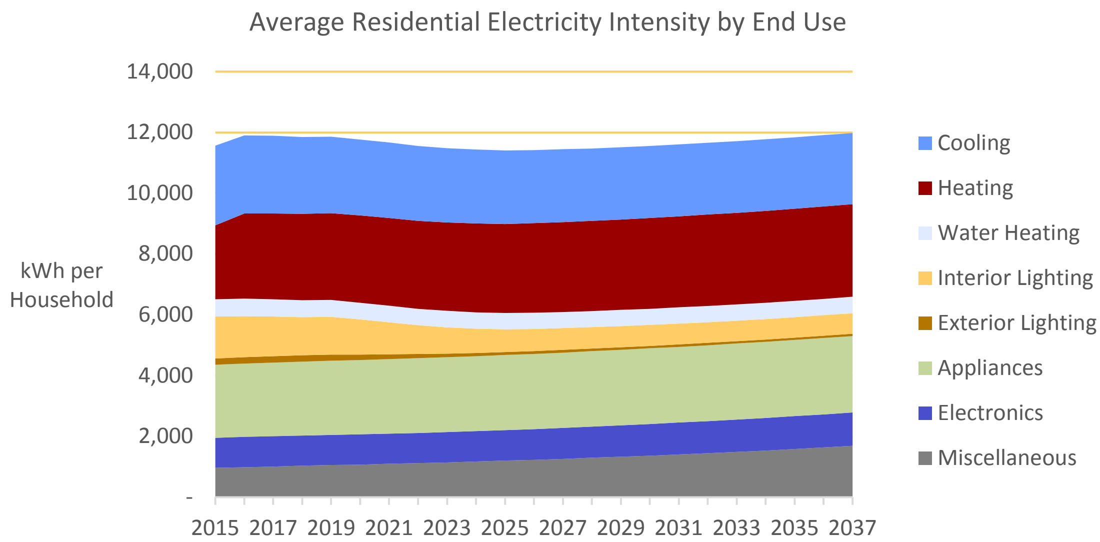

Figure 1-13 Average Residential Electric Intensity by End Use (kWh per Household)

Commercial Baseline Projection

Table 1-18 and Figure 1-14 present the baseline projection for electricity at the end-use level for the commercial sector as a whole. Overall, commercial use increases from 8,760 GWh in 2015 to 10,171 GWh in 2037, an increase of 16%. This reflects a moderate customer growth forecast.

Table 1-18 Commercial Baseline Electricity Use by End Use, Selected Years (GWh)

End Use	2015	2019	2020	2021	2030	2037	% Change
Cooling	1,747	1,707	1,704	1,702	1,708	1,740	-0.4%
Heating	864	1,011	1,015	1,020	1,058	1,085	25.7%
Ventilation	699	671	666	660	633	631	-9.7%
Water Heating	213	211	211	211	215	220	3.2%
Interior Lighting	1,835	1,720	1,682	1,656	1,629	1,648	-10%
Exterior Lighting	906	841	824	806	774	778	-14.1%
Refrigeration	533	521	518	515	509	525	-1%
Food Preparation	197	200	201	203	223	243	23.6%
Office Equipment	862	955	980	1,006	1,266	1,497	74%
Miscellaneous	907	1,031	1,064	1,098	1,455	1,805	99.0%
Total	**8,760**	**8,870**	**8,866**	**8,876**	**9,471**	**10,171**	**16.1%**

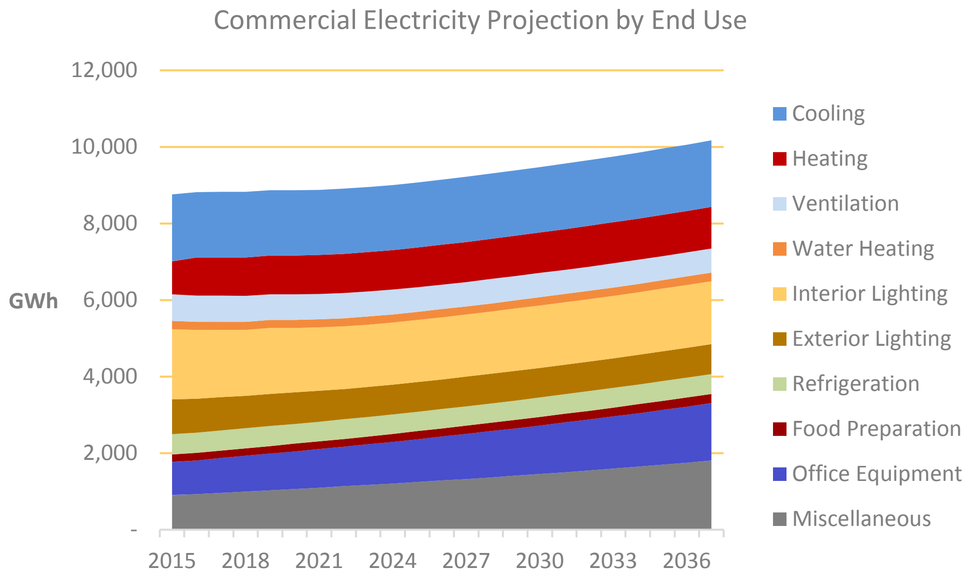

Figure 1-14 Commercial Baseline Electricity Projection by End Use

Figure 1-15 presents the intensity projection in kWh per square foot by end use for the commercial sector. There is modest growth in the overall baseline projection, however intensity per square foot only increases from 15.3 kWh to 16.2 kWh over the time horizon, a 6.1% increase.

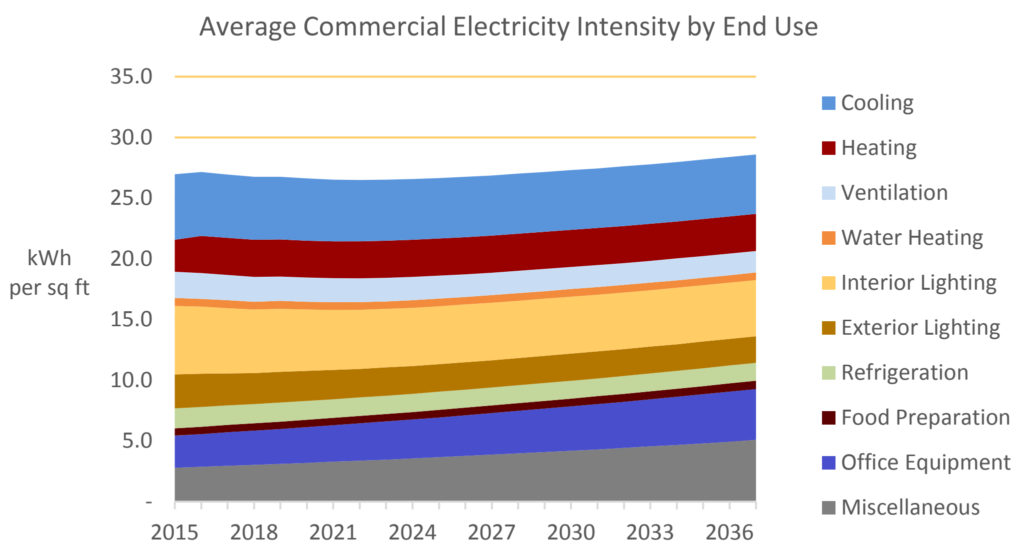

Figure 1-15 Average Commercial Electric Intensity by End Use (kWh per sq ft)

Industrial Baseline Projection

Table 1-19 and Figure 1-16 present the baseline projection for electricity at the end-use level for the industrial sector as a whole. Overall, industrial use increases from 8,585 GWh in 2014 to 10,041 GWh in 2037, an increase of 17%. This reflects a moderate customer growth forecast.

Table 1-19 Industrial Baseline Electricity Use by End Use, Selected Years (GWh)

End Use	2015	2019	2020	2021	2027	2037	% Change
Cooling	470	473	473	472	474	486	3.4%
Heating	152	180	180	180	183	189	24.1%
Ventilation	109	110	110	110	109	113	2.9%
Interior Lighting	364	358	356	353	352	364	-0.1%
Exterior Lighting	190	182	180	177	171	171	-10%
Motors	2,337	2,412	2,416	2,417	2,451	2,529	8.2%
Process	1,368	1,412	1,415	1,415	1,435	1,481	8.2%
Miscellaneous	217	224	225	225	228	235	8.2%
Total	**5,208**	**5,352**	**5,354**	**5,349**	**5,404**	**5,566**	**6.9%**

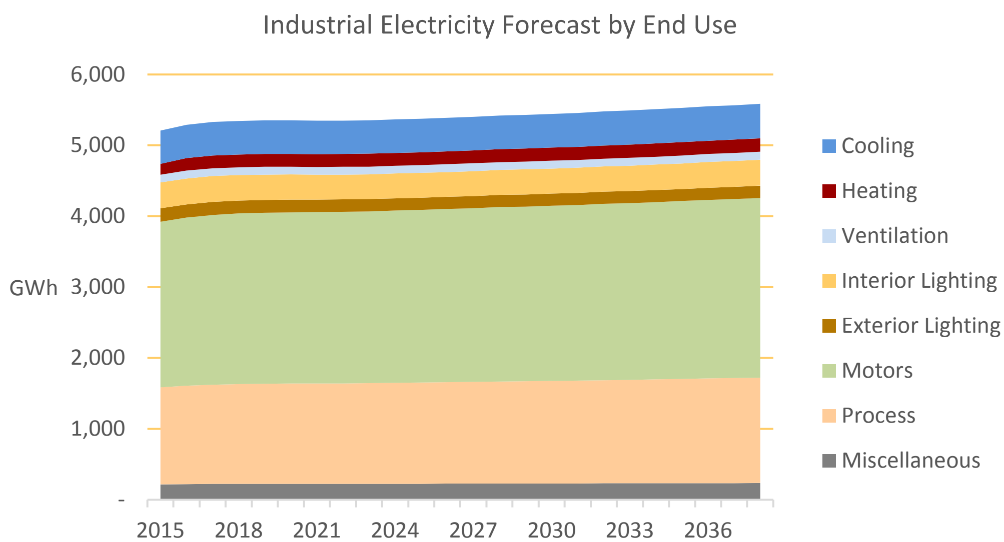

Figure 1-16 Industrial Baseline Electricity Projection by End Use

Overall Summary of Measure-Level EE Potential

This section first presents the annual energy savings and second the peak demand savings from energy-efficiency measures for all sectors combined. All impacts are presented at the customer meter. The cost-effectiveness screen applied for economic potential requires that a measure installation has a TRC benefit to cost ratio greater than 1.0 at the measure-level, meaning that 100% of the incremental cost is included, but no program administrative costs or delivery assumptions have yet been assigned. The only exception to this is for measures in Low Income Residential households, where KCP&L made the decision to relax the cost-effectiveness for measure-level TRC ratios from 1.0 to 0.5 to be more inclusive of measures in this segment.

Summary of Annual Measure-Level EE Energy Savings

Figure 1-17 summarize the EE savings in terms of annual energy use for all measures for the levels of potential relative to the baseline projection.

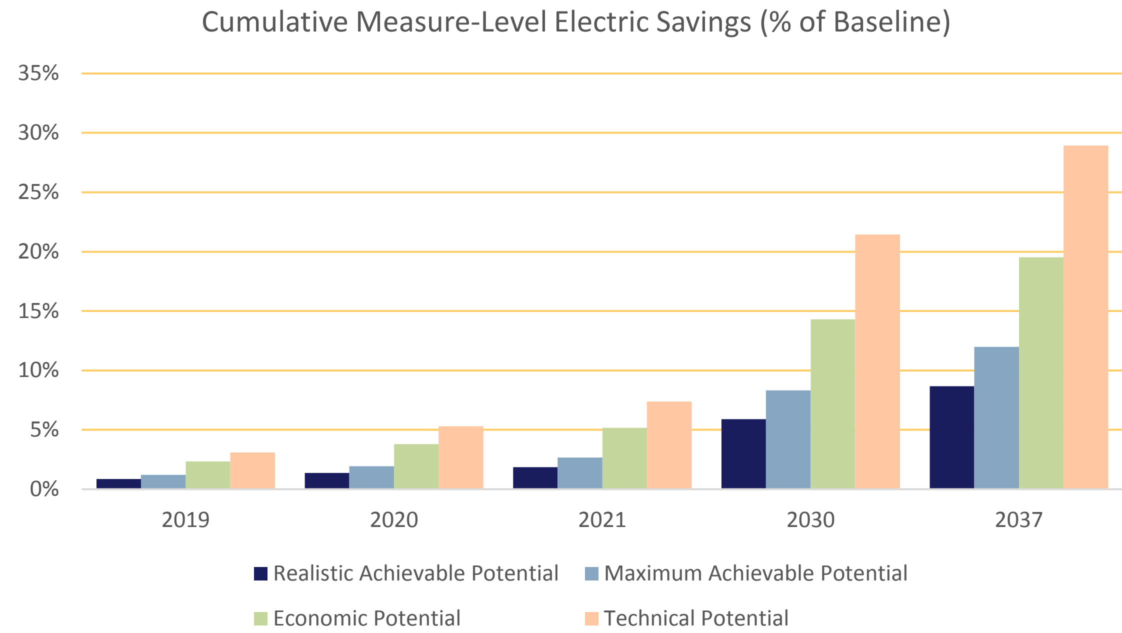

Figure 1-17 Summary of Cumulative Measure-Level EE Potential

Table 1-20 presents the baseline end-use projection, developed specifically for this study but aligned with the KCP&L official forecast, cumulative net savings in GWh and as a percent of the baseline, and incremental net savings in annual GWh and as a percent of the baseline[12].

- **Technical potential** reflects the adoption of all EE measures regardless of cost-effectiveness. First-year savings are 726 GWh, or 3.1% of the baseline projection. Cumulative gross savings in 2021 are 1,719 GWh, or 7.4% of the baseline. By 2037 cumulative savings reach 7,475 GWh, or 29% of the baseline.
- **Economic potential** reflects the savings when the most efficient cost-effective measures are taken by all customers. The first-year savings in 2019 are 549 GWh, or 2.4% of the baseline projection. By 2021, cumulative savings reach 1,209 GWh, or 5.2% of the baseline. By 2037, cumulative savings reach 5,051 GWh, or 19.6% of the baseline projection.
- **Maximum achievable potential** refines the economic potential by taking into the account the maximum expected participation and customer preferences without budget constraints. The first-year savings in 2019 are 283 GWh, or 1.2% of the baseline projection. By 2021, cumulative savings reach 624 GWh, or 2.7% of the baseline. By 2037, cumulative savings reach 3,101 GWh, or 12.0% of the baseline projection. The average annual incremental savings are 1.2% of the baseline (the average of the annual incremental savings in each year).
- **Realistic achievable potential** further refines maximum achievable potential by considering budgetary constraints and what could be realistically achievable with participation and awareness. It shows 203 GWh savings in the first year, or 0.9% of the baseline and by 2021 cumulative savings reach 431 GWh, or 1.9% of the baseline projection. By 2037, cumulative savings reach 2,245 GWh, or 8.7% of the baseline projection. The average annual incremental savings are 1.0% of the baseline each year.

[12] Please note that the sum of incremental savings will typically exceed cumulative savings in any given year, mainly due to the effects of measure persistence. Cumulative savings take into account the fact that measures installed in earlier years will have to be repurchased at their end of useful life. Incremental savings capture the total amount of measure purchases in a given year, which includes both new purchases and repurchases.

Full detail is available in the LoadMAP model set which has been provided to KCP&L. Figure 1-18 displays the EE potential projections.

Table 1-20 Summary of KCP&L Cumulative Measure-Level EE Potential

	2019	2020	2021	2030	2037
Baseline Projection (GWh)	23,304	23,289	23,278	24,331	25,779
Cumulative Net Savings (GWh)					
Realistic Achievable Potential	203	318	431	1,440	2,245
Maximum Achievable Potential	283	455	624	2,032	3,101
Economic Potential	549	888	1,209	3,488	5,051
Technical Potential	726	1,236	1,719	5,232	7,475
Cumulative as % of Baseline					
Realistic Achievable Potential	0.9%	1.4%	1.9%	5.9%	8.7%
Maximum Achievable Potential	1.2%	2.0%	2.7%	8.3%	12.0%
Economic Potential	2.4%	3.8%	5.2%	14.3%	19.6%
Technical Potential	3.1%	5.3%	7.4%	21.5%	29.0%
Incremental Net Savings (GWh)					
Realistic Achievable Potential	203	166	167	251	333
Maximum Achievable Potential	283	226	226	336	440
Economic Potential	549	442	431	569	689
Technical Potential	729	616	603	787	984
Incremental as % of Baseline					
Realistic Achievable Potential	0.9%	0.7%	0.7%	1.0%	1.3%
Maximum Achievable Potential	1.2%	1.0%	1.0%	1.4%	1.7%
Economic Potential	2.4%	1.9%	1.9%	2.3%	2.7%
Technical Potential	3.1%	2.6%	2.6%	3.2%	3.8%

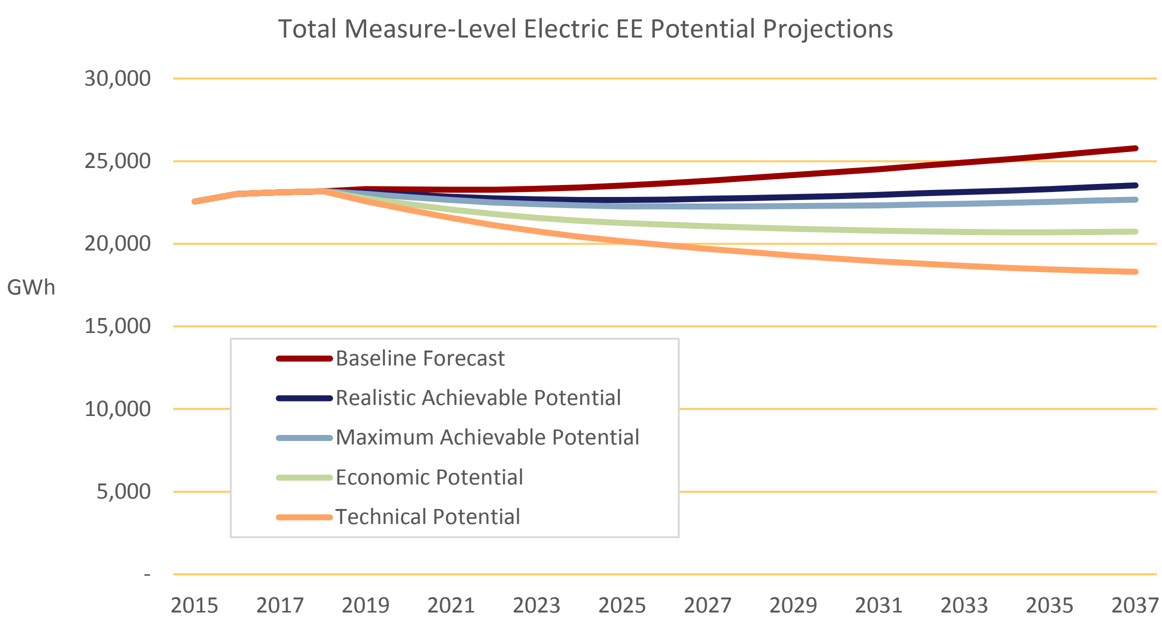

Figure 1-18 Summary of Baseline and Measure-Level EE Potential Projections

Summary of Annual Measure-Level EE Energy Savings by Territory

This section summarizes the overall cumulative energy efficiency potential for each service territory within the KCP&L system.

Table 1-21 KCP&L-MO Territory Measure-Level EE Summary

KCP&L-MO	2019	2020	2021	2030	2037
Baseline Projection (GWh)	8,567	8,559	8,554	8,930	9,436
Cumulative Net Savings (GWh)					
Realistic Achievable Potential	69	111	152	524	817
Maximum Achievable Potential	99	162	224	749	1,143
Economic Potential	187	310	426	1,276	1,849
Technical Potential	249	432	605	1,880	2,688
Cumulative as % of Baseline					
Realistic Achievable Potential	0.8%	1.3%	1.8%	5.9%	8.7%
Maximum Achievable Potential	1.1%	1.9%	2.6%	8.4%	12.1%
Economic Potential	2.2%	3.6%	5.0%	14.3%	19.6%
Technical Potential	2.9%	5.1%	7.1%	21.1%	28.5%

Table 1-22 KCP&L-KS Territory Measure-Level EE Summary

KCP&L-KS	2019	2020	2021	2030	2037
Baseline Projection (GWh)	6,519	6,518	6,517	6,852	7,311
Cumulative Net Savings (GWh)					
Realistic Achievable Potential	55	86	118	392	612
Maximum Achievable Potential	77	124	170	551	841
Economic Potential	157	249	338	953	1,378
Technical Potential	207	350	484	1,457	2,087
Cumulative as % of Baseline					
Realistic Achievable Potential	0.8%	1.3%	1.8%	5.7%	8.4%
Maximum Achievable Potential	1.2%	1.9%	2.6%	8.0%	11.5%
Economic Potential	2.4%	3.8%	5.2%	13.9%	18.8%
Technical Potential	3.2%	5.4%	7.4%	21.3%	28.5%

Table 1-23 GMO-MPS Territory Measure-Level EE Summary

GMO-MPS	2019	2020	2021	2030	2037
Baseline Projection (GWh)	6,127	6,125	6,124	6,404	6,784
Cumulative Net Savings (GWh)					
Realistic Achievable Potential	61	92	123	392	610
Maximum Achievable Potential	82	129	174	545	832
Economic Potential	158	251	339	940	1,359
Technical Potential	206	347	479	1,430	2,040
Cumulative as % of Baseline					
Realistic Achievable Potential	1.0%	1.5%	2.0%	6.1%	9.0%
Maximum Achievable Potential	1.3%	2.1%	2.8%	8.5%	12.3%
Economic Potential	2.6%	4.1%	5.5%	14.7%	20.0%
Technical Potential	3.4%	5.7%	7.8%	22.3%	30.1%

Table 1-24 GMO-SJLP Territory Measure-Level EE Summary

GMO-SJLP	2019	2020	2021	2030	2037
Baseline Projection (GWh)	2,092	2,087	2,083	2,145	2,248
Cumulative Net Savings (GWh)					
Realistic Achievable Potential	18	28	39	132	206
Maximum Achievable Potential	25	41	56	186	285
Economic Potential	47	78	107	319	465
Technical Potential	63	108	150	465	661
Cumulative as % of Baseline					
Realistic Achievable Potential	0.9%	1.4%	1.9%	6.1%	9.2%
Maximum Achievable Potential	1.2%	1.9%	2.7%	8.7%	12.7%
Economic Potential	2.3%	3.7%	5.1%	14.9%	20.7%
Technical Potential	3.0%	5.2%	7.2%	21.7%	29.4%

Summary of Annual Measure-Level EE Peak Demand Savings

Measure-Level EE Summer Peak Demand Savings

Table 1-25 summarizes the summer peak demand savings from all EE measures for the levels of potential relative to the baseline projection.[13]

- **Technical potential** for summer peak demand savings is 319 MW in 2021, or 5.7% of the baseline summer peak projection. This increases to 1,485 MW by 2037, or 24.2% of the baseline.
- **Economic potential** is estimated to be 216 MW or 3.8% reduction in the 2021 summer peak demand baseline projection. In 2037, savings are 974 MW or 15.8% of the summer peak baseline projection.
- **Maximum achievable potential** is 108 MW by 2021 or 1.9% of the baseline projection. By 2037, cumulative saving reach 558 MW or 9.1% of the baseline projection.

[13] Note that the potential savings from Demand Response and Demand-Side Rate options are shown in Chapter 2. The Demand Response potential analysis was done separately at the measure-level from the Energy Efficiency analysis.

- **Realistic achievable potential** is 77 MW by 2021, or 1.4% of the baseline projection. By 2037, cumulative savings reach 407 MW, or 6.6% of the baseline projection.

Table 1-25 Summary of Cumulative Measure-Level EE Summer Peak Demand Potential

	2019	2020	2021	2030	2037
Baseline Projection (MW) [14]	5,548	5,585	5,615	5,875	6,150
Cumulative Net Savings (MW)					
Realistic Achievable Potential	37	57	77	263	407
Maximum Achievable Potential	48	78	108	366	558
Economic Potential	96	157	216	672	974
Technical Potential	132	227	319	1,046	1,485
Cumulative as % of Baseline					
Realistic Achievable Potential	0.7%	1.0%	1.4%	4.5%	6.6%
Maximum Achievable Potential	0.9%	1.4%	1.9%	6.2%	9.1%
Economic Potential	1.7%	2.8%	3.8%	11.4%	15.8%
Technical Potential	2.4%	4.1%	5.7%	17.8%	24.2%

Table 1-26 provides the measure-level summer peak demand savings from all EE measures by KCP&L service territory in the final year of the study, 2037. As is the case for energy savings, KCP&L-MO shows the largest peak demand potential, but savings as a percent of baseline load are similar among areas.

Table 1-26 Cumulative EE Summer Peak Demand Savings in 2037 by Service Territory

	KCP&L-MO	KCP&L-KS	GMO-MPS	GMO-SJLP	All Service Territories
Baseline Projection (2037 MW)	**2,126**	**2,051**	**1,532**	**441**	**6,150**
Cumulative Energy Savings (2037 MW)					
Realistic Achievable Potential	149	116	107	35	**407**
Maximum Achievable Potential	206	158	146	48	**558**
Economic Potential	358	277	255	84	**974**
Technical Potential	542	431	391	122	**1,485**
Energy Savings (% of 2037 Baseline)					
Realistic Achievable Potential	7.0%	5.6%	7.0%	8.0%	**6.6%**
Maximum Achievable Potential	9.7%	7.7%	9.5%	11.0%	**9.1%**
Economic Potential	16.8%	13.5%	16.6%	19.1%	**15.8%**
Technical Potential	25.5%	21.0%	25.5%	27.6%	**24.2%**

[14] Note that the LoadMAP EE potential model constructs an independent baseline projection for peak demand in addition to energy. LoadMAP is calibrated for agreement with KCP&L's energy baseline forecast as mentioned above. LoadMAP's peak demand baseline projection is affected by this energy calibration, and therefore grows at a slightly different rate than the KCP&L peak demand forecast that is used to calibrate the DR and DSR models. For purposes of reporting and consistency, we replace the LoadMAP peak demand baseline with that used in the DR and DSR model.

Measure-Level EE Winter Peak Demand Savings

Table 1-27 summarizes the winter peak demand savings from all EE measures for three levels of potential relative to the baseline projection.[15]

- **Technical potential** for winter peak demand savings is 233 MW in 2021, or 5.4% of the baseline projection. This increases to 816 MW by 2037, or 17.5% of the winter peak baseline projection.
- **Economic potential** is estimated to be 190 MW or 4.4% reduction in the 2021 winter peak demand baseline projection. In 2037, savings are 623 MW or 13.3% of the winter peak baseline projection.
- **Maximum achievable potential** is 92 MW by 2021 or 2.1% of the baseline projection. By 2037, potential reaches 378 MW, or 8.1% of the baseline projection.
- **Realistic achievable potential** is 61 MW by 2021, or 1.4% of the baseline projection. By 2037, cumulative savings reach 274 MW, or 5.9% of the baseline projection.

Table 1-27 Summary of Cumulative Measure-Level EE Winter Peak Demand Potential

	2019	2020	2021	2030	2037
Baseline Projection (MW)	4,308	4,325	4,332	4,490	4,671
Cumulative Net Savings (MW)					
Realistic Achievable Potential	29	45	61	183	274
Maximum Achievable Potential	43	68	92	258	378
Economic Potential	88	141	190	444	623
Technical Potential	103	171	233	594	816
Cumulative as % of Baseline					
Realistic Achievable Potential	0.7%	1.0%	1.4%	4.1%	5.9%
Maximum Achievable Potential	1.0%	1.6%	2.1%	5.7%	8.1%
Economic Potential	2.0%	3.3%	4.4%	9.9%	13.3%
Technical Potential	2.4%	3.9%	5.4%	13.2%	17.5%

[15] Note that the potential savings from Demand Response and Demand-Side Rate options are shown in Chapter 2. The Demand Response potential analysis was done separately at the measure-level from the Energy Efficiency analysis.

MEASURE-LEVEL EE POTENTIAL RESULTS BY SECTOR

SUMMARY OF MEASURE-LEVEL EE POTENTIAL BY SECTOR

Table 1-28 and Figure 1-19 summarize the range of electric achievable potential by sector. The residential sector provides the most energy efficiency potential in the early years. The commercial sector surpasses it after 2021, however, largely through lighting savings; and reaches a level of nearly double the residential sector by 2037. The industrial sector contributes the fewest savings. Since a number of the largest industrial customers have opted out from EE programs, the savings here come largely from the remaining, somewhat smaller facilities.

Table 1-28 Summary of Measure-Level EE Potential by Sector

	2019	2020	2021	2030	2037
Realistic Achievable Potential					
Cumulative Savings (GWh)					
Residential	115	156	198	539	823
Commercial	75	135	194	727	1,135
Industrial	13	26	39	173	287
Total	**203**	**318**	**431**	**1,440**	**2,245**
Maximum Achievable Potential					
Cumulative Savings (GWh)					
Residential	145	204	263	697	1,046
Commercial	118	211	301	1,074	1,632
Industrial	20	41	60	261	423
Total	**283**	**455**	**624**	**2,032**	**3,101**

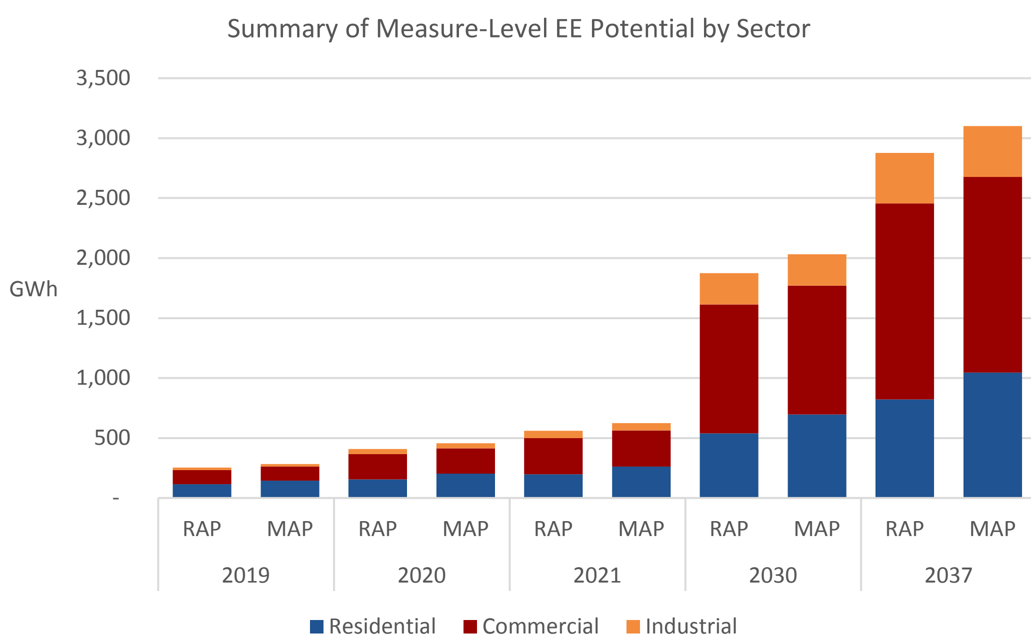

Figure 1-19 Summary of Measure-Level EE Potential by Sector

Measure-Level Residential Sector Results

Table 1-29 and Figure 1-20 present estimates for measure-level EE potential for the residential sector in terms of annual energy savings. Realistic achievable potential in 2019 is 115 GWh, or 1.3% of the baseline projection. By 2037, cumulative savings are 823 GWh, or 8.2% of the baseline projection. Realistic achievable potential represents roughly 46% of economic potential.

Table 1-29 Residential Sector EE Potential

	2019	2020	2021	2030	2037
Baseline Forecast (GWh)	9,082	9,069	9,053	9,416	10,041
Cumulative Savings (GWh)					
Realistic Achievable Potential	115	156	198	539	823
Maximum Achievable Potential	145	204	263	697	1,046
Economic Potential	299	433	558	1,254	1,777
Technical Potential	395	623	837	2,263	3,209
Energy Savings (% of Baseline)					
Realistic Achievable Potential	1.3%	1.7%	2.2%	5.7%	8.2%
Maximum Achievable Potential	1.6%	2.2%	2.9%	7.4%	10.4%
Economic Potential	3.3%	4.8%	6.2%	13.3%	17.7%
Technical Potential	4.3%	6.9%	9.2%	24.0%	32.0%

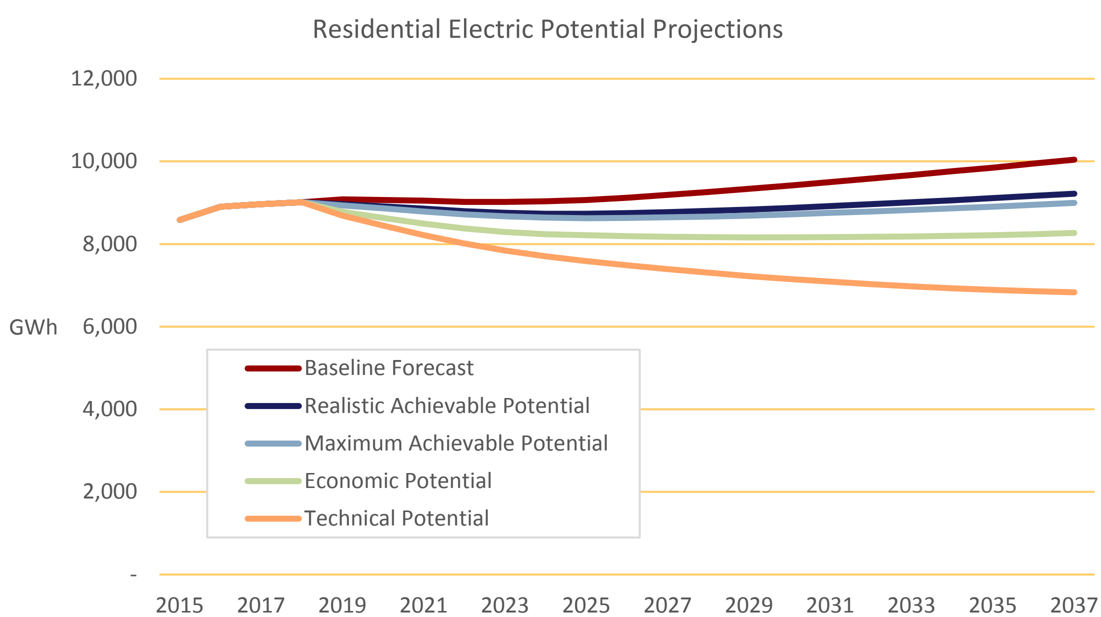

Figure 1-20 Residential Sector EE Potential Projections

Figure 1-21 presents a projection of energy savings by end use as a percent of total annual savings and cumulative savings. Lighting savings account for a substantial portion of the savings throughout the forecast horizon, but the share declines over time as the market is transformed. The same is true for exterior lighting. Savings from cooling measures and appliances are steadily increasing throughout the forecast horizon.

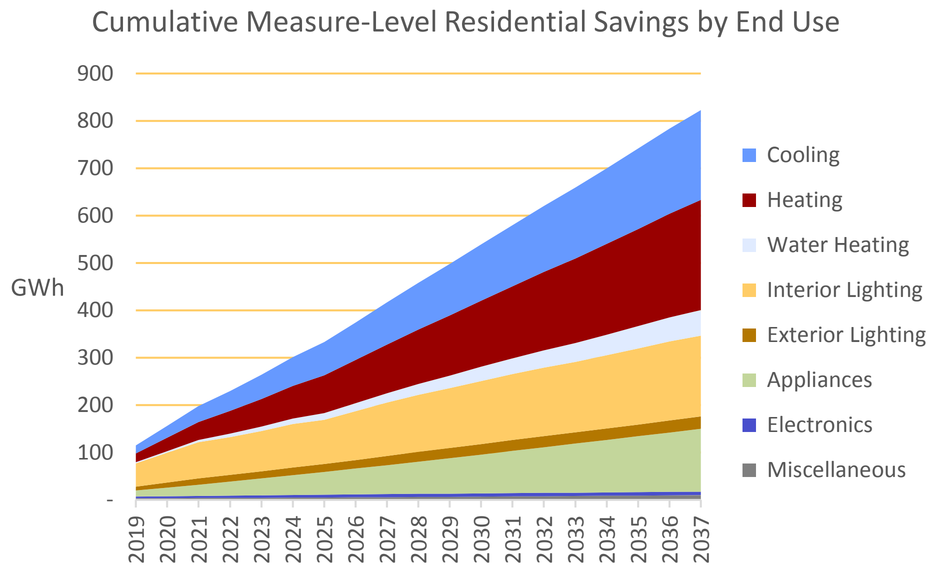

Figure 1-21 Residential Sector Cumulative Savings (GWh) by End Use

Table 1-30 identifies the top 20 residential measures from the perspective of annual energy savings in 2021. The top measure is interior screw-in lighting as a result of purchases of LED lamps, which are cost effective throughout the forecast horizon.

Table 1-30 Residential Sector Top EE Measures, 2021

Rank	Measure / Technology	2021 Cumulative Savings (GWh)	% of Total
1	Interior Lighting - General Service Screw-In LEDs	54.1	27.3%
2	Behavioral Programs	44.0	22.2%
3	Thermostat - WiFi/Interactive	14.2	7.2%
4	Interior Lighting - Exempted Screw-In LEDs	13.2	6.7%
5	Exterior Lighting - Screw-in LEDs	12.1	6.1%
6	Cooling - Central AC Upgrade	8.4	4.2%
7	Refrigerator - Decommissioning and Recycling	8.1	4.1%
8	Insulation - Wall Cavity Installation	6.1	3.1%
9	Insulation - Ceiling Installation	4.7	2.4%
10	Freezer - Decommissioning and Recycling	3.7	1.9%
11	Windows - Install Reflective Film	3.4	1.7%
12	Insulation - Radiant Barrier	3.3	1.6%
13	Ductless Mini Split Heat Pump (Ducted Forced Air)	2.6	1.3%
14	Ducting - Repair and Sealing	2.4	1.2%
15	Heating - Air-Source Heat Pump Upgrade	2.1	1.1%
16	Appliances – Efficient Refrigerator Upgrade	2.1	1.1%
17	Water Heating - Water Heater Upgrade (<= 55 Gal)	2.1	1.1%
18	Windows - High Efficiency/ENERGY STAR	1.3	0.7%
19	Furnace - Conversion to Air-Source Heat Pump	1.1	0.6%
20	Electronics – Efficient Personal Computers	1.0	0.5%
	Total	**190.1**	**95.9%**
	Total RAP savings in 2021	**198.2**	**100%**

MEASURE-LEVEL COMMERCIAL SECTOR RESULTS

Table 1-31 and Figure 1-22 present estimates for measure-level EE potential for the commercial sector in terms of annual energy savings. Realistic achievable potential in 2019 is 75 GWh, or 0.8% of the baseline projection. By 2037, cumulative savings are 1,135 GWh, or 11.2% of the baseline projection. Realistic achievable potential represents roughly 46% of economic potential. These numbers include the effect of adjusting participation rates in RAP and MAP (and therefore the resulting potential savings) to account for large commercial customers in Missouri who have opted out of programs.

Table 1-31 Commercial Sector EE Potential

	2019	2020	2021	2030	2037
Baseline Forecast (GWh)	8,870	8,866	8,876	9,471	10,171
Cumulative Savings (GWh)					
Realistic Achievable Potential	75	135	194	727	1,135
Maximum Achievable Potential	118	211	301	1,074	1,632
Economic Potential	203	364	516	1,698	2,450
Technical Potential	270	492	703	2,315	3,289
Energy Savings (% of Baseline)					
Realistic Achievable Potential	0.8%	1.5%	2.2%	7.7%	11.2%
Maximum Achievable Potential	1.3%	2.4%	3.4%	11.3%	16.0%
Economic Potential	2.3%	4.1%	5.8%	17.9%	24.1%
Technical Potential	3.0%	5.5%	7.9%	24.4%	32.3%

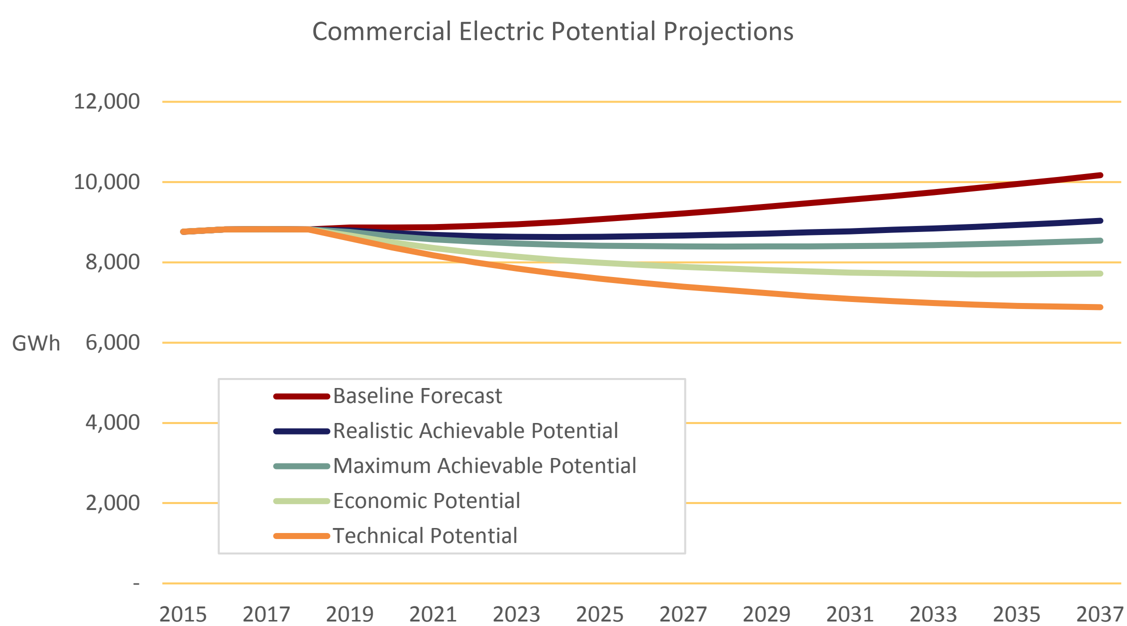

Figure 1-22 Commercial Sector EE Potential Projections

Figure 1-23 presents a projection of energy savings by end use as a percent of total annual savings and cumulative savings. Lighting savings account for a substantial portion of the savings throughout the forecast horizon. Savings from cooling measures and appliances steadily increase throughout the forecast horizon.

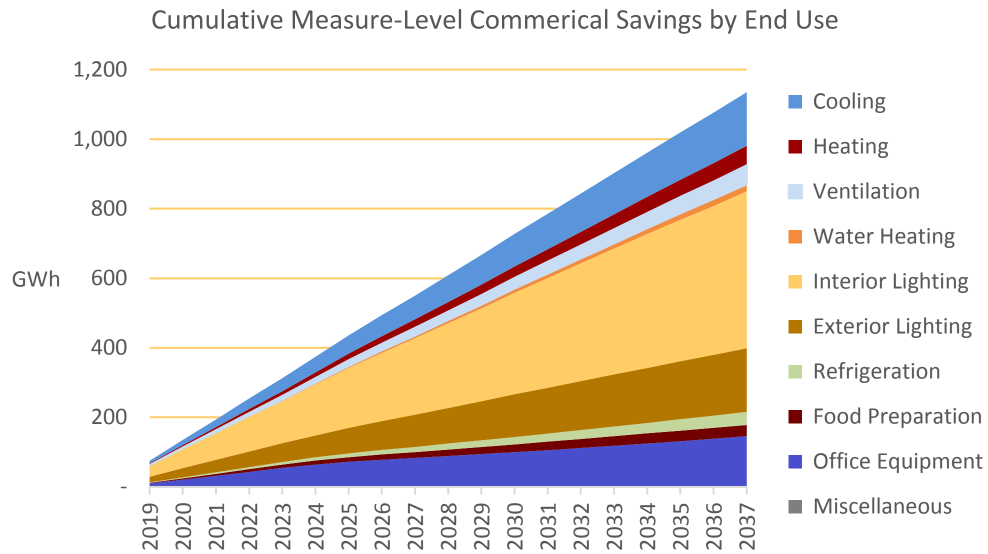

Figure 1-23 Commercial Sector Cumulative Savings (GWh) by End Use

Table 1-32 identifies the top 20 residential measures from the perspective of annual energy savings in 2021. Five of the top six measures are different applications of LED lighting, which is cost effective throughout the forecast horizon. Although the largest data centers and offices are opt out customers, there is still significant potential in office equipment.

Table 1-32 Commercial Sector Top EE Measures, 2021

Rank	Measure / Technology	2021 Cumulative Savings (GWh)	% of Total
1	Interior Lighting - Linear Lighting LEDs	19.4	10.0%
2	Interior Lighting - Screw-in LEDs	19.1	9.8%
3	Office Equipment – Efficient Server	17.3	8.9%
4	Interior Lighting - High-Bay Fixtures LEDs	16.8	8.7%
5	Exterior Lighting - Area Lighting LEDs	15.8	8.1%
6	Exterior Lighting - Screw-in LEDs	12.5	6.4%
7	Retrocommissioning	11.8	6.1%
8	Office Equipment – Efficient Desktop Computer	8.3	4.3%
9	Interior Lighting - Networked Fixture Controls	7.6	3.9%
10	Cooling - Water-Cooled Chiller Upgrade	5.9	3.1%
11	Interior Fluorescent - Delamp and Install Reflectors	5.9	3.0%
12	Exterior Lighting - Linear Lighting LEDs	5.7	2.9%
13	Ventilation System Upgrade	5.6	2.9%
14	Interior Lighting - Embedded Fixture Controls	5.2	2.7%
15	Thermostat - WiFi/Interactive	3.9	2.0%
16	Food Preparation – Efficient Broiler	3.7	1.9%
17	Data Center - Best Practice Measures	3.1	1.6%
18	Destratification Fans (HVLS)	2.9	1.5%
19	RTU - Advanced Controls	2.1	1.1%
20	Cooling - Air-Cooled Chiller Upgrade	2.0	1.0%
	Total	**174.5**	**89.8%**
	Total RAP savings in 2021	**194.2**	**100.0%**

Measure-Level Industrial Sector Results

Table 1-33 and Figure 1-24 present estimates for measure-level EE potential for the industrial sector in terms of annual energy savings. Realistic achievable potential in 2019 is 13 GWh, or 0.2% of the baseline projection. By 2037, cumulative savings are 287 GWh, or 5.2% of the baseline projection. Realistic achievable potential represents roughly 35% of economic potential. These numbers include the effect of adjusting participation rates in RAP and MAP (and therefore the resulting potential savings) to account for large industrial customers who have opted out of programs.

Table 1-33 Industrial Sector EE Potential

	2019	2020	2021	2030	2037
Baseline Forecast (GWh)	5,352	5,354	5,349	5,404	5,566
Cumulative Savings (GWh)					
Realistic Achievable Potential	13	26	39	179	287
Maximum Achievable Potential	20	41	60	261	423
Economic Potential	46	92	135	536	825
Technical Potential	61	122	178	654	977
Energy Savings (% of Baseline)					
Realistic Achievable Potential	0.2%	0.5%	0.7%	3.2%	5.2%
Maximum Achievable Potential	0.4%	0.8%	1.1%	4.8%	7.6%
Economic Potential	0.9%	1.7%	2.5%	9.8%	14.8%
Technical Potential	1.1%	2.3%	3.3%	12.0%	17.6%

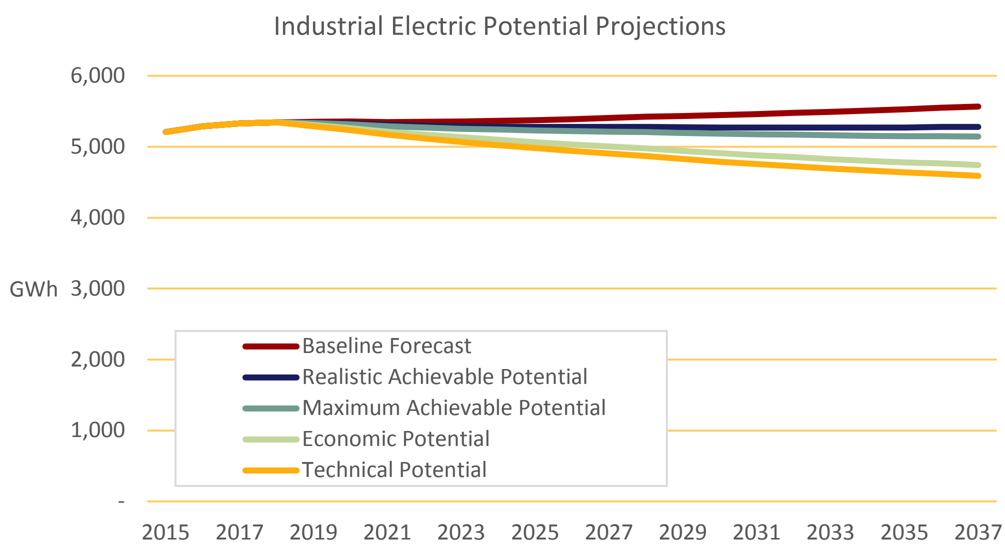

Figure 1-24 Industrial Sector EE Potential Projections

Figure 1-25 presents a projection of energy savings by end use as a percent of total annual savings and cumulative savings. Lighting savings account for a substantial portion of the savings throughout the forecast horizon, but the share declines over time as the market is transformed. Savings from cooling measures and appliances steadily increase throughout the forecast horizon.

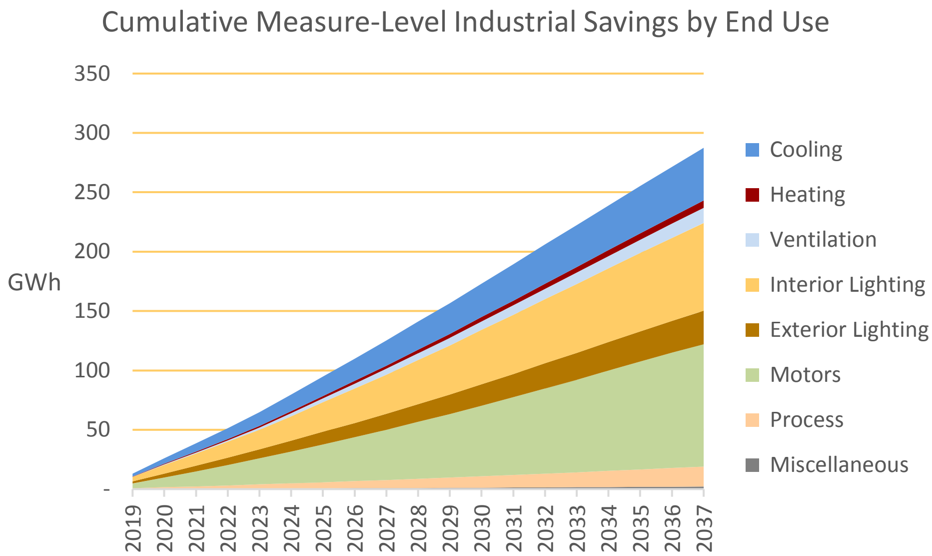

Figure 1-25 Industrial Sector Cumulative Savings (GWh) by End Use

Table 1-34 identifies the top 20 industrial measures from the perspective of annual energy savings in 2021. Similar to residential and commercial, LED lighting represents a significant share of savings, however in the industrial sector, savings from motor applications like pumps and compressed air are also a large portion of savings.

Table 1-34 Industrial Sector Top EE Measures, 2021

Rank	Measure / Technology	2021 Cumulative Savings (GWh)	% of Total
1	Interior Lighting - High-Bay Fixtures LEDs	4.9	12.2%
2	Cooling - Water-Cooled Chiller Upgrade	3.2	8.0%
3	Exterior Lighting - Area Lighting LEDs	3.0	7.4%
4	Process - Timers and Controls	2.3	5.6%
5	Interior Lighting - Linear Lighting LEDs	2.1	5.3%
6	Interior Lighting - Screw-in LEDs	2.0	4.8%
7	Compressed Air - Equipment Upgrade	1.9	4.7%
8	Compressed Air - Leak Mgmt Program	1.9	4.6%
9	Int. Lighting - Networked Fixture Ctrls	1.7	4.2%
10	Exterior Lighting - Screw-in LEDs	1.7	4.1%
11	Thermostat - WiFi/Interactive	1.6	3.9%
12	Destratification Fans (HVLS)	1.4	3.6%
13	Pumping System - Equipment Upgrade	1.4	3.4%
14	Mat'l Handling - Variable Speed Drive	1.3	3.3%
15	Strategic Energy Management	1.2	3.0%
16	Pumping System - System Optimization	1.0	2.5%
17	Pumping System - Variable Speed Drive	1.0	2.5%
18	Retrocommissioning	1.0	2.4%
19	HVAC – Economizer	0.9	2.3%
20	Int. Lighting - Embedded Fixture Ctrls	0.8	2.0%
	Total	**36.3**	**89.8%**
	Total RAP savings in 2021	**40.4**	**100.0%**

Measure-Level EE Sensitivity Analysis

Increased Avoided Costs

AEG ran a sensitivity analysis to investigate the impact of higher avoided costs of generation that could be caused by implementation of provisions of the Clean Power Plan or other similar legislation. These higher avoided costs prompted some marginal increase in late-year potential, as a handful of measures began to pass the economic screen slightly earlier, or passed in market segments where they previously were marginal.

Overall potential increased from 2,245 GWh to 2,402 GWh over the study period, an increase of only 0.6%. Table 1-35 and Figure 1-26 below present the comparison.

Table 1-35 Realistic Achievable Potential, High Avoided Costs Sensitivity

	2019	2020	2021	2030	2037
Baseline Usage (GWh)	**23,304**	**23,289**	**23,278**	**24,331**	**25,779**
Reference Case (Cumulative GWh Savings)					
Residential	115	156	198	539	823
Commercial	75	135	194	727	1,135
Industrial	13	26	39	173	287
Total	**203**	**318**	**431**	**1,440**	**2,245**
High Avoided Costs (Cumulative GWh Savings)					
Residential	114	157	200	588	918
Commercial	77	138	199	755	1,182
Industrial	14	29	43	185	302
Total	**205**	**324**	**442**	**1,528**	**2,402**
Savings as a % of baseline					
Reference Case	0.9%	1.4%	1.9%	5.9%	8.7%
High Avoided Costs	0.9%	1.4%	1.9%	6.3%	9.3%

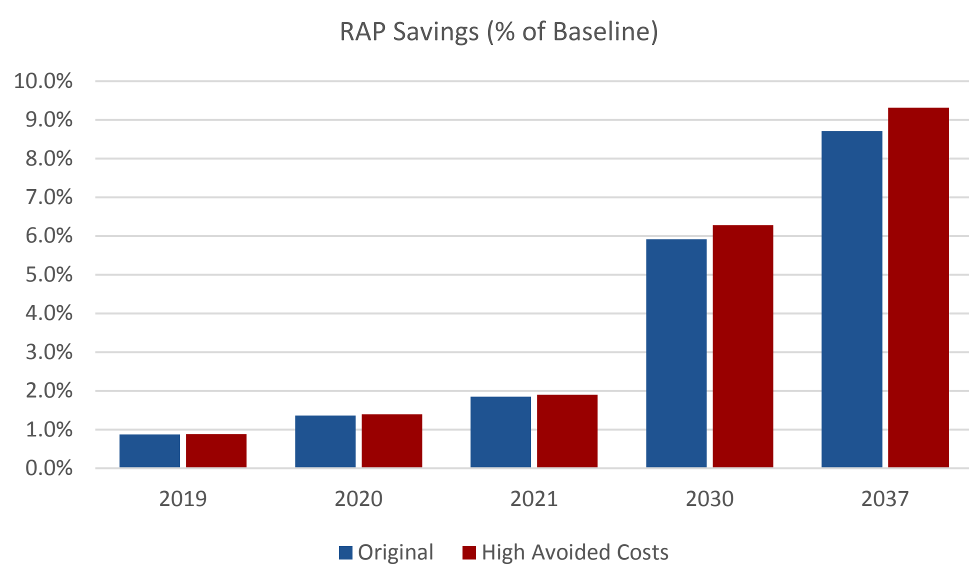

Figure 1-26 RAP Savings, High Avoided Costs Sensitivity

Maximum Eligible Opt Out

As mentioned previously, several of KCP&L's largest C&I customers have opted out of programs. These customers represent approximately 25% of the total load in the GMO and KCP&L-MO territories, and their missing participation is represented in the reference case by reducing the participation factors for the realistic and maximum achievable potential cases by an amount proportional to the opt-out customers' share of load for a given C&I segment.

As a worst-case sensitivity, AEG ran a sensitivity analysis where the maximum amount of customers opted out. In this scenario, all C&I customers with a peak demand of 2.5 MW or greater were assumed to opt out of programs, leading to a final opt out total of 46% of GMO C&I load, and 51% of KCP&L-MO, or roughly double the level assumed in the original reference case.

As a result, realistic achievable potential in 2037 decreased from 2,245 GWh to 1,988 GWh, a drop of 11%, as shown in Table 1-36 and Figure 1-27 below.

Table 1-36 Realistic Achievable Potential Maximum Opt Out Sensitivity

	2019	2020	2021	2030	2037
Baseline Usage (GWh)	**23,304**	**23,289**	**23,278**	**24,331**	**25,779**
Reference Case (Cumulative GWh Savings)					
Residential	115	156	198	539	823
Commercial	75	135	194	727	1,135
Industrial	13	26	39	173	287
Total	**203**	**318**	**431**	**1,440**	**2,245**
Max Opt Out (Cumulative GWh Savings)					
Residential	115	156	198	539	823
Commercial	64	115	166	627	981
Industrial	8	16	24	110	184
Total	**187**	**288**	**389**	**1,277**	**1,988**
Savings as % of baseline					
Reference Case	0.9%	1.4%	1.9%	5.9%	8.7%
Max Opt Out	0.8%	1.2%	1.7%	5.2%	7.7%

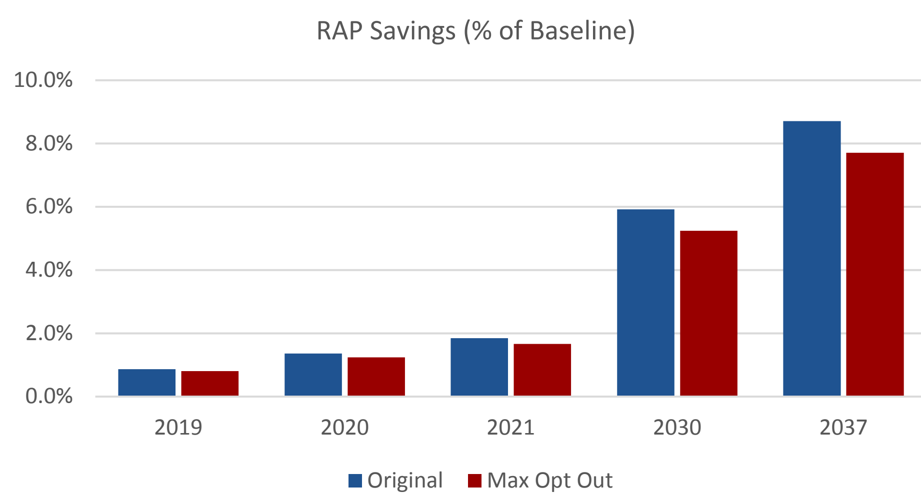

Figure 1-27 RAP Savings Maximum Opt Out Sensitivity

Impact of Naturally Occurring EE

The third and final sensitivity case was estimating the impact of naturally-occurring energy efficiency in the market. The reference baseline projection includes the effects of naturally-occurring energy efficiency anticipated without any utility DSM programs. We have the ability to deactivate these "above code" purchase decisions in the LoadMAP model to estimate energy consumption under a sensitivity where customers always choose the bare minimum if specified by a code or standard.

We estimate that without naturally-occurring energy efficiency, the baseline forecast would be 8.4% higher in 2037, a difference that is on the order of the Realistic Achievable and Maximum Achievable Potential savings. Figure 1-28 shows the relationship between the two projections.

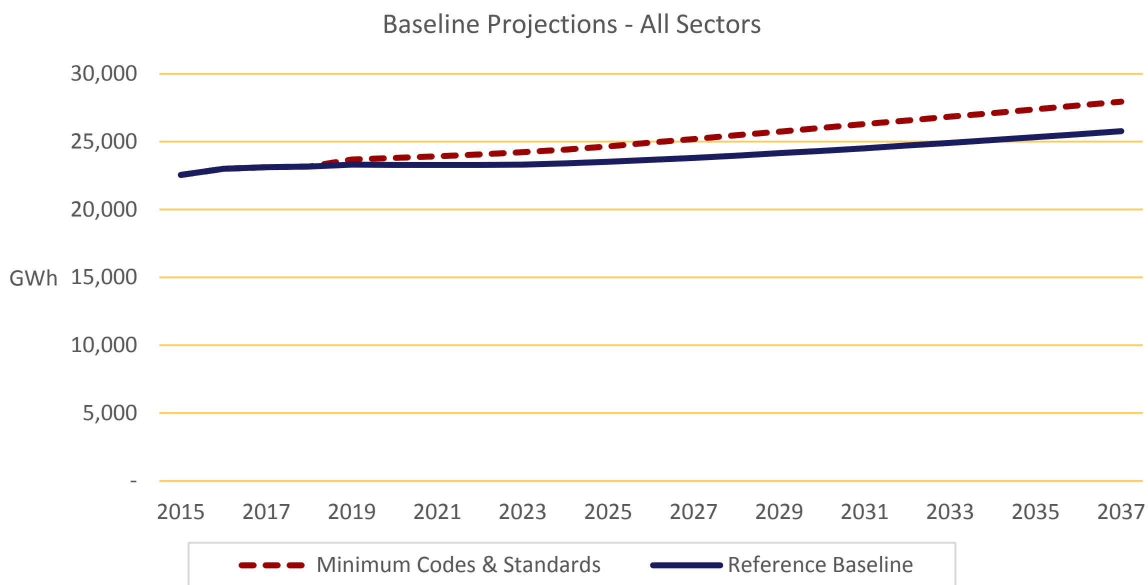

Figure 1-28 Baseline Projections with and without Naturally-occurring EE (All sectors)

Among the customer sectors, the effect is most noticeable in the commercial sector, where the baseline projection without naturally-occurring EE is 13.5% higher in 2037 compared to the Reference baseline. The residential sector shows the second highest impact at 6.3%, and industrial shows the least effect, only increasing the baseline by 3% at the end of the study period.

Figure 1-29, Figure 1-30, and Figure 1-31 show the impact of naturally-occurring energy efficiency for each sector, divided among the major end uses, which helps to highlight the sector differences that drive the varying impacts. For example, while all sectors benefit from naturally occurring customer lighting improvements, commercial customers also show a strong trend towards efficient office equipment (as evidenced by ENERGY STAR purchase data available from the Department of Energy). Industrial customers do not have significant naturally-occurring efficiency improvements in any other end uses.

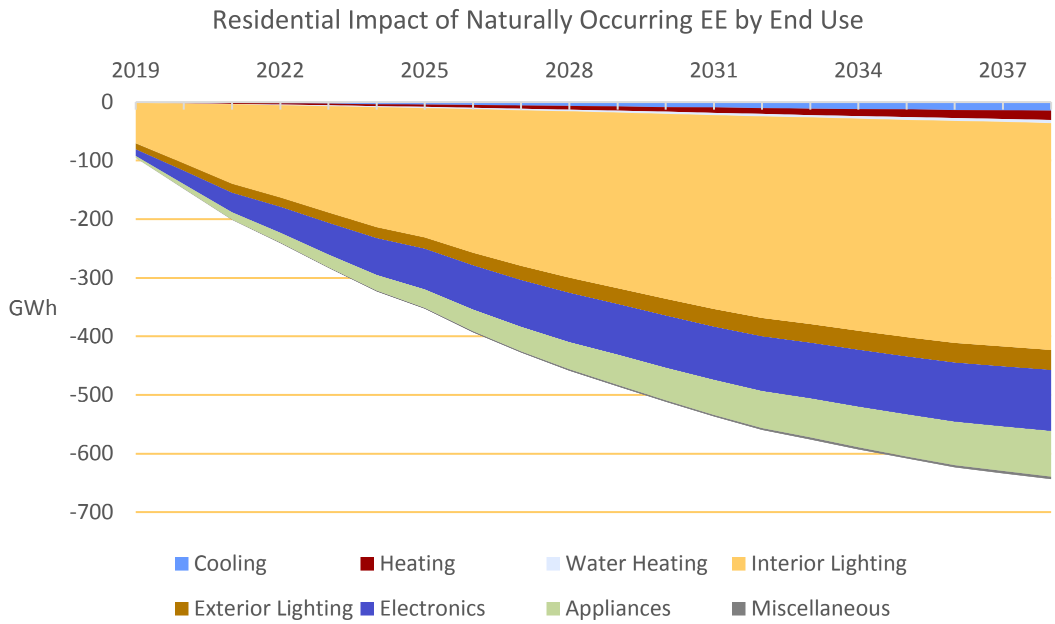

Figure 1-29 Residential Impact of Naturally-occurring Energy Efficiency

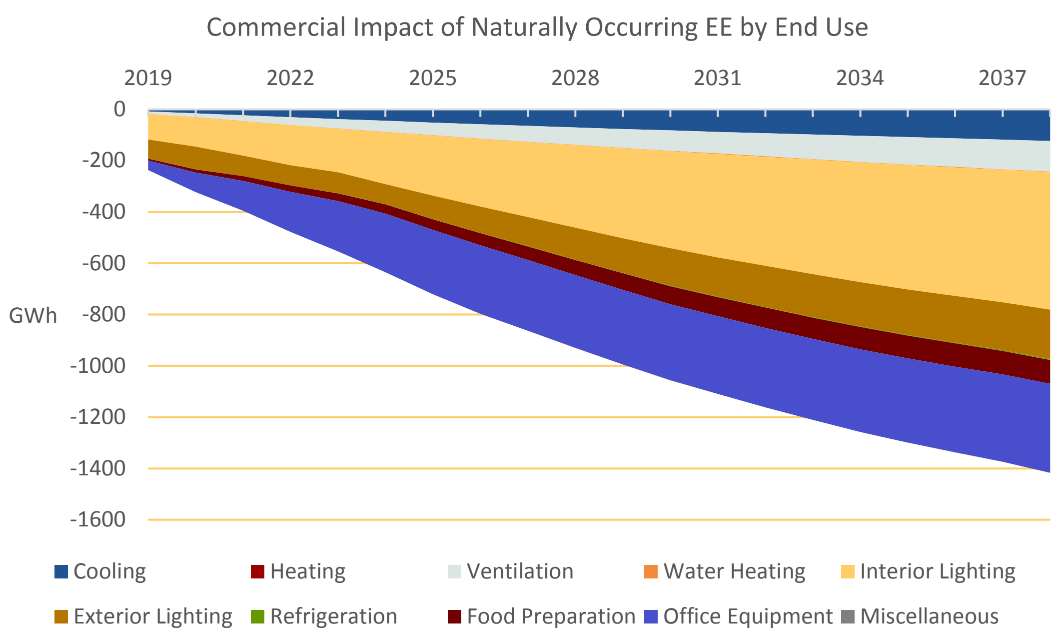

Figure 1-30 Commercial Impact of Naturally-occurring Energy Efficiency

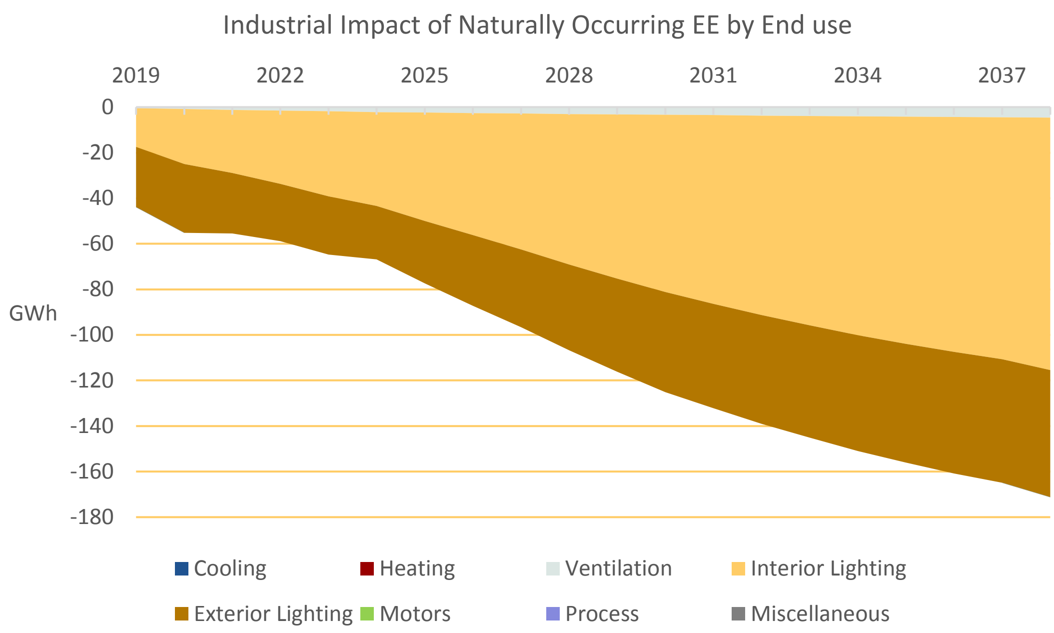

Figure 1-31 Industrial Impact of Naturally-occurring Energy Efficiency

2

Demand Response and Demand side Rates Potential

As a part of this DSM Market Potential Study, AEG conducted a demand response (DR) and demand side rates (DSR) potential analysis to understand the peak demand savings that could be achieved from peak-focused resources. This chapter will present the analysis process, key modeling assumptions, and potential results.

Demand Response and Demand-side Rates Analysis Approach

This portion of the analysis evaluates DR and incorporates the outcomes of the DSR development process with The Brattle Group (Brattle) and Stakeholders. The structure of and process for the DR and DSR potential assessment is similar to the EE potential analysis. The key difference is that DR and DSR are "program" concepts (not measures), meaning that customers will not take these actions without a utility offering. DR requires a program to induce savings (i.e., there is no naturally occurring DR). Similarly, DSR requires a "rate structure" to supply a price signal to induce savings or shift demand.

While DR and DSR are quite different from the customers' perspective, they are similar with respect to modeling requirements, so we analyze them together. Some programs will target the same customers so we take steps to avoid double-counting and overstating of participation.

The major analysis steps are listed below and described in detail in this chapter:

- Define the relevant DR and DSR resource options
- Characterize the market and develop a baseline projection
- Develop DR and DSR program assumptions
- Estimate DR and DSR potential
    - In order to estimate the potential, we first looked at each program on a standalone basis (and without an economic screen) in order to assess them individually.
    - Secondly, we impose a participation hierarchy so that customers can only participate in a maximum of one program of the same type. This eliminates double counting. In this "integrated" case, we also apply an economic screen to remove programs that do not have a TRC benefit to cost ratio > 1.0. These are achievable potential estimates. Note that technical and economic potential are not concepts typically applied to DR and DSR resources.

Identify Demand Response and Demand-side Rate Options

This study considers a comprehensive list of demand response programs available in the DSM marketplace today and projected into the 20-year study time horizon. These are controllable or dispatchable programmatic options where customers agree to reduce, shift, or modify their load during a limited number of event hours throughout the year. We briefly describe each of those options in Table 2-1 below.

Table 2-1 List of Demand Response Program Options in Analysis

Program Option	Eligible Customer Segments	Mechanism	Current Utility Offering?
DLC Space Cooling DLC Room AC DLC Water Heating DLC Space Heating	Residential, Small C&I	Direct Load Control switch installed on customer's equipment and operated remotely, typically by RF.	
DLC Smart Appliances	Residential, Small C&I	Internet-enabled control of operational cycles of white goods appliances.	
DLC Smart Thermostats	Residential, Small C&I	Internet-enabled control of thermostat set points.	Yes
Curtailment Agreements	Large C&I	Customers enact their customized, mandatory curtailment plan. May use stand-by generation. Penalties apply for non-performance. Various delivery mechanisms, contractual payment and penalty structures used – interruptible tariffs, third party aggregation, etc.	Yes
Ice Energy Storage	Small C&I	Peak shifting of primarily space cooling loads using stored ice.	
Battery Energy Storage	All	Peak shifting of loads using batteries on the customer side of the meter (stored electrochemical energy).	
Electric Vehicle DLC Smart Chargers	Residential	Smart, connected EV chargers that would automate vehicle charging such that it occurred preferentially during overnight, off-peak hours.	

Selecting Demand-Side Rates for Analysis

In addition to the demand response options, we also identified demand-side rate based options that are designed to incentivize customers to reduce, shift, or modify their load. Toward this end, AEG and Brattle first held a workshop with KCP&L staff to:

1. Review current KCP&L rates
2. Identify the universe of demand-side rate alternatives
3. Identify strategic pros and cons
4. Compare demand-side rates to KCP&L's current rates
5. Recommend a set of rates for the potential analysis

To assess alternative rate options, Brattle took a two-pronged approach that first considered how different each alternative rate is from current KCP&L rates. Currently, KCP&L has rates that include customer charges, seasonality, demand charges and declining block rates. Brattle notes that changes in rate designs must be thought of as incremental and, therefore, rate designs that are too different or divergent from the current KCP&L rates may not be realizable because of political feasibility or customer blowback. Second, rate options were assessed and scored based on the following Bonbright criteria:[16] 1) economic efficiency, 2) equity 3) revenue stability 4) bill stability 5) customer satisfaction. Out of these discussions, we identified the following ten rate options for initial, qualitative analysis and consideration:

[16] A set of utility rate design principles developed by James Cumming Bonbright that look to aid in rate development. James C. Bonbright, *Principles of Public Utility Rates* (New York: Columbia University Press, 1961).

- Critical Peak Pricing (CPP)
- Demand Charges
- Electric Vehicle (EV) Rates
- Inclining Block Rates (IBR)
- Peak Time Rebate (PTR)
- Prepaid Rebates
- Real Time Pricing
- Seasonal Rates
- Time of Use (TOU)
- Variable Peak Pricings (VPP)

To further select DSR options for quantitative analysis, AEG, Brattle, and KCP&L then met with Stakeholders, gathered their input, considered the degree of departure from KCP&L's current rates, weighed the strategic pros and cons with respect to the Bonbright criteria, and considered the analysis schedule and budget.

The final conclusion of the qualitative analysis was to proceed with the rates shown in *Table 2-2* for inclusion in the quantitative models:

Table 2-2 List of Demand Side Rate Options in the Analysis

Program Option	Eligible Customer Segments	Mechanism
Demand Rates	Residential	Opt-in rate that includes a billing component based on a customer's peak demand in a given month. This rate structure has traditionally been reserved for C&I customers, but better reflects the grid's evolving underlying cost structure and is being considered for residential application. Opt-in and opt-out options correspond to RAP and MAP respectively. We also investigate the effects of this rate on customers with electric vehicles, who would in effect have an "enabling technology" in the form of their EV that would enable them to shift large amounts of usage and demand by charging their EV during off-peak hours.
Time-of-use Rates	Residential, Small C&I, Large C&I	Higher rate for a particular block of hours that occurs every day. Requires interval meters. Opt-in and opt-out options correspond to RAP and MAP respectively. Similar to the demand rate, we also investigated TOU rates for customer with electric vehicles.
Real-time Pricing	Small C&I, Large C&I	Dynamic rate that fluctuates throughout the day based on energy market prices. Requires interval meters. This is modeled with an opt-in roll-out, which is the only typical implementation that has been observed in the industry. Low and high opt-in participation levels are assumed for RAP and MAP respectively.
Inclining Block Rates	Residential	Higher per-unit price for incremental blocks of monthly energy usage. This is modeled with a mandatory roll-out, which is the only typical implementation that has been observed in the industry. We investigate two cases here, one where the fixed charge remains the same, and another where the fixed charge increases in a manner that is often done in these implementations to preserve revenue stability.

Program Participation Hierarchy

To avoid double counting of load reduction impacts, program-eligibility criteria were defined to ensure that customers do not participate in mutually exclusive programs at the same time. For example, small C&I customers cannot participate in the DLC Space Cooling program and the Ice Energy Storage program since both of them would target the same load from the same end use for curtailment on the same days. Table 2-3 shows the participation hierarchy by customer sector for applicable DR options.

With the hierarchy activated, each successive resource that is run in the model stack has a newly updated pool of eligible participants where customers enrolled in previously-stacked, competing resource options have been removed. The participation rate for that resource is then applied to the new pool of eligible participants, rather than the entire, original pool.

Table 2-3 Participation Hierarchy in DR and DSR options by Customer Class

	Customer Class	Residential	Small C&I	Large C&I
Loaded First	DLC Space Cooling	x	x	
	DLC Space Heating	x	x	
	DLC Water Heating	x	x	
	DLC Smart Thermostats	x	x	
	DLC Smart Appliances	x		
	DLC Room AC	x		
	Ice Energy Storage		x	
	Curtail Agreements			x
	Battery Energy Storage	x	x	x
	DLC Elec Vehicle Charging	x		
Loaded Last	Rate structure:			
	Time-Of-Use with EV	x		
	Time-Of-Use	x	x	x
	Demand Rate with EV	x		
	Demand Rate	x		
	Real Time Pricing		x	x
	Inclining Block Rate	x		

Market Characterization

The analysis begins with segmentation of the KCP&L customer base and a description of how customers use energy in the peak hour.

The first dimension of customer segmentation is by sector and the second dimension is by customer size. The residential sector is considered a single group, designated by the same customer population and data used for the EE portion of this potential analysis. The non-residential sector combines both commercial and industrial customers and segments them into Small C&I and Large C&I. A size breakpoint, specifically one at 200 kW per customer, is relevant because it separates the smaller customers that are amenable to direct load control type programs from larger customers that exceed the minimum recruitment threshold to make them attractive and economical for Curtailment Agreement and/or Third-Party Aggregation style DR programs.

Unlike the EE portion of the analysis, opt out customers are included throughout the DR and DSR potential analysis, as the relevant legislation for opt out eligibility only applies to energy efficiency programs. All large C&I customers are therefore included in the DR and DSR analysis.

Also note that Advanced Metering Infrastructure (AMI) is actively rolling out now in KCP&L's service territory, with approximately 500,000 meters in the metro area already, and should be completed soon. For this analysis, we assume that AMI is fully available in all years of interest (2019-2037).

Baseline Customer and Coincident Peak Projection

The next step was to define the baseline projection for the number of customers and peak demand for each customer segment. Consistent with the EE potential analysis, the base year is 2015 and is characterized by using KCP&L's 2015 billing data. The baseline projection incorporates KCP&L's forecasts of summer peak demand and customer counts from 2015 through 2037. KCP&L's total customer count projections were allocated to correspond to the segmentation scheme defined above. KCP&L also provided their summer and winter peak demand projections with any savings or impacts from future DSM programs removed (same method as EE analysis above). The total system peak demand was allocated to the segments in a similar manner as the customer counts above.[17] Table 2-4 presents the system-wide control totals for the base year by sector. Table 2-5 presents the baseline projections for customers, summer peak, and winter peak. All territories are strongly summer peaking, except for GMO-SJLP, where the winter peak is still lower than the summer peak, but approaching parity due to high regional saturations of electric space and water heating.

Table 2-4 Baseline Market Characterization by Segment for DR Analysis

	No. of Customers	2015 Annual Energy (MWh)	2015 Summer Peak Demand (MW)	2015 Winter Peak Demand (MW)
Residential	742,047	8,584,589	2,786	2,043
Small C&I	87,264	4,102,200	818	717
Large C&I	13,416	9,866,288	1,697	1,490
C&I Subtotal	*100,680*	*13,968,487*	*2,516*	*2,207*
TOTAL SYSTEM	**842,727**	**22,553,077**	**5,302**	**4,250**

Table 2-5 Baseline Projections by Service Territory for DR Analysis

	2015	2019	2020	2021	2030	2037
Number of Customers						
KCP&L-MO	275,748	281,268	282,921	284,591	297,859	305,818
GMO-MPS	252,528	260,840	262,645	264,399	277,104	284,197
GMO-SJLP	65,319	65,521	65,662	65,800	66,823	67,389
KCP&L-KS	249,132	260,754	262,757	264,613	280,209	290,577
Total	**842,727**	**868,383**	**873,985**	**879,403**	**921,995**	**947,981**
Coincident Summer Peak Projection by Segment (MW @ Meter)						
KCP&L-MO	1,802	1,892	1,902	1,910	2,027	2,126
GMO-MPS	1,430	1,435	1,444	1,450	1,466	1,532
GMO-SJLP	447	450	446	442	426	441
KCP&L-KS	1,623	1,770	1,793	1,813	1,956	2,051
Total	**5,302**	**5,548**	**5,585**	**5,615**	**5,875**	**6,150**
Coincident Winter Peak Projection by Segment (MW @ Meter)						
KCP&L-MO	1,411	1,427	1,434	1,438	1,515	1,575
GMO-MPS	1,156	1,184	1,182	1,182	1,175	1,208
GMO-SJLP	423	422	422	421	413	421
KCP&L-KS	1,260	1,274	1,287	1,291	1,387	1,467
Total	**4,250**	**4,308**	**4,325**	**4,332**	**4,490**	**4,671**

[17] Because of differing methodologies, models and segmentation, the system peak demand projections used in the DR analysis are slightly different than that used in the EE analysis. This small difference does not, materially affect the outcome of the study.

DR AND DSR KEY PROGRAM ASSUMPTIONS

The next step is to develop the key data elements for the potential calculations: per-customer load reduction impacts, customer participation levels, and program costs.

PEAK DEMAND REDUCTION IMPACTS

The potential demand savings are calculated by multiplying the per-customer load reduction at system peak by the total number of participating customers. Existing program impacts were sourced from KCP&L program experience and the 2016-2018 MEEIA and KEEIA plan filings, specifically for the program options DLC Smart Thermostat and Curtailment Agreements. The remaining program impacts were developed through secondary research. Program impacts are equivalent across service territories and between the RAP and MAP cases, except for TOU and Demand Rate where impacts vary between RAP and MAP to reflect the difference between the customer population in the opt-in scenario (RAP) and those in the opt-out scenario (MAP). A more engaged population with higher responsiveness is anticipated to volunteer for a program, while an opt-out program will have moderated responsiveness due to the enrollment of the entire eligible customer base. The assumptions used in the model for per-customer summer and winter peak savings are shown in Table 2-6 below.

Table 2-6 Per-Unit DR & DSR Load Reduction Assumptions

Customer Class	Option	Unit	Summer Peak Impact	Winter Peak Impact
Residential	DLC Space Cooling	kW @meter	1.26	-
Residential	DLC Space Heating	kW @meter	-	1.65
Residential	DLC Water Heating	kW @meter	0.58	0.58
Residential	DLC Smart Thermostats	kW @meter	1.26	0.70
Residential	DLC Smart Appliances	kW @meter	0.14	0.14
Residential	DLC Room AC	kW @meter	0.47	-
Residential	Battery Energy Storage	kW @meter	2.00	2.00
Residential	DLC Elec Vehicle Charging	kW @meter	0.92	0.92
Residential	Time-Of-Use (opt-out)	% customer peak @meter (MAP)	*6.7%*	*6.1%*
Residential	Time-Of-Use (opt-in)	% customer peak @meter (RAP)	*10.9%*	*10.1%*
Residential	Time-Of-Us w EV	kW @meter	1.80	1.67
Residential	Demand Rate (opt-out)	% customer peak @meter (MAP)	*6.7%*	*7.8%*
Residential	Demand Rate (opt-in)	% customer peak @meter (RAP)	*11.1%*	*13.0%*
Residential	Demand Rate w EV	kW @meter	1.81	2.07
Residential	Inclining Block Rate	% customer peak @meter	1.3%	0.8%
Small C&I	DLC Space Cooling	kW @meter	1.51	-
Small C&I	DLC Space Heating	kW @meter	-	1.98
Small C&I	DLC Water Heating	kW @meter	0.70	0.70
Small C&I	DLC Smart Thermostats	kW @meter	1.51	0.78
Small C&I	Ice Energy Storage	kW @meter	5.00	0.00
Small C&I	Battery Energy Storage	kW @meter	2.00	2.00
Small C&I	Time-Of-Use	% customer peak @meter	0.4%	0.4%
Small C&I	Real Time Pricing	% customer peak @meter	0.7%	0.7%
Large C&I	Curtail Agreements	% customer peak @meter	21.0%	21.0%
Large C&I	Battery Energy Storage	kW @meter	15.00	15.00
Large C&I	Time-Of-Use	% customer peak @meter	4.4%	4.4%
Large C&I	Real Time Pricing	% customer peak @meter	9.5%	9.5%

Development of Demand Side Rate Impacts

For the residential sector, which included the option of a mandatory inclining block rate, Brattle developed specific assumptions about how the rate is designed and delivered. Brattle did so in revenue neutral configurations as illustrated in Table 2-7 below.

Table 2-7 Residential Demand Side Rate Designs[18]

	Season	Current Pricing	Demand Charge Pricing	Time of Use Pricing	Inclining Block Rate
Customer Charge ($/month)		$11.88	$11.88	$11.88	$21.88
Volumetric Charge ($/kWh)					
Tier 1	Summer	$0.13	$0.10		$0.12
	Winter	$0.12	0.06		$0.07
Tier 2	Summer	$0.13	$0.10		$0.14
	Winter	$0.07	$0.06		$0.09
Tier 3	Summer	$0.13	$0.10		
	Winter	$0.06	$0.06		
Peak (4PM-8PM)	Summer			$0.36	
	Winter			$0.22	
Off-Peak	Summer			$0.12	
	Winter			$0.07	
Super Off Peak	Summer			$0.06	
	Winter			$0.04	
Monthly Demand Charge	Summer		$8.00 / kW		
	Winter		$4.95 / kW		

It is assumed that if implemented, the inclining block rate (IBR) would be mandatory. The IBR model does not differentiate behavior responses by time of day. Therefore, the predicted percent impact on peak demand is set equal to the predicted percent impact on energy consumption. Summer peak impacts are calculated as the predicted impact on summer energy consumption.

To estimate residential rate impacts for each rate design. Brattle relied on the PRISM model. For demand charges and time-of-use energy charges, Brattle estimated the expected impact for each of an opt-in and an opt-out scenario.

For the commercial and industrial customers, Brattle estimated rate impacts under the Time-of-Use Energy Charge and a Real-Time Energy Pricing rate using the Arc of Price Responsiveness model, which estimates the impacts based on the ratio of on-peak to off-peak prices and not comprehensive rate designs. For this study, time-of-use impacts are estimated based on an on-peak to off-peak ratio of 3:1 and real-time pricing impacts are estimated based on a highest to lowest intraday price ratio of 10:1.

PROGRAM PARTICIPATION RATES

Participation rate assumptions are defined as the percent of eligible customers who take part in a given program in a given year. Note that a customer is not considered eligible if they do not have the relevant equipment or are already participating in a mutually exclusive program. The existing programs (DLC Smart Thermostat and Curtailment Agreements) are calibrated in year 1 to current performance. The

[18] Summer is defined here as June 1 through September 30. Results are modeled using PRISM coefficients for Zone 4. Residential Demand Charge and TOU are predicted for both an opt-in and opt-out scenario. In the opt-out scenario, a de-rate factor of 40% is applied to account for customer population characteristics.

remaining programs were developed by researching DR programs at utilities similar to KCP&L in size and region, then normalizing for the KCP&L system and customer base.

In general, new DR and DSR programs need time to ramp up and reach a steady state. During ramp up, customer education, marketing and recruitment take place, as well as the physical implementation and installation of any hardware, software, telemetry, or other equipment required. For KCP&L, it is assumed that programs ramp up to steady state over five years, typical of industry experience. There are some exceptions to this general rule:

- Under the mandatory residential inclining block rate, 100% of relevant customers are enrolled automatically
- Under an opt-out rate, which includes Time-Of-Use in the MAP case and Demand Rates in the MAP case, 100% of relevant customers are also enrolled automatically, but they may choose to leave the rate at any time.

Table 2-8 shows the assumed participation in DR and DSR options for the two scenarios considered, realistic and maximum achievable potential, by customer sector. All programs, except KCP&L's existing DLC Smart Thermostat and Curtailment agreement programs are assumed to begin ramping up in 2019.

Table 2-8 Participation Rates by Option and Customer Sector (percent of eligible customers)

			Steady State Participation Rate	
Option	**Category**	**Program**	**RAP**	**MAP**
Residential	DR	DLC Space Cooling	7.0%	8.0%
Residential	DR	DLC Space Heating	15.0%	22.5%
Residential	DR	DLC Water Heating	15.0%	22.5%
Residential	DR	DLC Smart Thermostats	18.0%	22.0%
Residential	DR	DLC Smart Appliances	5.0%	7.5%
Residential	DR	DLC Room AC	15.0%	22.5%
Residential	DR	Battery Energy Storage	1.0%	1.5%
Residential	DR	DLC Elec Vehicle Charging	20.0%	30.0%
Residential	DSR	Time-Of-Use	28.0%	85.0%
Residential	DSR	Time-Of-Use w EV	85.0%	100%
Residential	DSR	Demand Rate	28.0%	85.0%
Residential	DSR	Demand Rate w EV	84.0%	100.0%
Residential	DSR	Inclining Block Rate	100.0%	100.0%
Small C&I	DR	DLC Space Cooling	3.0%	4.5%
Small C&I	DR	DLC Space Heating	3.0%	30.0%
Small C&I	DR	DLC Water Heating	3.0%	4.5%
Small C&I	DR	DLC Smart Thermostats	5.0%	7.5%
Small C&I	DR	Ice Energy Storage	1.5%	2.3%
Small C&I	DR	Battery Energy Storage	1.0%	3.0%
Small C&I	DSR	Time-Of-Use	13.0%	74.0%
Small C&I	DSR	Real Time Pricing	18.0%	31.0%
Large C&I	DR	Curtail Agreements	45.9%	55.0%
Large C&I	DR	Battery Energy Storage	1.0%	3.0%
Large C&I	DSR	Time-Of-Use	13.0%	74.0%
Large C&I	DSR	Real Time Pricing	18.0%	31.0%

Program Costs

Program costs include fixed and variable cost elements for numerous aspects of program delivery: program development costs, annual program administration costs, marketing and recruitment costs, enabling technology costs for purchase and installation, annual O&M costs, and participant incentives. These assumptions are based on actual program costs from existing or past KCP&L programs. For new programs, assumptions are based on actual AEG program implementation experience, experience in developing program costs for other similar studies, and secondary research.

Estimating Demand Response and Demand-side Rate Potential

As with the EE analysis, we estimated several levels of potential as defined below:

- **Standalone DR/DSR potential.** In this case, each DR and DSR option is assessed independently, without regard for the participation hierarchy and assuming maximum expected participation (equivalent to the MAP case for EE). This gives the maximum savings that could be attained for each option. It also allows us to consider a first-level estimate of cost-effectiveness. Programs that have a benefit-cost ratio of 1.0 or greater pass into the estimation of achievable potential.[19]
- **Maximum achievable DR/DSR potential.** The case is analogous to MAP in the EE analysis. It considers only those programs that pass the first-level cost-effectiveness screen and assumes the highest level of customer participation. We also apply the participation hierarchy to restrict customer participation to only one DR or DSR option. Savings and cost-effectiveness are reported after the resource stacking and integration occurs with the subset of cost-effective options.
- **Realistic achievable DR/DSR potential.** This case is the same as the above maximum achievable potential case except that more realistic customer participation rates are assumed. Again, only those options that are cost-effective are included in the savings estimates.

Cost-effectiveness Screening

For each case, the DR and DSR options are assessed for cost-effectiveness using the TRC test, which uses avoided costs, discount rate, and line losses provided by KCP&L. As mentioned above, the costs are made up of program development costs, annual program administration costs, marketing and recruitment costs, enabling technology costs for purchase and installation, annual O&M costs, and participant incentives.

The cost-effectiveness of individual DR and DSR options are assessed with different program-start years until the first cost-effective year is identified. Demand savings are realized only in years the option is cost-effective. Once an option is deployed, benefit-to-cost ratios are estimated for each contiguous program cycle independently throughout the study time period.

Program Lifetime

Calculation of cost effectiveness requires an assumption about DR program lifetimes. Table 2-9 presents lifetime assumptions of the various DR option. The Curtailment Agreement lifetime is based on the typical contract term used by third-party DR aggregator firms, which is three to five years.

Table 2-9 DR Program Life Assumptions

DR Option	Lifetime (Years)
Direct Load Control	10
Ice Energy Storage	20
Battery Energy Storage	12
Curtailment Agreement	3

[19] Technical and Economic Potential are not useful theoretical concepts for Demand Response analyses because these resources are inherently based on customer behaviors and program activity. Therefore, it is necessary to include an assumption about levels of customer adoption and participation, which does not appear in the definition of technical or economic potential.

Demand Response and Demand Side Rate Potential Results

In the remainder of this section, we present estimates for the three cases described above. It is important to note that potential savings going into the study time horizon are essentially comprised of savings from existing KCP&L programs, which means the incremental new potential occurring in 2019 and beyond is smaller than the cumulative total by the amount of savings that KCP&L is already implementing. All impacts are presented at the customer meter.

Standalone DR/DSR Potential

Potential savings estimates and benefit-to-cost ratios for the standalone case are presented in Table 2-10 for summer and winter. Based on these results, the below list of DR and DSR program options are not cost-effective and are eliminated from moving forward into the calculation of achievable potential:

- DLC Space Heating
- DLC Smart Appliances
- DLC Room AC
- Ice Energy Storage
- DLC Electric Vehicle Charging
- Battery Energy Storage.

In summer, top savers are DLC Smart Thermostat, TOU Rate, and Demand Rate. In winter, top savers in 2037 are DLC Smart Thermostat, DLC Space Heating, Demand Rate, and TOU Rate. Again, these results assume the same participation levels used in the maximum achievable potential case, which will be discussed shortly. The sum total of all the options is not applicable since not all programs can run simultaneously in the standalone analysis case.

Table 2-10 Standalone DR & DSR Potential for 2037

	Summer Peak		Winter Peak		Cost-Effectiveness
	2037 MW	**2037 as a % of Baseline**	**2037 MW**	**2037 as a % of Baseline**	**2019-2037 TRC**
Baseline Forecast (MW)	**6,150**		**4,671**		
DLC Space Cooling	86.91	1.41%	-	0.00%	2.59
DLC Space Heating	-	-	126.07	2.70%	0.06
DLC Water Heating	23.08	0.38%	23.08	0.49%	1.35
DLC Smart Thermostats	234.63	3.82%	130.02	2.78%	2.38
DLC Smart Appliances	8.64	0.14%	8.64	0.19%	0.85
DLC Room AC	5.39	0.09%	-	0.00%	0.98
Ice Energy Storage	6.76	0.11%	-	0.00%	0.71
Curtail Agreements	227.75	3.70%	198.66	4.25%	1.74
DLC Elec Vehicle Charging	4.11	0.07%	4.11	0.09%	0.81
Battery Energy Storage	37.42	0.61%	37.42	0.80%	0.46
Time-Of-Use w EV	26.69	0.43%	24.86	0.53%	22.95
Time-Of-Use	241.59	3.93%	164.48	3.52%	55.27
Demand Rate w EV	26.94	0.44%	30.73	0.66%	39.62
Demand Rate	179.10	2.91%	136.85	2.93%	24.48
Real Time Pricing	60.16	0.98%	52.46	1.12%	82.15
Inclining Block Rate	40.15	0.65%	17.35	0.37%	9.04

Table 2-11 presents information on program costs for each option in the standalone case, again assuming participation levels equivalent to the maximum achievable potential scenario. The largest contributor to peak reduction, DLC Smart Thermostat, and many others, have levelized costs well below $100/kW-year. DLC Electric Vehicle has the highest levelized costs due to significant technology/equipment costs and fixed administration costs. Similar costs and trends are seen with Battery Storage and Ice Energy Storage.

Note that the 2019-2037 average TRC ratio only includes the value of capacity for summer peak demand savings. We did not assign any avoided cost benefits in the model to winter capacity savings. KCP&L is a summer peaking utility, so the capacity position is still measured and valued relative to the summer peak.

Table 2-11 Standalone DR & DSR Program Costs

Option	2037 Summer Peak MW Potential*	2019 – 2037 Cumulative Utility Spend (Million $)	2019 – 2037 Average Spend per Year (Million $)	2019 – 2037 Levelized Cost ($/kW-year)	2019-2037 TRC
DLC Space Cooling	86.91	$68.02	$3.40	$55.72	2.59
DLC Space Heating	*126.07**	*$75.11**	*$3.76**	*$41.56**	*0.06**
DLC Water Heating	23.08	$33.83	$1.69	$109.08	1.35
DLC Smart Thermostats	234.63	$212.02	$10.60	$61.31	2.38
DLC Smart Appliances	8.64	$23.39	$1.17	$231.43	0.85
DLC Room AC	5.39	$12.10	$0.60	$148.03	0.98
Ice Energy Storage	6.76	$15.19	$0.76	$189.68	0.71
Curtail Agreements	227.75	$311.57	$15.58	$80.32	1.74
DLC Elec Vehicle Charging	4.11	$9.36	$0.47	$247.41	0.81
Battery Energy Storage	37.42	$102.90	$5.14	$238.19	0.46
Time-Of-Use with EV	26.69	$2.17	$0.11	$8.61	22.95
Time-Of-Use	241.59	$10.84	$0.54	$3.34	55.27
Demand Rate with EV	26.94	$1.28	$0.06	$5.14	39.62
Demand Rate	179.10	$17.59	$0.88	$7.71	24.48
Real Time Pricing	60.16	$2.47	$0.12	$2.28	82.15
Inclining Block Rate	40.15	$18.38	$0.92	$37.12	9.04

**DLC Space Heating impacts and costs provided for winter instead of summer as other options in table*

Standalone DR/DSR Potential by Jurisdiction

In the tables below, we present the standalone impacts and program budgets by service territory. Levelized costs and TRC values are generally the same from one territory to another. Once again, these results assume the same participation levels used in the maximum achievable potential case, which will be discussed shortly. The sum total of all the options is not applicable since not all programs can run simultaneously in the standalone analysis case.

Table 2-12 Standalone DR & DSR Summer Peak MW Potential by Service Territory

Option	KCP&L-MO	KCP&L-KS	GMO-MPS	GMO-SJLP	All Service Territories
DLC Space Cooling	27.54	25.93	5.84	27.61	**86.91**
DLC Space Heating	-	-	-	-	**-**
DLC Water Heating	4.76	7.71	3.25	7.36	**23.08**
DLC Smart Thermostats	74.25	70.03	15.73	74.62	**234.63**
DLC Smart Appliances	2.77	2.59	0.62	2.66	**8.64**
DLC Room AC	2.03	2.00	0.74	0.61	**5.39**
Ice Energy Storage	2.28	1.98	0.50	2.01	**6.76**
Curtail Agreements	98.50	51.68	22.42	55.16	**227.75**
DLC Elec Vehicle Charging	2.21	0.87	0.50	0.53	**4.11**
Battery Energy Storage	12.13	11.46	2.51	11.32	**37.42**
Time-Of-Use w EV	14.34	5.67	3.22	3.46	**26.69**
Time-Of-Use	79.01	59.31	17.03	86.23	**241.59**
Demand Rate w EV	14.48	5.72	3.25	3.49	**26.94**
Demand Rate	51.68	45.07	10.86	71.49	**179.10**
Real Time Pricing	25.85	13.78	5.82	14.71	**60.16**
Inclining Block Rate	11.58	10.10	2.43	16.02	**40.15**

Table 2-13 Standalone DR & DSR Winter Peak MW Potential by Service Territory

Option	KCP&L-MO	KCP&L-KS	GMO-MPS	GMO-SJLP	All Service Territories
DLC Space Cooling	-	-	-	-	**-**
DLC Space Heating	33.89	41.86	11.58	38.74	**126.07**
DLC Water Heating	4.76	7.71	3.25	7.36	**23.08**
DLC Smart Thermostats	41.14	38.81	8.71	41.36	**130.02**
DLC Smart Appliances	2.77	2.59	0.62	2.66	**8.64**
DLC Room AC	-	-	-	-	**-**
Ice Energy Storage	-	-	-	-	**-**
Curtail Agreements	81.86	43.41	23.59	49.80	**198.66**
DLC Elec Vehicle Charging	2.21	0.87	0.50	0.53	**4.11**
Battery Energy Storage	12.13	11.46	2.51	11.32	**37.42**
Time-Of-Use w EV	13.36	5.28	3.00	3.22	**24.86**
Time-Of-Use	52.83	43.12	14.91	53.62	**164.48**
Demand Rate w EV	16.51	6.52	3.71	3.99	**30.73**
Demand Rate	37.47	38.93	10.48	49.97	**136.85**
Real Time Pricing	21.48	11.58	6.13	13.28	**52.46**
Inclining Block Rate	4.75	4.93	1.33	6.34	**17.35**

Table 2-14 Standalone DR & DSR 2019–2037 Cumulative Utility Spend (Million $) by Service Territory

Option	KCP&L-MO	KCP&L-KS	GMO-MPS	GMO-SJLP	All Service Territories
DLC Space Cooling	$18.08	$16.93	$3.85	$17.96	**$56.83**
DLC Space Heating	$17.03	$20.70	$5.76	$19.16	**$62.65**
DLC Water Heating	$5.52	$8.86	$3.76	$8.45	**$26.59**
DLC Smart Thermostats	$62.24	$58.37	$13.03	$62.09	**$195.73**
DLC Smart Appliances	$7.51	$7.01	$1.67	$7.21	**$23.39**
DLC Room AC	$3.55	$3.89	$1.43	$1.14	**$10.02**
Ice Energy Storage	$5.11	$4.45	$1.12	$4.50	**$15.19**
Curtail Agreements	$128.47	$72.73	$34.39	$75.98	**$311.57**
DLC Elec Vehicle Charging	$4.72	$1.87	$1.06	$1.14	**$8.79**
Battery Energy Storage	$3.47	$3.16	$0.77	$3.44	**$10.84**
Time-Of-Use w EV	$1.17	$0.46	$0.26	$0.28	**$2.17**
Time-Of-Use	$5.61	$5.18	$1.27	$5.53	**$17.59**
Demand Rate w EV	$0.69	$0.27	$0.15	$0.17	**$1.28**
Demand Rate	$0.88	$0.71	$0.19	$0.69	**$2.47**
Real Time Pricing	$5.85	$5.43	$1.29	$5.81	**$18.38**
Inclining Block Rate	$3.47	$3.16	$0.77	$3.44	**$10.84**

Achievable DR/DSR Potential

In this section, the potential savings are presented for programs in a more real-life, integrated basis with the participation hierarchy (see Table 2-3) in effect to prevent double-counting of customer impacts in overlapping programs. Table 2-15 presents the aggregate potential from DR and DSR options for the RAP and MAP in the summer season. Peak demand savings potential for RAP starts at 199 MW at the beginning of the study and rises to 676 MW in 2037. For MAP, savings start at 416 MW in 2019 and increase to 818 MW in 2037. This corresponds to a reduction of 11% and 13% respectively from KCPL's projected 2037 summer system peak. The expected impact on the peak load forecast is shown in Figure 2-1.

Table 2-15 Overall Summary of DR & DSR Achievable Potential for 2037 (Summer Peak)

	2019	2020	2021	2027	2037
Baseline Projection (Summer MW)	5,548	5,585	5,615	5,875	6,150
Potential Savings (MW)					
Realistic Achievable Potential	199	291	420	636	676
Maximum Achievable Potential	416	509	595	772	818
Potential Savings (% of baseline)					
Realistic Achievable Potential	3.6%	5.2%	7.5%	10.8%	11.0%
Maximum Achievable Potential	7.5%	9.1%	10.6%	13.1%	13.3%

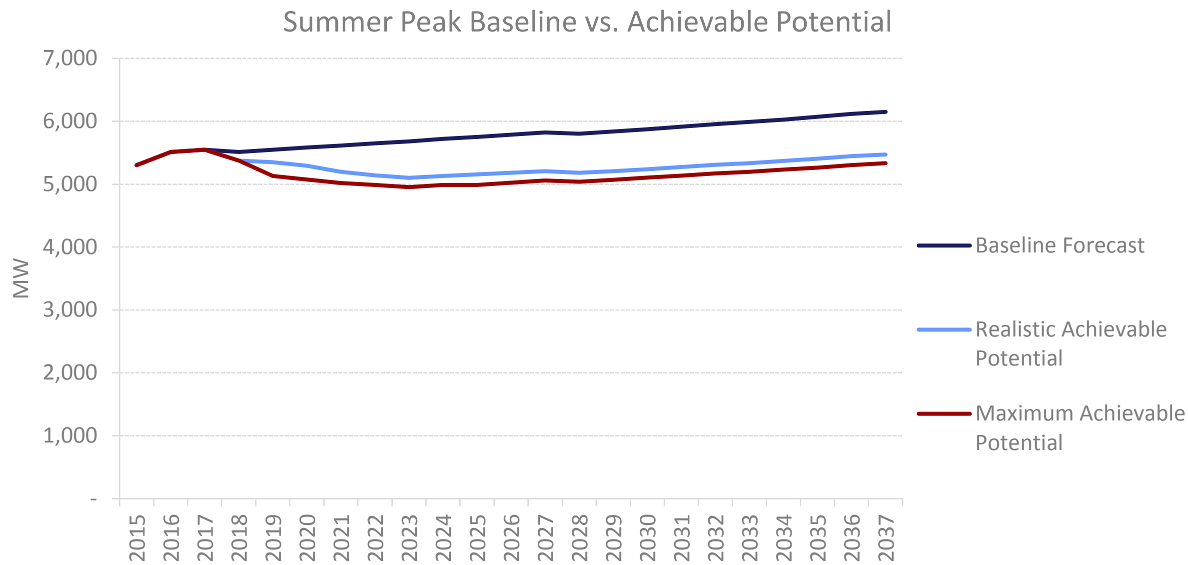

Figure 2-1 Baseline and Achievable DR & DSR Potential Forecasts (Summer Peak MW)

Table 2-16 and Table 2-17 provide the summer peak savings potential by program option for realistic achievable and maximum achievable potential, respectively. Figure 2-2 presents this same data graphically for the RAP case, making it easy to see that the largest savings come from Direct Load Control of Smart Thermostats and Curtailment Agreements programs with large C&I customers.

Regarding the residential DSR options, it is important to remember that each residential customer is on one of the rate options, with IBR being the default. In the RAP case, which offers demand rates and time-of-use rates on an opt-in basis, all customer start on IBR and, over time, some customers will opt-in (and switch) to the other two options. Therefore, IBR savings decrease and demand and TOU savings increase over the forecast horizon.

Table 2-16 Realistic Achievable Potential by Option (Summer Peak)

	2019	2020	2021	2030	2037	2037 as % of Baseline
Baseline Forecast (Summer MW)	**5,548**	**5,585**	**5,615**	**5,875**	**6,150**	
Achievable Potential (MW)	**198.72**	**290.76**	**420.09**	**636.36**	**675.96**	**10.99%**
DLC Space Cooling	6.26	19.00	44.86	70.52	75.21	1.22%
DLC Water Heating	1.18	3.60	8.54	13.98	15.39	0.25%
DLC Smart Thermostats	61.01	85.14	107.79	167.33	178.05	2.90%
Curtail Agreements	80.06	103.67	128.12	184.71	190.07	3.09%
Time-Of-Use w EV	0.30	1.05	2.79	12.16	17.26	0.28%
Time-Of-Use	9.18	26.66	59.20	80.66	84.35	1.37%
Demand Rate w EV	0.30	1.06	2.81	12.10	17.08	0.28%
Demand Rate	8.11	22.07	42.64	50.48	52.64	0.86%
Real Time Pricing	0.11	0.95	3.28	29.52	30.38	0.49%
Inclining Block Rate	32.20	27.55	20.05	14.90	15.54	0.25%

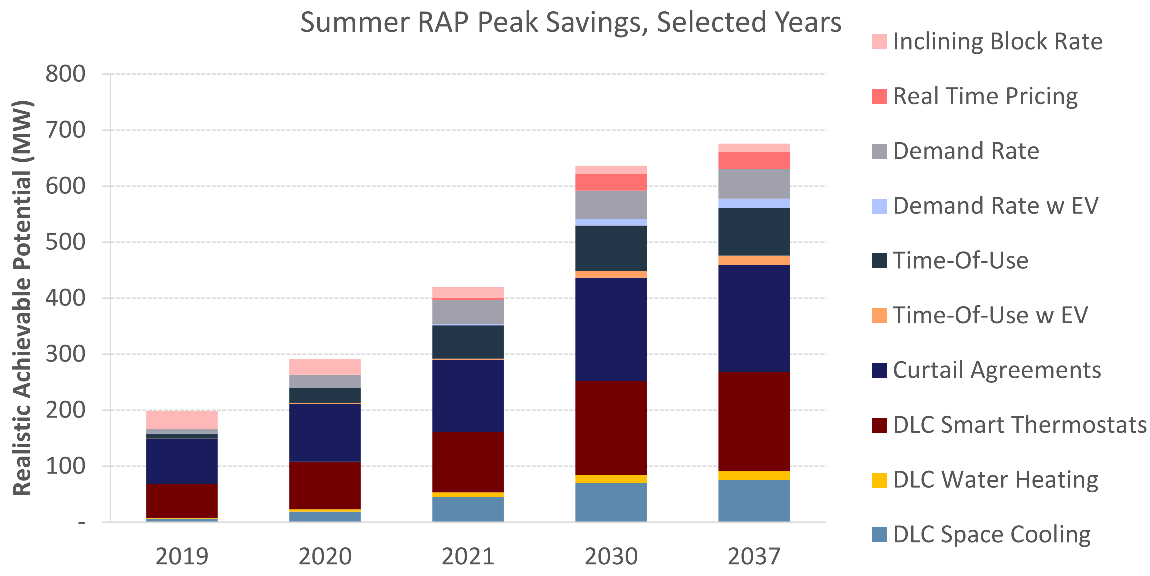

Figure 2-2 Realistic Achievable DR & DSR Potential (Summer MW)

Table 2-17 Maximum Achievable Potential by Option (Summer Peak)

	2019	2020	2021	2030	2037	2037 as % of Baseline
Baseline Forecast (Summer MW)	**5,548**	**5,585**	**5,615**	**5,875**	**6,150**	
Achievable Potential (MW)	**416.38**	**508.52**	**594.94**	**771.99**	**817.91**	**13.30%**
DLC Space Cooling	7.24	21.99	51.90	81.54	86.91	1.41%
DLC Water Heating	1.77	5.40	12.81	20.97	23.08	0.38%
DLC Smart Thermostats	60.96	93.93	124.81	203.63	216.55	3.52%
Curtail Agreements	80.06	131.06	158.34	221.32	227.75	3.70%
Time-Of-Use w EV	3.59	4.11	4.63	13.69	19.38	0.32%
Time-Of-Use	251.60	235.71	217.61	183.19	190.40	3.10%
Demand Rate w EV	3.62	4.13	4.65	13.59	19.10	0.31%
Demand Rate	1.32	6.02	9.74	17.84	18.05	0.29%
Real Time Pricing	6.22	6.13	10.31	15.59	16.04	0.26%
Inclining Block Rate	0.00	0.05	0.14	0.63	0.64	0.01%

Table 2-18 and Figure 2-3 present the winter peak savings by sector and option for realistic achievable potential. Table 2-19 presents the results for the maximum achievable potential in summer.

Top savers in 2037 are DLC Smart Thermostat, Demand Rate, and Large C&I Curtailment Agreements. Space Heating DLC was excluded because the program was not cost effective due the fact that we did not assign any value or avoided cost benefits in the model to winter capacity savings. KCP&L is a summer peaking utility, so the capacity position is still measured and valued relative to the summer peak.

Table 2-18 Realistic Achievable Potential by Option (Winter Peak)

	2019	2020	2021	2030	2037	2037 as % of Baseline
Baseline Forecast (Winter MW)	**4,308**	**4,325**	**4,332**	**4,490**	**4,671**	
Achievable Potential (MW)	**132.39**	**191.48**	**270.25**	**415.99**	**443.34**	**9.49%**
DLC Water Heating	1.18	3.60	8.54	13.98	15.39	0.33%
DLC Smart Thermostats	33.82	47.19	59.74	92.74	98.70	2.11%
Curtail Agreements	68.60	88.59	109.45	159.75	165.79	3.55%
Time-Of-Use w EV	0.28	0.98	2.60	11.32	16.08	1.17%
Time-Of-Use	6.25	18.09	39.92	52.89	54.44	0.34%
Demand Rate w EV	0.35	1.20	3.21	13.80	19.48	0.86%
Demand Rate	6.72	18.19	34.78	39.39	40.25	0.42%
Real Time Pricing	0.09	0.80	2.77	25.53	26.49	0.57%
Inclining Block Rate	15.09	12.83	9.24	6.57	6.72	0.14%

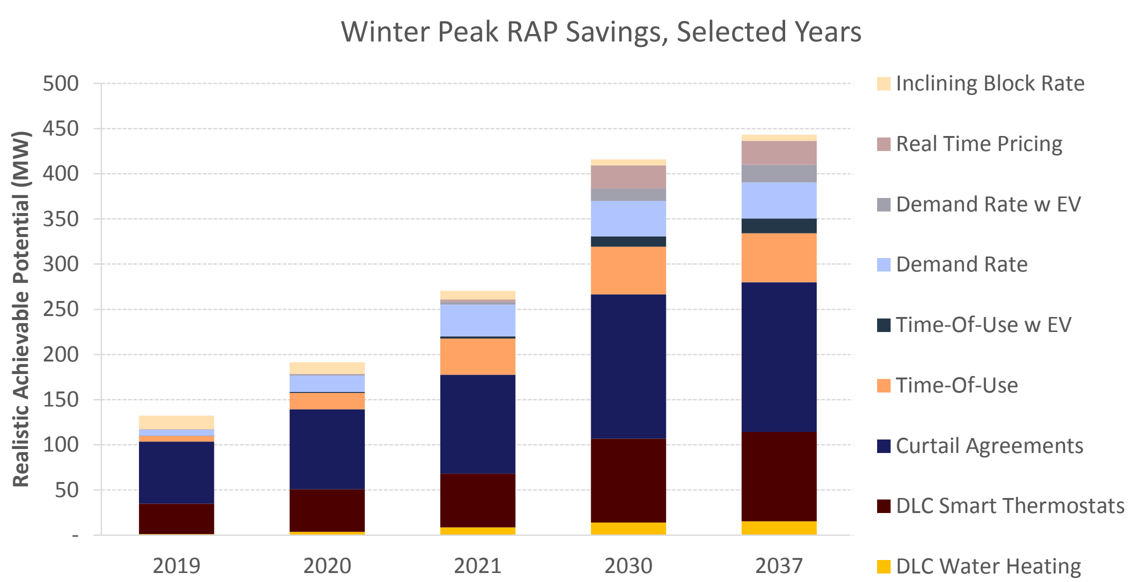

Figure 2-3 Realistic Achievable DR & DSR Potential (Winter MW)

Table 2-19 Maximum Achievable Potential by Option (Winter Peak)

	2019	2020	2021	2030	2037	2037 as % of Baseline
Baseline Forecast (Winter MW)	**4,308**	**4,325**	**4,332**	**4,490**	**4,671**	
Achievable Potential (MW)	**298.62**	**357.50**	**399.69**	**510.55**	**542.92**	**11.62%**
DLC Water Heating	1.77	5.40	12.81	20.97	23.08	0.49%
DLC Smart Thermostats	33.79	52.05	69.15	112.82	119.99	2.57%
Curtail Agreements	68.60	112.32	135.51	191.42	198.66	4.25%
Time-Of-Use w EV	180.63	169.05	155.85	129.44	133.30	2.85%
Time-Of-Use	3.35	3.82	4.31	12.75	18.05	0.39%
Demand Rate w EV	1.08	4.94	7.93	13.90	13.78	0.29%
Demand Rate	4.13	4.71	5.30	15.50	21.79	0.47%
Real Time Pricing	5.27	5.17	8.75	13.48	13.99	0.30%
Inclining Block Rate	0.00	0.02	0.06	0.28	0.28	0.01%

Program Costs

Table 2-20 and Table 2-21 present the program costs for the demand response and demand side rate options in the realistic achievable and maximum achievable scenarios respectively. Figure 2-4 and Figure 2-5 present the results of the annual program spending from 2019 to 2037 for the two cases.

Costs are higher for new programs in the first several years due to initial recruitment, marketing, and relevant installation of equipment like DLC switches for new participants. Program costs drop off after 2023 as a steady state is achieved and programs are maintained with fewer new participants and associated onboarding costs.

Customers in the maximum achievable scenario are paid incentives that are 1.5 times higher than those in the realistic achievable case. This is how the higher participation rates are achieved, but also results in larger budgets on both a per-customer and an absolute basis.

Table 2-20 DR & DSR Potential Program Costs for Realistic Achievable Potential

DR Option	2037 MW Potential	2019 – 2037 Cumulative Utility Spend (Million $)	2019 – 2037 Average Spend per Year (Million $)	2019 – 2037 Levelized Cost ($/kW-year)	2019-2037 TRC
DLC Space Cooling	75.21	$49.34	$2.47	$47.72	3.03
DLC Water Heating	15.39	$17.80	$0.89	$88.82	1.66
DLC Smart Thermostats	178.05	$130.49	$6.52	$49.16	2.97
Curtail Agreements	190.07	$179.08	$8.95	$55.06	2.54
Time-Of-Use w EV	17.26	$2.04	$0.10	$15.90	12.44
Time-Of-Use	84.35	$3.69	$0.18	$3.49	53.35
Demand Rate w EV	17.08	$1.01	$0.05	$9.48	21.48
Demand Rate	52.64	$4.11	$0.21	$6.18	30.73
Real Time Pricing	30.38	$1.61	$0.08	$5.79	33.17
Inclining Block Rate	15.54	$15.25	$0.76	$67.40	4.88
Total	**675.96**	**404.41**			

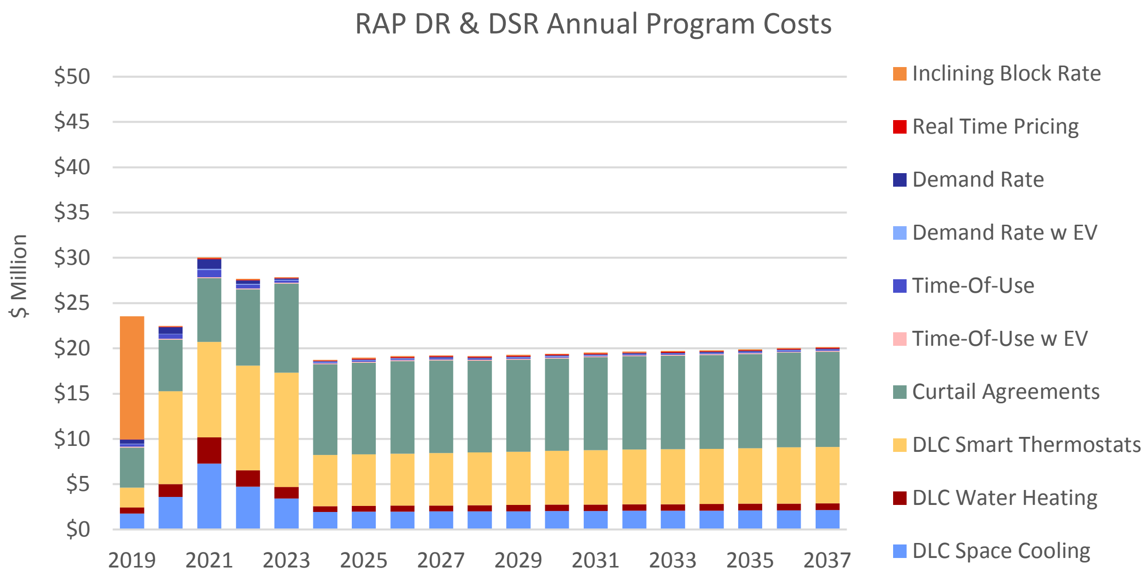

Figure 2-4 Realistic Achievable DR & DSR Program Costs

Table 2-21 DR & DSR Potential Program Costs for Maximum Achievable Potential

DR Option	2037 MW Potential	2019 – 2037 Cumulative Utility Spend (Million $)	2019 – 2037 Average Spend per Year (Million $)	2019 – 2037 Levelized Cost ($/kW-year)	2019-2037 TRC
DLC Space Cooling	86.91	$68.02	$3.40	$47.56	3.04
DLC Water Heating	23.08	$33.83	$1.69	$88.49	1.66
DLC Smart Thermostats	216.55	$195.43	$9.77	$48.62	3.00
Curtail Agreements	227.75	$311.57	$15.58	$55.06	2.54
Time-Of-Use w EV	19.38	$2.07	$0.10	$57.01	3.48
Time-Of-Use	190.40	$9.97	$0.50	$3.89	47.47
Demand Rate w EV	19.10	$1.06	$0.05	$117.31	1.75
Demand Rate	18.05	$3.10	$0.16	$12.85	14.82
Real Time Pricing	16.04	$2.41	$0.12	$10.82	17.40
Inclining Block Rate	0.64	$1.89	$0.09	$210.91	1.64
Total	**817.91**	**629.35**			

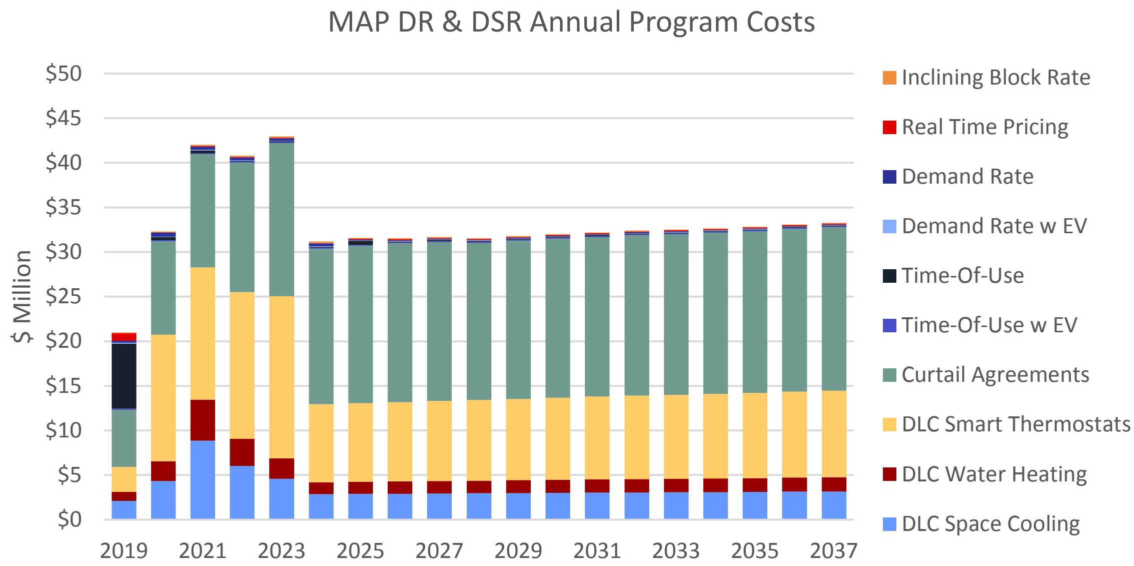

Figure 2-5 Maximum Achievable DR & DSR Program Costs

3

Combined Heat and Power Potential Analysis

As the final component to this study, AEG conducted an analysis of the potential for combined heat and power (CHP) to understand the energy and peak demand savings that could be achieved from CHP resources. This chapter presents the following sections:

- Analysis Approach
- Data Development
- Market Characterization and Baseline Projection
- Potential Results
- Potential Results by Sector
- Sensitivity Analysis

Analysis Approach

This portion of the analysis evaluates the energy and coincident peak impacts of customer-site combined heat and power systems in the KCP&L service territory. The methodology is similar to the energy efficiency analysis, with the added wrinkle that CHP systems generate electricity (rather than conserve it) while both consuming and offsetting natural gas usage. As such, a custom version of the LoadMAP model was constructed to natively assess all impacts in parallel. We refer to the impacts of CHP electricity generation as energy and demand savings from the perspective of system resource planning, which is analogous and consistent to how we treat other DSM resources in this report.

The major analysis steps are listed below and described in detail in this chapter:

- Define relevant CHP technologies and research technical data
- Characterize the market and develop baseline projection
- Develop technical applicability and achievable adoption rates for CHP equipment
- Estimate CHP savings potential

To estimate the CHP potential:

- First, we looked at the technical applicability for each CHP technology, identifying applications by customer segment. This allows us to constrain installations such that multiple CHP options are not competing for placement in the same customer application.
- Secondly, we define customer adoption rates. Assumed rates are low since these are highly complex systems that require significant capital investment, persistent staffing and O&M costs, and substantial coordination between utility and facility.
- Finally, we calculate the economic viability of each system based on all streams of costs and savings, including:
    - Benefits: offset of purchased electricity with onsite generation, offset of typical boiler operation with waste heat recovery.
    - Costs: first-year installation costs, utility program administration costs, purchase of natural gas fuel, persistent non-energy O&M.

Figure 3-1 below illustrates the energy flows associated with these costs and benefits, first in a traditional setting with no CHP, and second with a CHP system instead. The CHP system is thermodynamically more efficient since it can provide the same total output to the customer – 60 units of useful energy to this example facility – for a smaller footprint of input energy. In the example, the input energy of the traditional system is 100 units of fuel to feed both Grid and onsite resources, which is reduced to 80 units of fuel all-in to feed the CHP system. The specific values of these energy flows will fluctuate based on the application, but all must be accounted for in this way when assessing CHP potential and economics.

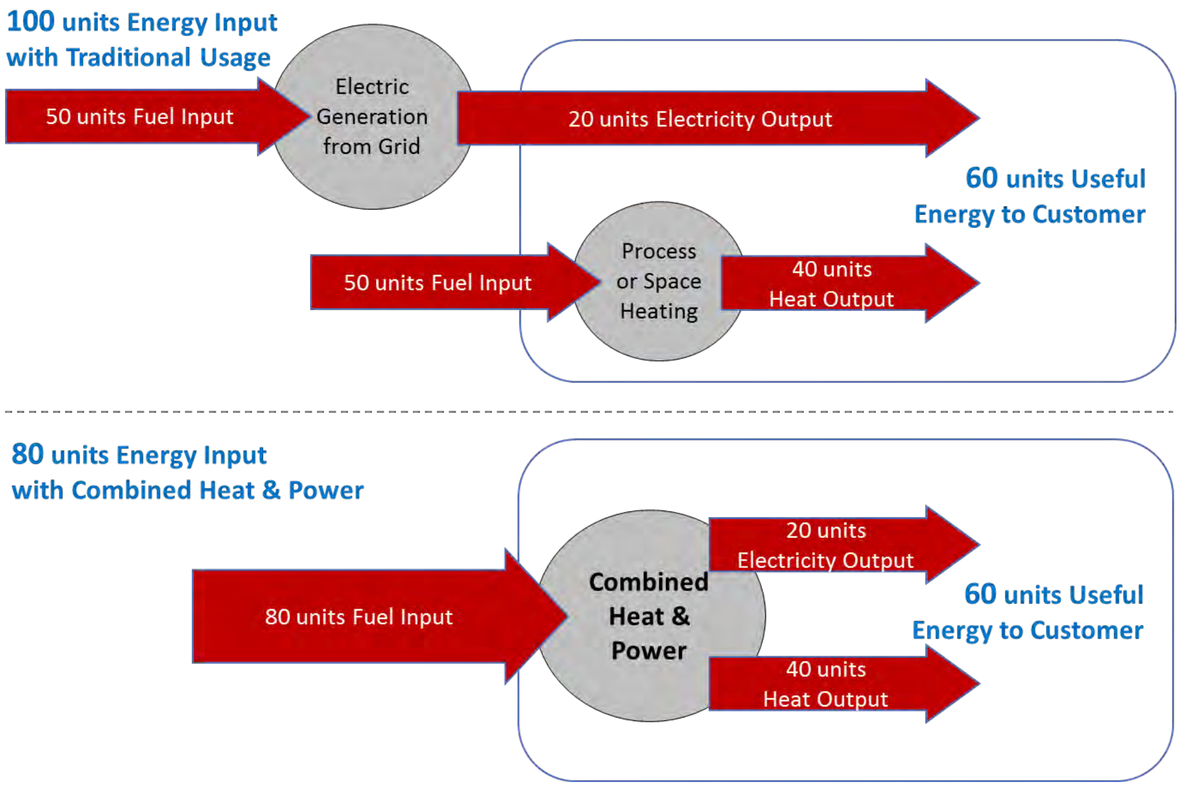

Figure 3-1 Review of CHP Energy Flows

ECONOMIC ANALYSIS OF CHP SYSTEMS

The equation below summarizes the benefits and costs analyzed in this CHP analysis:

$$TRC\ \ B/C\ \ Ratio = \frac{CHP\ Electricity\ Benefits + Displaced\ Boiler\ Benefit + Federal\ Tax\ Credits}{CHP\ System\ Costs + CHP\ Fuel\ Consumption + Utility\ Administration\ Costs}$$

We describe each of the components below. Also note that all streams of annual costs or benefits past the first year are annualized to 2015$ utilizing KCP&L's real discount rate.

CHP Electricity Benefits include the value of the electric energy and peak demand resources that are generated by the CHP system. Both benefits are calculated from an annual stream of impacts over the system's lifetime, utilizing equivalent value streams from KCP&L's avoided cost of energy ($/MWh) and avoided cost of capacity ($/kW) projections over the same lifetime.

Displaced Boiler Benefit refers to the reduction in consumption of a natural gas-fired boiler used for heating or process. This unit is assumed to be preinstalled on-site, and is the recipient of waste heat recovery from the electricity generation process on the analyzed CHP system. These annual natural gas benefits are monetized in a similar process to the CHP Electricity Benefits described above, but utilize wholesale natural gas pricing projections ($/MCF) as the per-unit avoided costs instead. Note that the displaced boiler stream of benefits does not apply to steam turbine systems as these are assumed to capture waste heat from an upstream boiler instead.

Federal Tax Credits are currently available for select CHP and renewable technologies. These are listed as a percent of first year project cost and intended to offset part of the large capital investment required to install the CHP system. Available tax credits are 10% for reciprocating engines, combustion turbines, and microturbines and 30% for fuel cells. No tax credit is available for steam turbine systems. Because AEG modeled this as a benefit in the TRC test, this means the society is defined as the utility plus its ratepayers. If economics were evaluated at the federal level, the tax credit would simply be a transfer payment within the evaluated test universe and no benefit would be tallied.

CHP System Costs refer to the incremental measure costs necessary to install and maintain a CHP system. This consists of a first-year capital installation cost and ongoing annual non-fuel O&M costs necessary to keep the CHP system in operation.

CHP Fuel Consumption represents the natural gas supply required to operate onsite CHP generation equipment over its lifetime. These annual natural gas benefits are valued in a similar process to the CHP Electricity and Displaced Boiler Benefits described above, utilizing wholesale natural gas pricing projections ($/MCF). This value is smaller for steam turbines compared to other types of generation since upstream waste heat is used to preheat water in the turbine.

Utility Administration Costs are first year costs which account for time spent by utility program staff for involvement in both implementation and interconnection of the CHP system as well as processing of rebate paperwork.

Market Characterization and Baseline Forecast

This analysis considers combined heat and power technology in the commercial and industrial sectors only. We utilize the same energy market characterization detailed in the EE potential chapter of this report when analyzing CHP, analyzing the same segments within both the commercial and industrial market sectors. Please refer to the "Market Characterization" and "Baseline Projection" sections of Chapter 1 for more information.

Data Development

For this analysis, AEG developed a comprehensive list of CHP technologies available on the market. This list was similar to the CHP technology list in KCP&L's prior DSM potential study. We then updated technical assumptions based on review of the latest industry sources, primarily from federal research institutions such as U.S. DOE, NREL, and LBNL.

We analyzed a total of ten different CHP system configurations, including fuel cells, reciprocating engines, combustion turbines, microturbines, and steam turbines; each in both a commercial and an industrial application. Each of these options is defined as having heat recovery potential, increasing potential measure benefits. Table 3-1 below details key assumptions for the equipment configurations utilized.

Other measure inputs utilized include: peak coincidence factors, efficiency factors, non-fuel O&M costs, available tax credits, natural gas fuel use and displaced fuel/energy use from a traditional heating system. Federal tax credits available and incorporated in the modeling are 30% of system cost for fuel cells, 0% for steam turbines, and 10% for all others.

Table 3-1 Key Assumptions for CHP Technology

Sector	Technology	Typical System Size (kW)	Lifetime	$/kW installed cost
Commercial	Fuel Cell w/ Heat Recovery (200 kW)	200	8	$11,673
Industrial	Fuel Cell w/ Heat Recovery (1000 kW)	1,000	8	$11,673
Commercial	Recip Engine w/ Heat Recovery (100 kW)	100	10	$2,958
Industrial	Recip Engine w/ Heat Recovery (1500 kW)	1,500	10	$2,390
Commercial	CT w/ Heat Recovery (3 MW)	3,000	20	$3,170
Industrial	CT w/ Heat Recovery (5 MW)	5,000	20	$2,639
Commercial	Microturbine w/ Heat Recovery (200 kW)	200	10	$3,213
Data Centers	Microturbine w/ Heat Recovery (1000 kW) & Absorption Chiller (450-ton)	1,000	10	$3,335
Commercial	Steam Turbine w/ Heat Recovery (4 MW)	4,000	30	$794
Industrial	Steam Turbine w/ Heat Recovery (15 MW)	15,000	30	$605

Overall CHP Potential Results

This section presents the annual energy savings from CHP measures for the commercial and industrial sectors combined, followed by the summer peak demand savings for the same configurations.

Summary of Annual Energy Savings

Table 3-2 summarizes CHP savings in terms of annual energy usage for all measures in 2021. Measures are organized by highest realistic achievable potential (RAP) savings, but potential for three other scenarios is presented as well. The 2021 cumulative realistic achievable potential of 1.9 GWh is much lower than the corresponding technical potential of 400.0 GWh in the same year. This is due to low cost-effectiveness of most applicable systems. In the sensitivity analysis presented at the end of this chapter, we explore CHP potential in a scenario where the most cost-effective system (steam turbines) is assumed to be universally available even in facilities where it is not technically applicable.

Table 3-2 Summary of KCP&L Cumulative CHP Potential

Rank	Measure / Technology	2021 Cumulative RAP Savings (GWh)	2021 Cumulative MAP Savings (GWh)	2021 Cumulative Economic Potential Savings (GWh)	2021 Cumulative Technical Potential Savings (GWh)
1	Ind - Steam Turbine w/ Heat Recovery	1.5	2.3	6.1	6.1
2	Com - Steam Turbine w/ Heat Recovery	0.4	0.6	1.3	1.3
3	Com - Fuel Cell w/ Heat Recovery	0.0	0.0	0.0	67.3
4	Com - Recip Engine w/ Heat Recovery	0.0	0.0	0.0	36.8
5	Com - CT w/ Heat Recovery	0.0	0.0	0.0	21.0
6	Com - Microturbine w/ Heat Recovery	0.0	0.0	0.0	36.8
7	Ind - Fuel Cell w/ Heat Recovery	0.0	0.0	0.0	63.6
8	Ind - Recip Engine w/ Heat Recovery	0.0	0.0	0.0	72.4
9	Ind - CT w/ Heat Recovery	0.0	0.0	0.0	71.2
10	Ind - Microturbine w/ Heat Recovery	0.0	0.0	0.0	23.4
	Total RAP savings in 2021	**1.9**	**2.9**	**7.4**	**400.0**

Table 3-3 summarizes TRC cost effectiveness for each technology type in selected years. Only the steam turbine with heat recovery measure is cost effective for the entire study duration. Installed Steam Turbine costs are lower than other technologies since costs represent only the turbine itself. This assumes that the requisite upstream steam boiler is already installed onsite, which is typically the case for this subset of installations. This has the effect of lowering overall technical applicability of this measure since only select facilities use steam boilers.

Table 3-3 TRC Cost Effectiveness for CHP Measures, Selected Years

TRC Benefit-to-Cost Ratio in 2019	Commercial	Industrial	TRC Benefit-to-Cost Ratio in 2037	Commercial	Industrial
Fuel Cell w/ Heat Recovery	0.45	0.45	Fuel Cell w/ Heat Recovery	0.50	0.51
Recip Engine w/ Heat Recovery	0.68	0.72	Recip Engine w/ Heat Recovery	0.78	0.85
CT w/ Heat Recovery	0.76	0.84	CT w/ Heat Recovery	0.83	0.93
Microturbine w/ Heat Recovery	0.64	0.65	Microturbine w/ Heat Recovery	0.75	0.76
Steam Turbine w/ Heat Recovery	1.48	1.65	Steam Turbine w/ Heat Recovery	1.65	1.84

Table 3-4 and Table 3-5 summarize cumulative energy and demand potential for CHP in the combined commercial and industrial sectors. Recall that Missouri opt-out customers are removed from consideration for the MAP and RAP results. The 2021 cumulative realistic achievable potential of 1.9 GWh is much lower than the corresponding technical potential of 400.0 GWh in the same year. This is due to low cost-effectiveness of most applicable systems.

- Technical potential reflects the adoption of all CHP measures regardless of cost-effectiveness. Cumulative savings in 2021 are 400 GWh, or 2.8% of the baseline. By 2037 cumulative savings reach 2,533 GWh, or 16% of projected 2037 baseline sales.
- Economic potential reflects the savings when all applicable cost-effective measures are installed by all customers. In 2021, cumulative savings reach 7.4 GWh. By 2037, cumulative savings reach 46.9 GWh, or 0.3% of the baseline projection. All economic and achievable savings in this case come from steam turbine CHP systems.

- Maximum Achievable potential refines the economic potential by taking into account the maximum expected participation and customer preferences without budget constraints. By the end of the study in 2037, cumulative savings reach 20.0 GWh.
- Realistic Achievable potential further refines maximum achievable potential with a lower level of program activity and customer adoption. By the end of the study in 2037, cumulative potential energy savings are 13.6 GWh.

Table 3-4 C&I CHP Energy Savings Potential – Opt-Out Removed from MAP and RAP

	2019	2020	2021	2030	2037
C&I Baseline Forecast (GWh)	**14,222**	**14,220**	**14,225**	**14,916**	**15,737**
Cumulative Energy Savings (GWh)					
Realistic Achievable Potential	0.6	1.3	1.9	8.1	13.6
Maximum Achievable Potential	1.0	1.9	2.9	12.2	20.0
Economic Potential	2.4	4.9	7.4	29.6	46.9
Technical Potential	133.3	266.7	400.0	1600.0	2533.2
Energy Savings (% of Baseline)					
Realistic Achievable Potential	0.00%	0.01%	0.01%	0.05%	0.09%
Maximum Achievable Potential	0.01%	0.01%	0.02%	0.08%	0.13%
Economic Potential	0.02%	0.03%	0.05%	0.20%	0.30%
Technical Potential	0.94%	1.88%	2.82%	10.74%	16.01%

Table 3-5 C&I CHP Summer Peak Demand Savings Potential – Opt-Out Removed from MAP and RAP

	2019	2020	2021	2030	2037
C&I Baseline Forecast (MW)	**2,521**	**2,521**	**2,522**	**2,617**	**2,735**
Cumulative Demand Savings (MW)					
Realistic Achievable Potential	0.1	0.1	0.2	0.9	1.5
Maximum Achievable Potential	0.1	0.2	0.4	1.4	2.3
Economic Potential	0.3	0.6	0.9	3.4	5.4
Technical Potential	15.4	30.6	46.0	183.8	291.0
Demand Savings (% of Baseline)					
Realistic Achievable Potential	0.00%	0.00%	0.01%	0.03%	0.05%
Maximum Achievable Potential	0.00%	0.01%	0.02%	0.05%	0.08%
Economic Potential	0.01%	0.02%	0.04%	0.13%	0.20%
Technical Potential	0.61%	1.21%	1.82%	7.04%	10.64%

Table 3-6 and Table 3-7 below show the 2037 energy and demand savings, respectively, broken out by service territory. Differences in the potential among service territories are largely a result of differences in customer base. KCP&L-MO, with a larger industrial sector than the other areas, has the largest CHP potential at 6.1 GWh and 0.7 MW of RAP and 8.9 GWh and 1.0 MW of MAP.

Table 3-6 C&I CHP Energy Savings Potential in 2037 by Service Territory – Opt-Out Removed from MAP and RAP

	KCP&L-MO	KCP&L-KS	GMO-MPS	GMO-SJLP	All Service Territories
C&I Baseline Forecast (2037 GWh)	**6,774**	**3,566**	**3,645**	**1,752**	**15,737**
Cumulative Energy Savings (2037 GWh)					
Realistic Achievable Potential	6.1	2.3	3.1	2.2	13.6
Maximum Achievable Potential	8.9	3.3	4.5	3.2	20.0
Economic Potential	21.7	6.3	10.9	7.9	46.8
Technical Potential	1,134.0	453.4	589.3	356.6	2,533.2
Energy Savings (% of 2037 Baseline)					
Realistic Achievable Potential	0.1%	0.1%	0.1%	0.1%	0.1%
Maximum Achievable Potential	0.1%	0.1%	0.1%	0.2%	0.1%
Economic Potential	0.3%	0.2%	0.3%	0.5%	0.3%
Technical Potential	16.7%	12.7%	16.2%	20.4%	16.1%

Table 3-7 C&I CHP Summer Peak Demand Savings Potential in 2037 by Service Territory – Opt-Out Removed from MAP and RAP

	KCP&L-MO	KCP&L-KS	GMO-MPS	GMO-SJLP	All Service Territories
C&I Baseline Forecast (2037 GWh)	**1,125**	**705**	**609**	**296**	**2,735**
Cumulative Summer Peak Savings (2037 MW)					
Realistic Achievable Potential	0.7	0.3	0.3	0.2	1.5
Maximum Achievable Potential	1.0	0.4	0.5	0.4	2.3
Economic Potential	2.5	0.7	1.2	0.9	5.3
Technical Potential	130.7	50.9	67.7	41.7	291.0
Summer Peak Demand Savings (% of 2037 Baseline)					
Realistic Achievable Potential	0.1%	0.0%	0.1%	0.1%	0.1%
Maximum Achievable Potential	0.1%	0.1%	0.1%	0.1%	0.1%
Economic Potential	0.2%	0.1%	0.2%	0.3%	0.2%
Technical Potential	11.6%	7.2%	11.1%	14.1%	10.6%

Note that estimated potential in many cases is lower than a single installation of the cost-effective archetype used for measure inputs (a steam turbine of 4 MW or 15 MW as in Table 3-1). This indicates that the estimates include smaller or fractional installations. In reality, discrete installations would be made with some minimal sizing threshold and project schedules dictated by individual customers.

Commercial sector CHP Potential Results

Table 3-8 and Table 3-9 summarize cumulative energy and demand potential for CHP in the commercial sector with opt-out customers removed from MAP and RAP.

- Technical potential reflects the adoption of all CHP measures regardless of cost-effectiveness. First-year savings are 54.4 GWh, or 0.6% of the baseline projection. Cumulative savings in 2021 are 163.3 GWh, or 1.9% of the baseline. By 2037 cumulative savings reach 1,034 GWh, or 10% of the baseline.

- Economic potential reflects the savings when the most efficient cost-effective measures are installed by all customers. The first-year savings are 0.4 GWh, which represent a negligible amount of the baseline projection. By 2021, cumulative savings reach 1.3 GWh. By 2037, cumulative savings reach 8.5 GWh, or 0.1% of the baseline projection. All economic and achievable savings in this case come from steam turbine CHP systems.
- Maximum Achievable potential refines the economic potential by taking into account the maximum expected participation and customer preferences without budget constraints. The first-year savings are 0.2 GWh, which represent a negligible amount of the baseline projection. By 2021, cumulative savings reach 0.6 GWh. By 2037, cumulative savings reach 4.3 GWh.
- Realistic Achievable potential further refines maximum achievable potential by considering budgetary constraints and what could be realistically achievable with participation and awareness. It shows 0.1 GWh savings in the first year, which represent a negligible amount of the baseline projection. By 2021 cumulative savings reach 0.4 GWh. By 2037, cumulative savings reach 2.9 GWh.

Table 3-8 Commercial CHP Energy Savings Potential – Opt-Out Removed from MAP and RAP

	2019	2020	2021	2030	2037
Baseline Forecast (GWh)	**8,870**	**8,866**	**8,876**	**9,471**	**10,171**
Cumulative Energy Savings (GWh)					
Realistic Achievable Potential	0.1	0.3	0.4	1.7	2.9
Maximum Achievable Potential	0.2	0.4	0.6	2.6	4.3
Economic Potential	0.4	0.9	1.3	5.4	8.5
Technical Potential	54.4	108.9	163.3	653.3	1,034.3
Energy Savings (% of Baseline)					
Realistic Achievable Potential	0.0%	0.0%	0.0%	0.0%	0.0%
Maximum Achievable Potential	0.0%	0.0%	0.0%	0.0%	0.0%
Economic Potential	0.0%	0.0%	0.0%	0.1%	0.1%
Technical Potential	0.6%	1.2%	1.9%	6.9%	10.1%

Table 3-9 Commercial CHP Summer Peak Demand Savings Potential – Opt-Out Removed from MAP and RAP

	2019	2020	2021	2030	2037
Baseline Forecast (MW)	**1,568**	**1,568**	**1,570**	**1,651**	**1,748**
Cumulative Demand Savings (MW)					
Realistic Achievable Potential	0.0	0.0	0.0	0.2	0.3
Maximum Achievable Potential	0.0	0.0	0.1	0.3	0.5
Economic Potential	0.1	0.1	0.2	0.6	1.0
Technical Potential	6.0	11.9	17.9	71.4	113.1
Demand Savings (% of Baseline)					
Realistic Achievable Potential	0.0%	0.0%	0.0%	0.0%	0.0%
Maximum Achievable Potential	0.0%	0.0%	0.0%	0.0%	0.0%
Economic Potential	0.0%	0.0%	0.0%	0.0%	0.1%
Technical Potential	0.4%	0.8%	1.1%	4.3%	6.5%

Industrial sector CHP Potential Results

Table 3-10 and Table 3-11 summarize cumulative energy and demand CHP potential for the industrial sector with opt-out customers removed from MAP and RAP.

- Technical potential reflects the adoption of all CHP measures regardless of cost-effectiveness. First-year savings are 78.9.4 GWh, or 1.5% of the baseline projection. Cumulative savings in 2021 are 236.7 GWh, or 4.4% of the baseline. By 2037 cumulative savings reach 1,499 GWh, or 27% of the baseline.
- Economic potential reflects the savings when the most efficient cost-effective measures are installed by all customers. The first-year savings are 2.0 GWh, which represent a negligible amount of the baseline projection. By 2021, cumulative savings reach 6.1 GWh, or 0.1% of the baseline projection. By 2037, cumulative savings reach 38.4 GWh, or 0.7% of the baseline projection. All economic and achievable savings in this case come from steam turbine CHP systems.
- Maximum Achievable potential refines the economic potential by taking into account the maximum expected participation and customer preferences without budget constraints. The first-year savings are 0.8 GWh, which represent a negligible amount of the baseline projection. By 2021, cumulative savings reach 2.3 GWh. By 2037, cumulative savings reach 15.7 GWh, or 0.3% of the baseline projection.
- Realistic Achievable potential further refines maximum achievable potential by considering budgetary constraints and what could be realistically achievable with participation and awareness. It shows 0.5 GWh savings in the first year, which represent a negligible amount of the baseline projection. By 2021 cumulative savings reach 1.5 GWh. By 2037, cumulative savings reach 10.7 GWh, or 0.2% of the baseline projection.

Table 3-10 Industrial CHP Energy Savings Potential – Opt-Out Removed from MAP and RAP

	2019	2020	2021	2030	2037
Baseline Forecast (GWh)	**5,352**	**5,354**	**5,349**	**5,444**	**5,566**
Cumulative Energy Savings (GWh)					
Realistic Achievable Potential	0.5	1.0	1.5	6.4	10.7
Maximum Achievable Potential	0.8	1.5	2.3	9.6	15.7
Economic Potential	2.0	4.0	6.1	24.2	38.4
Technical Potential	78.9	157.8	236.7	946.7	1,498.9
Energy Savings (% of Baseline)					
Realistic Achievable Potential	0.0%	0.0%	0.0%	0.1%	0.2%
Maximum Achievable Potential	0.0%	0.0%	0.0%	0.2%	0.3%
Economic Potential	0.0%	0.1%	0.1%	0.4%	0.7%
Technical Potential	1.5%	2.9%	4.4%	17.5%	26.9%

Table 3-11 Industrial CHP Summer Peak Demand Savings Potential – Opt-Out Removed from MAP and RAP

	2019	2020	2021	2030	2037
Baseline Forecast (MW)	**953**	**953**	**952**	**966**	**987**
Cumulative Demand Savings (MW)					
Realistic Achievable Potential	0.1	0.1	0.2	0.7	1.2
Maximum Achievable Potential	0.1	0.2	0.3	1.1	1.8
Economic Potential	0.2	0.5	0.7	2.8	4.4
Technical Potential	9.4	18.7	28.1	112.4	177.9
Demand Savings (% of Baseline)					
Realistic Achievable Potential	0.0%	0.0%	0.0%	0.1%	0.1%
Maximum Achievable Potential	0.0%	0.0%	0.0%	0.1%	0.2%
Economic Potential	0.0%	0.0%	0.1%	0.3%	0.4%
Technical Potential	1.0%	2.0%	3.0%	11.7%	18.0%

CHP Sensitivity Analysis

Universal Application of Cost-Effective Steam Turbine Option

In KCP&L's prior potential study, it was assumed that steam turbine CHP systems could be technically applicable in all CHP applications, which results in a much larger estimate of cost-effective CHP savings potential overall. As a sensitivity case, AEG increased steam turbine saturation in the same manner, excluding other technology options to eliminate double counting. This substantially increases steam turbine saturation in small facilities and facilities where existing steam systems do not exist. In practice, steam turbines require complex, capital-intensive systems to be pre-installed. Therefore, AEG does not expect this sensitivity to represent actual potential in the KCP&L service territory, but it can be used for informational purposes. Table 3-12 and Table 3-13 summarize cumulative energy and summer peak demand potential in the universal steam turbine applicability case for the commercial and industrial sectors combined. Note also that, in keeping with the CHP reference case and the EE potential analysis, opt-out customers are removed from MAP and RAP.

Overall technical potential remained constant at 2,553 GWh over the study period, but economic, maximum achievable, and realistic achievable potential results increased significantly. Twenty-year realistic achievable potential increased from 13.6 GWh to 359.6 GWh in 2037.

Table 3-12 CHP Energy Savings Potential, Universal Steam Turbine Application – Opt-Out Removed from MAP and RAP

	2019	2020	2021	2030	2037
C&I Baseline Forecast (GWh)	**14,222**	**14,220**	**14,225**	**14,916**	**15,737**
Cumulative Energy Savings (GWh)					
Realistic Achievable Potential	16.6	33.4	50.5	216.2	359.6
Maximum Achievable Potential	25.6	51.4	77.6	324.3	530.9
Economic Potential	66.2	132.3	198.5	793.9	1,257.0
Technical Potential	133.3	266.7	400.0	1,599.9	2,533.2
Energy Savings (% of Baseline)					
Realistic Achievable Potential	0.1%	0.2%	0.4%	1.5%	2.3%
Maximum Achievable Potential	0.2%	0.4%	0.5%	2.2%	3.4%
Economic Potential	0.5%	0.9%	1.4%	5.3%	7.9%
Technical Potential	0.9%	1.9%	2.8%	10.7%	16.0%

Table 3-13 CHP Summer Peak Demand Savings Potential, Universal Steam Turbine Application – Opt-Out Removed from MAP and RAP

	2019	2020	2021	2030	2037
C&I Baseline Forecast (MW)	**2,521**	**2,521**	**2,522**	**2,617**	**2,735**
Cumulative Demand Savings (MW)					
Realistic Achievable Potential	1.9	3.8	5.8	24.7	41.0
Maximum Achievable Potential	2.9	5.9	8.8	37.0	60.6
Economic Potential	7.5	15.1	22.6	90.6	143.4
Technical Potential	15.0	30.0	44.9	179.7	284.6
Demand Savings (% of Baseline)					
Realistic Achievable Potential	0.1%	0.2%	0.2%	0.9%	1.5%
Maximum Achievable Potential	0.1%	0.2%	0.4%	1.4%	2.2%
Economic Potential	0.3%	0.6%	0.9%	3.5%	5.2%
Technical Potential	0.6%	1.2%	1.8%	6.9%	10.4%

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