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April 13, 2017

Ms. Amy L. Green
Secretary of the Commission
Kansas Corporation Commission
1500 SW Arrowhead Road
Topeka, KS 66604-4027

Re: Kansas City Power & Light Company
Docket No. 16-KCPE-446-TAR

Dear Ms. Green:

During the evidentiary hearings held in the above-captioned docket, the Commissioners requested that Kansas City Power & Light Company ("KCP&L") provide to the Commissioners, General Counsel, and the parties, copies of its Integrated Resource Plan ("IRP") filed on behalf of KCP&L with the Missouri Public Service Commission. A copy of KCP&L's 2015 IRP is being filed concurrently with this letter.

Certain sections of the IRP contain information that is Confidential and those sections are being filed under seal in accordance with the provisions of K.S.A. 66-1220a and K.A.R. 82-1-221a. Confidential information within the IRP is designated as Confidential using the required **____** markings. Each item for which confidential status is asserted has been clearly marked "CONFIDENTIAL."

If you have any questions, please contact me at the above-captioned number, or Mary Turner at (816) 556-2874.

Sincerely,

/s/ Roger W. Steiner
Roger W. Steiner
Counsel for KCP&L

RWS/arw

cc: Service List for 16-KCPE-446-TAR

VOLUME 1

EXECUTIVE SUMMARY

KANSAS CITY POWER & LIGHT COMPANY (KCP&L)

INTEGRATED RESOURCE PLAN

4 CSR 240-22.010

APRIL, 2015

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SECTION 1: INTRODUCTION

The fundamental objective of the resource planning process shall be to provide the public with energy services that are safe, reliable and efficient, at just and reasonable rates, in a manner that serves the public interest and is consistent with state energy and environmental policies. This objective requires that the utility shall:

- Consider demand-side resources, renewable energy, and supply-side resources on an equivalent basis
- Use minimization of the present worth of long-run utility costs as the primary selection criterion
- Identify and where possible, quantitatively analyze any other considerations which are critical to meeting the fundamental objective of the resource planning process

1.1 IRP REPORT STRUCTURE

Nine (9) separate volumes comprise this IRP filing:

1. Volume 1: Executive Summary
2. Volume 2: Missouri Filing Requirements including an index of Rule compliance
3. Volume 3: Load Analysis and Load Forecasting
4. Volume 4: Supply-Side Resource Analysis
5. Volume 4.5: Transmission and Distribution Analysis
6. Volume 5: Demand-Side Resource Analysis
7. Volume 6: Integrated Resource Plan and Risk Analysis

8. Volume 7: Resource Acquisition Strategy Selection
9. Volume 8: Filing Schedule and Requirements

1.2 IRP DEVELOPMENT

In developing the IRP filing, KCP&L has endeavored to meet all requirements of Missouri's IRP rules covered under 4 CSR 240-22. KCP&L's IRP spans the 2015-2034 planning horizon. Data necessary to complete evaluations were derived from recognized industry sources, consultants, publications and other sources as appropriate. Data sources are noted in the text of the report or in the appendices of a volume.

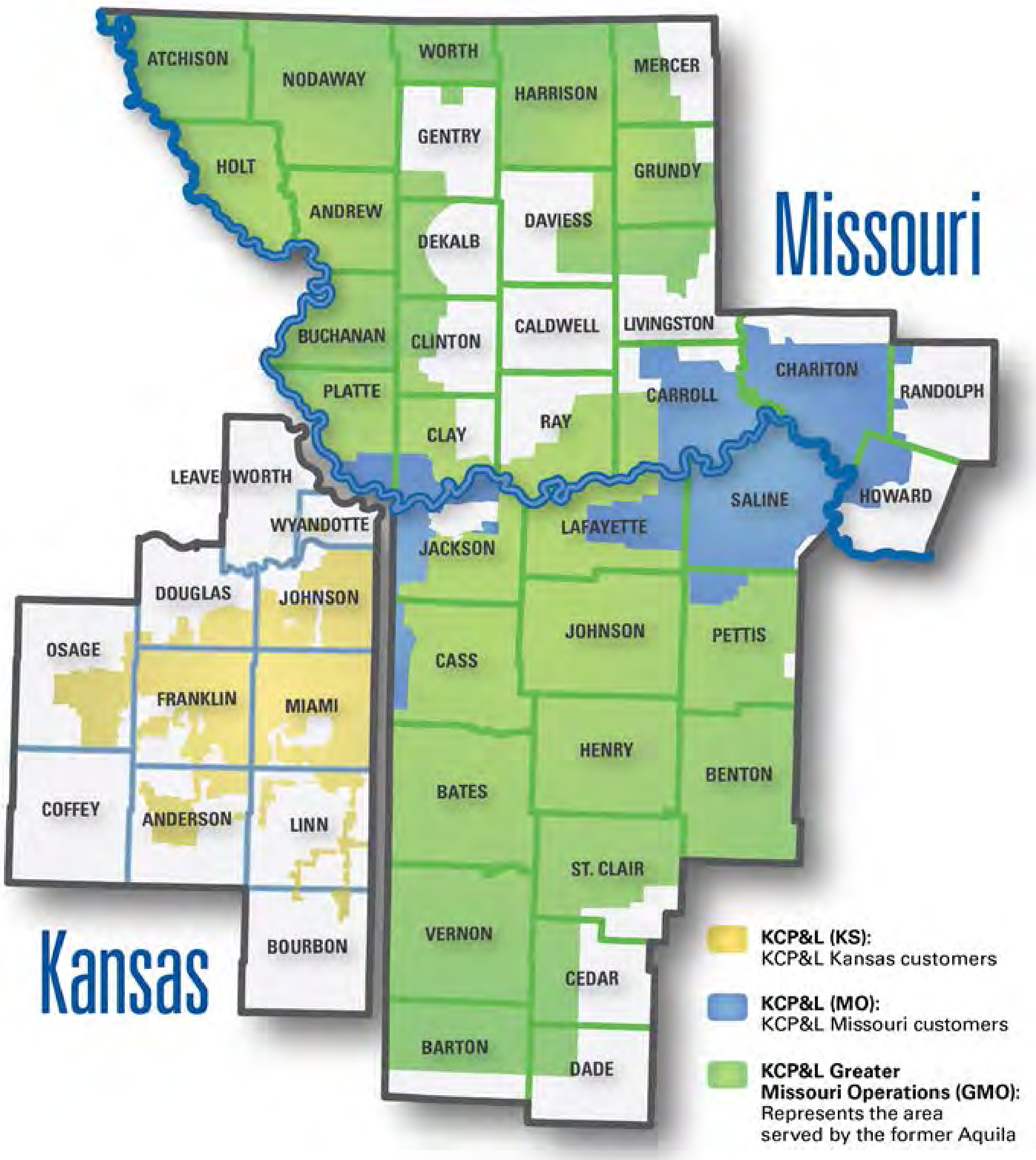
Several distinct tasks are included in the planning process:

- A detailed forecast of future demand and energy requirements
- An assessment of Supply-Side resource alternatives
- An assessment of Demand-Side resource alternatives
- An assessment of Transmission and Distribution alternatives
- Integrated Analysis evaluates the economics of various combinations of demand-side and supply-side alternatives that are developed as alternative resource plans over the planning timeline
- Risk Analysis provides a comparison of the range of economic results for the alternative resource plans due to identified critical uncertain factors
- The adoption and executive approval of a Resource Acquisition Strategy that includes a preferred resource plan, implementation plan, and contingency plans

SECTION 2: KCP&L SYSTEM OVERVIEW

KCP&L is an integrated, mid-sized electric utility serving the metropolitan region surrounding the Kansas City, Missouri metropolitan area including customers in Kansas and Missouri. A map of the Great Plains Energy (GPE) service territory which includes KCP&L is provided in Figure 1 below:

Figure 1: GPE Service Territory



KCP&L is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter. Table 1 provides a snapshot of the number of customers served, retail sales, and peak demand from 2014.

Table 1: 2014 Customers, Retail Sales, and Peak Demand

Jurisdiction	Number of Retail Customers	Retail Sales (MWh)	Net Peak Demand (MW)
KCP&L-Missouri	272,798	9,086,509	1,833
KCP&L-Kansas	246,175	6,397,289	1,605
KCP&L	518,973	15,483,798	3,412

KCP&L owns and operates a diverse generating portfolio and Power Purchase Agreements (PPA) to meet customer energy requirements. In June 2014, GPE signed a contract for a Power Purchase Agreement with EDF Energies for the output of a 150 MW wind farm named Slate Creek, located in Sumner and Cowley counties in Kansas. This new wind facility is expected to be on-line by the end of 2015, and at this time has been assigned to KCP&L. Table 2, Figure 2, and Figure 3 below reflect KCP&L's generation assets including all executed wind PPAs currently in place.

Table 2: Capacity and Energy By Resource Type

Resource Type	Capacity (MW)	% of Total Capacity	Estimated Energy (MWh)	% of Annual Energy
Coal	2,691	52%	16,657,929	69%
Nuclear	549	11%	4,076,020	17%
Oil	375	7%	0	0%
Nat. Gas	808	15%	155,574	1%
Wind	730*	14%	2,993,481	12%
Hydro	62	1%	181,326	1%
Solar	0.2	0.003%	140	0.001%
Total	5,215	100%	24,064,470	100%
*Nameplate Capacity				

Figure 2: Capacity By Resource Type

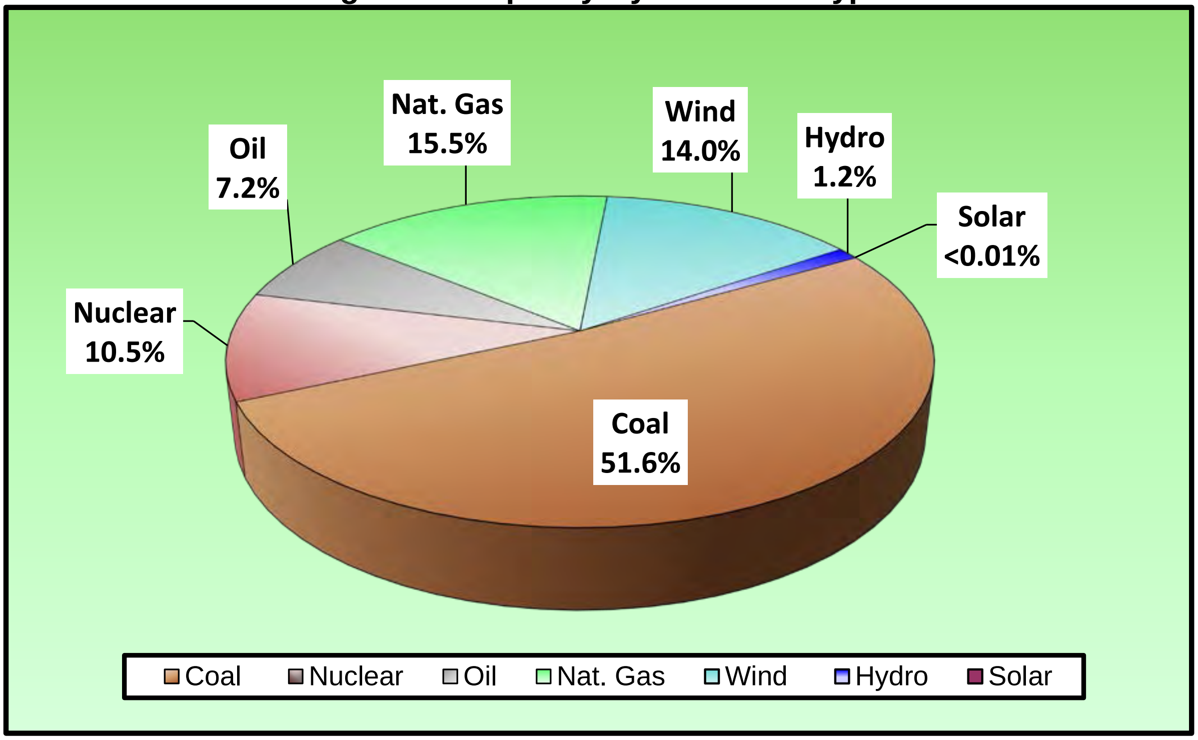
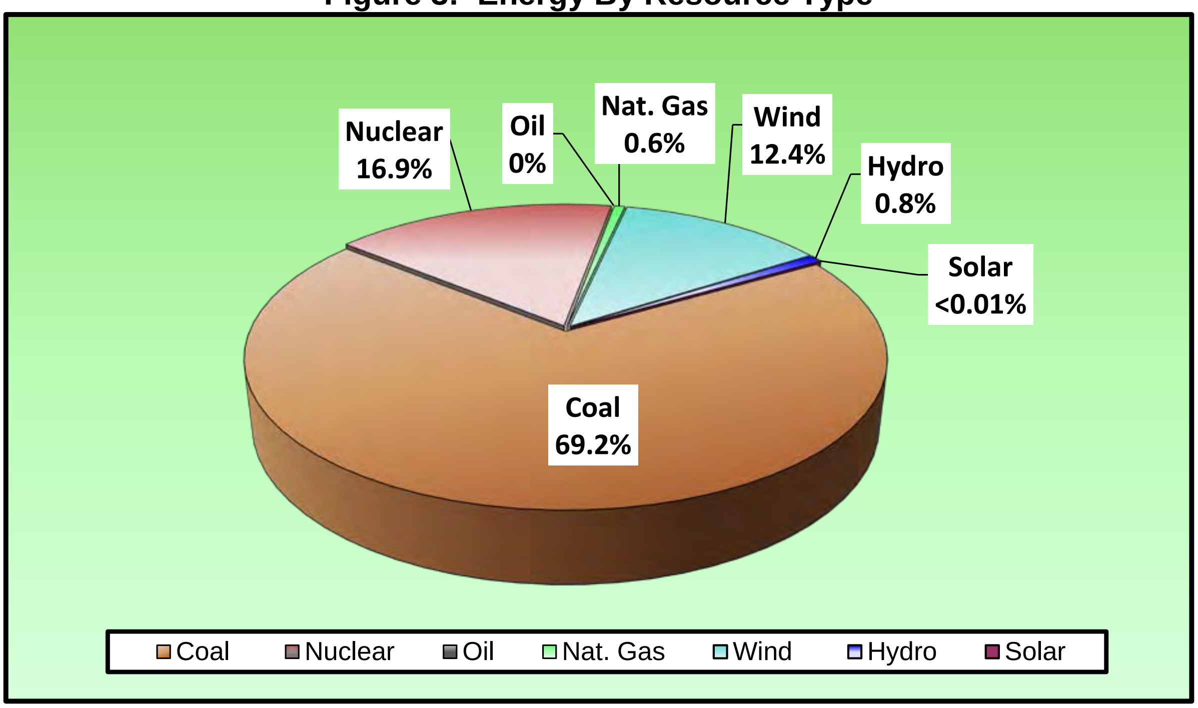


Figure 3: Energy By Resource Type



Additionally, GPE owns and operates a delivery system consisting of 3,700 miles of transmission lines, 22,400 miles of distribution lines, and 400 substations.

SECTION 3: LOAD FORECAST INFORMATION

2. For each major class and for the total of all major classes, the base load forecasts for peak demand and for energy for the planning horizon, with and without utility demand-side resources, and a listing of the economic and demographic assumptions associated with each base load forecast;

KCP&L used detailed end-use information along with statistical techniques to construct its load forecast. End-use information was obtained from KCP&L/GMO's semiannual appliance saturation surveys and from results published by the US Department of Energy (DOE) for the West North Central Midwest region. This information was used to construct end-use level forecasts of electricity sales based on economic forecasts of key drivers specific to the Kansas City metro area. Load was forecasted separately for each tariff group in each utility.

The forecasts of economic drivers was obtained through a contract with Moody's Analytics and include the number of households, population, personal income, gross metro product (GMP), manufacturing GMP, total employment, manufacturing employment, and the consumer price index (CPI). These drivers were provided for three scenarios that were used to construct base, high and low scenarios for KCP&L's load forecasts.

The end-use forecasts were calibrated to monthly billing statistics. Heating, cooling and base loads from the end-use models were each calibrated to optimize the ability of these forecasts to explain the monthly billing data. These calibrated models were then used to forecast monthly electric energy sales. Using load research data collected from a sample of KCP&L's customers, this end-use forecast was allocated to each hour of the forecast period and peak demands were determined from these results.

The load forecast used in the IRP was prepared using actual sales data through July 2014 and an economic forecast produced in June 2014.

Table 3 and Figure 4 summarize the forecast of energy sales and Net System Input (NSI) for KCP&L (including Kansas and Missouri) by rate class. Gross energy includes the impacts of energy efficiency and demand side management (DSM) program measures and thus represents actual energy sales. Net energy includes the impacts of future company programs. Neither gross nor net energy includes the impacts of programs that the company might adopt in the future as these are determined in the process for balancing supply and demand, discussed in a later section of this report. The energy sales shown in all but the last two columns are billed sales at the customers' meter. The last two columns show NSI, which includes line losses and company use and which represents the amount of generation and purchased power needed to serve the load of KCP&L. Sales for Resale (SFR) represents firm sales to other utilities under a FERC rate.

Growth rates are highest for the Residential class, 1.0%, between 2014 and 2035, and the lowest is Big Commercial (Medium General Service, Large General Service),0.3%.

Table 3: KCP&L Energy with and without DSM Impacts (GWh) **Highly Confidential**

[redacted]

Figure 4: KCP&L System Energy **Highly Confidential**

[redacted]

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Table 4 reports the peak demands by rate class. These numbers include line losses and company use. The growth rates between 2014 and 2035 show Residential growing at 1.1% on the high side and Big Commercial on the low side at 0.3%.

Table 4: KCP&L Peak Demand with and without DSM Impacts (MW) **Highly Confidential**

[redacted]

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Figure 5 summarizes the forecast of peak demands by year for KCP&L.

Figure 5: KCP&L System Peak **Highly Confidential**

[redacted]

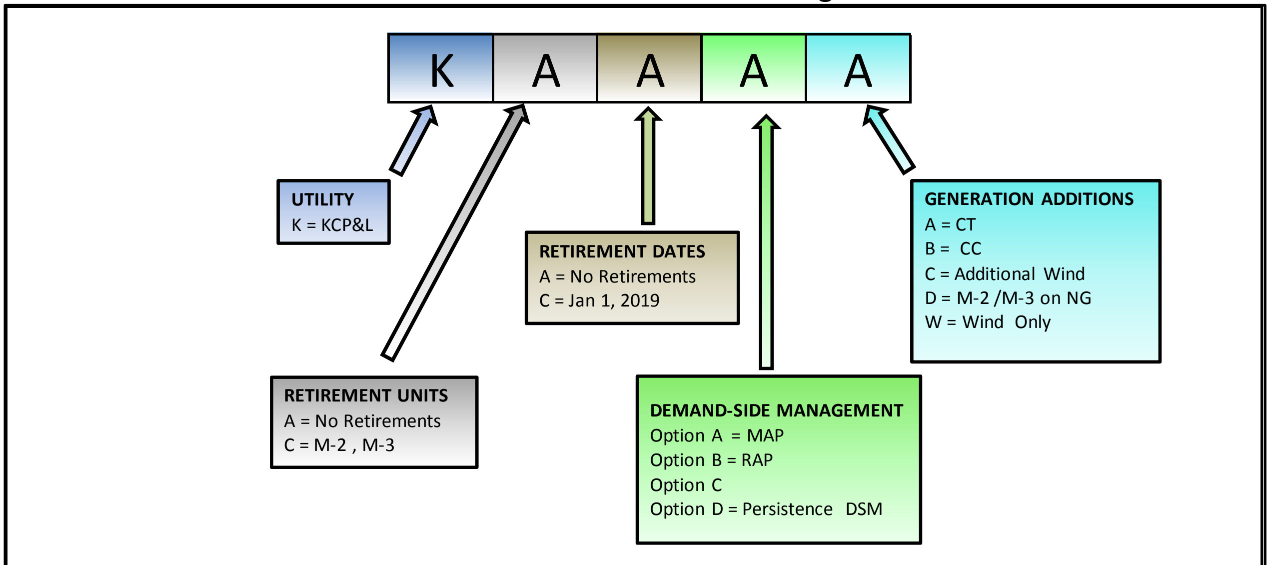
SECTION 4: PREFERRED RESOURCE PLAN SELECTION

4.1 ALTERNATIVE RESOURCE PLAN DEVELOPMENT

3. A summary of the preferred resource plan to meet expected energy service needs for the planning horizon, clearly showing the demand-side resources and supply-side resources (both renewable and non-renewable resources), including additions and retirements for each resource type;

Alternative resource plans were developed using a combination of various capacities of supply-side sources, demand-side resources resource addition timing. The plan-naming convention utilized for the alternative resource plans developed is shown in Table 5 below:

Table 5: Alternative Resource Plan Naming Convention



Definitions:

RAP - Realistic Achievable Potential	**M-2 - Montrose-2**	**CT - Combustion Turbine**
MAP - Maximum Achievable Potential	**M-3 - Montrose-3**	**CC - Combined Cycle**

In total, fifteen Alternative Resource Plans were developed for integrated resource analysis. Table 6 through Table 9 represents an overview of each plan over the 2015 through 2034 planning period.

Table 6 : Alternative Resource Plans

Plan Name	DSM Level	Facility	Year to Cease Burning Coal	Renewable Additions		Generation Addition (if needed)
KAAAA	Option A - MAP	Montrose-1 Montrose-2 Montrose-3	2016 2021 2021	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 300 MW	n/n
KAAAC	Option A - MAP	Montrose-1 Montrose-2 Montrose-3	2016 2021 2021	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 400 MW	n/n
KAAAD	Option A - MAP	Montrose 1	2016	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 300 MW	n/n
		Convert to NG: Montrose-2 Montrose-3	2019			

Table 7: Alternative Resource Plans (continued)

Plan Name	DSM Level	Facility	Year to Cease Burning Coal	Renewable Additions		Generation Addition (if needed)
KAABA	Option B - RAP	Montrose-1 Montrose-2 Montrose-3	2016 2021 2021	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 300 MW	n/n
KAABC	Option B - RAP	Montrose-1 Montrose-2 Montrose-3	2016 2021 2021	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 400 MW	n/n
KAABD	Option B - RAP	Montrose 1	2016	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 300 MW	n/n
		Convert to NG: Montrose-2 Montrose-3	2019			
KCCBA	Option B - RAP	Montrose-1 Montrose-2 Montrose-3	2016 2019 2019	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 300 MW	n/n

Table 8: Alternative Resource Plans (continued)

Plan Name	DSM Level	Facility	Year to Cease Burning Coal	Renewable Additions		Generation Addition (if needed)
KAACA	Option C	Montrose-1 Montrose-2 Montrose-3	2016 2021 2021	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 300 MW	207 MW CT in 2029
KAACB	Option C	Montrose-1 Montrose-2 Montrose-3	2016 2021 2021	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 300 MW	200 MW CC in 2029
KAACC	Option C	Montrose-1 Montrose-2 Montrose-3	2016 2021 2021	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 400 MW	207 MW CT in 2030
KAACD	Option C	Montrose 1 Convert to NG: Montrose-2 Montrose-3	2016 2019	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 300 MW	n/n
KAACW	Option C	Montrose-1 Montrose-2 Montrose-3	2016 2021 2021	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 300 MW	670 MW Wind in 2029

Table 9: Alternative Resource Plans (continued)

Plan Name	DSM Level	Facility	Year to Cease Burning Coal	Renewable Additions		Generation Addition (if needed)
KBBCA	Option C	Montrose-1 LaCygne-2 Montrose-2 Montrose-3	2016 2019 2021 2021	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 300 MW	414 MW CT in 2021 207 MW CT in 2032
KCCCA	Option C	Montrose-1 Montrose-2 Montrose-3	2016 2019 2019	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 300 MW	207 MW CT in 2029
KAADA	Option D - Persistence	Montrose-1 Montrose-2 Montrose-3	2016 2021 2021	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 300 MW	207 MW CT in 2021 207 MW CT in 2025 207 MW CT in 2031

Each plan is detailed in year-by-year charts in Volume 6, Section 4.

4.2 SELECTION OF PREFERRED RESOURCE PLAN

The Preferred Plan, Alternative Resource Plan KAACA, selected for KCP&L is shown in Table 10 below:

Table 10: KCP&L Preferred Resource Plan

Year	CT's (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)	Total Capacity
2015	0			29		4372
2016	0	350	3	71		4321
2017	0	300		103		4434
2018	0			124		4434
2019	0			139		4444
2020	0			176		4444
2021	0			206		4254
2022	0			228		4254
2023	0			248		4269
2024	0			266		4258
2025	0			284		4283
2026	0		7	299		4284
2027	0			308		4309
2028	0			316		4359
2029	207			325		4366
2030	0			333		4416
2031	0			337		4441
2032	0			341		4466
2033	0			345		4516
2034	0			349		4541

Based in part upon current Missouri RPS rule requirements, the Preferred Plan includes 10 MW of solar additions and 650 MW of wind additions over the twenty-year planning period. It should be noted that the 3 MW of solar resource additions are expected to consist of Commercial and Industrial rooftop installations owned by KCP&L. The 350 MW of wind additions are from power purchase agreements (PPA) executed in 2013 and 2014. The additional 300 MW of wind additions are planned to be in service in 2017. DSM resources consist of a suite of eight residential and eight commercial programs. The Preferred Plan also reflects ceasing to burn coal at Montrose unit 1 in 2016 and at Montrose units 2 and 3 in 2021. The environmental drivers that contributed to the discontinuing coal use at the Montrose units included Mercury and Air Toxics Standards Rule, Ozone National Ambient Air Quality Standards (NAAQS), PM NAAQS, Clean Water Act Section 316(a) and (b), Effluent Guidelines, Coal Combustion Residuals Rule, and Clean Power Plan.

The Preferred Plan was not the lowest cost plan from a Net Present Value of Revenue Requirement (NPVRR) perspective for KCP&L on a stand-alone planning basis. Alternative Resource Plan KCCCA had the lowest expected NPVRR of all modeled KCP&L plans. This plan is the same as the Preferred Plan except KCP&L would cease to burn coal in Montrose 2 and 3 starting in 2021 as opposed to 2019. It should be noted that the Preferred Plan is based upon resource planning in tandem with KCP&L-Greater Missouri Operations Company (GMO) and provides benefit to Missouri retail customers by planning on a joint basis. The joint KCP&L/GMO plan that includes keeping Montrose 2 and 3 in service as coal resources until 2021 is lower cost for Missouri electric customers than ceasing coal use in 2019.

The Preferred Plan also meets the fundamental planning objectives as required by Rule 22.010(2) to provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies.

The Forecast of Capacity Balance worksheet associated with Preferred Plan selected for KCP&L is shown in Table 11 below.

Table 11: KCP&L Forecast of Capacity Balance - Preferred Plan **Highly Confidential**

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SECTION 5: CRITICAL UNCERTAIN FACTORS

4. Identification of critical uncertain factors affecting the preferred resource plan;

The ranges of critical uncertain factors are calculated by finding the value at which the critical uncertain factor needs to change in order for the Preferred Resource Plan to no longer be the lowest cost option. The values of the NPVRR for the Preferred Resource Plan and the lowest cost plan under extreme conditions are compared and by using linear interpolation a crossover point value is found and expressed as a percent of the range of the critical uncertain factor. These percentages are superimposed on the forecast levels for each critical uncertain factor to develop the resulting ranges.

The Company has selected its Preferred Plan based in part on the results of the joint planning for KCP&L and GMO. Details on the joint plans can be found in Volume 6, Section 3.1. In the joint planning analysis, the Preferred Plan, CBBFA and two other plans, CCDCC and CCDFC proved to be the lowest cost plans under different risk scenarios. The values of these plans' NPVRR under each of the risks are detailed in the following table.

Table 12: Alternative Plans for Each Uncertain Factor

Assuming Low CO2						
NPVRR ($MM)	**High Load**	**High NG**	**Low CO2**	**EV**	**Low NG**	**Low Load**
CCDCC	28,446	27,661	28,028	29,230	28,332	27,674
CBBFA	28,236	27,258	27,831	29,106	28,367	27,490
Assuming High CO2						
NPVRR ($MM)	**High Load**	**High NG**	**High CO2**	**EV**	**Low NG**	**Low Load**
CCDFC	31,520	30,748	31,026	29,181	30,972	30,603
CBBFA	31,577	30,676	31,085	29,106	31,120	30,663

Based on joint planning, the uncertain factors which may cause the Company to modify the KCP&L Preferred Plan are limited to high CO_2 and low natural gas prices. Calculation details for the range of uncertain factors are given in Volume 7, Section 2.

SECTION 6: PERFORMANCE MEASURES

5. For existing legal mandates and approved cost recovery mechanisms, the following performance measures of the preferred resource plan for each year of the planning horizon:

A. Estimated annual revenue requirement;

B. Estimated level of average retail rates and percentage of change from the prior year; and

C. Estimated company financial ratios;

Data for the Preferred Plan is provided in the table below. This information is also provided in the Company response to Rule 240-22.060(4)(C)1 in Volume 6.

Table 13: Financial Performance - Preferred Plan

[redacted]

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SECTION 7: COMPANY FINANCIAL RATIOS

6. If the estimated company financial ratios in subparagraph (2)(E)5.C. of this rule are below investment grade in any year of the planning horizon, a description of any changes in legal mandates and cost recovery mechanisms necessary for the utility to maintain an investment grade credit rating in each year of the planning horizon and the resulting performance measures of the preferred resource plan;

The Company calculated performance measures for all studied alternative plans including the Preferred Plan. The expected values of alternative plan performance ratios do not materially change below current conditions. The expectations would be that the investment rating of the company is not at risk from the choice of any particular alternative resource plan.

SECTION 8: RESOURCE ACQUISITION INITIATIVES

7. Actions and initiatives to implement the resource acquisition strategy prior to the next triennial compliance filing; and

8.1 ENVIRONMENTAL RETROFITS

Based on the 2015 Preferred Plan, limited environmental retrofits are anticipated to be required for Montrose Units 2 & 3 prior to cease burning coal in 2021. These retrofits are required to operate the units through year 2020. Other projects anticipated to begin within the three year implementation period are Hawthorn 5 Cooling Tower and Spray Dry Absorber water reduction, Iatan 1 Cooling Tower, and LaCygne 2 Submerged Flight Conveyer. A draft schedule of major milestones for these retrofit projects are provided in the following table:

Table 14: Environmental Retrofits

Retrofit Project	Milestone Description	Date Range
Hawthorn 5 Cooling Tower	Studies/Specification/Bid/Award	01/2016 - 4/2018
Hawthorn 5 SDA water reduction	Study/Design/Construction	01/2015 - 07/2015
Iatan 1 Cooling Tower	Studies/Specification/Bid/Award	01/2016 - 4/2018
La Cygne 2 SFC	Design/Procurement/Construction	04/2015 - 09/2018
Montrose 2 & 3 ACI	Engineering/Procurement/Construction	01/2015 - 4/2015
Montrose 2 & 3 ACI	Checkout/Startup/Tuning/Testing	04/2015 - 02/2016
Montrose 2 & 3 ESP Improvements	Engineering/Procurement/Construction	01/2015 - 4/2015
Montrose 2 & 3 ESP Improvements	Checkout/Startup/Tuning/Testing	04/2015 - 02/2016
Montrose 2 & 3 sluiced ash modifications	Study/Design/Procurement/Construction	01/2015 - 12/2018
Montrose 2 & 3 new fly ash pug mill	Study/Design/Procurement/Construction	04/2015 - 04/2016
ACI : Activated Carbon Injection ESP: Electrostatic Precipitator SDA: Spray Dry Absorber SFC: Submerged Flight Conveyor		

8.2 SOLAR AND WIND INITIATIVES

The Preferred Plan includes solar resource additions in 2016 consisting of ownership in 3 MW of Commercial and Industrial solar rooftop installations. A draft schedule of the major milestones for this solar initiative is provided in the following table:

Table 15: Solar Initiative

Solar Initiative	Date Range
Evaluate/Select Developer(s)	04/2015 - 07/2015
Site Designs/Obtain Permits	8/2015 - 12/2015
Rooftop Installations Mobilization/Construction	01/2016 - 5/2016
Commercial Operation for Rooftop Installations	05/2016 - 06/2016

In addition, KCP&L is working towards procuring additional wind resources.

SECTION 9: MAJOR RESEARCH PROJECTS

8. A description of the major research projects and programs the utility will continue or commence during the implementation period;

9.1 LOAD FORECASTING

KCP&L plans to conduct its next Residential Appliance Saturation Survey in 2016-2017. KCP&L is also looking at the option of expanding the survey to the commercial sector in 2016-2017. The last residential survey was completed in 2013. The timeline currently expected for the Residential Appliance Saturation Survey is shown in the following table:

Appliance Saturation Survey Initiative	Date Range
Issue Appliance Saturation Survey Request for Proposal (RFP)	06/2015 - 12/2015
Evaluate Conducting a C&I Survey	1/2015 - 12/2015
Conduct Residential Appliance Saturation Survey	01/2016-06/2016
Tabulation Appliance Saturation Survey Results	06/2016-12/2016
Conduct Conditional Demand Study	01/2017-5/2017
Implement Survey Result in Load Forecast	05/2017-7/2017

9.2 DEMAND-SIDE MANAGEMENT PROJECTS

Major DSM research projects are discussed below.

9.2.1 DEMAND-SIDE MANAGEMENT MARKET POTENTIAL STUDY

KCP&L engaged Navigant Consulting, Inc. (Navigant) to conduct a Demand Side Management (DSM) Resource Potential Study in January 2012. Navigant provided a broad range of stakeholders opportunities to review and comment on the potential study methodologies, survey instruments and findings. The stakeholders included the Missouri Public Service Commission, Missouri Office of Public Counsel, Missouri Department of Natural Resources, National Resources Defense Council, Empire Electric District, Renew Missouri, and Ameren.

Navigant completed Demand-Side Management (DSM) Potential Study in August 2013, which included an assessment of:

- Realistic Achievable Potential (RAP) and Maximum Achievable Potential (MAP) energy efficiency potential for the period of 2014-2033
- RAP and MAP demand response potential including time-based rates
- Combined heat and power potential

KCP&L adjusted the RAP and MAP scenarios to account for the roll-off of measures at the end of the measures' life, commercial and industrial opt-outs, and to match the 2016-2034 time period need for the IRP analysis.

The final reports can be found in Appendix 5A Navigant Demand-Side Resource Potential Study Report and Appendix 5B Navigant Demand Response Potential Study Report.

Pursuant to 4 CSR 240-3.164 (2) (A), the current market potential study shall be updated no less frequently than every four (4) years. Therefore, in compliance with this requirement and as part of KCP&L's ongoing research efforts, KCP&L will initiate the next market potential study in 2015 with an estimated completion date of early 2017. KCP&L also recognizes that the current market potential study reflects a single data point and that a future market potential study may result in different energy and demand savings levels.

9.2.2 ADVANCED THERMOSTAT-COLLABORATION PROJECT WITH EPRI

KCP&L is collaborating with The Electric Power Research Institute (EPRI), as a host utility, to test and evaluate the potential of a new generation of programmable communicating thermostats that hold the potential for both energy and demand savings at a relatively low cost to the utility. Industry experience has shown that customer acceptance and usability can be key drivers to a thermostat's energy or demand reduction potential. Given that smart thermostats may offer better customer usability due to their remote programming capability, the objective of this program is to evaluate their energy and demand savings impacts, as well as how customers perceive and use them.

The program will inform utilities and the public of the potential energy savings benefits of smart thermostats. For utilities, it may provide a measure of how these thermostats fit into their programs and key features that might promote energy efficiency and demand response. Demand response from residential air conditioners has been a target of many utility programs, but the cost of installation of load control devices and the perceived compromise in customer comfort have been large barriers. These thermostats, which are consumer-managed and possibly consumer-procured, may overcome these barriers at a relatively low cost. The knowledge gained about how customers perceive and interact with these types of devices may potentially inform future product designs and help bring about better thermostat choices for consumers.

9.3 SMARTGRID DEMONSTRATION PROJECT

The 5 year KCP&L SmartGrid Demonstration Project (SGDP) is implementing and evaluating end-to-end SmartGrid platform that includes advanced renewable generation, storage resources, leading-edge substation and distribution automation and control, energy management interfaces, and innovative customer programs and rate structures. The SGDP is focused on the geographic area served by the KCP&L Midtown Substation within Kansas City's urban core. The SGDP was awarded a funding grant from the DOE in and also collaborated with EPRI's SmartGrid Demonstration Program as a host utility.

The SGDP includes detailed analysis and testing to demonstrate the benefits of optimizing energy and information flows and utility operations across supply and demand resources, T&D operations, and customer end-use programs. The operational testing and data collection phase of the SGDP concluded September 31, 2014. The analysis, evaluation, and documentation of findings for the twenty three operational demonstrations and tests conducted during the operational phase is ongoing and will be completed the first quarter of 2015. The SGDP Final Technical Report is due to the DOE May 1, 2015.

KCP&L anticipates that the results of SGDP and subsequent benefit cost analyses will determine that several of the advanced distribution grid technologies will be determined to be cost effective, or at a minimum we will understand under what conditions they become cost effective.

9.4 KCP&L CLEAN CHARGE NETWORK PILOT

KCP&L and KCP&L Greater Missouri Operations Company ("GMO") have launched an initiative to install and operate the KCP&L Clean Charge Network consisting of more than 1,000 electric vehicle charging stations throughout the Greater Kansas City region and within the KCP&L and GMO service territories.

KCP&L and GMO are partnering with organizations throughout our service territories that will host the charging station sites. Through these partnerships the KCP&L Clean Charge Network will offer free charging on every station to all drivers for a pilot period.

Prior to this pilot program KCP&L had deployed a limited number of EV charging stations as part of the SmartGrid Demonstration Project and a DOE Clean Cities grant. While these charging stations have provided some limited insight into EV charging characteristics, they have failed to provide much insight on the following questions:

- Can electric vehicles and electric vehicle charging stations enhance efficiency and utilization of the grid and, if so, how should such impacts be assessed, optimized and recognized?
- Do electric vehicles and electric vehicle charging stations present demand response opportunities and, if so, how should such opportunities be assessed, optimized and implemented?

The scale of the KCP&L Clean Charge Network is such that KCP&L should gain considerable insight in these and other public benefit areas, which could not be gained from the earlier limited deployments.

The Company plans to learn from these installations, gathering information during the pilot period to be shared with stakeholders in developing a longer term view.

9.5 DISTRIBUTED GENERATION AND PHOTOVOLTAIC SYSTEMS MARKET RESEARCH STUDY

KCP&L is participating with other utilities in an E Source market research study that will provide critical, timely information to help understand what motivates large and midsize business customers to acquire photovoltaic (PV) and other distributed generation (DG) technologies. It will also reveal which customers are most likely to reduce their demand for traditional utility-provided electricity.

Data will be gathered using a combination of qualitative and quantitative techniques on customer attitudes, desires, barriers, and actions that are essential to understand in order to create a viable PV and DG strategy. The E Source study covers the US and Canada and includes key market segments such as retail, grocery, healthcare, government, manufacturing, hotels and motels, data centers, and education. The DG questions focus on the following technologies: microturbines / combustion turbines, reciprocating engines, fuel cells, battery storage, thermal storage, combined heat and power (CHP), and waste heat recovery.

E Source will field a national survey, conduct customer interviews, perform research, and conduct analysis from January to April 2015. In addition, E Source will also field an oversample from the KCP&L service territory expected to be completed in the fall of 2015. The report and findings of the primary study is expected to be published in the spring of 2015.

Key questions addressed in this study include:

- What drives business customers to embrace PV and DG
- How do attitudes about utilities affect customers' decisions to adopt PV and DG
- What investment criteria are most commonly used for decision-making
- How do corporate sustainability goals affect these decisions
- What barriers may keep customers from adopting PV and DG
- Who are the preferred providers of PV and DG, including utilities, local contractors, and national vendors
- To what extent will on-site electric storage affect these decisions
- Can utility pricing models affect adoption
- How are corporate decisions made regarding PV and DG adoption
- Which customer segments are most likely to adopt PV and why

As a participant of this study KCP&L will receive:

- An interim intelligence report based on in-depth interviews
- A strategic outcome report, highlighting how the findings paint a picture for the future and illustrating how utilities can take advantage of, or defend, the PV and DG space
- A detailed results presentation report with key data in meaningful formats that can be used to help make strategic decisions
- A web conference on E Source's findings, including time for questions and a discussion of the results
- Full national data sets and, if fielded, utility-specific data sets

VOLUME 2

TABLE OF RULE REQUIREMENTS

KANSAS CITY POWER & LIGHT COMPANY (KCP&L)

INTEGRATED RESOURCE PLAN

4 CSR 240-22.020

APRIL, 2015

TABLE OF RULE REQUIREMENTS

22.040 Supply-Side Resource Analysis

22.045 Transmission and Distribution Analysis

22.050 Demand-Side Resource Analysis

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VOLUME 3:

LOAD ANALYSIS AND LOAD FORECASTING

KANSAS CITY POWER & LIGHT COMPANY (KCP&L)

INTEGRATED RESOURCE PLAN

4 CSR 240-22.030

APRIL, 2015

energizing life

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VOLUME 3 – LOAD ANALYSIS AND LOAD FORECASTING

HIGHLIGHTS

- KCP&L expects energy consumption to grow .6% and peak demand to grow .7% annually from 2015-2035.
- Residential energy consumption is expected to provide the most growth over the next 20 years.
- KCP&L customers are expected to grow .5% annually from 2015-2035.
- Key forecast uncertainties include the future mix of customers, the impact of rising prices, technological advancement in renewable energy sector, and energy efficiency.

PURPOSE: This rule sets minimum standards for the maintenance and updating of historical data, the level of detail required in analyzing loads, and the purposes to be accomplished by load analysis and by load forecast models. The load analysis discussed in this rule is intended to support both demand-side management efforts of 4 CSR 240-22.050 and the load forecast models of this rule. This rule also sets the minimum standards for the documentation of the inputs, components, and methods used to derive the load forecasts.

SECTION 1: SELECTING LOAD ANALYSIS METHODS

The utility may choose multiple methods of load analysis if it deems doing so is necessary to achieve all of the purposes of load analysis and if the methods are consistent with, and calibrated to, one another. The utility shall describe and document its intended purposes for load analysis methods, why the selected load analysis methods best fulfill those purposes, and how the load analysis methods are consistent with one another and with the endues consumption data used in the demand-side analysis as described in 4 CSR 240-22.050. At a minimum, the load analysis methods shall be selected to achieve the following purposes:

1.1 PURPOSE: IDENTIFICATION OF END-USE MEASURES

(A) To identify end-use measures that may be potential demand-side resources, generally, those end-use measures with an opportunity for energy and/or demand savings;

1.2 PURPOSE: DERIVATION OF DATA SET OF HISTORICAL VALUES

(B) To derive a data set of historical values from load research data that can be used as dependent and independent variables in the load forecasts;

1.3 PURPOSE: ANALYSIS OF IMPACTS OF IMPLEMENTED DSM AND DEMAND-SIDE RATES ON LOAD FORECASTS

(C) To facilitate the analysis of impacts of implemented demand-side programs and demand-side rates on the load forecasts and to augment measurement of the effectiveness of demand-side resources necessary for 4 CSR 240-22.070(8) in the evaluation of the performance of the demand-side programs or rates after they are implemented; and

1.4 PURPOSE: PRESERVATION OF LOAD ANALYSIS IN HISTORICAL DATABASE

(D) To preserve, in a historical database, the results of the load analysis used to perform the demand-side analysis as described in 4 CSR 240-22.050, and the load forecasting described in 4 CSR 240-22.030.

SECTION 2: HISTORICAL DATABASE FOR LOAD ANALYSIS

The utility shall develop and maintain data on the actual historical patterns of energy usage within its service territory. The following information shall be maintained and updated on an ongoing basis and described and documented in the triennial compliance filings:

2.1 CUSTOMER CLASS DETAIL

(A) Customer Class Detail. At a minimum, the historical database shall be maintained for each of the major classes;

KCP&L maintains a historical database of its loads for each major class, which are Residential, Small General Service (SGS), Medium General Service (MGS), Large General Service (LGS), Large Power (LP), Lighting and Sales for Resale (SFR). In addition, SGS, MGS, LGS and LP are split into the subclasses commercial and industrial. This data begins in May 2005 for KCP&L and will be maintained with at least 10 years of history going forward. Beginning with this IRP filling, KCP&L forecasts its loads for each major class, which are Residential, Commercial Small General Service (SGS), Commercial Big (The sum of MGS, LGS, and LP), Industrial (The sum of SGS, MGS, LGS, and LP), Lighting, and Sales for Resale (SFR).

2.2 LOAD DATA DETAIL

(B) The historical load database shall contain the following data:

2.2.1 ACTUAL AND WEATHER NORMALIZED ENERGY, AND NUMBER OF CUSTOMERS

1. For each jurisdiction for which it prepares customer and energy and demand forecasts, for each major class, to the actual monthly energy usage and number of customers and weather-normalized monthly energy usage;

MetrixND files are used to maintain this data for each subclass listed in 22.030 (2) (A). These files also contain the models used to forecast the number of customers and weather-normalize and forecast monthly energy sales.

2.2.2 ACTUAL AND WEATHER NORMALIZED DEMANDS

2. For each jurisdiction and major class, estimated actual and weather-normalized demands at the time of monthly system peaks; and

Actual and weather-normalized coincident demands are provided in the *load research* folder of the workpapers. This data is available beginning in May 2004 at which time the load research sample converted from revenue class to CCOS. The loads are currently weather normalized when a rate case is prepared.

2.2.3 ACTUAL AND WEATHER NORMALIZED SYSTEM PEAK DEMANDS

3. For the system, actual and weather normalized hourly net system load;

Actual and weather-normalized Net System Input (NSI) is contained in the MetrixLT files.

2.3 LOAD COMPONENT DETAIL

(C) The historical database for major class monthly energy usage and demands at time of monthly peaks shall be disaggregated into a number-of-units component and a use-per-unit component, for both actual and weather-normalized loads.

2.3.1 UNITS COMPONENT

1. The number-of-units component shall be the number of customers, square feet, devices, or other units as appropriate to the customer class and the load analysis method selected by the utility. The utility shall select the units component with the intent of providing meaningful load analysis for demand-side analysis and maintaining the integrity of the database over time.

The number-of-units is the number of customers for residential and SGS commercial. For the other subclasses, mWh sales are modeled because it is more stable than kWh sales per customer and the model fit statistics are higher. In the big commercial and Industrial customer classes, the size of customers varies more than in the smaller classes and use per customer can vary substantially as customers enter or exit the class.

2.3.2 UPDATE PROCEDURE

2. The utility shall develop and implement a procedure to routinely measure and regularly update estimates of the effect of departures from normal weather on class and system electric loads. The estimates of the effect of weather on historical major class and system loads shall incorporate the nonlinear response of loads to daily weather and seasonal variations in loads.

KCP&L has developed a MetrixND model for each subclass of kWh sales that both forecasts and weather normalizes sales or sales per unit. These models will update weather normalized sales at the subclass level whenever these models are updated. This procedure is automatic. Major class level demands are currently weather normalized only for a rate case and this process is not automatic as it requires a large number of manual steps. Heating and cooling degree days calculated with different base temperatures were tested and kept in the models if statistically significant so that nonlinear weather response functions could be represented.

2.3.3 WEATHER MEASURES AND ESTIMATION OF WEATHER EFFECTS DESCRIPTION AND DOCUMENTATION

3. The utility shall describe and document the methods used to develop weather measures and the methods used to estimate the effect of weather on electric loads. If statistical models are used, the documentation shall include at least: the functional form of the models; the estimation techniques employed; and the relevant statistical results of the models, including parameter estimates and tests of statistical significance. The data used to estimate the models, including the development of model input data from basic data, shall be included in the workpapers supplied at the time the compliance report is filed;

In this IRP filing, KCP&L used different methods to model the effects of weather for normalization and for forecasting. One reason for using different methods is that the sample period for WN needed to cover the entire period that historical data was available so that data could be WN. On the other hand, the forecasting models often need a more recent shorter sample period since the focus is on calibrating an end-use forecast to recent data. The method of WN used in this IRP filing is different than that used in the rate cases because it is designed to WN many years of data whereas the rate case models are based on only two years of data. Also the method used here is much less labor intensive and can be updated more routinely.

Degree days computed at different base temperatures were tested in explaining the effects of weather on sales and system load. Degree days computed with more than one base temperature were tested in the same model to determine if the load response is nonlinear. The statistical results of model estimation in the weather normalization models of monthly sales are presented in this section. Additional information is available in the MetrixND model files that are included in the electronic workpapers. This additional information includes formulas that define the explanatory variables, plots and tables of residuals, plots and tables of actual, weather-normalized and predicted values, plots and tables of explanatory variables and model statistics and coefficients. The model coefficients were estimated using ordinary least squares regression in MetrixND. The estimation period generally includes January 2000 to July 2014 for the residential and Industrial classes and May 2005 to July 2014 for the commercial classes.

Table 1 WN Model for MO Residential Sales

Variable	Coefficient	StdErr	T-Stat	P-Value	Units
CONST	555.740	9.710	57.231	0.00%	
BinaryVars.trend1	1.910	1.212	1.576	11.70%	
BinaryVars.trend2	-98.011	33.282	-2.945	0.37%	
BinaryVars.Jan	72.996	10.657	6.850	0.00%	
BinaryVars.Dec	76.822	9.716	7.907	0.00%	
WthrTrans.cddTrend1	-28.770	6.445	-4.464	0.00%	
WthrTrans.cddTrend2	267.094	185.674	1.439	15.22%	
WthrTrans.hddTrend1	63.991	7.033	9.099	0.00%	
WthrTrans.hddTrend2	-434.267	190.366	-2.281	2.38%	
WthrTrans.cdd65shoulder	-150.991	133.066	-1.135	25.82%	
WthrIndex.CDD65_Index	2113.781	175.586	12.038	0.00%	
WthrIndex.CDD70_Index	289.565	138.560	2.090	3.82%	
WthrIndex.HDD55_Index	1608.935	60.555	26.570	0.00%	

Table 2 WN Model for MO Small GS Commercial Sales

Variable	Coefficient	StdErr	T-Stat	P-Value	Units
CONST	1062.547	21.558	49.288	0.00%	
WthrTrans.Cdd60trend1_SML	-230.058	44.830	-5.132	0.00%	
WthrTrans.Cdd60trend2_SML	2919.519	666.997	4.377	0.00%	
WthrTrans.Hdd55trend1_SML	-118.522	65.788	-1.802	7.45%	
WthrTrans.Hdd55trend2_SML	1905.190	779.812	2.443	1.63%	
BinaryVars.trend1	-23.926	5.519	-4.335	0.00%	
WthrIndex.CDD60_Index	2612.724	117.770	22.185	0.00%	
WthrIndex.HDD55_Index	1827.590	145.383	12.571	0.00%	

Table 3 WN Model for MO Big GS Commercial Sales (MGS, LGS and LP)

Variable	Coefficient	StdErr	T-Stat	P-Value	Units
CONST	263913632.995	4279847.308	61.664	0.00%	
WthrTrans.Hdd55trend1_BIG	-22241323.436	16660700.953	-1.335	18.49%	
WthrTrans.Hdd55trend2_BIG	292179313.219	240092109.977	1.217	22.65%	
WthrTrans.Cdd55trend1_BIG	-12448111.849	15540768.558	-0.801	42.50%	
WthrTrans.Cdd55trend2_BIG	97677221.591	258445329.305	0.378	70.63%	
BinaryVars.trend1	9953397.526	2718286.138	3.662	0.04%	
BinaryVars.trend2	-234553327.821	68504712.529	-3.424	0.09%	
BinaryVars.trend3	149915498.686	64647632.293	2.319	2.24%	
WthrIndex.HDD55_Index	293131055.029	26866971.249	10.910	0.00%	
WthrIndex.CDD55_Index	481211531.889	24097662.095	19.969	0.00%	

Table 4 WN Model for MO Industrial Sales (SGS, MGS, LGS and LP)

Variable	Coefficient	StdErr	T-Stat	P-Value	Units
CONST	134779787.810	830244.027	162.338	0.00%	
WthrIndex.CDD55_Index	65935509.669	4895008.473	13.470	0.00%	
BinaryVars.trend1	-855075.048	94161.755	-9.081	0.00%	
BinaryVars.trend2	-21092808.395	2499906.296	-8.437	0.00%	
BinaryVars.Feb	-5898323.331	1543793.786	-3.821	0.02%	
BinaryVars.Apr	-5312704.196	1455682.278	-3.650	0.04%	
BinaryVars.Nov	-4025488.260	1504964.175	-2.675	0.82%	
IND_SalesWn.Jun09	-13286809.545	5190610.752	-2.560	1.14%	
IND_SalesWn.May09	-14358219.724	5191301.311	-2.766	0.63%	
IND_SalesWn.aug2005	-19024693.622	5230030.173	-3.638	0.04%	
IND_SalesWn.Feb14	17975122.767	5432537.909	3.309	0.12%	

Table 5 WN Model for KS Residential Sales

Variable	Coefficient	StdErr	T-Stat	P-Value	Units
CONST	700.731	9.623	72.821	0.00%	
BinaryVars.trend1	1.219	1.265	0.964	33.66%	
BinaryVars.trend2	-139.442	34.623	-4.027	0.01%	
WNAvgUse.Jan	118.019	11.077	10.655	0.00%	
WNAvgUse.Dec	113.140	10.107	11.194	0.00%	
WthrTrans.cddTrend1	-26.440	6.775	-3.902	0.01%	
WthrTrans.cddTrend2	371.661	193.686	1.919	5.68%	
WthrTrans.hddTrend1	35.235	7.332	4.806	0.00%	
WthrTrans.hddTrend2	-472.343	197.833	-2.388	1.81%	
WthrTrans.cddShoulder	-511.783	138.652	-3.691	0.03%	
WthrIndex.HDD55_Index	1828.568	61.080	29.937	0.00%	
WthrIndex.CDD65_Index	3444.708	85.440	40.317	0.00%	
WthrIndex.CDD75_Index	-309.759	49.401	-6.270	0.00%	
WNAvgUse.Jul11	112.031	33.756	3.319	0.11%	

Table 6 WN Model for KS Small GS Commercial Sales

Variable	Coefficient	StdErr	T-Stat	P-Value	Units
CONST	988.221	19.576	50.481	0.00%	
WthrTrans.Hdd55trend2_SML	935.978	1082.883	0.864	38.95%	
WthrTrans.Hdd55trend1_SML	-18.289	75.410	-0.243	80.89%	
WthrTrans.Cdd60trend1_SML	-112.730	61.661	-1.828	7.05%	
WthrTrans.Cdd60trend2_SML	1707.459	1045.798	1.633	10.57%	
BinaryVars.trend1	-30.896	11.696	-2.642	0.96%	
BinaryVars.trend2	933.487	553.468	1.687	9.48%	
BinaryVars.trend3	-2104.039	1622.363	-1.297	19.77%	
BinaryVars.trend4	1541.066	1352.550	1.139	25.73%	
WthrIndex.HDD55_Index	1352.353	120.517	11.221	0.00%	
WthrIndex.CDD60_Index	2248.555	94.617	23.765	0.00%	

Table 7 WN Model for KS Big GS Commercial Sales (MGS and LGS)

Variable	Coefficient	StdErr	T-Stat	P-Value	Units
CONST	195918132.476	2487196.129	78.771	0.00%	
WthrTrans.Hdd50trend1_BIG	538368.160	9350082.537	0.058	95.42%	
WthrTrans.Cdd55trend1_BIG	-1316825.060	9314854.745	-0.141	88.79%	
WthrTrans.Hdd50trend2_BIG	6919780.709	132424176.816	0.052	95.84%	
WthrTrans.Cdd55trend2_BIG	-13377701.042	155264846.363	-0.086	93.15%	
BinaryVars.trend1	5245404.000	1594014.890	3.291	0.14%	
BinaryVars.trend2	-200553780.974	42991733.829	-4.665	0.00%	
BinaryVars.trend3	181659475.311	41997724.813	4.325	0.00%	
WthrIndex.HDD50_Index	150240176.383	15170183.777	9.904	0.00%	
WthrIndex.CDD55_Index	314262552.368	14383838.576	21.848	0.00%	

Table 8 WN Model for KS Industrial Sales (SGS, MGS and LGS)

Variable	Coefficient	StdErr	T-Stat	P-Value	Units
CONST	15168520.084	2302774.966	6.587	0.00%	
StrucVars.XOther_IND	8479093.630	2077683.952	4.081	0.01%	
StrucVars.XCool55_IND	21885842.411	1398964.147	15.644	0.00%	
IND_Sales.Aug10	1639494.151	609698.300	2.689	0.83%	
IND_Sales.Feb10	4757169.050	604702.427	7.867	0.00%	
IND_Sales.Nov06	1505471.898	615910.337	2.444	1.62%	
IND_Sales.Oct13	1416451.832	605155.534	2.341	2.11%	
IND_Sales.Jan09	-1830106.532	604019.512	-3.030	0.31%	
AR(1)	0.906	0.042	21.733	0.00%	

2.4 ASSESSMENTS

(D) For each major class specified pursuant to subsection (2)(A), the utility shall provide, on a seasonal and annual basis for each year of the historical period—

For the current KCP&L filing, historical sales and customers broken out by class cost of service for residential and industrial customers were available beginning in January 2000. Commercial class cost of service data was available beginning May 2005. Going forward, KCP&L will maintain this data for at least the previous 10 years.

2.4.1 HISTORIC END-USE DRIVERS OF ENERGY USAGE AND PEAK DEMAND

1. Its assessment of the historical end-use drivers of energy usage and peak demand, including trends in numbers of units and energy consumption per unit;

Historical plots of customers and kwh/customer for energy usage and peak demand can be found in *Appendix 3A.*

2.4.2 WEATHER SENSITIVITY OF ENERGY AND PEAK DEMAND

2. Its assessment of the weather sensitivity of energy and peak demand.

The following plots illustrate the weather response function of daily energy and peak demand for each major class. This data is weather normalized in the rate case process during which the weather response function is represented with an equation estimated with statistical regression analysis for the time period of January 2012 through March 2014. The blue symbols in the plot represent weekdays and the red symbols represent weekends.

Figure 1: MO Residential Daily Energy vs Average Temp

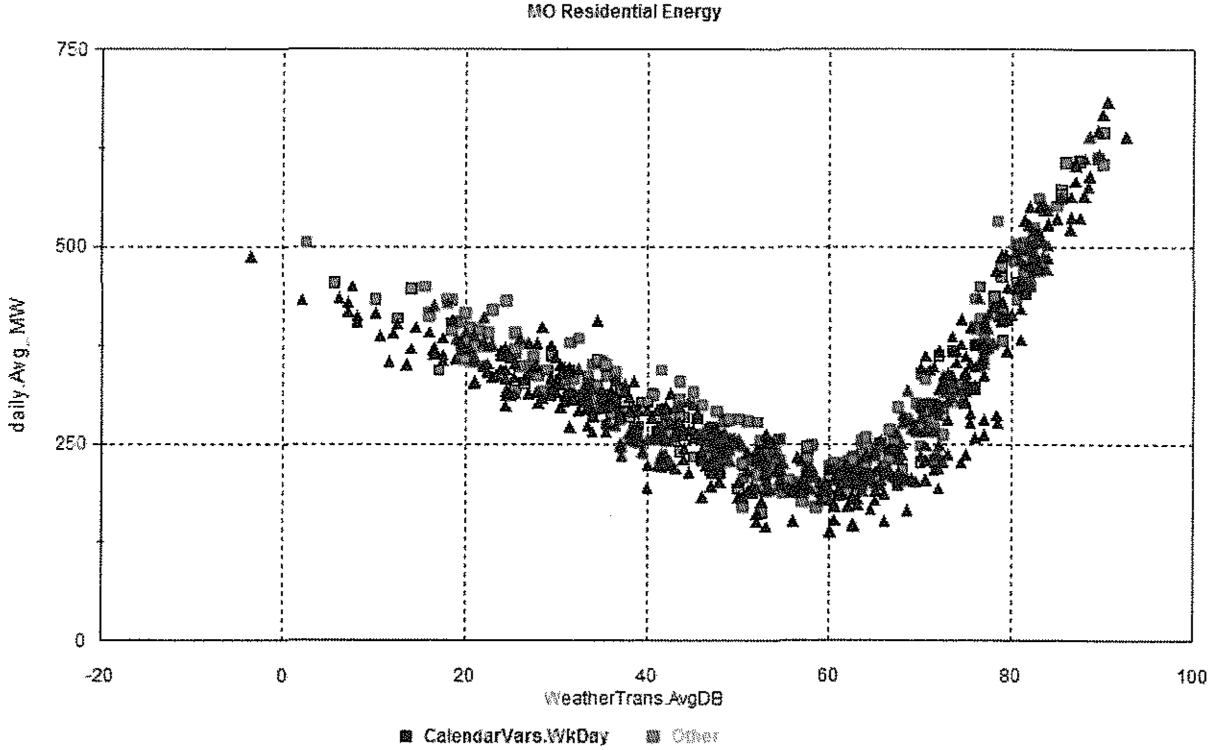


Figure 2: MO Residential Daily Peak Demand vs Average Temp

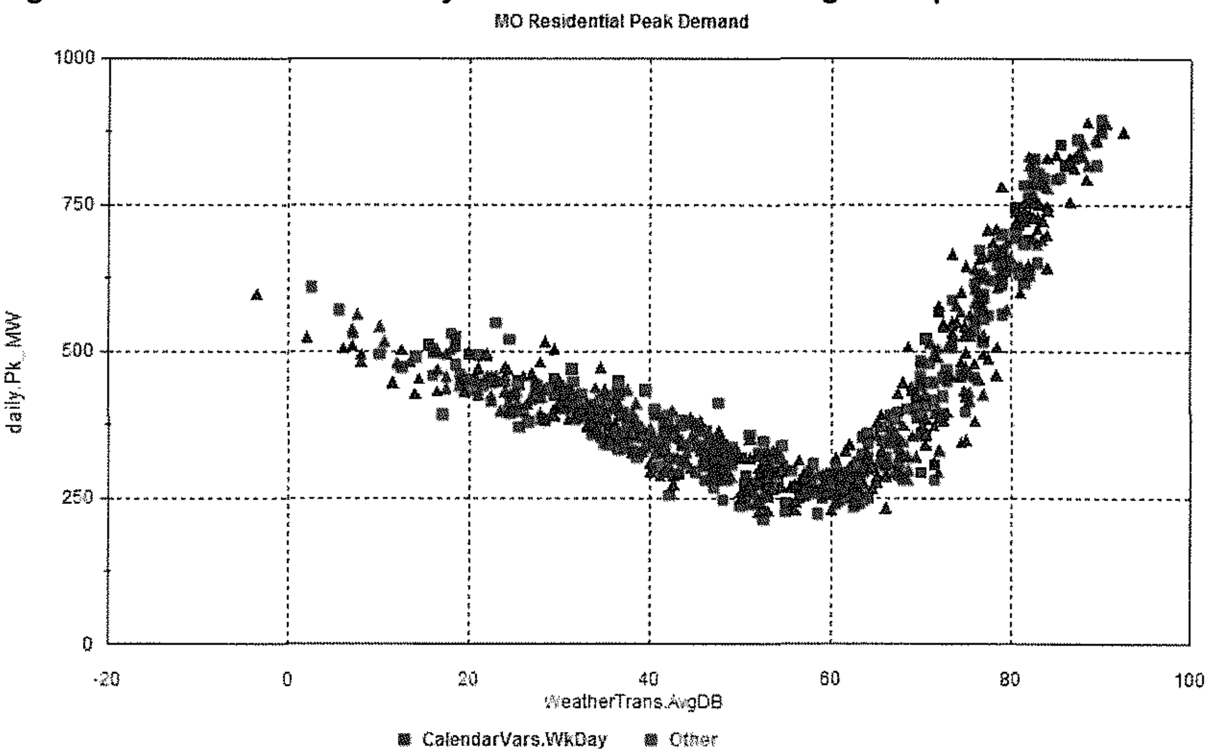


Figure 3: MO Small General Service Daily Energy vs Average Temp

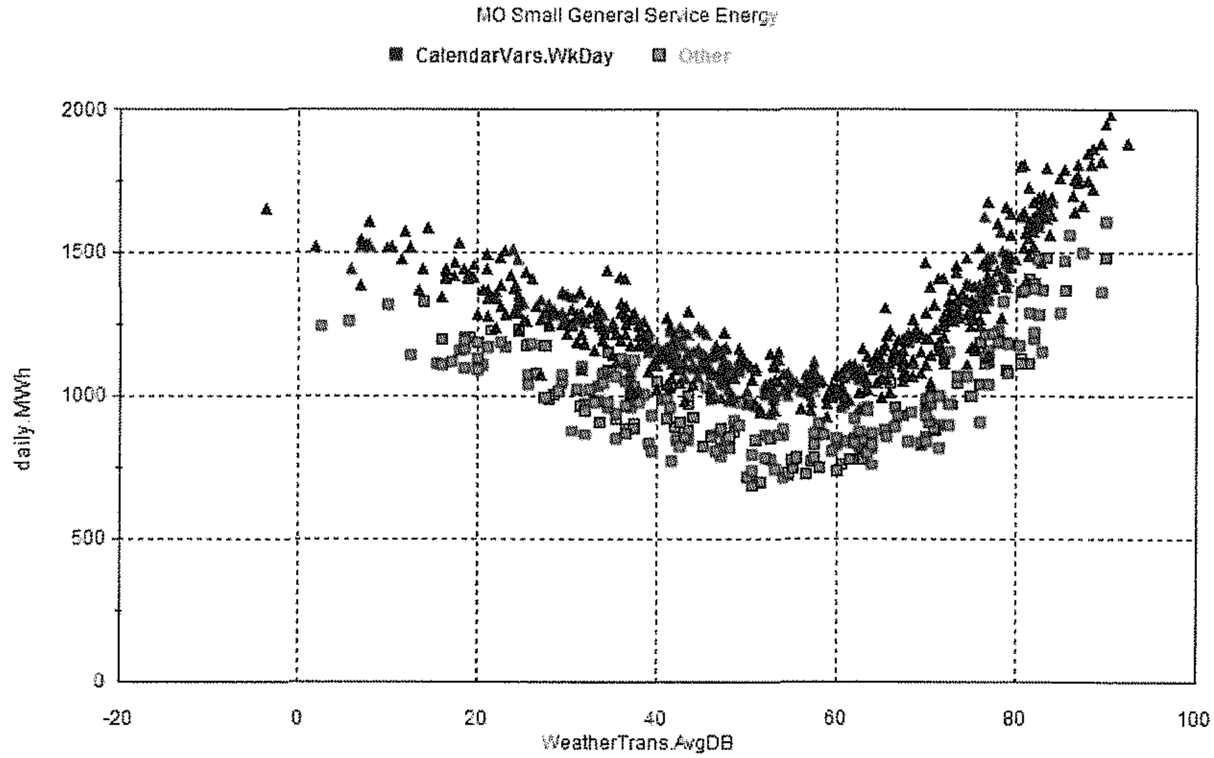


Figure 4: MO Small General Service Daily Peak vs Average Temp

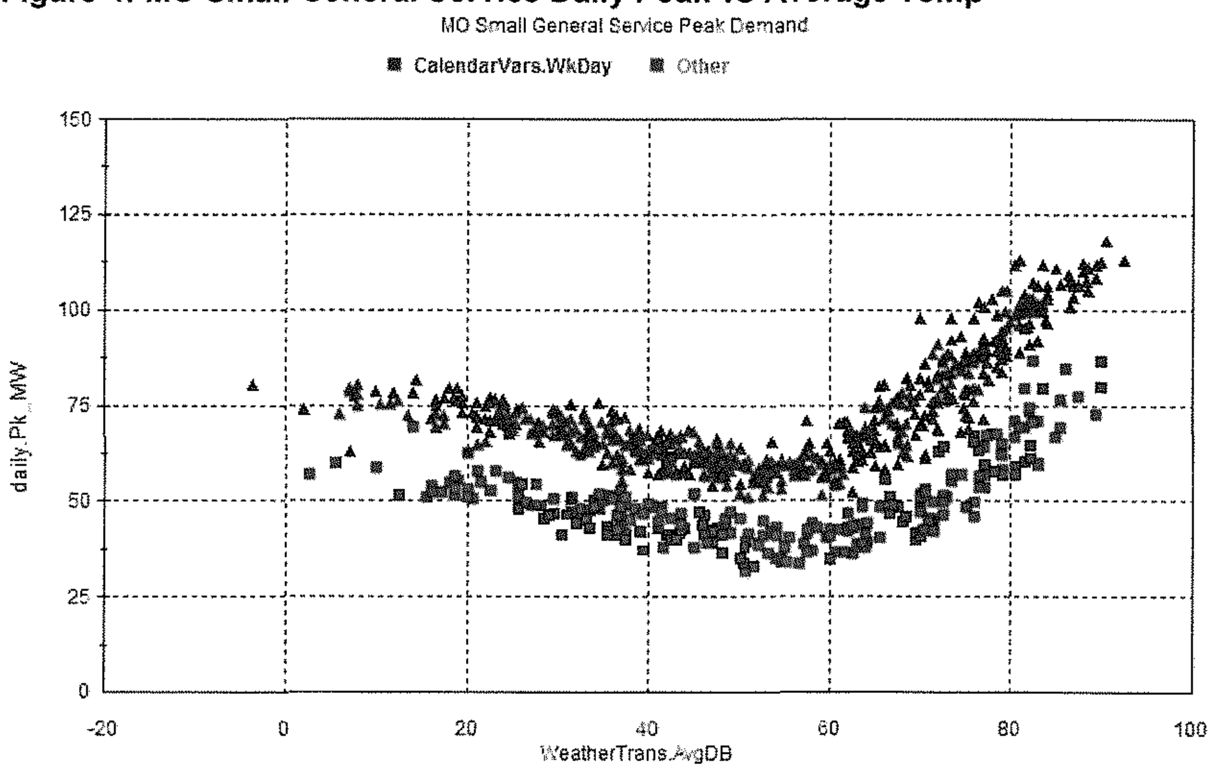


Figure 5: MO Medium General Service Daily Energy vs Average Temp

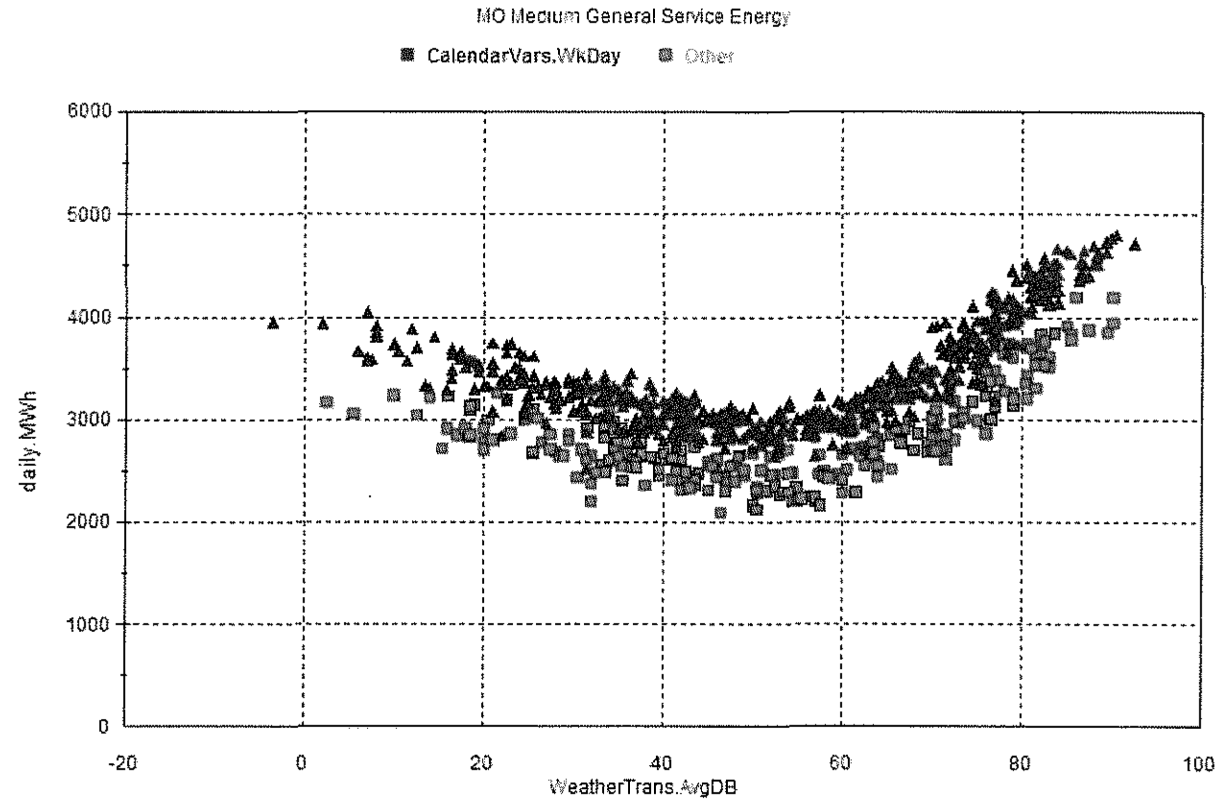


Figure 6: MO Medium General Service Daily Peak Demand vs Average Temp

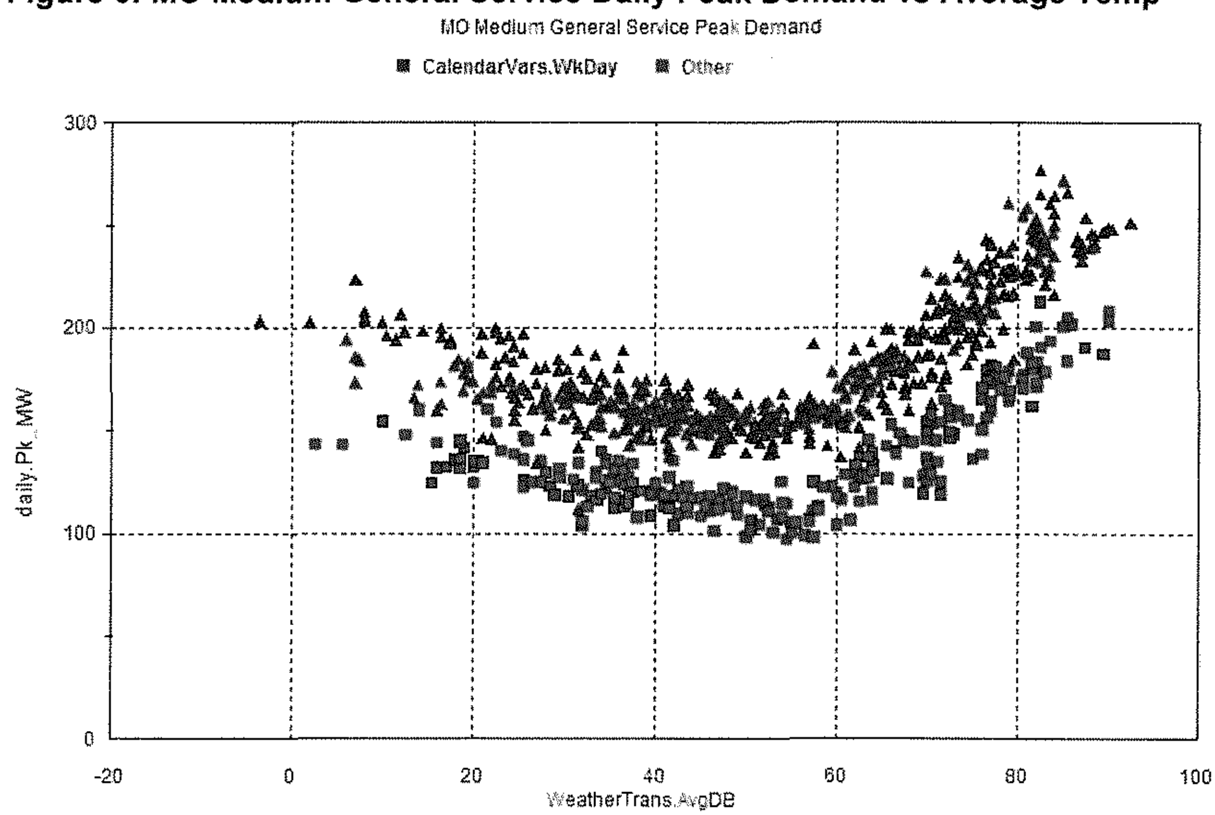


Figure 7: MO Large General Service Daily Energy vs Average Temp

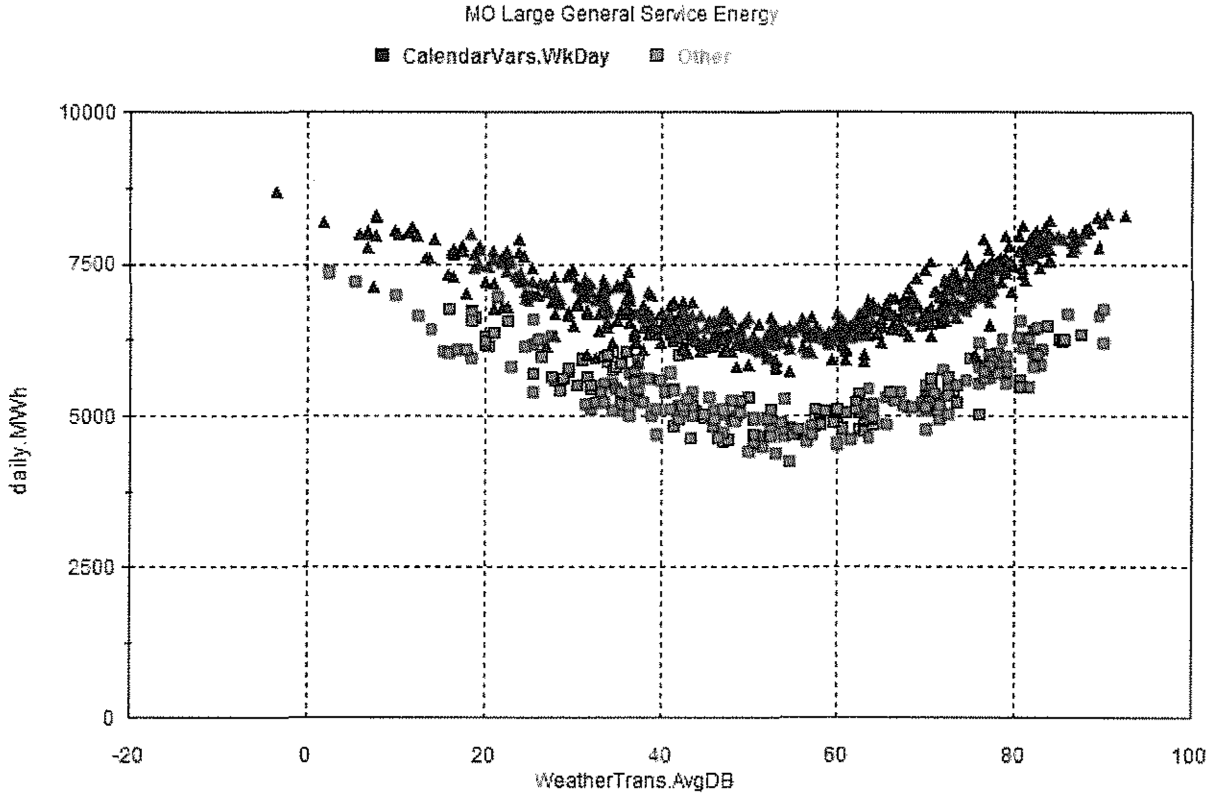


Figure 8: MO Large General Service Daily Peak Demand vs Average Temp

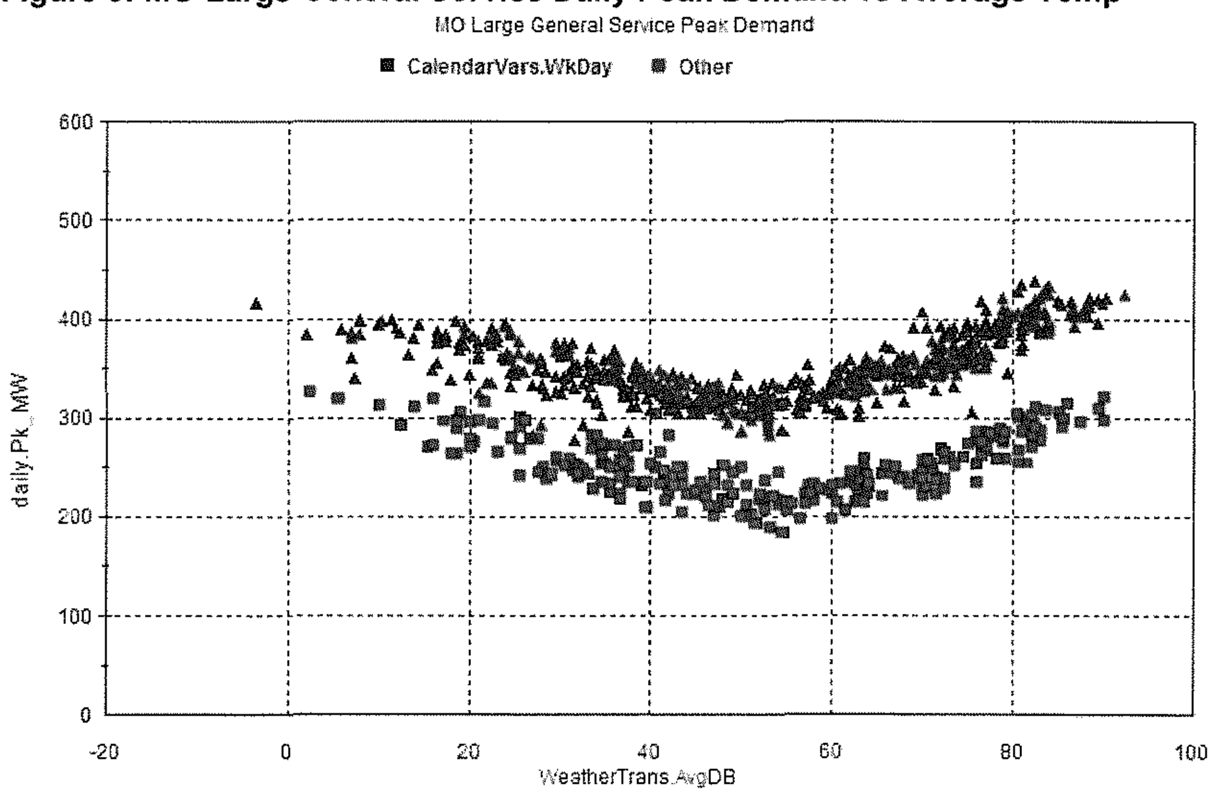


Figure 9: MO Large Power Daily Energy vs Average Temp

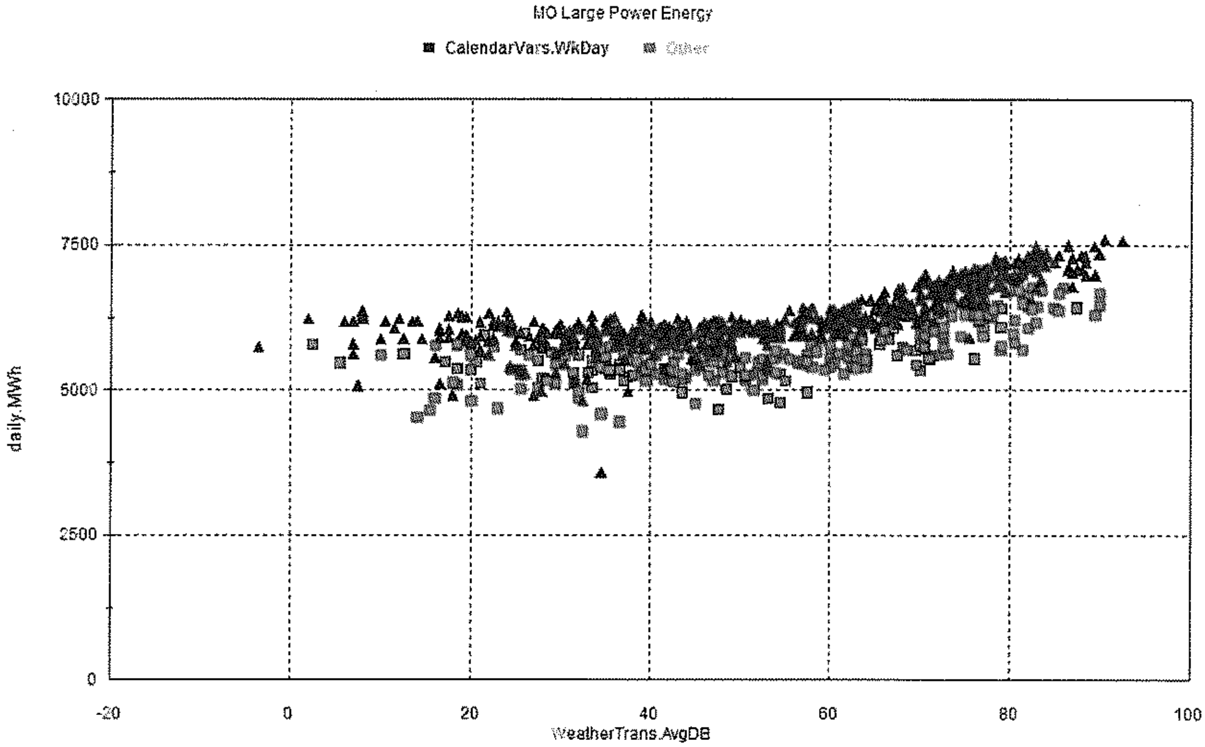


Figure 10: MO Large Power Daily Peak Demand vs Average Temp

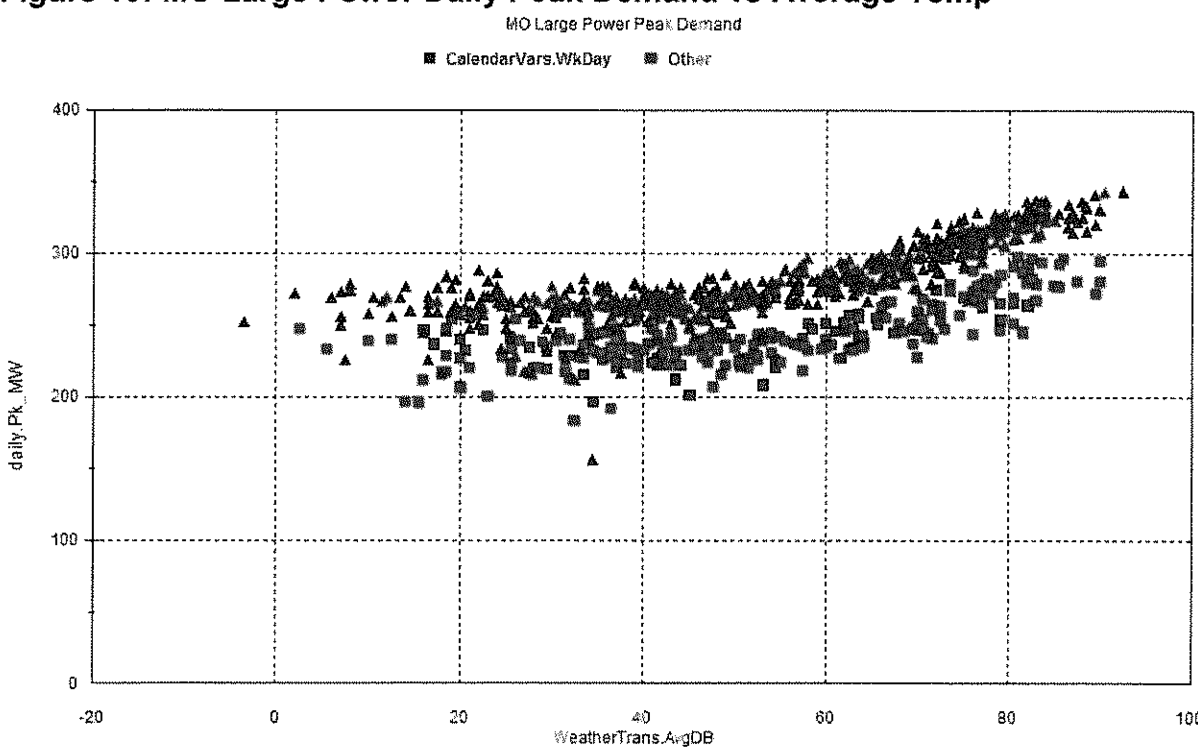


Figure 11: MO Sales for Resale Daily Energy vs Average Temp

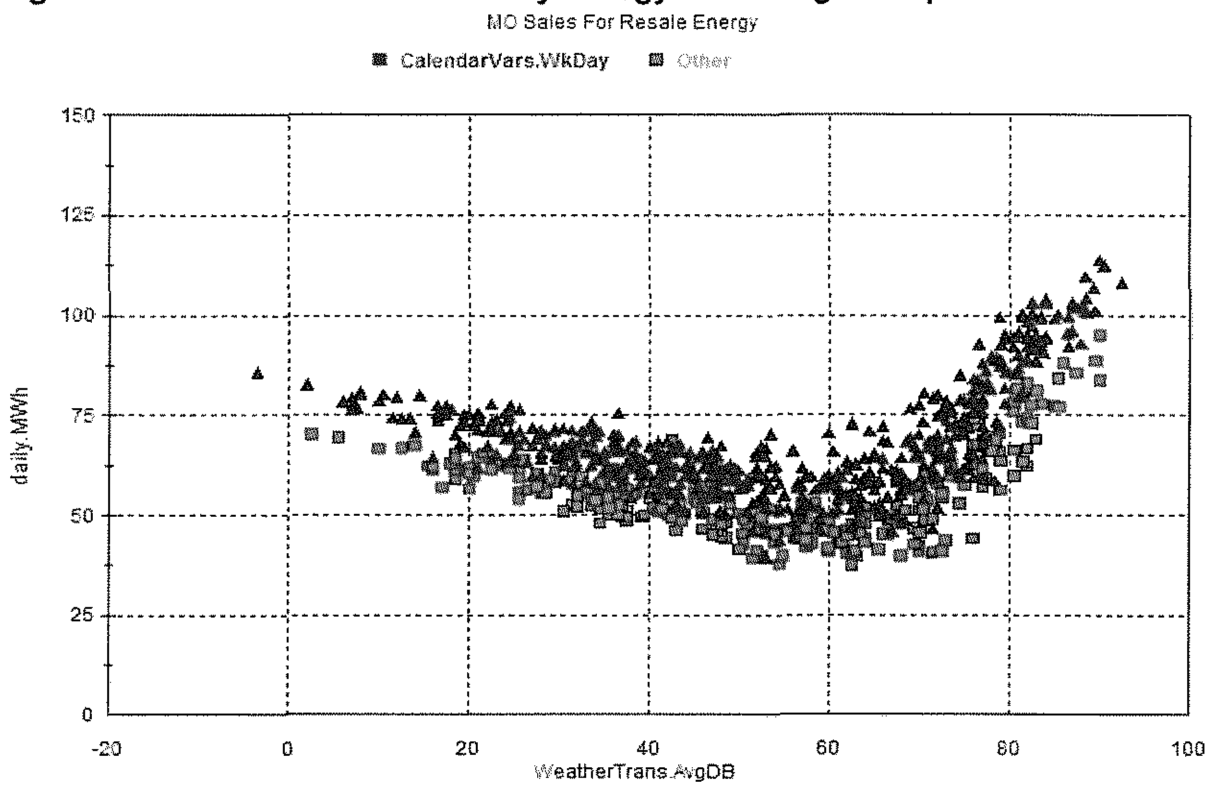


Figure 12: MO Sales for Resale Daily Peak Demand vs Average Temp

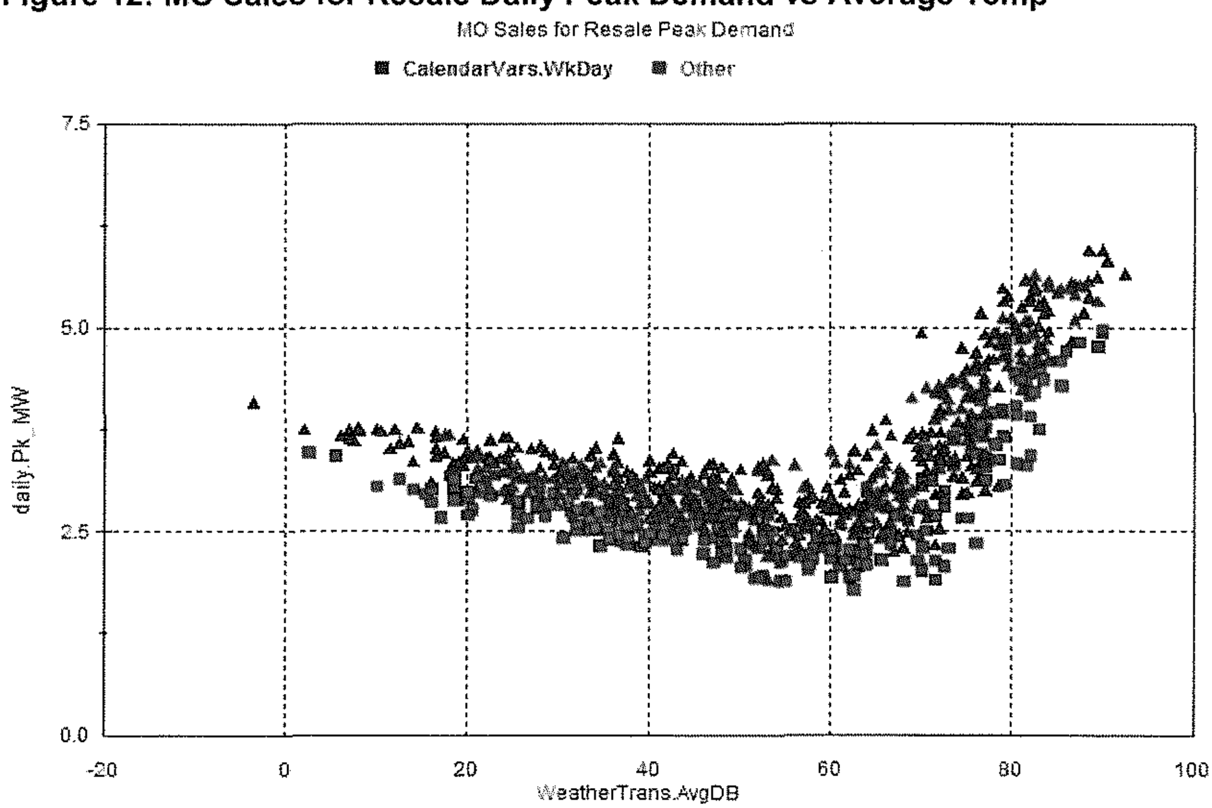


Figure 13: KS Residential Daily Energy vs Average Temp

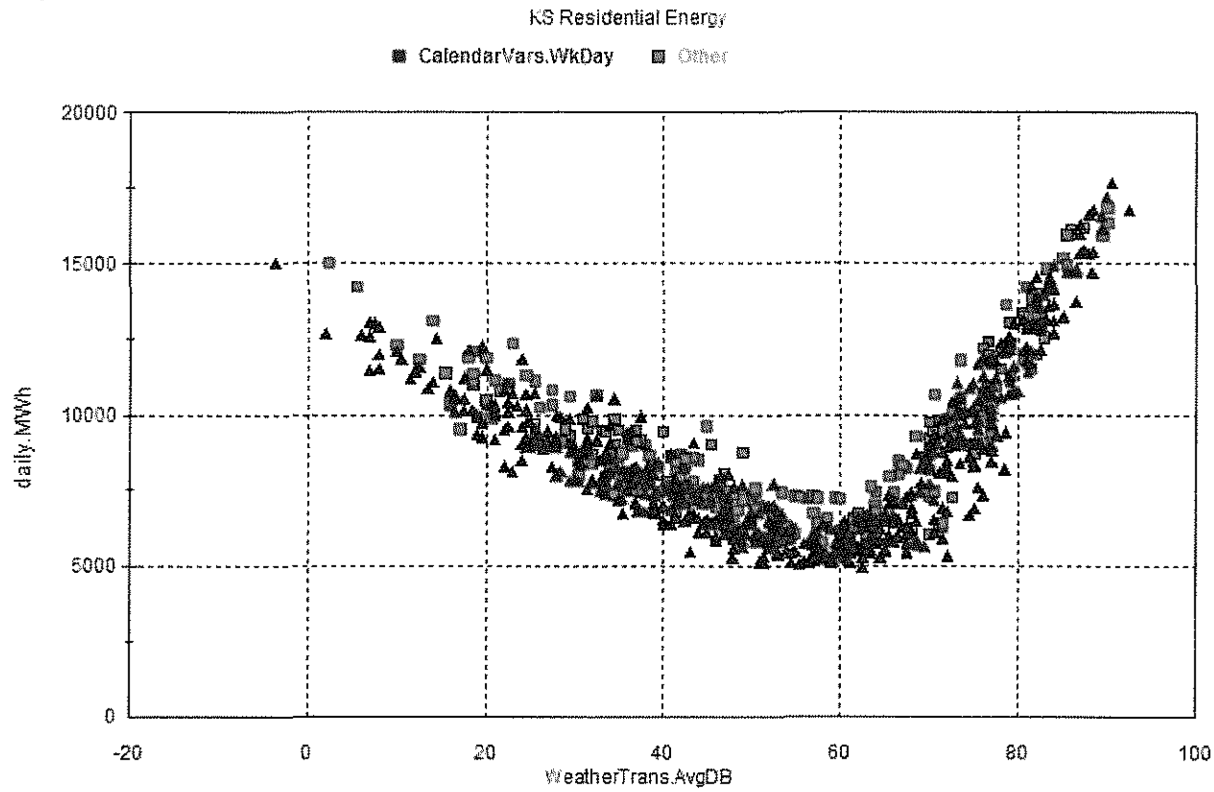


Figure 14: KS Residential Daily Peak Demand vs Average Temp

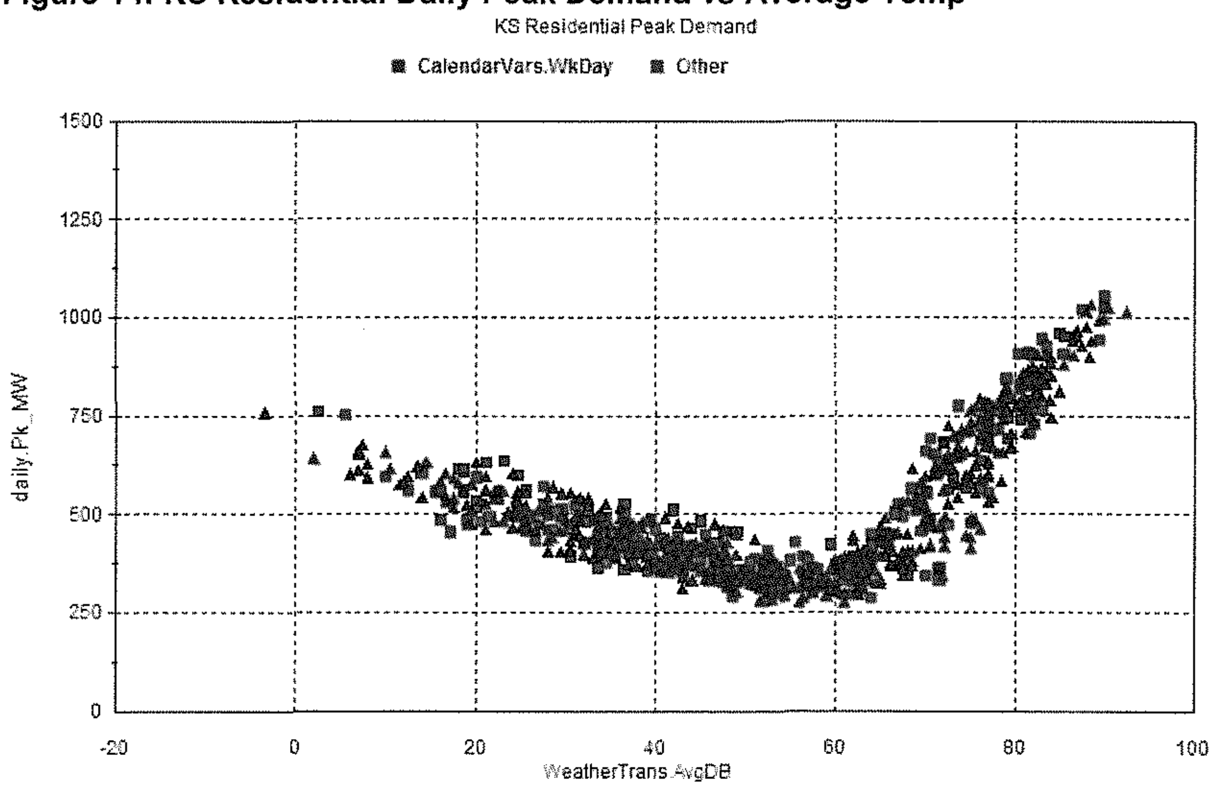


Figure 15: KS Small General Service Daily Energy vs Average Temp

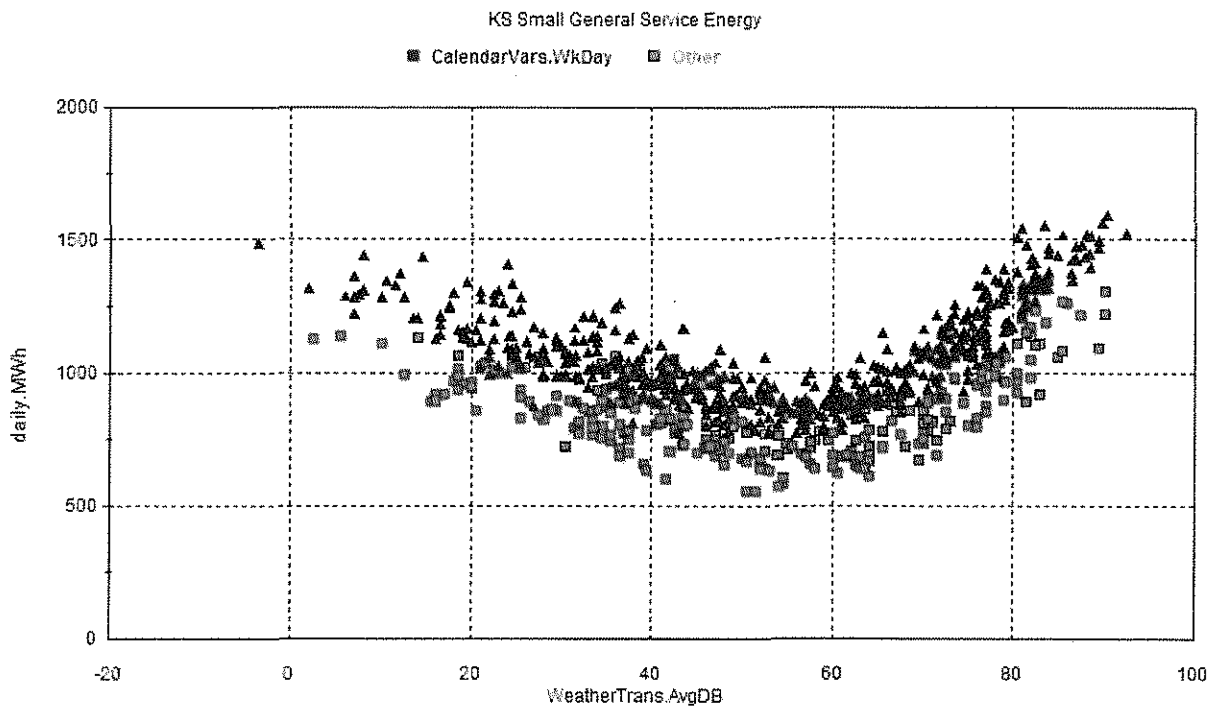


Figure 16: KS Small General Service Daily Peak Demand vs Average Temp

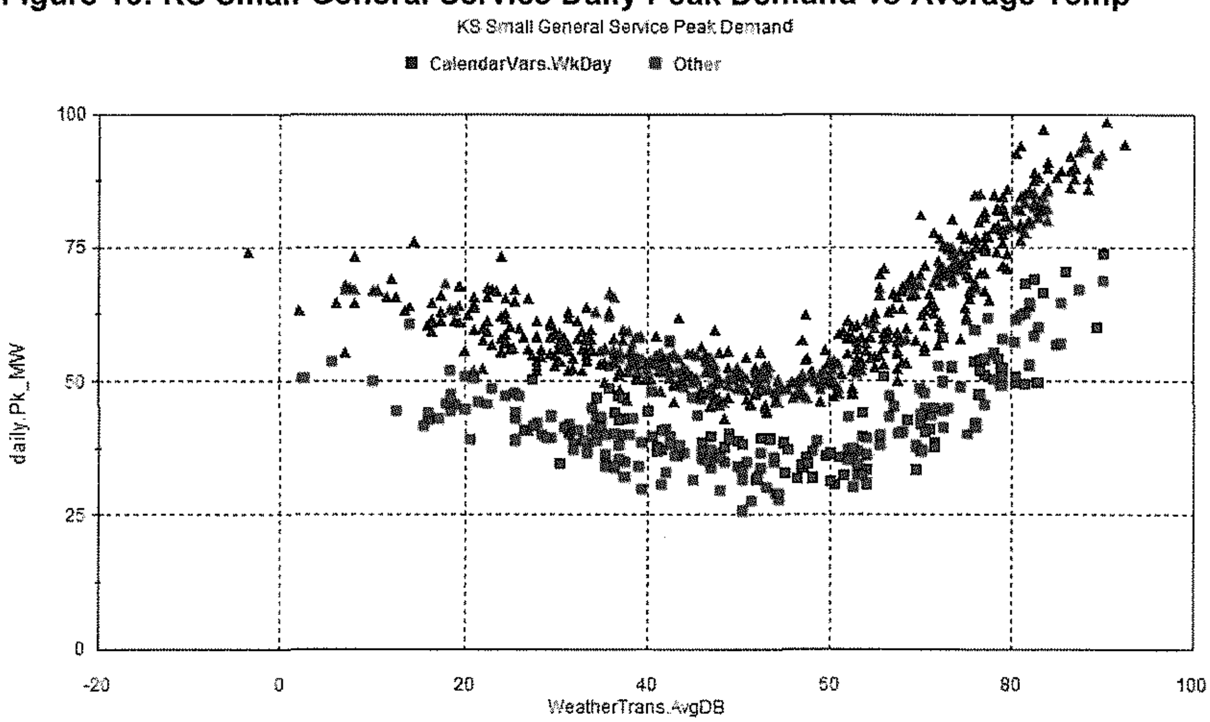


Figure 17: KS Medium General Service Daily Energy vs Average Temp

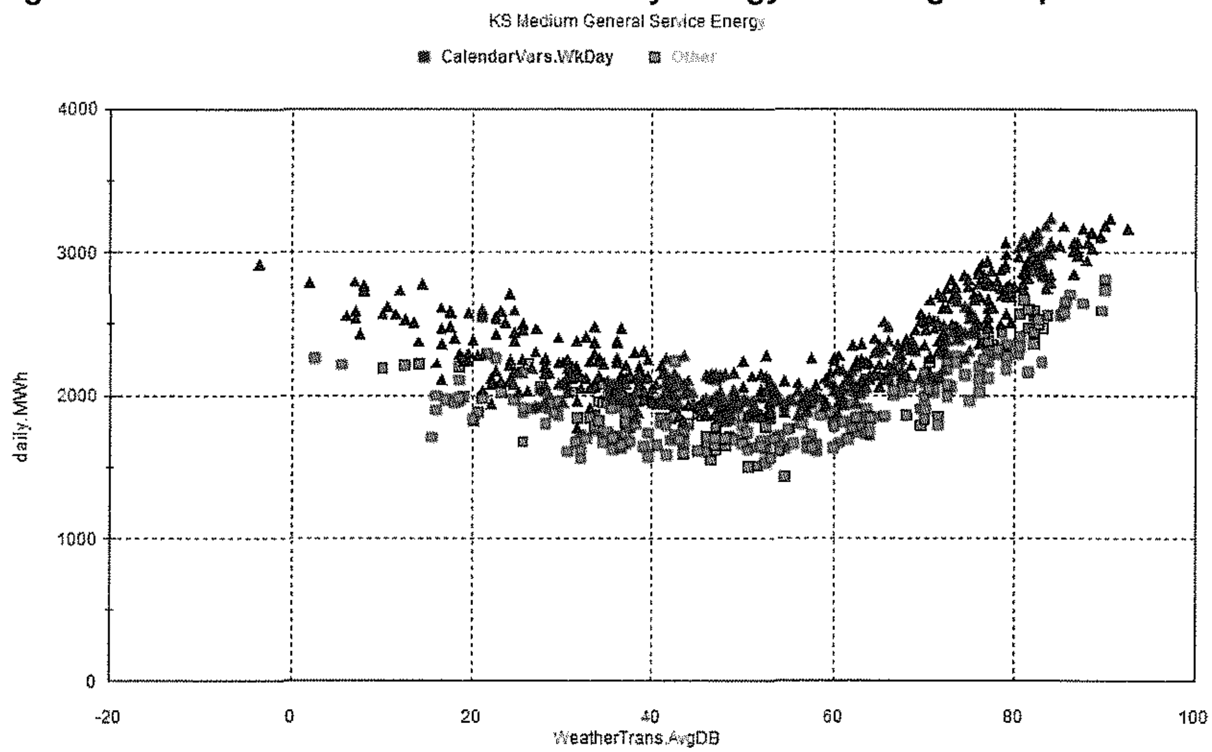


Figure 18: KS Medium General Service Daily Peak Demand vs Average Temp

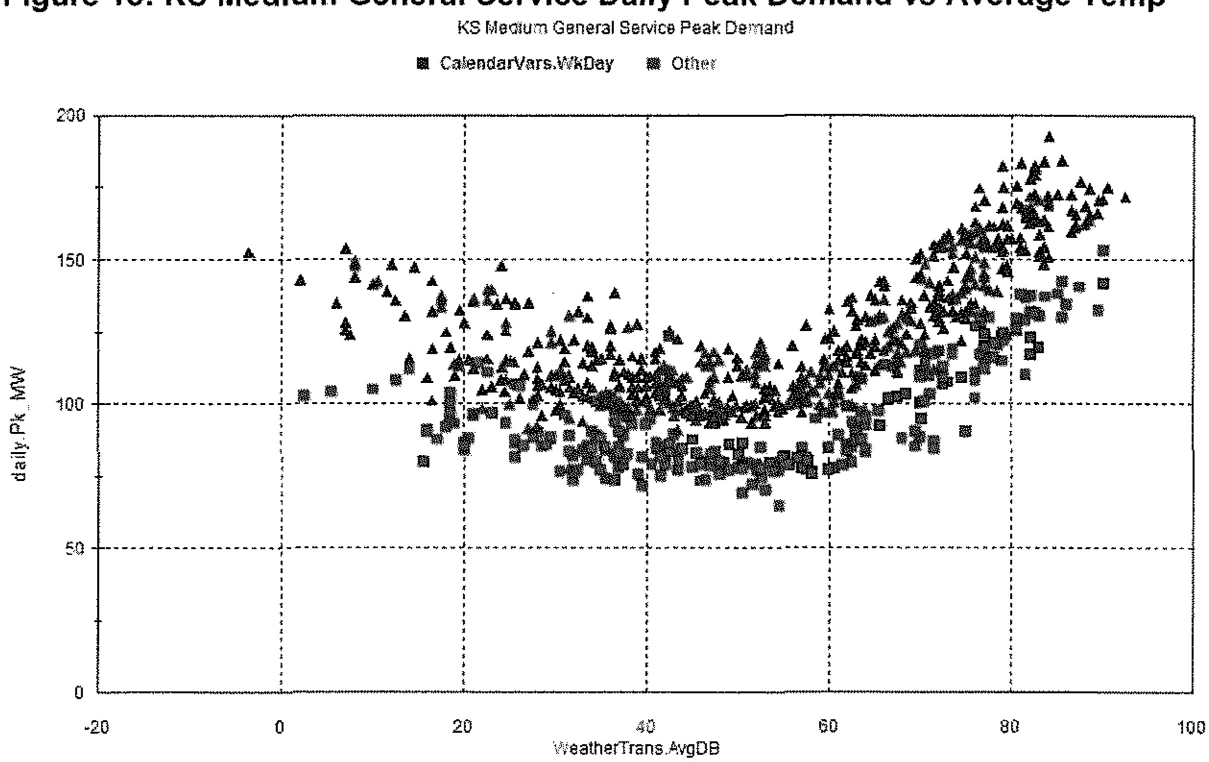


Figure 19: KS Large General Service Daily Energy vs Average Temp

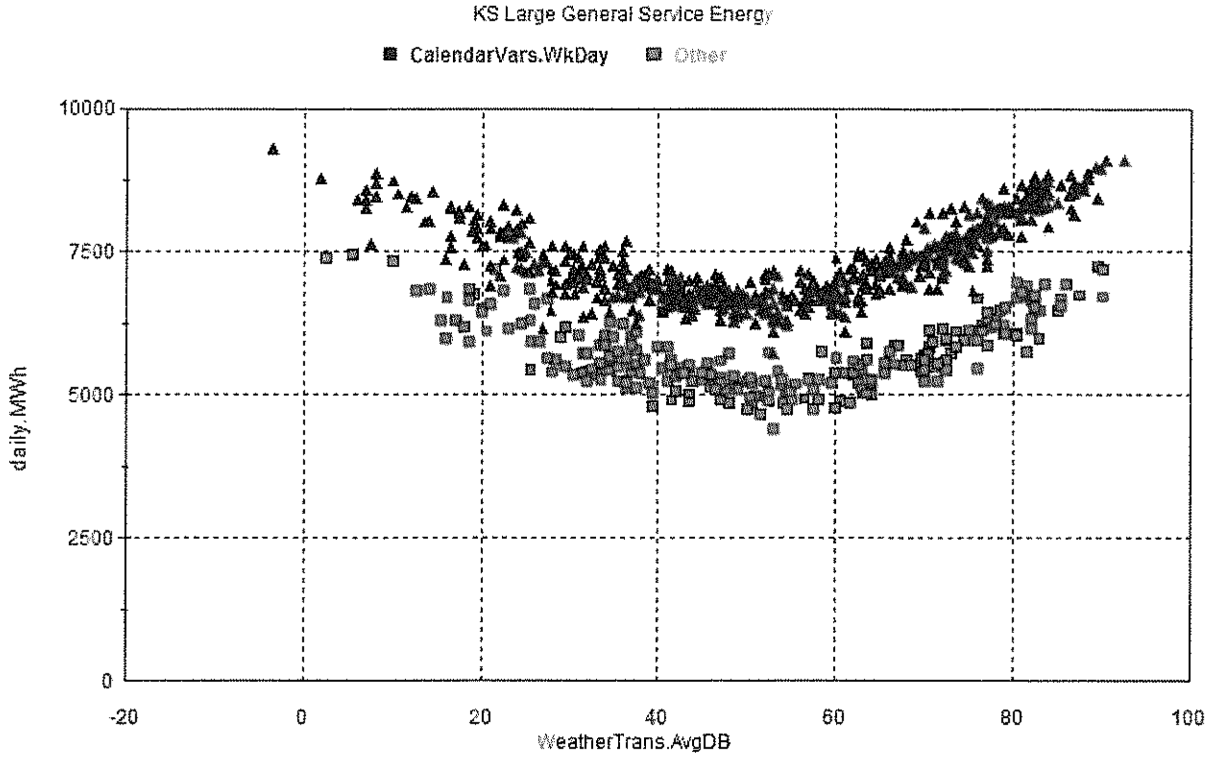


Figure 20: KS Large General Service Daily Peak Demand vs Average Temp

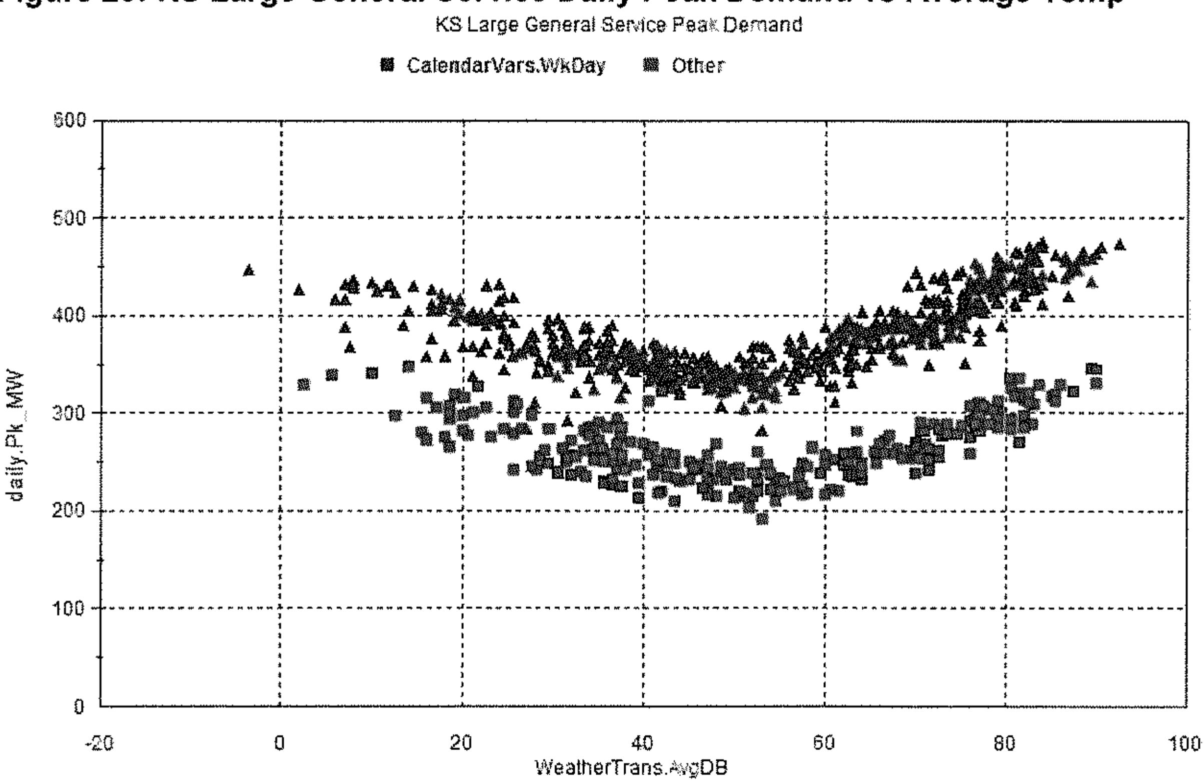


Figure 21: KS Sales for Resale Daily Energy vs Average Temp

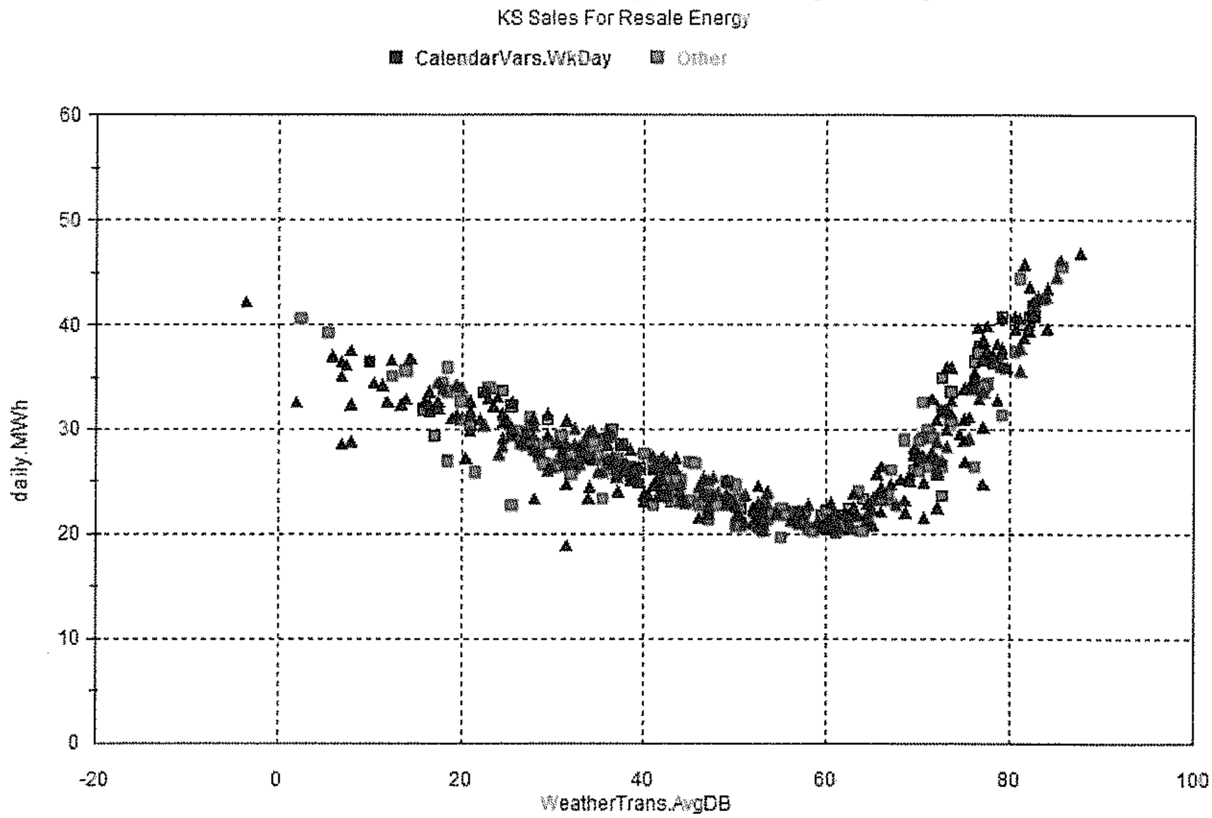
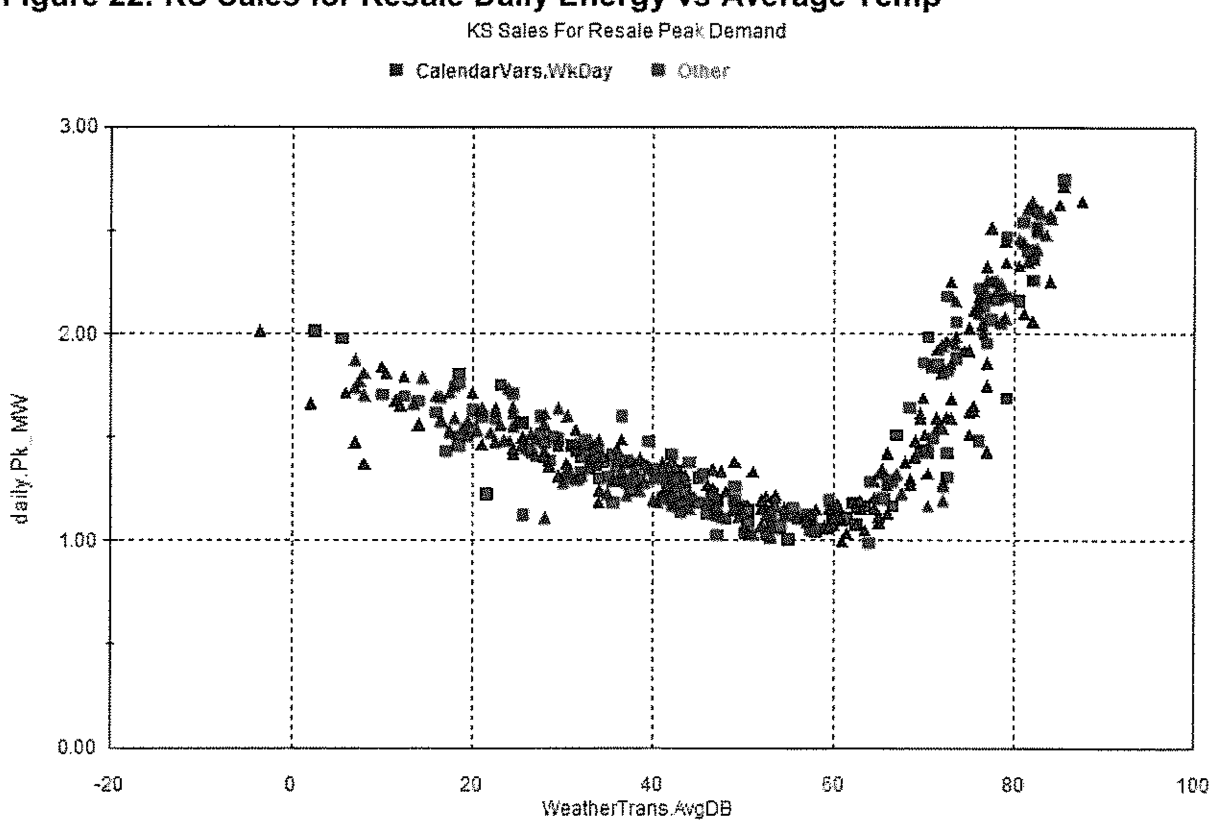


Figure 22: KS Sales for Resale Daily Energy vs Average Temp



and 3. Plots illustrating trends materially affecting electricity consumption over the historical period.

Historical class plots of customers, kwh, average use and peak are provided in *Appendix 3A1.*

2.5 ADJUSTMENTS TO HISTORICAL DATA DESCRIPTION AND DOCUMENTATION

(E) The utility shall describe and document any adjustments that it made to historical data prior to using it in its development or interpretation of the forecasting models; and

KCP&L used binary variables in regression models to explain outliers rather than make adjustments to the data.

2.6 LENGTH OF HISTORICAL DATABASE

(F) Length of Historical Database. The utility shall develop and retain the historical database over the historical period.

For KCP&L, historical sales and customers broken out by class cost of service for residential and industrial customers were available beginning in January 2000. Commercial class cost of service data was available beginning May 2005. Going forward, KCP&L will maintain this data for at least the previous 10 years.

SECTION 3: ANALYSIS OF NUMBER OF UNITS

For each major class, the utility shall describe and document its analysis of the historical relationship between the number of units and the economic and/or demographic factors (explanatory variables) that affect the number of units for that major class. The analysis may incorporate or substitute the results of secondary analyses, with the proviso that the utility analyze and verify the applicability of those results to its service territory. If the utility develops primary analyses, or to the extent they are available from secondary analyses, these relationships shall be specified as statistical or mathematical models that relate the number of units to the explanatory variables.

3.1 IDENTIFICATION OF EXPLANATORY VARIABLES

(A) Choice of Explanatory Variables. The utility shall identify appropriate explanatory variables as predictors of the number of units for each major class. The critical assumptions that influence the explanatory variables shall also be identified and documented.

A forecast of the number of households in the KC metro area from Moody's Analytics was the driver for the number of residential customers of KCP&L. The KC metro area is the same as the Metropolitan Statistical Area (MSA) defined by the US Census Bureau and it includes some counties in both states that are not served by KCP&L. Also, KCP&L's service area includes some counties that are not included in the MSA. Despite these inconsistencies in geographic areas, the number of households in the metro area is a good driver to predict the number of our residential customers because the metro area functions economically as a single entity and the metro area includes the vast majority of our customers. Many people live on one side of the state line and work on the other side. Many people shop on both sides of the state line. And many companies each year move from one side of the state line to the other. Documentation for Moody's forecast of economic activity is provided in the workpapers in the folder *\models\KCP&L Base Case\Data\Economics* and Documentation\Economics.

KCP&L tested the use of county level forecasts from Moody's several years ago, but saw no improvement in forecasting accuracy. This might be because it is difficult to forecast economic activity for a small geographic area, or because economic activity crosses county lines in the metro area.

The residential customer models where test with both households and population used as drivers and the one with the best fit was chosen. If neither was significant or had a positive coefficient, the driver was tested without a constant term in the model, and if still insignificant, a driver was not used. Typically households had the best fit.

The main driver for the number of small general service customers was the number of residential customers. This driver was chosen because it has worked well in the past and because most small commercial customers exist to serve households and these customers will increase in areas where there are new housing developments. Examples of small commercial customers that serve households are medical offices, grocery stores, drug stores, restaurants, churches, schools, hair salons, and movie theaters.

In the models for Big (Medium GS, Large GS and Large Power) commercial customers, both non-manufacturing employment and non-manufacturing gross metro product were tested as drivers and the one with the best fit was chosen. If neither was significant or had a positive coefficient, the driver was tested without a constant term in the model, and if still insignificant, a driver was not used.

3.2 STATISTICAL MODEL DOCUMENTATION

(B) Documentation of statistical models shall include the elements specified in subsection (2)(C) of this rule. Documentation of mathematical models shall include a specification of the functional form of the equations if the utility develops primary analyses, or to the extent they are available if the utility incorporates secondary analyses.

The following tables show the statistics for the variables in the regression models. Additional statistics and residual plots are available in the Metrix ND model files and a word document is located in KCPL\KCPL Model Statistics.docx.

Table 9 MO Residential Customers

Variable	Coefficient	StdErr	T-Stat	P-Value	Units
CONST	185843.727	15676.352	11.931	0.00%	
Economics.Households	66.354	19.663	3.375	0.09%	Ths
RUCust.Nov09	1154.847	373.071	3.096	0.23%	
RUCust.Feb06	1394.580	375.756	3.711	0.03%	
RUCust.May12	-928.630	366.464	-2.534	1.22%	
RUCust.Jun00	-1472.177	376.456	-3.911	0.01%	
RUCust.Jul14	-1914.708	513.042	-3.732	0.03%	
BinaryVars.Jan	-376.756	135.505	-2.780	0.61%	
BinaryVars.Feb	516.922	118.283	4.370	0.00%	
BinaryVars.Jun	-682.456	99.700	-6.845	0.00%	
BinaryVars.Aug	-783.613	118.912	-6.590	0.00%	
BinaryVars.Sep	-715.976	137.668	-5.201	0.00%	
BinaryVars.Oct	-755.779	120.389	-6.278	0.00%	
BinaryVars.Dec	-816.663	119.745	-6.820	0.00%	
AR(1)	0.938	0.024	39.502	0.00%	

Table 10 MO Small GS Commercial Customers

Variable	Coefficient	StdErr	T-Stat	P-Value	Units
CONST	16607.787	3664.991	4.531	0.00%	
ResCustomers.RU_Cust	0.036	0.015	2.333	2.18%	
SML_Customer.Dec09	-675.130	90.768	-7.438	0.00%	
SML_Customer.Feb10	-281.184	89.609	-3.138	0.23%	
SML_Customer.Apr12	448.631	89.686	5.002	0.00%	
SML_Customer.Oct08	-202.964	89.448	-2.269	2.55%	
SML_Customer.Nov13	-270.088	88.627	-3.047	0.30%	
AR(1)	0.827	0.054	15.189	0.00%	

Table 11 MO Big Commercial Customers (MGS, LGS and LP)

Variable	Coefficient	StdErr	T-Stat	P-Value	Units
ResCustomers.RU_Cust	0.025	0.000	67.500	0.00%	
BIG_Customer.Jul08	165.121	50.219	3.288	0.15%	
BIG_Customer.Aug08	177.785	58.023	3.064	0.29%	
BIG_Customer.Sep08	107.836	50.194	2.148	3.46%	
BIG_Customer.Dec08	160.091	40.865	3.918	0.02%	
BIG_Customer.Jul14	232.788	56.159	4.145	0.01%	
AR(1)	0.932	0.031	30.395	0.00%	

The variable ending with month and year, shown in the table above, is defined as 1 for that month and 0 for all other months.

In the model for big commercial customers in Missouri, the intercept term was dropped so and economic drive so that customer driver would be statistically significant.

Table 12 MO Industrial Customers

Variable	Coefficient	StdErr	T-Stat	P-Value	Units
CONST	7.578	12.060	0.628	53.08%	
IND_Customer.LagDep(1)	0.992	0.011	91.858	0.00%	
IND_Customer.Jul03	60.513	11.721	5.163	0.00%	
IND_Customer.Aug03	-66.077	11.724	-5.636	0.00%	
IND_Customer.Aug08	39.716	10.862	3.656	0.04%	
IND_Customer.May14	34.591	10.924	3.166	0.19%	
IND_Customer.Aug09	-36.285	10.980	-3.305	0.12%	
AR(1)	-0.425	0.079	-5.368	0.00%	

Table 13 KS Residential Customers

Variable	Coefficient	StdErr	T-Stat	P-Value	Units
Economics.Households	140.572	218.843	0.642	52.18%	Ths
RUCust.Nov09	921.376	278.496	3.308	0.12%	
RUCust.Apr02	0.000	0.000	0.000	100.00%	
BinaryVars.Feb	243.775	78.539	3.104	0.24%	
BinaryVars.Apr	277.059	90.684	3.055	0.27%	
BinaryVars.May	265.487	90.686	2.928	0.40%	
BinaryVars.Jul	284.952	80.240	3.551	0.05%	
BinaryVars.Oct	-430.239	83.000	-5.184	0.00%	
BinaryVars.Dec	-320.175	83.044	-3.855	0.02%	
AR(1)	1.001	0.001	1839.100	0.00%	

Table 14 KS Small GS Commercial Customers

Variable	Coefficient	StdErr	T-Stat	P-Value	Units
Economics.Total_Households	1.021	0.398	2.565	1.12%	
SML_Customer.Sep05	1280.282	132.862	9.636	0.00%	
SML_Customer.Sep11	-734.893	142.913	-5.142	0.00%	
SML_Customer.Oct11	-1282.904	150.775	-8.509	0.00%	
SML_Customer.Nov11	1034.584	143.780	7.196	0.00%	
SML_Customer.Feb13	-624.393	131.359	-4.753	0.00%	
SML_Customer.Mar14	308.353	132.076	2.335	2.08%	
SML_Customer.May05	-1264.307	131.247	-9.633	0.00%	
SML_Customer.LagDep(1)	0.961	0.016	61.021	0.00%	
AR(1)	-0.401	0.074	-5.462	0.00%	

Table 15 KS Big GS Commercial Customers

Variable	Coefficient	StdErr	T-Stat	P-Value	Units
Economics.Emp_NonMan	0.129	0.069	1.888	6.18%	Ths
BIG_Customer.Nov07	57.057	31.025	1.839	6.88%	
BIG_Customer.Jul08	123.777	30.842	4.013	0.01%	
BIG_Customer.Jul09	54.412	30.813	1.766	8.04%	
BIG_Customer.Dec08	66.982	30.690	2.183	3.14%	
BIG_Customer.LagDep(1)	0.976	0.013	74.761	0.00%	
AR(1)	-0.442	0.089	-4.938	0.00%	

Table 16 KS Industrial Customers

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	0.391	0.088	4.428	0.000
Trend	-0.109	0.006	-18.678	0.000
Damp Factor	0.987	0.002	566.578	0.000

No economic drivers were significant in the model for industrial customers in Kansas.

SECTION 4: USE PER UNIT ANALYSIS

For each major class, the utility shall describe and document its analysis of historical use per unit by end use.

4.1 END-USE LOAD DETAIL

(A) End-Use Load Detail. For each major class, use per unit shall be disaggregated, where information permits, by end-uses that contribute significantly to energy use or peak demand.

4.1.1 END-USE LOAD INFORMATION

1. The utility shall consider developing information on at least the following end-use loads:

4.1.1.1 Residential Sector

A. For the residential sector: lighting, space cooling, space heating, ventilation, water heating, refrigerators, freezers, cooking, clothes washers, clothes dryers, television, personal computers, furnace fans, plug loads, and other uses;

The list of residential end uses that KCP&L maintains the number of units and energy use per unit include electric furnaces, heat pumps with electric resistance backup, heat pumps with natural gas backup, ground source heat pumps, central air conditioning without a heat pump, window or wall AC units, electric water heaters, electric ovens, cook tops and ranges, full-sized refrigerators, small refrigerators and wine coolers, freezers, dishwashers, clothes washers, electric dryers, TVs, air cleaners, computers, video game systems, hot tubs, swimming pools, electric vehicles and miscellaneous uses.

4.1.1.2 Commercial Sector

B. For the commercial sector: space heat, space cooling, ventilation, water heat, refrigeration, lighting, office equipment, cooking equipment, and other uses; and

KCP&L maintains information on saturations per square foot of floor space and energy use per square foot (EUI) for end uses including heating, cooling, ventilation, electric water heating, electric cooking, refrigeration, outdoor lighting, indoor lighting, and office equipment and miscellaneous uses. In this filing, secondary data from the U.S. DOE for the West North Central region was adopted for both KCP&L Kansas and Missouri. The region includes the states of North Dakota, South Dakota, Minnesota, Iowa, Nebraska, Kansas and Missouri. The results are combined across building types using building type weights. The building types include assembly (theaters, libraries, churches etc.), education, food sales, food service, health care, lodging, small office, large office, mercantile/service, warehouse and other. This data is maintained in *ComIndices_MO.xls* and *ComIndices_KS.xls*. The building types are defined in *2012 NAICS Index File-AEO commercial sectorrev.xls*. These spreadsheets were provided to KCP&L by Itron Inc. through the Energy Forecasting Group (EFG). The spreadsheets are documented in *2014_CommercialSAE.pdf*. These files are provided in the workpapers.

4.1.1.3 Industrial Sector

C. For the industrial sector: machine drives, space heat, space cooling, ventilation, lighting, process heating, and other uses.

KCP&L has a relatively small industrial sector, accounting for approximately 13% of retail sales. KCP&L lacks the concentration of heavy industry that some utilities have. As such, KCP&L has modeled our industrial sector with commercial sector drivers. Major end uses are heating, cooling and other.

4.1.2 MODIFICATION OF END-USE LOADS

2. The utility may modify the end-use loads specified in paragraph (4)(A)1.

4.1.2.1 Removal or Consolidation of End-Use Loads

A. The utility may remove or consolidate the specified end-use loads if it determines that a specified end-use load is not contributing, and is not likely to contribute in the future, significantly to energy use or peak demand in a major class.

In the last few years, KCP&L has dropped several end uses from its residential survey including VCRs, DVD players, printers, fax machines, copier/scanners and attic fans since these do not contribute significantly to energy use or peak demand.

4.1.2.2 Additions to End-Use Loads

B. The utility shall add to the specified end-use loads if it determines that an end-use load currently not specified is likely to contribute significantly to energy use or peak demand in a major class.

KCP&L has recently added replacement of residential HVAC equipment from the 2013 survey. In 2011 KCP&L added electric vehicles (including PHEVs) to our database. KCP&L is currently using DOE projections for this end use and plan to add a question for this end use on our next residential appliance saturation survey.

In our previous residential survey conducted in 2010, KCP&L added mini/wine refrigerators and video game systems and, in 2008, KCP&L added well pumps to the residential survey questionnaire.

4.1.2.3 Modification of End-Use Documentation

C. The utility shall provide documentation of its decision to modify the specified end-use loads for which information is developed, as well as an assessment of how the modifications can be made to best preserve the continuity and integrity of the end-use load database.

KCP&L dropped the end uses listed in the previous section A because VCRs, DVD players, printers, fax machines and copier/scanners are mainly plug loads that do not contribute significantly to energy use. KCP&L added well pumps, video game systems and mini\wine refrigerators because these use substantial amounts of energy and KCP&L believes that these had a significant saturation in our service areas.

KCP&L added electric vehicles because these are likely to significantly impact our energy and peak load in the future based on various projections published in different studies. These studies are included in our workpapers.

4.1.3 SCHEDULE FOR ACQUIRING END-USE LOAD INFORMATION

3. For each major class and each end-use load, including those listed in paragraph (4)(A)1., if information is not available, the utility shall provide a schedule for acquiring this end-use load information or demonstrate that either the expected costs of acquisition were found to outweigh the expected benefits over the planning horizon or that gathering the end-use load information has proven to be infeasible.

KCP&L completed a DSM potential study in 2013. The study collected detailed end-use saturation and efficiency data from our customers in the residential, commercial and industrial sectors. KCP&L provided copies of the completed study to stakeholders' group.

4.1.4 WEATHER EFFECTS ON LOAD

4. The utility shall determine the effect that weather has on the total load of each major class by disaggregating the load into its cooling, heating, and non-weather-sensitive components. If the cooling or heating components are a significant portion of the total load of the major class, then the cooling or heating components of that load shall be designated as end uses for that major class.

KCP&L used statistical regression analysis applied to the load research data to develop HELM like hourly load profiles for each month, for three different day types and for base, heating and cooling loads. The three day types are weekdays, weekends and peak days. Daily temperature was used in the regression models to identify the heating and cooling portions of the loads. The profiles were developed for each CCOS. The regressions were performed in Eviews with the program *createloadshapesccos2.prg.* The data for Eviews was created in SPSS with the program *dataprep2011kcplCCOS.SPS* which matches actual and normal temperatures to the hourly loads.

These load profiles are used in this IRP filing to allocated monthly base, heating and cooling energy to each hour of the month. These profiles are stored in *DTShapesKCPLCCOS.mdb.*

4.2 END-USE DEVELOPMENT

(B) The database and historical analysis required for each end use shall be developed from a utility-specific survey or other primary data. The database and analysis may incorporate or substitute the results of secondary data, with the proviso that the utility analyze and verify the applicability of those results to its service territory. The database and historical analysis required for each end use shall include at least the following:

4.2.1 MEASURES OF THE STOCK OF ENERGY-USING CAPITAL GOODS

1. Measures of the stock of energy-using capital goods. For each major class and end-use load identified in subsection (4)(A), the utility shall implement a procedure to develop and maintain adequate data on the energy-related characteristics of the building, appliance and equipment stock including saturation levels, efficiency levels, and sizes, where applicable. The utility shall update the data before each triennial compliance filing; and

KCP&L has conducted a residential appliance saturation survey every other year for many decades. The surveys have been conducted by mail. The last survey was conducted in the fourth quarter of 2013. Questionnaires were sent to 2,500 households in each jurisdiction and 600 and 766 responses were received from customers in Missouri and Kansas. The survey responses were matched with each customers' billing records for the previous 12 months and with heating and cooling degree days computed for the billing period and the combined data was used in a conditional demand study to estimate the energy used by each type of appliance.

KCP&L conducted a DSM potential study that was completed in 2013. This study collected detailed end-use saturation and efficiency data from our customers in the residential, commercial and industrial sectors. KCP&L provided copies of the final report to the Stakeholders' group.

4.2.2 END-USE ENERGY AND DEMAND ESTIMATES

2. Estimates of end-use energy and demand. For the end-use loads identified in subsection (4)(A), the utility shall estimate monthly energies and demands at the time of monthly system peaks and shall calibrate these energies and demands to equal the weather-normalized monthly energies and demands at the time of monthly peaks for each major class for the most recently available data.

Monthly energies for the end uses that are included in our SAE models are calibrated in the SAE models to monthly billed sales for each CCOS. The coefficients for the base, heating and cooling loads calibrate those loads and the coefficient for the base load raises or lowers all the components of the base load when the base load is calibrated to monthly billed sales.

Monthly demand for the major end uses that are included in our SAE models are calibrated to the time of the monthly system peaks. This is done in the models by taking the hourly system demands and matching them to the hourly class end use demands. This computes the coincident peak by class and end use. To calibrate class end use demands to the weather normalized system peak, the system peak and weather normalized peaks are used to develop a calibration factor that is applied to each class and end use. This process is done for both Missouri and Kansas. This process is completed in an Excel worksheet which is provided in the workpapers.

SECTION 5: SELECTING LOAD FORECASTING MODELS

The utility shall select load forecast models and develop the historical database needed to support the selected models. The selected load forecast models will include a method of end-use load analysis for at least the residential and small commercial classes, unless the utility demonstrates that end-use load methods are not practicable and provides documentation that other methods are at a minimum comparable to end-use methods. The utility may choose multiple models and methods if it deems doing so is necessary to achieve all of the purposes of load forecasting and if the methods and models are consistent with, and calibrated to, one another. The utility shall describe and document its intended purposes for load forecast models, why the selected load forecast models best fulfill those purposes, and how the load forecast models are consistent with one another and with the end-use usage data used in the demand-side analysis as described in 4 CSR 240-22.050. As a minimum, the load forecast models shall be selected to achieve the following purposes:

5.1 CONSUMPTION DRIVERS AND USAGE PATTERNS

(A) Assessment of consumption drivers and customer usage patterns—to better understand customer preferences and their impacts on future energy and demand requirements, including weather sensitivity of load;

KCP&L uses the Statistically Adjusted End-use (SAE) method to forecast energy sales and demand for all classes except lighting and sales for resale. The SAE method creates a forecast of sales at the end-use level and then for each class aggregates the forecasts into base, heating and cooling energy and then calibrates these loads to monthly billed sales using statistical regressions. The SAE models were designed and are supported by staff at Itron Inc. This same staff used to support the end-use models REEPS, COMMEND and INFORM for EPRI.

Our end-use level forecasts are developed using both primary data collected by KCP&L and secondary data and projections produced by the U.S. Department of Energy (DOE) for the West North Central region of the U.S. DOE projections used in our models include projections of saturations for household appliances and equipment used in commercial buildings and projections of efficiencies for appliances, buildings and equipment. DOE has a large professional staff that is responsible for constructing and maintaining energy demand models and for managing contractors. The contractors survey households, businesses and buildings on a regular schedule. Contractors are also used to conduct special studies. DOE's projections are designed to account for changes in consumer preferences, technology and building design practices. Their projections also account for the impacts of appliance and equipment standards. DOE updates its projections at least once a year and KCP&L use the most recently available projections whenever KCP&L updates the models.

KCP&L calibrates DOE appliance saturation projections to the saturation numbers that is obtained from our residential surveys. KCP&L also calibrate DOE's projections of unit energy consumption (UEC) for appliances to the results of the conditional demand study.

Itron hosts an annual meeting for the Energy Forecasting Group (EFG), which supports utilities that use the SAE method to forecast their sales. DOE staff attends the meeting of the EFG (which KCP&L attends) to explain changes in the assumptions, data and methods that have occurred during the previous year. Their slide decks provided during these meetings for the past several years are included in our workpapers. On their website, DOE provides detailed documentation and computer code for their models and assumptions.

5.2 LONG-TERM LOAD FORECASTS

(B) Long-term load forecasts—to serve as a basis for planning capacity and energy service needs. This can be served by any forecasting method or methods that produce reasonable projections (based on comparing model projections of loads to actual loads) of future demand and energy loads;

KCP&L believes that the SAE methodology is the best available for producing our load forecasts. REEPS, COMMEND and INFORM are no longer supported and never were supported as well as the DOE projections. DOE forecasts the impacts of all appliance and equipment standards most of which will substantially increase efficiency.[i] DOE also models trends in appliance ownership and utilization.

The Annual Energy Outlook for 2014 (AEO2014) differed from the previous year's forecast for both the residential and commercial outlooks. The residential outlook had changes for the following:

- 2009 Residential Energy Consumption Survey (RECS)
- Housing stock formation and decay
- Lighting modules
- Weather elasticities
- Removing the regional gas furnace standard
- Miscellaneous electric loads (MELS)
- Residential photovoltaic (PV)

The biggest change with RECS is that there is a smaller share of single family households. The latest outlook has expects a slower household growth than the previous outlook. The lighting modules changed with lighting projections being completely driven by input file specifications, the removal of the torchieres end use category, the addition of the exterior end use category, reducing the cost of halogen light bulbs, and adding a LED alternative to the linear fluorescent end use. Other changes to the outlook include slightly higher electricity prices, declining residential use of other fuels, more mobile use in the computer electricity use section, and a shift in PV use due to lower cost assumptions and higher electricity prices.

For the commercial outlook, changes were made to the following:

- End-use capacity factors
- Data center servers

- Hurdle rate floor
- MELS
- Commercial PV

The majority of the end-use capacity factors decreased in the 2014 outlook compared to the previous outlook, which affected the adoption of efficient equipment for some commercial uses. Since data servers will grow at a similar rate to that service sector of the economy, the impact of these grew as well in the most recent outlook. Other changes from this outlook include additional MELS coverage, the growth of commercial security systems primarily driven by video surveillance, like residential the increase of electricity prices from the previous outlook, expected growth of commercial video displays, and a similar response to PV changes as explained in the residential outlook above.

5.3 POLICY ANALYSIS

(C) Policy analysis—to assess the impact of legal mandates, economic policies, and rate designs on future energy and demand requirements. The utility may use any load forecasting method or methods that it demonstrates can adequately analyze the impacts of legal mandates, economic policies, and rate designs.

KCP&L believes that the SAE approach is the best available method to incorporate the impacts of appliance and equipment efficiency standards because the DOE is the best qualified institution to estimate these impacts. DOE will also incorporate any federal legal impacts into its forecasts. For example, DOE has incorporated CAFÉ regulations into its forecasts of electric vehicle unit sales, which in turn impacts kWh sales for recharging EVs.

Table 17 Products Covered by DOE Standards[ii]

Covered Product Categories		
Lighting Products: • 3-Way Incandescent Lamp • Candelabra base incandescent lamp • Ceiling Fan Light Kits • Ceiling Fans • Fluorescent lamp ballasts • General Service Fluorescent Lamps • General Service Incandescent Lamps • Incandescent Reflector Lamps • Intermediate Base Incandescent Lamps • Light Emitting Diodes (LEDs) • Medium Base Compact Fluorescent Lamps • Organic Light Emitting Diodes (OLEDs) • Rough Service Lamp • Shatter-Resistant Lamp • Torchieres • Vibration Service Lamp • Mercury Vapor Lamp Ballasts • Metal Halide Lamp Ballast • Metal Halide Lamp Fixtures • High-intensity discharge lamps • Traffic Signal Modules and Pedestrian Modules • Illuminated Exit Signs	**Heating Products:** Residential: • Direct heating equipment • Furnace Fans • Furnaces • Mobile Home Furnace • Pool heaters (Gas Fired) • Residential Boilers • Residential Water heaters • Small Furnaces Commercial: • Commercial warm air furnaces • Packaged boilers • Storage water heaters, instantaneous water heaters, and unfired hot water storage tanks • Unit Heaters	**Space Cooling Products:** Residential: • Central Air Conditioners and Central Air Conditioning Heat Pumps • Room Air Conditioners Commercial: • Packaged terminal air conditioners and packaged terminal heat pumps • Single package vertical air conditioners and single package vertical heat pumps • Small commercial package air conditioning and heating equipment • Large commercial package air conditioning and heating equipment • Very large commercial package air conditioning and heating equipment

Table 18 Products Covered by DOE Standards, continued

Covered Product Categories		
Commercial Refrigeration Products: • Automatic commercial ice makers • Commercial refrigerators, freezers, and refrigerator-freezers • Refrigerated Beverage Vending Machines • Walk-in coolers and walk-in freezers	**Appliances:** Residential: • Clothes dryers • Dehumidifiers • Dishwashers • Kitchen ranges and ovens • Microwave ovens • Refrigerators, Freezers and Refrigerator-Freezers • Residential Clothes washers Commercial: • Commercial clothes washers	**Computers and Electronics:** • Battery Chargers • External Power Supplies, Class A and non-Class A • Television sets
Transformers and Motors: • Electric Motors (medium to large) • Small Electric Motors • Distribution Transformers, MV Dry and Liquid-Immersed	**Plumbing Products:** Residential: • Faucets • Showerheads (except safety shower showerheads) • Urinals • Water closets Commercial: • Commercial Pre-rinse Spray Valves	**Building Products** • None

SECTION 6: LOAD FORECASTING MODEL SPECIFICATIONS

6.1 DESCRIPTION AND DOCUMENTATION

(A) For each load forecasting model selected by the utility pursuant to section 4 CSR 240-22.030(5), the utility shall describe and document its—

6.1.1 DETERMINATION OF INDEPENDENT VARIABLES

1. Determination of appropriate independent variables as predictors of energy and peak demand for each major class. The critical assumptions that influence the independent variables shall also be identified.

In the models of residential use per customer, the independent variables were appliance saturations, appliance UECs, the real price of electricity, real per capita income and persons per household. The appliance saturations and UEC forecasts were adopted from DOE's forecast for the west north central region. The critical assumptions influencing the forecasts of saturations and UECs are discussed in *m067(2013).pdf*, which is supplied in the electronic workpapers and which describes the model assumptions, computational methodology, parameter estimation techniques, and FORTRAN source code. These forecasts incorporate appliance ownership trends, trends in efficiency, updated building standards and technological change.

The forecasts of real per capita income and persons per household were produced by Moody's analytics for the KC metro area. Moody's documents its assumptions in *macromodel.pdf*, *state-model-methodology.pdf* and *assum_metro_midwest.pdf*, which are supplied in the workpapers. These independent variables were used to construct an end-use forecast of residential use per customer for three major end uses: heating, cooling and other, and these were then calibrated to monthly billed sales per customer in a linear regression. This is described in *Residential SAE Modeling Framework* in the file *Res2014SAEUpdate.pdf*.

In the models of commercial and industrial sales and use per customer, the independent variables were equipment saturations and EUIs, the real price of electricity and economic variables. Economic variables were non-manufacturing employment or non-manufacturing GMP or manufacturing employment or manufacturing GMP. The forecasts from DOE incorporate trends in equipment saturations, equipment efficiencies, equipment standards, building standards and technological change. These independent variables were used to construct an end-use forecast of commercial use for three major end uses: heating, cooling and other, and these were then calibrated to monthly billed sales or sales per customer in a linear regression. This is described in *Commercial Statistically Adjusted End-Use Model* in the file *2014_CommercialSAE.pdf.*

A. The utility shall assess the applicability of the historical explanatory variables pursuant to subsection (3)(A) to its selected forecast model.

The explanatory variables used by KCP&L in its forecasting models incorporate the most important drivers of energy use. These drivers are energy standards, building standards, trends in saturations and equipment efficiency, economic growth at the sector level and existing company energy efficiency and DSM programs.

B. To the extent that the independent variables selected by the utility differ from the historical explanatory variables, the utility shall describe and document those differences;

KCP&L has used the SAE approach since 2004 to forecast its loads. The economic drivers for the residential sector have been the number of households in the KC metro area during this time period. This filing is the first time that KCP&L has modeled small commercial (SGS), big commercial (MGS, LGS, and LP) and industrial sales at this level, so these models are new.

For this filing, KCP&L is using updated projections from DOE for 2014 and a June 2014 vintage economic forecast of the KC metro area from Moody's Analytics.

2. Development of any mathematical or statistical equations comprising the load forecast models, including a specification of the functional form of the equations; and

Table 19 MO Residential kWh per Customer

Variable	Coefficient	StdErr	T-Stat	P-Value	Units
StrucVars.XHeat55	0.932	0.025	37.745	0.00%	kWh/cust
StrucVars.XCool65	2.796	0.030	94.557	0.00%	kwh/cust
StrucVars.XOther	0.736	0.008	86.726	0.00%	kWh/cust
RUAvgUse.Jun06	-60.770	23.878	-2.545	1.18%	
RUAvgUse.Jul12	-50.550	23.925	-2.113	3.61%	
BinaryVars.Jan	15.031	6.492	2.315	2.18%	
BinaryVars.Mar	21.949	6.057	3.624	0.04%	
BinaryVars.Jun	-35.322	7.061	-5.003	0.00%	
BinaryVars.Jul	-24.052	7.326	-3.283	0.13%	
BinaryVars.Nov	-15.311	6.441	-2.377	1.86%	
AR(1)	0.518	0.069	7.551	0.00%	

Table 20 MO Small GS Commercial kWh per Customer

Variable	Coefficient	StdErr	T-Stat	P-Value	Units
StrucVars.XHeat55_SML	0.871	0.050	17.457	0.00%	kWh
StrucVars.XCool60_SML	2.198	0.079	27.801	0.00%	Kwh
StrucVars.XOther_SML	0.888	0.016	55.700	0.00%	kWh
SML_AvgUse.Nov08	-166.401	45.571	-3.651	0.04%	
SML_AvgUse.Dec08	-139.047	46.716	-2.976	0.37%	
BinaryVars.Jan	-63.069	17.589	-3.586	0.06%	
BinaryVars.Aug	61.616	18.652	3.303	0.14%	
BinaryVars.Sep	63.646	19.382	3.284	0.15%	
BinaryVars.Oct	48.458	17.253	2.809	0.61%	
BinaryVars.Dec	-94.521	17.845	-5.297	0.00%	
SML_AvgUse.Calib	-59.592	17.912	-3.327	0.13%	
AR(1)	0.475	0.092	5.182	0.00%	

Table 21 MO Big GS Commercial Sales

Variable	Coefficient	StdErr	T-Stat	P-Value	Units
CONST	188255277.983	17373644.102	10.836	0.00%	
StrucVars.XHeat55_BIG	601.186	28.533	21.070	0.00%	kWh
StrucVars.XCool55_BIG	2013.932	47.818	42.117	0.00%	Kwh
StrucVars.XOther_BIG	318.757	69.353	4.596	0.00%	kWh
BinaryVars.Mar	4467054.927	2435327.244	1.834	7.09%	
BinaryVars.Sep	8921337.397	2508058.222	3.557	0.07%	
BinaryVars.Oct	12747942.431	2562052.362	4.976	0.00%	
BinaryVars.Dec	13152460.395	2978472.467	4.416	0.00%	
BIG_Sales.Calib	-5511203.506	1835591.226	-3.002	0.37%	

Table 22 MO Industrial Sales

Variable	Coefficient	StdErr	T-Stat	P-Value	Units
CONST	63023300.025	9857414.000	6.393	0.00%	
StrucVars.XCool55_IND	84688124.834	3988631.547	21.232	0.00%	kWh
StrucVars.XOther_IND	59374092.045	9955537.693	5.964	0.00%	kWh
IND_Sales.Aug05	-19675499.305	3977458.750	-4.947	0.00%	
IND_Sales.May07	11044510.356	3930851.200	2.810	0.57%	
IND_Sales.Sep12	-14071759.256	3950503.324	-3.562	0.05%	
IND_Sales.Nov12	-13840548.350	3950400.164	-3.504	0.06%	
IND_Sales.Mar13	-12666700.593	4105899.835	-3.085	0.25%	
IND_Sales.Expr1	9155578.043	787331.082	11.629	0.00%	
BinaryVars.Mar	6866492.963	1320245.846	5.201	0.00%	

Table 23 KS Residential kWh per Customer

Variable	Coefficient	StdErr	T-Stat	P-Value	Units
StrucVars.XHeat55	0.929	0.020	46.171	0.00%	kWh/cust
StrucVars.XCool65	2.478	0.025	98.016	0.00%	kwh/cust
StrucVars.XOther	0.789	0.007	105.569	0.00%	kWh/cust
RUAvgUse.Jul11	65.706	26.311	2.497	1.36%	
RUAvgUse.Jun09	59.512	26.326	2.261	2.52%	
BinaryVars.Feb	-45.892	8.348	-5.498	0.00%	
BinaryVars.Mar	-55.568	8.678	-6.404	0.00%	
BinaryVars.Apr	-25.837	7.754	-3.332	0.11%	
BinaryVars.Jun	46.874	7.971	5.880	0.00%	
BinaryVars.Jul	62.510	8.405	7.437	0.00%	
BinaryVars.Nov	-10.817	7.418	-1.458	14.69%	
AR(1)	0.413	0.075	5.513	0.00%	

Table 24 KS Small GS Commercial kWh per Customer

Variable	Coefficient	StdErr	T-Stat	P-Value	Units
CONST	404.537	85.028	4.758	0.00%	
StrucVars.XHeat55_SML	0.711	0.043	16.535	0.00%	kWh
StrucVars.XCool60_SML	2.229	0.063	35.355	0.00%	Kwh
StrucVars.XOther_SML	0.511	0.079	6.458	0.00%	kWh
SML_AvgUse.Oct11	-104.473	32.301	-3.234	0.17%	
SML_AvgUse.Apr12	-101.602	32.172	-3.158	0.21%	
SML_AvgUse.Oct13	-193.496	32.484	-5.957	0.00%	
SML_AvgUse.Jul14	128.118	37.561	3.411	0.10%	
AR(1)	0.534	0.094	5.666	0.00%	

Table 25 KS Big GS Commercial Sales

Variable	Coefficient	StdErr	T-Stat	P-Value	Units
CONST	87199069.874	10257429.275	8.501	0.00%	
StrucVars.XHeat50_BIG	431.062	23.460	18.374	0.00%	kWh
StrucVars.XCool55_BIG	2002.658	47.041	42.572	0.00%	Kwh
StrucVars.XOther_BIG	614.960	57.047	10.780	0.00%	kWh
BIG_Sales.Calib	-6046172.876	1481226.594	-4.082	0.01%	
AR(1)	0.210	0.107	1.961	5.32%	

Table 26 KS Industrial Sales

Variable	Coefficient	StdErr	T-Stat	P-Value	Units
CONST	15168520.084	2302774.966	6.587	0.00%	
StrucVars.XOther_IND	8479093.630	2077683.952	4.081	0.01%	
StrucVars.XCool55_IND	21885842.411	1398964.147	15.644	0.00%	
IND_Sales.Aug10	1639494.151	609698.300	2.689	0.83%	
IND_Sales.Feb10	4757169.050	604702.427	7.867	0.00%	
IND_Sales.Nov06	1505471.898	615910.337	2.444	1.62%	
IND_Sales.Oct13	1416451.832	605155.534	2.341	2.11%	
IND_Sales.Jan09	-1830106.532	604019.512	-3.030	0.31%	
AR(1)	0.906	0.042	21.733	0.00%	

3. Assessment of the applicability of any load forecast models or portions of models that were utilized by the utility but developed by others, including a specification of the functional forms of any equations or models, to the extent they are available.

The load forecasting models rely on a forecast of economic activity for the KC metro area that was produced by Moody's Analytics. The KC metro area is the same as the Metropolitan Statistical Area (MSA) defined by the US Census Bureau and it includes some counties in both states that are not served by KCP&L. Also, KCP&L's service area includes some counties that are not included in the MSA. Despite these inconsistencies in geographic areas, there are reasons why this forecast is representative of our service areas. Many people live on one side of the state line and work on the other side. Many people shop on both sides of the state line. And many companies each year move from one side of the state line to the other. Documentation for Moody's forecast of economic activity is provided in the workpapers in the folder \KCPL Base Case\Data\Economics.

The load forecasting models also rely on saturation and appliance and equipment utilization forecasts from the DOE. The advantages of the projections from these models is 1) DOE's Forecasting and Analyst staff includes dozens of experts and maintains a large budget for data collection and consultants, 2) DOE has a focus on measuring the impacts of appliance and equipment standards and legal mandates and 3) DOE is very transparent, making available its work and computer code on its website.[iii] KCP&L also relies on the staff that developed and maintained some of EPRI's end-use models recommended and developed the SAE approach for KCP&L and many other utilities. EPRI no longer maintains its end-use forecasting models.

A potential downside of these projections for KCP&L is that the data and models developed by DOE are developed at a regional level rather than specifically for KCP&L, although this can be an advantage when one service area or region has insufficient variation to measure the impact of a variable such as electric price. Cross sectional variation in the data can be an advantage in situations where price or income elasticities are being modeled.

(B) If the utility selects load forecast models that include end-use load methods, the utility shall describe and document any deviations in the independent variables or functional forms of the equations from those derived from load analysis in sections (3) and (4).

KCP&L is not aware of any such deviations.

(C) Historical Database for Load Forecasting. In addition to the load analysis database, the utility shall develop and maintain a database consistent with and as needed to run each forecast model utilized by the utility. The utility shall describe and document its load forecasting historical database in the triennial compliance filings. As a minimum, the utility shall—

1. Develop and maintain a data set of historical values for each independent variable of each forecast model. The historical values for each independent variable shall be collected for a period of ten (10) years, or such period deemed sufficient to allow the independent variables to be accurately forecasted over the entire planning horizon;

The independent variables acquired from Moody's are available back to 1990. These are updated every time that KCP&L acquires a new economic and demographic forecast as revisions to this data far back in time are common.

The independent variables acquired from DOE are also available back to 1990 and these too replace the historical values when each year new spreadsheets are provided to

KCP&L. New studies or data can revise historical estimates of efficiencies and saturations.

The independent variables for natural gas prices of local utilities are maintained back to 1991.

Temperature data is maintained back to 1971 when the Kansas City International Airport opened for business.

2. Explain any adjustments that it made to historical data prior to using it in its development of the forecasting models;

KCP&L staff is not aware of any adjustments made to independent variables used in its load forecasting models.

3. Archive previous projections of all independent variables used in the energy usage and peak load forecasts made in at least the past ten (10) years and provide a comparison of the historical projected values in prior plan filings to actual historical values and to projected values in the current compliance filing; and

KCP&L still possesses the electronic files that it received with the independent variables used in producing energy and peak forecasts during the last ten years. Below KCP&L plots the base, high and low bands for the most important economic and demographic independent variables used in the current and two previous IRP filings.

Figure 23: Households ** Highly Confidential **

[redacted]

KCP&L asked about the change in the household forecast that occurred with that used in this filing, Moody's responded

> "we view the metro area as having solid growth drivers that should enable population growth to outpace the nation. It has below average costs and an extremely diversified economy. Its workforce has an above average educational attainment when compared with the regional average, which will help it attract new businesses. In light of these characteristics, a severe decline in the rate of population growth beginning immediately in the forecast period simply couldn't be justified, hence the revisions. The changes in the household forecast follow directly from changes to population."[iv]

The high and low bands for the current forecast are closer together compared to the previous forecasts. KCP&L requested an explanation, Moody's responded

> "The different properties of the high/low bands I sent most recently are a result of the newer methodology I mentioned. Previously, your data delivery used a

different, older methodology, but it will be migrated to the new one going forward. Since you requested an update of the households data, I used the new methodology since it will match what you will be receiving in the future.

"The new methodology relies on the historical variation in the growth rates of the time series. Growth in households (both in general and for Kansas City) is quite consistent compared with many other economic time series. For KAN, quarterly growth has ranged only from about 0.1% and 0.7%, with a standard deviation of just over 0.1%. This is what is causing the high and low bands to have relatively small divergence. To illustrate slightly further: If households for KAN were 10% higher than the baseline in 2035, that would be equivalent to a quarterly growth rate about a full standard deviation higher than the baseline expectation in every single quarter. KCP&L views that as being too unlikely for the purposes of these high/low bands."[v]

Figure 24: Employment Non-Manufacturing ** Highly Confidential **

[redacted]

The 2012 and 2015 forecast of non-manufacturing employment shows a substantial drop during and several years after the last recession, then a rapid rebound and then steady robust growth. The 2008 forecast shows only a small drop and no increases until the mid 20s. The current forecast reflects a change in assumptions mentioned in the paragraph above for households for the competitiveness of the KC metro economy.

Figure 25: Employment Manufacturing **Highly Confidential **

[redacted]

In the current forecast, manufacturing employment shows a huge decline during and several years after the last recession. After a strong rebound, employment continues to decline thereafter. Moody's indicates that the decline in employment for manufacturing workers is due to increased productivity from the workers, as manufacturing becomes more automated. The decline in manufacturing employment for the forecast horizon is also consistent with the observed downward trend dating back to the 1990s.

Figure 26: Gross Metro Product Non-Manufacturing ** Highly Confidential **

[redacted]

Real non-manufacturing GMP is growing much faster than employment in all three scenarios. The current forecast was lowered from the previous forecast. Moody's stated that the current forecast was lowered from the previous forecast because the actual or historical data for Missouri fell below their expectations due to national economic fluctuations, and caused the Missouri forecast to be lowered. In turn, the lower pattern was shared down to the Kansas City metropolitan area. Real GMP in the current forecast was also rebased from 2005$ to 2009$.

HC

Figure 27: Gross Metro Product Manufacturing ** Highly Confidential **

[redacted]

While manufacturing employment is flat after 2015, real manufacturing GMP shows strong growth due to increase productivity. The current forecast shows the strongest growth.

When asked about the faster rate of growth in the out years for GMP manufacturing forecast that occurred with that used in this filing, Moody's responded

"In our forecast, the Missouri Gross State Product underperforms US GDP in the near term, before growth outperforms later in the forecast. Much of this fluctuation is due to improvement in the goods market, including manufacturing and construction. Missouri manufacturing employment is expected to outperform the national average. Manufacturing jobs in Missouri will decline in the short-term, as manufacturing productivity gains weigh on employment. However, losses will narrow later in the forecast, as Missouri and its metro areas seem likely to emerge as niche manufacturing locations. A niche manufacturing market is where the state/metro area holds a comparative advantage in producing a specific product, and this advantage will last over the course of the forecast. For example, St. Louis is likely to emerge as a chemical and pharmaceutical manufacturing hub, and St. Joseph is likely to become a niche market for animal health product, and processed food manufacturing. As for construction, our model is based on historical patterns of data. The increases that are in the forecast are based on historical patterns and trends, and not based on any knowledge that KCP&L has of any forthcoming construction projects. Also, the Missouri construction forecast trends similarly to the national forecast, so some of the fluctuation is due to exposure to the national business cycle."[vi]

4. Archive all previous forecasts of energy and peak demand, including the final data sets used to develop the forecasts, made in at least the past ten (10) years. Provide a comparison of the historical final forecasts to the actual historical energy and peak demands and to the current forecasts in the current triennial compliance filing.

KCP&L maintains an archive of the electronic files associated with our previous forecasts of energy use and peak demand for at least the last ten years. The graphs below compare our previous long-run forecasts of NSI and peak demand. The most recent forecast reflects a significant slowdown in economic growth that began in 2008, expectations for slower economic growth and additional energy standards.

Figure 28: Net System Input (NSI) Historical and Forecasts ** High Confidential **

[redacted]

Figure 29: Peak Demand Historical and Forecasts ** High Confidential **

[redacted]

HC

SECTION 7: BASE-CASE LOAD FORECAST

The utility's base-case load forecast shall be based on projections of the independent variables that utility decision-makers believe to be most likely. All components of the base-case load forecast shall assume normal weather conditions. The load impacts of implemented demand-side programs and rates shall be incorporated in the base-case load forecast, but the load impacts of proposed demand-side programs and rates shall not be included in the base-case forecast.

KCP&L's base-case forecast was produced with a base-case economic forecast from Moody's Analytics obtained in June 2014. The forecast included the impacts of KCP&L's implemented energy efficiency and DSM programs on NSI and peak load. The forecast was produced using normal weather.

7.1 MAJOR CLASS AND TOTAL LOAD DETAIL

(A) Major Class and Total Load Detail.

The utility shall produce forecasts of monthly energy usage and demands at the time of the summer and winter system peaks by major class for each year of the planning horizon, and shall describe and document those forecasts in its triennial compliance filings. Where applicable, these major class forecasts shall be separated into their jurisdictional components.

7.1.1 DESCRIBE AND DOCUMENT RELEVENT ECONOMIC AND DEMOGRAPHICS

1. The utility shall describe and document how the base-case forecasts of energy usage and demands have taken into account the effects of real prices of electricity, real prices of competitive energy sources, real incomes, and any other relevant economic and demographic factors. If the methodology does not incorporate economic and demographic factors, the utility shall explain how it accounted for the effects of these factors.

KCP&L accounted for the effects of real electricity prices in two ways. First, the prices of electricity and natural gas were used in the models that forecast the saturations of electric space heating for residential and commercial customers. These models are described in the section of this document for rule 7.B.1. Second, KCP&L assumes a price elasticity of -0.15 in each model of sales or sales per customer. These elasticities are close to the default values in the ERPI models REEPS and COMEND, which ITRON used in the original SAE models that they delivered to KCP&L in 2004. Since, then KCP&L has made some small changes to these values to improve the fit of the models.

In the residential models of kWh per customer, KCP&L assumes an income elasticity of 0.2 for heating and cooling and 0.2 for other uses and a persons-per-household elasticity of 0.2. Moody's forecast of households for the KC metro area were used in the models of residential customers as was described previously in the section for rule 3.B.

7.1.2 <u>DESCRIBE AND DOCUMENT EFFECTS OF LEGAL MANDATES</u>

2. The utility shall describe and document how the forecasts of energy usage and demands have taken into account the effects of legal mandates affecting the consumption of electricity.

KCP&L uses the SAE methodology to forecast kWh sales for residential, commercial and industrial sales. This methodology relies on DOE forecasts of UECs and EUIs, which account for appliance efficiency standards and building codes.[vii]

7.1.3 <u>DESCRIBE AND DOCUMENT CONSISTENCY</u>

3. The utility shall describe and document how the forecasts of energy usage and demands are consistent with trends in historical consumption patterns, end uses, and end-use efficiency in the utility's service area as identified pursuant to sections 4 CSR 240-22.030(2), (3), and (4).

KCP&L forecasts incorporate and thus are consistent with the following trends:

- Electric space heating models explain the rapid rise of electric space heating saturations in the residential and commercial sector as a function of the relative costs of using electricity and natural gas. These costs depend on electricity and natural gas prices and the efficiencies of heat pumps and natural gas furnaces.

- Forecasts of UECs and EUIs used in our models reflect the impacts of energy standards in both the past and the future.

- Forecasts of appliance and equipment saturations reflect the penetration of new devices such as CFL/LED Light Bulbs, HDTVs and the limitations of further increases for appliances that are reaching equilibrium such as dishwashers and central air conditioners.

7.1.4 DESCRIBE AND DOCUMENT WEATHER NORMALIZED CLASS LOADS

4. For at least the base year of the forecast, the utility shall describe and document its estimates of the monthly cooling, heating, and non-weather-sensitive components of the weather-normalized major class loads.

The estimates are shown below. Details for the full 20 years can be found in MO_Fcst.ltm and KS_Fcst.ltm in the END_Use Energy Frequency Transforms.

Figure 30: Estimates of MO Residential Monthly Cooling, Heating, and Base

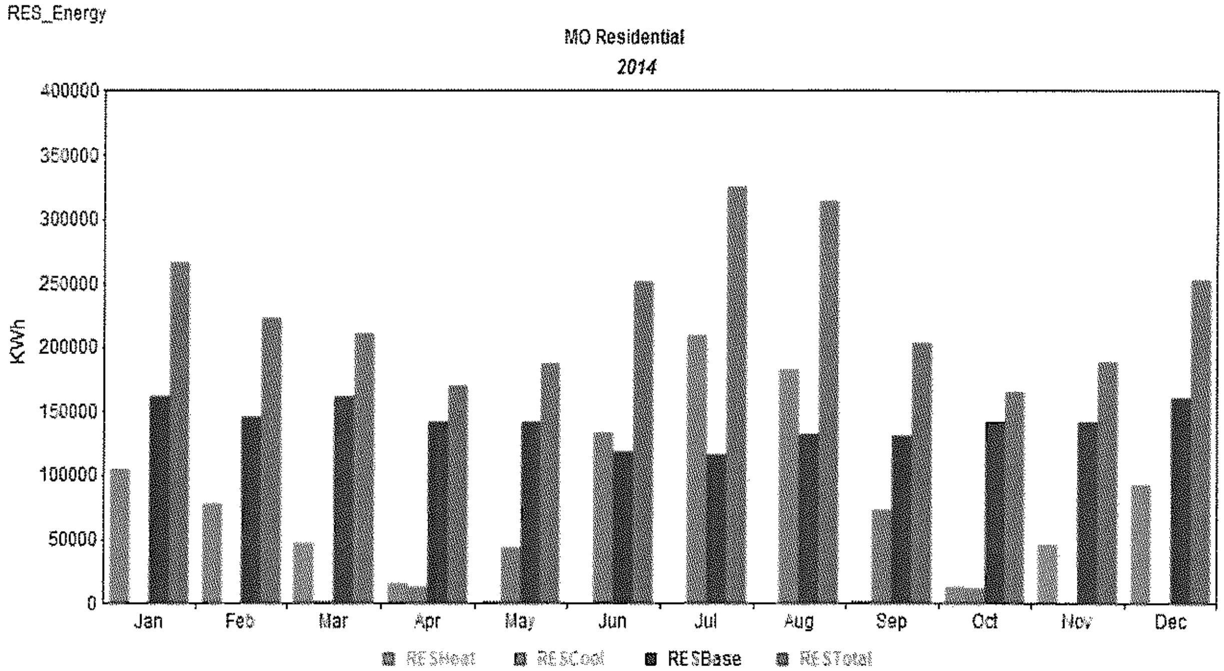


Table 27: Data Table of MO Residential Monthly Cooling, Heating, and Base

Date	RESHeat	RESCool	RESBase	RESTotal
Jan-14	104,866.4	-	161,088.2	265,954.7
Feb-14	78,114.4	-	145,225.2	223,339.5
Mar-14	46,955.1	2,001.8	162,050.7	211,007.6
Apr-14	15,473.1	12,582.1	142,169.5	170,224.6
May-14	1,323.2	43,525.3	142,389.9	187,238.4
Jun-14	-	133,029.9	118,333.1	251,363.0
Jul-14	-	209,550.2	116,051.0	325,601.2
Aug-14	-	182,285.0	131,984.2	314,269.2
Sep-14	1,127.0	72,529.5	130,466.3	204,122.7
Oct-14	12,213.9	11,289.4	141,534.5	165,037.8
Nov-14	46,237.3	488.7	141,818.9	188,544.8
Dec-14	92,431.2	10.3	159,901.3	252,342.8

Figure 31: Estimates of MO Commercial Small General Service Monthly Cooling, Heating, and Base

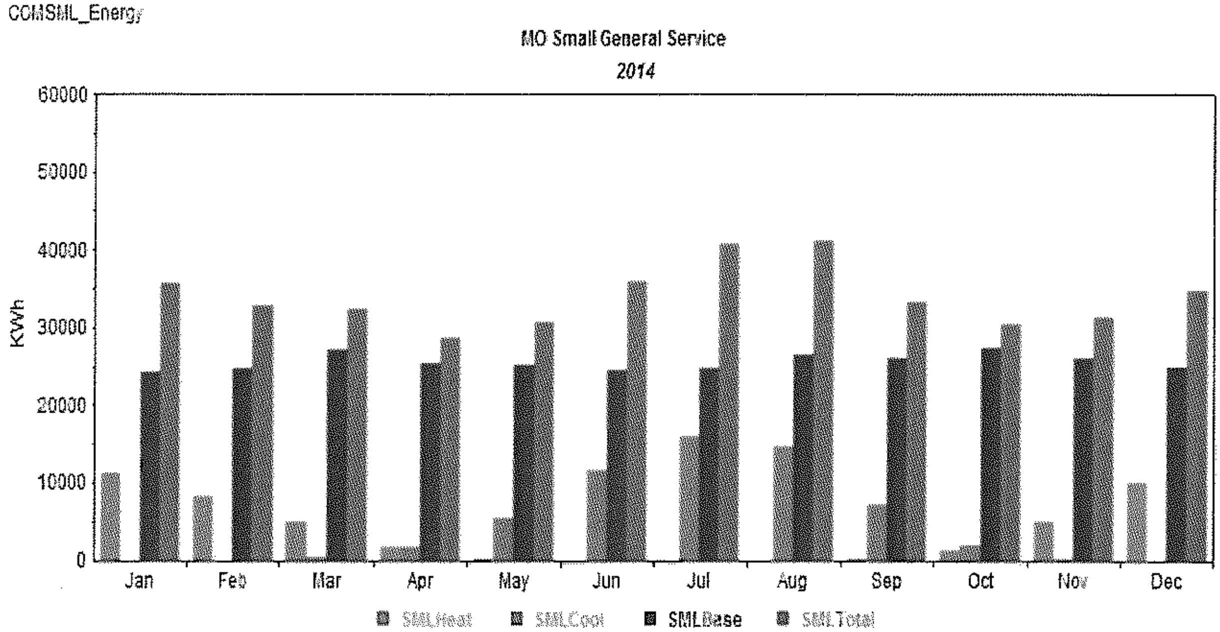


Table 28: Data Table of MO Commercial Small General Service Monthly Cooling, Heating, and Base

Date	SMLHeat	SMLCool	SMLBase	SMLTotal
Jan-14	11,351.9	-	24,263.5	35,615.4
Feb-14	8,278.7	4.6	24,623.1	32,906.4
Mar-14	4,992.7	436.8	27,073.6	32,503.1
Apr-14	1,639.5	1,681.4	25,352.9	28,673.7
May-14	152.6	5,336.3	25,132.5	30,621.4
Jun-14	-	11,519.7	24,408.3	35,928.0
Jul-14	-	15,869.4	24,772.1	40,641.5
Aug-14	-	14,557.6	26,510.5	41,068.1
Sep-14	121.6	7,152.9	26,085.5	33,360.1
Oct-14	1,319.1	1,787.7	27,399.6	30,506.4
Nov-14	4,985.2	187.7	26,021.0	31,193.9
Dec-14	9,995.2	13.5	24,871.5	34,880.2

Figure 32: Estimates of MO Commercial Big (MGS, LGS & LP) Monthly Cooling, Heating, and Base

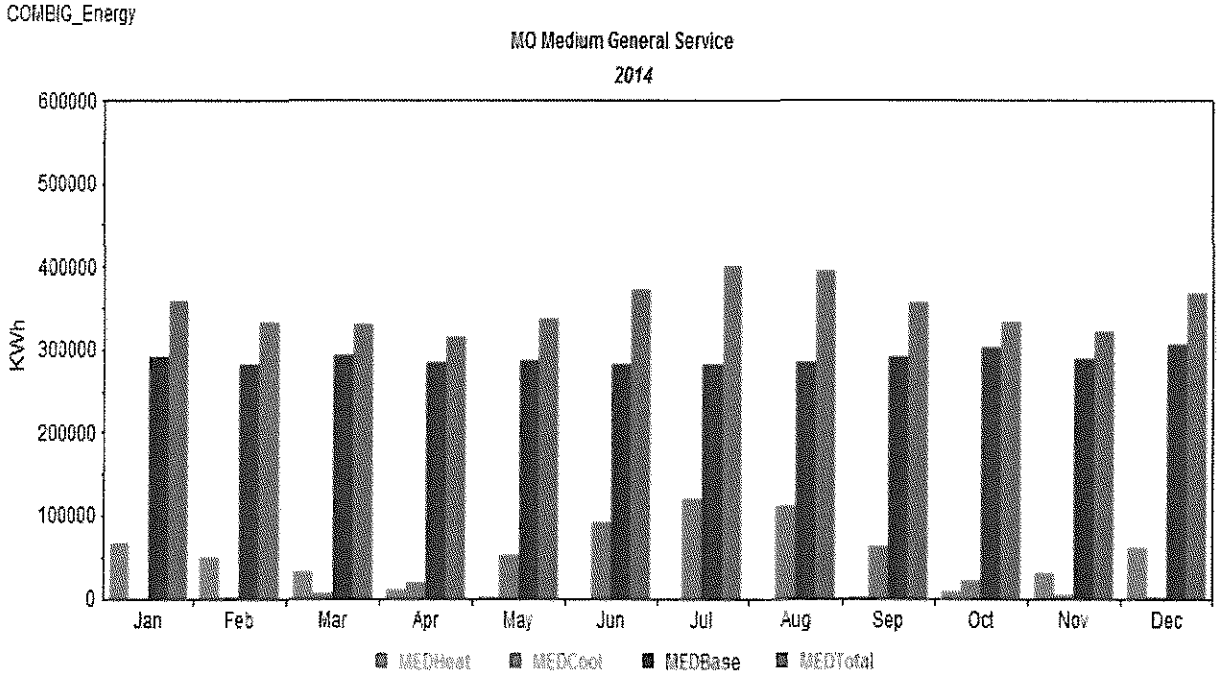


Table 29: Data Table of MO Commercial Big (MGS, LGS & LP) Monthly Cooling, Heating, and Base

Date	MEDHeat	MEDCool	MEDBase	MEDTotal
Jan-14	68,031.2	69.9	291,193.1	359,294.1
Feb-14	50,533.4	350.4	282,014.5	332,898.2
Mar-14	30,883.8	6,332.4	294,104.2	331,320.3
Apr-14	10,038.8	19,155.9	285,279.4	314,474.1
May-14	923.0	51,433.0	285,698.1	338,054.1
Jun-14	-	91,326.1	281,863.3	373,189.4
Jul-14	-	119,854.3	281,498.0	401,352.3
Aug-14	-	110,058.0	283,939.4	393,997.3
Sep-14	742.7	63,275.4	291,861.3	355,879.4
Oct-14	8,058.3	22,018.2	301,724.9	331,801.4
Nov-14	30,435.5	3,517.7	287,820.4	321,773.6
Dec-14	61,118.2	352.4	306,658.4	368,129.0

Figure 33: Estimates of MO Industrial Monthly Cooling, Heating, and Base

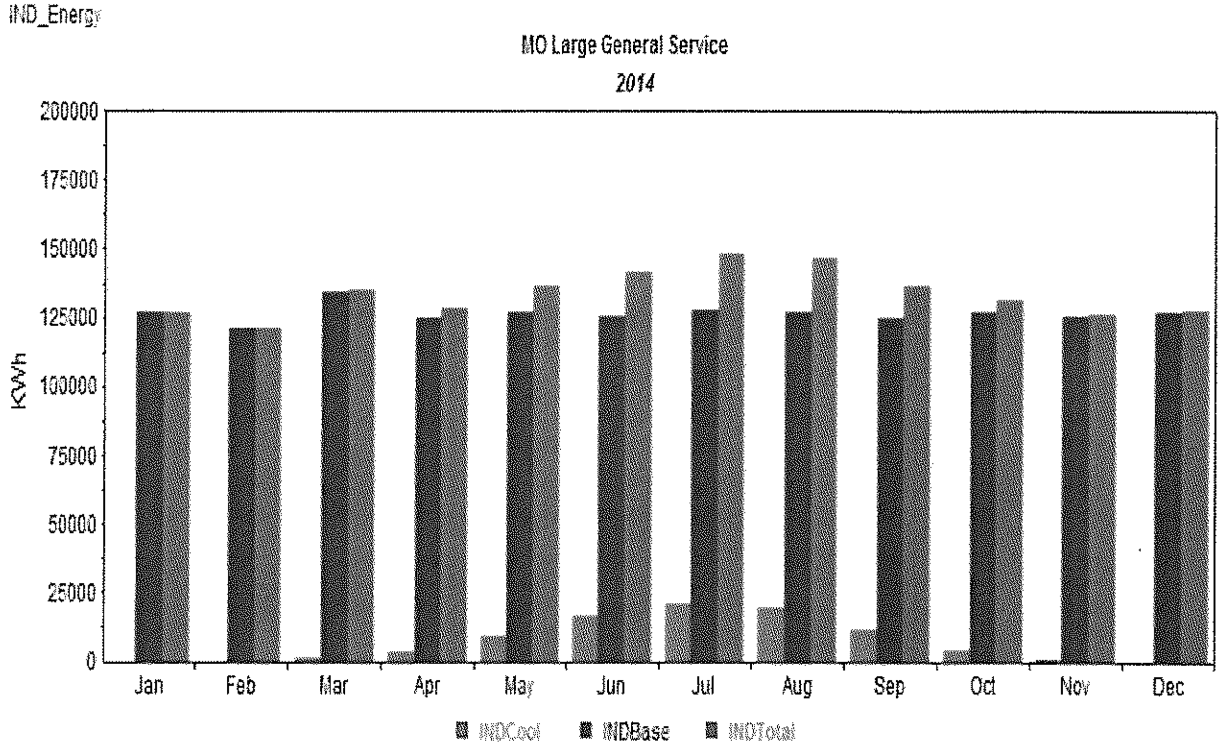


Table 30: Data Table of MO Industrial Monthly Cooling, Heating, and Base

Date	INDCool	INDBase	INDTotal
Jan-14	12.4	126,887.3	126,899.7
Feb-14	67.8	120,849.6	120,917.5
Mar-14	1,144.4	133,943.8	135,088.2
Apr-14	3,469.2	124,990.5	128,459.7
May-14	9,225.2	127,077.6	136,302.7
Jun-14	16,441.5	125,280.9	141,722.4
Jul-14	20,784.2	127,598.6	148,382.8
Aug-14	19,769.6	127,083.3	146,852.9
Sep-14	11,358.5	125,054.6	136,413.1
Oct-14	3,953.2	127,076.8	131,029.9
Nov-14	633.0	125,283.9	125,916.9
Dec-14	63.4	127,306.0	127,369.4

Figure 34: Other MO Load (SFR & Lighting)

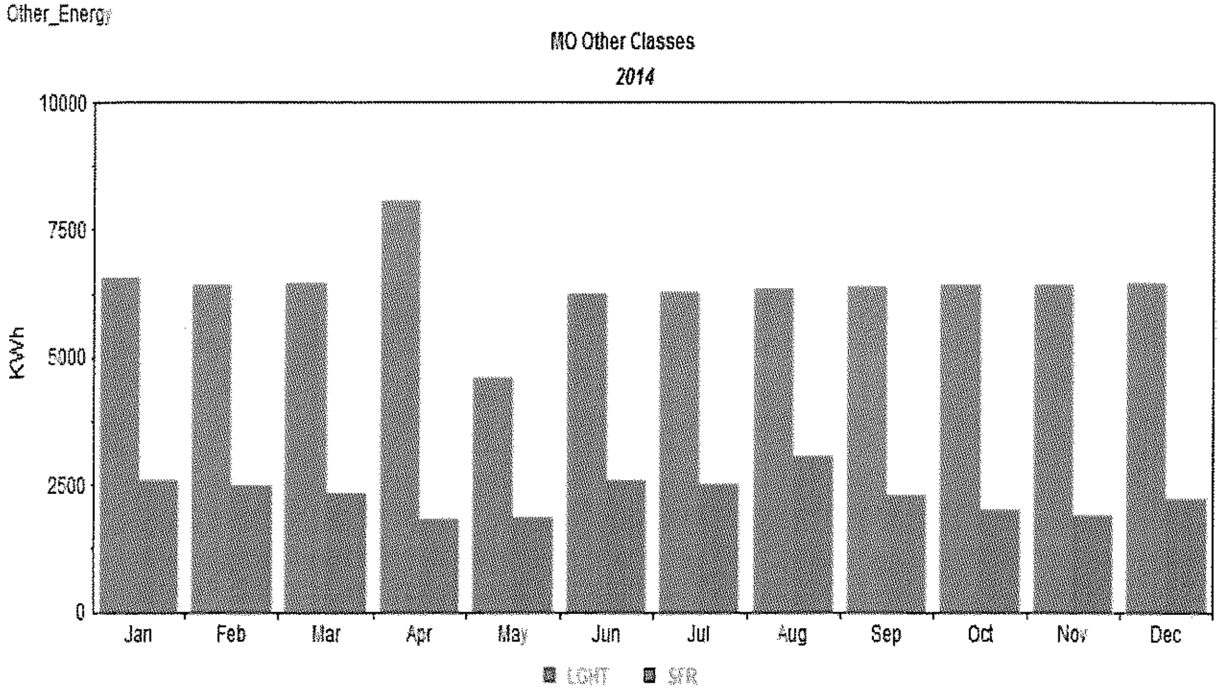


Table 31: Data Table Other MO Load (SFR & Lighting)

Date	LGHT	SFR
Jan-14	6,559.8	2,574.0
Feb-14	6,436.5	2,461.1
Mar-14	6,460.5	2,332.5
Apr-14	8,073.2	1,800.1
May-14	4,592.2	1,845.6
Jun-14	6,255.2	2,569.4
Jul-14	6,288.9	2,527.5
Aug-14	6,340.3	3,048.7
Sep-14	6,378.4	2,301.9
Oct-14	6,412.1	1,981.7
Nov-14	6,435.2	1,884.0
Dec-14	6,457.6	2,225.3

Figure 35: Estimates of KS Residential Monthly Cooling, Heating, and Base

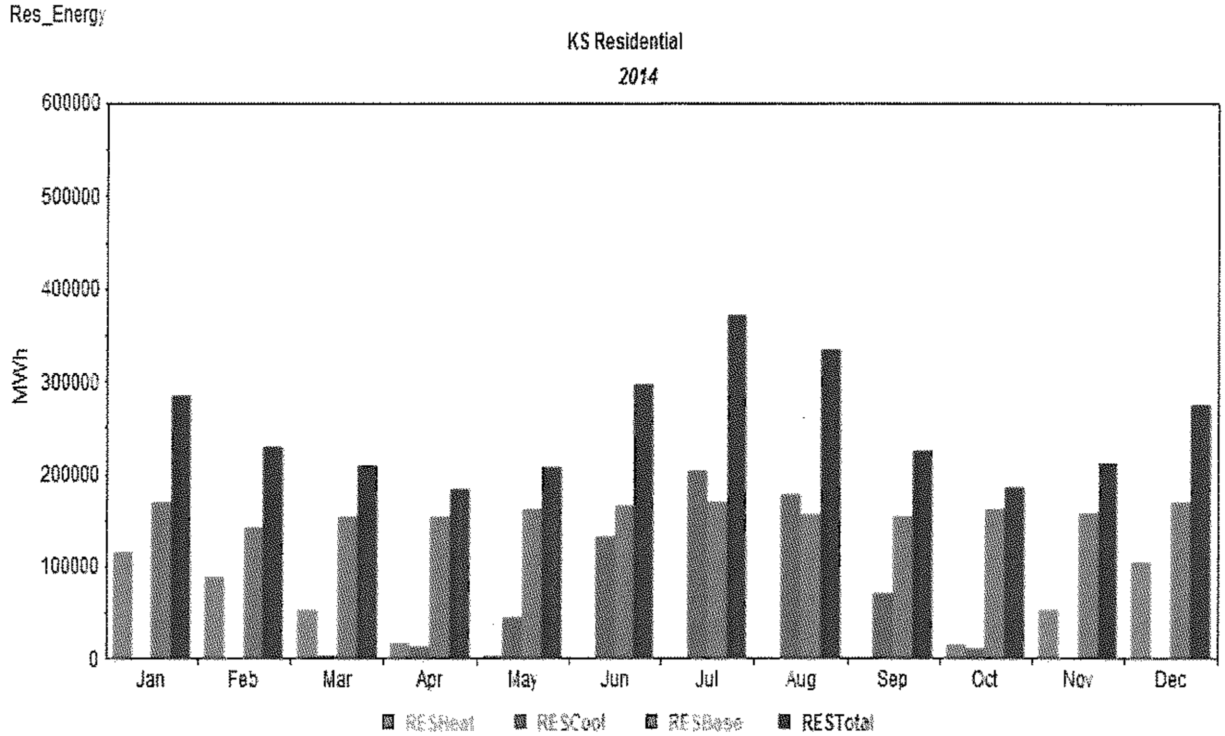


Table 32: Data Table of KS Residential Monthly Cooling, Heating, and Base

Date	RESHeat	RESCool	RESBase	RESTotal
Jan-14	115,242.9	-	168,557.2	283,800.1
Feb-14	87,032.4	-	140,707.5	227,739.9
Mar-14	52,979.9	1,948.3	153,030.0	207,958.2
Apr-14	17,246.5	12,104.6	153,905.9	183,256.9
May-14	1,561.6	44,359.5	161,662.7	207,583.7
Jun-14	-	131,798.1	164,401.7	296,199.8
Jul-14	-	202,920.2	169,006.2	371,926.4
Aug-14	-	177,183.8	155,926.9	333,110.7
Sep-14	1,270.8	70,537.8	152,752.1	224,560.7
Oct-14	13,764.3	10,967.9	161,255.4	185,987.6
Nov-14	52,111.0	474.6	157,478.7	210,064.2
Dec-14	104,546.1	10.0	169,091.2	273,647.3

Figure 36: Estimates of KS Commercial Small General Service Monthly Cooling, Heating, and Base

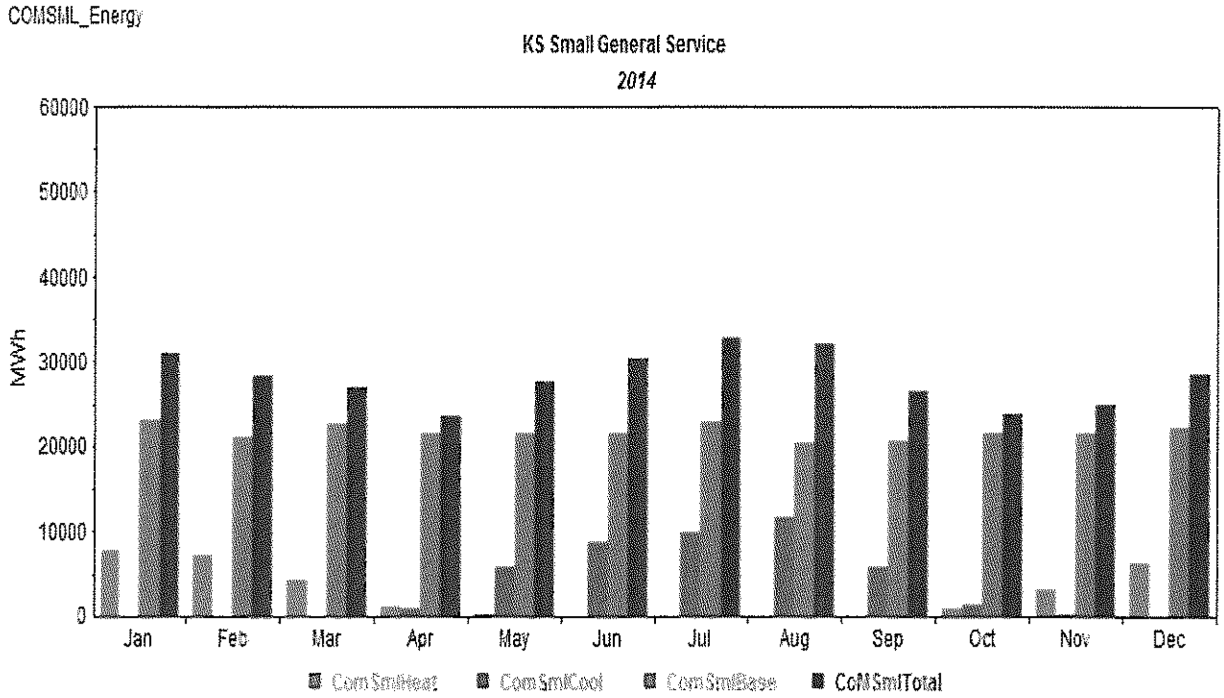


Table 33: Data Table of KS Commercial Small General Service Monthly Cooling, Heating, and Base

Date	ComSmlHeat	ComSmlCool	ɔmSmlBase	oMSmlTotal
Jan-14	7,921.6	-	23,161.0	31,082.6
Feb-14	7,228.3	-	21,163.7	28,392.0
Mar-14	4,199.3	68.5	22,588.9	26,856.7
Apr-14	1,073.0	971.1	21,556.3	23,600.4
May-14	240.2	5,896.9	21,515.5	27,652.6
Jun-14	-	8,683.6	21,603.5	30,287.2
Jul-14	-	9,888.4	22,981.9	32,870.3
Aug-14	-	11,704.3	20,525.0	32,229.2
Sep-14	76.8	5,763.6	20,565.5	26,405.9
Oct-14	834.0	1,442.0	21,511.5	23,787.5
Nov-14	3,151.7	151.4	21,550.3	24,853.4
Dec-14	6,333.6	10.9	22,281.0	28,625.6

Figure 37: Estimates of KS Commercial Big General Service (MGS and LGS) Monthly Cooling, Heating, and Base

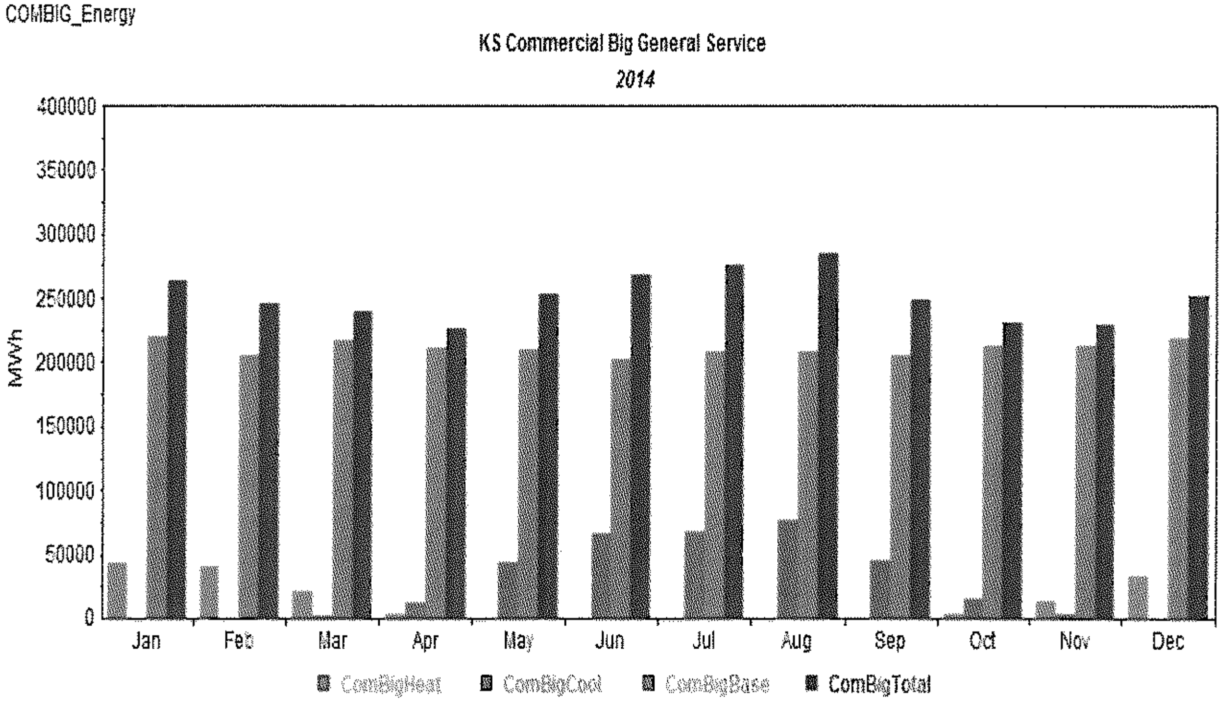


Table 34: Data Table of KS Commercial Big General Service (MGS and LGS) Monthly Cooling, Heating, and Base

Date	ComBigHeat	ComBigCool	ComBigBase	ComBigTotal
Jan-14	43,454.2	-	220,477.4	263,931.7
Feb-14	40,789.9	-	205,421.7	246,211.6
Mar-14	20,433.3	1,235.1	217,736.4	239,404.9
Apr-14	3,643.0	12,123.5	210,459.9	226,226.4
May-14	322.3	43,315.5	210,054.1	253,691.9
Jun-14	-	66,072.9	202,606.5	268,679.4
Jul-14	-	67,496.4	207,615.8	275,112.2
Aug-14	-	76,839.7	207,507.3	284,347.0
Sep-14	123.1	44,194.2	205,190.0	249,507.3
Oct-14	2,354.2	15,379.1	213,107.1	230,840.4
Nov-14	13,798.6	2,456.7	212,607.9	228,863.2
Dec-14	32,722.5	246.1	219,204.7	252,173.3

Figure 38: Estimates of KS Industrial Monthly Cooling, Heating, and Base

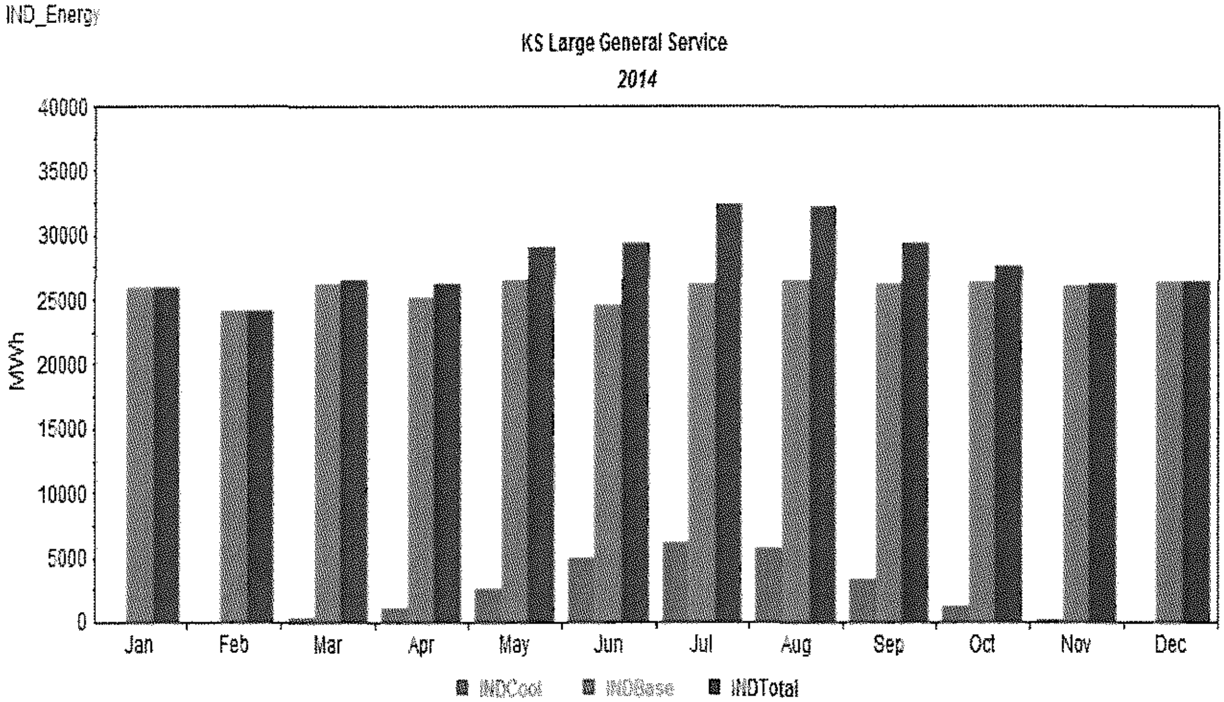


Table 35: Data Table of KS Industrial Monthly Cooling, Heating, and Base

Date	INDCool	INDBase	INDTotal
Jan-14	3.4	25,963.9	25,967.3
Feb-14	18.8	24,091.8	24,110.5
Mar-14	310.2	26,268.8	26,579.0
Apr-14	1,027.7	25,125.5	26,153.2
May-14	2,482.8	26,531.2	29,014.1
Jun-14	4,910.6	24,525.3	29,435.8
Jul-14	6,142.1	26,147.0	32,289.2
Aug-14	5,651.2	26,526.1	32,177.3
Sep-14	3,251.2	26,151.8	29,403.0
Oct-14	1,131.3	26,409.7	27,541.0
Nov-14	180.9	26,056.6	26,237.5
Dec-14	18.1	26,334.0	26,352.1

Figure 39: Other KS Load (SFR & Lighting)

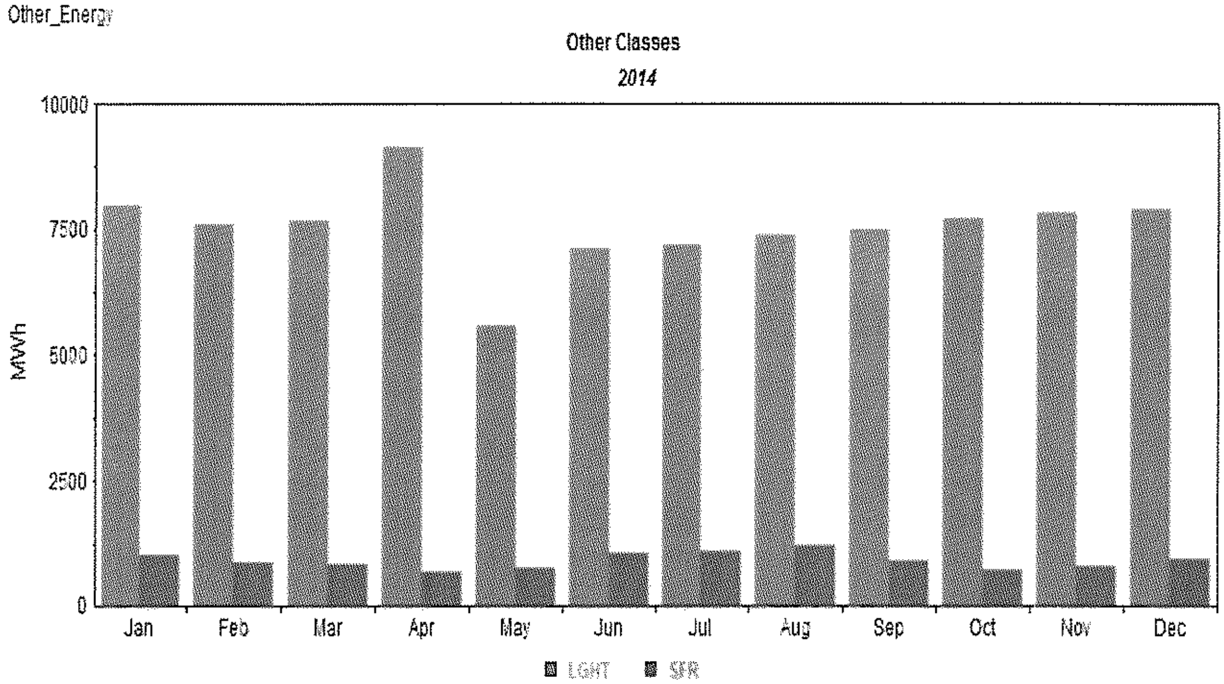


Table 36: Data Table Other KS Load (SFR & Lighting)

Date	LGHT	SFR
Jan-14	7,991.4	1,001.6
Feb-14	7,595.2	845.3
Mar-14	7,668.0	812.5
Apr-14	9,124.7	668.5
May-14	5,576.5	735.3
Jun-14	7,116.1	1,055.9
Jul-14	7,209.0	1,072.7
Aug-14	7,365.6	1,207.7
Sep-14	7,494.0	903.2
Oct-14	7,700.7	720.0
Nov-14	7,834.4	792.6
Dec-14	7,921.2	931.9

7.1.5 DESCRIBE AND DOCUMENT MODIFICATION OF MODELS

5. Where judgment has been applied to modify the results of its energy and peak forecast models, the utility shall describe and document the factors which caused the modification and how those factors were quantified.

The results of all models were used as is except to calibrate the system peak forecast to the weather normalized 2014 peak in each jurisdiction.

The first step is the weather normalization of the jurisdictional hourly load data. After normalizing the hourly loads, the demand side management, mpower and dynamic voltage control reductions at the time of peak are determined. This reduction in load is then added back to the weather normalized data to produce weather normalized monthly gross peaks. The base year weather normalized annual peak is then used to calibrate the jurisdictional peaks that are produced in MetrixLT. This is done by taking the base year normalized peak and using it as the first data point in the calibration process and then applying the annual growth rates from the peak forecast produced in MetrixLT. Then the annual peak is distributed across the months based on the percentage of that month's peak as percent to the annual peak. The percent of each month's contribution to the annual peaks is determined by the output of monthly peaks from MetrixLT. After each jurisdiction has been calibrated, the monthly peaks are then imported back in to MetrixLT and each hour for the peak day is adjusted to reflect the new calibrated peak.

The calibration of the peaks can be found in the jurisdictional system datalyzer folder which is provided in the work papers.

7.1.6 PLOTS OF CLASS MONTHLY ENERGY AND COINCIDENT PEAK DEMAND

6. For each major class specified pursuant to subsection (2)(A), the utility shall provide plots of class monthly energy and coincident peak demand at the time of summer and winter system peaks. The plots shall cover the historical database period and the forecast period of at least twenty (20) years. The plots of coincident peak demands for the historical period shall include both actual and weather-normalized peak demands at the time of summer and winter system peaks. The plots of coincident peak demand for the forecast period shall show the class coincident demands for the base-case forecast at the time of summer and winter system peaks.

Plots for class monthly energy and coincident peak demand at the time of summer and winter system loads are provided in *Appendix 3B*. Energy plots by jurisdiction and system are provided in the file *IRP_7.1.6_KCPL_MWh.xlsx* and peak plots are in the file *IRP_7.1.6_KCPL_Peaks.xlsx.*

7.1.7 PLOTS OF NET SYSTEM LOAD PROFILES

7. The utility shall provide plots of the net system load profiles for the summer peak day and the winter peak day showing the contribution of each major class. The plots shall be provided in the triennial filing for the base year of the forecast and for the fifth, tenth, and twentieth years of the forecast. Plots for all years shall be included in the workpapers supplied at the time of the triennial filing.

The figures below show the load profiles for the base, fifth, tenth, and twentieth years broken out by summer and winter peak days for each major class in Missouri, Kansas and for the system. The plots with data tables are provided in *Appendix 3C.* Plots for additional years can be found in the MetrixLT files (*MO_Fcst*, *KS_Fcst*, and *System*) included in the workpapers.

Figure 40: Base Year (2014) Net System Load Profiles for MO, KS, and System
**** High Confidential ****

[redacted]

HC

Figure 41: Fifth Year (2019) Net System Load Profiles for MO, KS, and System
**** High Confidential ****

[redacted]

HC

Figure 42: Tenth Year (2024) Net System Load Profiles for MO, KS, and System
**** High Confidential ****

[redacted]

HC

Figure 43: Twentieth Year (2034) Net System Load Profiles for MO, KS, and System ** High Confidential **

[redacted]

HC

7.2 DESCRIBE AND DOCUMENT FORECASTS OF INDEPENDENT VARIABLES

(B) Forecasts of Independent Variables.

The forecasts of independent variables shall be specified, described, and documented.

The forecasts of independent variables were described above in the section for rule 6.C.3 and below in the section for rule for 7.B.3.

7.2.1 DOCUMENTATION OF MATHEMATICAL MODELS

1. Documentation of mathematical models developed by the utility to forecast the independent variables shall include the reasons the utility selected the models as well as specification of the functional form of the equations.

KCP&L acquired forecasts of independent variables from Moody's and DOE as described previously. KCP&L developed its own models to forecast the saturation of electric space heating for residential and commercial customers (*SpaceHeating.xls*). KCP&L has specific tariffs for customers that have electric space heating and the percentage of customers on these tariffs is used as a measure of electric space heating saturations. The models predict both the penetration rate of electric space heating for new customers and the percentage rate of conversion to electric space heating for customers that use natural gas or propane to heat their homes. These rates are driven by the difference in costs to heat a home by electricity and natural gas. These costs are determined by the average natural gas rates for local gas utilities, KCP&L's winter tail-block rates and heating equipment efficiency rates.

The real price differential per million Btu is computed as

$$PD = (1{,}000{,}000/1{,}028{,}000/\text{Gas Furnace Efficiency}*\text{Gas rate}$$
$$-1{,}000{,}000/(\text{Heat pump Efficiency}*1{,}000)*\text{Electric tail block rate})*CPI_{2005}/CPI_t$$

The heat pump efficiency is Btu out per Watt hour in.

The equation to predict the number of additional customers using electric space heating is

New customers/(1+EXP(-newCust*PD-C_1))+

customers wo electric heat/(1+EXP(-conversions*PD+C_2+incentive*tax credit))

where tax credit = federal tax credits and KCP&L rebates available,

newCust, conversions, incentive, C_1, C_2 are coefficients.

The coefficients were estimated with least squares regression pooling the data for Kansas and Missouri. Equations were estimated separately for residential and commercial customers.

The forecasts for KCP&L and GMO are compared in the figure below.

Figure 44: Residential Space Heating Saturations Highly Confidential** **

Residential Electric Space Heating Saturations

[redacted]

7.2.2 DOCUMENTATION OF ADOPTED FORECASTS DEVELOPED BY ANOTHER ENTITY

2. If the utility adopted forecasts of independent variables developed by another entity, documentation shall include the reasons the utility selected those forecasts, an analysis showing that the forecasts are applicable to the utility's service territory, and, if available, a specification of the functional form of the equations used to forecast the independent variables.

KCP&L used a forecast of economic and demographic variables for the KC metro area that was developed by Moody's Analytics. The reasons for using this forecast, the applicability to KCP&L's service area and documentation for the forecast were discussed in the sections for rules 3 A and 6 A 3.

KCP&L used forecasts of saturations, UECs, EUIs and building efficiencies from DOE. The reasons for using these forecasts, the applicability to KCP&L's service area and documentation for the forecast were discussed in the sections for rules 3 A, 4 A 1 B, 5 A, 5 B AND 6 A 3.

7.2.3 COMPARISON OF FORECAST FROM INDEPENDENT VARIABLES TO HISTORICAL TRENDS

3. These forecasts of independent variables shall be compared to historical trends in the variables, and significant differences between the forecasts and long-term and recent trends shall be analyzed and explained.

Table 37 Economic Growth Rates for KC Metro Area ** Highly Confidential **

[redacted]

HC

Figure 45: Households ** Highly Confidential **

[redacted]

the last recession at the end of 2007, at which time growth slowed substantially. The forecast is for the housing stock to growth rapidly again after the current period of low U.S. economic growth to allow the housing stock to catch up with demographic growth. Then growth slows to a level lower than what KCP&L has seen in the last two decades.

HC

Figure 46: Employment Non-Manufacturing ** Highly Confidential **

[redacted]

Non-manufacturing showed very strong growth in the 1990s, 1.9% per year, then stalled after the 2001 recession, picked up strongly in 2004 and then turned negative during the last recession. Moody's expects growth to rebound strongly after the current slump and then hold at about 1% after that.

HC

Figure 47: Employment Manufacturing ** Highly Confidential **

[redacted]

Manufacturing employment peaked in the late 1990s and has fallen since. It fell precipitously between 1999 and 2003 and again during the last recession. Moody's expects employment to resume its historical decline after KCP&L bounces back from the economic slump.

Figure 48: Gross Metro Product Non-Manufacturing **Highly Confidential **

[redacted]

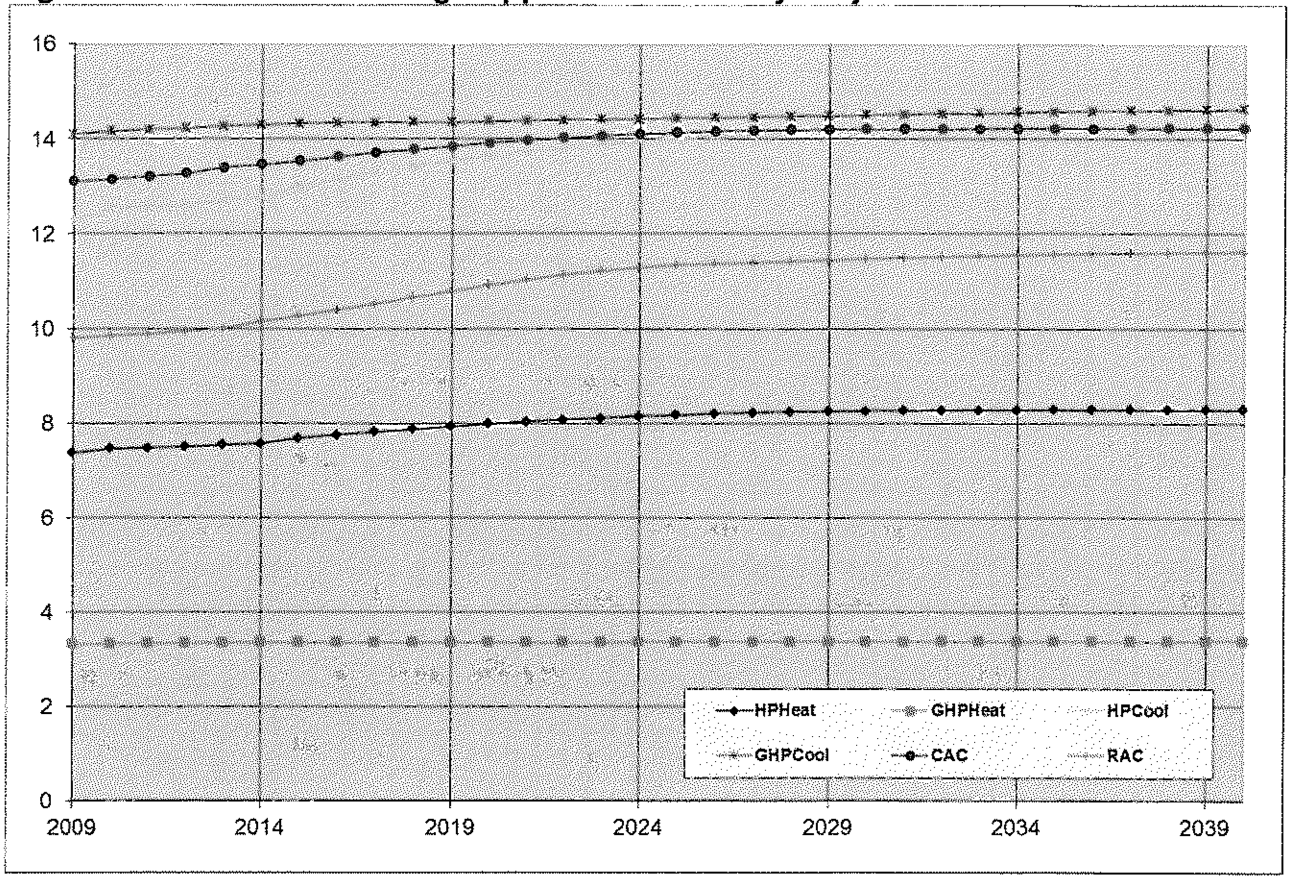
Real non-manufacturing gross metro product grew 3% per year during the 1990s, slowed down a bit after that and then declined during the last recession. GMP is growing faster than employment because of increasing productivity, a trend seen nationally and across many service sectors. Moody's expects above trend growth coming out of the current slump and then trend growth after that.

Figure 49: Gross Metro Product Manufacturing **Highly Confidential **

[redacted]

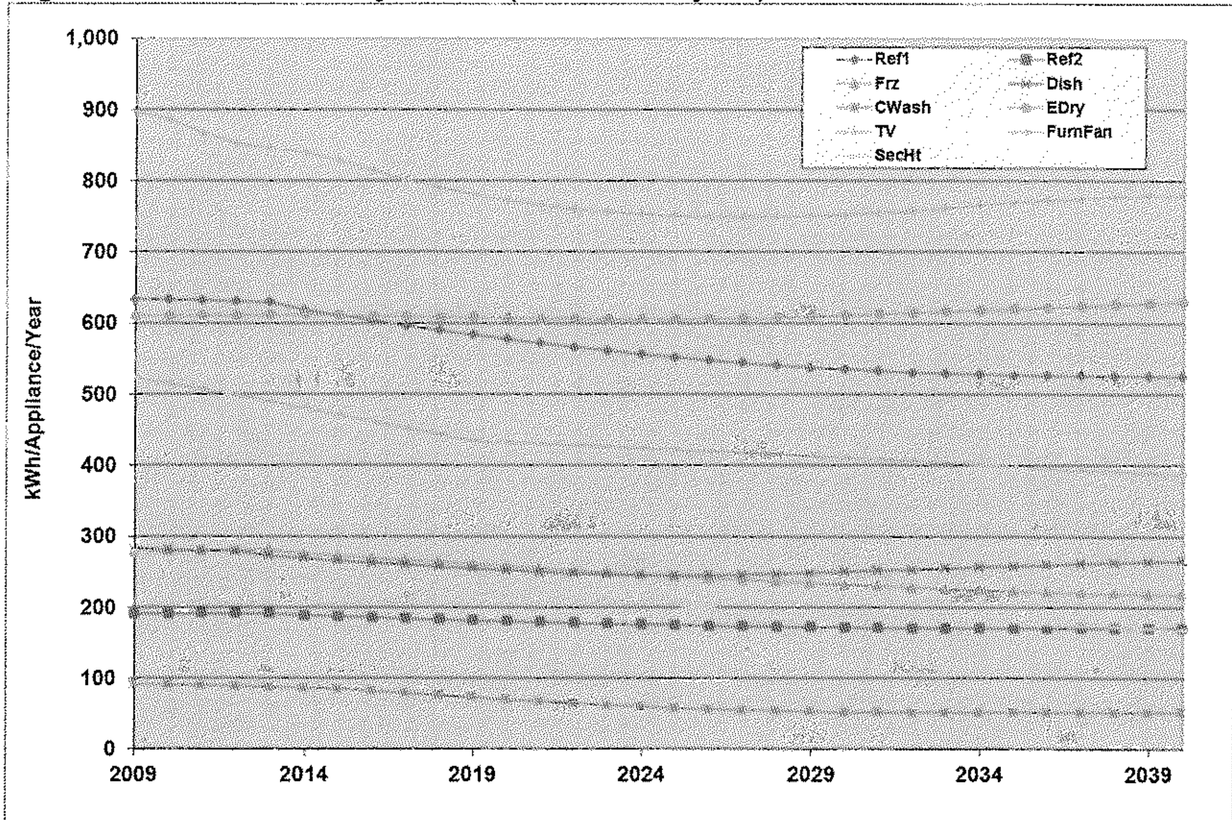
Real gross metro product from the manufacturing sector grew strongly during the 1990s and then fell flat until it plunged during the last recession. Moody's expects rebound growth coming out of the current economic slump and then trend growth after that. GMP for this sector is growing while employment is flat or declining because of increasing productivity, automation of the manufacturing processes and because more labor intensive industries tend to move overseas where there is lower cost labor.

Figure 50: DOE Stock Average Appliance Efficiency Projections



DOE is expecting increases in the stock average appliance efficiencies for residential heating and cooling equipment. This is resulting from appliance standards. In January 2006 a new standard raised the SEER standard by 30 percent for central air conditioners and has continued to increase since that time. This standard impacts the stock average efficiency both from new construction and when units are replaced.

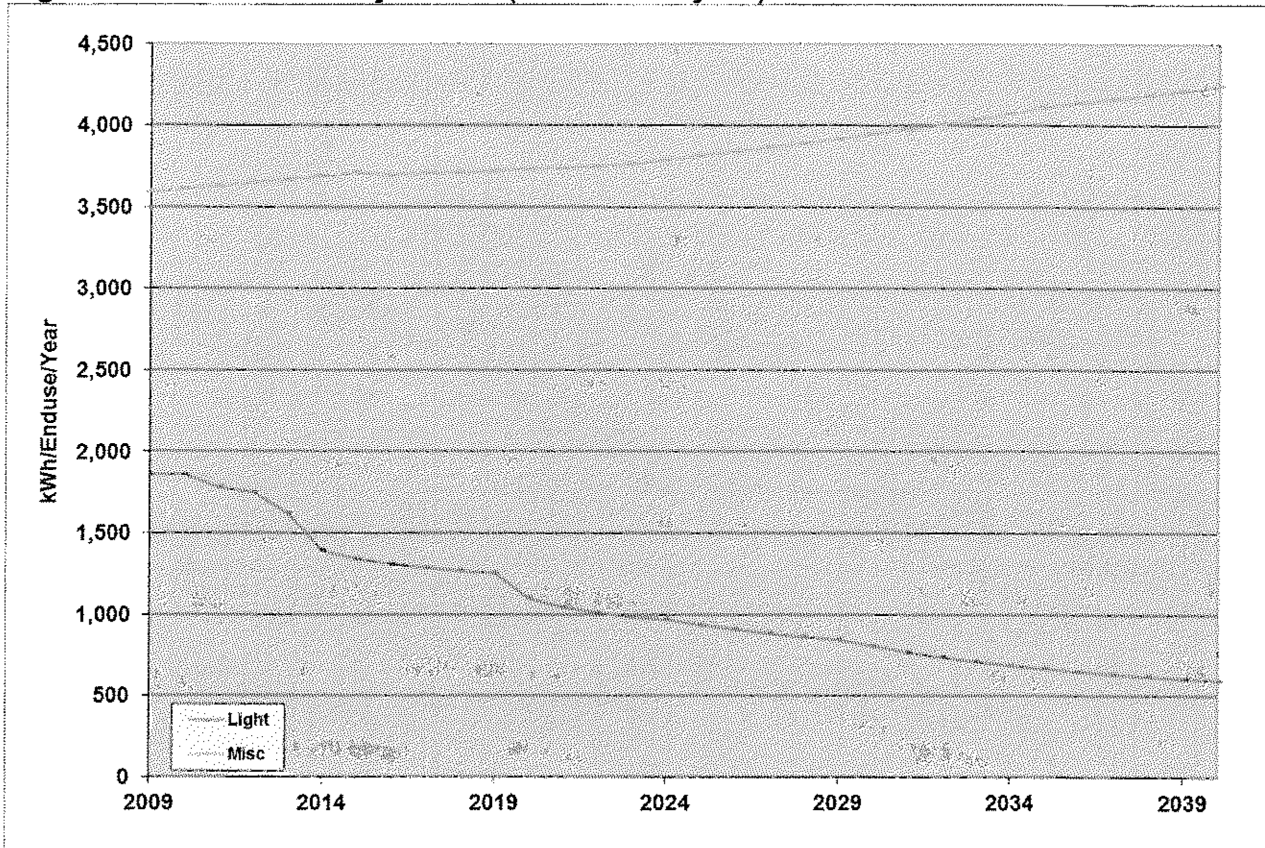
Figure 51: DOE UEC Projections (<1000 kWh/year)



UECs are expected to decline substantially for electric clothes dryers, refrigerators, electric cooking and dishwashers due to appliance efficiency standards.

This year the TV category has been expanded to include all home entertainment equipment such as home audio, video-game consoles, and DVR's. As a result, starting TV intensities are higher causing the intensity now to have a projected decline.

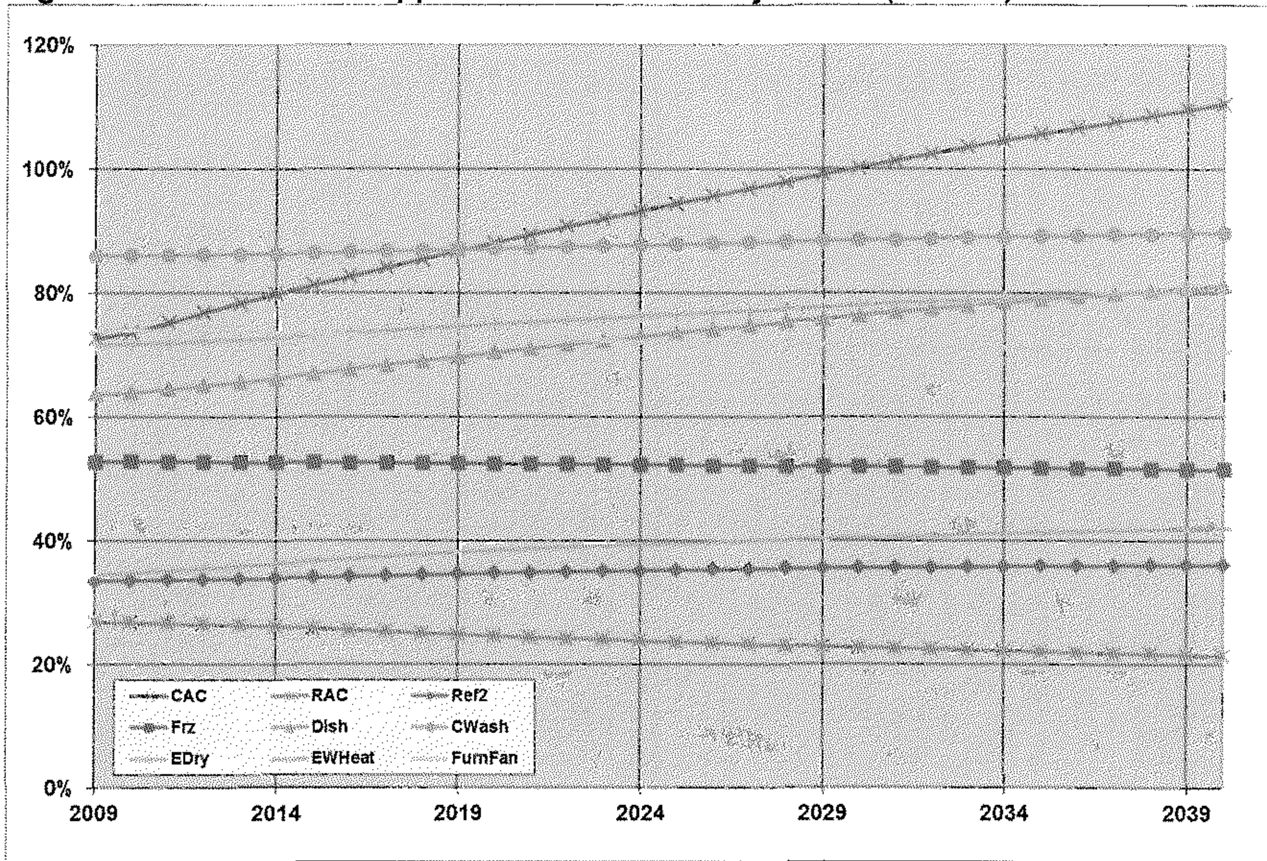
Figure 52: DOE UEC Projections (>1000 kWh/year)



The UEC for lighting is declining because of the increasing sales of CFLs and is expected to decline even more rapidly beginning in 2013 due to a new standard for light bulbs and the increased adoption of LED technology which will gain significant share of the overall lighting technologies going forward.

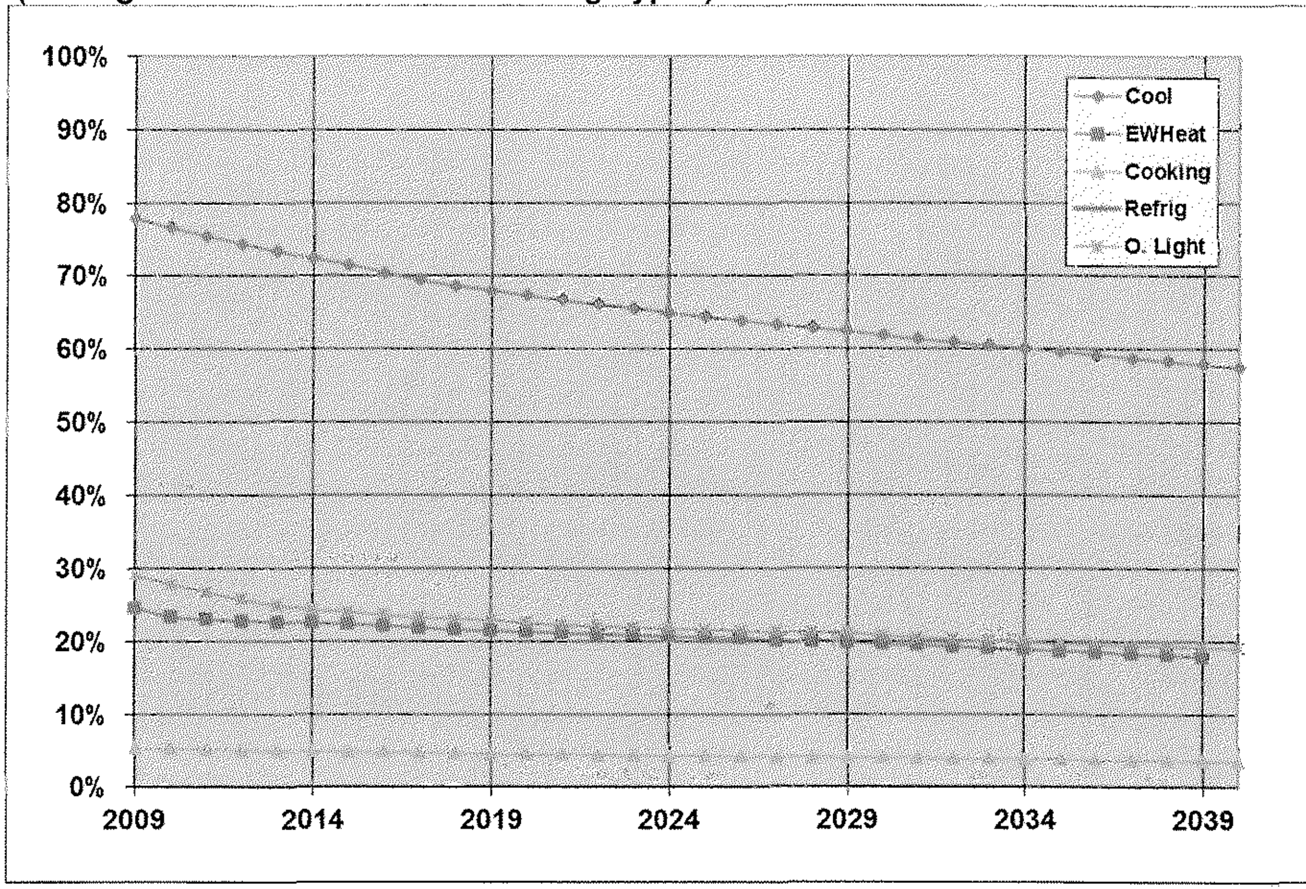
One of the most significant changes is that DOE is now projecting much slower growth in miscellaneous sales. The miscellaneous intensity is expected to average 0.3% over the next ten years compared to the nearly 1.0% in prior forecasts. This is largely the result of calibration into the 2009 RECS.

Figure 53: DOE Electric Appliance Saturation Projections (< 100%)



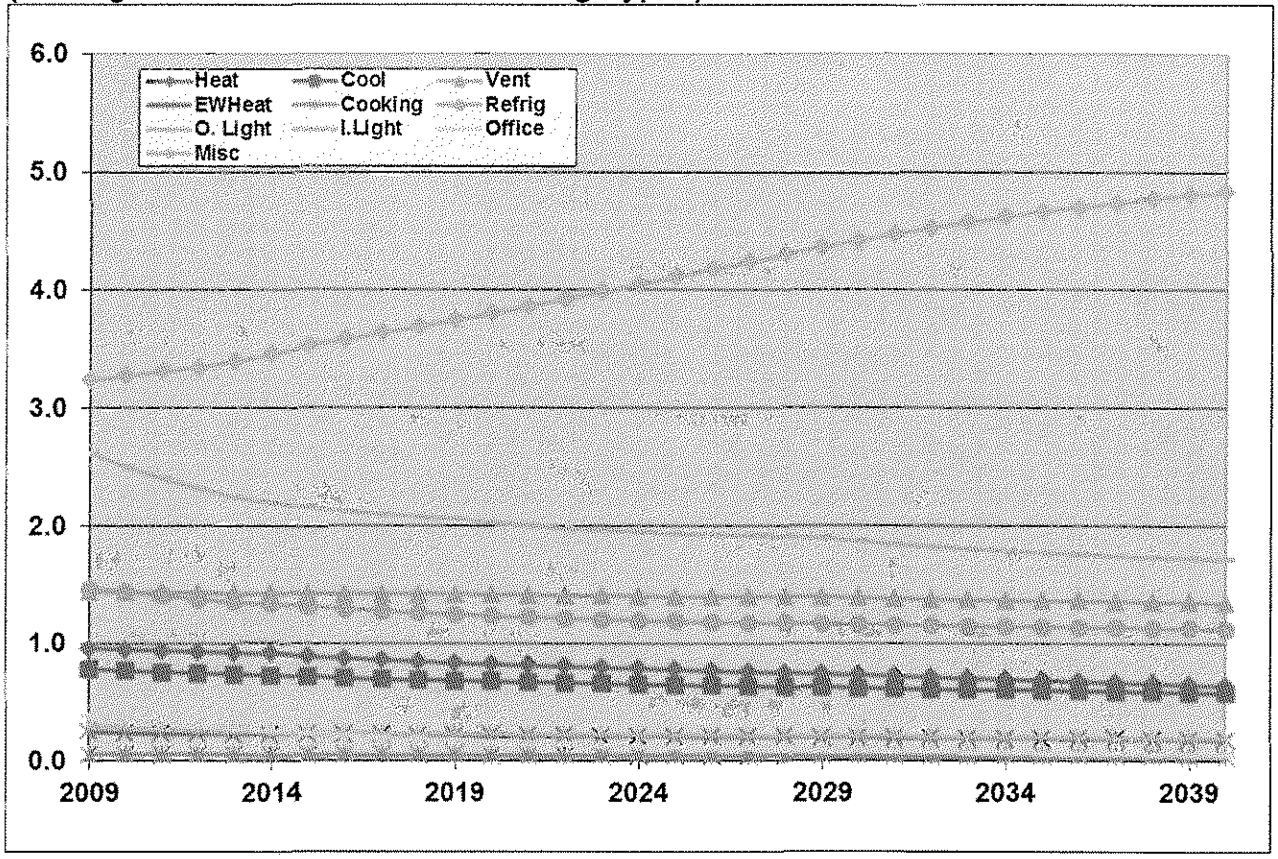
DOE saturation projections shown above are in line with recent historical trends.

Figure 54: DOE Commercial Equipment Saturation Projections (Average over all Commercial Building Types)



DOE commercial sector saturations are mostly in line with trends in recent historical data. The saturation of electric water heating dropped from about 34% in 2004 to 27% in 2014 perhaps because natural gas prices have fallen precipitously. Electric cooking saturations are also falling.

Figure 55 DOE Commercial EUI Projections (Average over all Commercial Building Types)



DOE estimates of the EUI for lighting has been declining since 1995 and started falling more rapidly in 2005, probably because of the use of CFLs, especially for lodging and in recessed fixtures in offices. The refrigeration EUI has been declining historically and started a more rapid decline in 2009, which continues with the projection. New standards for commercial refrigeration equipment went into effect at the beginning of 2010 and updated in 2012.New refrigeration standards will become effective in 2017..[viii] The heating EUI is declining and expected to further decline. A new standard for commercial heating and cooling equipment became effective in April 2007 and November 2004 and updated in 2010.[ix] The EUI for miscellaneous equipment has been rising rapidly and is expected to continue that trend.

7.2.4 SPECIFICATION AND QUANTIFICATION OF FACTORS

4. Where judgment has been applied to modify the results of a statistical or mathematical model, the utility shall specify the factors which caused the modification and shall explain how those factors were quantified.

KCP&L used the forecasts of economic and demographic variables as is from Moody's Analytics.

The projections of appliance saturations from DOE were calibrated to the results of our Residential Appliance Saturation. An additional calibration was made to lighting to account for the KCP&L lighting program that had been in place prior to the implementation of the 2013 federal lighting standard. The adjustment slows the rate of decline.

7.3 NET SYSTEM LOAD FORECAST

(C) Net System Load Forecast. The utility shall produce a forecast of net system load profiles for each year of the planning horizon. The net system load forecast shall be consistent with the utility's forecasts of monthly energy and peak demands at time of summer and winter system peaks for each major class.

KCP&L has produced an hourly forecast for each major class and the sum of these forecasts is the hourly forecast of NSI.

SECTION 8: LOAD FORECAST SENSITIVITY ANALYSIS

(8) Load Forecast Sensitivity Analysis.

The utility shall describe and document its analysis of the sensitivity of the dependent variables of the base-case forecast for each major class to variations in the independent variables identified in subsection 4 CSR 240-22.030(8).

To perform a sensitivity analysis, KCP&L is using a method that was suggested by the Missouri Public Service Commission Staff for KCP&L's IRP. For each customer class, mwh sales were regressed on important driver variables and degree days and the standardized variables are used to show the relative importance of each explanatory variable. KCP&L also show the elasticity for each driver variable as measured by the statistical regression. The sensitivity analysis was first run using the class cost of service groups. Unfortunately, there was not enough data to obtain statically significant results since this data was available only from 2005. The analysis was repeated using revenue classes, residential, commercial and industrial with monthly data available from 2001 to 2014.

Table 38 displays the results for MO residential customers. Among the driving variables, the cooling degree days variable has the largest standardized coefficient, followed by the heating degree days variable. Note that the base temperature for the cooling degree days variable was 65^0 F and the base temperature for the heating degree days variable was 55^0 F. The variable hddPriceRatio variable is heating degree days with a base temperature of 55^0 F times the price of natural gas for MGE's residential customers divided by the price of electricity. The purpose of this variable is to measure the impact of gas and electric prices on electric space heating loads. The variable BDays is the number of billing days averaged over each billing cycle. The regression periods used for these regressions are monthly from January 2001 to July 2014.

Table 38 Missouri Residential

VARIABLE	Standardized Coefficient	t-Statistic	Elasticity
BDays	4,121,350	71.5	0.60
hddPriceRatio	11,552,017	3.4	0.04
resCusCDD65	67,975,438	63.9	0.24
resCusHdd55	35,682,147	11.4	0.14
hddTrend	11,177,932	7.6	-0.03

Table 39 provides the results for Missouri commercial customers. As for residential customers, the two variables with the largest standardized coefficients were heating and cooling degree days. The heating degree day base temperature for the commercial model was the same as the residential model, but the cooling degree day base temperature was 55^0 F. The HDDpriceRatio variable, similar to the same named variable in the residential model, was right behind the heating degree day variable in terms of size of the coefficient. Several economic drivers were tested and the number of households was more significant than non-manufacturing employment or GMP.

Table 39 Missouri Commercial

VARIABLE	Standardized Coefficient	t-Statistic	Elasticity
Total_Households	3,515,752	4.0	0.23
BDays	7,242,942	10.5	0.62
HDDpriceRatio	11,442,528	2.7	0.02
comCusCDD55	40,087,067	29.5	0.11
comCusHdd55	13,463,718	3.4	0.03
HddTrend	8,021,731	4.5	-0.01
Jun02	-1,989,454	-3.0	0.00
Apr03	-1,901,080	-2.9	0.00

The Missouri industrial model results are shown in Table 40. Unlike the commercial and residential models, the largest coefficient is not weather related with model variable prElecCus (which is the industrial electricity price times the industrial customers) closely followed by the industrial electricity prices variable. The cooling degree variable was next in line when it came to largest coefficients. Of the economic variables, the manufacturing employment variable was the most significant. Using industrial customers as a variable was also statistically significant.

Table 40 Missouri Industrial

VARIABLE	Standardized Coefficient	t-Statistic	Elasticity
Emp_Man	4,492,581	3.7	0.51
prElecCus	-11,483,533	-6.8	-0.92
indCus	5,386,241	4.1	0.68
indCusCDD55	9,177,068	14.2	0.07
indPriceElec	11,073,968	7.6	0.67
Aug03	-1,413,506	-3.6	0.00
Aug05	-1,760,902	-4.7	0.00
Nov12	-1,157,553	-3.1	0.00

Table 41 shows the results for residential customers in Kansas. The variables with the largest standardized coefficients are degree days followed by the number of bulling days. The hddPriceRatio variable is the same formula used for the same named variables in the Missouri models.

Table 41 Kansas Residential

VARIABLE	Standardized Coefficient	t-Statistic	Elasticity
BDays	7,754,172	12.8	1.04
resCus	-4,096,171	-5.2	-0.41
hddPriceRatio	6,066,747	1.5	0.02
resCusCDD65	72,460,684	74.8	0.24
resCusHdd55	35,605,488	9.8	0.13
hddTrend	6,096,838	3.3	-0.01

Table 42 shows the results for commercial customers in Kansas. Again the degree day variables represented the variables with the largest coefficients. The other four variables all had coefficient values in the four million range.

Table 42 Kansas Commercial

VARIABLE	Standardized Coefficient	t-Statistic	Elasticity
BDays	4,915,100	10.7	0.59
resCus	4,049,257	5.1	0.37
prElecCus	-4,844,425	-2.8	-0.11
HDDpriceRatio	-4,439,903	-1.8	-0.01
comCusCDD55	31,046,729	27.0	0.12
comCusHdd55	18,375,270	7.1	0.05

Table 43 reports the results of the sensitivity analysis for manufacturing customers in Kansas. The manufacturing employment economic variable had the largest coefficient closely followed by the cooling degree variable. The next largest coefficient was from the prElecCus variable, which had the same formula as the same named variable in the Missouri models.

Table 43 Kansas Industrial

VARIABLE	Standardized Coefficient	t-Statistic	Elasticity
Emp_Man	2,725,600	21.6	1.03
prElecCus	-428,564	-2.7	-0.11
indCusCDD55	2,618,652	16.2	0.08
Sep00	-180,834	-3.0	0.00
Dec00	161,250	2.6	0.00
Feb01	-131,519	-2.2	0.00

8.1 TWO ADDITIONAL NORMAL WEATHER LOAD FORECASTS

(A) The utility shall produce at least two (2) additional normal weather load forecasts (a high-growth case and a low-growth case) that bracket the base-case load forecast. Subjective probabilities shall be assigned to each of the load forecast cases. These forecasts and associated subjective probabilities shall be used as inputs to the risk analysis required by 4 CSR 240-22.060.

KCP&L used two additional economic forecasts from Moody's Analytics to produce high-growth and low-growth load forecast scenarios. These additional scenarios represent economic growth one standard deviation above and below the base case forecast.

In addition to these two scenarios, KCP&L produced an additional scenario representing significant loss of customer.

KCP&L constructed this scenario by subtracting the energy and peak demand from the largest customer in both Kansas and Missouri from the results for the base case scenario. The most recent 12 billing records from each customer were used and the energy and peak from each month was used for that particular month in the forecast. Losses were added to the energy and peak demands.

The corresponding figures below show the base-case, low-case, high-case, and significant loss forecasts for energy and demand. The impact of the last recession and the economic malaise since then are evident in the plot for energy. Growth in the forecast is lower than it was prior to the last recession and this is primarily because U.S. growth prior to the recession was fueled by circumstances that will not be repeated in the forecast horizon such as extremely lax lending standards.

Figure 56: Base, Low, High and Significant Loss Net System Input Forecast ** Highly Confidential **

[redacted]

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Figure 57: Base, Low, High and Significant Loss Peak Demand Forecast ** Highly Confidential **

[redacted]

(B) The utility shall estimate the sensitivity of system peak load forecasts to extreme weather conditions. This information shall be considered by utility decision-makers to assess the ability of alternative resource plans to serve load under extreme weather conditions when selecting the preferred resource plan pursuant to 4 CSR 240-22.070(1).

KCP&L created a forecast scenario using the base case economic scenario and weather from the years with more than 1,700 cooling degree days at KCI. These years were 1980, 1988, 2006 and 2012. The number of cooling degree days those years were 1,746, 1,724, 1,724 and 1,839. The scenario was created by running our computer programs with normal weather computed with those four years instead of with 30 years. In 2014, the peak rose from 3,558 mW to 3,657 mW. In 2020, the peak increased from 3,637 to 3,920 under this scenario. The complete set of results is in a file, *KCPL NSI_Peak*

Monthly_Annual.xls. This file contains monthly NSI and peak load for all forecast scenarios.

The corresponding figures below show the base-case, low-case, high-case, and extreme weather forecasts for energy and demand.

Figure 58: Base, Low, High, and Extreme Weather Energy Forecast ** Highly Confidential **

[redacted]

Figure 59: Base, Low, High, and Extreme Weather Peak Demand Forecast ** Highly Confidential **

[redacted]

(C) The utility shall provide plots of energy usage and peak demand covering the historical database period and the forecast period of at least twenty (20) years.

1. The energy plots shall include the summer, non-summer, and total energy usage for each calendar year. The peak demand plots shall include the summer and winter peak demands.

The figures below represent actual and weather normalized Net System Input (Energy) for summer, non-summer, and total year for the base case forecast. Corresponding tables can be found in *Appendix 3D* and in the file *IRP_8C_KCPL_NSI_Peak.xls*. Weather normalization significantly smooths out the energy plots. Growth in the forecasts is substantially slower than during the period prior to the last recession.

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Figure 60: Base Case Actual and Weather Normalized Summer Energy Plots ** Highly Confidential **

[redacted]

Figure 61: Base Case Actual and Weather Normalized Non-Summer Energy Plots Highly Confidential **

[redacted]

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Figure 62: Base Case Actual and Weather Normalized Total Energy Plots ** Highly Confidential **

[redacted]

The figures below represent actual and weather normalized peak demand for summer and non-summer for the base case forecast. Annual peak demand plots are not shown, since they are the same as summer demand plots. Corresponding tables can be found in *Appendix 3D* and the file *IRP_8C_KCPL_NSI_Peak.xls.*

Figure 63: Base Case Actual and Weather Normalized Summer Peak Demand Plots **Highly Confidential **

[redacted]

Figure 64: Base Case Actual and Weather Normalized Winter Peak Demand Plots ** Highly Confidential **

[redacted]

2. The historical period shall include both actual and weather-normalized values. The forecast period shall include the base-case, low-case, and high-case forecasts.

The figures below represent Net System Input (energy) for summer, non-summer, and the whole year for the base, low and high scenario forecasts. Corresponding tables can be found in *Appendix 3D* and the file *IRP_8C_KCPL_NSI_Peak.xls*.

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Figure 65: Base-Case, Low-Case, and High-Case Summer Energy Plots ** Highly Confidential **

[redacted]

Figure 66: Base-Case, Low-Case, and High-Case Non-Summer Energy Plots ** Highly Confidential **

[redacted]

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Figure 67: Base-Case, Low-Case, and High-Case Total Energy Plots ** Highly Confidential **

[redacted]

The figures below represent peak demand for summer and non-summer for the base, low, and high scenario forecasts. Annual peak demand plots are not shown, since they are the same as summer demand plots. Corresponding tables can be found in *Appendix 3D* and in the file *IRP_8C_KCPL_NSI_Peak.xls.*

Figure 68: Base-Case, Low-Case, and High-Case Summer Peak Demand Plots ** Highly Confidential

[redacted]

Figure 69: Base-Case, Low-Case, and High-Case Winter Peak Demand Plots ** Highly Confidential

[redacted]

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[i] http://www1.eere.energy.gov/buildings/appliance_standards/residential/residential_cac_hp.html
[ii] Multi-Year Program Plan, Building Regulatory Programs, U.S. Department of Energy Energy Efficiency and Renewable Energy Building Technologies Program October 2010.
[iii] http://www.eia.gov/analysis/model-documentation.cfm
[iv] Email from Benjamin Kanigel dated 7/6/2010.
[v] Email to Al Bass from Benjamin Kanigel dated 9/23/2010.
[vi] Email from Christopher Velarides dated 8/20/2014.
[vii] See regulatory_programs_mypp.pdf .
[viii] www1.eere.energy.gov/buildings/appliance_standards/commercial/refrig_equip_final_rule.html and www1.eere.energy.gov/buildings/appliance_standards/commercial/automatic_ice_making_equipment.html
[ix] www1.eere.energy.gov/buildings/appliance_standards/commercial/ashrae_products_docs_meeting.html

VOLUME 4:

SUPPLY-SIDE RESOURCE ANALYSIS

KANSAS CITY POWER & LIGHT COMPANY (KCP&L)

INTEGRATED RESOURCE PLAN

4 CSR 240-22.040

APRIL, 2015

KCP&L
energizing *life*

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HIGHLIGHTS

- Over twenty generating technologies in various stages of development maturity have been analyzed and screened as potential future supply-side resources
- Candidate generation resources that passed screening included combustion turbines (CT), combined-cycle (CC), coal, nuclear , wind, and solar options and were made available as new generation resources in Integrated Analyses
- Existing power plant efficiency improvements have been an ongoing initiative at KCP&L generating units
- Future power plant efficiency projects have been identified and expected to be completed in upcoming years
- Existing generation resources have been studied to determine future environmental retrofit requirements and expected maintenance needs

PURPOSE: This rule establishes minimum standards for the scope and level of detail required in supply-side resource analysis.

SECTION 1: SUPPLY-SIDE RESOURCE

(1) The utility shall evaluate all existing supply-side resources and identify a variety of potential supply-side resource options which the utility can reasonably expect to use, develop, implement, or acquire, and, for purposes of integrated resource planning, all such supply-side resources shall be considered as potential supply-side resource options. These potential supply-side resource options include full or partial ownership of new plants using existing generation technologies; full or partial ownership

of new plants using new generation technologies, including technologies expected to become commercially available within the twenty (20)-year planning horizon; renewable energy resources on the utility-side of the meter, including a wide variety of renewable generation technologies; technologies for distributed generation; life extension and refurbishment at existing generating plants; enhancement of the emission controls at existing or new generating plants; purchased power from bi-lateral transactions and from organized capacity and energy markets; generating plant efficiency improvements which reduce the utility's own use of energy; and upgrading of the transmission and distribution systems to reduce power and energy losses. The utility shall collect generic cost and performance information sufficient to fairly analyze and compare each of these potential supply-side resource options, including at least those attributes needed to assess capital cost, fixed and variable operation and maintenance costs, probable environmental costs, and operating characteristics.

1.1 NEW PLANT RESOURCE OPTIONS

1.1.1 TECHNOLOGY CATEGORIES

The evaluation of potential supply-side resource options began with the identification of twenty-three existing or new technology alternatives. The information for these potential supply-side technologies was gathered from multiple sources including the Electric Power Research Institute (EPRI), the Department of Energy (DOE), responses to recent Request for Proposals (RFP), and other internal resources. The supply-side technologies were broken down into the following categories:

- Base load technologies
- Intermediate load technologies
- Peaking load technologies

- Renewable technologies

1.1.2 TECHNOLOGY DEVELOPMENT STATUS

For each technology, the development status was also considered and identified as either mature, commercial, demonstration, pilot, or developmental. Following is a brief description of these different technology stages:

- Mature technologies are proven and well established in the electric power generation industry.
- Commercial technologies are in operation, but efforts to optimize the heat rate and reduce the O&M costs are still on-going.
- Demonstration technologies have designs that are quite advanced, but very few plants exist with actual operating experience.
- Developmental technologies are still emerging.

These technologies and their current development status are shown below in Table 1 and Table 2.

Table 1: Generating Technology Categories

BASE LOAD		
Pulverized Coal	**Integrated Gasification Combined Cycle**	**Nuclear**
SCPC SCPC w CCS	IGCC IGCC w CCS	Large Scale - AP1000 Small Modular Reactors (SMR)
INTERMEDIATE LOAD		
Combined Cycle	**Fuel Cell**	**Energy Storage**
2x1 CC CC w CCS	Solid Oxide	Compressed Air Energy Storage Pumped Hydro Sodium Sulfur Battery
PEAKING LOAD		
Combustion Turbines and Small Scale Alternatives		
GE 7FA.05 GE LMS100 GE LM6000 Reciprocating Engines - Wartsila		
RENEWABLES		
Solar	**Wind, Biomass**	**Waste to Energy**
Photovoltaic (PV) - Fixed Axis PV - Tracking Thermal - Trough Thermal - Dish	Wind Biomass BFB Boiler	Landfill Gas

Table 2: Technology Development Status

Technology Type	Description	Maturity
Combined Cycle	2x1 Combined Cycle Combined Cycle w/CCS	Mature Demonstration
Combustion Turbine	GE 7FA GE LMS100 GE LM6000	Mature Commercial Mature
Energy Storage	Compressed Air Energy Storage Pumped Hydro Sodium Sulfur Battery	Commercial Mature Demonstration
Fuel Cells	Fuel Cell - Solid Oxide	Developmental
Integrated Gasification Comb Cycle	IGCC IGCC w/CCS	Demonstration Demonstration
Nuclear	Large Scale - AP1000 Small Modular Reactors (SMR)	Mature Developmental
Pulverized Coal	SCPC SCPC w/CCS	Mature Demonstration
Small Scale Alternatives	Reciprocating Engines - Wartsila	Mature
Solar	Solar PV - Fixed Axis Solar PV - Tracking Solar Thermal - Trough Solar Thermal - Dish	Commercial Commercial Commercial Commercial
Wind, Biomass, Waste-to-Energy	Wind Biomass BFB Boiler Landfill Gas	Commercial Commercial Mature

1.2 LIFE EXTENSION & EMISSION CONTROL ENHANCEMENT OPTIONS

In addition to the potential new supply-side resource options identified above, KCP&L evaluated the life extension and refurbishment of existing generating plants, along with the enhancement of the existing emission controls. To evaluate the life extension, an internal review of the long-term plant equipment needs was developed by using the Life Assessment and Management Program (LAMP).

To evaluate the cost and operating characteristics due to potential future environmental equipment, the services of Burns and McDonnell, Inc. were retained to evaluate several of the KCP&L coal-fired units including Montrose Units 2 and 3, Iatan-1, LaCygne Units 1 and 2, and Hawthorn-5. Further discussion of the LAMP process and the environmental retrofit costs can be found in Section 4.1.2.

1.3 PLANT EFFICIENCY IMPROVEMENTS

In order to minimize the negative impact to plant efficiency from KCP&L's projects to improve air quality emissions from our major coal units, KCP&L has proactively engaged on a dual pronged effort to improve the boiler and turbine side efficiency and reduce our own use of energy at our plants. The first half of this effort is to improve performance monitoring and daily attention to operational issues that may be negatively impacting plant efficiency. Below are details on these efforts:

- Issued fleet request for proposal and chose the industry leading EtaPRO© performance monitoring software from GP Strategies in 2009. Software has been implemented on the following units:
    - Hawthorn Unit 5, 6&9
    - Iatan Units 1 & 2
    - LaCygne Units 1 & 2
    - Montrose Units 1, 2, and 3

- Engineering positions dedicated to Plant Efficiency were staffed as follows:
    - Hawthorn Performance Engineer
    - Iatan Performance Engineer
    - LaCygne Performance Engineer
    - LaCygne Combustion Engineer
    - Montrose Performance Engineer

- Beginning in 2013, KCP&L initiated a remote monitoring contract with GP Strategies. GP Strategies monitors each unit for performance issues and recommends operational improvements on monthly conference calls.

In addition to the daily efforts detailed above, KCP&L has performed considerable capital improvement projects to maintain or improve plant efficiency. These projects are detailed in Table 3 below:

Table 3: Power Plant Efficiency Projects

Project Description	Unit	Completed	Performance Impact
Iatan Station			
IPT/LPT spill strips replaced	Iatan 1	2007	Significant
IPT blades and diaphragm replaced	Iatan 1	2007	Nominal
Replace ash sluice system with a submerged flight conveyor	Iatan 1	2007	Nominal
Addition of Boiler Economizer surface area	Iatan 1	2008	Moderate
Replace High Pressure Turbine with GE dense pack	Iatan 1	2008	Moderate
Replace air heater baskets	Iatan 1	2010	Moderate
Replace FD fan motor & rotor	Iatan 1	2010	Nominal
Perf Monitoring / Optimization software	Iatan 1	2010	Moderate
BFP runner replacement	Iatan 1	2011	Moderate
Hawthorn Station			
Add four sootblowers at lower slope of convection pass	Hawthorn 5	2008	Nominal
LPT seal upgrade	Hawthorn 5	2008	Nominal
Replace air heater baskets	Hawthorn 5	2009	Moderate
Install new condensate pump motor	Hawthorn 5	2009	Nominal
Perf Monitoring / Optimization software	Hawthorn 5	2009	Moderate
HP/IP turbine seals	Hawthorn 5	2010	Moderate
Closed Loop Combustion Optimization software	Hawthorn 5	2013	Significant
LaCygne Station			
Replace BFP runner and recirc valves	LaCygne 1	2009	Moderate
Perf Monitoring / Optimization software	LaCygne 1	2010	Moderate
Replace 3A & 3B HP heaters	LaCygne 1	2010	Nominal
Replace #6 LP heater	LaCygne 1	2012	Nominal
Cycle Isolation Audit & Valve Repair/Replacement on 2 Units	L 1 & 2	2012	Moderate
Closed Loop Combustion Optimization software	LaCygne 1	2013	Moderate
Condenser air in-leakage monitoring	LaCygne 1	2013	Nominal
Perf Monitoring / Optimization software	LaCygne 2	2010	Moderate
Replace BFP runner and recirc valves	LaCygne 2	2010	Moderate
Closed Loop Combustion Optimization software	LaCygne 2	2012	Moderate
Condenser air in-leakage monitoring	LaCygne 2	2013	Nominal
Montrose Station			
Feedwater heater replacement (13th Stage)	Montrose 1	2007	Nominal
Feedwater heater replacement (6th Stage)	Montrose 1	2007	Nominal
Install additional water lances	Montrose 1	2008	Nominal
Replace BFP motors	Montrose 1	2008	Nominal
Condenser re-tube	Montrose 1	2008	Nominal
Cycle Isolation Audit & Valve Repair/Replacement on 3 Units	M 1,2,&3	2012	Moderate
Perf Monitoring / Optimization software on 3 Units	M 1,2,&3	2012	Moderate
Install additional water lances	Montrose 2	2009	Nominal
Replace BFP motors	Montrose 2	2009	Nominal
Condenser re-tube	Montrose 2	2009	Nominal
Air heater basket replacement	Montrose 3	2007	Nominal
Condenser re-tube	Montrose 3	2007	Nominal
Estimated Performance Impact: Nominal - Less than 0.1% efficiency improvement; Moderate - 0.1 - 0.5% improvement; Significant - Greater than 0.5% improvement			

KCP&L's performance efforts have resulted in the following recognition:

- **2013 Power Plant Operational Excellence & Stewardship Award Presented to KCP&L from GP Strategies**
    - KCP&L's Iatan Plant achieved the #1 PRB (Sub-bituminous coal) heat rate ranking in the US according to the US Energy Information Association's 2012 EOY Heat Rate Benchmarking Report.* Iatan was the most efficient plant in the US for converting PRB coal into electricity in 2012. In addition, GP Strategies believes that Iatan-2 was the most efficient coal-fired unit in the U.S.
- **2011 Power Plant Operational Excellence Award Presented to KCP&L from General Physics.**
    - General Physics proudly recognizes the success of KCP&L's Hawthorn Generating Station for achieving a 3% heat rate improvement on Unit 5 which directly resulted in reducing 150,000 tons of CO_2 emissions in 2010.

KCP&L's next phase of performance improvement is primarily focused on operationalizing advanced Combustion and Sootblowing optimization on the major coal units. Combustion Optimization efforts are currently in progress at Iatan-1, Hawthorn-5, and LaCygne Units 1 & 2. Sootblowing Optimization efforts are currently in progress at Iatan-1 and LaCygne-1. In addition, the following capital projects have been budgeted as shown in Table 4 below:

Table 4: Future Performance Improvement Projects

Project Description	Unit	Budget Year	Performance Impact
Iatan Station			
Replace Air Heater Cold End Baskets	Iatan 1	2015	Nominal
Traveling Screen Upgrade	Iatan 1	2015	Moderate
Hawthorn Station			
Automated Burner and Overfire Air Dampers	Hawthorn 5	2015	Nominal
Air Heater Basket Replacement	Hawthorn 5	2016	Nominal
Condenser Retube	Hawthorn 5	2016	Nominal
HP/IP Turbine Overhaul	Hawthorn 5	2016	Moderate
LP Turbine Overhaul	Hawthorn 5	2019	Moderate
LaCygne Station			
Startup System Valve Replacement	LaCygne 1	2015	Moderate
Replace Feedwater Heater 4	LaCygne 1	2016	Nominal
Replace Feedwater Heater 26	LaCygne 2	2016	Nominal
Estimated Performance Impact: Nominal - Less than 0.1% efficiency improvement; Moderate - 0.1 - 0.5% improvement; Significant - Greater than 0.5% improvement			

1.4 EXCLUDED TECHNOLOGIES

During the process of identifying potential supply-side alternatives, there were also certain resource alternatives excluded from the pre-screening exercise on the basis of not being viable candidate resource options. The reasons these resource alternatives could not be reasonably developed or implemented by KCP&L include lack of technology maturity, lack of suitability for this geographic region, and environmental concerns. The resources that were not considered in the pre-screening exercise and the reason for their exclusion is listed in Table 5 below:

Table 5: Technologies Excluded From Pre-Screening

Technology Type	Reason For Exclusion
Central-Station Geothermal	Central US lacks adequate geological resources
Municipal Solid Waste	Developmental phase, environmental concerns concerning delivery of waste
Hydrokinetic (Run-of-River)	Experimental/unproven technology and wildlife concerns
Animal Waste	Delivery issues and high moisture content is problematic

Progress in the 'experimental' hydrokinetic (run of river) and technologies will be tracked going forward, and they will be considered as potential future supply-side technology options if they advance beyond the experimental stage. The hydrokinetic technology is designed to channel and convert current from the river into electricity by the rotation of a turbine from the river flow. Potential issues beyond the economic feasibility include rivers being full of debris and sediment, turbine depths of at least nine feet to avoid collisions with boats, and environmental concerns as it pertains to wildlife that have to be addressed.

Municipal Solid Waste (MSW) technologies were also excluded from the prescreening process for several reasons. Some of the MSW technologies, in particular gasification and plasma arc, are in the developmental stage with limited data to support the capital cost estimates. While MSW incineration is a proven commercially available option, there are significant environmental concerns including air pollution control. Given that, it is doubtful a new MSW incineration plant could be sited or permitted. The potential of limited regional supplies of MSW, along with potential issues on delivery of sufficient supplies to fuel the technologies, are also limiting factors for these technologies. Finally, much of the revenue stream for MSW technologies comes in the form of 'tipping fee' revenues, which is a payment made for diverting the waste from the landfills. This revenue stream is another large unknown that makes it difficult to project the total cost of MSW technologies.

Animal Waste technologies, including anaerobic digestion, direct combustion, co-firing, and gasification, were excluded from the prescreening process. These technologies are viewed as an alternative, renewable fuel for electricity generation, but they have several key barriers. Some of the primary problems inherent with using animal waste as fuel include limited regional availability, prohibitive transportation costs, high moisture content which requires pre-drying of animal waste, and unmanageable ash disposition and slagging that can cause frequent boiler shutdowns. In light of these issues, these technologies were not included in the prescreening process.

SECTION 2: SUPPLY-SIDE ANALYSIS

The utility shall describe and document its analysis of each potential supply-side resource option referred to in section (1). The utility may conduct a preliminary screening analysis to determine a short list of preliminary supply-side candidate resource options, or it may consider all of the potential supply-side resource options to be preliminary supply-side candidate resource options pursuant to subsection (2)(C). All costs shall be expressed in nominal dollars.

2.1 SUPPLY-SIDE RESOURCE COST RANKINGS

(A) Cost rankings of each potential supply-side resource option shall be based on estimates of the installed capital costs plus fixed and variable operation and maintenance costs levelized over the useful life of the potential supply-side resource option using the utility discount rate. The utility shall include the costs of ancillary and/or back-up sources of supply required to achieve necessary reliability levels in connection with intermittent and/or uncontrollable sources of generation (i.e., wind and solar).

Each of the technologies identified in Table 1 above were initially ranked based on their relative annualized utility cost, which was then broken down into an average cost per MWh. In calculating the average cost per MWh, the following characteristics were considered:

- The unit size and capacity factor, which varied depending on the technology's generating unit duty cycle (base load, intermediate, or peaking). Renewable technologies were considered as a separate group due to the requirement that some renewable alternatives would have to be passed on to the integrated resource analysis, irrespective of the cost ranking, in order to meet the MO Renewable Energy Standard (RES). The unit sizes and capacity factors varied widely across all technologies, and the net capacity and capacity factors for each alternative are shown below in Table 6 and Table 7.

- The total capital requirement for building the unit, including the plant capital costs, transmission capital costs, owner costs, and interest during construction. A levelized fixed charge rate (FCR) was applied to these capital requirements to arrive at an annual carrying cost for each technology. The levelized FCR calculation considers the book life, tax life, debt and equity rates to arrive at the annual rate, which is then applied to the total capital requirement. The technology capital costs, including interest during construction, are shown below for each alternative in Table 8.

- The fixed O&M and variable O&M costs. The fixed O&M costs include operating labor, total maintenance costs, and overhead charges. The variable O&M costs include any materials that are consumed in proportion to the energy output, and the calculation of annual variable O&M cost is dependent upon the capacity factor assumption mentioned above. The fixed O&M and variable O&M cost assumptions for each technology are shown below in Table 9 and Table 10.

- The fuel costs based on a projected long-term average cost per MWh, along with the technology heat rate (where applicable). Further discussion of fuel cost projections is provided below in Section 5.1. The primary fuel types for each technology are shown below in Table 11.

- The probable environmental costs, including forecasted allowance prices for SO_2, NO_x, and CO_2, applied using the appropriate emission rates for each technology. The projected emission rates for each technology are shown below in Table 12. Further discussion on the development of the probable environmental costs is provided below in Section 2.2.

Table 6: Technology Net Capacities

Technology Type	Description	Net Capacity (MW)
Combined Cycle	2x1 Combined Cycle	621
	Combined Cycle w CCS	485
Combustion Turbine	GE 7FA	207
	GE LMS100	92
	GE LM6000 (2x)	88
Energy Storage	Compressed Air Energy Storage	441
	Pumped Hydro	280
	Sodium Sulfur Battery	50
Fuel Cells	Fuel Cell - Solid Oxide	1
Integrated Gasification Comb Cycle	IGCC	600
	IGCC w CCS	500
Nuclear	Large Scale - AP1000	1400
	Small Modular Reactors (SMR) (4x)	1340
Pulverized Coal	SCPC	750
	SCPC w CCS	525
Small Scale Alternatives	Reciprocating Engines - Wartsila	99
Solar	Solar PV - Fixed Axis	20
	Solar PV - Tracking	10
	Solar Thermal - Trough	250
	Solar Thermal - Dish	100
Wind, Biomass, Waste-to-Energy	Wind	145
	Biomass BFB Boiler	100
	Landfill Gas	3

Table 7: Technology Capacity Factors

Technology Type	Description	Capacity Factor
Combined Cycle	2x1 Combined Cycle	60%
	Combined Cycle w/CCS	60%
Combustion Turbine	GE 7FA	10%
	GE LMS100	10%
	GE LM6000	10%
Energy Storage	Compressed Air Energy Storage	23%
	Pumped Hydro	27%
	Sodium Sulfur Battery	19%
Fuel Cells	Fuel Cell - Solid Oxide	30%
Integrated Gasification Comb Cycle	IGCC	85%
	IGCC w/CCS	85%
Nuclear	Large Scale	90%
	Small Modular Reactors (SMR)	90%
Pulverized Coal	SCPC	85%
	SCPC w/CCS	85%
Small Scale Alternatives	Reciprocating Engines - Wartsila	10%
Solar	Solar PV - Fixed Axis	17%
	Solar PV - Tracking	20%
	Solar Thermal - Trough	25%
	Solar Thermal - Dish	24%
Wind, Biomass, Waste-to-Energy	Wind	54%
	Biomass BFB Boiler	85%
	Landfill Gas	88%

Table 8: Technology Capital Costs ($/kW) **Highly Confidential**

[redacted]

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Table 9: Technology Fixed O&M Costs **Highly Confidential**

[redacted]

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Table 10: Technology Variable O&M Costs **Highly Confidential**

[redacted]

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Table 11: Technology Primary Fuels

Technology Type	Description	Primary Fuels
Combined Cycle	2x1 Combined Cycle	Natural Gas
	Combined Cycle w/CCS	Natural Gas
Combustion Turbine	GE 7FA	Natural Gas
	GE LMS100	Natural Gas
	GE LM6000	Natural Gas
Energy Storage	Compressed Air Energy Storage	Natural Gas
	Pumped Hydro	Hydro
	Sodium Sulfur Battery	None
Fuel Cells	Fuel Cell - Solid Oxide	Natural Gas
Integrated Gasification Comb Cycle	IGCC	Coal
	IGCC w/CCS	Coal
Nuclear	Large Scale - AP1000	Uranium
	Small Modular Reactors (SMR)	Uranium
Pulverized Coal	SCPC	Coal
	SCPC w/CCS	Coal
Small Scale Alternatives	Reciprocating Engines - Wartsila	Natural Gas
Solar	Solar PV - Fixed Axis	Solar
	Solar PV - Tracking	Solar
	Solar Thermal - Trough	Solar
	Solar Thermal - Dish	Solar
Wind, Biomass, Waste-to-Energy	Wind	Wind
	Biomass BFB Boiler	Biomass - Wood
	Landfill Gas	Landfill Gas

Table 12: Technology Emission Rates

Technology Description	NOx (lbs/mmBtu)	SO2 (lbs/mmBtu)	Hg (lbs/TBtu)	CO2 (lbs/mmBtu)	PM10 (lbs/mmBtu)
2x1 Combined Cycle	0.01	-	-	119	0.01
Combined Cycle w/CCS	0.01	-	-	12	0.01
GE 7FA	0.01	-	-	119	0.01
GE LMS100	0.10	0.01	-	113	0.01
GE LM6000	0.03	0.01	-	114	0.01
Compressed Air Energy Storage	0.01	-	-	117	-
Pumped Hydro	-	-	-	-	-
Sodium Sulfur Battery	-	-	-	-	-
Fuel Cell - Solid Oxide	-	-	-	115	-
IGCC	0.01	0.03	1.20	206	0.02
IGCC w/CCS	0.01	0.02	1.20	21	0.02
Large Scale - AP1000	-	-	-	-	-
Small Modular Reactors (SMR)	-	-	-	-	-
SCPC	0.06	0.10	1.20	206	0.02
SCPC w/CCS	0.05	0.06	1.20	21	0.02
Reciprocating Engines - Wartsila	0.02	-	-	122	0.03
Solar PV - Fixed Axis	-	-	-	-	-
Solar PV - Tracking	-	-	-	-	-
Solar Thermal - Trough	-	-	-	-	-
Solar Thermal - Dish	-	-	-	-	-
Wind	-	-	-	-	-
Biomass BFB Boiler	0.10	0.01	-	-	0.02
Landfill Gas	0.20	0.10	-	-	-

2.2 SUPPLY-SIDE RESOURCE PROBABLE ENVIRONMENTAL COSTS

(B) The probable environmental costs of each potential supply-side resource option shall be quantified by estimating the cost to the utility to comply with additional environmental legal mandates that may be imposed at some point within the planning horizon. The utility shall identify a list of environmental pollutants for which, in the judgment of the utility decision-makers, legal mandates may be imposed during the planning horizon which would result in compliance costs that could significantly impact utility rates. The utility shall specify a subjective probability that represents utility decision-maker's judgment of the likelihood that legal mandates requiring additional levels of mitigation will be imposed at some point

within the planning horizon. The utility, based on these probabilities, shall calculate an expected mitigation cost for each identified pollutant.

Environmental laws or regulations that may be imposed at some point within the planning horizon may impact air emissions, water discharges, or waste material disposal. Following is a brief discussion of each of these pollutants that could result in compliance costs that may have a significant impact on utility rates. For a more detailed discussion of these potential environmental laws and regulations, refer to Appendix 4A.

2.2.1 AIR EMISSION IMPACTS

2.2.1.1 National Ambient Air Quality Standards

The Clean Air Act (CAA) requires the Environmental Protection Agency (EPA) to set National Ambient Air Quality Standards (NAAQS) for six common air pollutants, including particulate matter (PM), ground-level ozone, carbon monoxide (CO), sulfur oxides (SO_x), Nitrogen Oxides (NO_x), and lead. These air pollutants are regulated by setting human health-based or environmentally-based criteria for permissible levels.

2.2.1.2 Particulate Matter

In 2013, the EPA strengthened the PM standard. The Kansas City area is currently in attainment of the 2013 PM NAAQS. No additional emission control equipment is currently needed to comply with this standard. It is not known whether the Kansas City area will remain in attainment of a future revision of the standard. Future non-attainment of revised standards could require additional reduction technologies, emission limits, or both on fossil-fueled units.

2.2.1.3 Ozone

In 2008, the EPA strengthened the NAAQS for ground-level ozone. Ambient air monitors indicate the Kansas City area could be placed in non-attainment of the 2008 Ozone NAAQS but the EPA has not yet acted.

In 2014, the EPA proposed to further strengthen the ozone standard. Until the 2015 Ozone NAAQS is finalized and designations determined, it is unknown if the Kansas City area will be in attainment of the 2015 Ozone NAAQS. Future non-attainment of revised standards could result in regulations requiring additional NO_x reduction technologies, emission limits or both on fossil-fueled units.

2.2.1.4 Carbon Monoxide

In 2011, the EPA issued a decision to retain the existing NAAQS for CO, and the Kansas City area is in attainment of the standard. Future non-attainment could result in requiring additional CO reduction technologies, emission limits or both on fossil-fueled units.

2.2.1.5 Acid Rain Program – Sulfur Dioxide and Nitrogen Oxides

The overall goal of the Acid Rain Program (ARP) is to achieve environmental and public health benefits by reducing emissions of SO_2 and NO_x. In 2012, the EPA determined that no area in the country is violating the 2010 national air quality standards for NO_2. In 2010, the EPA revised the primary NAAQS for SO_2 and in 2014 provided guidance on implementing the new 1-hour SO_2 standard. For further discussion, refer to Appendix 4A, Section 1.5.

2.2.1.6 Clean Air Interstate Rule (CAIR)

In 2005, the EPA issued the CAIR, a rule reducing air pollution that moves across state boundaries. Through the use of a cap-and-trade approach, CAIR provides a Federal framework requiring states to reduce emissions of SO_2 and NO_x. For further discussion, refer to Appendix 4A, Section 1.8.

2.2.1.7 Cross-State Air Pollution Rule

In 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR), requiring eastern and central states to significantly reduce power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in other states. The Company will comply through a combination of trading allowances within or outside its system in addition to changes in operations as necessary. For further discussion, refer to Appendix 4A, Section 1.9.

2.2.1.8 Regional Haze

For discussion of regional haze, refer to Appendix 4A, Section 1.10.

2.2.1.9 Lead

The Kansas City area is in attainment of the current NAAQS for lead. Non-attainment of a revised standard could result in regulations requiring additional lead reduction technologies, emission limits or both on coal units.

2.2.1.10 Carbon Dioxide

In 2014, the EPA issued its proposed rule regarding regulation of CO_2 emissions from existing power plants under section 111(d), which the Agency calls the Clean Power Plan. The Clean Power Plan would require each state with fossil fuel-fired generation to meet state-specific emission rate-based CO_2 goals by 2030. Each state's rate is calculated using a basic formula: CO_2 emissions from fossil fuel-fired power plants in pounds divided by state electricity generation from fossil fuel-fired power plants and certain low- or zero-emitting power sources in megawatt hours. State- and regional-specific information (such as the state's fuel mix and its electricity market) is plugged into the formula, and the result of the equation is the state-specific goal that must be met by 2030. In addition to the 2030 final goal, the EPA assigned each state an interim reduction target, which is an average emission rate that must be met over the period 2020 to 2029. For further discussion, refer to Appendix 4A, Section 1.12.

2.2.1.11 Mercury and Air Toxics Standards

In 2011, the EPA signed a rule to reduce emissions of toxic air pollutants from power plants. These mercury and air toxics standards (MATS) for power plants will reduce emissions from new and existing coal and oil-fired electric EGUs. Existing sources will have up to 4 years if they need to comply with MATS, and compliance strategies include wet and dry scrubbers, dry sorbent injection systems, activated carbon injection systems, and fabric filters. For further discussion, refer to Appendix 4A, Section 1.13.

2.2.1.12 Industrial Boiler Maximum Achievable Control Technology Standards

In January 2013, the EPA finalized a revised Industrial Boiler MACT rule to reduce emissions of toxic air pollutants from new and existing industrial, commercial, and institutional boilers and process heaters at major sources facilities. The final rule will reduce emissions of toxic air pollutants including mercury, other metals, and organic air toxics. For further discussion, refer to Appendix 4A, Section 1.14.

2.2.1.13 Potential Future Regulated Air Pollutants

Future multi-pollutant legislation or regulations could require reduced emissions for criteria pollutants, HAPs, or CO_2. KCP&L will continue to track the status of any future regulations.

2.2.2 WATER EMISSION IMPACTS

2.2.2.1 Clean Water Act Section 316(A)

KCP&L's river plants comply with the calculated limits defined in the current permits. Future regulations could be issued that would restrict the thermal discharges and require alternative cooling technologies to be installed at coal-fired units using once through cooling. For further discussion, see Appendix 4A, Section 3.1.

2.2.2.2 Clean Water Act Section 316(B)

In May 2014, the EPA finalized standards to reduce the injury and death of fish and other aquatic life caused by cooling water intake structures at power plants and factories. The rule could severely restrict cooling water inlet structures and potentially require closed cycle cooling technologies instead. For further discussion, refer to Appendix 4A, Section 3.2.

2.2.2.3 Steam Electric Power Generating Effluent Limitations Guidelines

In April 2013, the EPA proposed to revise the technology-based effluent limitations guidelines and standards that would strengthen the existing controls on discharges from steam electric power plants. The proposal sets the federal limits on the levels of toxic metals in wastewater that can be discharged from power plants, based on technology improvements in the steam electric power industry over the last three decades, refer to Appendix 4A, Section 3.3.

2.2.2.4 Zebra Mussel Infestation

KCP&L monitors for zebra mussels at generation facilities, and a significant infestation could cause operational changes to the stations. Refer to Appendix 4A, Section 3.4 for additional information.

2.2.2.5 Total Maximum Daily Loads

A Total Maximum Daily Load (TMDL) is a calculation of the maximum amount of a given pollutant that a body of water can absorb before its quality is impacted. A stream is considered impaired if it fails to meet Water Quality Standards established by the Clean Water Commission. Future TMDL standards could restrict discharges and require equipment to be installed to minimize or control the discharge. For further discussion, refer to Appendix 4A, Section 3.5.

2.2.3 WASTE MATERIAL IMPACTS

2.2.3.1 Coal Combustion Residuals (CCR's)

In December 2014, the EPA finalized regulations to regulate CCRs under the RCRA subtitle D to address the risks from the disposal of CCRs generated from the combustion of coal at electric generating facilities. The rule requires periodic assessments; groundwater monitoring; location restrictions; design and operating requirements; recordkeeping and notifications; and closure, among other requirements, for CCR units. The regulations could require existing CCR units to be closed and replaced with new landfills designed to more stringent standards. For further discussion, refer to Appendix 4E, Section 4.1.

For the purposes of ranking the supply-side resource options, the subjective probabilities assigned to comply with future environmental laws or regulations are listed as follows:

- Landfills required to provide dry handling of CCPs = 100% probability
- A coal cleaning process to remove HAPs = 100% probability
- A cap and trade program requiring the use of CO_2 allowances for generation technologies that emit CO_2 = 100% probability
- Cooling towers required to comply with Clean Water Act (CWA) Sections 316(a) and (b) = 100% probability

The probable environmental cost for each supply-side resource can be found below in Table 13.

2.3 PRELIMINARY SUPPLY-SIDE CANDIDATE RESOURCE OPTIONS

(C) The utility shall indicate which potential supply-side resource options it considers to be preliminary supply-side candidate resource options. Any utility using the preliminary screening analysis to identify preliminary supply-side candidate resource options shall rank all preliminary supply-side candidate resource options based on estimates of the utility costs and also on utility costs plus probable environmental costs. The utility shall—

Each of the supply-side resource options identified was ranked in terms of a 'utility cost' estimate and a 'utility cost plus probable environmental cost' estimate. The utility cost estimate is expressed in dollars per megawatt-hour, and it is comprised of fixed O&M, variable O&M, fuel cost, and a levelized carrying cost applied to the capital costs incurred for the technology installation and the transmission interconnection (if applicable). In developing the dollar per MWh cost, the technology heat rate and the projected capacity factor also play an important role. In particular, the capacity factor can have a large impact and the base load technologies have the highest capacity factors, followed by the intermediate load and peaking load technologies. The capacity factor of renewable technologies can vary significantly depending on the type of renewable resource. All of the capacity factor assumptions can be found in Table 7 above.

2.3.1 POTENTIAL SUPPLY-SIDE RESOURCE OPTION TABLE

1. Provide a summary table showing each potential supply-side resource option and the utility cost and the probable environmental cost for each potential supply-side resource option and an assessment of whether each potential supply-side resource option qualifies as a utility renewable energy resource; and

The development of the nominal utility costs for each of the twenty-three potential new supply-side resource options was calculated in an Excel workbook, which is attached as a worksheet. Rankings were developed for these technologies for both the 'utility' cost and the 'utility plus probable environmental' cost. The difference between the 2 rankings is driven primarily by the potential of environmental costs for CO_2 emissions in anticipation of legislation being passed to reduce U.S. emissions. The estimated probable environmental costs in nominal dollars for each of the twenty-three technologies are shown in Table 13 below.

The ‘utility cost’ rankings for all the supply-side resource options are shown below in Table 14. The ‘utility cost plus probable environmental’ rankings are show below in Table 15. Both the utility cost and probable environmental cost rankings show the lowest-cost alternatives to include wind, combined cycle and supercritical pulverized coal technologies. For both of these cost rankings, it is important to note that the energy storage/battery technologies only store energy and do not produce it, so a cost of energy was added into the dollar per MWh cost based upon projected market power prices.

Table 13: Probable Environmental Cost **Highly Confidential**

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[redacted]

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Table 15: Technology Ranking by Nominal Probable Environmental Cost
****Highly Confidential****

[redacted]

2.3.2 ELIMINATION OF POTENTIAL SUPPLY-SIDE RESOURCE OPTIONS

2. Explain which potential supply-side resource options are eliminated from further consideration and the reasons for their elimination.

2.3.2.1 Supply-Side Resource Options Eliminated

The technology options that were eliminated from further consideration on the basis of the pre-screening analysis, along with the reason for their elimination, are addressed in the discussion below. It should be noted that some of the higher-cost options were passed on to integrated resource analysis because the technology was required to help meet the Missouri Renewable Energy Standard (RES) Requirements, regardless of its cost ranking. On the other

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hand, certain low-cost options were not passed on to the integrated resource analysis for a multitude of reasons. Following is a discussion of the supply-side candidate resource options that were not moved on to the integrated resource analysis.

2.3.2.1.1 Integrated Gasification Combined Cycle Technologies

The IGCC technologies, IGCC and IGCC with CO_2 Capture, were not passed on to the integrated resource analysis. These technologies are in the demonstration stage with very little operating experience, and they also have higher projected capital costs and operating expenses relative to the pulverized coal technologies. The development status of IGCC will be monitored and the technology will continue to be considered in future analyses.

2.3.2.1.2 Landfill Gas Technology

The landfill gas technology was not passed on to the integrated resource analysis, due to the limited regional availability of landfill gas opportunities. However, KCP&L will continue to pursue innovative renewable projects including landfill gas-to-energy projects, such as the existing 1.6 MW landfill power generation facility in partnership with the City of St. Joseph.

2.3.2.1.3 Combustion Turbine (CT) Technologies

Three combustion turbine technologies were identified for the prescreening process and one of those was chosen to move into integrated resource analysis. As shown in Table 14 above, their nominal cost rankings on a dollar per MWh basis were relatively similar. The CT technologies of the LM6000 and the LMS100 were not passed on to the integrated resource planning process. The GE 7FA combustion turbine technology was passed on to the integrated resource planning process. For further discussion, refer to Section 4.1.1.1

2.3.2.1.4 Biomass Bubbling Fluidized Bed (BFB) Boiler Technology

This technology was not passed on to integrated resource analysis due to the high capital and fixed O&M costs, along with potential lack of fuel in this region and its inability to compete with cheaper renewable alternatives such as wind.

2.3.2.1.5 Energy Storage Technologies

The energy storage technologies included in the prescreening process were compressed air energy storage (CAES), pumped hydro, and sodium sulfur batteries. Due to their relatively high cost, along with the early development stage and limited utility application, these energy storage technologies were not passed on to the integrated resource analysis. These technologies will continue to be monitored and will also be considered for their ability to accommodate the impact of hour-by-hour fluctuations from variable wind and solar resources.

2.3.2.1.6 Fuel Cell Technologies

The solid oxide fuel cell technology was not passed on to integrated resource analysis. Fuel cells are still in the technology development stage, and they are high-cost relative to the other technologies in the prescreening process that were moved on to the integrated resource analysis.

2.3.2.1.7 Solar Technologies

The solar thermal technologies in the prescreening process– parabolic trough and dish – were excluded from integrated resource analysis due to high cost and the geographic region requirements. High temperatures and solar concentration systems are required for the thermal technologies to operate with reasonable efficiencies, and the highest quality resources for solar thermal within the United States are located in the Southwest (Nevada, Arizona, California, New Mexico). No solar thermal facilities currently exist in the Midwest, due to these geographic requirements. However, to meet the solar requirements of the MO RES, KCP&L did pass on the solar photovoltaic (PV) fixed flat-plate technology to the integrated resource analysis given its slight cost advantage over the solar PV tracking technology.

2.3.2.1.8 Small Scale CT Technologies

The Wartsila reciprocating engine small scale CT technology was not passed on to the integrated resource analysis process. The primary disadvantage is the higher cost relative to the larger scale GE 7FA.05 CT that was moved on to the integrated resource analysis.

SECTION 3: INTERCONNECTION AND TRANSMISSION REQUIREMENTS

(3) The utility shall describe and document its analysis of the interconnection and any other transmission requirements associated with the preliminary supply-side candidate resource options identified in subsection (2)(C).

3.1 INTERCONNECTION AND TRANSMISSION CONSTRAINTS ANALYSIS

(A) The analysis shall include the identification of transmission constraints, as estimated pursuant to 4 CSR 240-22.045(3), whether within the Regional Transmission Organization's (RTO's) footprint, on an interconnected RTO, or a transmission system that is not part of an RTO. The purpose of this analysis shall be to ensure that the transmission network is capable of reliably supporting the preliminary supply-side candidate resource options under consideration, that the costs of the transmission system investments associated with preliminary supply-side candidate resource options, as estimated pursuant to 4 CSR 240-22.045(3), are properly considered and to provide an adequate foundation of basic information for decisions to include, but not be limited to, the following:

1. Joint ownership or participation in generation construction projects;

2. Construction of wholly-owned generation facilities;

3. Participation in major refurbishment, life extension, upgrading, or retrofitting of existing generation facilities;

4. Improvements on its transmission and distribution system to increase efficiency and reduce power losses;

5. Acquisition of existing generating facilities; and

6. Opportunities for new long-term power purchases and sales, and short-term power purchases that may be required for bridging the gap between other supply options, both firm and non-firm, that are likely to be available over all or part of the planning horizon.

In general, all major KCP&L transmission upgrade projects are currently made available as public information through either KCP&L's public OASIS site or as part of the Southwest Power Pool's (SPP) Transmission Expansion Plan (STEP). In addition, there are also smaller projects of minimal cost and construction time that are not available for public viewing, since they do not result in increases in transmission capacity or transfer capability. These would include projects for replacement of damaged, worn out, or obsolete equipment.

The major regional transmission constraints currently impacting the KCP&L transmission system are the Iatan-Stranger Creek 345kV line, the St. Joseph-Hawthorn 345kV line, and the Cooper South Flowgate. The first two constraints will be eliminated with the completion of the Iatan-Nashua project, while the Cooper South Flowgate constraint will be eliminated with the completion of the Nebraska City-Mullin Creek-Sibley project.

As a member of SPP, KCP&L participates in the SPP open access transmission tariff (OATT). All transmission service requests, including generation interconnection requests, must be submitted to the SPP and studied in a non-discriminatory process. Due to the nature of this 'open access' transmission system process, it makes it difficult to predict future transmission constraints. As of November, 2014, the current SPP Aggregate Study process has four active study groups with 83 transmission service requests (TSR), totaling approximately 21,493 MW of TSR.

Due to the iterative nature of the Aggregate Facility Study process, it is not possible to identify specific transmission upgrades needed to delivery energy from a resource in the RTO footprint to KCP&L until the process for a specific transmission service request has been completed. Any new generation resource requesting interconnection to the transmission system will have to go through the SPP Generator Interconnection process and the Aggregate Study process. These processes are designed to provide adequate transmission capacity for resource interconnection and delivery to load.

3.2 NEW SUPPLY-SIDE RESOURCES OUTPUT LIMITATIONS

(B) This analysis shall include the identification of any output limitations imposed on existing or new supply-side resources due to transmission and/or distribution system capacity constraints, in order to ensure that supply-side candidate resource options are evaluated in accordance with any such constraints.

As discussed in Section 3.1, output limitations are difficult to predict without knowledge of the specific project site. In regards to renewable resources in the southwest Kansas region, it is known that the total current firm transmission service requests to SPP exceed the total transmission service availability which will be provided by transmission construction projects. Until large scale investments in transmission upgrades are made, the timing of future renewable resource additions in that region will be difficult to determine with certainty. This could lead to output and/or delivery limitations on future renewable resource additions in the southwest Kansas region.

SECTION 4: SUPPLY-SIDE CANDIDATE RESOURCE OPTIONS

(4) All preliminary supply-side candidate resource options which are not eliminated shall be identified as supply-side candidate resource options. The supply-side candidate resource options that the utility passes on for further evaluation in the integration process shall represent a wide variety of supply-side resource options with diverse fuel and generation technologies, including a wide range of renewable technologies and technologies suitable for distributed generation.

The supply-side technologies passed on to the integrated resource analysis as candidate resource options represent a wide range of diverse fuel and generation technologies, including natural gas, coal and nuclear powered options. Renewable technologies for wind and solar were also moved on to the integrated resource analysis. In addition to new generation additions, alternatives to retrofit the existing Montrose Units 1-3 were moved on to the integrated resource analysis. This list of supply side technologies passed on to the integrated resource analysis can be found in Table 16 below. Cost and operating data for the technologies that moved on to the integrated resource analysis came from multiple sources including the Electric Power Research Institute (EPRI), the Department of Energy (DOE), responses to recent Request for Proposals (RFP), and other internal resources.

Table 16: Candidate Resource Options

Technology Type	Description
Combined Cycle	2x1 GE 7FA 2x1 GE 7FA w Carbon Capture
Combustion Turbine	GE 7FA
Nuclear	Large Scale Small Modular Reactors
Pulverized Coal	Super Critical Pulverized Coal (SCPC) SCPC w Carbon Capture
Solar	Photovoltaic - Fixed Axis
Wind	Wind Turbines
Existing Resources	Montrose Units 1-3 Environmental Retrofits

4.1 IDENTIFICATION PROCESS FOR POTENTIAL SUPPLY-SIDE RESOURCE OPTIONS

(A) The utility shall describe and document its process for identifying and analyzing potential supply-side resource options and preliminary supply-side candidate resource options and for choosing its supply-side candidate resource options to advance to the integration analysis.

4.1.1 NEW PLANT RESOURCE OPTIONS

Following is a discussion of the supply-side candidate resource options that were advanced to the integration analysis for new generation additions:

4.1.1.1 Combustion Turbine Technologies

The combustion turbine (CT) technology of the GE 7FA was passed on to the integrated resource analysis process as being representative of the larger group of CT technologies that were considered, which included the LMS100 and the LM6000.

4.1.1.2 Combined Cycle Technologies

The combined cycle (CC) technologies of the 2x1 GE 7FA.05 and the CC with CO_2 Capture were both passed on to the integrated resource analysis process. The local engineering firm Sega, Inc. assisted in providing CC technology characteristics that were used in the integrated resource analysis and which are more accurate figures for the KCP&L territory.

4.1.1.3 Coal Technology

The super critical pulverized coal (SCPC) technology and the SCPC technology with CO_2 Capture were both passed on to the integrated resource analysis as representative coal technologies.

4.1.1.4 Nuclear Technology

Both large-scale and small modular reactor (SMR) nuclear technologies were passed on to the integrated resource analysis. While still in the developmental stages, the SMR technology may represent a more likely long-term alternative and was advanced to the integration analysis for that reason.

4.1.1.5 Wind Technology

Wind generation was passed on to the integrated resource analysis, due to its ability to help meet the Missouri Renewable Energy Standard (RES) requirements and a low cost on a dollar per MWh basis when compared to other prescreened technologies.

4.1.1.6 Solar Technology

As an alternative for meeting the Missouri RES solar carve out requirements, the solar photovoltaic (PV) technology was passed on to the integrated resource analysis.

4.1.2 ENVIRONMENTAL RETROFIT & LIFE EXTENSION OPTIONS

For the 20-year planning period, KCP&L has evaluated potential environmental retrofits and future capital projects considered necessary to ensure continued reliability of the coal-generation units.

4.1.2.1 Environmental Retrofits

Future potential environmental retrofit equipment costs have been analyzed by Burns and McDonnell and are incorporated into Montrose Units 2 and 3, Iatan-1, and Hawthorn-5 future costs. Future potential environmental regulations are the drivers for the equipment assumed. Budgetary costs, fixed and variable O&M costs determined through the studies are provided in Table 17 through Table 19 below:

Table 17: Environmental Retrofit Capital Costs **Highly Confidential**

Environmental Retrofit Technology Capital Cost (2014 $ x Millions)	Montrose 2	Montrose 3	LaCygne 1 and 2 [1]	Hawthorn	Iatan 1 [1]
Activated Carbon Injection	[redacted]				
ESP Rebuild					
Fish-Friendly Screens					
Cooling Towers					
Wet-to-Dry Bottom Ash Conversion					

Notes
NA = Not Applicable
✓ Equipment Installed
R=Retirement expected to occur before retrofit would be required
[1] KCP&L's Share

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Table 18: Environmental Retrofit Fixed O&M Costs **Highly Confidential**

Environmental Retrofit Technology Fixed O&M ($/kW - 2014 $)	Montrose 2	Montrose 3	LaCygne 1 and 2	Hawthorn	Iatan 1
Activated Carbon Injection	[redacted]				
ESP Rebuild					
Fish-Friendly Screens					
Cooling Towers					
Wet-to-Dry Bottom Ash Conversion					

Notes
NA = Not Applicable
Equipment Installed
R=Retirement expected to occur before retrofit would be required

Table 19: Environmental Retrofit Variable O&M Costs **Highly Confidential**

Environmental Retrofit Technology Variable O&M ($/MWh - 2014 $)	Montrose 2	Montrose 3	LaCygne 1 and 2	Hawthorn	Iatan 1
Activated Carbon Injection	[redacted]				
ESP Rebuild					
Fish-Friendly Screens					
Cooling Towers					
Wet-to-Dry Bottom Ash Conversion					

Notes
NA = Not Applicable
Equipment Installed
R=Retirement expected to occur before retrofit would be required

4.1.2.2 Life Assessment & Management Program

An internal review of long-term plant equipment needs was developed using the Life Assessment and Management Program (LAMP). The program was developed in the late 1980's for the purpose of identifying, evaluating, and recommending improvements and special maintenance requirements necessary for continued reliable operation of KCP&L coal-

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fired generating units. The primary objectives of the LAMP program include:

1. Identify and recommend unit requirements associated with future operating plans

2. Identify and recommend areas of improvement and special maintenance requirements necessary to extend the operating life of each unit

3. Identify and recommend areas of improvement to achieve any or all of the following goals:

    a. Capacity

    b. Performance

    c. Reliability/Availability

    d. Safety/ Environmental

    e. Operational Changes

4. Provide a basis for identification and prevention of major component failure, and costly interruptions associated with continued use of existing equipment

5. Provide the tools for managing and protecting remaining life of critical components/assets.

Current schedules of identified LAMP projects and costs for Montrose Units 2 and 3, Hawthorn Unit 5, and LaCygne Units 1 and 2 (KCP&L Share) are shown below in Table 20 through Table 32.

Table 20: Montrose-2 LAMP Capital Plan Years 2020 - 2027 ($000's) **Highly Confidential**

Project Name	2020	2021	2022	2023	2024	2025	2026	2027
M2 Transformer Replacement	[redacted]							
M2 Replace Main Steam Line	[redacted]							
M2 Replace Mud Drums	[redacted]							
M2 Replacement of primary superheater Outlet Header	[redacted]							
M2 Lower Water Wall Replacement	[redacted]							
M2 Middle Water Wall Replacement	[redacted]							
M2 Upper Water Wall Replacement	[redacted]							
M2 Replacement of Relief Tubes	[redacted]							
M2 Generator Field Replacement	[redacted]							
M2 Replace reheat & superheater outlet headers in 2029	[redacted]							
M2 Turbine Blading	[redacted]							
M2 Distributed Control System Replacement	[redacted]							
M2 Secondary Superheat Replacement	[redacted]							
M2 6th Stage Heater Replacement	[redacted]							
M2 9th Stage Heater Replacement	[redacted]							
M2 Turbine Blade Replacement	[redacted]							
M2 Windbox Replacement	[redacted]							
M2 A Boiler Feed Pump Replacement	[redacted]							
M2 B Boiler Feed Pump Replacement	[redacted]							
M2 Ash Silo Replacement	[redacted]							
M2 Curtain Wall Replacement	[redacted]							
M2 Waterlance Sootblower	[redacted]							
M2 Economizer Hoppers	[redacted]							

HC

Table 21: Montrose-2 LAMP Capital Plan Years 2028 - 2034 ($000's) **Highly Confidential**

Project Name	2028	2029	2030	2031	2032	2033	2034	Plant Total
M2 Transformer Replacement	[redacted]							
M2 Replace Main Steam Line	[redacted]							
M2 Replace Mud Drums	[redacted]							
M2 Replacement of primary superheater Outlet Header	[redacted]							
M2 Lower Water Wall Replacement	[redacted]							
M2 Middle Water Wall Replacement	[redacted]							
M2 Upper Water Wall Replacement	[redacted]							
M2 Replacement of Relief Tubes	[redacted]							
M2 Generator Field Replacement	[redacted]							
M2 Replace reheat & superheater outlet headers in 2029	[redacted]							
M2 Turbine Blading	[redacted]							
M2 Distributed Control System Replacement	[redacted]							
M2 Secondary Superheat Replacement	[redacted]							
M2 6th Stage Heater Replacement	[redacted]							
M2 9th Stage Heater Replacement	[redacted]							
M2 Turbine Blade Replacement	[redacted]							
M2 Windbox Replacement	[redacted]							
M2 A Boiler Feed Pump Replacement	[redacted]							
M2 B Boiler Feed Pump Replacement	[redacted]							
M2 Ash Silo Replacement	[redacted]							
M2 Curtain Wall Replacement	[redacted]							
M2 Waterlance Sootblower	[redacted]							
M2 Economizer Hoppers	[redacted]							

HC

Table 22: Montrose-3 LAMP Capital Plan Years 2020 - 2027 ($000's) **Highly Confidential**

Project Name	2020	2021	2022	2023	2024	2025	2026	2027
M3 Reheater Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Replace Main Steam Line	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Replace Mud Drums	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 DC Rotating Exciter - Conv. to Static Exciter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 High Pressure / Intermediate Pressure Blading	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Replacement of primary superheater Outlet Header	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Middle Water Wall Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Upper Water Wall Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Replacement of Relief Tubes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Replacement of Supply Tubes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 300# Oil Control Sys.- Upgrade ctrls to Distributed Control System	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Replacer Low Pressure Heaters 26 & 27	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Distributed Control System Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Secondary Superheat Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Main Transformer Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 10th Stage Heater Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 15th Stage Heater Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Turbine Blade Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Windbox Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 A Boiler Feed Pump Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 B Boiler Feed Pump Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Ash Silo Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Curtain Wall Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Waterlance Sootblower	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Economizer Hoppers	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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Table 23: Montrose-3 LAMP Capital Plan Years 2028 - 2034 ($000's) **Highly Confidential**

Project Name	2028	2029	2030	2031	2032	2033	2034	Plant Total
M3 Reheater Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Replace Main Steam Line	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Replace Mud Drums	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 DC Rotating Exciter - Conv. to Static Exciter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 High Pressure / Intermediate Pressure Blading	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Replacement of primary superheater Outlet Header	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Middle Water Wall Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Upper Water Wall Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Replacement of Relief Tubes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Replacement of Supply Tubes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 300# Oil Control Sys.- Upgrade ctrls to Distributed Control System	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Replacer Low Pressure Heaters 26 & 27	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Distributed Control System Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Secondary Superheat Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Main Transformer Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 10th Stage Heater Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 15th Stage Heater Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Turbine Blade Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Windbox Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 A Boiler Feed Pump Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 B Boiler Feed Pump Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Ash Silo Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Curtain Wall Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Waterlance Sootblower	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
M3 Economizer Hoppers	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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Table 24: Montrose Station Common LAMP Capital Plan Years 2020 - 2034 ($000's) **Highly Confidential**

Project Name	2020	2021	2022	2023	2024	2025	2026	2027
MS Underground Piping Replacement	[redacted]							
MS Additional Spends	[redacted]							
MS Yearly	[redacted]							
MS 41 Conveyor Replacement	[redacted]							
MS 42 Conveyor Replacement	[redacted]							
MS 43 Conveyor Replacement	[redacted]							
Project Name	[redacted]							
MS Underground Piping Replacement	[redacted]							
MS Additional Spends	[redacted]							
MS Yearly	[redacted]							
MS 41 Conveyor Replacement	[redacted]							
MS 42 Conveyor Replacement	[redacted]							
MS 43 Conveyor Replacement	[redacted]							

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Table 25: Hawthorn-5 LAMP Capital Plan Years 2020 - 2027 ($000's) **Highly Confidential**

Project Name	2020	2021	2022	2023	2024	2025	2026	2027
Haw #5 - Secondary Crushers	[redacted]							
Haw #5 - Ultrafiltration System	[redacted]							
Haw #5 - Air Heater Basket Replacement	[redacted]							
Haw #5 - Crossover Expansion Joint Replacement	[redacted]							
Haw #5 - Submerged Flight Conveyor Replacement	[redacted]							
Haw #5 - Replace High Pressure Feedwater Heaters 2	[redacted]							
Haw #5 - Replace/Upgrade Low Pressure rotor	[redacted]							
Haw #5 - Waterwall Replacement	[redacted]							
Haw #5 - Main Stop/Control Valve Chest Repl.	[redacted]							
Haw #5 - High Pressure / Intermediate Pressure Overhaul	[redacted]							
Haw #5 - Superheat Pendant and Header	[redacted]							
Haw #5 - Reheat Pendants and Header	[redacted]							
Haw #5 - Economizer Bundle	[redacted]							
Haw #5 - Main Boiler Feedpump Turbine Overhaul	[redacted]							
Haw #5 - Generator Rewind	[redacted]							
Haw #5 - Coal Piping Replacement	[redacted]							
Haw #5 - Dumper Overhaul	[redacted]							
Haw #5 - Stack Liner Replacement	[redacted]							
Haw #5 - Lower Slope Wall Replacement	[redacted]							
Haw #5 - Aux Transformer Replacement	[redacted]							
Haw #5 - Low Pressure Heater Replacement	[redacted]							
Haw #5 - Stack Continuous Emissions Monitoring Replacement	[redacted]							
Haw #5 - Inlet Continuous Emissions Monitoring	[redacted]							
Haw #5 - Pulse-Jet Baghouse Bag Replacement	[redacted]							
Haw #5 - Selective Catalytic Reduction Catalyst Replacement	[redacted]							
Haw #5 - New Atomizer	[redacted]							
Haw #5 - Spray Dryer Absorber Vessel Wall Replacement	[redacted]							
Haw #5 - Spray Dryer Absorber Upper Cone Replacement	[redacted]							
Haw #5 - Sootblower Replacements	[redacted]							
Haw #5 - Distributed Control System	[redacted]							

HC

Table 26: Hawthorn-5 LAMP Capital Plan Years 2028 - 2034 ($000's) **Highly Confidential**

Project Name	2028	2029	2030	2031	2032	2033	2034	Plant Total
Haw #5 - Secondary Crushers	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Ultrafiltration System	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Air Heater Basket Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Crossover Expansion Joint Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Submerged Flight Conveyor Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Replace High Pressure Feedwater Heaters 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Replace/Upgrade Low Pressure rotor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Waterwall Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Main Stop/Control Valve Chest Repl.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - High Pressure / Intermediate Pressure Overhaul	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Superheat Pendant and Header	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Reheat Pendants and Header	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Economizer Bundle	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Main Boiler Feedpump Turbine Overhaul	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Generator Rewind	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Coal Piping Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Dumper Overhaul	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Stack Liner Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Lower Slope Wall Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Aux Transformer Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Low Pressure Heater Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Stack Continuous Emissions Monitoring Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Inlet Continuous Emissions Monitoring	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Pulse-Jet Baghouse Bag Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Selective Catalytic Reduction Catalyst Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - New Atomizer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Spray Dryer Absorber Vessel Wall Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Spray Dryer Absorber Upper Cone Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Sootblower Replacements	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haw #5 - Distributed Control System	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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Table 27: Hawthorn Station Common LAMP Capital Plan Years 2020 - 2034 ($000's) **Highly Confidential**

Project Name	2020	2021	2022	2023	2024	2025	2026	2027
Haw Sta - New Administration Building	[redacted]							
Haw Sta - New Warehouse	[redacted]							
Haw Sta - Hawthorn Station Yearly	[redacted]							
Additional Spends	[redacted]							
Project Name	[redacted]							
Haw Sta - New Administration Building	[redacted]							
Haw Sta - New Warehouse	[redacted]							
Haw Sta - Hawthorn Station Yearly	[redacted]							
Additional Spends	[redacted]							

HC

Table 28: KCP&L Share LaCygne-1 LAMP Capital Plan Years 2020 - 2027 ($000's) **Highly Confidential**

Project Name	2020	2021	2022	2023	2024	2025	2026	2027
Lac #1 - Condenser Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #1 - Replace High Pressure Heater 2A	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #1 - Replace Low Pressure Heater - Deaerator	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #1 - Replace Reheater Outlet Headers	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #1 - Replace Superht. Outlet Headers	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #1 - Replace Main Steam Line	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #1 - Replace Secondary Superheater Inlet Pend.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #1 - Air Heater Basket Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #1 - Economizer Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #1 - Cold Reheat Piping Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #1 - Distributed Control System Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #1 - ID Fan Rotor Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #1 - Gas Recirculating Fan Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #1 - Ball Mill Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #1 - 7kV Cable Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #1 - Replace Low Pressure Heaters 7 A&B	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #1 - Replace High Pressure Heater 1A	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #1 - Replace High Pressure Heater 1B	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #1 - Replace Vertical Reheater	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #1 - Fuel Handling Conveyor Modernization	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #1 - Catalyst Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #1 - Pulse Jet Fabric Filter Bag Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac#1 - Mist Eliminator	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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Table 29: KCP&L Share LaCygne-1 LAMP Capital Plan Years 2028 - 2034 ($000's) **Highly Confidential**

Project Name	2028	2029	2030	2031	2032	2033	2034	Plant Total
Lac #1 - Condenser Replacement	[redacted]							
Lac #1 - Replace High Pressure Heater 2A								
Lac #1 - Replace Low Pressure Heater - Deaerator								
Lac #1 - Replace Reheater Outlet Headers								
Lac #1 - Replace Superht. Outlet Headers								
Lac #1 - Replace Main Steam Line								
Lac #1 - Replace Secondary Superheater Inlet Pend.								
Lac #1 - Air Heater Basket Replacement								
Lac #1 - Economizer Replacement								
Lac #1 - Cold Reheat Piping Replacement								
Lac #1 - Distributed Control System Replacement								
Lac #1 - ID Fan Rotor Replacement								
Lac #1 - Gas Recirculating Fan Replacement								
Lac #1 - Ball Mill Replacement								
Lac #1 - 7kV Cable Replacement								
Lac #1 - Replace Low Pressure Heaters 7 A&B								
Lac #1 - Replace High Pressure Heater 1A								
Lac #1 - Replace High Pressure Heater 1B								
Lac #1 - Replace Vertical Reheater								
Lac #1 - Fuel Handling Conveyor Modernization								
Lac #1 - Catalyst Replacement								
Lac #1 - Pulse Jet Fabric Filter Bag Replacement								
Lac#1 - Mist Eliminator								

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Table 30: KCP&L Share LaCygne-2 LAMP Capital Plan Years 2020 - 2027 ($000's) **Highly Confidential**

Project Name	2020	2021	2022	2023	2024	2025	2026	2027
Lac #2- Replace Deaerator	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #2- Replace Reheat Outlet Headers	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #2 - Replace/Upgrade Intermediate Pressure Rotor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #2- Replace/Upgrade Low Pressure Rotor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #2 - High Pressure Dense Pack Upgrade	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #2 - High Pressure Turbine Uprate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #2 - Replace Economizer Casing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #2 - Distributed Control System Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #2 - ID Fan Rotor Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #2 - Economizer Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #2 - Replace High Pressure Heater 21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #2 - Replace Low Pressure Heaters 27 A&B	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #2 - Condenser Retube	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #2 - Replace 25% Of Water Walls	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #2 - Replace Econ. Inlet Header	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #2 - Replace 25% Of Water Walls	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #2 - Replace Vertical Reheater	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #2 - Replace Lower Slope	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #2 - Fuel Handling Conveyor Modernization	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #2 - Catalyst Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #2 - Pulse Jet Fabric Filter Bag Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #2 - Air Heater Basket Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac #2 - Mist Eliminator	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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Table 31: KCP&L Share LaCygne-2 LAMP Capital Plan Years 2028 - 2034 ($000's) **Highly Confidential**

Project Name	2028	2029	2030	2031	2032	2033	2034	Plant Total
Lac #2- Replace Deaerator	[redacted]							
Lac #2- Replace Reheat Outlet Headers	[redacted]							
Lac #2 - Replace/Upgrade Intermediate Pressure Rotor	[redacted]							
Lac #2- Replace/Upgrade Low Pressure Rotor	[redacted]							
Lac #2 - High Pressure Dense Pack Upgrade	[redacted]							
Lac #2 - High Pressure Turbine Uprate	[redacted]							
Lac #2 - Replace Economizer Casing	[redacted]							
Lac #2 - Distributed Control System Replacement	[redacted]							
Lac #2 - ID Fan Rotor Replacement	[redacted]							
Lac #2 - Economizer Replacement	[redacted]							
Lac #2 - Replace High Pressure Heater 21	[redacted]							
Lac #2 - Replace Low Pressure Heaters 27 A&B	[redacted]							
Lac #2 - Condenser Retube	[redacted]							
Lac #2 - Replace 25% Of Water Walls	[redacted]							
Lac #2 - Replace Econ. Inlet Header	[redacted]							
Lac #2 - Replace 25% Of Water Walls	[redacted]							
Lac #2 - Replace Vertical Reheater	[redacted]							
Lac #2 - Replace Lower Slope	[redacted]							
Lac #2 - Fuel Handling Conveyor Modernization	[redacted]							
Lac #2 - Catalyst Replacement	[redacted]							
Lac #2 - Pulse Jet Fabric Filter Bag Replacement				$ 2,250				$ 6,750
Lac #2 - Air Heater Basket Replacement							$ 1,000	$ 2,000
Lac #2 - Mist Eliminator					$ 500			$ 1,500

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Table 32: KCP&L Share LaCygne Common LAMP Capital Plan Years 2020 - 2034 ($000's) **Highly Confidential**

Project Name	2020	2021	2022	2023	2024	2025	2026	2027
Lac Sta - Upgrade Car Dumper/150 Car Train	[redacted]							
Lac Sta - 2A Silo Structural Upgrades								
Lac Sta - Fuel Yard Conveyor Modernization								
Lac Sta - Replace Station Air Compressors								
Lac Sta - Car Dumper Barrel Replacement								
Lac Sta - Car Dumper Gearbox Replacement								
Lac Sta - River Water Piping Replacement								
Lac Sta - Additional Spends								
Lac Sta - Yearly Projects								
Project Name								
Lac Sta - Upgrade Car Dumper/150 Car Train								
Lac Sta - 2A Silo Structural Upgrades								
Lac Sta - Fuel Yard Conveyor Modernization								
Lac Sta - Replace Station Air Compressors								
Lac Sta - Car Dumper Barrel Replacement								
Lac Sta - Car Dumper Gearbox Replacement								
Lac Sta - River Water Piping Replacement								
Lac Sta - Additional Spends								
Lac Sta - Yearly Projects								

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4.2 ELIMINATION OF PRELIMINARY SUPPLY-SIDE RESOURCES DUE TO INTERCONNECTION OR TRANSMISSION

(B) The utility shall indicate which, if any, of the preliminary supply-side candidate resource options identified in subsection (2)(C) are eliminated from further consideration on the basis of the interconnection and other transmission analysis and shall explain the reasons for their elimination.

None of the preliminary supply-side candidate resource options were eliminated from consideration based on interconnection or other transmission analysis. For further discussion of the SPP open access transmission tariff (OATT) in which KCP&L participates, refer above to Section 3.1.

4.3 INTERCONNECTION COST FOR SUPPLY-SIDE RESOURCE OPTIONS

(C) The utility shall include the cost of interconnection and any other transmission requirements, in addition to the utility cost and probable environmental cost, in the cost of supply-side candidate resource options advanced for purposes of developing the alternative resource plans required by 4 CSR 240-22.060(3).

The cost of interconnection was added to the cost of supply-side candidate resource options using a weighted average of recent interconnection requests with the Southwest Power Pool (SPP). There was a separate analysis of the cost for interconnection requests related to wind projects versus other non-wind projects, with the results showing higher interconnection costs for wind projects. This cost adder on a dollar per kW basis is shown below in Table 33. The detailed analysis of the interconnection calculations has been provided in the Volume 4 workpapers.

Table 33: Transmission Interconnect Cost Projection

Capital Cost Adder (w/ Substation)	Wind Technology	All Other Supply-Side Options
$/kW ($ 2014)	[redacted]	[redacted]

SECTION 5: SUPPLY-SIDE UNCERTAIN FACTORS

(5) The utility shall develop, and describe and document, ranges of values and probabilities for several important uncertain factors related to supply-side candidate resource options identified in section (4). These cost estimates shall include at least the following elements, as applicable to the supply-side candidate resource option:

5.1 FUEL FORECASTS

(A) Fuel price forecasts, including fuel delivery costs, over the planning horizon for the appropriate type and grade of primary fuel and for any alternative fuel that may be practical as a contingency option;

Fuel price forecasts were developed for coal, natural gas, fuel oil, and uranium. KCP&L performed an investigation to determine the best possible commodity forecasts for use in the supply-side resource analysis and modeling, and that investigation showed that using an average of forecasts proves to be most reliable. The result of the averaging process is that random errors cancel each other out, when forecasts from multiple sources are utilized. Several assumptions apply when averaging multiple forecasts, including the belief that all expert forecasts are interchangeable and the closer to the time period being forecast, the lower the expected error to actual. A detailed description of the fuel price forecasting methodology can be found in Appendix 4B, "Fuel Price Forecasting". Following is an overview of the forecasting process applied for coal, natural gas, fuel oil, and uranium.

5.1.1 COAL FORECAST

A composite coal price forecast was created by combining the forecasts of the Energy Information Administration (EIA), Energy Ventures Analysis (EVA), IHS Energy (IHS), JD Energy (JDE), and Hanou Energy Consulting (HEC). Each source provided their forecast in either nominal or real dollars. The forecasts that

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were provided in real dollars were converted to nominal dollars using Moody's Analytics' GDP implicit price deflator. The forecasts were then combined and weighted equally to create a composite price forecast that represents the base case consensus of the major forecast sources. The variation of individual forecasts within the composite was then used within a t-distribution to mathematically calculate high and low forecast price curves. The three resultant price curves with their probability of occurrence were base 50%, high 25%, and low 25%. To ensure the early part of the forecast reflects expected cost, to the extent contracts are in place, actual contract prices or projections of those contract prices are used for the duration of the contract, which is typically less than six years.

5.1.2 NATURAL GAS FORECAST

A composite Henry Hub natural gas price forecast was created by combining forecasts from the EIA, EVA, IHS, and PIRA Energy Group (PIRA). Like with our coal forecast, each source provided their forecast in either nominal or real dollars. The forecasts that were provided in real dollars were converted to nominal dollars using Moody's Analytics' GDP implicit price deflator. The forecasts were then all combined in equal weight to create a composite price forecast representing the expected or base case consensus of the forecast sources. The variation of individual forecasts within the composite was then used within a t-distribution to mathematically calculate high and low forecast price curves. The three resultant price curves with their probability of occurrence were base 50%, high 25%, and low 25%. To better synchronize the early part of the forecast with current market data, the first few years of the forecast are overwritten by the NYMEX strip and a "bridge" is constructed from the NYMEX strip to the long-term forecast described above.

5.1.3 FUEL OIL FORECAST

Oil fired power generation is not a major source of electricity generation, and there are presently no price forecast scenarios in which oil would become the lowest cost fuel option for generating electricity when compared to other fossil fuels. A composite crude oil price forecast was created by combining forecasts from the EIA, EVA, and IHS. Like with our coal and natural gas forecasts, each source provided their forecast in either nominal or real dollars. The forecasts that were provided in real dollars were converted to nominal dollars using Moody's Analytics' GDP implicit price deflator. The forecasts were then all combined in equal weight to create a composite price forecast representing the expected or base case consensus of the major forecast sources. The variation of individual forecasts within the composite was then used within a t-distribution to mathematically calculate high and low forecast price curves. The three resultant price curves with their probability of occurrence were base 50%, high 25%, and low 25%.

5.1.4 URANIUM FORECAST

There are not nearly as many economic consulting organizations that regularly produce long-term forecasts for uranium as there are for natural gas, crude oil, or coal. With few sources, it is difficult to construct long-term consensus forecasts similar to the coal, gas, and oil forecasts. For the uranium forecast, KCP&L utilized the most recent Global Energy Velocity Suite database long-term price forecast. The 'High' and 'Low' forecasts were set at plus or minus 20%.

The 'Base', 'High', and 'Low' fuel price forecasts are shown below in Table 34 and Table 35. The sources used in developing the forecasts are shown below in Table 36.

Table 34: Fuel Price Forecasts – Coal, Natural Gas, Fuel Oil **Highly Confidential**

Fuel Price Forecast	2015	2016	2017	2018	2019
Coal	[redacted]				
Coal Base					
Coal High					
Coal Low					
Natural Gas					
N.G. Base					
N.G. High					
N.G. Low					
Oil					
Fuel Oil Base					
Fuel Oil High					
Fuel Oil Low					
Fuel Price Forecast					
Coal					
Coal Base					
Coal High					
Coal Low					
Natural Gas					
N.G. Base					
N.G. High					
N.G. Low					
Oil					
Fuel Oil Base					
Fuel Oil High					
Fuel Oil Low					
Fuel Price Forecast					
Coal					
Coal Base					
Coal High					
Coal Low					
Natural Gas					
N.G. Base					
N.G. High					
N.G. Low					
Oil					
Fuel Oil Base					
Fuel Oil High					
Fuel Oil Low					
Fuel Price Forecast					
Coal					
Coal Base					
Coal High					
Coal Low					
Natural Gas					
N.G. Base					
N.G. High					
N.G. Low					
Oil					
Fuel Oil Base					
Fuel Oil High					
Fuel Oil Low					

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Table 35: Fuel Price Forecast – Nuclear **Highly Confidential**

Fuel Price Forecast	2015	2016	2017	2018	2019
Nuclear	[redacted]				
Mid					
High					
Low					
Fuel Price Forecast					
Nuclear					
Mid					
High					
Low					
Fuel Price Forecast					
Nuclear					
Mid					
High					
Low					
Fuel Price Forecast					
Nuclear					
Mid					
High					
Low					

Table 36: Source Forecasts for Coal, Natural Gas, and Fuel Oil

Forecast Source	Coal	Natural Gas	Fuel Oil	Nuclear
IHS	x	x	x	
EIA	x	x	x	
PIRA		x		
Energy Ventures Analysis	x	x	x	
Wood Mac				
JD Energy	x			
Synapse				
SNL Financial				
Hanou Energy Consulting	x			

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5.2 NEW FACILITY CAPITAL COSTS, EXISTING FACILITIES CAPITAL EXPENDITURES

(B) Estimated capital costs including engineering design, construction, testing, startup, and certification of new facilities or major upgrades, refurbishment, or rehabilitation of existing facilities;

Capital cost estimates for the technologies that moved on to integrated resource analysis were developed for both 'High' and 'Low' capital cost scenarios. As a starting point for all technologies, the 'High' capital cost estimate was set at 115% of the 'Mid' cost and the 'Low' capital cost estimate was set at 90% of the 'Mid' cost. From there, some of the technologies were assigned 'High' or 'Low' estimates that varied from these amounts, and following is a discussion on those decisions.

5.2.1 TECHNOLOGIES WITH 'HIGH' CAPITAL COST ABOVE 115%

5.2.1.1 Supercritical Pulverized Coal & SCPC w/Carbon Capture

Given the uncertainty surrounding potential environmental requirements for SCPC, this technology's 'High' capital cost range was set at 120% of the 'Mid' cost rather than 115%. The 'High' capital cost for SCPC w Carbon Capture was set even higher at 140% of the 'Mid' cost, since it has the added uncertainty of very few plants having been built.

5.2.1.2 Nuclear

Given the current challenging environment for building a nuclear facility, along with no recent construction activity for nuclear plants and uncertainty for the pricing of SMR technology, the 'High' capital cost range for nuclear technologies was set at 140% of the 'Mid' cost estimate.

5.2.1.3 Combined Cycle w Carbon Capture

The 'High' capital cost for Combined Cycle w Carbon Capture was set at 140% of the 'Mid' cost, since it has the uncertainty of very few plants having been built.

5.2.2 TECHNOLOGIES WITH 'LOW' CAPITAL COSTS BELOW 90%

5.2.2.1 Wind

With the reduction in wind capital costs over the past several years, this technology's 'Low' capital cost range was set at 80% of the 'Mid' cost rather than 90%.

5.2.2.2 Central Solar PV

With a continuous and significant reduction in solar PV capital costs over the past few years, the 'Low' capital cost range was set at 60% of the 'Mid' cost to account for the potential of continued reductions in solar capital costs.

The 'Mid', 'High', and 'Low' capital cost ranges and the resulting capital cost estimates on a $/kW basis are shown below in Table 37 and Table 38.

Table 37: Technology Capital Cost Ranges

Technology Description	Mid Range	High Range	Low Range
2x1 Combined Cycle	100%	115%	90%
CC w Carbon Capture	100%	140%	90%
Combustion Turbine 7FA	100%	115%	90%
Nuclear - Large Scale	100%	140%	90%
Nuclear - SMR	100%	140%	90%
SCPC	100%	120%	90%
SCPC w Carbon Capture	100%	140%	90%
Solar PV	100%	115%	60%
Wind	100%	115%	80%

Table 38: Capital Cost Estimates Utilized in Integrated Resource Analysis
****Highly Confidential****

Technology Description	Mid Range	High Range	Low Range
2x1 Combined Cycle	[redacted]	[redacted]	[redacted]
CC w Carbon Capture	[redacted]	[redacted]	[redacted]
Combustion Turbine 7FA	[redacted]	[redacted]	[redacted]
Nuclear - Large Scale	[redacted]	[redacted]	[redacted]
Nuclear - SMR	[redacted]	[redacted]	[redacted]
SCPC	[redacted]	[redacted]	[redacted]
SCPC w Carbon Capture	[redacted]	[redacted]	[redacted]
Solar PV	[redacted]	[redacted]	[redacted]
Wind	[redacted]	[redacted]	[redacted]

5.3 NEW FACILITY AND EXISTING FACILITY FIXED AND VARIABLE O&M

(C) Estimated annual fixed and variable operation and maintenance costs over the planning horizon for new facilities or for existing facilities that are being upgraded, refurbished, or rehabilitated;

The range of values for estimated annual fixed and variable operation and maintenance costs for new facilities considered in integrated analysis are shown below in Table 39 and Table 40. The 'High' O&M cost estimates were set at 110% of the 'Mid' cost estimate and the 'Low' O&M cost estimates were set at 90% of the 'Mid' cost. The projected increase in fixed and variable operation and maintenance costs due to the potential environmental retrofits of existing facilities is shown above in Table 18 through Table 19. Further discussion of the FOM and VOM estimates was provided earlier in Section 1.1.

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Table 39: Fixed O&M Estimates Utilized In Integrated Resource Analysis
****Highly Confidential****

Technology Description	Mid FOM ($/kW-Yr)	High FOM ($/kW-Yr)	Low FOM ($/kW-Yr)
2x1 Combined Cycle	[redacted]		
CC w Carbon Capture			
Combustion Turbine 7FA			
Nuclear - Large Scale			
Nuclear - SMR			
SCPC			
SCPC w Carbon Capture			
Solar PV			
Wind			

Table 40: Variable O&M Estimates Utilized in Integrated Resource Analysis
****Highly Confidential****

Technology Description	Mid VOM ($/MWh)	High VOM ($/MWh)	Low VOM ($/MWh)
2x1 Combined Cycle	[redacted]		
CC w Carbon Capture			
Combustion Turbine 7FA			
Nuclear - Large Scale			
Nuclear - SMR			
SCPC			
SCPC w Carbon Capture			
Solar PV			
Wind			

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5.4 EMISSION ALLOWANCE FORECASTS

(D) Forecasts of the annual cost or value of emission allowances to be used or produced by each generating facility over the planning horizon;

The CO_2 emission allowance price forecast was modified to reflect the paradigm shift caused by EPA's proposed Clean Power Plan (CPP). The CPP used four "building blocks" to construct state specific emissions rates. It did not develop a national CO_2 emission allowance program. On the other hand, the CPP did leave room for states to join together and develop regional programs. Given the view that the CPP is focused on reducing CO_2 emissions through means other than a trading program such as adopted under the CSAPR, the Company assigned a probability of 0.6 to the scenario there would be no CO_2 emission allowance trading program. Given the CPP would allow states to form a regional trading program and that the CPP may ultimately be changed to include a national trading program, the Company assigned a probability of 0.4 to the implementation of a CO_2 trading program that would apply to units in Kansas or Missouri. Under that scenario, CO_2 allowance prices were forecast as the composite of the individual price forecasts.

The forecasted cost of sulfur dioxide emission allowances over the planning horizon is shown in Table 41 and Table 42 below:

Table 41: SO_2 Group 1 Price Forecast **Highly Confidential**

[redacted]

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Table 42: SO_2 Group 2 Price Forecast **Highly Confidential**

[redacted]

Also provided in this section are the forecasts for Annual NO_x, Seasonal NO_x, and CO_2 in Table 43, Table 44, and Table 45 below:

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Table 43: NO_x Annual Price Forecast **Highly Confidential**

[redacted]

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Table 44: NO_x Seasonal Price Forecast **Highly Confidential**

[redacted]

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Table 45: CO_2 Price Forecast **Highly Confidential**

[redacted]

The source forecasts utilized to develop the emission allowance forecasts are shown in Table 46 below:

Table 46: Source Forecasts for Emission Allowances

Forecast Source	SO_2	NO_x	CO_2
IHS	x	x	x
EIA			
PIRA			x
Energy Ventures Analysis	x	x	x
Wood Mac			
JD Energy	x	x	x
Synapse			x
SNL Financial			
Hanou Energy Consulting			

5.5 LEASED OR RENTED FACILITIES FIXED CHARGES

(E) Annual fixed charges for any facility to be included in the rate base, or annual payment schedule for leased or rented facilities; and

There are no leased or rented facilities included in any of the KCP&L alternative resource plans or in the rate base, so this rule does not apply to this IRP evaluation.

5.6 INTERCONNECTION OR TRANSMISSION COSTS FOR SUPPLY-SIDE CANDIDATES

(F) Estimated costs of interconnection or other transmission requirements associated with each supply-side candidate resource option.

The estimated cost of interconnection associated with the supply-side candidate resource options is shown above in Section 4.3.

VOLUME 4.5

TRANSMISSION AND DISTRIBUTION ANALYSIS

KANSAS CITY POWER & LIGHT COMPANY (KCP&L)

INTEGRATED RESOURCE PLAN

4 CSR 240-22.045

APRIL, 2015

KCP&L℠ energizing life

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HIGHLIGHTS

- KCP&L's transmission losses as a percent of peak load served are low relative to the SPP footprint as a whole.

- SPP identified one economic project in the KCP&L footprint through its 2015 ITP10 process – a voltage conversion of the Iatan – Stranger Creek 161 kV transmission line to 345 kV. A need date was set at 1/1/2019.

- SPP identified one reliability project in the KCP&L footprint through its 2015 ITPNT process – an upgrade to the 161/69 kV transformer at South Waverly. A need date was set at 6/1/2015.

- A total of five transmission projects have been identified in the KCP&L territory, with need dates between 2015 and 2033.

PURPOSE: This rule specifies the minimum standards for the scope and level of detail required for transmission and distribution network analysis and reporting.

SECTION 1: ADEQUACY OF THE TRANSMISSION AND DISTRIBUTION NETWORKS

(1) The electric utility shall describe and document its consideration of the adequacy of the transmission and distribution networks in fulfilling the fundamental planning objective set out in 4 CSR 240-22.010. Each utility shall consider, at a minimum, improvements to the transmission and distribution networks that—

1.1 OPPORTUNITIES TO REDUCE TRANSMISSION POWER AND ENERGY LOSSES

(A) Reduce transmission power and energy losses. Opportunities to reduce transmission network losses are among the supply-side resources evaluated pursuant to 4 CSR 240-22.040(3). The utility shall assess the age, condition, and efficiency level of existing transmission and distribution facilities and shall analyze the feasibility and cost-effectiveness of transmission and distribution network loss-reduction measures. This provision shall not be construed to require a detailed line-by-line analysis of the transmission and distribution systems, but is intended to require the utility to identify and analyze opportunities for efficiency improvements in a manner that is consistent with the analysis of other supply-side resource options;

Electrical losses in a transmission line are primarily dependent on the specific characteristics of the line (conductor type, line length, etc.) and the amount of power flowing (I^2R) on the transmission line. KCP&L uses 161 kV transmission lines (approximately 1000 miles) for the majority of its load serving substations. Most of KCP&L's existing 161 kV transmission lines use a single 1192 ACSR conductor per phase on H-frame wood structures. This design provides a normal line rating of 293 Mva and an emergency rating of 334 Mva for summer conditions. For increased transmission capability and lower line losses, KCP&L Transmission Engineering recommended using a line design with two, 1192

ACSR conductors per phase on H-frame wood or steel structures. This design provides a normal line rating of 586 Mva and an emergency rating of 668 Mva for summer conditions. Adding the additional conductor per phase reduces the line's electrical resistance by half and results in reduced transmission losses. Transmission Engineering estimated the cost to rebuild a single conductor per phase line to a two conductor per phase line at $862,200 per mile.

In order to "analyze the feasibility and cost-effectiveness of transmission network loss-reduction measures", KCP&L Transmission Planning staff analyzed the costs and loss reductions associated with rebuilding five of KCP&L's most heavily loaded 161kV transmission lines. This analysis involved calculating new impedances values for the five transmission lines converted from single 1192 conductor to bundled 1192 conductors and performing a loadflow analysis to determine the level of loss reduction for the rebuilt lines. Results of this analysis for 2015 summer peak conditions are shown in Table 1, below.

Table 1: Cost Analysis for 161kV Transmission Line Loss Reduction

TRANSMISSION LINES		2015 SP Flow	LINE IMPEDENCE			LINE	
FROM	TO	MW	R	X	B	MILE	
			1192 ACSR CONDUCTOR				
MARTCTY5	STHTOWN5	203.2	0.00339	0.02230	0.01170	7.76	
WGARDNR5	MOONLT 5	197.4	0.00188	0.01692	0.00928	6.04	
RNRIDGE5	NASHUA-5	169	0.00202	0.01750	0.00930	6.10	
CRAIG 5	LENEXAN5	162.8	0.00100	0.00840	0.00460	3.00	
STILWEL5	HICKMAN5	159.4	0.00460	0.03870	0.02050	13.54	
			TOTAL KCP&L LOSSES AT PEAK LOAD				65.2
			1192 BUNDLED CONDUCTOR				
MARTCTY5	STHTOWN5	236	0.00170	0.01115	0.01630	7.76	
WGARDNR5	MOONLT 5	217.6	0.00094	0.00846	0.01268	6.04	
RNRIDGE5	NASHUA-5	202.4	0.00101	0.00875	0.01281	6.10	
CRAIG 5	LENEXAN5	179.6	0.00050	0.00420	0.00630	3.00	
STILWEL5	HICKMAN5	200.5	0.00230	0.01935	0.02843	13.54	
			TOTAL KCP&L LOSSES AT PEAK LOAD				63.1
MW LOSS REDUCTION using 1192 BD conductor in KCP&L							2.10
TOTAL LINE MILES							42.5
TOTAL COST TO RECONDUCTOR/REBUILD AT $862,200 PER MILE							$36,626,256
AVERAGE COST OF LOSS REDUCTION					$/KW		$17,441

The average cost of loss reduction for these five transmission lines is $17,441/kw. This is approximately five times the average $/kw construction cost of Iatan 2. Clearly transmission loss reduction is not cost effective for KCP&L when compared to the cost of construction for new supply side resources. This is mainly due to the fact that KCP&L already has a relatively low loss transmission system.

The KCP&L transmission system is a relatively low loss network due to good line design, concentration of load, and the distribution of its generation resources throughout its service territory. As shown in Table 2, KCP&L's projected transmission loss as a percent of peak load served for 2015 summer peak load conditions is only 1.7%. The comparative value for the rest of the Southwest Power Pool (SPP) is 2.43%.

Table 2: SPP 2015 Transmission Losses by Area

AREA	Load Mw	Loss Mw	% Loss
515	667.3	20.6	3.1%
520	10168.0	234	2.3%
523	1102.0	21.8	2.0%
524	6197.7	136.6	2.2%
525	1568.4	44.1	2.8%
526	6252.7	201	3.2%
527	356.8	0.4	0.1%
531	440.9	9	2.0%
534	1302.4	33.7	2.6%
536	5817.2	133.4	2.3%
540	2054.5	29.9	1.5%
KCP&L	***3942.8***	***65.2***	***1.7%***
542	501.7	2.2	0.4%
544	1138.9	31	2.7%
545	306.3	2.5	0.8%
546	772.4	10.5	1.4%
640	3778.7	140.7	3.7%
645	2787.0	34.6	1.2%
650	766.7	8.7	1.1%
SPP	49922.4	1159.7	2.3%

1.1.1 DISTRIBUTION SYSTEM OVERVIEW

The various KCP&L planning groups (Supply, Transmission, and Distribution) assimilates a broad set of engineering inputs to determine how the company will invest in improving the respective systems to meet ongoing load growth, system reliability, operational efficiency and asset optimization needs. The Distribution Planning group analyzes data, identifies patterns, develops electrical models representative of the KCP&L distribution system, and performs studies to understand and prioritize system improvement needs.

The inner urban core can be characterized by high utilization of its distribution assets and its aging infrastructure. Reliability risk in this area is addressed by installing replacement or contingency infrastructure. The distribution system over many decades has been built by adding only enough capacity to serve immediate load requirements. These types of problems have been categorized as condition or contingency, and specific recognizable projects like Troost Substation and the Twelfth Street Duct Bank Reconstruction are good examples of this type of investment.

In contrast are the suburban areas of the KCP&L system, where new development of open land requires the build-out of the distribution system. The highest load growth is seen on the fringe, demanding investments to serve new emerging electrical loads – largely a capacity issue. Circuits must be tied together more effectively to allow for contingency switching and disperse the load across a larger number of circuits, all the while expanding substation breaker positions for these new circuits. Many investments like this have been made in recent years, especially around Tiffany Springs, Cedar Creek, and Riley Substations.

The rural areas have the most widespread infrastructure components and have the fewest or most limited emergency ties, where any load manipulation can cause large disturbances to customers' voltage. Distribution Planning carefully examines these systems to assure customer voltages are within tolerance, a process which demands high-quality mapping and device load data. With so many widespread components, acquiring data has become one of the greatest challenges in these areas.

The Distribution Planning group is tasked with elevating the highest priority and highest-risk projects to a point where investments are made earlier than those with lower priorities and risk profiles. Many years of constant review have provided the group with a robust set of criteria within which these problems are evaluated, and even today process improvements are being made to further analyze how well to build out the distribution system to assure cost-effectiveness.

Furthermore, the Long-Term Planning component handled by Distribution Planning assures strategic long-term investments are made. Solutions are selected based upon how well they fit into an area-plan, not only the cost-effectiveness for the immediate need. Between the robust planning criteria and the strategic long-term vision, Distribution Planning will continue to construct the distribution system capable of serving tomorrow's needs by making appropriate investments when they are needed.

In the inner-urban core of Kansas City, the long-term vision involves installing replacement substation assets in new locations to strategically phase-out deteriorated underground components, improve reliability, and provide additional area capacity. Components nearing the end of their useful life can then be abandoned, removed, or rebuilt, and the company will have an upgraded distribution system better suited to reliably serve the inner-urban core of Kansas City well into the future. The Charlotte Substation and associated duct bank projects have been budgeted in the five-year plan and will continue to have components critical to the long term strategy over the next twenty years.

On the suburban fringe, Distribution Planning plots out growth patterns to identify substation sites well ahead of the need. On the Northern edge of the Metro Area, several substation sites have already been purchased in anticipation of future load growth. Distribution Planning constantly reviews the build-out of the distribution system on the suburban fringe as development in Kansas City continues this march North, South, and East of the current Metro Area.

The rural areas of the service territory are envisioned to one day have entirely remotely-received load and condition data – a completely automated system. Today, load information is difficult to obtain, due to inaccurate watt-var charts or costly field load checks during peak periods. Strategic and timely decisions can better be made with abundant characteristic data for the components being studied. Efforts are underway to systematically bring all rural components up to metro-area data acquisition standards.

As KCP&L builds toward its own future here in Kansas City, it is the goal of Distribution Planning to assure that every investment optimizes capital spend and balances risk, meets current and future needs, and is built strategically when and where they are needed.

1.1.2 ANNUAL SCOPE OF WORK

Throughout each year, Distribution Planning prepares a number of system studies to determine weaknesses or risks to reliability and to assess the overall adequacy of our distribution system. The majority of the work focuses on increasing reliability and prioritizing work based upon cost, scope, impact, and effectiveness. This work is centered around four (4) specific areas which include capacity, contingency, voltage and condition. The table below illustrates the various deliverables associated with each focus area:

Table 3: Distribution Planning - Annual Scope of Work

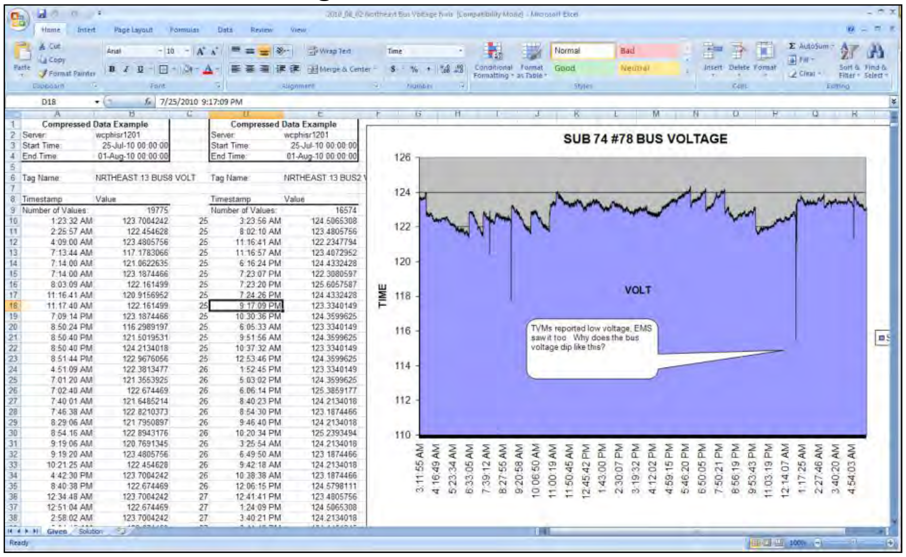
Category	Study Name	Deliverable
Capacity	Load Preservation 5 Yr. System Expansion – Load Device Weather Adjustment 20 Year Forecast Circuit Rating Study	Black Start Plan Budgetary Recommendations Distribution Load Book Forecasted Substation Loads Circuit Rating utilized for Operational Guidance
Contingency	5 Yr. System Expansion – contingency N-1 Circuit Contingency Study N-1 Transformer Contingency Study	Budgetary Recommendations Circuit Contingency Plan Transformer Contingency Plan
Voltage & Losses	Phase Balancing Voltage Drop Studies System Efficiency Studies Capacitor Studies Voltage Regulation Studies	Load-Swap Recommendations DVC Operational Guidance System Loss Studies Capacitor Installations Substation Tap Settings
Condition	Worst Performing Circuits Circuit Review Short Circuit Studies Other Reviews	Budgetary Recommendations Budgetary Recommendations Customer-Required Special Studies

To complete this identified scope of work, KCP&L Planning Engineers utilize a variety of tools that make use of the device loads and system schematics as input. There are several tools currently in use at KCP&L to collect and process this information.

PI/Network Manager

During the summer of 2010, the new Network Manager Energy Management (SCADA) system was placed in-service. With this ABB product KCP&L also acquired the PI Historian data archive, which now contains device loads and other historical system characteristics. Once all system components are merged into the new system, the PI Historian will be the primary archive for engineers to find and extract load and voltage history. The figure below provides a snapshot of PI Historian.

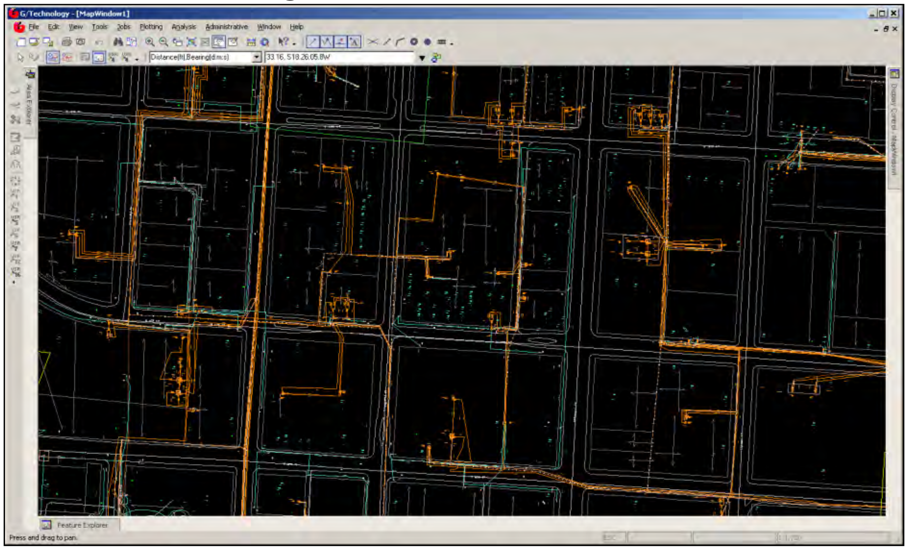
Figure 1: PI Screenshot



GTechnology

The software mapping tool used by Distribution Planning engineers is called GTech. The KCP&L distribution system G.I.S. database is viewed and extracted from GTech, where engineers acquire model data for use in SynerGEE. Device characteristics and connectivity drive load-flow models in use by Distribution Planners. The figure below provides a snapshot of G/Tech.

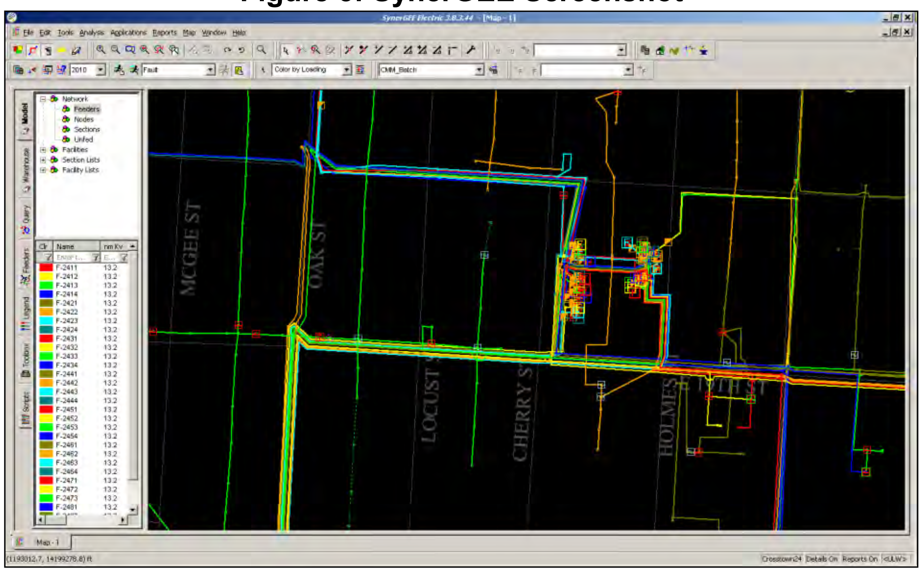
Figure 2: G/Tech Screenshot



SynerGEE

A multipurpose tool primarily used by engineers to analyze load flow characteristics of distribution feeders. Distribution Planning is also responsible for providing fault current information to customer’s electrical contractors when performing arc-flash studies, a process which requires the use of SynerGEE. The figure below provides a snapshot of the SyngerGee software program.

Figure 3: SynerGEE Screenshot



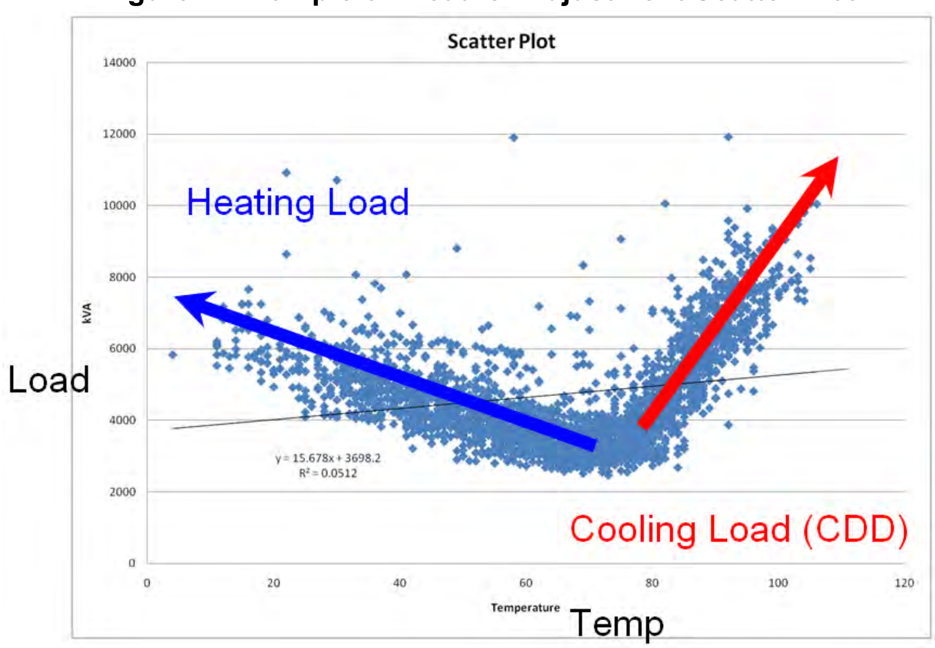
1.1.2.1 Capacity Planning

Device loads, such as substation transformer and distribution circuit loads are collected annually from a number of remote-sensing sources and are weather-adjusted to determine the effects of temperature (heating & cooling). This load data is compared to previous years' loads and device maximum loading to determine how the load is changing over time and if any component is overloaded and in need of an upgrade. These types of problems are given a higher priority than others to assure continued reliability.

1.1.2.1.1 Device Weather Adjustment

The whole system improvement process begins with Device Weather Adjustment. There are a number of ways engineering monitors and records the loads experienced across the distribution system, and however this is done, load data is gathered and tabulated. The daily peak demand is then compared with the daily high temperature (for Winter, the daily low temperature), and a comparison is made using an excel scatter-plot with a linear-regression best-fit line.

Figure 4: Example of Weather-Adjustment Scatter Plot



Distribution Planning cleanses the data using filters to assure outlying data points (abnormal behaviors) are omitted from the study. What results is a linear equation, where the variable ‘x’ refers to the temperature. For ‘x’, Distribution Planning inserts 100 degrees Fahrenheit, the chosen planning temperature at KCP&L. This then yields a weather-adjusted peak demand, which is utilized throughout the rest of the planning process.

Figure 5: Example Scatter Plot after data filtered to show collating loads

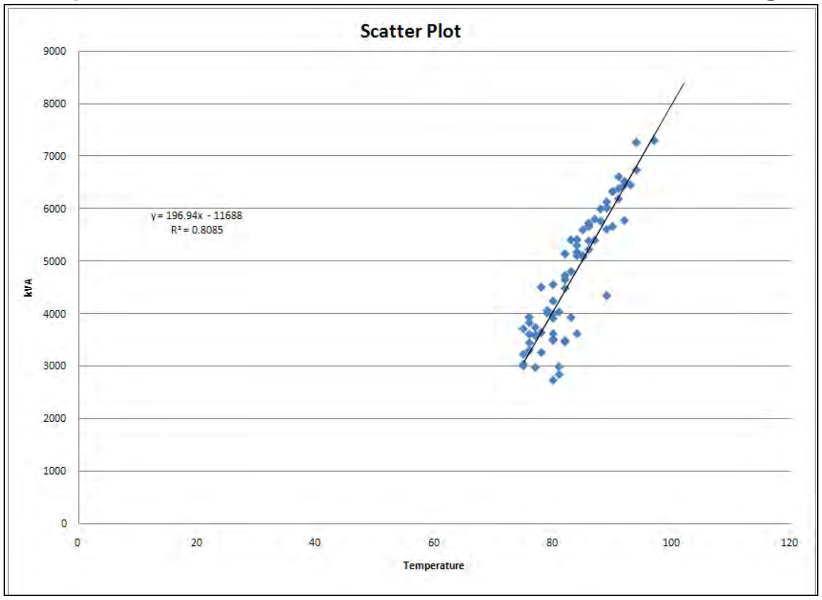
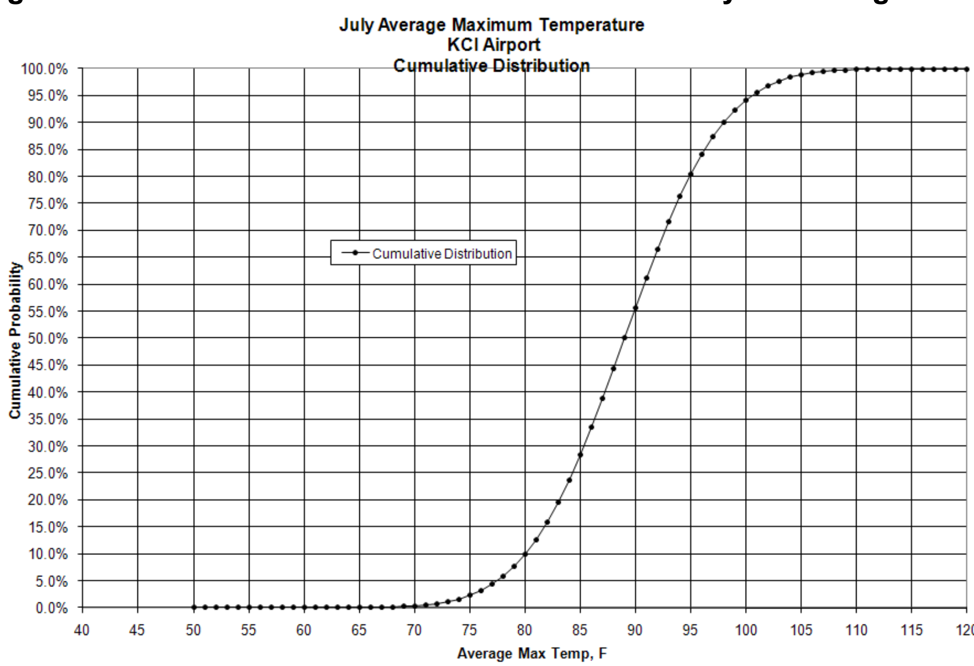


Figure 6: Cumulative Distribution Plot - 95% certainty at 100 degrees F



For load driven higher by increasing temperatures, the chart above shows at what temperature the Kansas City Area tops out. Temperatures above 105 degrees Fahrenheit are almost nonexistent historically and statistically. For Kansas City, the 95% mark (5% of the time temperature runs hotter) is 100 degrees F. For Distribution Planning, taking 5% risk means planning to a weather-adjusted temperature of 100 degrees F.

One hundred degrees Fahrenheit planning temperature was chosen for several reasons. First, Corporate Planning uses 100 degrees for their studies, and Distribution Planning felt it appropriate to match their criteria for distribution expansion projects. Second, 100 degrees represents a five percent risk, meaning there is a five percent chance in any given year the temperature will exceed 100 degrees on at least one day, sending system loads beyond designed capacity. Third, 100 degrees best-matched the previous design criteria in terms of system improvement dollars needed in a given year.

1.1.2.1.2 Circuit Rating Study

Armed with weather-adjusted loads, Distribution Planning can produce ratings for each circuit. Again, this study is done in several different ways depending on the configuration and style of the distribution components being looked at. The most complex of these studies deals with underground feeder cables within duct bank, which de-rate each other by mutual heating. Distribution Planning uses weather-adjusted loads to determine capacity 'choke-points' in order to rate the circuit. These ratings are provided to operations to set alarms, and become an integral part of the N-1 Contingency Study. These ratings are also compared with native device loads to determine where normal-load capacity expansions are needed.

Figure 7: Screenshot from Cable De-rating Program

Description	Duct Bank from M.H. 2312 East to M.H. 2313		
Rows	6	***# of Positions***	
Columns	2	10	
Ambient	22		
Earth Rho	90		

Position	*Circuit*	*load factor*	*running load*	*vertical*	*horiz.*	*Nom Ckt Voltage*	*Duct Type*	*Cable Type*
1	1561	0.67	204	77.8	5.6	13	4.5"-Fibre	1-400 KCM-3C PILC
2	7472	0.67	35	77.8	12.9	13	4.5"-Fibre	1-400 KCM-3C PILC
3	1574	0.67	201	70.5	5.6	13	4.5"-Fibre	1-750 KCM-3C PILC
4	1511	0.67	123	70.5	12.9	13	4.5"-Fibre	1-750 KCM-3C PILC
5	1743	0.67	185	63.2	5.6	13	4.5"-Fibre	1-750 KCM-3C PILC
7	1567	0.67	109	55.9	5.6	13	4.5"-Fibre	1-750 KCM-3C PILC
9	7432	0.67	228	48.6	5.6	13	4.5"-Fibre	1-750 KCM-3C PILC
10	1522	0.67	178	48.6	12.9	13	4.5"-Fibre	1-750 KCM-3C PILC
11	1523	0.67	180	41.3	5.6	13	4.5"-Fibre	1-750 KCM-3C PILC
12	1512	0.67	195	41.3	12.9	13	4.5"-Fibre	1-750 KCM-3C PILC

Circuit	*Load (A)*	*Oper. Temp.*	*Norm. Amp.*	*Norm. MVA*	*Emerg. Amp.*	*Emerg. MVA*
1561	204	50.6	380	8.68	428	9.78
7472	35	37.8	369	8.44	418	9.55
1574	201	45.1	522	11.93	575	13.15
1511	123	40.6	520	11.88	575	13.15
1743	185	44.0	522	11.94	575	13.15
1567	109	40.3	522	11.93	575	13.15
7432	228	45.7	536	12.26	575	13.15
1522	178	42.4	533	12.19	575	13.15
1523	180	41.0	544	12.44	575	13.15
1512	195	41.7	546	12.47	575	13.15

1.1.2.1.3 Spatial Electric Load Forecast Study (Electric Vehicle Study)

KCP&L with the help of Integral Analytics, Inc. (IA) conducted a rigorous electric vehicle impact study and a long-range spatial load forecast study. The study details long-range substation load growth due to increases in employment, population, and estimates the future adoption of electric vehicles at different penetration levels for the entire KCP&L service territory. The study intent was to help distribution planners identify future capacity constrained areas due to future electric vehicle load additions and to proactively plan for distribution expansion work before system loading became an issue.

Electric vehicles present a significantly large end use load to the distribution system. To study the potential distribution impact of vehicle electrification, one must understand the customer key drivers of adoption. Therefore, IA designed a discrete choice survey and recruited 113 KCP&L residential customers randomly to participate in a discrete choice survey online. The survey results were processed and unique electric vehicle adoption and charging behavior segments were developed. The segmentation was applied to the KCP&L customer base with demographic information pulled from the Experian database. A probability of adoption score was assigned to each KCP&L customer based on the segmentation analysis. The scoring identified the customers most likely to purchase electric vehicles. Finally, the customers were mapped geographically to locate potential electric vehicle customer clusters at different penetration levels in the KCP&L service territory.

The worst case scenario of 100 percent of new vehicles sold in the KCP&L service territory are electric vehicles show, on average, the load will increase by 2,500 kilowatts per substation over the next 20 years. Therefore, residential electric vehicle charging at the local or neighborhood levels will resemble normal load growth. KCP&L annually reviews distribution feeder capabilities and implements necessary upgrades to meet the electricity requirements. KCP&L does not anticipate substation loading issues. However, KCP&L does anticipate localized loading issues at the distribution line transformer level providing service to a cluster of customer who all adopt EV. Localized distribution line transformer loading can be easily resolved by upgrading the size of the transformer.

The electric vehicle impact study provides distribution planning a 20 year forecast of future loading by substation for different electric vehicle penetration scenarios. The scenario based planning methodology has allowed distribution planning to understand the impact of electric vehicles in the KCP&L service territory at the substation level. The electric vehicle study did highlight a few potential loading issues but overall the impact of electric vehicles on the distribution networks will to be very minimal over the next 20 years. Appendix 4.5.A contains a complete copy of the “Spatial Electric Load Forecast Study”.

1.1.2.2 Contingency Planning

Contingency Planning is similar to Capacity Planning in its view of loads compared to device capacity, but deals in an N-1 contingency setting. KCP&L designs its system to withstand a failure of any one component at a given time. It is the responsibility of Distribution Planning Engineers to determine system weaknesses which do not comply with this and to make the necessary changes to allow emergency switching to restore power without overloading backup devices. These issues have a secondary priority in the budgetary process.

1.1.2.2.1 N-1 Contingency

The annual contingency study will provide the earliest indication of system improvement needs. It is more likely wire upgrades will be needed in the case of feeder or transformer loss, rather than there being simply too much native load on a single feeder or substation transformer. For Distribution Planning, the N-1 Contingency Study is a very systematic and complex process due to the magnitude of the individual distribution system circuit components. SynerGEE is the primary software tool in use to determine the load flow across a circuit. Distribution Planners break apart circuits into segments of load, and establish switching orders for restoration in the case of a feeder or substation transformer loss. SynerGEE, using G.I.S. models exported from GTech and weather-adjusted load data, actually determines how that load is spread across the circuit by taking a third input from the C.I.S. – metered customer load data. The SynerGEE CMM Module allows Distribution Planning to allocate feeder breaker weather-adjusted load on a given feeder based upon how it appears by its metered customer load, which is typically measured in kWh.

Three very complex inputs into one N-1 Contingency Study using a highly-technical software program yields effective results determining where system improvement is needed. By using the model to rearrange the configuration of circuitry using SynerGEE, Distribution Planning can detect where mapping errors exist, where low voltage can be problematic, and where wire sizes can limit how the distribution system is operated. Contingency Planning is an intensely complex process taking significant engineering time in order to determine system weaknesses for a given planning year. The study is completed every year for every distribution feeder and for the loss of every substation transformer.

These weaknesses, once identified, are further analyzed to determine the impact to system reliability and are ranked against each other correspondingly. Ultimately, this ranking, energy efficiency impacts, reliability and customer impact risks, and the project cost determine whether a system improvement is constructed or not. Distribution Planning therefore must not only identify the weakness, but provide some budgetary estimation and project description. It also becomes the responsibility of Distribution Planning to thoroughly communicate why a project exists throughout the company, until it becomes part of the approved budget and is handed-off to a design engineer for sponsorship.

1.1.2.3 Distribution Voltage

At the customer-end of any given line, distribution voltage must be maintained within specific tolerances. It is the responsibility of Distribution Planning to assure system-level issues do not adversely affect the voltage received by KCP&L customers. To do this, G.I.S. models are used in a load-flow program called SynerGEE to simulate voltage levels in the field. In addition to supplying adequate voltage levels to our customers, we also strive to maintain an efficient low-loss distribution system. Several examples of this are the annual load balancing efforts and capacitor studies to optimize voltage levels and reduce system losses.

1.1.2.3.1 Loss Studies

Another method of analyzing overall system efficiency is through the performance of system loss studies. These are done periodically and the information gathered is used by Planning Engineering as well as in rate case filings. The most recent system loss study was performed by Siemens in October, 2014. A complete copy of this study, “Kansas City Power and Light Electric System Loss Analysis”, can be found in Appendix 4.5.B.

1.1.2.3.2 KCP&L Green Circuits Analysis

Another example of KCP&L's efforts to improve overall circuit efficiency and reduce system losses was a study commissioned by KCP&L and completed by EPRI (Electric Power Research Institute). This study analyzed various loss reduction options such as phase balancing, capacitor controls, re-conductoring, and/or voltage optimization. The information gathered by this study has been used by Planning Engineering to optimize their approach to circuit construction, configuration and operation. A complete copy of this study, "KCP&L Green Circuits Analysis Study", can be found in Appendix 4.5.C.

1.1.2.3.3 Transformer Efficiency Analysis

Currently, KCP&L purchases transformers based on the Total Ownership Cost (TOC), which includes the transformer purchase price as well as the cost of the no-load and load-losses associated with each transformer, capitalized over a 30 year expected transformer life. As of 2010, all KCP&L transformers were purchased utilizing the Department of Energy (DOE) transformer efficiency standards, which has enabled KCP&L to optimize the TOC of all transformers over a 30 year period.

1.1.2.4 Condition

Another important focus area for Planning Engineering deals with component conditions and their effect on reliability as it relates to capacity, contingency, voltage and overall system efficiency. Ongoing strategic planning to maintain reliability must account for device degradation over time, and planning engineers look for cost-effective replacement or maintenance opportunities where they coincide with capacity expansion plans. By working with the Asset Management group to determine the best course of action, these replacements in some cases are combined into Distribution Planning's capacity expansion projects – an increase in project scope from the normal course of action. System expansion to replace degraded system components can be a more cost-effective solution than the "run-to-failure" strategy.

1.1.2.4.1 URD Cable Replacement Programs

Currently, there are two cable replacement programs in existence at KCP&L: 1) Proactive Cable Replacement, and 2) Reactive Cable Replacement.

The proactive cable replacement program uses a mix of analysis techniques. One technique does partial discharge testing of entire underground loops and replaces the cable sections that do not pass this test. Another option is to look at the number of failures on the loop and calculate the number of segments that have had failures. If this percentage is greater than 40%, the cable segments on the entire loop are eligible for replacement. These methods provide targeted proactive cable replacements based on cable condition or failure history. The goal is to target high-risk cables, and replace these cable segments before failure.

The reactive cable replacement program requires replacement of a cable when it has failed two or more times. The current policy of the reactive URD replacement program is to replace any direct buried cable after its second failure with cable in conduit. A section of cable receives a priority which is a function of the number of customers affected by the cable outage, the duration of the outage, the vintage of the cable, the number of failures of cable, the time elapsed from the most recent failure, and the number of outages that the lateral has experienced in past 12-months.

1.1.2.4.2 Cable Injection Program

In addition to cable replacement, cable injection proactively addresses high-risk cables. Cable injection techniques prolong the cable's life and improve reliability. Injection can be performed on cables that have faulted, but as with proactive replacement, the goal is to prevent failures from happening in the first place. Injection contractors provide a minimum warranty of 20 years, with the option to upgrade to as much as 40 years with better injection fluids. Cable injection companies are used by KCP&L to perform these activities.

1.1.2.4.3 Worst Performing Circuit Analysis

The inventory assessment projects have given Kansas City Power and Light an advantage that we can employ with worst performing circuit analysis. Annually, we identify worst performing circuits as mandated by the MPSC and develop reliability plans and make repairs. The performance of circuits varies significantly and no two of them have identical problems to fix. We use the assessment data to be included in our analysis of those worst performing circuits. There are approximately 70 to 80 WPC's under review each year that covers Missouri and Kansas's regulatory rules. Pole Replacement and Reinforcement Program

1.1.2.4.4 Pole Replacement and Reinforcement Program

The Distribution Pole Replacement/Reinforcement Program addresses reliability issues associated with the condition of distribution poles. Per MPSC mandate, KCP&L annually conducts a ground-line inspection of the system to determine if there is a need to replace or reinforce distribution poles. The evaluation includes an examination for indications of decay and/or fungi at or below ground level, hollowness and shell rot. When a pole is identified for replacement or reinforcement, the Company uses an independent contractor who is an expert in pole evaluation, maintenance, and repair, to prioritize and coordinate pole maintenance or replacement. The work is prioritized based on conditions with the greatest risk to safety and impact to customer reliability. Annual pole rejection rate is calculated to be 0.0356% per 1,000 pole inspections.

1.1.2.4.5 Lateral Improvement Program

This program is an organized effort to evaluate the performance of all laterals on our system. The criteria considered for fuse lateral selection are customer interrupted and outage frequency. Examples shown in Figure 8 below are all laterals to consider for analytical reviews to determine critical value. The blue circle drawn around the areas with the highest critical values is the chosen laterals. Laterals tagged as critical value represents 0.9% of the total. Figure 8 show customers interrupted ranges starting at 400 customers interrupted (CI) down to less than 49 CI per event. Frequency rate is identified by using letters starting with (A), (B), (C), and (D). Each letter category represents 25% of the total frequency rate equal to 100%. The numbers within the figure are lateral counts in each category. For instance, IR (1-2) means one or two outage events occurring on a lateral. The selection scheme has proven to be the best approach.

Figure 8

Criteria for Fuse Lateral Selection – Critical Values				
	Frequency Rate			
Customers Interrupted	A IR(1-2)	B IR(3-5)	C IR(6-7)	D IR> (8)
400-300	13			
299-200	45	4		
199-100	250	24	1	
99-50	600	63	2	1
49<	5,062	312	8	1
Totals	5,970	403	11	2

1.1.2.4.6 Proactive Retirement of 50 MVA Substation Transformers

The Asset Management group has also proactively undertaken a study to asses KCP&L’s fleet of 50 MVA dual-secondary winding transformers, determine their risk of failure, and develop a retirement/replacement program. The condition of each transformer is primarily based upon dissolved gas analysis taken from annual transformer oil sampling. KCP&L utilizes a transformer analysis package that categorizes each transformer as a category 1, 2, 3, or 4, with category 4 being the worst condition. This program reduces the overall operational risk associated with transformers that are identified as being at a higher risk for failure.

1.1.2.4.7 Mobile Substations

Asset Management is also looking into the purchase of 2 mobile substation units to reduce the risk of long-term power outages in the event of a failure of a high-voltage substation transformer. Presently, there is a need for several units with various capacities and voltage levels in addition to the mobile units KCP&L and KCP&L GMO currently have in their fleet. Purchase of these additional units will provide greater operational flexibility while also minimizing spare transformer inventory throughout KCP&L's service areas.

1.2 ASSESEMENT OF INTERCONNECTING NEW FACILITIES

(B) Interconnect new generation facilities. The utility shall assess the need to construct transmission facilities to interconnect any new generation pursuant to 4 CSR 240-22.040(3) and shall reflect those transmission facilities in the cost benefit analyses of the resource options;

KCP&L Transmission Planning must plan to meet interconnection needs of transmission customers for connection to and use of the KCP&L transmission system. The Interconnection procedures are covered within the Federal Energy Regulatory Commission (FERC) approved transmission tariff provisions where customers are provided detailed transmission studies and interconnection estimates for connecting to and using KCP&L's transmission system.

An example of such is the 2014 review of potential sites for addition of new KCP&L generation resources that considered large additions (620 MW combined cycle units), medium size additions (200 MW simple cycle units), and small incremental additions (100 MW reciprocating engine units). This process included review of brown field (existing) and green field (new) sites within or near the KCP&L and GMO service territories. KCP&L 161 kV transmission lines are generally not adequate to provide firm transmission for a 620 MW generation resource unless multiple (2+) transmission lines are available for generation outlet. KCP&L 345 kV transmission lines can generally provide firm transmission for a 620 MW generation resource if there is available transmission capacity.

The resource siting study identified potential sites for addition of large, mid, and small generation resources. Transmission Planning provided a range of transmission costs for each site and identified potential transmission limitations.

Any KCP&L generation resource addition that would impact transmission level (>60 kV) flows would have to proceed through the SPP Generation Interconnection process before it could be interconnected to the transmission system. The resource addition would also have to be included in the SPP Aggregate Facility Study process to obtain firm transmission service for delivery of generation to load.

1.3 ASSESSMENT OF TRANSMISSION UPGRADES FOR POWER PURCHASES

(C) Facilitate power purchases or sales. The utility shall assess the transmission upgrades needed to purchase or sell pursuant to 4 CSR 240-22.040(3). An estimate of the portion of costs of these upgrades that are allocated to the utility shall be reflected in the analysis of preliminary supply-side candidate resource options; and

KCP&L is member of the Southwest Power Pool (SPP) a Regional Transmission Organization (RTO), mandated by the Federal Energy Regulatory Commission to ensure reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices of electricity. As a North American Electric Reliability Corporation (NERC) Regional Entity, SPP oversees enforcement and development of reliability standards. SPP has members in nine states. As a member of SPP, KCP&L participates in the regional transmission expansion plan processes of the RTO. Two recent expansion plan processes conducted by SPP are the Balanced Portfolio (June 2009) and the Priority Projects (April 2010).

The Balanced Portfolio is an SPP strategic initiative to develop a grouping of economic based regional transmission upgrades that benefit the SPP region while allocating the cost of the upgrades regionally. Projects in the Balanced Portfolio include transmission upgrades of 345 kV projects that will provide customers with potential savings that exceed project costs. These economic upgrades are intended to reduce congestion on the SPP transmission system, resulting in savings in generation production costs. Economic upgrades may provide other benefits to the power grid; i.e., increasing reliability and lowering required reserve margins, deferring reliability upgrades, and providing environmental benefits due to more efficient operation of assets and greater utilization of renewable resources. SPP analyzed the benefits and costs of the Balanced Portfolio and established that these projects provided a region-wide per-customer average benefit of $1.66/month with a corresponding cost of $0.88/month. The Balanced Portfolio included a total of seven transmission projects with an estimated engineering and construction cost of approximately $700 million (initial estimate). Two of these projects are within the KCP&L service territory. They are the Iatan – Nashua 345 kV line (~$65 million) and the Swissvale-Stilwell tap at West Gardner (~$2 million).

In the Priority Projects plan, SPP sought to identify, evaluate, and recommend transmission projects that would improve regional production costs, reduce grid congestion, enable large-scale renewable resources (primarily wind), improve the Generation Interconnection and Aggregate Facility Study processes, and better integrate SPP's east and west regions. A total of six transmission projects with an estimated cost of $1.1 billion were selected for construction in the Priority Projects process providing a variety of benefits to the region. One of the projects included is a GMO project as the Nebraska City-Mullin Creek-Sibley 345 kV transmission line. These Priority Projects achieve the strategic goals of reducing transmission congestion, improving the Aggregate Facility Study process by creating additional transfer capability and increasing the ability to transfer power in an eastward direction for the majority of the transmission paths between SPP's western and eastern areas.

The costs for the Balanced Portfolio and Priority Projects will be allocated on a regional basis by specific allocation methods whether or not KCP&L makes any resource additions. For this reason, KCP&L's share of the allocated costs for Balanced Portfolio and Priority Projects were not reflected in the analysis of preliminary supply-side candidate resource options.

The preferred resource plan for KCP&L includes additional wind and solar generation resources. The solar resources are relatively small amounts of generation and are assumed to be interconnected at the distribution voltage levels. For this reason there is no associated transmission interconnection or upgrade costs for these solar generation resources. The wind resources remotely located in western Kansas will utilize regional transmission capacity and transmission service to deliver their output to KCP&L loads. Any new generation resources would have to apply for interconnection through the SPP generator interconnection process and apply for transmission service in the SPP Aggregate Study process.

1.4 ASSESSMENT OF TRANSMISSION OR DISTRIBUTION IMPROVEMENTS WITH RESPECT TO COST EFFECTIVENESS OR DSM OR SUPPLY-SIDE RESOURCES

(D) Incorporate advanced transmission and distribution network technologies affecting supply-side resources or demand-side resources. The utility shall assess transmission and distribution improvements that may become available during the planning horizon that facilitate or expand the availability and cost effectiveness of demand-side resources or supply-side resources. The costs and capabilities of these advanced transmission and distribution technologies shall be reflected in the analyses of each resource option.

1.4.1 CAPACITOR AUTOMATION EFFORTS

KCP&L, an industry leader in Distribution Automation (DA), began its automation initiatives in the early 1990's by deploying several hundred automated capacitors in the metropolitan area using the CellNet fixed network communication system also used for the automated meter reading system (AMR) at that time.

Since the early 1990’s, KCP&L has worked with Sensus (formerly Telemetric) to develop automated capacitor controls with integrated radios for use throughout the KCP&L service territory. This technology uses radios that leverage the commercial cell coverage infrastructure while also providing secure communications and technology applications for KCP&L users. This added technology is particularly cost effective and successful in rural and other areas where other communication infrastructure is not cost effective.

In anticipation of retirement of the CellNet fixed network system due to it’s replacement with a new AMI mesh network, KCP&L has contracted with Sensus to pilot their Flexnet communications system. Flexnet utilizes cellular radio technology, but on a private cellular network rather than commercial cellular coverage. The original target for Flexnet will be to replace the Cellnet communications up through the second half of 2015. KCP&L will evaluate the Flexnet pilot to determine if it can be economically expanded for greater coverage.

The business case for automated capacitors includes:

- Upgrade existing capacitors with controls with new technical features
    - Voltage Override
    - Neutral Sensing
    - Limiting number of switching operations per day
    - Ability to change setpoints remotely
    - Ability to obtain power quality data for improved customer service
- Optimizing utilization of these existing capacitor banks
- Enhancing safety for KCP&L workers
    - Five minute time delay in control for a close after an open
    - One minute timer for close after faceplate control operation
- Reduced O&M

- Limiting number of capacitor patrols due to real time data
    - Limiting number of customer voltage complaints
    - Extending life of existing capacitor switches

- Improved Distribution and Transmission Power Factor
    - Enhance System Stability
    - Enhance system volt/VAr response
    - Increase system efficiency

1.4.2 DYNAMIC VOLTAGE CONTROL

KCP&L also has been a pioneer in demand reduction from voltage reduction during peak summer loading. KCP&L already had a progressive capacitor automation system in place. This became the foundation for another successful KCP&L distribution automation project called Dynamic Voltage Control (DVC).

The business case for this project is as follows:

MW Demand reduction from controlled voltage reduction

Better substation voltage regulation

Improved process for load tap changer setpoints

Integration of substation load tap changer and distribution capacitors by settings and practical application versus complex feedback loops

Remote control of load tap changer for planned switching

Provide Remote setpoint changes for authorized users

Release MVAr in support of transmission and distribution system

The project involved replacing electromechanical and non-communicating load tap changer controls with electronic load tap changer controls that use DNP (Distributed Network Protocol) messaging. This intelligent electronic device (IED) streams DNP messaging into a remote terminal unit (RTU). KCP&L developed

EMS screens and applications to support remote setpoint changes as well as the ability to see the actual settings values.

KCP&L installed this system throughout the legacy KCP&L metro area from 2005-2008. KCP&L dispatchers now use the system to successfully accomplish all the desired tasks shown above. KCP&L performed various proof of concept tests on the use of DVC to reduce demand on system peak. The tests showed a reduction of 0.92% MW reduction for each 1.0% voltage reduction upon system peak. This extrapolates to nearly 50 MW reduction on the KCP&L metro system during summer peak conditions.

SECTION 2: AVOIDED TRANSMISSION AND DISTRIBUTION COST

(2) Avoided Transmission and Distribution Cost. The utility shall develop, describe, and document an avoided transmission capacity cost and an avoided distribution capacity cost. The avoided transmission and distribution capacity costs are components of the avoided demand cost pursuant to 4 CSR 240-22.050(5)(A).

The KCP&L transmission projects included in the SPP regional planning processes for reliability improvement or economic benefits would not be impacted by the implementation of DSM programs. Therefore, the only avoided cost for transmission facilities are the transmission equipment additions associated with distribution facility expansions.

2.1 IMPACT OF DSM ON DISTRIBUTION EXPANSION

As in the 2012 IRP submittal, KCP&L made assumptions regarding planned system expansion projects in areas that are designated as "growth areas" versus areas designated as "established areas". Again, targeting was focused on capital projects associated within established areas since targeted DSM programs were unlikely to be able to delay the need to expand substations on the fringe of metro-area growth due to the fact that these areas contained significant "green space" with large areas that remain undeveloped.

Distribution Planning's annual review of 20 year load projections revealed the fact that loads for these "established areas" continue to flatten and more commonly, decline, which has eliminated the need for expansion projects in these areas. It seems reasonable that as load growth has fallen off in the established areas, that efficiencies gained by replacing older heating/cooling units, lighting, and other older appliances, would begin to significantly impact peak loads for these areas. In the 2012 IRP submittal, the Gladstone, Claycomo, and Chouteau substations were identified as substations located in established areas where a system expansion project might be needed at some point in the future, making these a good candidate for targeted DSM programs. However, a review of the most recent 20 year projections actually identify these substations to be in modest to significant load decline through year 2034, with total substation loads dropping from as little as 2% at Gladstone to as much as 17% at Choteau substation.

Currently, KCP&L has not identified any specific capital projects located within any established areas that can be specifically targeted for DSM programs. Areas that have been identified as established areas either have sufficient capacity available to absorb the limited growth, or are in load decline. These areas will continue to be monitored by Distribution Planning to determine if future opportunities for targeted DSM might become available. Should economic conditions improve, and/or significant redevelopment occurs in these established areas, opportunities to target DSM programs to delay or eliminate the cost to expand capacities for these areas may again exist.

SECTION 3: ANALYSIS OF TRANSMISSION NETWORK PERTAINENT TO A RESOURCE ACQUISITION STRATEGY

(3) Transmission Analysis. The utility shall compile information and perform analyses of the transmission networks pertinent to the selection of a resource acquisition strategy. The utility and the Regional Transmission Organization (RTO) to which it belongs both participate in the process for planning transmission upgrades.

3.1 TRANSMISSION ASSESSMENTS

(A) The utility shall provide, and describe and document, its—

3.1.1 TRANSMISSION ASSESSMENT FOR CONGESTION UPGRADES

1. Assessment of the cost and timing of transmission upgrades to reduce congestion and/or losses, to interconnect generation, to facilitate power purchases and sales, and to otherwise maintain a viable transmission network;

In 2009, the SPP Board of Directors approved a new Integrated Transmission Planning (ITP) process that will determine the transmission needed to maintain electric reliability and provide near- and long-term economic benefits to the SPP RTO region, which includes all or parts of Arkansas, Kansas, Louisiana, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. Successful implementation of the ITP will result in a list of transmission expansion projects and completion dates that facilitate the creation of a reliable, robust, flexible, and cost-effective transmission network that improves access to the region's diverse resources, including its vast potential for renewable energy. Significant wind energy development is taking place in parts of Oklahoma, Kansas, Nebraska, and Texas.

The ITP is an iterative three-year process that includes a 20-Year, 10-Year, and Near-Term Assessment. The 20-Year Assessment evaluates the high voltage transmission (345 kV +) needs over a 20 year study period to meet load growth and other future scenarios and potential developments. The second iteration of the 20-Year Assessment (ITP20), conducted in 2012-2013, included an examination of high voltage transmission needs while taking into account reliability, economic, and public policy needs. Five distinct futures were considered to account for possible variations in system conditions over the assessment's 20-year horizon, including: (1) business as usual; (2) additional wind assuming a 20% federal Renewable Electricity Standard; (3) additional wind as in item (2) plus approximately 10 GW of additional wind generation to be exported outside of SPP; (4) combined policy, which approximates the effects of additional investment in Demand Side Management and Smart Grid technology, additional wind as in item (2), and a carbon constraint; and (5) a joint SPP/MISO future. The SPP Board of Directors voted to approve the ITP20 Report on July 30, 2013. The cost of the plan was estimated at $560 million through the construction of 405 miles of 345 kV lines, 31 miles of 161 kV lines, and six various 345 kV step-down transformers. KCP&L did receive one transmission project as a result of the ITP20 study – an increase of the 345/161 kV transformer size to 650/715 MVA at Nashua.

The 10-Year Assessment is a value-based planning approach that analyzes the transmission system over a 10-year horizon. Economic and reliability analyses are utilized to identify 100 kV and above solutions for issues identified on the 69 kV and above system, as well as issues identified by the 20-Year Assessment appropriate for the 10-Year Assessment. The second iteration of the 10-Year Assessment (ITP10) was conducted in 2013-2014, with the final report issued in January 2015. Two distinct futures were considered to account for possible variations in system conditions: (1) business-as-usual, which includes all statutory/regulatory renewable mandates and goals resulting in 11.5 GW of renewable resources modeled in SPP, load growth projected by load serving entities, and SPP member-identified generator retirement projections, and (2) decreased base load capacity, which considers factors that could drive a reduction in existing generation. The recommended 2015 ITP10 portfolio was estimated at $273 million engineering and construction cost and includes projects needed to meet potential reliability, economic, and policy requirements. These projects, with a total estimated net present value revenue requirement of $334 million, are expected to provide net benefits of approximately $1.4 billion over the life of the projects under a business-as-usual scenario containing 10.3 GW of wind capacity expected to be contracted by SPP members. Project need dates were identified between 2019 and 2024. KCP&L received one transmission project as a result of the ITP10 study – a voltage conversion of the current Iatan – Stranger Creek 161 kV line to 345 kV. SPP identified the need date for this upgrade as 1/1/2019.

The Near-Term Assessment of the ITP evaluates transmission system reliability in the near-term planning horizon. The Assessment will identify potential problems using NERC Reliability Standards, SPP Criteria, and local planning criteria. Mitigation plans are developed to meet regional reliability needs and identify necessary reliability upgrades for all voltage levels for approval and construction. The most recent iteration of the Near-Term Assessment (ITPNT) was conducted in 2014, with the final report issued in January 2015. The 2015 ITPNT used two scenario models built across multiple years and seasons to account for various system conditions across the near-term horizon. The first scenario contains projected transmission transfers between SPP legacy BAs and generation dispatch on the system. The second scenario maximized all applicable confirmed long-term firm transmission service with its necessary generation dispatch. Additionally, a Consolidated Balancing Authority (CBA) model scenario was built across the same years and seasons to show the needs on the SPP transmission system as a result of a Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED). SPP performed reliability analyses identifying potential bulk power system problems. These findings were presented to Transmission Owners and stakeholders to solicit transmission solutions. Also considered were transmission options from other SPP studies, such as the Aggregate Study and Generation Interconnection processes. From the resulting list of potential solutions, staff identified the best regional solutions for potential reliability violations. Staff presented these solutions for member and stakeholder review at SPP's December 2014 planning summit. Through this process, SPP developed a final list of 69 kV and above solutions necessary to ensure the reliability in the SPP region in the near-term. Engineering and Construction (E&C) cost estimates for new and modified reliability projects needed in the years 2015-2020 totaled $248.2 million. In the 2015 ITPNT assessment, an upgrade to the S. Waverly 161/69kV transformer was selected as the solution to six unique reliability needs, four in KCP&L and two in GMO. SPP identified the need date for this upgrade as 6/1/2015.

The ITP process has been a fundamental change in the way in which transmission planning occurs in the SPP region. This process, with its iterative nature and wide range of planning periods, helps to ensure robust planning, lowest cost solutions and a reliable bulk electric grid for the region. It also strengthens the balance between future needs of the system with an ever-changing grid topology, load growth, generation resources, energy policy and planning criteria.

3.1.2 TRANSMISSION ASSESSMENT FOR ADVANCE TECHNOLOGIES

2. Assessment of transmission upgrades to incorporate advanced technologies;

KCP&L currently makes use of four advanced technologies in its transmission system; Real Time Line Rating, Hybrid Structure Design, Solid Dielectric Cables, and Fiber Optic Shield Wire.

KCP&L currently uses a commercial application, based upon actual conductor tension, to provide real time line ratings for two of the more critically loaded 345 kV transmission lines. Basing the ratings upon a direct measurement of the actual conductor tension is the most direct method currently available to establish real time (dynamic) conductor ratings, and using the conductor tension captures all of the local conditions that affect the conductor tension and current carrying capacity. The real time line ratings are provided not only to our Transmission System Operators but also to the SPP Reliability Coordinator. This equipment allows transmission lines to carry more power when conditions are favorable and reduce transmission congestion.

KCP&L uses a hybrid steel and wood H-Frame structures for both single and double circuit applications. Using steel poles, provides easier installation due to their lower weights compared to other materials, and the use of wood X-bracing provides a cost effective option to conventional steel bracing and allows us to use established stock materials. Steel replacement arms and bracing for both 161 and 345 kV H-Frame structures are used to reduce construction and maintenance costs. Each assembly is rated for helicopter installation weight not to exceed 800 pounds per lift. This layout allows the use of smaller helicopters for both energized and normal maintenance change out work.

KCP&L is using solid dielectric cables at 161 kV for specific applications at power plants where limited space made conventional bus or overhead circuit installations impractical or impossible. The cable design is based on 230 kV cable specifications with insulation levels for 161 kV operation.

KCP&L currently uses optical ground wire (OPGW) for most or all of new shield wire installations. This gives not only superior lightning performance, due to the lower resistance of the OPGW compared to conventional galvanized steel strand shield wires, but also provides a high capacity path for internal communications and system protection functions. The standard OPGW options provide either 48 or 72 single mode fibers per shield wire.

3.1.3 <u>AVOIDED TRANSMISSION COST ESTIMATE</u>

3. Estimate of avoided transmission costs; 22.045 Transmission and Distribution Analysis,

The KCP&L transmission projects included in the SPP regional planning processes for reliability improvement or economic benefits would not be impacted by the implementation of DSM programs. Therefore, the only avoided cost for transmission facilities are the transmission equipment additions associated with distribution facility expansions.

3.1.4 REGIONAL TRANSMISSION UPGRADE ESTIMATE

4. Estimate of the portion and amount of costs of proposed regional transmission upgrades that would be allocated to the utility, and if such costs may differ due to plans for the construction of facilities by an affiliate of the utility instead of the utility itself, then an estimate, by upgrade, of this cost difference;

Table 4 below shows the SPP projected annual transmission revenue requirement allocated to KCP&L for regional transmission upgrades.

Table 4: SPP Projected ATRR Allocated to KCP&L

YEAR	ANNUAL TRANSMISSION REVENUE REQUIREMENT ALLOCATED TO KCP&L
2015	$ 34,055,762
2016	$ 37,509,508
2017	$ 42,874,706
2018	$ 48,640,102
2019	$ 52,219,837
2020	$ 52,602,949
2021	$ 53,879,998
2022	$ 53,677,035
2023	$ 52,613,087
2024	$ 50,997,005
2025	$ 49,380,922

On April 4, 2012 Great Plains Energy ("GXP"), the holding company for both KCP&L and GMO, and American Electric Power ("AEP") announced the formation of a company to build and invest in transmission infrastructure. The new company, Transource EnergySM LLC ("Transource"), will pursue competitive transmission projects in the SPP region, the MISO and PJM regions, and potentially other regions in the future. GXP owns 13.5 percent of Transource through its newly-formed subsidiary, GPE Transmission Holding Company, LLC (“GPETHCO”). AEP owns the other 86.5 percent of Transource through its subsidiary, AEP Transmission Holding Company, LLC (“AEPTHC”).

At this point, it is GXP’s intent to pursue, develop, construct, and own through GPETHCO’s interest in Transource – rather than through KCP&L and/or GMO – any future regional and inter-regional transmission projects subject to regional cost allocation. While it is premature to determine the specific impact on the regionally allocated costs resulting from constructing projects within Transource, it is anticipated that the partnership between GXP and AEP will provide for a financially-strong, cost-competitive, and technically-proficient transmission development entity. The scale, execution experience, and engineering expertise that Transource expects to be able to bring to the projects should provide benefits to customers through lower construction costs, better access to capital, and operational efficiencies.

3.1.5 REVENUE CREDITS ESTIMATE

5. Estimate of any revenue credits the utility will receive in the future for previously built or planned regional transmission upgrades; and

Estimated Transmission Service revenue that KCP&L will receive is based on the amounts included in FERC account 456100.

Table 5 below shows historical and projected amounts for account 456100 for 2012-2025. The revenue credit process for future regional transmission upgrades has not been fully developed by SPP at this time and is not included in these projections.

Table 5: KCP&L Transmission Service Revenues from SPP

YEAR	TS REVENUE	BASIS
2012	$10,080,825	actual
2013	$8,402,688	actual
2014	$9,135,432	forecast
2015	$8,989,824	budget
2016	$8,989,824	projected
2017	$8,989,824	projected
2018	$8,989,824	projected
2019	$8,989,824	projected
2020	$8,989,824	projected
2021	$8,989,824	projected
2022	$8,989,824	projected
2023	$8,989,824	projected
2024	$8,989,824	projected
2025	$8,989,824	projected

3.1.6 TIMING OF NEEDED RESOURCES ESTIMATE

6. Estimate of the timing of needed transmission and distribution resources and any transmission resources being planned by the RTO primarily for economic reasons that may impact the alternative resource plans of the utility.

The SPP Balanced Portfolio of regional transmission projects included two projects in the KCP&L service territory. The Swissvale – Stilwell 345 kV tap at West Gardner and the Iatan – Nashua 345 kV line are primarily economic-based transmission projects. The Swissvale – Stilwell 345 kV tap at West Gardner was placed into service on 1/1/2013. The expected in-service date for Iatan – Nashua 345 kV is 6/1/2015.

The 2015 ITP10 identified one economic project in the KCP&L service territory – a voltage conversion of the current Iatan – Stranger Creek 161 kV line to 345 kV. The need date for this project was identified as 1/1/2019.

These projects were identified within the SPP transmission planning process to reduce transmission congestion and provide regional production costs and trade benefits. They will have minimal impact on KCP&L alternative resource plans.

3.2 USE OF RTO TRANSMISSION EXPANSION PLAN

(B) The utility may use the RTO transmission expansion plan in its consideration of the factors set out in subsection (3)(A) if all of the following conditions are satisfied:

See response to Section 3.1.1 above for description of SPP RTO transmission expansion planning processes.

3.2.1 UTILITY PARTICIPATION IN RTO TRANSMISSION PLAN

1. The utility actively participates in the development of the RTO transmission plan;

KCP&L actively participates in the development of SPP transmission expansion plans through a number of related activities. These include participation in the Model Development Working Group (MDWG), the Transmission Working Group (TWG), and regional transmission expansion workshops

Participation in the MDWG involves reviewing and updating the transmission planning models used for regional transmission expansion analysis. This includes adding KCP&L transmission projects into the planning models and providing a substation level load forecast for the seasonal and future years planning models. The expected generation dispatch required to meet KCP&L load requirements is also included in these models. These models form the basis for the reliability analysis needed to identify future transmission projects to maintain reliable service and reduce transmission congestion.

The Transmission Working Group (TWG) is responsible for planning criteria to evaluate transmission additions, seasonal Available Transfer Capability (ATC) calculations, seasonal flowgate ratings, oversight of coordinated planning efforts, and oversight of transmission contingency evaluations. The TWG works with individual transmission owners on issues of coordinated planning and North American Electric Reliability Corporation (NERC) and SPP compliance. The TWG coordinates the calculation of the ATC for commerce maintaining regional reliability, while ensuring study procedures and criteria are updated to meet the regional needs of SPP, in cooperation with governing regulatory entities. The TWG is responsible for publication of seasonal and future reliability assessment studies on the transmission system of the SPP region. The TWG works closely with the Economic Studies Working Group (ESWG) to develop the scope documents used to direct the analysis and studies performed for the ITP process.

SPP hosts three to four ITP workshops annually to get stakeholder input to the transmission planning process and provide analysis results for stakeholder review. The workshops allow SPP stakeholders to provide input on assumptions for economic analysis and review identified needs and proposed solutions selected by SPP. KCP&L proposes projects through SPP's FERC Order No. 1000 process, reviews selected transmission projects in its area and coordinates with SPP regarding details within its area that may affect proposed solutions. In other instances KCP&L offers an operating guide to mitigate a transmission problem and avoid new transmission construction.

3.2.2 <u>ANNUAL REVIEW OF RTO EXPANSION PLANS</u>

2. The utility reviews the RTO transmission overall expansion plans each year to assess whether the RTO transmission expansion plans, in the judgment of the utility decision makers, are in the interests of the utility's Missouri customers;

KCP&L reviews transmission projects in its area and coordinates with SPP regarding details within its area that may affect proposed solutions or requests restudy for projects that it believes are not required. In other instances KCP&L offers an operating guide to mitigate a transmission problem and avoid or delay new transmission construction.

3.2.3 ANNUAL REVIEW OF SERVICE TERRITORY EXPANSION PLAN

3. The utility reviews the portion of RTO transmission expansion plans each year within its service territory to assess whether the RTO transmission expansion plans pertaining to projects that are partially- or fully-driven by economic considerations (i.e., projects that are not solely or primarily based on reliability considerations), in the judgment of the utility decision-makers, are in the interests of the utility's Missouri customers;

KCP&L reviews transmission plans and projects within its service territory that develop through the SPP RTO transmission expansion plan. Many are zonal projects providing additional obligations to serve or meet specific planning and bulk electric reliability criteria.

For region-wide project sets such as the SPP Balanced Portfolio, projects meet a wide range of needs including reduced production costs, reduced congestion, reduced system losses and base reliability needs. For example, in the case of the Iatan-Nashua 345kV project in KCP&L's territory, it is a project that will significantly reduce congestion of a major regional flowgate near the Kansas City-north area and directly relieves growing limitations on the ability to dispatch KCP&L's new Iatan 2 generating unit. The Iatan – Nashua project also provides approximately 8 Mw of loss reduction for the KCP&L and GMO transmission system at peak load conditions. Iatan – Nashua also eliminates two flowgates; one on the KCP&L – Westar boundary and one on the GMO – KCP&L boundary.

3.2.4 DOCUMENTATION AND DESCRIPTION OF ANNUAL REVIEW OF RTO OVERALL AND UTILITY-SPECIFIC EXPANSION PLANS

4. The utility documents and describes its review and assessment of the RTO overall and utility-specific transmission expansion plans; and

KCP&L reviews transmission projects in its area and coordinates with SPP regarding details within its area that may affect proposed solutions or requests restudy for projects that it believes are not required. KCP&L planning personnel participate throughout the year within the planning process providing insight and review of the transmission plans. In some instances KCP&L may be able to offer an operating guide to mitigate a transmission problem and avoid or delay new transmission construction. Also, KCP&L personnel participate in the overall approval of RTO expansion plans through the SPP approval process within the Markets and Operation Policy Committee and Members Committee.

3.2.5 AFFILIATE BUILD TRANSMISSION PROJECT DISCUSSION

5. If any affiliate of the utility intends to build transmission within the utility's service territory where the project(s) are partially- or fully-driven by economic considerations, then the utility shall explain why such affiliate built transmission is in the best interest of the utility's Missouri customers and describe and document the analysis performed by the utility to determine whether such affiliate-built transmission is in the interest of the utility's Missouri customers.

On April 4, 2012 Great Plains Energy ("GXP"), the holding company for both KCP&L and GMO, and American Electric Power ("AEP") announced the formation of a company to build and invest in transmission infrastructure. The new company, Transource EnergySM LLC ("Transource"), will pursue competitive transmission projects in the SPP region, the MISO and PJM regions, and potentially other regions in the future. GXP owns 13.5 percent of Transource through its newly-formed subsidiary, GPE Transmission Holding Company, LLC ("GPETHCO"). AEP owns the other 86.5 percent of Transource through its subsidiary, AEP Transmission Holding Company, LLC ("AEPTHC").

At this point, it is GXP's intent to pursue, develop, construct, and own through GPETHCO's interest in Transource – rather than through KCP&L and/or GMO – any future regional and inter-regional transmission projects subject to regional cost allocation. While it is premature to determine the specific impact on the regionally allocated costs resulting from constructing projects within Transource, it is anticipated that the partnership between GXP and AEP will provide for a financially-strong, cost-competitive, and technically-proficient transmission development entity. The scale, execution experience, and engineering expertise that Transource expects to be able to bring to the projects should provide benefits to customers through lower construction costs, better access to capital, and operational efficiencies.

3.3 RTO EXPANSION PLAN INFORMATION

(C) The utility shall provide copies of the RTO expansion plans, its assessment of the plans, and any supplemental information developed by the utility to fulfill the requirements in subsection (3)(B) of this rule.

The following SPP regional transmission planning reports are provided as attachments to this report.

2009 Balanced Portfolio - Final Approved Report.pdf (Appendix 4.5 - 3.3A)

Priority Projects Phase II Rev 1 Report - 4-27-10_final.pdf (Appendix 4.5 - 3.3B)

20130730_2013_ITP20_Report_clean.pdf (Appendix 4.5 - 3.3C)

Final_2015_ITP10_Report_BOD_Approved_012715 .pdf(Appendix 4.5 - 3.3D)

Final_2015_ITPNT_Assessment_BOD_Approved.pdf (Appendix 4.5 - 3.3E)

2015_STEP_Report.pdf (Appendix 4.5 - 3.3F)

2015_STEP_Project_List_Protected (Appendix 4.5 – 3.3G)

The Balanced Portfolio and Priority Projects reports are described in Section 1.3 above. The ITP20, ITP10, ITPNT reports are described in Section 3.1.1 above. The 2015 SPP Transmission Expansion Plan (STEP) Report and Project List summarize 2014 activities that impact future development of the SPP transmission grid. Seven distinct areas of transmission planning are discussed in this report, each of which are critical to meeting mandates of either the 2011 SPP Strategic Plan or the nine planning principles in FERC Order 890. These areas are Transmission Services, Generation Interconnection, Integrated Transmission Planning, Balanced Portfolio, High Priority Studies, Sponsored Upgrades, and Interregional Coordination.

3.4 TRANSMISSION UPGRADES REPORT

(D) The utility shall provide a report for consideration in 4 CSR 240-22.040(3) that identifies the physical transmission upgrades needed to interconnect generation, facilitate power purchases and sales, and otherwise maintain a viable transmission network, including:

3.4.1 TRANSMISSION UPGRADES REPORT – PHYSICAL INTERCONNECTION WITHIN RTO

1. A list of the transmission upgrades needed to physically interconnect a generation source within the RTO footprint;

It is not possible to provide a specific list of transmission upgrades needed to physically interconnect a generation resource within the SPP footprint. Any generation interconnection request within the SPP must proceed through the generation interconnection process as defined by the SPP transmission tariff. That process will examine the specific location proposed for generator interconnection and develop the necessary transmission upgrades needed at that location.

Generally speaking, generator interconnections for green field sites will require a three breaker ring bus substation for interconnection to the existing transmission system. Estimated costs for the interconnecting substation are in the range of $8-10 million at 345kV and $4-8 million at 161kV. Costs for interconnection of new generation resources at existing substations are generally significantly less due to the availability of existing substation infrastructure.

3.4.2 TRANSMISSION UPGRADES REPORT – DELIVERABILITY ENHANCEMENT WITHIN RTO

2. A list of the transmission upgrades needed to enhance deliverability from a point of delivery within the RTO including requirements for firm transmission service from the point of delivery to the utility's load and requirements for financial transmission rights from a point of delivery within the RTO to the utility's load;

In the SPP, requests for firm transmission service are processed through the Aggregate Facility Study (AFS) process. The AFS process is performed three times per year by collectively analyzing specific transmission service requests, including those associated with generation interconnection requests, across the entire SPP footprint. These service reservations are modeled based on control area to control area transfers. The transmission system is assessed with these potential service requests and, where needed, transmission improvements are identified that would enable the service to occur without standard or criteria violations. All transmission customers are allocated cost responsibility for portions of the various upgrades needed to deliver all of the transmission service requests. Transmission customers may decline to pay their portion of the allocated cost and drop out of the study process. Study analysis is repeated on the reduced set of transmission service requests. This is an iterative process until a final set of transmission service requests for those customers remaining in the process has been reached. The remaining transmission customers with service requests in the process agree to the projects needed to deliver the remaining transmission service and share the resulting upgrade costs. Those remaining upgrade projects are included in the next SPP transmission expansion plan process.

Because of the iterative nature of the Aggregate Facility Study process it is not possible to identify specific transmission upgrades needed to deliver energy from a resource in the RTO footprint to KCP&L until the process for a specific transmission service request has been completed.

3.4.3 TRANSMISSION UPGRADES REPORT – PHYSICAL INTERCONNECTION OUTSIDE RTO

3. A list of transmission upgrades needed to physically interconnect a generation source located outside the RTO footprint;

It is not possible to develop a list of specific upgrades needed to interconnect a generation resource located outside the SPP without actually making a generation interconnection request at a specific location.

3.4.4 TRANSMISSION UPGRADES REPORT – DELIVERABILITY ENHANCEMENT OUTSIDE RTO

4. A list of the transmission upgrades needed to enhance deliverability from a generator located outside the RTO including requirements for firm transmission service to a point of delivery within the RTO footprint and requirements for financial transmission rights to a point of delivery within the RTO footprint;

It is not possible to develop a list of specific upgrades needed to deliver capacity and energy from a generation resource located outside the SPP without actually making a generation interconnection request and an associated transmission service request at a specific location.

3.4.5 TRANSMISSION UPGRADES REPORT – ESTIMATE OF TOTAL COST

5. The estimated total cost of each transmission upgrade; and

A list of KCP&L transmission projects included in the 2015 SPP Transmission Expansion Plan (STEP) is shown below in Table 6.

Table 6: KCP&L Transmission Upgrades 2015 SPP STEP

TRANSMISSION PROJECT	COST ESTIMATE	TYPE	DATE
Install new 345/161 kV transformer at Nashua	$4,620,000	Balanced Portfolio	06/01/15
Add 345 kV line terminal at Iatan. Add ring bus at Iatan to accommodate line terminals.	$10,811,309	Balanced Portfolio	06/01/15
Replace existing 161/69 kV transformer at South Waverly	$1,355,978	ITP	06/01/15
Iatan – Stranger Creek 345 kV Voltage Conversion	$16,119,446	ITP	01/01/19
Increase rating of Nashua transformer to 650/715.	$12,600,000	ITP	01/01/33

Total estimated construction cost for these transmission upgrades is $45,506,733.

3.4.6 TRANSMISSION UPGRADES REPORT – COST ESTIMATES

6. The estimated fraction of the total cost and amount of each transmission upgrade allocated to the utility.

A list of KCP&L transmission projects included in the 2015 SPP STEP and the portion of their estimated cost allocated to KCP&L is shown below in Table 7.

Table 7: Transmission Upgrade Cost Allocated to KCP&L

TRANSMISSION PROJECT	COST ESTIMATE	% ALLOCATED TO KCP&L	KCP&L $
Install new 345/161 kV transformer at Nashua	$4,620,000	TBD	TBD
Add 345 kV line terminal at Iatan. Add ring bus at Iatan to accommodate line terminals.	$10,811,309	TBD	TBD
Replace existing 161/69 kV transformer at South Waverly	$1,355,978	100	$1,355,978
Iatan – Stranger Creek 345 kV Voltage Conversion	$16,119,446	7.8	$1,257,316
Increase rating of Nashua 345/161 kV transformer to 650/715.	$12,600,000	69.5	$8,757,000

The cost allocation between SPP members for Balanced Portfolio projects has not been determined at this time. A primary feature of the Balanced Portfolio cost allocation is to provide all SPP members a benefit/cost ratio of at least 1.0 and thus there will be revenue transfers in order to keep members at or above that threshold.

SECTION 4: ADVANCED TECHNOLOGY ANALYSIS

(4) Analysis Required for Transmission and Distribution Network Investments to Incorporate Advanced Technologies.

4.1 TRANSMISSION UPGRADES FOR ADVANCED TRANSMISSION TECHNOLOGIES

(A) The utility shall develop, and describe and document, plans for transmission upgrades to incorporate advanced transmission technologies as necessary to optimize the investment in the advanced technologies for transmission facilities owned by the utility. The utility may use the RTO transmission expansion plan in its consideration of advanced transmission technologies if all of the conditions in paragraphs (3)(B)1. Through (3)(B)3. are satisfied.

KCP&L will use advanced technologies such as Hybrid Structure Design, Solid Dielectric Cables, and Fiber Optic Shield Wire where applicable in transmission upgrades included in the SPP regional transmission expansion plan.

4.2 DISTRIBUTION UPGRADES FOR ADVANCED DISTRIBUTION TECHNOLOGIES

(B) The utility shall develop, and describe and document, plans for distribution network upgrades as necessary to optimize its investment in advanced distribution technologies.

KCP&L has not established a program to invest in distribution network upgrades to optimize it's investments in advanced distribution technologies. Instead, KCP&L deploys advanced distribution technologies selectively to the network where they are the most economical alternative to maintain the desired level of operational performance, reliability, and power quality.

The previous discussion, in Section 1.4 of this document, discusses how KCP&L plans distribution network upgrades, many of which incorporate the deployment of the previously established advanced grid technologies described in Section 4.6.2.1.

4.3 OPTIMIZATION OF INVESTMENT IN ADVANCED TRANSMISSION AND DISTRIBUTION TECHNOLOGIES

(C) The utility shall describe and document its optimization of investment in advanced transmission and distribution technologies based on an analysis of—

4.3.1 OPTIMIZATION OF INVESTMENT – TOTAL COSTS AND BENEFITS

1. ***Total costs and benefits, including:***

4.3.1.1 Distribution Analysis

KCP&L has not yet performed a comprehensive analysis to optimize investments in advanced distribution technologies pursuant to 4 CSR 240-22.045(4)(C).

KCP&L developed a DRAFT SmartGrid Vision, Architecture, and Road Map in 2008 as a potential guide to future KCP&L investments in advanced distribution technologies. The road map focused on the deployment of the advanced distribution technologies needed to implement the SmartGrid functions as described in Title XIII of the Energy Independence and Security Act of 2007 (EISA).

With the passage of the American Recovery and Reinvestment Act of 2009 (ARRA) in February 2009, it became apparent that the draft road map would be too aggressive and possibly limiting from a technical point of view. The architecture, on which the plan was developed, was based on prior EPRI Intelligrid research. It was unclear, to what extent, the NIST SmartGrid Interoperability Framework initiative funded by ARRA may change our future SmartGrid architecture design and technology selections.

With technology architecture uncertainties and an overly aggressive schedule of the ARRA funded SmartGrid Investment Grants (3 years), KCP&L management decided to focus on pursuing a DOE SmartGrid Demonstration Grant. KCP&L was awarded this grant in 2009 and executed a contract with the DOE for the demonstration in September 2010. The project will end in the first half of 2015. The geographical components of the project all lie within Kansas City, MO.

Upon completion of the SmartGrid Demonstration Project KCP&L plans to use the findings of the project to enlighten KCP&L's technology vision, architecture, and road map that will provide the framework for evaluating feasibility of these and similar advanced technologies.

KCP&L will perform studies to optimize investments in advanced distribution that incorporates cost-benefit analysis to determine if a business case can be made for technology deployment. Learning from the SmartGrid Demonstration will be used in these analyses when appropriate.

4.3.2 OPTIMIZATION OF INVESTMENT – COST OF ADVANCED GRID INVESTMENTS

A. Costs of the advanced grid investments;

4.3.2.1 Distribution

Refer to comments in Section 4.3.1.1

4.3.3 OPTIMIZATION OF INVESTMENT – COST OF NON-ADVANCED GRID INVESTMENTS

B. Costs of the non-advanced grid investments;

4.3.3.1 Distribution

Refer to comments in Section 4.3.1.1

4.3.4 OPTIMIZATION OF INVESTMENT – REDUCTION OF RESOURCE COSTS

C. Reduced resource costs through enhanced demand response resources and enhanced integration of customer-owned generation resources; and

4.3.4.1 Distribution

Refer to comments in Section 4.3.1.1

4.3.5 OPTIMIZATION OF INVESTMENT – REDUCTION OF SUPPLY-SIDE COSTS

D. Reduced supply-side production costs;

4.3.5.1 Distribution

Refer to comments in Section 4.3.1.1

4.4 COST EFFECTIVENESS OF INVESTMENT IN ADVANCED TRANSMISSION AND DISTRIBUTION TECHNOLOGIES

2. Cost effectiveness, including

4.4.1 COST EFFECTIVENESS – INCREMENTAL COSTS ADVANCED GRID TECHNOLOGIES VS NON-ADVANCED GRID TECHNOLOGIES

A. The monetary values of all incremental costs of the energy resources and delivery system based on advanced grid technologies relative to the costs of the energy resources and delivery system based on non-advanced grid technologies;

4.4.1.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.2 COST EFFECTIVENESS – INCREMENTAL BENEFITS ADVANCED GRID TECHNOLOGIES VS NON-ADVANCED GRID TECHNOLOGIES

B. The monetary values of all incremental benefits of the energy resources and delivery system based on advanced grid technologies relative to the costs and benefits of the energy resources and delivery system based on non-advanced grid technologies; and

4.4.2.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.3 OPTIMIZATION OF INVESTMENT – NON-MONETARY FACTORS

C. Additional non-monetary factors considered by the utility;

4.4.3.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.4 OPTIMIZATION OF INVESTMENT – SOCIETAL BENEFIT

3. Societal benefit, including:

4.4.4.1 Societal Benefit – Consumer Choice

A. More consumer power choices;

4.4.4.1.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.4.2 Societal Benefit – Existing Resource Improvement

B. Improved utilization of existing resources;

4.4.4.2.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.4.3 Societal Benefit – Price Signal Cost Reduction

C. Opportunity to reduce cost in response to price signals;

4.4.4.3.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.4.4 Societal Benefit –

D. Opportunity to reduce environmental impact in response to environmental signals; Environmental Impact

4.4.4.4.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.5 OPTIMIZATION OF INVESTMENT – OTHER UTILITY-IDENTIFIED FACTORS

4. Any other factors identified by the utility; and

4.4.5.1.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.6 OPTIMIZATION OF INVESTMENT –OTHER NON-UTILITY IDENTIFIED FACTORS

5. Any other factors identified in the special contemporary issues process pursuant to 4 CSR 240-22.080(4) or the stakeholder group process pursuant to 4 CSR 240-22.080(5).

4.4.6.1.1 Distribution

Refer to comments in Section 4.3.1.1

4.5 NON-ADVANCED TRANSMISSION AND DISTRIBUTION INCLUSION

(D) Before the utility includes non-advanced transmission and distribution grid technologies in its triennial compliance filing or annual update filing, the utility shall—

4.5.1 NON-ADVANCED TRANSMISSION AND DISTRIBUTION REQUIRED ANALYSIS

1. Conduct an analysis which demonstrates that investment in each non-advanced transmission and distribution upgrade is more beneficial to consumers than an investment in the equivalent upgrade incorporating advanced grid technologies. The utility may rely on a generic analysis as long as it verifies its applicability; and

4.5.1.1 Distribution

KCP&L is not proposing any new non-advanced distribution grid technologies or programs in this triennial IRP compliance filing.

KCP&L understands that prior to including new non-advanced distribution grid technologies in future IRP filings, KCP&L will conduct, describe, and document an analysis which demonstrates that investment in each non-advanced distribution upgrade is more beneficial to consumers than an investment in the equivalent upgrade incorporating advanced grid technologies. KCP&L further understands that we may present a generic analysis as long as we verify its applicability.

4.5.2 NON-ADVANCED TRANSMISSION AND DISTRIBUTION ANALYSIS DOCUMENTATION

2. Describe and document the analysis.

4.5.2.1 Distribution

Refer to comments in Section 4.5.1.1

4.6 ADVANCED TRANSMISSION AND DISTRIBUTION REQUIRED COST-BENEFIT ANALYSIS

(E) The utility shall develop, describe, and document the utility's cost benefit analysis and implementation of advanced grid technologies to include:

4.6.1.1 Distribution

KCP&L is not proposing any new advanced distribution grid technologies or programs in this triennial IRP compliance filing.

KCP&L understands that prior to including new advanced distribution grid technology in future IRP filings, KCP&L will develop, describe, and document the cost benefit analysis for implementation of the advanced grid technology.

Upon completion of the SmartGrid Demonstration Project, KCP&L plans to use the findings of the project to enlighten KCP&L's technology vision, architecture, and road map that will provide framework for evaluating the feasibility of and guiding the implementation of advanced distribution grid technologies.

In developing the road map, KCP&L intends to use the build and impact metrics from our project and other industry sources to perform a cost/benefit analysis of advanced distribution grid technologies considered prior to implementation.

4.6.2 ADVANCED GRID TECHNOLOGIES UTILITY'S EFFORTS DESCRIPTION

1. A description of the utility's efforts at incorporating advanced grid technologies into its transmission and distribution networks;

4.6.2.1 Distribution

Historical Advanced Grid Technology Deployments

The distribution grid in place at KCP&L today is substantially "smart" having benefited from decades of power engineering expertise. The existing systems already execute a variety of sophisticated system operations and protection functions. In addition it should be noted that what is now termed "smart grid" has been under development by KCP&L and the industry for many years. Much of the automation has been accomplished through incremental applications of technology. The following sections describe many of the advanced distribution technologies that have and are currently being implemented at KCP&L. The previous response to section 22.045 (1)(D) describe how KCP&L applies these previously adopted advanced grid technologies to improve the operation of the distribution network.

DA – A 1993-1999 Strategic Initiative

In 1993, Kansas City Power & Light Company (KCP&L) management established an internal, interdivisional, multi-disciplined team to develop definitions, economic evaluations, recommendation plans for Distribution Automation (DA) at KCP&L. The team's purpose was to determine the feasibility of consolidating numerous existing, but independent, automation efforts that were undergoing evaluation throughout the company. Consequently, KCP&L management consolidated multiple DA efforts into one project and between 1995 and 1999 the following components of the DA vision were implemented.

- **AMR -** Automated Meter Reading**.** KCP&L implemented the first utility wide 1-way AMR system in the industry automating over 90% of all customer meters..
- **ACD/VRU** – Automatic Call Director with Voice Response Unit. Provides improved call handling capability for the Call Center and will provide a direct transfer of Outage Calls to the Outage Management System (OMS)
- **DFMS-AMFM/GIS** – Automated Mapping/Facilities Management/ Geographic Information System. Provides the functionality to support the mapping, record keeping and operation of the electrical system via a fully connected and geographically related model. KCP&L entered into data sharing agreements with 7 city and county entities to obtain the most accurate land base information available on which it's hard copy facility maps were digitized
- **DFMS-WMS –** Work Management System. Provides for automated job planning and management of resources.
- **DFMS-EAS –** Engineering Analysis System. Provides the functionality for analysis of the distribution systems electrical performance and plans for the necessary construction and maintenance of the system***.***
- **DFMS-TRS** Trouble Reporting System. Provides functionality to support the day-to-day trouble call tracking, outage analysis, and service restoration of the electrical distribution system. This system is now referred to as the OMS (Outage Management System).
- **DFMS-LDA -** Line Device Automation. Device Automation was initially limited to Capacitor Automation. Over 600 line capacitors have been automated and routinely maintain the urban circuits at nearly unity power factor.

Leveraging the DA Investment

Having successfully implemented the systems initiated by the DA Initiative, KCP&L identified, cost justified, and implemented a series of projects that leveraged the system implementations establishing greater process integration, operational savings and improved operational performance for customers. Many of these projects included first of its kind technology deployments within the utility industry.

- **AMFM/GIS Upgrade**. KCP&L became the first utility to port our vendors AMFM/GIS system from their production legacy CAD-RDBMS platform to a fully RDBMS platform.
- **AMFM/GIS to WMS Integration.** - Integration automated the population of GIS attributes based on the WMS compatible units. This functionality established the foundation for an eventual integrated graphic design function.
- **WMS Expanded to Maintenance Work. -** Use of the WMS was expanded from design-construction jobs to high volume maintenance and construction service orders, automating and streamlining those processes.
- **Account Link WEB portal integrated AMR and CIS –** The AccountLink customer web portal was established and daily AMR read information was made available to customers
- **AMR integrated with OMS**. AMR outage (last gasp) alerts and AMR meter 'pings' were implemented to improve outage and trouble response.
- **ORS dashboard integrated with OMS. -** Implemented the Outage Records System, an OMS data mining and management dashboard provides real time summary and overview of outage statistics. This system provides the real-time "Outage Watch" map on the KCP&L web page, www.kcpl.com.
- **MWFM Integrated with AMFM/GIS, OMS, and CIS** - Implemented the Mobile Work Force Management system which automated the field processing of Trouble, Outage, and CIS Meter Service Orders.

Comprehensive Energy Plan – 2004-2009

An element of the KCP&L plan involved infrastructure improvements to strengthen the overall reliability of our system and network. Our plan included the following programs involving distribution facilities to incorporate new advanced technologies for faster diagnosis and repair of service interruptions.

- **Distribution System Inventory Verification Program.** This program involves conducting a full overhead distribution system field inventory to verify and augment existing distribution asset information at the component level. The program for the combined KCPL & KCP&L GMO service territories was completed in 2011.
- **Network Automation.** The Network Automation Project involves monitoring of KCP&L's underground (UG) secondary networks. Automation of the network alerts engineers, dispatchers, and the underground workers to abnormal situations that can potentially cascade into larger problems if left unchecked.
- **"Integrated Circuit of the Future".** The "Integrated Circuit of the Future" project involved the field installation and testing of various distribution automation technologies to evaluate the feasibility of larger scale deployment on the KCP&L's distribution grid.
- **50 C.O. Relay Automation.** The 50 C.O. Automation Project involves remote enabling or disabling of the distribution feeder over-current relays in substations. The ability to turn the relays off under fair weather conditions result in a forty to fifty percent reduction in momentary outages–greatly improving reliability and customer quality-of-service. When turned on during storms, this system allows reclosing to save fuses and reduce outages.
- **Dynamic Voltage Control (DVC).** The program allows operators to reduce the substation voltage a predetermined amount for demand reduction (DR). As a result of successful testing of the DVC system on the Integrated Circuit of the Future, KCP&L accelerated implementation of the DVC system to all 203 metro Kansas City substation buses resulting in an estimated 60MW of peak demand reduction.
- **34-kV Switching Device Automation and Fault Indication.** Project involves installation of automated switching devices and fault indicators.

American Recovery and Reinvestment Act of 2009

In February 2009, Congress passed, and the President approved, American Recovery and Reinvestment Act of 2009 (ARRA). ARRA provided, among other recoverey act funding, the appropriations required the DOE and NIST to implement their legslative mandate established by Title 13 of EISA.

- NIST - $20 Million to fund Smart Grid Interoperability Framework.Initiative
- DOE - $3.4 billion to fund SmartGrid Investment grants
- DOE - $600 million to fund Smart Grid Demonstration Grants

As 2009 progressed, it became apparent that enterprise SmartGrid deployments may be too aggressive and possibly imprudent from a technical point of view. It was unclear how much the NIST Interoperability Framework initiative may change our planned architecture and technology selection.

With technology architecture uncertainties and resource limitations, KCP&L management decided to focus on pursuing a demonstration grant. The KCP&L SmartGrid Demonstration Project Application – Project Narrative is included as Appendix 4.5.D. The KCP&L project was selected in late 2009 and a contract with the DOE was subsequently awarded in September 2010

KCP&L plans to use findings of the SmartGrid demonstration project to enlighten KCP&L's technology vision, architecture, and road map that will provide framework for evaluating the feasibility of, and guiding the implementation of advanced distribution grid technologies.

KCP&L SmartGrid Demonstration Project

KCP&L's SmartGrid Demonstration Project deployed an end-to-end SmartGrid (within Kansas City, MO) that includes a wide array of

SmartGrid technologies and components. These have been grouped into five (5) major sectors: Smart Distribution, Smart Metering, Interoperability and Security, Smart End-Use and Smart Generation. Below are additional details within each of these sectors:.

- Smart Distribution
  - Distribution Management System (DMS) including Outage Management System (OMS) and Distribution SCADA
  - IP/RF 2 –way Field Area Network for communications
  - Advanced distribution applications
  - Smart Substation
- Smart Metering
  - Advanced Metering Infrastructure (AMI)
  - Meter Data Management system (MDM)
  - Integration between Customer Info System (CIS), MDM, AMI and OMS
  - Data Analytics
- Interoperability and Security
  - Enterprise Service Bus (ESB) flexible architecture
  - IEC 61850 Substation Communications
  - OpenADR Communications for Advanced Demand Response

    - Zigbee Smart Energy Profile (SEP) communications between meters and in-home devices
    - State of the art network and physical security
- Smart End-Use
    - Home Energy Management Portal (HEMP)
    - Home Area Network (HAN)
    - In-Home Display (IHD)
    - Time of Use (TOU) pilot rate
    - Electric Vehicle (EV) charging
- Smart Generation
    - Distributed Energy Resource Management (DERM) system
    - Demand Response (DR) programs
    - Utility-owned rooftop solar generation
    - Utility scale battery

One of the main goals of the demonstration project was to implement this wide array of technologies and systems and demonstrate the level to which they could be integrated and truly interoperable according to emerging governmental/industry standards. The back office IT integration and infrastructure components were a very significant part of the overall project. The high number of vendors involved and immaturity (and interpretability) of the industry standards proved challenging to the interoperability objective.

4.6.3 <u>DISTRIBUTION ADVANCED GRID TECHNOLOGIES IMPACT DESCRIPTION</u>

2. A description of the impact of the implementation of distribution advanced grid technologies on the selection of a resource acquisition strategy; and

The implementation of (or lack thereof) distribution advanced grid technologies did not influence the selection of the resource acquisition strategy presented in this filing.

The advanced distribution grid technologies being evaluated through KCP&L's SmartGrid Demonstration Project, are foundational, potentially enabling technologies that may provide traditional operational benefits to the utility while enabling new demand side management and pricing programs; integration of utility and customer owned distributed generation; greater grid utilization through increased monitoring and control of grid resources; and enhanced utilization of customer demand response capabilities.

KCP&L anticipates that the results of SmartGrid Demonstration Project and subsequent benefit cost analyses will determine that several of the advanced distribution grid technologies will be determined to be cost effective, or at a minimum we will understand under what conditions they become cost effective.

As a DOE Smart Grid Demonstration Project requirement, KCP&L produced its first and second Interim Technology Performance Reports (TPR) on December 31, 2012 and December 31, 2013 respectively. These documents summarized all achievements on the project through the respective dates. . Key topics include summaries of the project design, implementation,testing, analysis, and some lessons learned. Due to the voluminous size of these reports, they have not been included in the Annual Update, but can be downloaded from the following DOE website;

> https://www.smartgrid.gov/recovery_act/program_impacts/regional_demonstration_technology_performance_reports

A third Interim Technology Performance Report will be produced in early 2015. This document will extend the 2013 interim report by providing greater detail regarding the results of the operational demonstrations conducted and summarize the corresponding benefits analysis performed using the DOE SmartGrid and Energy Storage Computational Tools. The report will conclude with a summary of the build and impact metrics reported to the DOE.

A project Final Technical Report will be produced in the first half of 2015 following the conclusion of the project and will synthesize all learnings from the entirety of project. KCP&L assumes the DOE will make it available on the same website listed previously.

SmartGrid Demonstration Project High Level Status

The demonstration project has completed all but its final phases: Decommissioning and Final Reporting. The final operational test was performed in November 2014. Components that will not continue are being decommissioned. Components that will continue are being moved into the appropriate production environment. Analysis for the remaining Technology Performance Reports is being performed for report issuance.

Present Roadmap Influence

Although the SmartGrid Demonstration project is not fully complete, learning has been applied to KCP&L's technology road map and business case development for several projects. KCP&L is already in process of implementing the following components in broader deployments:

- Advanced Metering Infrastructure (AMI)
- Meter Data Management (MDM)
- Outage Management System (OMS) upgrade
- Distribution SCADA “lite” integration of Sensus DA communications into the OMS Upgrade
- Enterprise Service Bus (ESB) architecture (Oracle Service Bus)
- Fault Location advanced distribution automation application as part of the OMS upgrade
- Electric Vehicle (EV) Charging Infrastructure
- Two-way communicating programmable thermostats
- Implemented a technical Project Management Organization (PMO) to manage technology projects and coordinate integration and interoperability

AMI and EV Charging are the only items in the above list where KCP&L is using the same vendor solutions as used in the demonstration, but implementation and operational lessons still apply in all cases.

SECTION 5: UTILITY AFFILIATION

(5) The electric utility shall identify and describe any affiliate or other relationship with transmission planning, designing, engineering, building, and/or construction management companies that impact or may be impacted by the electric utility. Any description and documentation requirements in sections (1) through (4) also apply to any affiliate transmission planning, designing, engineering, building, and/or construction management company or other transmission planning, designing, engineering, building, and/or construction management company currently participating in transmission works or transmission projects for and/or with the electric utility

On April 4, 2012 Great Plains Energy ("GXP"), the holding company for both KCP&L and GMO, and American Electric Power ("AEP") announced the formation of a company to build and invest in transmission infrastructure. The new company, Transource EnergySM LLC ("Transource"), will pursue competitive transmission projects in the SPP region, the MISO and PJM regions, and potentially other regions in the future. GXP owns 13.5 percent of Transource through its newly-formed subsidiary, GPE Transmission Holding Company, LLC ("GPETHCO"). AEP owns the other 86.5 percent of Transource through its subsidiary, AEP Transmission Holding Company, LLC ("AEPTHC").

At this point, it is GXP's intent to pursue, develop, construct, and own through GPETHCO's interest in Transource – rather than through KCP&L and/or GMO – any future regional and inter-regional transmission projects subject to regional cost allocation. While it is premature to determine the specific impact on the regionally allocated costs resulting from constructing projects within Transource, it is anticipated that the partnership between GXP and AEP will provide for a financially-strong, cost-competitive, and technically-proficient transmission development entity. The scale, execution experience, and engineering expertise that Transource expects to be able to bring to the projects should provide benefits to customers through lower construction costs, better access to capital, and operational efficiencies.

SECTION 6: FUTURE TRANSMISSION PROJECTS

(6) The electric utility shall identify and describe any transmission projects under consideration by an RTO for the electric utility's service territory.

The SPP regional transmission planning process will begin another ITP10 planning cycle in 2015, to be completed in 2017, and an ITPNT to be completed in 2016, thus there are no transmission projects under consideration at this time.

VOLUME 5:

DEMAND-SIDE RESOURCE ANALYSIS

KANSAS CITY POWER & LIGHT COMPANY (KCP&L)

INTEGRATED RESOURCE PLAN

4 CSR 240-22.050

APRIL, 2015

KCP&L[SM]
energizing life

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VOLUME 5: DEMAND-SIDE RESOURCE ANALYSIS

HIGHLIGHTS

- KCP&L completed its Demand-Side Management (DSM) Potential Study in August 2013, which included an assessment of:
    - Realistic Achievable Potential (RAP) and Maximum Achievable Potential (MAP) energy efficiency potential for the period of 2014-2033
    - RAP and MAP demand response potential including time-based rates
    - Combined heat and power potential
- KCP&L adjusted the RAP and MAP scenarios to account for the roll-off of measures at the end of the measures' life, commercial and industrial opt-outs, and aligned the time period to 2016-2034 for the IRP analysis.
- KCP&L engaged Applied Energy Group (AEG) to design a demand side management (DSM) scenario (Option C) beginning in 2016.
- KCP&L engaged AEG to design an additional DSM energy efficiency and demand response portfolio (Option C) beginning in 2016

INTRODUCTION

KCP&L engaged Navigant Consulting, Inc. (Navigant) to conduct a Demand Side Management (DSM) Resource Potential Study (Potential Study) in January 2012. The Potential Study was delivered to KCP&L in August 2013 and included both a RAP level of DSM and a MAP level of DSM, as defined in the IRP Rules. This Potential Study was used as the basis for the scenarios evaluated in this integrated analysis.

RAP and MAP

Adjustments were needed for the Potential Study RAP and MAP scenarios before they could be used in the 2015 integrated analysis. The Potential Study reported energy and demand savings that did not account for the roll-off of measures at the end of the measures' life, nor did it account for opt-out of commercial and industrial customers.

At KCP&L's request, Navigant adjusted the RAP and MAP scenarios to adjust for measure roll-off. KCP&L then applied an additional adjustment using an estimated 10% opt-out of commercial and industrial customers. This assumption is based upon KCP&L's actual opt-out rate for the 2014 program year. Additionally, KCP&L adjusted the Potential study RAP and MAP scenarios to align with the time period needed for the 2015 IRP (2016-2034). The Potential Study analysis was based on a time period of 2014-2033. KCP&L has an approved portfolio for 2013-2015; therefore the effects of programs that were assumed to be adopted by customers in 2014 and 2015 were removed and savings were extended to 2034.

The impacts of these adjustments are shown in Tables 48-50. The remainder of the tables and charts represent the unadjusted Potential Study results. These adjustments can be found in the KCP&L workpapers[1].

OPTION C

KCP&L began its initial planning for its DSM portfolio for the 2016-2018 period concurrent with its planning for its 2015 IRP filing period. In September 2014, KCP&L engaged with AEG to review its current DSM program offering, which was just beginning its 18 month approved program cycle. The objectives of the program design included:

(1) design programs that have a TRC cost effectiveness ratio greater than 1.0,

(2) seek programs that have high peak demand impacts in order to reduce supply-side capacity needs,

(3) increase customer satisfaction by delivering DSM programs with a positive customer experience in mind,

[1] MO IRP Output - Maximum, FINAL - Program Totals IRP HC.xlsx
MO IRP Output - Realistic, FINAL - Program Totals IRP HC.xlsx
KS IRP Output - Maximum, FINAL - Program Totals IRP HC.xlsx
KS IRP Output - Realistic, FINAL - Program Totals IRP HC.xlsx

(4) consider additional programs and measures such as whole building approaches, multi-family, and LED street lighting initiatives.

Option C reflects the portfolio design resulting from AEG's analysis.

Option C demonstrates a strong level of energy efficiency commitment and it continues to build upon our experience with and learnings from our existing portfolio; however at a level lower than RAP or MAP identified in the Potential Study. Option C was developed based on our current and previous experience; understanding of customer adoption of energy efficiency within our service territory; and evaluation, measurement, and verification (EMV) results from the KCP&L-GMO 2013 EMV report, while designing an overall portfolio that is cost effective.

Option C represents a more conservative level of achievable DSM levels than RAP or MAP identified in the Potential Study. The RAP and MAP levels developed are from a single Potential Study at a point in time based on assumptions that may or may not be comprehensive to achieve such results as defined in the study. For example,

(1) A NTG ratio of 1.0 was used in the Potential Study for all measures, with the exception of appliance recycling. For appliance recycling a NTG ratio of 0.52 was used as agreed upon with the stakeholders. Thus, the potential estimates for all other measures are "gross" savings.

(2) The Potential Study did not include an allowance for commercial and industrial customer opt-outs. (However, as noted above, KCP&L did make an adjustment to the RAP and MAP levels used in the integrated analysis by factoring in an estimated 10% opt-out of commercial and industrial customers.)

(3) KCP&L has also learned that the new baselines that begin in 2020 as a result of the Energy Independence and Security Act of 2007 (EISA) were not reflected in the Potential Study.

(4) The Potential Study also includes gas impacts for certain measures (19 residential measures and 10 C&I measures), which result in both significant

electric and gas savings, such as shell and envelope measures. Technologies that focused primarily on natural gas savings, however, were not included.

(5) The Potential Study conducted by Navigant is at the measure level. As such, the Potential Study did not consider or adjust for the interactive effects between measures when multiple energy efficiency measures are installed at a single location.

(6) KCP&L has learned that some potential studies estimate and adjust for naturally occurring energy efficiency. Naturally occurring energy efficiency is savings that would occur over and above those that would occur from changes in codes and standards but in the absence of any market intervention. No such adjustment was made in the KCP&L potential study.

Each of the above input assumptions would result in the potential savings to be overestimated, however, the effects of these assumption have not been quantified individually or in total.

Option C reflects the following assumptions that are not considered in the Potential Study:

(1) Recent program developments, evaluations, and new technology,

(2) An update of the net-to-gross (NTG) ratios for measures (programs) indicated in KCP&L-GMO's 2013 EMV,

(3) Cost effectiveness that does not include the impacts from natural gas savings,

(4) New EISA baselines that are effective in 2020,

(5) Commercial and industrial opt-outs, and

(6) After a review of KCP&L's existing programs and the Potential Study, as well as interviews with KCP&L program managers and staff, the programs were modified

to enhance their performance and incorporate the updated measure characteristics.

AEG performed industry standard cost-effectiveness tests in order to gauge the economic merits of the measures, programs and portfolio. The end-use measures most likely to achieve cost-effective savings were then selected and bundled into programs.

PURPOSE: *This rule specifies the principles by which potential demand-side resource options shall be developed and analyzed for cost effectiveness, with the goal of achieving all cost-effective demand-side savings. It also requires the selection of demand-side candidate resource options that are passed on to integrated resource analysis in 4 CSR 240-22.060 and an assessment of their maximum achievable potentials, technical potentials, and realistic achievable potentials.*

SECTION 1: POTENTIAL DEMAND-SIDE RESOURCES

(1) ***The utility shall identify a set of potential demand-side resources from which demand-side candidate resource options will be identified for the purposes of developing the alternative resource plans required by 4 CSR 240-22.060(3). A potential demand-side resource consists of a demand-side program designed to deliver one (1) or more energy efficiency and energy management measures or a demand-side rate. The utility shall select the set of potential demand-side resources and describe and document its selection —***

1.1 DESCRIBE AND DOCUMENT SELECTIONS

(A) To provide broad coverage of —

1.1.1 MARKET SEGMENTS COVERAGE

1. Appropriate market segments within each major class; —

Kansas City Power and Light (KCP&L) engaged Navigant Consulting, Inc. (Navigant) to conduct a Demand Side Management (DSM) Resource Potential Study in January

2012. Navigant identified KCP&L's market segments by categorizing historic customer energy usage by SIC code. The market segments included:

- Residential: single family, single family low-income, multi-family, multi-family low-income
- Commercial: grocery, healthcare, lodging, office – large, office – small, restaurants, retail, schools, warehouses, other commercial
- Industrial: chemicals, electronics, food, rubber-plastics, stone-clay-glass, motor freight transportation, other industrial

Table 1: Market Segments (2014), MWh

Segment	KCP&L-MO
Industrial-Chemicals	451,450
Industrial-Electronics	10,702
Industrial-Food	383,343
Industrial-Motor Freight	65,188
Industrial-Other Industrial	510,800
Industrial-Rubber-Plastics	80,755
Industrial-Stone-Clay-Glass	185,834
Commercial-College	82,701
Commercial-Grocery	106,052
Commercial-Healthcare	393,073
Commercial-Lodging	142,051
Commercial-Office - Large	1,724,071
Commercial-Office - Small	403,775
Commercial-Other Commercial	638,256
Commercial-Restaurant	166,375
Commercial-Retail	360,965
Commercial-School	221,833
Commercial-Warehouse	254,913
Residential-Single Family	1,602,132
Residential-SF Low Income	686,628
Residential-Multi-Family	223,868
Residential-MF Low Income	95,943
Total	**8,790,707**

1.1.2 DECISION-MAKER COVERAGE

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

KCP&L staff meets regularly with customer groups, architects, engineers, trade representatives, contractors, distributors, public agency staff and others to discuss energy usage issues, review KCP&L's energy plan, discuss energy efficiency and demand response programs, and elicit feedback and suggestions.

Navigant provided a broad range of stakeholders opportunities to review and comment on the potential study methodologies, survey instruments and findings. The stakeholders included the Missouri Public Service Commission, Missouri Office of Public Counsel, Missouri Department of Natural Resources, National Resources Defense Council, Empire Electric District, Renew Missouri, and Ameren.

1.1.3 MAJOR END USES COVERAGE

3. All major end uses, including at least the end uses which are to be considered in the utility's load analysis as listed in 4 CSR 240-22.030(4)(A)1.; —

KCP&L engaged Navigant to conduct a DSM Resource Potential Study. Navigant developed a comprehensive list of conventional and emerging technologies considering all customer sectors and end uses. The major end uses by sector include:

- Residential: lighting, space cooling, space heating, ventilation, water heating, refrigerators, freezers, cooking, clothes washers, clothes dryers, television, personal computers, fans, plug loads, behavioral.
- Commercial: heating, space cooling, ventilation, water heating, refrigeration, lighting, office equipment, cooking equipment, combined heat and power (CHP), data centers, behavioral

- Industrial: machine drives, space heating, space cooling, ventilation, lighting, process heating, CHP, compressed air, fans, pumps, refrigeration, transformers

1.2 DESIGNING EFFECTIVE POTENTIAL DEMAND-SIDE PROGRAMS

(B) To fulfill the goal of achieving all cost effective demand-side savings, the utility shall design highly effective potential demand-side programs consistent with subsection (1)(A) that broadly cover the full spectrum of cost-effective end-use measures for all customer market segments; —

KCP&L engaged Navigant to conduct a DSM Resource Potential Study. Navigant developed a set of DSM programs by grouping market segments and end-use measures into programs. The table below includes brief descriptions of the programs included in Navigant's *Demand-Side Resource Potential Study Report.*

Table 2: Brief Description of Navigant DSM Programs

Program	High Level Program Description
C&I Custom Rebates	Encourage and assist non-residential customers improve the energy efficiency of existing facilities through a broad range of options that address all major end uses and processes. The program is designed for non-prescriptive retrofit and replacement projects and offers financial incentives, paid on a fixed kWh basis, based on the project's first year energy savings.
C&I Prescriptive Rebates	Encourage and assist non-residential customers improve the energy efficiency of existing facilities through a broad range of options that address all major end uses and processes. The program offers fixed, per-unit rebates to customers and engages equipment suppliers and contractors to promote eligible equipment.
C&I New Construction	Work with design professionals and construction contractors to influence prospective building owners and developers to construct high-performance buildings that provide improved energy efficiency, systems performance, and comfort. Energy saving targets will be accomplished by stimulating incremental efficiency improvements. The program will seek to capture synergistic energy savings by encouraging the design and construction of buildings as integrated systems.
Small Business Direct Install	Encourage and assist small businesses improve the energy efficiency of their facilities through turn-key installation and rapid project completion. The program includes lighting, refrigeration, air-conditioning, water heating and control measures that are typically low-cost with reliable, prescriptive energy savings and costs per unit. The program is designed to assist small business owners overcome barriers to achieving energy efficiency, including time constraints, capital constraints, lack of energy efficiency awareness, and lack of labor resources.

Program	High Level Program Description
Building Operator Certification (BOC)	Training and certification program for operations and maintenance staff working in commercial, institutional, or industrial buildings. Operators attend training and complete project assignments in their facilities. BOC achieves energy savings by training individuals directly responsible for the maintenance of energy-using building equipment and day-to-day building operations.
Home Performance with ENERGY STAR	Coordinate the development of a statewide network of independent contractors trained and mentored on the delivery of comprehensive energy analysis and measure installations under the Home Performance with ENERGY STAR model. Train contractors to Building Performance Institute standards on building science and offer marketing and incentive packages to accelerate customer awareness and demand. Customers will pay a market-based fee for the analysis and receive partial reimbursement when recommendations are implemented.
Low-Income Weatherization	Facilitate the implementation of cost-effective electric saving measures in residential low-income households. In an ongoing effort, KCP&L intends to work with the agencies responsible for implementing the federal LIHEAP program to leverage its funding, thereby increasing the number of homes served. If local weatherization agencies initially lack the resources to handle the additional workload, KCP&L will temporarily contract with private sector firms to address the overload.
Efficient Products	Promote ENERGY STAR® appliances, lighting and home electronics. The program also promotes products that are energy efficient, for which there are not yet ENERGY STAR labels, such as solid state lighting and light emitting diode technologies.
Multifamily Rebate	Offer property owners a comprehensive service for reducing common area energy use and help residents reduce energy use in their living units. Property owners will be given the opportunity to participate in either or both components of the program.
Cool Homes	Influence the installation of high-efficiency heating, cooling and water heating technologies through a combination of market push and pull strategies that stimulate demand, while simultaneously increasing market provider investment in promoting high-efficiency products. The program will stimulate demand by educating customers about the energy and money-saving benefits associated with efficient equipment and providing financial incentives to overcome the first cost barrier. The program will stimulate market provider investment in stocking and promoting efficient products by offering HVAC contractors several services including training, educational materials, cooperative advertising and sales brochures.
Appliance Turn-In	The average household replaces a refrigerator or freezer every ten years. Many of these units replaced are still functioning and often end up as back-up appliances in basements and garages or are sold in a used appliance market. The program will target these “second” refrigerators and freezers, providing the dual benefit of cutting energy consumption and keeping the appliances out of the used market. Units removed will be recycled and disabled through a certified recycling agency.

Program	High Level Program Description
Home Energy Reports	Provide residential customers with an energy report that provides an analysis of their household energy usage information along with comparison to similar customers or "neighbors." The intention of the energy report is to provide information that will influence customers' behavior in such a way that they lower their energy usage.
Energy Education	Provide curriculum, teacher training, and supplies for in-class instruction about how to use energy efficiently at home. The program will target students in 5th through 8th grades, providing education and a "take-home" kit that raises awareness about how individual actions and low-cost measures can provide significant reductions in electricity and water consumption.
ENERGY STAR Homes	Provide education and rebates to inform and encourage architects, builders, and home buyers on the benefits of ENERGY STAR homes as well as requirements for gaining certification.

KCP&L also engaged Applied Energy Group (AEG) to design an additional DSM portfolio (Option C) for the KCP&L-MO service territory. AEG took the following steps:

1. **Review Existing KCP&L DSM Portfolio**. AEG reviewed program descriptions and evaluations as well as program tracking data, including program participation, budgets versus expenditures and program savings. AEG held two collaborative program design workshops with KCP&L program managers and staff to discuss the program design process and gain insight into the existing DSM programs.

2. **Review DSM Potential Study**. AEG reviewed the *Demand-Side Resource Potential Study Report* and the *Demand-Side Resource Potential Study Report – Demand Response* completed by Navigant in August 2013. AEG compared the existing KCP&L portfolios with the potential study and best practice programs from industry research, primarily using information from utilities that are similar in size and customer composition as KCP&L. AEG updated measure inputs and incorporated additional measures on an as-needed basis to reflect more recent program developments, evaluations, and new technology developments (e.g. the dramatic cost and efficacy improvements occurring in the LED lighting market).

3. **Review Stakeholder Input and Regulatory Requirements**. AEG reviewed KCP&L stakeholder input on the DSM programs provided through written comments and prior collaborative workshops. Similarly, AEG reviewed reporting and filing requirements, as well as the Stipulation and Agreement, which specified items to be

considered in the design of future DSM programs. AEG attempted to design the portfolio and programs in such a way to address and satisfy all of these concerns.

4. **Develop DSM Program Plan**. AEG constructed program design for the 20-year period from 2016 through 2034. With the existing KCP&L DSM programs and the Navigant potential study as a starting point, the programs were modified to enhance their performance and incorporate the updated measure characteristics.

   AEG analyzed cost-effectiveness in order to gauge the economic merits of the measures, programs and portfolio. Cost-effectiveness was measured using four of the industry standard cost-effectiveness tests; total resource cost test, utility cost test, participant cost test, and rate impact measure test. As required in 22.050 (5) (B) the total resource cost test was used as the final determination of cost-effectiveness. As permitted in 22.050 (5) (D), the cost-effectiveness criterion was relaxed for the income-eligible programs since they are considered to have potential benefits that are not otherwise captured by the cost-effectiveness test.

The AEG additional DSM programs are shown in the tables below.

Table 3: Home Lighting Rebate

Objective	Increase the penetration of efficient lighting in customer homes by incentivizing the purchase of ENERGY STAR® qualified lighting.
Target Market	Residential customers as well as lighting manufacturers and local retailers.
Description	The Home Lighting Rebate Program incentivizes the purchase and installation of efficient lighting utilizing an upstream strategy to provide customers incentives on qualifying CFL and LED light bulbs at participating retailers. Customers receive an instant incentive at the point-of-purchase. The incentives vary depending upon the type of light bulb, manufacturer and the associated retail cost.
Implementation Strategy	KCP&L will engage a third-party implementation contractor to efficiently obtain the energy savings goals while adhering to the budget. The implementation contractor will: • Establish relationships with lighting manufacturers and retailers throughout KCP&L's service territory. • Provide in-store promotional materials and retail sales staff training. • Track program performance, including tracking sales data, reviewing sales data for accuracy and payment to retailers. • Periodically report progress towards program goals and opportunities for improvement. KCP&L will work with the implementation contractor to market the program to customers and educate retailer sales staff. Marketing efforts to increase customer awareness may include, but not be limited to: • Bill inserts

	• Newspaper advertisements • Internet placement • Point-of-Purchase materials (hang tags, posters)
Risk Management	Upstream programs simplify the participation process for residential customers, eliminating the need to complete and submit a rebate application. However, upstream programs typically have higher free ridership and leakage outside of the service territory. A number of steps will be taken to reduce free ridership and leakage while increasing spillover, including: • KCP&L will work with the implementation contractor to select retailers located well within KCP&L's service territory to reduce leakage outside of the service territory. • The Home Lighting Rebate Program will be cross-marketed with KCP&L's other Residential DSM Programs (e.g. bill inserts will promote multiple programs). • Incentives will be modified as needed to respond to the market price of qualifying light bulbs, with a goal of the incentive being no higher than 50% of the incremental cost. • KCP&L will work with the implementation contractor and third party evaluator to understand any market transformation elements that arise from this upstream program.
Measures & Incentives	Incentives were set for planning purposes and may be modified to reflect market conditions.

Measure	Unit	Average Incentive per Unit
CFL	per Bulb	$1.35
LED	per Bulb	$5.00

Table 4: Home Appliance Recycling Rebate

Objectives	Promote the removal and retirement of inefficient appliances.
Target Market	All residential customers.
Description	The program incentivizes residential customers to remove inefficient refrigerators and freezers from the electric system and dispose of them in an environmentally safe and responsible manner. The refrigerator/freezer must be in working conditioner, between 10 and 32 cubic feet in size, and a 2002 model or older. The refrigerators and freezers are picked-up at no cost to the customer. Room air conditioners and dehumidifiers may be picked-up free of charge during a scheduled trip for a qualifying refrigerator and/or freezer. Customers are limited to 2 refrigerator and/or freezer rebates and 3 room air conditioners and/or dehumidifiers per household per year.
Implementation Strategy	KCP&L will select an implementation contractor that demonstrates a record of providing the services offered and responsibly disposing the appliances. It is likely that a single provider will be engaged to perform, or subcontract for, all the services. The implementation contractor will be responsible for: • Scheduling pickups from customer homes, verification of appliance qualification, and appliance removal from customer homes. • Rebate processing. • Program tracking. • Periodically report progress towards program goals and opportunities for improvement. The implementation contractor will work with KCP&L to develop innovative and creative

	marketing strategies and materials. Marketing may include, but not be limited to, bill inserts, newspaper/community newsletter advertisements, community events, billboards, radio advertisements and the KCP&L website. The program will include an educational component that informs customers about the benefits of recycling their inefficient appliances and environmentally responsible disposal of appliances.
Risk Management	Experience at other utilities and discussions with implementation contractors suggest that program cost-effectiveness hinges on volume because unit disposal costs can be reduced by ensuring higher volumes. The implementation contractor will need to use extensive and effective marketing to obtain the volumes. There is a high probability that customers will buy a new appliance to replace the recycled unit. The planning energy and demand savings could be lowered if a customer that recycles a secondary appliance simply buys a new unit and begins utilizing their former primary unit as a secondary unit. The program will attempt to influence consumer behavior by encouraging residential customers to avoid replacing recycled secondary refrigerators or freezers. Appliance recycling programs typically have higher free ridership rates, primarily due to: (1) Customers that were planning to replace their appliance prior to participating in the program. (2) Customers that were not using their appliance prior to participating in the program. In an effort to reduce free ridership, the implementation contractor will emphasize and enforce the requirement that the appliance is plugged in and in operating condition at the time of pick-up. In an effort to increase spillover, the program will be cross-marketed with KCP&L's other Residential DSM Programs (e.g. bill inserts will promote multiple programs).
Measures & Incentives	Incentives were set for planning purposes and may be modified to reflect market conditions. The program will provide, on average, a $50 incentive for each refrigerator and/or freezer recycled. There will be no incentive for room air conditioners and dehumidifiers recycled. Customers are limited to 2 refrigerator and/or freezer rebates per household per program year and 3 room air conditioners and/or dehumidifiers recycled per household per year.

Table 5: Home Energy Report

Objectives	Reduce consumption via socially- and information-driven behavioral change and raise general awareness of energy efficiency and KCP&L's DSM programs.
Target Market	Residential single family homes.
Description	The Home Energy Report Program provides individualized energy use information to customers while simultaneously offering recommendations on how to save energy and money by making small changes to energy consuming behaviors. Energy reports are sent periodically to customer households to give them self-awareness and a peer comparison of their energy usage. Customers are also provided access to an online tool to track energy consumption and offer tips to reduce usage. Social competitiveness increases behavior to reduce energy consumption.
Implementation Strategy	KCP&L will select an implementation contractor that specializes in developing and issuing residential energy reports. The implementation contractor will utilize experimental design to select report recipients and a control group, design the reports and develop customized energy reduction tips with input from KCP&L. The program will cross-promote and market the KCP&L DSM portfolio.
Risk Management	Potential issues/risks to be aware of: • The program may undergo a meaningful change in customer responsiveness and evaluation paradigms in the coming years. • Research is being conducted on the persistence of savings after the program has ended.

	The program has been assumed to have a one year measure life and therefore has a relatively high-cost of energy savings on a lifetime or levelized cost basis. The program provides a significant opportunity to promote KCP&L's residential DSM programs via the customer reports and the online tool, thereby resulting in increased program spillover. However, the spillover impact will need to be carefully determined through an impact evaluation.
Measures & Incentives	Customers receive personalized energy reports, but there is no monetary incentive.

Table 6: Online Home Energy Audit

Objectives	Encourage energy education and conservation, as well as further engagement in the broader portfolio of DSM programs.
Target Market	Residential customers.
Description	The program provides customers access to a free online tool to analyze the energy efficiency of their home, educational materials regarding energy efficiency and conservation, and information on KCP&L DSM Programs. The program goals include: • Increase awareness of household energy consumption. • Educate residential customers about the benefits of energy efficiency and the opportunities to reduce energy consumption. • Increase awareness of and participation in other KCP&L DSM programs.
Implementation Strategy	KCP&L will engage a third-party contractor to develop and maintain the online tool(s).
Risk Management	The Online Home Energy Audit Program is an educational program that informs customers of household energy consumption and methods to reduce energy usage. KCP&L will need to strategize ways to highlight the audit tool on the KCP&L website and increase customer engagement.
Measures & Incentives	There are no monetary incentives.

Table 7: Whole House Efficiency

Objectives	Encourage whole-house improvements to existing homes by promoting home energy audits and comprehensive retrofit services.
Target Market	Residential customers that own or rent a residence as well as HVAC contractors for trade ally participation.
Description	The Whole House Efficiency Program consists of 3 Tiers: **Tier 1: Customer Audit**. Customer receives a home energy audit and direct installation of low-cost measures. The audit identifies potential efficiency improvements. The low-cost measures to be installed include: faucet aerator, low-flow showerhead, advanced power strip, water heater tank wrap, hot water pipe insulation and CFL/LEDs. **Tier 2: Infiltration Measures**. Customers that have completed Tier 1 are eligible to receive incentives for the purchase and installation of air sealing, insulation and ENERGY STAR® windows. **Tier 3. HVAC Equipment**. Customers are eligible to receive incentives for qualifying HVAC equipment installed by a participating contractor. Customers are not required to participate in Tier 1 or 2. Qualifying measures include heat pump water heaters, ECM furnace fans, heat pump ductless mini splits, central air conditioners and heat pumps. Early retirement incentives are provided to customers with central air conditioners and/or heat pumps in operable condition and at least 5 years of age. Residential customers that rent a residence must receive the written approval of the homeowner/landlord to participate in the program. The program goals include: • Demonstrate persistent energy savings. • Encourage energy saving behavior and whole house improvements. • Help residential customers reduce their electricity bills. • Educate customers about the benefits of installing high efficiency HVAC equipment. • Develop partnerships with HVAC contractors to bring efficient systems to market.
Implementation Strategy	KCP&L will engage a third-party implementation contractor to efficiently obtain the savings goals while adhering to the budget. The implementation contractor will: • Hire/sub-contract local staff to perform home audits and direct measure installation. • Engage customers and schedule home audit appointments. • Provide customer service support. • Establish relationships with local HVAC contractors to work with the program installing energy efficient HVAC equipment and infiltration measures. • Process rebate applications, including review and verification of applications and payment of customer rebates. • Track program performance, including customer and HVAC contractor participation as well as quality assurance/quality control (QA/QC). • Periodically report progress towards program goals. KCP&L will work with the implementation contractor to market the program to residential customers and HVAC contractors utilizing the following approaches: • Direct outreach to customers, including bill inserts, newspaper advertisements, email blasts, direct mail, bill messaging, and community events. • Engage contractors to promote awareness of and use rebates to help sell qualifying equipment.
Risk Management	It is important that the measures are properly installed and customer satisfaction is high. Therefore, it is crucial to engage experienced contractors. To enroll in the program, it is recommended that contractors provide KCP&L with (1) proof of insurance on an annual basis and (2) at least two customer references. KCP&L and/or the implementation contractor should

	conduct QA/QC of a random group of completed projects by project type and contractor. The QA/QC process should include verification of the equipment installed and customer satisfaction with the contractor and the program. A number of steps will be taken to reduce free ridership and increase spillover, including: • Incentives will be modified as needed to respond to the market price of qualifying measures, with a goal of the incentive being no higher than 50% of the incremental cost. • KCP&L will work with the implementation contractor to properly set the rebate levels to ensure customers have adequate buy-in to the program. • Cross-market the program with KCP&L's other Residential DSM Programs • Encourage customers to participate in all three tiers.
Measures & Incentives	Incentives were set for planning purposes and may be modified to reflect market conditions. Customers will pay $50 to receive the home energy audit and direct measure installation.

Tier 2 Incentive per Unit

Measure	Unit	Incentive per Unit
Air Sealing	per sq. ft.	$0.08, up to $300
Ceiling Insulation, R-38	per sq. ft.	$0.30, up to $500
Wall Insulation, R-5	per sq. ft.	$0.65, up to $150
ENERGY STAR® Windows	per Window	$75, up to $750

Central air conditioners and heat pumps are assumed to be 3-tons and the heat pump ductless mini split is assumed to be 1.5-tons.

Tier 3 Incentive per Unit

Measure	Unit	Replace/ New	Early Retirement	Replace Electric Resistance Heat
Heat Pump Water Heater	per Unit	$200	n/a	n/a
ECM Furnace Fan	per Unit	$50	n/a	n/a
Heat Pump Ductless Mini-Split	per Unit	$300	n/a	n/a
SEER 15 Central Air Conditioner	per Unit	$125	$250	n/a
SEER 16 Central Air Conditioner	per Unit	$200	$400	n/a
SEER 15, HSPF 8.5 Heat Pump	per Unit	$150	$300	$800
SEER 16, HSPF 8.5 Heat Pump	per Unit	$300	$600	$1,000
SEER 17, HSPF 8.6 Heat Pump	per Unit	$500	n/a	n/a

Table 8: Income-Eligible Multi-Family

Objective	Deliver long-term energy savings and bill reductions to low-income customers in multi-family housing and multi-family common area energy savings.
Target Market	Low-income residential homeowners and renters that meet the Federal guidelines for Weatherization Assistance and reside in multi-family housing as well as multi-family buildings with low-income residents.
Description	The program includes 2 tiers: **Tier 1. Multi-Family Kits.** Direct installation of low-cost measures for low-income homeowners and renters in multi-family housing, at no cost to the participant. The measures installed include: faucet aerator, low-flow showerhead, advanced power strip, hot water pipe insulation and CFL/LEDs. **Tier 2. Multi-Family Common Areas.** Installation of lighting measures in multi-family common areas, at no cost to the participant.
Implementation Strategy	KCP&L will engage a third-party implementation contractor to: • Identify and establish relationships with multi-family building owners that have a number of low-income residents. • Engage customers and schedule appointments. • Install measures and determine the insulation needed. • Track program performance. • Periodically report progress towards program goals. KCP&L will work with the implementation contractor to market the program to low-income customers and multi-family building owners utilizing the following approaches: • Direct outreach to customers, including bill inserts, direct mail, bill messaging, community events and community organizations. • Engage building owners to promote awareness of and use of the program.
Risk Management	The program focuses on providing energy efficiency services to low-income residents to ensure reduced consumption. There is little risk associated with this product.
Measures & Incentives	All measures are installed free of charge. There are no monetary incentives.

Table 9: Income-Eligible Weatherization

Objective	Deliver long-term energy savings and bill reductions to low-income customers.
Target Market	Low-income residential homeowners and renters that meet the Federal guidelines for Weatherization Assistance.
Description	The program includes 2 tiers: **Tier 1. Kits.** Direct installation of low-cost measures for low-income homeowners and renters, at no cost to the participant. The measures installed include: faucet aerator, low-flow showerhead, advanced power strip, hot water pipe insulation, hot water heater tank wrap and CFL/LEDs. **Tier 2. Weatherization.** Installation of ceiling, duct and/or wall insulation, at no cost to the participant. Customers work with local community action agency to participate.
Implementation Strategy	KCP&L will engage a third-party implementation contractor to: • Engage customers and schedule appointments. • Install measures and determine the insulation needed. • Track program performance. • Periodically report progress towards program goals. KCP&L will work with the implementation contractor to market the program to low-income customers utilizing bill inserts, direct mail, bill messaging, community events and community organizations.
Risk Management	The program focuses on providing energy efficiency services to low-income residents to ensure reduced consumption. There is little risk associated with this product.
Measures & Incentives	All measures are installed free of charge. There are no monetary incentives.

Table 10: Residential Programmable Thermostat

Objective	Decrease peak demand usage to provide system and grid relief during particularly high-load, high-congestion peak hours.
Target Market	Individually metered residential customers. Target primarily single family homeowners, expanding into multi-family as the single family market opportunities begin to saturate.
Description	The Residential Programmable Thermostat Program reduces peak demand by controlling participant cooling equipment during periods of system peak demand and when there may be delivery constraints within certain load zones. This is done by way of a remotely communicating, programmable thermostat. During a program event, the program operations center sends a radio frequency signal to the thermostat to adjust its set-point by 2 to 4 degrees F such that the system will consume less energy and run less frequently throughout the 3 to 6 hour event duration. One method of participation will be for customers to receive the thermostat and professional installation (a $150 value) for free upon qualification and enrollment in the program.
Implementation Strategy	KCP&L will engage a third-party implementation contractor to: • Hire/sub-contract local staff to install the programmable thermostats. • Engage customers, schedule installation appointments and process customer incentives. • Provide customer service support. • Track program performance and event data. • Periodically report progress towards program goals and opportunities for improvement. Events will typically occur between June 1 and September 30, Monday to Friday. Event duration is typically 3 to 6 hours per day. Customers may opt-out twice a year by calling KCP&L a day in advance. The program will be marketed through direct contact with consumers using bill inserts, newsletters, website, broadcast and print media, and direct mail.
Risk Management	The primary benefit of demand response programs is to mitigate the risks and costs associated with system peak loads. From a planning perspective, using demand response resources in the most valuable way would imply that system planners would include the peak impacts in the load forecast nominated to the RTO (regional transmission organization), thereby reducing the utility system peak, required capacity, and also the reserve requirements. This also implies that events would primarily be called when the day-ahead forecast projects a load in excess of that nominated peak, rather than using another event trigger mechanism, such as energy market prices above a certain threshold or weather above a certain temperature. Having the thermostats available as a resource year-round is potentially of value to system operations in the event of plant maintenance or other grid events. Curtailment in participating homes with electric heat could provide additional risk management capabilities in the future. Providing the opportunity for customers to opt-out or override a limited number of events provides choice and control to the customer, minimizing the risk of attrition and lost participants.
Measures & Incentives	Customers receive a free communicating, programmable thermostat with installation ($150 value) for joining the program. After this, no cash payment is required for continued participation, making this a very cost effective capacity resource. Incentives were set for planning purposes and may be modified to reflect market conditions.

Table 11: Business Energy Efficiency Rebate - Standard

Objective	Encourage purchase and installation of energy efficient equipment by providing incentives to lower the cost of purchasing efficient equipment for commercial and industrial facilities.
Target Market	All commercial and industrial customers.
Description	The Business Energy Efficiency Rebate – Standard is designed to help commercial and industrial customers save energy through a broad range of energy efficiency options that address all major end uses and processes. Pre-qualified rebates are available for measures, including lighting, HVAC equipment and motors. The measures are proven technologies that are readily available with known performance characteristics.
Implementation Strategy	KCP&L will engage a third-party implementation contractor to: • Process customer applications, verify eligibility and process customer rebates. • Conduct QA/QC to verify equipment installation. • Provide customer service support. • Track program performance. • Periodically report progress towards program goals and opportunities for improvement. Key pillars of the marketing strategy will include Trade Allies and direct customer marketing, including direct mail, newspaper advertisements, email blasts, bill inserts and HVAC trade publications. Additional marketing tactics will include: • Education. Train and educate Trade Allies on the programs and how to effectively sell the program to customers. • Trade Associations. Businesses rely on trade associations to represent industry's best interests in lobbying, growth, and identification of business opportunities. KCP&L will coordinate with specific associations to highlight suitable program offerings. • Highlight successfully completed projects. KCP&L will select projects to display the process and benefits of the program. This type of marketing will spur the customer's competitors to improve building performance and increase business process efficiency.
Risk Management	The key barriers are return on investment, decision timing and customer internal funding and approval processes. Many customers have internal return on investment hurdles that are quite aggressive, sometimes as short as a one year payback. Another barrier is ensuring that enough vendors are properly educated to allow them to actively engage customers by explaining the myriad benefits of efficiency improvements. Measure savings are expected to be updated annually. Potential changes to measure savings, costs, and other key assumptions could affect the measure's ability to pass cost-effectiveness tests. Therefore, the mix of measures that can be offered could change from year to year to reflect changes made to the original measure attributes. Incentives will be modified as needed to respond to market prices, with a goal of the incentive being no higher than 50% of the incremental cost. Proper incentives can reduce free ridership while still encouraging customers to participate in the program.

Measures & Incentives

Incentives were set for planning purposes and may be modified to reflect market conditions.

Measure	Unit	Incentive per Unit
Air Sourced A/C, <65 kBtuh	per ton	$50
Air Sourced A/C, ≥65 kBtuh	per ton	$40
Air Sourced HP, 65 < 135 kBtuh	per ton	$45
Ceramic Metal Halide	per fixture	$40
ENERGY STAR® Beverage Machines	per unit	$65
Heat Pump Water Heater	per unit	$200
High Bay T5	per fixture	$50
High Bay T8	per fixture	$40
LED Display Lighting	per door	$75
LED Exit Sign	per fixture	$6
Lo Flow Faucet Aerators	per unit	$5
Occupancy Sensors	per Watt	$0.80
Packaged Terminal AC/HP	per kBtuh	$150
Pipe Wrap/Insulation	per unit	$15
Pool Pump, High Efficiency	per unit	$100
Pool Pump, VSD	per unit	$200
Premium T8 Linear Fluorescent	per fixture	$5
Pre-Rinse Spray Valves	per unit	$50
Programmable Thermostat	per ton	$3
Pumps/Fans, VSD (HVAC only)	per HP	$130
Reach In Refrigerator/Freezer	per unit	$100
Reduced Lighting Power Density	per sq. ft.	$0.08, up to $750
Screw-In CFLs	per fixture	$1.00
Screw-In LEDs	per fixture	$8
Strip Curtains	per sq. ft.	$5
T8 Linear Fluorescent with	per fixture	$5

Table 12: Business Energy Efficiency Rebate - Custom

Objective	Encourage purchase and installation of energy efficient equipment by providing incentives to lower the cost of purchasing efficient equipment for commercial and industrial facilities.
Target Market	All commercial and industrial customers.
Description	The Business Energy Efficiency Rebate – Custom Program is designed to help commercial and industrial customers save energy through a broad range of energy efficiency options that address all major end uses and processes. Equipment that does not qualify for a prescriptive rebate will be eligible for a custom rebate. Applications must be pre-approved by KCP&L before equipment is purchased and installed and must have a Total Resource Cost Test benefit-cost ratio of at least 1.0. Incentives, up to 50% of the project cost, were included as: • $0.07 per first-year-kWh saved for lighting incentives • $0.10 per first-year-kWh saved for non-lighting incentives A $500,000 incentive cap is imposed per facility per program year. Multiple rebate applications for different measures may be submitted. As a new addition for the 2016-2018 implementation cycle, combined heat and power (CHP) projects will be considered in the Business Energy Efficiency Rebate – Custom Program. KCP&L and the implementation contractor will work with customers interested in CHP to determine project costs, cost-effectiveness, tax credits, and financing options. For the purposes of the analysis, the incentive payment for CHP projects is determined to be $300 per kW of installed electric generation capacity and the $500,000 cap criteria will be reviewed and determined on a case-by-case basis and based upon available program funding.
Implementation Strategy	KCP&L will engage a third-party implementation contractor to: • Process customer applications, verify eligibility, review pre-approval applications, and process customer rebates. • Conduct QA/QC to verify equipment installation. Randomly inspect 10% of projects and all projects over a threshold determined by KCP&L (e.g. $10,000). • Provide customer service support. • Track program performance. • Periodically report progress towards program goals and opportunities for improvement. Key pillars of the marketing strategy will include Trade Allies and direct customer marketing, including direct mail, newspaper advertisements, email blasts, bill inserts and HVAC trade publications. Additional marketing tactics will include: • Education. Educate Trade Allies on how to effectively sell the program to customers. • Trade Associations. Businesses rely on trade associations to represent industry's best interests in lobbying, growth, and identification of business opportunities. KCP&L will coordinate with specific associations to highlight suitable program offerings. • Highlight successfully completed projects. KCP&L will select projects to display the process and benefits of the program. This type of marketing will spur the customer's competitors to improve building performance and increase business process efficiency.
Risk Management	The key barriers are return on investment, decision timing and customer internal funding and approval processes. Many customers have internal return on investment hurdles that are quite aggressive, sometimes as short as a one year payback. Another barrier is ensuring that enough vendors are properly educated to allow them to actively engage customers by explaining the myriad benefits of efficiency improvements.
Measures & Incentives	Incentives were set for planning purposes and may be modified to reflect market conditions. Incentives, up to 50% of the project cost and up to a maximum cap of $500,000, are:

	• $0.07 per kWh saved for lighting incentives • $0.10 per kWh saved for non-lighting incentives

Table 13: Strategic Energy Management

Objective	Provide energy education, technical assistance, and company-wide coaching to large commercial and industrial customers to drive behavioral change and transformation of company culture with respect to energy use and management.
Target Market	Customers with high energy use and operational sophistication. The best candidates are likely to have the following attributes: • Large manufacturing companies or commercial facilities with >300 kW peak demand. • Companies and institutional customers with multiple sites (i.e. operations/offices in another state or country). • Customers with commitment to sustainability and environmental stewardship. • Customers in regulated industries. • Companies that have well established management systems like quality/safety or those using continuous improvement practices. • Companies in a stable or rapid growth mode.
Description	The Strategic Energy Management (SEM) Program is a systematic approach to delivering persistent energy savings to organizations by integrating energy management into regular business practices. The program involves appointment of an energy liaison(s) and a team within participating organizations who regularly correspond with program representatives. The program includes two program tracks that use different delivery mechanisms: • One-on-One Consultative SEM provides the customer with access to an energy expert who works intensively with the customer to integrate energy management into the organization's business practices by helping the customer set up an energy management process and implement improvements. The participant receives frequent and personalized attention throughout the implementation period. Touch points and milestones are agreed upon between the two parties. • SEM Cohort places companies into groups that work alongside each other for one year or longer, coming together in periodic workshops, approximately quarterly, and working on their own between the sessions. The group setting enhances participant action as they strive to perform in front of their peers. Structured groups are composed of 5 to 12 participants that are often located in the same geographical area, sharing best practices and learning together. The group is typically filled with participants from non-competing industries; however, if mutual agreement is established, competitors may participate in the same group. A methodology is developed early in the engagement to forecast each participant's baseline energy consumption, from which savings goals are created and measured. To isolate energy savings attributable to SEM efforts, any savings from equipment measures installed under other programs in the portfolio can be netted out of these savings. SEM has been shown to produce larger and longer lasting energy savings when compared to other energy management offerings. Few customers, however, have the internal resources to pursue and sustain these initiatives on their own, without the support of a utility program.
Implementation Strategy	The design relies on a Program Administrator and Energy Management Providers. *Program Administrator:* KCP&L staff and a third-party implementation contractor to deliver the program and manage administrative functions, such as marketing, customer recruitment, and results tracking. *Energy Management Providers:* firms and personnel with specific knowledge and

	expertise who work with customers to achieve savings. The Energy Management Provider must have a combination of the following: • Experience in customer consulting and change management. • Experience with continuous improvement methodologies. • Experience engaging customer personnel at all levels, particularly executives. • Experience using and deploying management systems such as quality, environmental impact, and safety. • Technical expertise for understanding production process and operations to identify energy savings opportunities. • Established track record deploying utility-based SEM programs, driving energy savings along with customer change and customer satisfaction. Program delivery will be integrated with other programs. Customers that have already completed or are currently participating in the Business Energy Efficiency Rebate Programs can achieve additional efficiency gains. If capital measures are identified during the course of participation in SEM, they can be submitted for incentives under the appropriate Business Energy Efficiency Rebate Program. The Program Administrator recruits customers through one-on-one contacts. To achieve goals, the program will likely need to target two- to three-times the participation goal. The recruitment process will build an SEM pipeline, wherein potential participants can be monitored as their priorities and business situations change over time. One-on-one recruiting builds familiarity and trust, providing the basis for successful engagements. • *Recruit Customers*. Recruiting requires a two-prong approach at both the facility management level and executive level. KCP&L should leverage relationships with large customers and peer relationships that KCP&L executives have with customer executives. • *Screen Customers*. Potential participants will be screened on the size of their connected load and on factors including history of implementing energy efficiency projects, experience with other continuous improvement programs, general responsiveness of plant personnel, etc. Screening will take place through discussions with account managers and preliminary conversations with prospective participants. • *Gain Customer Commitment*. As part of the screening process, participating customers will commit to an on-site executive-level sponsor, dedicated program budget, access to key human resources, inclusion of an energy continuous improvement statement within existing corporate goals, and a training program for new and existing personnel. An Energy Management Provider will be assigned to each participant and have primary responsibility for implementing the program and working with participant. The provider will have three roles: • *Project Manager*. Coordinate customer communication and meetings, develop reports. • *Organizational Facilitator(s)*. Conduct initial Energy Management Assessment, provide ongoing customer coaching, maintain customer satisfaction, and provide input to energy maps and savings models. Identify and cultivate an energy champion or team leader. • *Savings Modeler*. Develop energy maps and savings models. Provide technical assistance to participating customers to understand current energy use, identify opportunities to reduce energy use, and to set energy-use reduction goals. The key marketing message should be that KCP&L is supporting customers to more strategically manage energy and to invest in their future by building an organizational foundation for energy management, providing consultative resources and incentives. Marketing will rely heavily upon presentations and letters, supported by brochures, case studies and success stories. It is important for the marketing materials to: • Provide a basic understanding of the concept of SEM and the program. • Outline the compelling business case (benefits and costs) of participation.

	• Connect the SEM offering to the existing DSM portfolio.
Risk Management	The most challenging aspect of a SEM Program is maintaining long-term customer commitment because it directly affects savings persistence. To ensure commitment, the customer must clearly understand the following: • The level of staff time, management review, and other resources they are committing. • The services, such as consulting and training, they will receive. • The benefits, such as a more systematic and proactive approach to managing energy. Successful efforts involve setting rigorous expectations through ongoing meetings with the participant, Energy Management Providers, Program Administrator and KCP&L staff. • *Participating Customer and Program Administrator*. To ensure the customer maintains momentum and arrives at an agreed upon success point, a Stage-gate approach is recommended. This includes clearly defined stages based on progress indicators, such as the existence of an energy goal, consistent meetings of an energy team, and the engagement of employees in energy awareness. • *Program Administrator, Energy Management Provider(s) and KCP&L*. A periodic review meeting on a quarterly basis brings together KCP&L staff, the Program Administrator, and the Energy Management Provider(s) to discuss each participant with respect to successes, challenges, and overall progress. If it is determined that a customer's progress is lagging, they will agree to next steps, including increased engagement scope and discussions with the customer to ensure that they understand program support may be withdrawn if they do not improve performance. Working with customers' energy and production data is vital to the tracking of progress in this program. The data are frequently proprietary and competition-sensitive, so steps must be taken to establish a secure mechanism and procedure for sharing and storage of data.
Measures & Incentives	Behavioral and operational energy savings, as measured relative to the participant's personal baseline consumption, are paid incentives of $0.02 per first-year-kWh saved. These levels were set for planning purposes and may be modified to reflect market conditions. Separately, capital measures that are adopted due to participation in the SEM Program, and which are eligible for incentives under other programs such as the Business Standard and Custom initiatives, are routed through them and receive the applicable incentives as if they were regular projects. These savings are netted out of the SEM savings and recorded under the Standard or Custom programs. In this way, SEM also becomes a lead generator for other programs and further drives portfolio success.

Table 14: Block Bidding

Objective	Encourage high-volume energy savings projects from customers and third-party suppliers working on behalf of customers at lower cost than traditional programs. This program provides an opportunity to organize and procure non-conventional projects that may not be eligible or appropriately incentivized to participate in other programs.
Target Market	Any commercial, industrial or municipal customer as well as third-party suppliers, such as energy service companies, trade allies and performance contractors.
Description	The Block Bidding Program seeks to purchase blocks of electric savings by issuing a Request For Proposal (RFP) to eligible customers and third-party suppliers. The RFP details the proposal requirements as well as the electric savings that must be achieved. Customers and/or third parties submit proposals to deliver the requested block of cost-effective electric savings. The electric savings may be achieved in a variety of ways; for example, one customer facility installing energy efficiency equipment or a bundle of projects across multiple sites and/or customers. Bidder proposals are reviewed to: • Verify customer eligibility. • Ensure completeness and accuracy of proposed energy savings. • Screen the proposed measures for cost-effectiveness. All projects must have a Total Resource Cost Test benefit-cost ratio of greater than 1.0. Qualifying and cost-effective bidder proposals are ranked based upon the proposed cost per kWh saved ($/kWh). Program funds are awarded to bidders starting with the lowest $/kWh saved until the funding is depleted. KCP&L enters into contracts with the bidders that receive program funding. All projects must receive pre- and post-implementation inspections to verify the existing and upgraded equipment. The acquired savings may differ from the expected savings stated in the contract based upon actual performance and the post-implementation inspection.
Implementation Strategy	KCP&L staff will administer the Block Bidding Program with assistance from a third-party implementation contractor. Implementation contractor activities include: • Assist with outreach and education to potential bidders. • Review bidder proposals and recommend the bids to be funded. • Perform pre- and post-implementation inspections. • Provide customer service support. • Track program performance. • Periodically report progress towards program goals and opportunities for improvement. Marketing will be targeted to third-party suppliers and customers. Tactics will include: • Training sessions to educate third-party suppliers and customers on the program, proposal requirements and any associated paperwork requirements. • Direct outreach via KCP&L key account representatives, news releases, announcements, telephone calls and email. • Highlight successfully completed projects to display the benefits of the program. • Third-party suppliers will promote the program directly to eligible customers.
Risk Management	The most challenging aspect is engaging customers and the ability of customers to achieve the required blocks of electric savings. The implementation contractor and KCP&L staff must work closely to ensure that potential bidders understand the program requirements and work to correct any issues or concerns that arise in bidder proposals. Customers must be made aware of the ability to bundle projects and/or work with a third-party supplier to achieve the required blocks of electric savings. The implementation contractor and KCP&L staff must work closely with the contracted bidders to ensure projects are being completed in a timely fashion and issues are addressed in a timely fashion.

Measures & Incentives	Incentives of $0.06 per first-year-kWh saved were assumed for planning purposes, but the actual incentive payments will be a result of the individual project bids received during the RFP process. Program management can choose the threshold cost below which they are willing to pay based on the condition of budgets and energy and peak demand savings goals at the time the bids are received.

Table 15: Online Building Energy Audit

Objectives	Encourage energy education and conservation, as well as further engagement in the broader portfolio of DSM programs.
Target Market	Non-residential customers.
Description	The program provides customers access to a free online tool to analyze the energy efficiency of their businesses, educational materials regarding energy efficiency and conservation, and information on KCP&L DSM Programs. The program goals include: • Increase awareness of business and building energy consumption. • Educate commercial customers about the benefits of energy efficiency and the opportunities to reduce energy consumption. • Increase awareness of and participation in other KCP&L DSM programs.
Implementation Strategy	KCP&L will engage a third-party contractor to develop and maintain the online tool(s).
Risk Management	The Online Building Energy Audit Program is an educational program that informs customers of business energy consumption and methods to reduce energy usage. KCP&L will need to strategize ways to highlight the audit tool on the KCP&L website and increase customer engagement.
Measures & Incentives	There are no monetary incentives.

Table 16: Small Business Direct Install

Objective	Provide targeted, highly cost-effective measures to small business customers in a quickly deployable program delivery mechanism.
Target Market	Small business customers with an average electric demand of less than 30 kW per year.
Description	The Small Business Direct Install Program offers customers an energy assessment that includes information on potential energy savings and anticipated payback as well as incentives that cover up to 70% percent of the equipment and installation costs. Eligible measures include, but are not limited to, occupancy sensors, LED exit signs, and T5 lamps. The program works best if the assessment and applicable equipment/measure installations can be completed on the same day. KCP&L will select an implementation contractor that will provide the lighting audit and information on lighting incentives. Incentives will be assigned directly to the contractor, so that the value of utility incentives is reduced directly from the project cost. The program is part of a long-term strategy to raise awareness of energy savings opportunities among business customers and to help them take action using incentives offered by KCP&L.
Implementation Strategy	The implementation strategy will incorporate the following components: • *Walk-Through Audits.* Trained auditors complete a walk-through examination of the business using standard audit software, identifying specific energy saving opportunities. The auditor will review the anticipated costs and savings of the measures, along with information on financial resources available to help defray costs. Customers will be provided with a report and check list of recommendations from the audit. • *Direct Installation of Measures.* Upon customer approval of a job scope, the implementation contractor will install pertinent lighting measures identified during the audit on the same day as the audit, if possible. • *Customer Education.* Customers will be educated on energy efficient equipment and KCP&L's full suite of DSM programs. Particular attention will be paid to areas identified in the audit. KCP&L will hire an implementation contractor to: • Hire qualified, local individuals to conduct energy audits and install efficient lighting equipment. Provide training, ongoing as needed, to auditors. • Ensure that auditors are familiar with all KCP&L DSM programs available to customers. • Assist with program marketing and outreach. • Provide customer service support. • Track program performance, including audit requests, audit activities and customer actions. • Periodically report progress towards program goals and opportunities for improvement. The marketing and outreach strategies will include direct customer marketing such as bill inserts, newsletters, email, and on-bill messaging. The auditors will market the program directly to customers. KCP&L will highlight successfully completed projects to display the benefits of the program.
Risk Management	Small business customers are typically a hard-to-reach market without the time available to become educated on energy efficient equipment and the money available to upgrade to efficient equipment. One potential risk is a limited supply of qualified individuals with the skills to conduct audits and market energy efficiency improvements. A solution is the development of a local network of qualified professionals to provide audit and installation services and to promote the program to customers. The implementation contractor will: • Offer technical training to auditors, including classroom and field sessions. • Offer sales and business process training to help contractors succeed in selling and delivering energy efficiency services.
Measures &	Incentives were set for planning purposes and may be modified to reflect market

Incentives	conditions. Incentives cover up to 70% percent of the equipment and installation costs.

Table 17: Commercial Programmable Thermostat

Objective	Decrease peak demand usage to provide system and grid relief during particularly high-load, high-congestion peak hours.
Target Market	Small business customers with qualifying, applicable equipment. The type of customer that has HVAC units that are controlled by a single thermostat. It would not be possible for the Commercial Programmable Thermostat program, for example, to meaningfully control the HVAC system in a large hospital with a building energy management system and multiple control points.
Description	The Residential Programmable Thermostat Program reduces peak demand by controlling participant cooling equipment during periods of system peak demand and when there may be delivery constraints within certain load zones. This is done by way of a remotely communicating, programmable thermostat. During a program event, the program operations center sends a radio frequency signal to the thermostat to adjust its set-point by 2 to 4 degrees F such that the system will consume less energy and run less frequently throughout the 3 to 6 hour event duration. One method of participation will be for customers to receive the thermostat and professional installation (a $150 value) for free upon qualification and enrollment in the program.
Implementation Strategy	KCP&L will engage a third-party implementation contractor to: • Hire/sub-contract local staff to install the programmable thermostats. • Engage customers, schedule installation appointments and process incentives. • Provide customer service support. • Track program performance and event data. • Periodically report progress towards program goals and opportunities for improvement. Events will typically occur between June 1 and September 30, Monday to Friday. Event duration is typically 3 to 6 hours per day. Customers may opt-out twice a year by calling KCP&L a day in advance. The program will be marketed through direct contact with consumers using bill inserts, newsletters, website, broadcast and print media, and direct mail.
Risk Management	The primary benefit of demand response programs is to mitigate the risks and costs associated with system peak loads. From a planning perspective, using demand response resources in the most valuable way would imply that system planners would include the peak impacts in the load forecast nominated to the RTO, thereby reducing the utility system peak, required capacity, and also the reserve requirements. This also implies that events would primarily be called when the day-ahead forecast projects a load in excess of that nominated peak, rather than using another event trigger mechanism, such as energy market prices above a certain threshold or weather above a certain temperature. Having the thermostats available as a resource year-round is potentially of value to system operations in the event of plant maintenance or other grid events. Curtailment in participating homes with electric heat could provide additional risk management capabilities in the future. Providing the opportunity for customers to opt-out or override a limited number of events provides choice and control to the customer, minimizing the risk of attrition and lost participants.
Measures & Incentives	Customers receive a free communicating, programmable thermostat with installation ($150 value) for joining the program. After this, no cash payment is required for continued participation, making this a very cost effective capacity resource. Incentives were set for planning purposes and may be modified to reflect market conditions.

Table 18: Demand Response Incentive

Objective	Decrease peak demand usage to provide system and grid relief during particularly high-load, high-congestion peak hours.
Target Market	Large commercial and industrial customers with load curtailment capability of at least 25 kW.
Description	The Demand Response Incentive Program provides firm contractual arrangements with customers for periodic curtailments at times of system peak demand. Customers enter into a contract for a one-, three- or five-year term and receive a payment/bill credit based upon the curtailable load, the contract term and number of consecutive years under contract. Participants receive notification of an event at least 4 hours prior to the start time.
Implementation Strategy	Curtailment events may occur between June 1 through September 30, Monday through Friday between the hours of 12 pm and 10 pm (holidays are excluded). Event duration is typically 3 to 6 hours per day for a maximum of 15 events per year. KCP&L key account executives will be vital to coordinating with the largest customers and gaining their participation and collaboration. The program will also be marketed through direct contact with customers using bill inserts, newsletters, website, broadcast and print media, and direct mail.
Risk Management	The primary benefit of demand response programs is to mitigate the risks and costs associated with system peak loads. From a planning perspective, using demand response resources in the most valuable way would imply that system planners would include the peak impacts in the load forecast nominated to the RTO, thereby reducing the utility system peak, required capacity, and also the reserve requirements. This also implies that events would primarily be called when the day-ahead forecast projects a load in excess of that nominated peak, rather than using another event trigger mechanism, such as energy market prices above a certain threshold or weather above a certain temperature. Providing the opportunity for customers to opt-out or override a limited number of events provides choice and control to the customer, minimizing the risk of attrition and lost participants.
Measures & Incentives	Customers receive a fixed, capacity-reserve payment in terms of $/kW, based on the number of curtailable kW, the contract term, and number of consecutive years under contract. The fixed payment is supplemented by a performance payment on a $/kWh basis, calculated from the customer's actual load curtailment relative to their baseline load, as calculated by program management.

1.3 DEMAND-SIDE RATES

(C) To include demand-side rates for all customer market segments; —

KCP&L engaged Navigant to conduct a DSM Resource Potential Study. The study identified four major demand-side rate and demand response programs:

- *Pricing without Enabling Technology.* Customers manually curtail load in response to the pricing signals, communicated to via delivery mechanisms such as text message or email.
- *Pricing with Enabling Technology.* Customers have enabling technology for automatic load curtailment. These technologies include, but are not limited to, programmable thermostats, load switches, and automated demand response.
- *Interruptible Tariff* is a rate structure where customers agree to reduce demand to a pre-specified level/amount in exchange for an incentive payment. The tariff is limited to medium and large C&I customers and doesn't require advanced metering infrastructure (AMI) meters or equivalent equipment.
- *Direct Load Control.* Residential and small commercial customers allow specific equipment (e.g. central air conditioner) to be cycled to reduce system load. The program doesn't require AMI meters but does require equipment to remotely signal equipment (e.g. programmable thermostat).

1.4 MULTIPLE DESIGNS

(D) To consider and assess multiple designs for demand-side programs and demand-side rates, selecting the optimal designs for implementation, and modifying them as necessary to enhance their performance; and —)

KCP&L engaged Navigant to conduct a DSM Resource Potential Study. Navigant considered multiple design scenarios including the realistic achievable potential (RAP) and maximum achievable potential (MAP) as well as three additional scenarios roughly equally spaced between the RAP and MAP scenarios.

Additionally, KCP&L engaged AEG to design an additional DSM portfolio (Option C) for the KCP&L-MO service territory. AEG updated measure inputs and incorporated additional measures on an as-needed basis to reflect more recent program developments, evaluations, and new technology developments. After a review of KCP&L's existing programs and the Navigant potential study as well as workshops with KCP&L program managers and staff, the programs were modified to enhance their performance and incorporate the updated measure characteristics. AEG performed industry standard cost-effectiveness tests in order to gauge the economic merits of the measures, programs and portfolio. The end-use measures most likely to achieve cost-effective savings were then selected and bundled into programs.

1.5 EFFECTS OF IMPROVED TECHNOLOGIES

(E) To include the effects of improved technologies expected over the planning horizon to —

1.5.1 REDUCE OR MANAGE ENERGY USE

***1. Reduce or manage energy use;* or —**

KCP&L engaged Navigant to conduct a DSM Resource Potential Study for the KCP&L-MO service territory, which included the effects of improved technologies expected over the 20-year planning horizon. As a part of the scope of work, Navigant selected potential demand-side resources to fulfill the goal of achieving all cost-effective demand-side savings by designing highly effective potential demand-side programs. Navigant included the effects of improved technologies expected over the planning horizon to reduce or manage energy use and incorporate on-site CHP as a resource.

1.5.2 IMPROVE THE DELIVERY OF PROGRAMS

2. Improve the delivery of demand-side programs or demand-side rates. —

KCP&L engaged Navigant to conduct a DSM Resource Potential Study for the KCP&L-MO service territory, which included the effects of improved technologies expected over the 20-year planning horizon. As a part of the scope of work, Navigant selected potential demand-side resources to fulfill the goal of achieving all cost-effective demand-side savings by designing highly effective potential demand-side programs. Navigant included the effects of improved technologies expected over the planning horizon to improve the delivery of demand-side programs or demand-side rates and include on-site CHP as a resource.

SECTION 2: DEMAND-SIDE RESEARCH

(2) The utility shall conduct, describe, and document market research studies, customer surveys, pilot demand-side programs, pilot demand-side rates, test marketing programs, and other activities as necessary to estimate the maximum achievable potential, technical potential, and realistic achievable potential of potential demand-side resource options for the utility and to develop the information necessary to design and implement cost-effective demand-side programs and demand-side rates. These research activities shall be designed to provide a solid foundation of information applicable to the utility about how and by whom energy-related decisions are made and about the most appropriate and cost-effective methods of influencing these decisions in favor of greater long-run energy efficiency and energy management impacts. The utility may compile existing data or adopt data developed by other entities, including government agencies and other utilities, as long as the utility verifies the applicability of the adopted data to its service territory. The utility shall provide copies of completed market research studies, pilot programs, pilot rates, test marketing programs, and other studies as required by this rule and descriptions of those studies that are planned or in progress and the scheduled completion dates. —

KCP&L engaged Navigant to conduct a DSM Resource Potential Study. Navigant reviewed potential studies, technical reference manuals, and demand-side management program evaluations as well as regional and national sources. A comprehensive measure list was developed through a review of (a) DSM potential studies conducted for the state of Missouri and Missouri utilities,[2,3] (b) other Navigant potential, evaluation and program design work, and (c) existing KCP&L programs.

Navigant employed a variety of analytical approaches to estimate annual energy savings and coincident peak demand savings for each measure including: engineering algorithms, building energy computer simulation models, and secondary resources. The

[2] KEMA Consulting (March 04, 2011). Missouri Statewide DSM Potential Study – Final Report – Appendix.
[3] Global Energy Partners (January 2010). AmerenUE Demand-side Management Market Potential Study Volume 3: Analysis of Energy-Efficiency Potential.

majority of measures employed engineering algorithms and appropriate inputs from Technical Reference Manuals (TRM). When possible, Navigant utilized TRMs for Mid-Western states and utilities to capture effects of climate and regional similarities, including Ameren Missouri[4] and Illinois.[5]

Most building envelope measures were characterized through the use of building simulation models. Residential envelope measure savings were derived from BEopt™ software and calibrated to customer billing data. Commercial envelope measures were derived from simulations leveraging the *U.S. Department of Energy Commercial Reference Building Models of the National Building Stock* with a Kansas City, MO weather file.

Navigant conducted primary data collection of 139 non-residential customer sites across KPC&L's service territories. The 97 commercial and 42 industrial sites were randomly recruited by telephone according to a stratified sample design. Professionally trained surveyors collected a detailed inventory of energy-using equipment and building characteristics by inspection and, at some of the larger sites, customer-provided schedules of equipment. Surveyors also collected operation and power management behavior, including specifics on CHP (if present). Data collected covered all relevant energy aspects of customer facilities and businesses, including:

- Building size and orientation.
- Building envelope, such as insulation levels and wall and window sizes.
- Complete inventories of energy-using equipment covering all end uses, including lighting, HVAC, motors, water heating, commercial refrigeration, cooking, office equipment, air compressors, and other types of process equipment.
- Equipment and operation schedules and controls.

[4] *Appendix A, Technical Resource Manual, 2012 Energy Efficiency Filing.* Missouri Department of Natural Resources comments were considered and accounted for.
[5] State of Illinois Energy Efficiency Technical Reference Manual

Note that the evaluation and results for the commercial and industrial sectors do not reflect the fact that certain eligible customers may opt out of the program. This includes the energy and demand savings projections for the Realistic Achievable Potential (RAP) and Maximum Achievable Potential (MAP) scenarios.

Navigant conducted primary data collection of 69 residential customers across KPC&L's service territories. Customers were randomly recruited by telephone according to a stratified sample design. Surveyors conducted a brief interview with the customer, collecting a detailed inventory of energy-using equipment and building characteristics. The inspection covered all relevant energy aspects, including:

- Home size and orientation.
- Building envelope, such as insulation levels and wall and window sizes.
- Inventory of energy-using equipment covering all end uses.

Pursuant to 4 CSR 240-3.164 (2) (A), the current market potential study shall be updated no less frequently than every four (4) years. Therefore, in compliance with this requirement and as part of KCP&L's ongoing research efforts, KCP&L will conduct a new market potential study. KCP&L will initiate the next market potential study in 2015 with an estimated completion date of early 2017. KCP&L also recognizes that the current market potential study reflects a single data point and that a future market potential study may result in different energy and demand savings levels.

KCP&L SmartGrid Demonstration Project

The 2009 American Recovery and Reinvestment Act provided the United State Department of Energy with $600 million to fund Smart Grid Demonstration Projects. The KCP&L SmartGrid Demonstration Project (SGDP) was awarded a contract in August 2010. The operational testing and data collection phase of the SGDP concluded September 31, 2014. The analysis, evaluation, and documentation of findings for the twenty three operational demonstrations and tests conducted during the operational phase is ongoing and will be completed the first quarter of 2015. The SGDP Final Technical Report is due to the DOE May 1, 2015.

The SGDP is an end-to-end SmartGrid platform that includes advanced renewable generation, storage resources, leading-edge substation and distribution automation and control, energy management interfaces, and innovative customer programs and rate structures. The SGDP is focused on the geographic area served by the KCP&L Midtown Substation within Kansas City's urban core, an economic development region with a large number of customers living below the poverty line and/or in arrears with their utility bills.

The SGDP includes detailed analysis and testing to demonstrate the benefits of optimizing energy and information flows and utility operations across supply and demand resources, T&D operations, and customer end-use programs. Project components include:

Distribution Grid Management Infrastructure: The project will deploy a next generation end-to-end (or top-to-bottom) distribution grid management infrastructure based on distributed-hierarchical control concepts. The infrastructure will include:

- DR/DER Management System (DERM)
- Distribution Management System (DMS), including Distribution SCADA (D-SCADA), Dynamic Network Analysis (DNA), and Outage Management (OMS)
- AMI Head End
- Meter Data Management System (MDM)
- Distributed Control and Data Acquisition (DCADA)

SmartSubstation: develop and demonstrate a fully automated; next-generation distribution SmartSubstation with a local distributed control system based on IEC 61850 protocols.

SmartDistribution: develop and demonstrate a next generation DMS/D-SCADA system. The DMS/D-SCADA and Smart-Substation Controllers will provide the operational backbone of the system supporting significant levels of automation on the feeders, complex and automated feeder reconfiguration decisions, and tightly integrated supervision with the Control Centers.

SmartDR/DERM : develop and demonstrate a next-generation, end-to-end DERM system that provides balancing of renewable and variable energy sources with controllable demand as it becomes integrated in the utility grid.

SmartGeneration: implement DER technologies and DR programs sufficient in quantity and diversity to support the DERM development and demonstration.

SmartMetering: develop and demonstrate state-of-the-art integrated AMI and meter data management (MDM) systems that support two-way communication with 14,000 SmartMeters in the demonstration area and provides the integration with CIS, DMS, OMS, and DERM.

SmartEnd-Use Program: achieve a sufficient number of consumers enrolled in a variety of consumer facing programs to 1) support the DERM development and demonstration and 2) measure, analyze, and evaluate the impact of consumer education, enhanced energy consumption information, energy cost and pricing programs and other consumer based programs have on end-use consumption.

SmartGrid Demonstration Project – 2014 Process Evaluation

Navigant conducted a process evaluation of the SGDP. The customer offerings evaluated included the following:

- *MySmart Portal:* An energy management web portal that displays energy usage and utility bill cost information in hourly, daily, and monthly configurations.
- *MySmartDisplay:* An in-home monitor that displays current energy usage and utility bill cost information.
- *MySmart Thermostat:* An advanced metering infrastructure (AMI) enabled programmable thermostat.

- *Home Area Network:* A home energy network consisting of AMI-enabled programmable thermostat and load control devices.
- *Time-of-Use Rates:* A rate structure that supports summer peak load shedding through higher costs on weekdays from 3:00 to 7:00 p.m. from May 16 to September 15.

Over the course of a number of years (2012-2014), Navigant conducted a process evaluation of each of these SGDP end-use components. The evaluation team used online and phone surveys to explore participant experience and satisfaction, conducted an analysis of the MySmart Portal's analytics to understand participant usage patterns, and interviewed project stakeholders to identify lessons learned about the program operations and technologies deployed throughout the program.

Navigant identified the following key overall findings from their evaluation of the SGDP customer programs.

- *Participant awareness of the overall SGDP varied by program component. For example, MySmart Portal participants did not seem to connect the portal with the SGDP, while MySmart Thermostat and TOU participants reported high levels of awareness of the SGDP.*
- *Participant motivations for signing up for their respective program components were consistently driven by a desire to understand and control their energy use, in many cases to save money. Less motivating was a desire to help the environment or assist KCP&L in managing its business risks, such as power outages or having to build new generation.*
- *Participants reported high levels of satisfaction with the SGDP program components, as well as high levels of satisfaction with KPC&L. When asked, most participants felt that the program improved or maintained their level of satisfaction with KCP&L as a utility.*

The final report can be found in Appendix 5D Navigant SGDP 2014 Process Evaluation Report.

ELECTRIC POWER RESEARCH INSTITUTE

KCP&L financially supports research conducted by the Electric Power Research Institute (EPRI). KCP&L has access to the EPRI library of energy efficiency and demand response research and data that is available to program participants.

The electric utility industry launched the Energy Efficiency Initiative in 2007 to investigate, demonstrate, and assess application of efficient end-use technologies and demand response systems. More than 40 utility companies collaborated to identify cost-effective technology and system options for increasing efficiency and enabling dynamic energy management. A key accomplishment includes the creation of a Living Laboratory to test energy efficiency and demand response technologies and their interoperability.

Research results are available as a significant collection of reports and data on technology and program potential, including material related to influencing factors such as greenhouse gas emissions and smart grid development. Through EPRI research, the industry has developed information on load growth (which could potentially offset efficiency benefits) and the potential cost/benefit of energy efficiency and demand response. Major converging factors that affect efficiency and load management are addressed, such as greenhouse gas effects and integration with advanced metering infrastructure and smart grid deployment.

More information about the EPRI energy efficiency and demand response program research can be found on their website, www.epri.com. Additional specific EPRI energy efficiency and demand response programs recently and/or currently supported by KCP&L are summarized below.

EPRI Program 170: Energy Efficiency and Demand Response

This program is focused on the assessment, testing, demonstration, and deployment of energy efficient and smart end-use technologies to accelerate their adoption into utility programs, which can influence the progress of codes and standards and ultimately lead to market transformation. The program also develops analytical frameworks essential to utility application of energy efficiency and demand response, including assessment of resource potential, characterization of end-use load profiles, calculation of environmental impacts, and integration into utility resource planning.

The research has helped manage risk mitigation and avoided costs related to understanding and assessing emerging end use technologies, including:

- Assessment, testing, and demonstration of energy efficient and demand-responsive technologies and systems to determine efficacy prior to deployments in utility pilots or programs.
- Synthesis of end-use load research results and techniques to provide predictive insights into electricity use forecasts.

The program also provided significant input into standards development process, including use-case functional specifications of demand response–ready end-use devices through a multidisciplinary process involving utilities, equipment manufacturers, public agencies and other industry stakeholders.

The 2012 and 2013 Technology Readiness Guides provided a methodology for benchmarking the status of technologies with respect to the stages of EPRI's Energy Efficiency Technology Pipeline and included a comprehensive assessment encompassing required and scored criteria, criteria weighting, and an estimation of technical potential for energy efficiency.

EPRI Program 170 Supplemental: Evaluating Smart Thermostats’ Impact on Energy Efficiency and Demand Response

Advances in technology have led to the development of a new generation of programmable communicating thermostats that hold the potential for energy and demand savings at a relatively low cost to electric and gas utilities. Industry experience has shown that customer acceptance and usability can be key drivers to a thermostat’s energy or demand reduction potential. Given that smart thermostats may offer better customer usability due to their remote programming capability, the objective of this program is to evaluate their energy and demand savings impacts, as well as how customers perceive and use them.

New learning for the industry and the public will come about by addressing the program's key research question: Do smart thermostats result in energy and/or demand savings with residential customers? Other new learnings will be derived in answering secondary research questions relating to the technological characterization of various smart thermostats on the market, and customer interest and uptake. The program offers the opportunity to pool and compare data across different utility and technology contexts, therefore contributing a larger breadth of results than any single evaluation.

The program will inform natural gas and electric utilities and the public of the potential energy savings benefits of smart thermostats. For utilities, it may provide a measure of how these thermostats fit into their programs and key features that might promote energy efficiency and demand response. Demand response from residential air conditioners has been a target of many utility programs, but the cost of installation of load control devices and the perceived compromise in customer comfort have been large barriers. These thermostats, which are consumer-managed and possibly consumer-procured, may overcome these barriers at a relatively low cost. The knowledge gained about how customers perceive and interact with these types of devices may potentially inform future product designs and help bring about better thermostat choices for consumers.

EPRI Program 182: Understanding Electric Utility Customers

Electric utilities increasingly realize that they need to better understand and engage with customers. Overall, customer satisfaction is a key measure of how well a utility is meeting its customers' needs and expectations. However, engagement is taking on a new dimension. Technology advances along with the success of new electric service options, as demonstrated in pilots, make offering customers choices for how they buy electricity possible in almost any electricity market. Choices require more engagement because customers need confidence in the information that will help them make the right choice. Mutually beneficial results are the expectation, but are realized only if the choices offered customers jointly meet their needs and contribute to the utility fulfilling its obligation to provide reliable and affordable power.

Since customers have diverse electricity demands, it follows that a single service offering leaves some of those demands unfulfilled. Diversity of demands is advantageous because electricity supply is subject to temporal and spatial supply cost differences that are best managed if there are complementary demands. Some customers will use less when prices are high and more when they are low. Information about when they use electricity helps customers better allocate their budget to meet all their needs.

Fundamental research is required to identify the root drivers of utility customer behavior. Such drivers include the effects of rate structure, feedback, and control technologies on customer response, response variation by customer segment, and other pertinent research questions. Subsequent field tests are necessary to verify behavioral models and quantity their impact over a range of customer and market circumstances. This program employs two parallel and coordinated initiatives—original research and utilizing the research of others—to fill important knowledge gaps about how consumers and businesses use and value electricity. The program focuses on three categories of behavioral inducements: pricing structures, information provision (feedback), and control technologies.

EPRI Program 182 Supplemental: Matching Electric Service Plans to Utility Strategic Goals

KCP&L is collaborating with EPRI to evaluate the performance of its current residential rates in light of fundamental changes in its electricity supply costs and its desire to diversify its service offerings to engage customers. Important considerations in establishing a time-indexed plan for developing, testing and implementing Electric Service Plans (ESP) include: the success of existing dynamic pricing programs; expected impacts: the level of customer interest; metering and other service fulfillment requirements, and compatibility of KCPL programs with ISO/RTO demand response offerings. ESP screening would contribute to defining the best path to achieve that objective.

EPRI Program 182 Supplemental: Characterizing Residential Customer Preferences for Electric Service Plans

Advances in metering, data management, and information technologies have reduced many of the barriers that limited the availability of dynamic electricity rates, especially to residential customers. For example, AMI enables electricity usage to be measured at almost any level of granularity, removing many of the barriers to offering pricing structures like time-of-use, peak-time rebates, critical peak pricing, real-time pricing, and variations thereof, to all customers on a self-selecting basis. Additionally, utilities and other retail providers can help customers plan and execute beneficial changes in usage under any rate structure by proving feedback and facilitating their use of control technologies. Considered together, these rate structures, feedback mechanisms, and control technologies can be combined into various types of service offerings (ESPs).

However, designing, marketing, implementing, and administering ESPs still involves additional costs, many of which are incurred up-front. The extent to which feedback is provided and incentives offered to promote adoption of control technologies is predicated on how and which ESPs customers elect to join. The cost of providing customer choice is substantial and driven by the scale and scope of ESP acceptance. In the absence of credible estimates of consumers' relative ESP preferences (market shares), justifying those expenditures is difficult. Recent pilots involving pricing, feedback, and control technology provide limited insight into why customers join ESPs (EPRI 1025856).

The program objective is to develop, test, and administer research methods that retail electric service providers can employ to gauge customer preferences for different types of ESPs. The results will provide initial insight into ESP preferences, and produce research tools that can be widely employed by utilities, on their own or collaboratively, to improve their understanding of customers' preferences for how they buy electricity.

EPRI Program 161: Information & Communication Technologies (IntelliGrid)

Utilities are increasingly deploying monitoring, communications, computing, and information technologies to enable grid modernization applications such as wide area monitoring and control, integration of bulk or distributed renewable generation, distribution automation, and demand response. Companies face significant challenges when deploying these technologies. IntelliGrid addresses these challenges by:

- Promoting interoperable systems by leading an industry effort to develop open, interoperable AMI systems, contributing to the development of key standards (e.g. Common Information Model), assessing emerging standards (e.g. Open Automated Demand Response), conducting interoperability tests of products that implement key standards, and providing training and information to utilities on how to implement standards.
- Providing tracking and analysis of emerging communications technologies, investigating synchrophasor communications infrastructure to support grid control, conducting research on emerging technologies (e.g. TV white space and other lightly licensed spectrum), and conducting field demonstrations of 4G technologies for utility operations.
- Performing research into the nature and structure of utility data—where data is required, how data is turned into actionable information and effectively presented to a user—and understanding the cost of poor data quality to a utility.
- Capturing best practices and lessons learned from utility deployments of grid modernization technologies and applications.
- Tracking federal government and regulatory activities relating to standards and communications, and interpreting the impact these actions will have on the utility industry.

With the knowledge acquired through this program, members will be able to lower costs and reduce risks as they implement grid modernization technologies and applications. Specifically, members will have access to information that can help them:

- Implement standards-based approaches for achieving interoperability of devices and systems that make up a smart grid infrastructure.

- Understand the impact of new standards and communications technologies on utilities.
- Apply lessons learned from utility implementations of grid modernization technologies and systems.
- Understand communications and information system architecture requirements and technologies to support grid modernization applications.
- Understand the impact that federal government and regulatory activities related to standards and communications will have on the utility industry.

Research results will address near-term needs and make contributions that will advance the industry toward open, standards-based systems and devices that are interoperable and secure.

EPRI Program 161 Supplemental: Automated Demand Response and Ancillary Services Demonstration

This program will perform research associated with emerging energy price and product messaging-protocol standards to take advantage of ubiquitous low-cost communication infrastructures that may be able to reliably perform automated demand response (DR) and ancillary services or fast DR functions. Internationally recognized standards for DR and ancillary services are a key enabler for the development of commercially available products that have largely been proprietary over the last 30 years.

Emerging standards development from the Lawrence Berkeley National Lab, the Organization for the Advancement of Structured Information Standards, and the National Institute of Standards and Technology have advanced sufficiently so that demonstrations are feasible and products are beginning to become commercially available. However, research questions remain about the level of quality of service, reliability, security, and scalability. Other issues include the level of measurement and verification required and an understanding of the load characteristics and how it can meet the ancillary services requirements.

The program may help to accelerate development of standards that automatically manage loads and distributed energy resources (DER) for DR and ancillary services requiring faster response. The use of standardized communication protocols for these functions will benefit the public by enabling the use of multiple types of low-cost ubiquitous communication networks, crossing many utility boundaries from distributor to ISOs and facilitating access to ancillary markets.

This work is expected to increase market participation in the development of devices, eventually, with this functionality directly built in. Electric utilities are expected to gain an understanding of the performance capabilities load types, infrastructure requirements, product availability, and market opportunities associated with the advancement of this smart grid application.

EPRI Program D_SG: Smart Grid Demonstration

The Smart Grid Demonstration Initiative is a seven-year collaborative research effort to design, deploy, and evaluate how to integrate DER into utility grid and market operations. The Initiative leverages multi-million dollar investments in the smart grid by the electric utility industry, with the goal of sharing information and research results on a wide range of smart grid technologies and applications. Twenty-four collaborating and host utilities from Australia, Canada, France, Ireland, Japan and the United States have been designing and implementing demonstrations of smart grid technology and applications since 2008 as part of the Initiative.

SECTION 3: DEVELOPMENT OF POTENTIAL DEMAND-SIDE PROGRAMS

(3) The utility shall develop potential demand-side programs that are designed to deliver an appropriate selection of end-use measures to each market segment. The utility shall describe and document its potential demand-side program planning and design process which shall include at least the following activities and elements: —

KCP&L engaged Navigant to conduct a DSM Resource Potential Study. The potential study calculated four types of DSM resource potential:

Technical Potential: Assumes that all installed measures can immediately be replaced with an efficient technology, regardless of cost or market acceptance.

Economic Potential: A subset of technical potential that assumes that all installed measures can immediately be replaced with a cost-effective efficient technology. Cost-effectiveness is determined utilizing the total resource cost test.

Achievable Potential: Achievable potential estimates consider market acceptance, technology turn-over and diffusion of technology awareness and product adoption. The only difference between the scenarios is the assumed measure incentive.

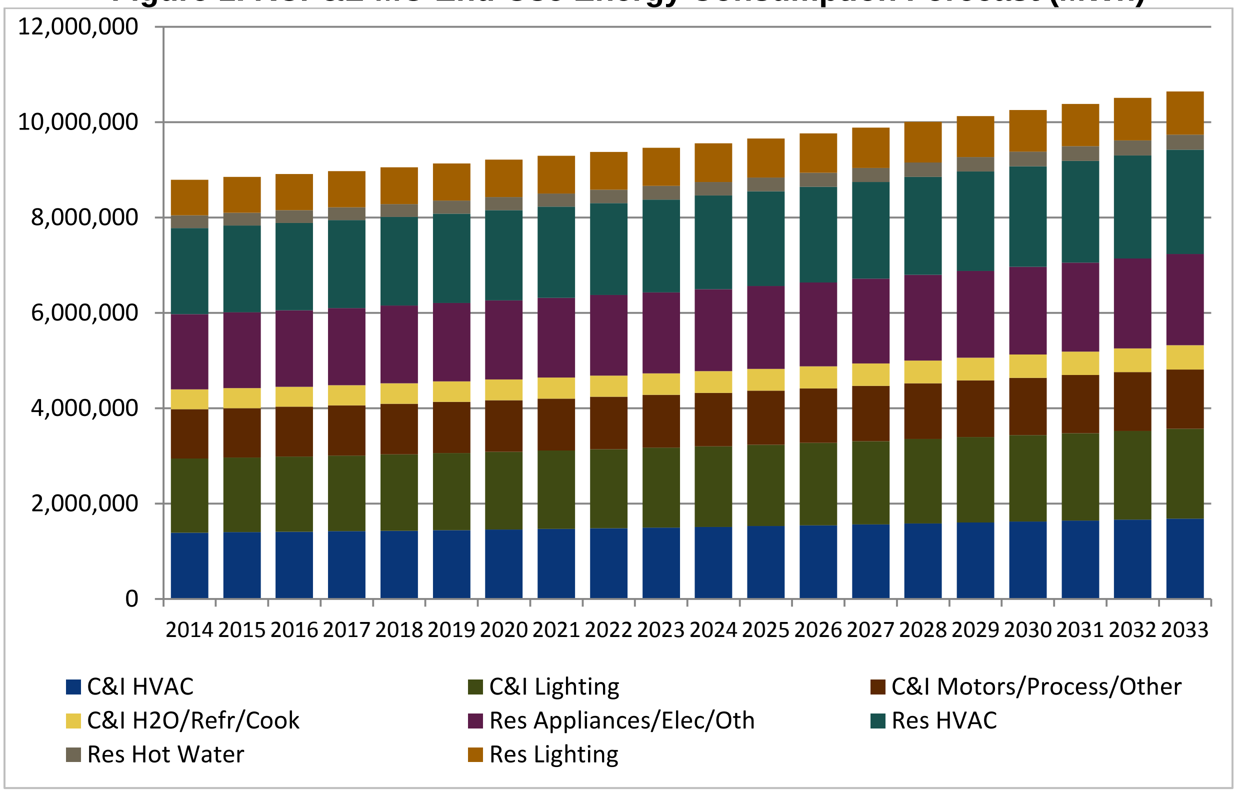
- *Maximum Achievable Potential (MAP):* incentive levels are set at 100% of the incremental cost of the measure. The scenario maximizes savings achieved, but also results in a portfolio cost that far exceeds that typically encountered in efficiency programs for a given level of energy saved.
- *Realistic Achievable Potential (RAP):* incentive levels are set based upon the efficiency supply curve by limiting the maximum $/kWh paid (calculated on a levelized cost basis) for any given measure.

A number of analytical steps were taken to produce potential estimates.

Step 1. Baseline Market Characterization and Historical Load Analysis[6]

Navigant conducted primary data collection, gathering detailed measure data and building characteristics from 208 buildings (69 residential and 139 commercial & industrial). Navigant also mapped the SIC code to historic energy usage, resulting into 11 commercial, 7 industrial, and 4 residential customer segments. The data were used to forecast building stock by customer segment, estimate market penetration of efficient measures, and develop measure-level savings estimates. The data, in combination with the measure characterization of the next task, were also used to estimate the forecast energy breakdown by end use category.

Figure 1. KCP&L-MO End-Use Energy Consumption Forecast (MWh)



Note: Navigant's potential study analysis is conducted at the measure level and is disaggregated by customer segment. As a result, the potential study does not rely on a customer end-use forecast.

Step 2. Measure Identification and Characterization

Navigant developed a comprehensive measure list of conventional and emerging technologies. The initial measure list was identified through a review of a) previous

[6] At the time of the study, the list of opt-out customers was in flux due to changes in customer decision-making. Navigant and KCP&L decided they would not reduce the potential results of the study to exclude opt-out customers.

DSM potential studies conducted for the state of Missouri and other Missouri utilities, b) other Navigant potential, evaluation and program design work, and c) existing KCP&L program descriptions and custom applications. Navigant then modified the measure list to incorporate feedback from KCP&L and Missouri stakeholders. Overall, 500 measures were identified and 300[7] characterized for the final model.

Inputs from the baseline market characterization were used to develop measure-level savings estimates and initial technology densities. Navigant used a number of techniques to estimate measure-level savings, including calibrated building simulation and standard engineering algorithms. Navigant also estimated measure costs, accounting for regional cost differences using standard adjustment techniques. The measure characterization consisted of the following key parameters:

1) *Measure Definition*: the baseline and efficient equipment definitions, unit basis, and measure application.
2) *Energy Consumption*: annual energy consumption in kilowatt-hours (kWh).
3) *Coincident Electric Demand*: peak coincident demand in kilowatts (kW).
4) *Measure Lifetime*: the lifetime in years.
5) *Incremental Cost*: the difference in cost between the efficient equipment and the base or code equipment. Labor costs are only applied for retrofit measures.
6) *Net-to-Gross Ratio*: adjust savings and costs to account for free-ridership and spillover.
7) *Technology Density:* define the saturation of the baseline and efficient technologies in KCP&L territory. The values are on a "per home" basis for the residential sector and on a "per 1000 square feet of building space" for the commercial and industrial sectors.
8) *Technology Applicability:* the percentage of the base technology that can be reasonably and practically replaced with the specified efficient technology.

[7] Measures that were not characterized either had low or no density per the baseline data collection effort or were accounted for by other measures.

Step 3. Estimation of Technical and Economic Potential

Navigant estimated the technical, economic, and achievable potential using its proprietary Demand Side Management Simulator (DSMSim™) model. DSMSim is a bottom-up technology diffusion and stock tracking model implemented using a System Dynamics[8] framework. The figure below provides a high-level summary of the key input and output of DSMSim.

Figure 2. DSMSim Key Input and Output

Key Input	Key Output
» EE Measure Costs, Energy/Demand Savings » Utility Data • Electricity Rates, Avoided Costs, Incentives (can also be an output), Energy Sales, Demand, etc. » Initial Measure Saturation » Maximum Measure "Density" (e.g., units/home) » NTG Ratios » Consumer Sensitivity to Payback » Diffusion Parameters	» Energy/Demand Svgs (Tech/Econ/Achievable) » Utility Costs (Incremental and Cumulative) » Portfolio & Measure Benefit/Cost Ratios » Incentive Levels » Average $/kWh » Costs/Savings and % of Revenue & Elec. Sales

Navigant also estimated combined heat and power (CHP) and demand response potential.

- CHP: Navigant considered a wide range of CHP technologies, fuel types and system sizes (e.g. fuel cells, micro-turbines, reciprocating engines, gas turbines, steam turbines), screened them for cost-effectiveness, and estimated adoption of technologies using a separate in-house CHP potential spreadsheet model.
- Demand Response: potential was estimated using the Demand Response Simulator (DRSim™) model, which follows the approach used in the FERC National Assessment of Demand Response Potential.[9] Consistent with the FERC

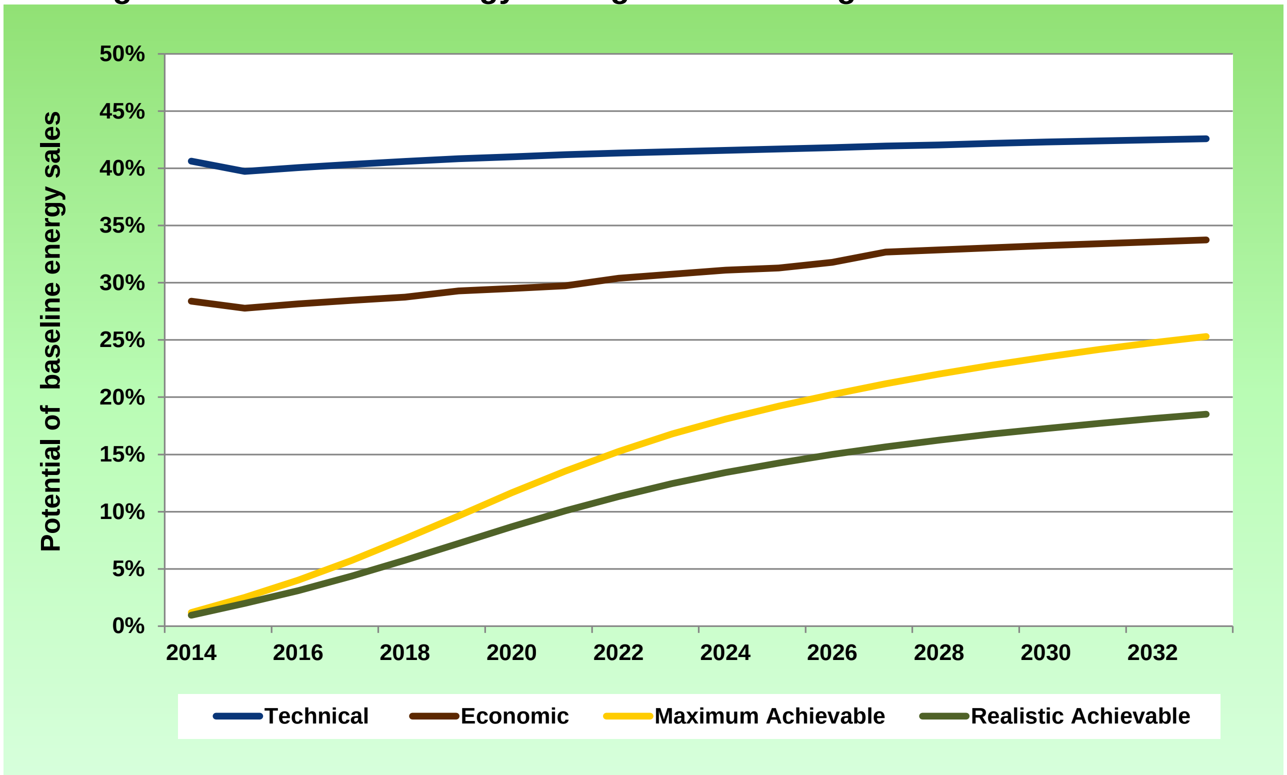
[8] Sterman, John D. *Business Dynamics: Systems Thinking and Modeling for a Complex World*. 2000. Irwin McGraw-Hill. Also see http://en.wikipedia.org/wiki/System_dynamics for a high-level overview.
[9] Federal Energy Regulatory Commission, *A National Assessment of Demand Response Potential*. Prepared by The Brattle Group, June 2009.

approach, Navigant estimated demand response potential for five categories, including interruptible tariffs, direct load control, pricing without enabling technology, pricing with enabling technology, and other.

Navigant developed a suite of DSM programs consistent with the RAP scenario and ran scenario analysis between the RAP and MAP scenarios to understand how increasing savings targets would likely increase total costs.

The figure below illustrates the potential for energy savings as a percentage of the baseline energy forecast. As seen in this figure, technical potential represents roughly 41% of baseline energy sales over the 20-year forecast horizon, whereas economic potential ranges from 27 to 34% over the forecast horizon. Maximum achievable potential reaches 16.8% after 10 years and 25.3% by the year 2033. Realistic achievable potential is 12.4% of baseline energy sales by 2023 and 18.5% by 2033, which is roughly 55% the economic potential in that year. Note that these figures do not reflect the roll-off of measures at the end of the measures' life, C&I opt outs nor other required adjustments.

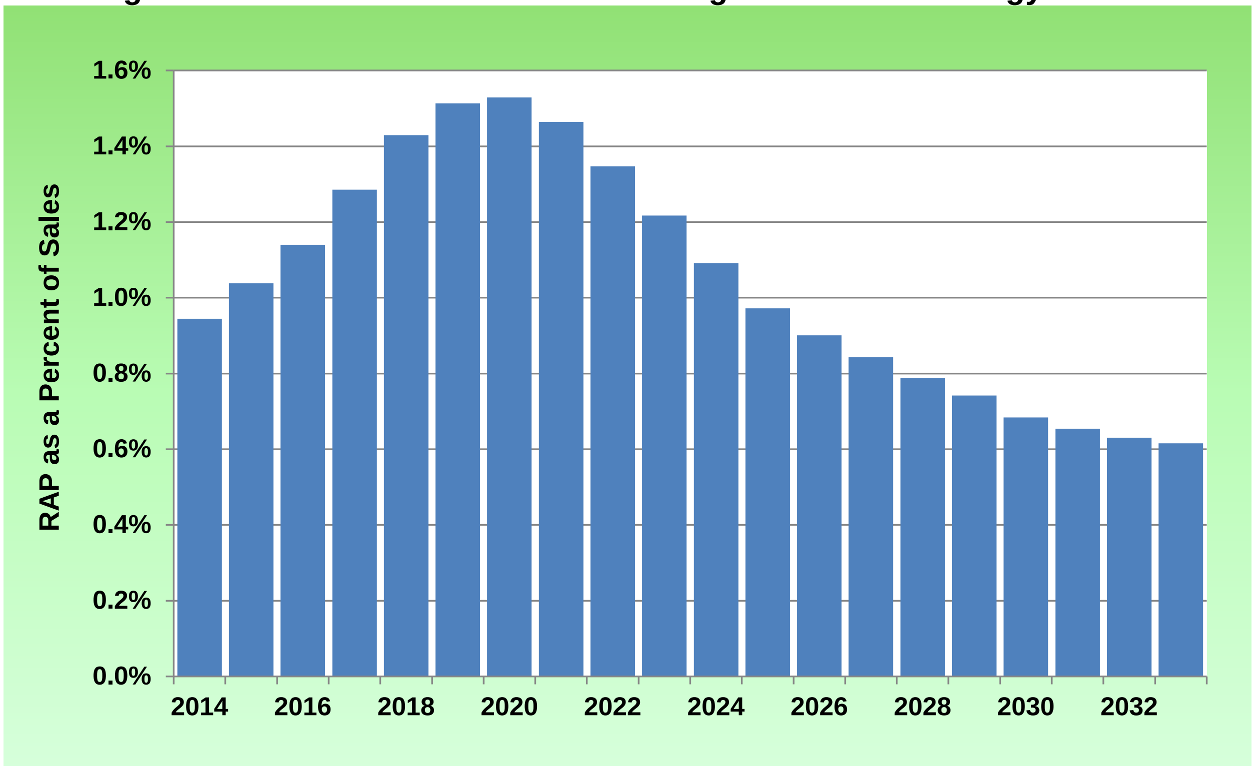
Figure 3. Cumulative Energy Savings as Percentage of Baseline Sales[10]



The figure below presents the annual incremental realistic achievable potential as a percentage of baseline forecast energy sales. The table shows the cumulative energy and demand savings from energy efficiency measures.

[10] Note that this chart does not reflect roll-off of measures at the end of the measures' life, C&I opt outs nor other required adjustments.

Figure 4. Incremental RAP as a Percentage of Baseline Energy Sales[11]



[11] Note that this chart does not reflect roll-off of measures at the end of the measures' life, C&I opt outs nor other required adjustments.

Table 19. Cumulative Energy and Demand[12]

Year	Cumulative Energy Savings (MWh)				Cumulative Demand Savings (MW)			
	Technical	Economic	MAP	RAP	Technical	Economic	MAP	RAP
2014	3,581,027	2,501,491	103,809	83,217	976	615	26	19
2015	3,524,940	2,464,568	222,681	175,255	963	611	56	41
2016	3,579,226	2,514,060	358,190	277,039	974	621	92	65
2017	3,630,483	2,560,346	515,413	392,661	985	630	134	94
2018	3,684,404	2,608,862	692,514	522,323	997	640	181	127
2019	3,738,378	2,680,433	881,699	660,805	1,009	654	232	162
2020	3,786,858	2,723,815	1,075,116	801,979	1,020	664	285	198
2021	3,837,153	2,768,866	1,261,494	938,370	1,032	674	336	233
2022	3,885,410	2,857,765	1,435,067	1,064,988	1,043	716	384	266
2023	3,932,526	2,917,142	1,591,901	1,180,430	1,054	730	427	295
2024	3,983,472	2,980,930	1,733,479	1,284,982	1,066	741	466	320
2025	4,036,927	3,029,471	1,860,562	1,379,080	1,078	752	501	343
2026	4,092,455	3,110,198	1,980,594	1,467,237	1,091	773	534	364
2027	4,153,604	3,236,336	2,096,715	1,550,686	1,106	791	565	382
2028	4,215,936	3,296,513	2,208,109	1,629,698	1,120	805	594	400
2029	4,280,483	3,356,160	2,315,369	1,704,979	1,135	818	621	416
2030	4,346,720	3,417,337	2,416,230	1,775,261	1,151	832	647	432
2031	4,409,916	3,476,352	2,513,709	1,843,326	1,165	846	671	447
2032	4,475,357	3,536,815	2,607,909	1,909,732	1,181	860	693	461
2033	4,543,031	3,599,358	2,699,565	1,975,390	1,197	874	715	475

Residential single family homes offer the largest potential for energy savings, accounting for 19% of the realistic achievable potential by 2033. The figure below presents the cumulative energy savings by end-use. As seen in the figure, C&I HVAC/Shell/Whole Building measures provide the largest savings opportunity by 2033, driven largely by new construction measures that reduce savings greater than 30% relative to a baseline building. This end use category accounts for between 25% and 32% of total realistic achievable potential over the 20-year forecast horizon. Residential and C&I Lighting still account for substantial savings notwithstanding new federal lighting standards that reduce opportunity relative to past achievement. Residential and C&I lighting combined account for between 28% and 30% of realistic achievable savings over the 20-year forecast horizon.

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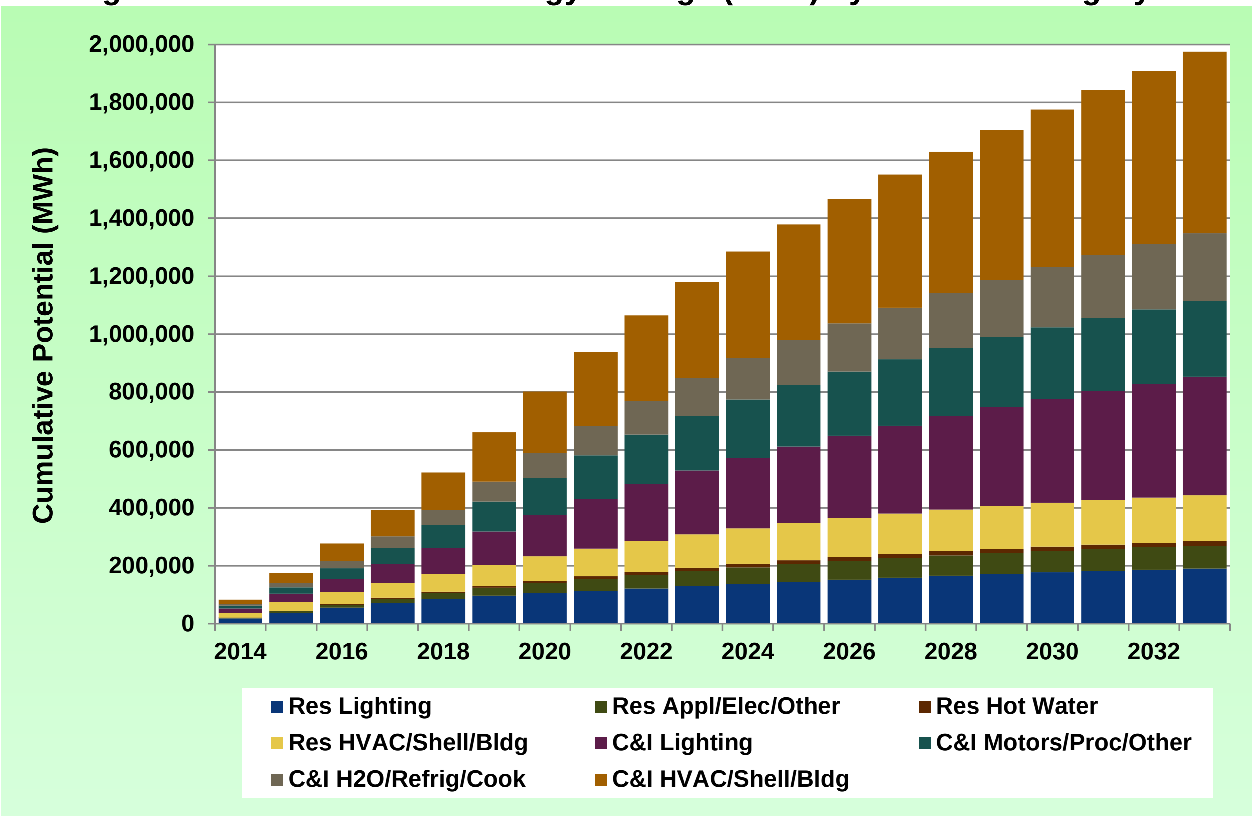
[12] Note that this table does not reflect roll-off of measures at the end of the measures' life, C&I opt outs nor other required adjustments.

Figure 5. Cumulative RAP Energy Savings (MWh) by End Use Category[13]



KCP&L engaged AEG to design an additional DSM portfolio (Option C) for the KCP&L-MO service territory. AEG took the following steps:

1. **Review Existing KCP&L DSM Portfolio**. AEG reviewed program descriptions and evaluations as well as program tracking data, including program participation, budgets versus expenditures and program savings. AEG held two collaborative program design workshops with KCP&L program managers and staff to discuss the program design process and gain insight into the existing DSM programs.

2. **Review DSM Potential Study**. AEG reviewed the *Demand-Side Resource Potential Study Report* and the *Demand-Side Resource Potential Study Report – Demand Response* completed by Navigant in August 2013. AEG compared the existing KCP&L portfolios with the potential study and best practice programs from industry

[13] Note that this chart does not reflect roll-off of measures at the end of the measures' life, C&I opt outs nor other required adjustments.

research, primarily using information from utilities that are similar in size and customer composition as KCP&L. AEG updated measure inputs and incorporated additional measures on an as-needed basis to reflect more recent program developments, evaluations, and new technology developments (for example the dramatic cost and efficacy improvements occurring in the LED lighting market).

3. **Review Stakeholder Input and Regulatory Requirements**. AEG reviewed KCP&L stakeholder input on the DSM programs provided through written comments and prior collaborative workshops. Similarly, AEG reviewed reporting and filing requirements, as well as the Stipulation and Agreement, which specified items to be considered in the design of future DSM programs. AEG attempted to design the portfolio and programs in such a way to address and satisfy all of these concerns.

4. **Develop DSM Program Plan**. AEG constructed program design for the 20-year period from 2016 through 2034. With the existing KCP&L DSM programs and the Navigant potential study as a starting point, the programs were modified to enhance their performance and incorporate the updated measure impacts. AEG analyzed cost-effectiveness in order to gauge the economic merits of the measures, programs and portfolio. Cost-effectiveness was measured using four of the industry standard cost-effectiveness tests; total resource cost test, utility cost test, participant cost test, and rate impact measure test. As required in 22.050 (5) (B) the total resource cost test was used as the final determination of cost-effectiveness. As permitted in 22.050 (5) (D), the cost-effectiveness criterion was relaxed for the income-eligible programs since they are considered to have potential benefits that are not otherwise captured by the cost-effectiveness test.

5. **Adjust Potential Study RAP and MAP**. In the Navigant potential study report, the reported energy and demand savings did not account for the roll-off of measures at the end of the measures' life nor did it factor in the opt-out of commercial and industrial customers. At KCP&L's request, Navigant provided additional spreadsheets that take measure roll-off into account. KCP&L then used the new energy and demand savings and factored in an estimated 10% opt-

out of commercial and industrial customers. In addition, KCP&L adjusted the Navigant potential study RAP and MAP scenarios to match the time period needed for the IRP. The potential study included the years 2014 through 2033. KCP&L already has existing programs through 2015. Thus, the effects of programs in 2014 and 2015 were removed and the savings were extended to 2034. The impacts of these adjustments are shown in Table 48, Table 49, and Table 50. These calculations and adjustments can be found in the KCP&L workpapers[14].

3.1 PREVIOUSLY IMPLEMENTED DEMAND-SIDE PROGRAMS FROM OTHER UTILITIES

***(A) Review demand-side programs that have been implemented by other utilities with similar characteristics and identify programs that would be applicable for the utility*; —**

KCP&L engaged Navigant to conduct a DSM Resource Potential Study. Navigant conducted a benchmarking assessment of similar utility programs and top-performing utilities to (1) ensure the potential estimates developed were reasonable and appropriate and (2) identify best practices.

The benchmarking analysis included residential and C&I DSM programs at KCP&L in Kansas and Missouri as well as the following 14 utilities/program administrators: Pacific Gas & Electric (California), Interstate Power & Light (Iowa), MidAmerican (Iowa), Ameren Illinois, Commonwealth Edison (Illinois), Westar (Kansas), AEP Ohio, Consumer's Energy (Michigan), Detroit Edison (Michigan), Minnesota Power, Otter Tail Power (Minnesota), Xcel Energy (Minnesota), Efficiency Vermont, and Wisconsin Focus on Energy.

For sector comparison purposes, Navigant focused on the following high performing utility portfolios:

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[14] MO IRP Output - Maximum, FINAL - Program Totals IRP HC.xlsx, MO IRP Output - Realistic, FINAL – Program, Totals IRP HC.xlsx, KS IRP Output - Maximum, FINAL - Program Totals IRP HC.xlsx
KS IRP Output - Realistic, FINAL - Program Totals IRP HC.xlsx

- C&I sector: Interstate Power & Light, Minnesota Power, Otter Tail Power and Xcel Energy.
- Residential sector: Commonwealth Edison, Detroit Edison, MidAmerican, Minnesota Power and Xcel Energy.

3.2 MARKET SEGMENT IDENTIFICATION

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

KCP&L engaged Navigant to conduct a DSM Resource Potential Study. Navigant identified KCP&L's market segments by categorizing historic customer energy usage by SIC code. The residential, commercial and industrial sector market segments included:

- Residential: Single Family, Single Family Low-Income, Multi-Family, Multi-Family Low Income
- Commercial: Grocery, Healthcare, Lodging, Office – Large, Office – Small, Restaurants, Retail, Schools, Warehouses, Other Commercial
- Industrial: Chemicals, Electronics, Food, Rubber-Plastics, Stone-Clay-Glass, Motor Freight Transportation, Other Industrial

Table 20. Market Segments (2014), MWh

Segment	KCP&L-MO
Industrial-Chemicals	451,450
Industrial-Electronics	10,702
Industrial-Food	383,343
Industrial-Motor Freight	65,188
Industrial-Other Industrial	510,800
Industrial-Rubber-Plastics	80,755
Industrial-Stone-Clay-Glass	185,834
Commercial-College	82,701
Commercial-Grocery	106,052
Commercial-Healthcare	393,073
Commercial-Lodging	142,051
Commercial-Office - Large	1,724,071
Commercial-Office - Small	403,775
Commercial-Other Commercial	638,256
Commercial-Restaurant	166,375
Commercial-Retail	360,965
Commercial-School	221,833
Commercial-Warehouse	254,913
Residential-Single Family	1,602,132
Residential-SF Low Income	686,628
Residential-Multi-Family	223,868
Residential-MF Low Income	95,943
Total	**8,790,707**

3.3 DEVELOPMENT OF END USE MEASURES

(C) Identify a comprehensive list of end-use measures and demand-side programs considered by the utility and develop menus of end-use measures for each demand-side program. The demand-side programs shall be appropriate to the shared characteristics of each market segment. The end-use measures shall reflect technological changes in end-uses that may be reasonably anticipated to occur during the planning horizon; —

KCP&L engaged AEG to design an additional DSM portfolio (Option C) for the KCP&L-MO service territory. AEG began with the *Demand-Side Resource Potential Study Report* and the *Demand-Side Resource Potential Study Report – Demand Response* completed by Navigant in August 2013. Navigant developed a comprehensive measure list through a review of (a) DSM potential studies conducted for the state of Missouri and Missouri utilities,[15,16] (b) other Navigant potential, evaluation and program design work, and (c) existing KCP&L programs. Navigant then modified the measure list to incorporate feedback from KCP&L and Missouri stakeholders. Overall, 500 measures were identified and 300 were characterized for the final model.

Navigant employed a variety of analytical approaches to estimate measure-level energy savings and coincident peak demand savings, including standard engineering algorithms, calibrated simulation models, and secondary resources. The majority of measures employed engineering algorithms and appropriate inputs from TRMs. When possible, Navigant utilized TRMs for Mid-Western states and utilities to capture effects of climate and regional similarities, including Ameren Missouri[17] and Illinois.[18] Most building envelope measures were characterized through the use of building simulation models. Residential envelope measure savings were derived from BEopt™ software and calibrated to customer billing data. Commercial envelope measures were derived from simulations leveraging the *U.S. Department of Energy Commercial Reference Building Models of the National Building Stock* with a Kansas City, MO weather file.

Navigant also estimated measure costs, accounting for regional cost differences using standard adjustment techniques. Material and labor costs were derived from a variety of resources including TRMs, online research, the California Database for Energy Efficiency Resources, and RS Means cost work.

AEG reviewed the end-use measures developed in the Navigant potential study and the measures in KCP&L's MEEIA portfolio. Based on research and industry best practices, AEG updated the measure inputs and added additional end-use measures to reflect changes in technology that have emerged since the potential study was completed.

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[15] KEMA Consulting (March 04, 2011). Missouri Statewide DSM Potential Study – Final Report – Appendix.
[16] Global Energy Partners (January 2010). AmerenUE Demand-side Management Market Potential Study Volume 3: Analysis of Energy-Efficiency Potential.
[17] *Appendix A, Technical Resource Manual, 2012 Energy Efficiency Filing.* Missouri Department of Natural Resources comments were considered and accounted for.
[18] State of Illinois Energy Efficiency Technical Reference Manual

Table 21. Residential End-Use Measures

End-Use	Efficient Description	Base Description
Appliance	Combination Oven	Standard Oven
Appliance	Convection Oven	Standard Oven
Appliance	Efficient Ceiling Fan	Standard Ceiling Fan
Appliance	ENERGY STAR Dehumidifier	Standard Dehumidifier
Appliance	ENERGY STAR Dishwasher	Standard Dishwasher
Appliance	ENERGY STAR Dual Speed Pool Pump	Standard Pool Pump
Appliance	ENERGY STAR Freezer	Standard Freezer
Appliance	ENERGY STAR Refrigerator	Standard Refrigerator
Appliance	ENERGY STAR Variable Speed Pool Pump	Standard Pool Pump
Appliance	Heat Pump Clothes Dryer	Standard Clothes Dryer
Appliance	High Efficiency Clothes Dryer	Standard Clothes Dryer
Appliance	High Efficiency Clothes Washer	Standard Clothes Washer
Appliance	High Efficiency Pool Pump	Standard Pool Pump
Appliance	Induction Stove	Standard Stove
Appliance	Pool Pump Timer	Standard Pool Pump
Appliance	Pool Pump VSD	Standard Pool Pump
Appliances	ENERGY STAR Air Purifier	Standard Air Purifier
Behavioral	Home Energy Display	No Home Energy Displays
Behavioral	Home Energy Reports	No Home Energy Report
Electronics	80 Plus Power Supplies	Standard Power Supplies
Electronics	ENERGY STAR Copier/Printer	Standard Copier/Printer
Electronics	ENERGY STAR Desktop PC	Standard Desktop PC
Electronics	ENERGY STAR DVD/VCR	Standard DVD/VCR
Electronics	ENERGY STAR Laptop Computer	Standard Laptop Computer
Electronics	ENERGY STAR LCD TV	Standard LCD TV
Electronics	ENERGY STAR LED TV	Standard LED TV
Electronics	ENERGY STAR Plasma TV	Standard Plasma TV
Electronics	Smart Power Strip	Standard Power Strip
Hot Water	Drain Water Heat Recovery	No Drain Water Heat Recovery
Hot Water	Efficient Water Heater	Standard Water Heater
Hot Water	Heat Pump Integrated on Existing Water Heater	Standard Water Heater
Hot Water	Heat Pump Water Heater	Standard Water Heater
Hot Water	Heat Pump Water Heater, Early Retirement	Standard Water Heater
Hot Water	Heat Recovery from Heat Pump Water Heater	Standard Water Heater
Hot Water	Low Flow Faucet Aerator	Standard Faucet Aerator
Hot Water	Low Flow Showerhead	Standard Showerhead
Hot Water	Pipe Insulated	No Pipe Insulation
Hot Water	Solar Water Heater	Standard Water Heater
Hot Water	Tankless Water Heater	Standard Water Heater
Hot Water	Water Heater Tank Wrap	No Blanket

End-Use	Efficient Description	Base Description
HVAC	AC DLC Switch	No Switch
HVAC	Air Conditioner SEER 15	Standard Air Conditioner
HVAC	Air Conditioner SEER 15, Early Retirement	Standard Air Conditioner
HVAC	Air Conditioner SEER 16	Standard Air Conditioner
HVAC	Air Conditioner SEER 16, Early Retirement	Standard Air Conditioner
HVAC	Air Conditioner SEER 17	Standard Air Conditioner
HVAC	Air Conditioner SEER 17, Early Retirement	Standard Air Conditioner
HVAC	Attic Venting	No Attic Venting
HVAC	Efficient ECM Fan	Standard AC/Furnace Fan
HVAC	ENERGY STAR Ventilation Fan	Standard Ventilation Fan
HVAC	Geothermal Heat Pump	Standard Heat Pump
HVAC	Heat Pump Ductless Mini Split	Standard AC/Heat Pump
HVAC	Heat Pump SEER 15	Standard Heat Pump
HVAC	Heat Pump SEER 15, Early Retirement	Standard Heat Pump
HVAC	Heat Pump SEER 15, Replace Electric Resistance Heat	Electric Resistance Heat & CAC
HVAC	Heat Pump SEER 16	Standard Heat Pump
HVAC	Heat Pump SEER 16, Early Retirement	Standard Heat Pump
HVAC	Heat Pump SEER 16, Replace Electric Resistance Heat	Electric Resistance Heat & CAC
HVAC	Heat Pump SEER 17	Standard Heat Pump
HVAC	Heat Pump SEER 17, Early Retirement	Standard Heat Pump
HVAC	Heat Pump SEER 17, Replace Electric Resistance Heat	Electric Resistance Heat & CAC
HVAC	Heat/Energy Recovery Ventilation	No Heat/Energy Recovery Ventilation
HVAC	High Efficiency Room A/C	Standard Room A/C
HVAC	High Efficiency Room A/C, Early Retirement	Standard Room A/C
HVAC	HVAC Diagnostics and Tune-Up	Standard AC/Heat Pump
HVAC	Sizing, Refrigerant Charge & Airflow Correction	Standard AC/Heat Pump
Lighting	Linear Fluorescent - Premium T8	Linear Fluorescent - T12
Lighting	Linear Fluorescent - T5	Linear Fluorescent - T12
Lighting	Linear Fluorescent - T8	Linear Fluorescent - T12
Lighting	Occupancy Sensors	No Occupancy Sensors
Lighting	Photocell/Time-Clock Controls	No Outdoor Controls
Lighting	Screw In - CFLs	Screw In - Halogen
Lighting	Screw In - LEDs	Screw In - Halogen
Other	Major Renovation (Shell + HVAC)	Baseline Home
Recycle	Dehumidifier Recycle	Standard Dehumidifier
Recycle	Freezer Recycle	Standard Freezer
Recycle	Refrigerator Recycle	Standard Refrigerator
Recycle	Room A/C Recycle	Standard Room Air Conditioner
Shell	Add Storm Window	Standard Window
Shell	Air Sealing	Base Infiltration
Shell	Cool Roof	Standard Roof

End-Use	Efficient Description	Base Description
Shell	Crawlspace/Basement Wall Insulation	No Crawlspace/Basement Wall Insulation
Shell	Duct Sealing/Repair	Standard Duct Leakage
Shell	ENERGY STAR Windows	Standard Window
Shell	Increased Ceiling Insulation	Base Ceiling Insulation
Shell	Increased Duct Insulation	No/Low Duct Insulation
Shell	Increased Floor Insulation	Base Floor Insulation
Shell	Increased Wall Insulation	Base Wall Insulation
Shell	Self-Install Weatherization	Base Infiltration
Shell	Sunscreen	Standard Window
Shell	Window Film	Standard Window

Table 22. Business End-Use Measures

End-Use	Efficient Description	Base Description
Behavioral	Building Operator Certification	No BOC training
Behavioral	Energy Feedback Device	No Energy Feedback Device
Compressed Air	Comp Air - ASD	Comp Air - No ASD
Compressed Air	Comp Air - Controls	Comp Air - No Controls
Compressed Air	Comp Air - Dryer Cycling	Comp Air - Base System
Compressed Air	Comp Air - Eliminate In-Efficient Uses	Comp Air - Base System
Compressed Air	Comp Air - Leaks Repaired	Comp Air - Leaks
Compressed Air	Comp Air - Motor Practices	Comp Air - Standard Practice
Compressed Air	Comp Air - No Loss Drains	Comp Air - Standard Drains
Compressed Air	Comp Air - O&M	Comp Air - No O&M
Compressed Air	Comp Air - Power Recovery	Comp Air - No Power Recovery
Compressed Air	Comp Air - Pressure Reduction	Comp Air - Base System
Compressed Air	Comp Air - Replace Motor	Comp Air - Standard Efficiency
Compressed Air	Comp Air - Sizing	Comp Air - Oversized
Compressed Air	Comp Air - Storage/Air Receivers	Comp Air - No Storage
Cooking	Combination Oven	Standard Oven
Cooking	Convection Oven	Standard Oven
Cooking	ENERGY STAR Fryer	Standard Fryer
Cooking	ENERGY STAR Hot Food Holding Cabinet	Standard Hot Food Holding Cabinet
Cooking	ENERGY STAR Steamer	Standard Steamer
Drives	Drive - Custom	Standard Drive
Drives	Drive - Direct Drive	Base Drive - V Belt
Drives	Drive - Motor	Standard Motor
Drives	Drive - O&M	Standard Drive
Drives	Drive - VFD (Other)	Constant Speed
Fans	Fans - ASD	No ASD
Fans	Fans - Controls	No Controls
Fans	Fans - Improve Components	Standard Components
Fans	Fans - Motor Practices	Standard Practice

End-Use	Efficient Description	Base Description
Fans	Fans - O&M	No O&M
Fans	Fans - Power Recovery	No Power Recovery
Fans	Fans - Replace Motor	Standard Efficiency
Fans	Fans - System Optimization	Standard
Hot Water	Demand Controlled Circulation	Standard Water Heater
Hot Water	Efficient Water Heater	Standard Water Heater
Hot Water	Heat Pump Water Heater	Standard Water Heater
Hot Water	Heat Trap	Standard Water Heater
Hot Water	Laundry Waste Water Recovery	No Waste Water Recovery
Hot Water	Low Flow Faucet Aerator	Standard Faucet Aerator
Hot Water	Low Flow Showerhead	Standard Showerhead
Hot Water	Pipe Wrap/Insulation	Standard Water Heater
Hot Water	Pre-Rinse Spray Valves	No Pre-Rinse Spray Valves
Hot Water	Solar Water Heater	Standard Water Heater
Hot Water	Tank Blanket	Standard Water Heater
Hot Water	Tankless Water Heater	Standard Water Heater
Hot Water	Water Heater - Heat Recovery from Air Source HP	Standard Water Heater
Hot Water	Water Heater - Heat Recovery from Geothermal HP	Standard Water Heater
Hot Water	Water Heater - Heat Recovery from Refrigeration	Standard Water Heater
HVAC	Absorption Chiller	Standard Chiller
HVAC	AC DLC Switch	No Switch
HVAC	AC/HP Coil Cleaning	Standard AC/HP
HVAC	AC/HP Ductless Mini Split	Standard AC/HP
HVAC	AC/HP Ductless Mini Split VRF	Standard AC/HP
HVAC	AC/HP Evaporative Pre-Cooling	No Pre-Cooling
HVAC	Air Source Heat Pump	Standard Heat Pump
HVAC	Air Sourced Air Conditioner	Standard Air Conditioner
HVAC	Chilled/Hot Water Temp Reset	No Reset
HVAC	Demand Control Ventilation - CO Sensors (Parking)	No Demand Control Ventilation
HVAC	Demand Control Ventilation - CO2 Sensors (Occupancy)	No Demand Control Ventilation
HVAC	Economizer Controls	No Economizer
HVAC	Efficient Air Cooled Chiller	Standard Chiller
HVAC	Efficient Water Cooled Chiller	Standard Chiller
HVAC	EMS Controls	No EMS
HVAC	Geothermal Heat Pump	Standard AC/HP
HVAC	Heat/Energy Recovery Ventilation	No Heat/Energy Recovery Ventilation
HVAC	High Efficiency PTAC/PTHP	Standard PTAC/PTHP
HVAC	High Efficiency Room AC/HP	Standard Room AC/HP
HVAC	Hotel Occupancy Sensor Controls	No Occupancy Sensor
HVAC	HVAC O&M	HVAC - NO O&M
HVAC	Make Up/Exhaust - Separate/Optimized	Standard Make Up/Exhaust

End-Use	Efficient Description	Base Description
HVAC	Programmable Thermostat Controls	Standard Thermostat
HVAC	Retrocommissioning/Optimization	No Retrocommissioning
HVAC	Tune Up/Diagnostics	No Tune Up/Diagnostics
HVAC	Water Side Economizer w/Efficient Tower	Efficient Water Cooled Chiller
HVAC	Water Source Heat Pump	Standard Heat Pump
Lighting	Ceramic Metal Halide	High Intensity Discharge
Lighting	Continuous Dimming Controls	No Dimming
Lighting	High Bay Premium T8	High Intensity Discharge
Lighting	High Bay T5	High Intensity Discharge
Lighting	High Bay T8	High Intensity Discharge
Lighting	Hotel Room Occupancy Controls	No Controls
Lighting	Induction Lighting	High Intensity Discharge
Lighting	Induction Street Lighting	Standard Street Lighting
Lighting	LED Exit Sign	CFL/Incandescent Exit Sign
Lighting	LED Flood Light	25% 50W MH
Lighting	LED Linear Fluorescent	T12 Linear Fluorescent
Lighting	LED Outdoor Pole/Arm Mounted Parking/Roadway	100W MH
Lighting	LED Parking Garage/Canopy	175W MH
Lighting	LED Parking Lot Lighting	Standard Parking Lot Lighting
Lighting	LED Wall-Mounted Area Lights	100W MH
Lighting	Occupancy Sensors	No Occupancy Sensor
Lighting	Outdoor Bi-Level LED Lighting	Outdoor Mercury Vapor
Lighting	Outdoor LED Lighting	Outdoor Mercury Vapor
Lighting	Photocell/Time-Clock Controls	No Outdoor Controls
Lighting	Premium T8 Linear Fluorescent	T12 Linear Fluorescent
Lighting	Premium T8 Linear Fluorescent with Reflector/Delamping	T12 Linear Fluorescent
Lighting	Reduced Lighting Power Density	Standard Lighting Power Density
Lighting	Screw In - CFLs	Screw In - Halogen
Lighting	Screw In - LEDs	Screw In - Halogen
Lighting	T5 Linear Fluorescent	T12 Linear Fluorescent
Lighting	T8 Linear Fluorescent	T12 Linear Fluorescent
Lighting	T8 Linear Fluorescent with Reflector/Delamping	T12 Linear Fluorescent
Motor	ECM Motor	PSC Motor
New Construction	High Performance - 30% savings	Code Minimum
New Construction	High Performance - 50% savings	Code Minimum
New Construction	High Performance - 70% savings	Code Minimum
Office Equipment	80 PLUS Power Supply Desktop Derived Server	Standard Power Supply
Office Equipment	80 PLUS Power Supply Desktop PC	Standard Power Supply
Office Equipment	Data Center Best Practices	Standard Data Center
Office Equipment	ENERGY STAR Copier	Standard Copier
Office Equipment	ENERGY STAR CRT Monitor	Standard CRT Monitor

End-Use	Efficient Description	Base Description
Office Equipment	ENERGY STAR Desktop PC	Standard Desktop PC
Office Equipment	ENERGY STAR LCD Monitor	Standard CRT Monitor
Office Equipment	LCD Manual Power Management Enabling	Standard CRT Monitor
Office Equipment	Power Management Enabling - Manual	Standard Copier
Office Equipment	Power Management Enabling - Networked	Standard Copier
Office Equipment	Work Station Plug Load Occupancy Sensor	No Work Station Occupancy Sensor
Other	Block Bidding	No Block Bidding
Other	CT w/ Heat Recovery	No CHP
Other	Curtailable Rate	Normal Rate
Other	Efficient Transformers	Standard Transformer
Other	Fuel Cell w/ Heat Recovery	No CHP
Other	Heating - O&M	No O&M
Other	Heating - Process Control	No Controls
Other	Injection Molding - Barrel Wrap	No Barrel Wrap
Other	Reciprocating Engine w/ Heat Recovery	No CHP
Other	Retro-Commissioning	No Program
Other	Strategic Energy Management	No Program
Pools	High Efficiency Pool Pump	Standard Pool Pump
Pools	Pool Pump Timer	Standard Pool Pump
Pools	Pool Pump VSD	Standard Pool Pump
Pumps	Efficient Pumps/Fan	Standard Pumps/Fans
Pumps	Pumps - ASD	No ASD
Pumps	Pumps - Controls	No Controls
Pumps	Pumps - Motor Practices	Standard Practice
Pumps	Pumps - O&M	No O&M
Pumps	Pumps - Power Recovery	No Power Recovery
Pumps	Pumps - Replace Motor	Standard Efficiency
Pumps	Pumps - Sizing	Oversized
Pumps	Pumps - System Optimization	Standard
Pumps	VSD Pumps/Fan	No VSD
Refrigeration	Commissioning/Re-Commissioning	Standard Refrigeration
Refrigeration	Demand Defrost	Standard Refrigeration
Refrigeration	Efficient Compressor	Standard Refrigeration
Refrigeration	Efficient Motor	Standard Motor
Refrigeration	Efficient Refrigeration - O&M	Standard Refrigeration
Refrigeration	Efficient Refrigeration - System Optimization	Standard Refrigeration
Refrigeration	ENERGY STAR Beverage Machine	Standard Beverage Machine
Refrigeration	ENERGY STAR Refrigerator	Standard Refrigerator
Refrigeration	Evaporator Fan Controller on Med Temp Walk-Ins	Standard Refrigeration
Refrigeration	Fiber Optic Display Lighting	Standard Refrigeration
Refrigeration	Floating Head Pressure Controls	Standard Refrigeration

End-Use	Efficient Description	Base Description
Refrigeration	Freezer/Cooler Replacement Gaskets	Standard Refrigeration
Refrigeration	High Efficiency Ice Maker	Standard Ice Maker
Refrigeration	High Efficiency Reach-In Refrigerator/Freezer	Standard Reach In Refrigerator/Freezer
Refrigeration	High Efficiency Walk-In Refrigerator/Freezer	Standard Walk-In Refrigerator/Freezer
Refrigeration	High R-Value Glass Doors	Standard Refrigeration
Refrigeration	Humidistat Controls	Standard Refrigeration
Refrigeration	LED Display Lighting	Standard Refrigeration
Refrigeration	Multiplex Compressor System	Standard Refrigeration
Refrigeration	Night Covers	Standard Refrigeration
Refrigeration	Oversized Air Cooled Condenser	Standard Refrigeration
Refrigeration	Strip Curtains	Standard Refrigeration
Refrigeration	Vending Miser Beverage Machine	Beverage Machines - Standard
Refrigeration	VSD Compressor	Standard Refrigeration
Shell	Cool Roof	Standard Roof
Shell	Duct Insulation	No Duct Insulation
Shell	Duct Sealing/Repair	Standard Duct Leakage
Shell	External Shading/Overhangs	No Shading
Shell	High Performance Glazing	Standard Glazing
Shell	Increase Ceiling Insulation	No/Low Ceiling Insulation
Shell	Increase Wall Insulation	No/Low Wall Insulation
Shell	Solar Shades	No Solar Shades
Shell	Window Film	No Window Film

3.4 ADVANCED METERING AND DISTRIBUTION ASSESSMENT

(D) Assess how advancements in metering and distribution technologies that may be reasonably anticipated to occur during the planning horizon affect the ability to implement or deliver potential demand-side programs; **—Error! Bookmark not defined.**

KCP&L engaged Navigant to conduct a DSM Resource Potential Study for the KCP&L-MO service territory. The analysis assumed that a customer must have access to an advanced metering infrastructure (AMI) meter integrated with KCP&L's backend system to participate in a demand-side program. To support the analysis, Navigant developed a forecast for AMI deployment in each service territory as well as an estimate of when KCP&L might install a Meter Data Management (MDM) system to support enhanced pricing programs. The AMI deployment forecast used in the Navigant study was based on the company's best estimates at the time.

Subsequent to the Navigant study, KCP&L developed a IT technology roadmap that includes the following elements;

- *AMI Metro (2014-2016)*. KCP&L initiated an upgrade of the legacy AMR meters with new AMI meters and technology in the entire Kansas City Metro service area.
- *MDM (2015)*. KCP&L will deploy an enterprise MDM system to manage all meter reading data.
- *CIS (2017)*. KCP&L has a project underway to deploy a new CIS that will upgrade and consolidate the existing KCP&L-MO and KCP&L-GMO systems. AMI deployments will be suspended in 2017 to facilitate the CIS implementation, migration and testing.
- *AMI Rural (2018-2020)*. While not yet approved, KCP&L projects that after the new CIS project, AMI meters will be deployed in all service territories outside of the Kansas City.

The table below provides a revised forecast for AMI meter deployments based on the current and projected system implementation schedules.

Table 23. AMI Deployment Forecast

2014	2015	2016	2017	2018	2019	2020
0%	95%	95%	95%	95%	95%	95%

Currently, AMI meters are projected to be deployed to 95% of customers recognizing the fact that deploying AMI communications in sparse, rural areas may not be cost-effective. However, KCP&L continues to work with the AMI communications network provider to develop and deploy a 100% solution. If AMI deployment throughout the entire service territory is not cost-effective, individual customers could potentially be provided an AMI meter that communicates via public (e.g. ATT or Verizon) carrier. This alternative to the AMI communications network is currently under development by the AMI vendor and should be market ready by the time the CIS upgrade project completes.

3.5 END-USE MEASURES MARKETING PLAN

(E) Design a marketing plan and delivery process to present the menu of end-use measures to the members of each market segment and to persuade decision-makers to implement as many of these measures as may be appropriate to their situation. When appropriate, consider multiple approaches such as rebates, financing, and direct installations for the same menu of end-use measures; —

The marketing plan and delivery process will be designed to inform customers of the DSM programs, the benefits of each program and how they can participate in a program. The plan will include a combination of strategies to reach all market segments and decision-makers. The KCP&L website content and functionality will be a crucial component of the marketing plan, as the website directs customers to information about the DSM programs.

A strategy will be developed to move customers along the marketing funnel from awareness to education to conversion to engagement. Key points of the strategy and ensuing marketing campaigns will be to:

1. Develop a set of campaigns driven by seasonal timeliness and opportunities during and immediately after customers' engagement with each product to generate leads for the portfolio, especially the priority programs.

2. Drive customers from awareness to conversion by matching campaign elements to customers' informational needs at various points within the marketing funnel. Continue supporting customers through the engagement portion of the funnel via cross-promotion.

3. Ensure planned campaigns remain flexible and responsive to shifts in program strategy based on current unknowns becoming clearer, the need to balance costs versus participation through the year, and other unanticipated variables.

4. Craft malleable and creative approaches for planned campaigns, preserving our ability to complement and roll up to new creative strategy that will be developed for the general awareness advertising campaign.

5. Develop quarterly KCP&L employee communications campaigns that will increase employee awareness of products so they can help tell our story to customers, and encourage participation among eligible employees.

Tactics that can help move customers to participation include the following:

- KCP&L website content providing program information resources, contact information, and links to other relevant service and information resources.
- Program brochures that describe the benefits and features of the program.
- Bill inserts, on-bill messages and targeted email messages.
- Print and radio advertisements.
- Direct customer outreach (e.g. KCP&L customer representatives and/or an implementation contractor).
- Presence at conferences and public events used to increase general awareness of the program and distribute promotional materials.
- Partnerships with local contractors/businesses.
- Customized newsletters.

3.6 STATEWIDE MARKETING AND OUTREACH PROGRAM EVALUATION

***(F) Evaluate, describe, and document the feasibility, cost-reduction potential, and potential benefits of statewide marketing and outreach programs, joint programs with natural gas utilities, upstream market transformation programs, and other activities. In the event that statewide marketing and outreach programs are preferred, the utilities shall develop joint programs in consultation with the stakeholder group*; —**

Challenges definitely exist with an overall statewide marketing plan considering the variety of program offerings across the state and within service territories. KCP&L has seen this in the degree of effort and diligence needed to properly educate customers and promote programs in the KCP&L-Missouri territory vs. the KCP&L territory based on slightly different vintages of the programs. That being said, we continue to engage with peer utilities across the state at least once per year to identify opportunities with programs that are similar to evaluate the effectiveness in delivery.

Areas of cooperation thus far include efforts KCP&L has undertaken to market programs jointly run with outside organizations, such as non-profit organizations and state agencies involved with the Income Eligible Weatherization Program. The multi-family housing sector also seems like a promising area to partner with various interested parties across the state to promote and convert customers into energy efficient participants.

3.7 COST-EFFECTIVENESS

(G)Estimate the characteristics needed for the twenty (20)-year planning horizon to assess the cost effectiveness of each potential demand-side program, including: —

3.7.1 STAND-ALONE DEMAND AND ENERGY REDUCTION IMPACTS

1. An assessment of the demand and energy reduction impacts of each stand-alone end-use measure contained in each potential demand-side program; —

KCP&L engaged AEG to design an additional DSM portfolio (Option C) for the KCP&L-MO service territory. AEG began with the *Demand-Side Resource Potential Study Report* and the *Demand-Side Resource Potential Study Report – Demand Response* completed by Navigant in August 2013. Navigant developed a comprehensive measure list through a review of (a) DSM potential studies conducted for the state of Missouri and Missouri utilities,[19,20] (b) other Navigant potential, evaluation and program design

[19] KEMA Consulting (March 04, 2011). Missouri Statewide DSM Potential Study – Final Report – Appendix.

work, and (c) existing KCP&L programs. Navigant then modified the measure list to incorporate feedback from KCP&L and Missouri stakeholders. Overall, 500 measures were identified and 300 were characterized for the final model.

Navigant employed a variety of analytical approaches to estimate measure-level energy savings and coincident peak demand savings, including standard engineering algorithms, calibrated simulation models, and secondary resources. The majority of measures employed engineering algorithms and appropriate inputs from TRMs. When possible, Navigant utilized TRMs for Mid-Western states and utilities to capture effects of climate and regional similarities, including Ameren Missouri[21] and Illinois.[22] Most building envelope measures were characterized through the use of building simulation models. Residential envelope measure savings were derived from BEopt™ software and calibrated to customer billing data. Commercial envelope measures were derived from simulations leveraging the *U.S. Department of Energy Commercial Reference Building Models of the National Building Stock* with a Kansas City, MO weather file.

Navigant also estimated measure costs, accounting for regional cost differences using standard adjustment techniques. Material and labor costs were derived from a variety of resources including TRMs, online research, the California Database for Energy Efficiency Resources, and RS Means cost work.

AEG reviewed the end-use measures developed in the Navigant potential study and the measures in KCP&L's MEEIA portfolio. Based on research and industry best practices, AEG updated the measure inputs and added additional end-use measures to reflect changes in technology that have emerged since the potential study was completed.

The demand and energy reduction impacts of each end-use measure included in the additional DSM portfolio (Option C) are presented below.

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[20] Global Energy Partners (January 2010). AmerenUE Demand-side Management Market Potential Study Volume 3: Analysis of Energy-Efficiency Potential.
[21] *Appendix A, Technical Resource Manual, 2012 Energy Efficiency Filing.* Missouri Department of Natural Resources comments were considered and accounted for.
[22] State of Illinois Energy Efficiency Technical Reference Manual

Residential Measures

In 2007, the United States Congress passed the Energy Independence and Security Act (EISA) which set efficiency standards for 'general service' light bulbs, implemented in two phases. From 2012 to 2014, standard light bulbs manufactured were be required to use approximately 20 to 30 percent less energy than current incandescent light bulbs. By 2020, there must be a 60 percent reduction in light bulb energy use.[23] The effective dates of the EISA legislation pertain to newly manufactured bulbs, not existing stock.

Table 24. Residential Lighting Measures

Measure	Measure Life	Gross kWh Savings	Gross kW Savings	Incremental Cost
CFL pre-2020	5	28	0.003	$1.70
CFL 2020	5	6	0.001	$1.00
LED pre-2020	20	31	0.003	$15
LED 2020	20	9	0.001	$10

KCP&L proposes to offer measures to multi-family and single family customers. The energy and demand savings vary for low-flow faucet aerator or hot water pipe insulation depending on whether the customer resides in a multi-family or single family residence.

Table 25. Residential Low-Flow Faucet Aerator & Pipe Insulation

Measure	Measure Life	Gross kWh Savings	Gross kW Savings	Incremental Cost
Faucet Aerator – Multi-Family	9	42	0.005	$3
Family	9	65	0.010	$3
Pipe Insulated – Multi-Family	10	236	0.017	$15
Pipe Insulated – Single Family	10	273	0.024	$15

The remaining residential measure inputs are presented in the table below.

[23] See Database of State Incentives for Renewables & Efficiency (DSIRE). *Federal Appliance Standards*. Available at: www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US04R&re=1&ee=1

Table 26. Residential Measures

Measure	Unit	Measure Life	Gross kWh Savings	Gross kW Savings	Incremental Cost
A/C SEER 15	per ton	18	69	0.016	$93
A/C SEER 15, Early Retirement	per ton	6	486	0.234	$642
A/C SEER 16	per ton	18	130	0.016	$185
A/C SEER 16, Early Retirement	per ton	6	547	0.234	$642
A/C SEER 17	per ton	18	184	0.041	$278
A/C SEER 17, Early Retirement	per ton	6	600	0.259	$642
Air Sealing	per sq. ft.	15	0	0.000	$0.12
Dehumidifier Recycle	per unit	4	139	0.035	$49
Efficient ECM Fan	per unit	20	644	0.360	$97
ENERGY STAR Windows	per sq. ft.	25	2	0.001	$1.50
Freezer Recycle	per unit	8	1,201	0.191	$93
Heat Pump Ductless Mini Split	per ton	18	1,285	0.817	$716
HP SEER 15	per ton	18	173	0.054	$98
HP SEER 15, Early Retirement	per ton	6	1,195	0.502	$729
HP SEER 15, Replace Electric Resistance Heat	per ton	6	4,838	1.765	$729
HP SEER 16	per ton	18	234	0.054	$196
HP SEER 16, Early Retirement	per ton	6	1,256	0.502	$729
HP SEER 16, Replace Electric Resistance Heat	per ton	6	4,891	1.765	$729
HP SEER 17	per ton	18	321	0.093	$294
HP SEER 17, Early Retirement	per ton	6	1,342	0.540	$729
Heat Pump Water Heater	per unit	13	1,766	0.084	$1,000
Home Energy Reports	per home	1	145	0.028	$0
Increased Ceiling Insulation	per sq. ft.	25	1	0.000	$0.76
Increased Duct Insulation	per home	20	210	0.118	$720
Increased Wall Insulation	per sq. ft.	25	1	0.000	$1.32
Pipe Insulated	per unit	15	74	0.008	$2.81
Refrigerator Recycle	per unit	8	1,190	0.190	$93
Room A/C Recycle	per unit	4	121	0.114	$49
Smart Power Strip	per unit	5	74	0.005	$15
Water Heater Tank Wrap	per unit	5	131	0.015	$18

C&I End-Use Measures

In 2007, the United States Congress passed EISA which set efficiency standards for ‘general service’ light bulbs, implemented in two phases. From 2012 to 2014, standard light bulbs manufactured were be required to use approximately 20 to 30 percent less energy than current incandescent light bulbs. By 2020, there must be a 60 percent reduction in light bulb energy use. The effective dates of the EISA legislation pertain to newly manufactured bulbs, not existing stock.

Table 27. C&I Lighting Measures

Measure	Measure Life	Gross kWh Savings	Gross kW Savings	Incremental Cost
CFL pre-2020	5	188	0.006	$3.30
CFL 2020	5	82	0.003	$1.00
LED pre-2020	20	200	0.006	$25
LED 2020	20	94	0.003	$39

The remaining C&I measures are presented in the table below.

Table 28. C&I Measures

Efficient Description	Unit	Measure Life	Gross kWh Savings	Gross kW Savings	Incremental Cost
80 PLUS Power Supply Desktop Derived Server	per unit	5	334	0.038	$2.00
Air Source Heat Pump 65<135 kBtuh	per ton	15	91	0.124	$100
Air Sourced Air Conditioner <65 kBtuh	per ton	15	82	0.066	$120
Air Sourced Air Conditioner >240 kBtuh	per ton	15	71	0.057	$100
Air Sourced Air Conditioner 135<240 kBtuh	per ton	15	81	0.065	$100
Air Sourced Air Conditioner 65<135 kBtuh	per ton	15	57	0.046	$100
Block Bidding	per Bid	10	2,514,850	436	$496,331
Ceramic Metal Halide (replace HID HPS)	per unit	15	712	0.024	$104
Ceramic Metal Halide (replace HID MH)	per unit	15	697	0.023	$106
Chilled/Hot Water Temp Reset	per ton	5	82	0.003	$2.06
Comp Air - ASD (100+ HP)	per HP	6	693	0.167	$132
Comp Air - ASD (1-5 HP)	per HP	14	693	0.167	$385
Comp Air - ASD (6-100 HP)	per HP	10	693	0.167	$147
Comp Air - Controls	per HP	10	454	0.160	$20
Comp Air - Dryer Cycling	per HP	10	47	0.011	$11
Comp Air - Eliminate In-Efficient Uses	per HP	8	333	0.080	$67
Comp Air - Leaks Repaired	per HP	10	666	0.160	$133
Comp Air - Motor Practices (100+ HP)	per HP	6	56	0.010	$7.86
Comp Air - Motor Practices (1-5 HP)	per HP	14	180	0.034	$79
Comp Air - Motor Practices (6-100 HP)	per HP	10	90	0.017	$20
Comp Air - No Loss Drains	per HP	5	13	0.003	$3
Comp Air - Pressure Reduction	per HP	6	100	0.024	$1
Comp Air - Replace Motor (100+ HP)	per HP	15	31	0.007	$8
Comp Air - Replace Motor (6-100 HP)	per HP	15	46	0.011	$8
Comp Air - Sizing	per HP	10	100	0.024	$15
Comp Air - Storage/Air Receivers	per HP	10	292	0.070	$20
Curtailable Rate	per kW	1	-	1.000	$1.00
Drive - Custom	per HP	15	29	0.006	$10

Efficient Description	Unit	Measure Life	Gross kWh Savings	Gross kW Savings	Incremental Cost
Drive - Direct Drive	per HP	15	146	0.031	$25
Drive - VFD (Other)	per HP	15	512	0.082	$355
Efficient Pumps/Fan	per HP	15	3	0.002	$1.77
Efficient Transformers	per kVA	25	14	0.002	$2.06
ENERGY STAR Beverage Machine	per unit	14	1,754	0.116	$140
Fans - ASD (100+ HP)	per HP	15	948	0.147	$133
Fans - ASD (1-5 HP)	per HP	15	1,037	0.161	$460
Fans - ASD (6-100 HP)	per HP	15	973	0	$155
Fans - Controls	per HP	15	57	0.012	$20
Fans - Improve Components	per HP	15	142	0.030	$49
Fans - Motor Practices (100+ HP)	per HP	15	62	0.013	$21
Fans - Motor Practices (1-5 HP)	per HP	15	67	0.014	$23
Fans - Motor Practices (6-100 HP)	per HP	15	63	0.013	$22
Fans - Power Recovery	per HP	15	283	0.060	$98
Fans - System Optimization	per HP	15	283	0.060	$98
Geothermal Heat Pump	per ton	15	443	0.781	$379
Heat Pump Water Heater	per unit	10	1,993	0.298	$925
High Bay T5 (replace HID HPS)	per unit	15	443	0.032	$104
High Bay T5 (replace HID MH)	per unit	15	390	0.028	$102
High Bay T8 (replace HID HPS)	per unit	15	325	0.023	$100
High Efficiency PTAC/PTHP	per kBtuh	15	30	0.012	$12
High Efficiency Reach-In Refrigerator/Freezer	per unit	12	3,026	0.129	$263
LED Display Lighting	per unit	8	731	0.071	$256
LED Exit Sign (replace CFL)	per unit	13	65	0.008	$23
LED Exit Sign (replace Incandescent)	per unit	13	258	0.031	$30
LED Linear Fluorescent	per unit	15	225	0.062	$45
Low Flow Faucet Aerator	per unit	9	131	0.196	$8.35
Make Up/Exhaust - Separate/Optimized	per HP	15	568	0.285	$116
Occupancy Sensors	per Watt	8	2	0.001	$0.12
Pipe Wrap/Insulation	per unit	6	224	0.278	$47
Pool Pump - High Efficiency	per unit	10	1,301	0.149	$273
Pool Pump - VSD	per unit	10	2,461	0.281	$579
Premium T8 Linear Fluorescent	per unit	15	55	0.004	$10
Pre-Rinse Spray Valves	per unit	5	2,671	-	$100
Programmable Thermostat Controls	per ton	8	126	-	$6
Pumps - ASD (100+ HP)	per HP	15	1,002	0.085	$133
Pumps - ASD (1-5 HP)	per HP	15	1,096	0.092	$460
Pumps - ASD (6-100 HP)	per HP	15	1,028	0.087	$155
Pumps - Controls	per HP	15	239	0.062	$85
Pumps - Motor Practices (100+ HP)	per HP	15	87	0.022	$31
Pumps - Motor Practices (1-5 HP)	per HP	15	95	0.024	$34

Efficient Description	Unit	Measure Life	Gross kWh Savings	Gross kW Savings	Incremental Cost
Pumps - Motor Practices (6-100 HP)	per HP	15	89	0.023	$32
Pumps - Power Recovery	per HP	15	227	0.059	$81
Pumps - Replace Motor (1-5 HP)	per HP	15	33	0.008	$19
Pumps - Sizing	per HP	15	162	0.042	$58
Reduced Lighting Power Density	per sq. ft.	13	0	0.000	$0.14
Screw In - CFLs	per unit	5	188	0.006	$3.33
Screw In - LEDs	per unit	25	200	0.006	$25
Strategic Energy Management	per Customer	3	150,454	33.690	$3,009
Strip Curtains	per sq. ft.	6	129	0.015	$10
T8 Linear Fluorescent with Reflector/Delamping	per unit	15	67	0.005	$8
VSD Compressor	per HP	10	234	0.038	$78
VSD Pumps/Fan	per HP	15	478	0.145	$305
Water Heater - Heat Recovery from Air Source HP	per unit	18	1,923	0.133	$900
Water Heater - Heat Recovery from Geothermal HP	per unit	18	1,923	0.127	$900

3.7.2 IMPACT OF BUNDLING END-USE MEASURES

2. An assessment of how the interactions between end-use measures, when bundled with other end-use measures in the potential demand-side program, would affect the stand-alone end-use measure impact estimates; —

Navigant modeled the end-use interactions through application of HVAC interaction factors for lighting measures, which account for increased heating and/or decreased cooling loads resulting from reduced lighting wattages. In addition, impacts for New Construction/Major Rehab projects account for bundles of end-use measures needed to meet targeted energy efficiency levels.

KCP&L also engaged AEG to design an additional DSM portfolio (Option C) for the KCP&L-MO service territory. AEG reviewed the end-use measures developed in the Navigant potential study and the measures in KCP&L's MEEIA portfolio. Based on research and industry best practices, AEG updated the measure inputs and added additional end-use measures to reflect changes in technology that have emerged since the potential study was completed.

The end-use measures identified were screened for cost-effectiveness on a stand-alone basis. Measures that were cost-effective on a stand-alone basis were bundled into programs and re-screened for cost-effectiveness. Except for the low-income programs, the DSM programs were designed to be cost-effective. Measures were bundled based on end-use and implementation. For example, space cooling and heating end-use measures benefit from being installed by an experienced HVAC contractor.

Table 29. DSM Program Measure Offerings

Residential Programs	
Home Lighting Rebate	CFL and LED Bulbs
Appliance Recycling	Recycle inefficient refrigerators, freezers, dehumidifiers or room air conditioners.
Home Energy Report	Behavior program utilizing customized energy reports sent periodically to households.
Online Home Energy Audit	Online energy audit tool.
Whole House Efficiency	The program has three tiers. To participate in Tier 2, customers must complete Tier 1. - Tier 1. Audit and direct install of CFL/LED bulbs, low flow faucet aerators, low flow showerheads, hot water pipe insulation, water heater tank wrap, and smart power strips. - Tier 2. Air Sealing, Insulation (ceiling/wall) and ENERGY STAR Windows - Tier 3. HVAC Equipment - Heat Pump Water Heater - Efficient ECM Fan - Central Air Conditioners (SEER 15, 16) - Central Air Conditioner Early Retirement (SEER 15, 16) - Heat Pump (SEER 15, 16 and 17) - Heat Pump Early Retirement (SEER 15, 16) - Heat Pump Replace Electric Resistance Heat (SEER 15, 16)
Income-Eligible Multi-Family	The program is comprised of two tiers. - Tier 1. Home Kit (includes CFL/LED bulbs, low flow faucet aerators, low flow showerheads, pipe insulation, water heater tank wrap, and smart power strip). - Tier 2. Common Area Lighting
Income-Eligible Weatherization	The program is comprised of two tiers. - Tier 1. Home Kit (includes CFL/LED bulbs, low flow faucet aerators, low flow showerheads, pipe insulation, water heater tank wrap, and smart power strip). - Tier 2. Weatherization (ceiling, duct or wall insulation)
Residential Programmable Thermostat	Direct load control program that cycles and curtails central air conditioners by way of a remote-controlled switch.

Commercial Programs	
Business Energy Efficiency Rebate – Standard	Customers may receive incentives by installing efficient measures from a pre-qualified list of options.
Business Energy Efficiency Rebate – Custom	Customers may receive incentives for non-prescriptive measures.
Strategic Energy Management	Provides education, technical assistance, and coaching for large customers to drive behavioral change and transform company culture.
Block Bidding	Purchase blocks of electricity savings representing reduced electric usage from eligible customers or third parties working with eligible customers.
Online Building Energy Audit	Online energy audit tool.
Small Business Direct Install	Small customers receive 70% of the full cost of qualifying measures.
Commercial Programmable Thermostat	Direct load control program that cycles and curtails central air conditioners by way of a remote-controlled switch.
Demand Response Incentive	Interruptible tariff program for customers that can reduce load by at least 25 kW during times of system peak congestion.

3.7.3 CHANGE IN PARTICIPANTS AND INSTALLATIONS

3. An estimate of the incremental and cumulative number of program participants and end-use measure installations due to the potential demand-side program; —

An estimate of the potential DSM Program incremental and cumulative end-use measure installations and participants can be found in the work paper “KCPL IRP Filing Tables.xlsx.” Cumulative participants does not equal the sum of all incremental participants because some customers will participate in multiple programs. The analysis assumes that there will be a 25% overlap.

3.7.4 DEMAND REDUCTION AND ENERGY SAVINGS

4. For each year of the planning horizon, an estimate of the incremental and cumulative demand reduction and energy savings due to the potential demand-side program; and —

An estimate of the incremental and cumulative demand reduction and energy savings due to the potential DSM programs can be found in the work paper “KCPL IRP Filing Tables.xlsx.”

3.7.5 COST ESTIMATES

5. For each year of the planning horizon, an estimate of the costs, including: —

A. The incremental cost of each stand-alone end-use measure; —

The incremental cost of each stand-alone energy use measure can be found in the work paper “KCPL IRP Filing Tables.xlsx.”

B. The cost of incentives paid by the utility to customers or utility financing to encourage participation in the potential demand-side program. The utility shall consider multiple levels of incentives paid by the utility for each end-use measure within a potential demand-side program, with corresponding adjustments to the maximum achievable potential and the realistic achievable potential of that potential demand-side program; —

Navigant considered multiple levels of incentives in the development of the RAP and MAP scenarios. MAP scenario incentives were set at 100% of the incremental cost, with some exceptions for certain measures such as CFLs. RAP scenario incentives varied based on a methodology using the energy efficiency supply curve, with some exceptions for certain measures. AEG also considered other incentive levels in the development of the Option C, varying incentives by end-use measure and program.

Customer incentives paid by the utility can be found in the work paper “KCPL IRP Filing Tables.xlsx.”

C. The cost of incentives to customers to participate in the potential demand-side program paid by the entities other than the utility; —

No assumption was made that any incentives would be paid by entities other than the utility.

D. The cost to the customer and to the utility of technology to implement a potential demand–side program; —

The cost to the customer and the utility to implement the potential DSM programs can be found in the work paper “KCPL IRP Filing Tables.xlsx.”

E. The utility’s cost to administer the potential demand-side program; and —

The utility’s cost to administer the potential DSM programs can be found in the work paper “KCPL IRP Filing Tables.xlsx.”

F. Other costs identified by the utility; —

AEG did not identify other utility costs.

3.8 TABULATION OF PARTICIPANTS, IMPACT, & COSTS

G. A tabulation of the incremental and cumulative number of participants, load impacts, utility costs, and program participant costs in each year of the planning horizon for each potential demand-side program; and —

The incremental and cumulative participations, load impacts, utility costs and program participant costs in each year for the potential DSM programs can be found in the work paper “KCPL IRP Filing Tables.xlsx.” Cumulative participants does not equal the sum of all incremental participants because some customers will participate in multiple programs. The analysis assumes that there will be a 25% overlap.

3.9 SOURCES AND QUALITY OF INFORMATION

H. The utility shall describe and document how it performed the assessments and developed the estimates pursuant to subsection (3)(G) and shall provide documentation of its sources and quality of information. —

KCP&L engaged AEG to design an additional DSM portfolio (Option C) for the KCP&L-MO service territory. AEG began with the *Demand-Side Resource Potential Study Report* and the *Demand-Side Resource Potential Study Report – Demand Response* completed by Navigant in August 2013. Navigant developed a comprehensive measure list through a review of (a) DSM potential studies conducted for the state of Missouri and Missouri utilities,[24,25] (b) other Navigant potential, evaluation and program design work, and (c) existing KCP&L programs. Navigant then modified the measure list to incorporate feedback from KCP&L and Missouri stakeholders. Overall, 500 measures were identified and 300 were characterized for the final model.

Navigant employed a variety of analytical approaches to estimate measure-level energy savings and coincident peak demand savings, including standard engineering algorithms, calibrated simulation models, and secondary resources. The majority of measures employed engineering algorithms and appropriate inputs from TRMs. When possible, Navigant utilized TRMs for Mid-Western states and utilities to capture effects of climate and regional similarities, including Ameren Missouri[26] and Illinois.[27] Most building envelope measures were characterized through the use of building simulation models. Residential envelope measure savings were derived from BEopt™ software and calibrated to customer billing data. Commercial envelope measures were derived from simulations leveraging the *U.S. Department of Energy Commercial Reference Building Models of the National Building Stock* with a Kansas City, MO weather file.

Navigant also estimated measure costs, accounting for regional cost differences using standard adjustment techniques. Material and labor costs were derived from a variety of resources including TRMs, online research, the California Database for Energy Efficiency Resources, and RS Means cost work.

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[24] KEMA Consulting (March 04, 2011). Missouri Statewide DSM Potential Study – Final Report – Appendix.
[25] Global Energy Partners (January 2010). AmerenUE Demand-side Management Market Potential Study Volume 3: Analysis of Energy-Efficiency Potential.
[26] *Appendix A, Technical Resource Manual, 2012 Energy Efficiency Filing.* Missouri Department of Natural Resources comments were considered and accounted for.
[27] State of Illinois Energy Efficiency Technical Reference Manual

AEG reviewed the end-use measures developed in the Navigant potential study and the measures in KCP&L's MEEIA portfolio. Based on research and industry best practices, AEG updated the measure inputs and added additional end-use measures to reflect changes in technology that have emerged since the potential study was completed.

In addition to the Navigant potential study, AEG gathered the end-use measure data from multiple sources including:

- Southwest Energy Efficiency Project (March 2013). Utility Strategic Energy Management Programs.
- United States Energy Information Administration. Form EIA-826. Monthly Electric Utility Sales and Revenue Report with State Distributions.
- State of Illinois. (2012). Energy Efficiency Technical Reference Manual.
- U.S. Department of Energy. Building Technologies Program: Residential Products.
- Michigan Public Service Commission (2013). Michigan Energy Measures Database. Prepared by Morgan Marketing Partners.
- Northeast Energy Efficiency Partnerships (June 2014). Mid-Atlantic Technical Reference Manual. Version 4. Prepared by Shelter Analytics.
- Navigant Consulting, Inc. (July 2014). GMO Evaluation, Measurement, & Verification Report – Final Draft. Program Year 2013. Highly Confidential. Prepared for KCP&L.
- The Cadmus Group, Inc. (August 2013). Nonresidential Block Bidding Program Evaluation Report. Prepared for New York State Electric & Gas and Rochester Gas and Electric Corporations.

The table below presents the source documentation by measure.

Table 30. DSM Measure Documentation

Sector	Measure	Source(s)
Residential	Screw In - CFLs	Illinois/Mid-Atlantic
Residential	Screw In - LEDs	Illinois/Mid-Atlantic
Residential	Low Flow Faucet Aerator	Navigant Potential Study
Residential	Low Flow Showerhead	Navigant Potential Study
Residential	AC DLC Switch	KCP&L Inputs
Residential	Air Conditioner	DOE/Illinois/Michigan
Residential	Air Sealing	Illinois/Michigan
Residential	Dehumidifier Recycle	Navigant Evaluation
Residential	Efficient ECM Fan	Illinois
Residential	ENERGY STAR Windows	Mid-Atlantic
Residential	Freezer Recycle	Navigant Evaluation
Residential	Heat Pump Ductless Mini Split	DOE/Energy Star/Illinois/Michigan
Residential	Heat Pump	DOE/Illinois/Michigan
Residential	Heat Pump Water Heater	Illinois
Residential	Home Energy Reports	Opower

Sector	Measure	Source(s)
Residential	Increased Ceiling Insulation	Illinois/Michigan
Residential	Increased Duct Insulation	Illinois/Michigan
Residential	Increased Wall Insulation	Illinois/Michigan
Residential	Pipe Insulated	Navigant Potential Study
Residential	Refrigerator Recycle	Navigant Evaluation
Residential	Room A/C Recycle	Navigant Evaluation
Residential	Smart Power Strip	Navigant Potential Study
Residential	Water Heater Tank Wrap	Navigant Potential Study
C&I	80 PLUS Power Supply Desktop Derived Server	Navigant Potential Study
C&I	AC DLC Switch	KCP&L Inputs
C&I	Air Source Heat Pump 65<135 kBtuh	Illinois/Mid-Atlantic/CEE
C&I	Block Bidding	NYSEG/RGE
C&I	Ceramic Metal Halide	Navigant Potential Study
C&I	Chilled/Hot Water Temp Reset	Navigant Potential Study
C&I	Comp Air	Navigant Potential Study
C&I	Curtailable Rate	KCP&L Inputs
C&I	Drive	Navigant Potential Study
C&I	Efficient Pumps/Fan	Navigant Potential Study
C&I	Efficient Transformers	Navigant Potential Study
C&I	ENERGY STAR Beverage Machine	Navigant Potential Study
C&I	Fans	Navigant Potential Study
C&I	Geothermal Heat Pump	Navigant Potential Study
C&I	Heat Pump Water Heater	Navigant Potential Study/Mid-Atlantic
C&I	High Bay T5	Navigant Potential Study
C&I	High Bay T8	Navigant Potential Study
C&I	High Efficiency PTAC/PTHP	Navigant Potential Study
C&I	High Efficiency Reach-In Refrigerator/Freezer	Navigant Potential Study
C&I	LED Display Lighting	Navigant Potential Study
C&I	LED Exit Sign (replace CFL)	Navigant Potential Study/Mid-Atlantic
C&I	LED Exit Sign (replace Incandescent)	Navigant Potential Study/Illinois
C&I	LED Linear Fluorescent	Navigant Potential Study/EIA
C&I	Low Flow Faucet Aerator	Navigant Potential Study
C&I	Make Up/Exhaust - Separate/Optimized	Navigant Potential Study
C&I	Occupancy Sensors	Illinois
C&I	Pipe Wrap/Insulation	Navigant Potential Study
C&I	Pool Pump	Navigant Potential Study
C&I	Premium T8 Linear Fluorescent	Navigant Potential Study
C&I	Pre-Rinse Spray Valves	Illinois
C&I	Programmable Thermostat Controls	Navigant Potential Study
C&I	Pumps	Navigant Potential Study
C&I	Reduced Lighting Power Density	Navigant Potential Study

Sector	Measure	Source(s)
C&I	Screw In - CFLs	Navigant Potential Study
C&I	Screw In - LEDs	Navigant Potential Study
C&I	Strategic Energy Management	SWEEP/EIA
C&I	Strip Curtains	Navigant Potential Study
C&I	T8 Linear Fluorescent with Reflector/Delamping	Navigant Potential Study
C&I	VSD Compressor	Navigant Potential Study
C&I	VSD Pumps/Fan	Navigant Potential Study
C&I	Water Heater - Heat Recovery	Navigant Potential Study

SECTION 4: DEMAND-SIDE RATE DEVELOPMENT 22.050 (4)

(4) The utility shall develop potential demand-side rates designed for each market segment to reduce the net consumption of electricity or modify the timing of its use. The utility shall describe and document its demand-side rate planning and design process and shall include at least the following activities and elements: — 22.050 (4)

4.1 DEMAND-SIDE RATE REVIEW

(A) Review demand-side rates that have been implemented by other utilities and identify whether similar demand-side rates would be applicable for the utility taking into account factors such as similarity in electric prices and customer makeup; —

KCP&L engaged Navigant to conduct a DSM Resource Potential Study for the KCP&L-MO service territory. Navigant reviewed utility demand-side rates and third-party research, including:

- KEMA Consulting (March 4, 2011). Missouri Statewide DSM Potential Study – Final Report.
- Global Energy Partners (January 2010). AmerenUE Demand-side Management (DSM) market Potential Study, Volume 3.
- Electric Power Research Institute (October 2012). Understanding Electric Utility Customers – Summary Report. Report #1025856.
- Federal Energy Regulatory Commission (December 2012). 2012 Survey on Demand Response and Advanced Metering. Demand Response Survey Data.
- The Brattle Group (June 2009). A National Assessment of Demand Response Potential. Prepared for Federal Energy Regulatory Commission.
- The Brattle Group (June 2009). National Demand Response Potential Model Guide. Prepared for Federal Energy Regulatory Commission.

4.2 IDENTIFY DEMAND SIDE RATES

(B) Identify demand-side rates applicable to the major classes and decision-makers identified in subsection (1)(A). When appropriate, consider multiple demand-side rate designs for the same major classes; —

KCP&L engaged Navigant to conduct a DSM Resource Potential Study. The study identified four major demand-side rate and demand response programs: Pricing without Enabling Technology, Pricing with Enabling Technology, Interruptible Tariffs, and Direct Load Control.

- *Pricing without Enabling Technology.* Customers manually curtail load in response to the pricing signals, communicated to via delivery mechanisms such as text messages or email.
- *Pricing with Enabling Technology.* Customers have enabling technology for automatic load curtailment. These technologies include, but are not limited to, programmable thermostats, load switches, and automated demand response.
- *Interruptible Tariff* is a rate structure where customers agree to reduce demand to a pre-specified level/amount in exchange for an incentive payment. These tariffs are limited to medium and large C&I customers and do not require AMI meters or equivalent equipment.
- *Direct Load Control.* Residential and small commercial customers allow HVAC equipment (e.g. central air conditioner) to be cycled to reduce system load. The program does not require AMI meters but does require equipment to remotely signal the HVAC equipment, such as a programmable thermostat.

As shown in the table below, Navigant considered multiple demand response programs for each of the major classes.

Table 31. Program Types and Rate Classes Assessed

	Rate Classes			
	Residential	Small C&I	Medium C&I	Large C&I
Interruptible/Curtailable Tariffs			X	X
Direct Load Control	X	X		
Pricing without Enabling Technology	X	X	X	X
Pricing with Enabling Technology	X	X	X	X
Other Demand Response		X	X	

4.3 ASSESS TECHNOLOGICAL ADVANCEMENTS

(C) Assess how technological advancements that may be reasonably anticipated to occur during the planning horizon, including advanced metering and distribution systems, affect the ability to implement demand-side rates; —

KCP&L engaged Navigant to conduct a DSM Resource Potential Study. An important consideration in the deployment of the demand-side rates is that most require investment in AMI meters and MDM systems to integrate the time-based rate structures with the billing system. Navigant assessed the impact that AMI meters would have on the ability to implement demand-side rates. AMI metering will make it possible to collect detailed data on whether or not participants changed their behavior after opting in to a time of use rate and to measure differences between participant behavior with and without various types of enabling technology.

Subsequent to the Navigant study, KCP&L developed a IT technology roadmap that includes the following elements;

- *AMI Metro (2014-2016)*. KCP&L initiated an upgrade of the legacy AMR meters with new AMI meters and technology in the entire Kansas City Metro service area.

- *MDM (2015)*. KCP&L will deploy an enterprise MDM system to manage all meter reading data.
- *CIS (2017)*. KCP&L has a project underway to deploy a new CIS that will upgrade and consolidate the existing KCP&L-MO and KCP&L-GMO systems. AMI deployments will be suspended in 2017 to facilitate the CIS implementation, migration and testing.
- *AMI Rural (2018-2020)*. While not yet approved, KCP&L projects that after the new CIS project, AMI meters will be deployed in all service territories outside of the Kansas City.

4.4 ESTIMATE INPUT DATA AND OTHER CHARACTERISTICS

(D) Estimate the input data and other characteristics needed for the twenty (20)-year planning horizon to assess the cost effectiveness of each potential demand-side rate, including: —

4.4.1 DEMAND AND ENERGY REDUCTION IMPACT

1. An assessment of the demand and energy reduction impacts of each potential demand-side rate; —

KCP&L engaged AEG to design an additional DSM portfolio (Option C) for the KCP&L-MO service territory. AEG began with the *Demand-Side Resource Potential Study Report – Demand Response* completed by Navigant in August 2013. Navigant estimated the participant peak reduction as a percentage of the average load profile for that rate class.

Table 32. Program Type and Potential Peak Savings

Program Type	Potential Peak Savings
Pricing without Enabling Technology	7%
Pricing with Enabling Technology	18%

Source: Based on the averaged load reductions for Residential pricing pilots with and without enabling technology. Electric Power Research Institute (October 2012). Understanding Electric Utility Customers - Summary Report. Report #1025856.

For Interruptible Tariffs and Direct Load Control, Navigant used actual 2012 peak demand reduction values from the KCP&L programs. Navigant conservatively assumed there were no significant energy savings.

AEG updated the measure inputs to reflect KCP&L's 2014 Residential and Commercial Programmable Thermostat Programs. There are no energy savings currently assumed with the programs as designed, although studies are currently underway to evaluate this potential. The AC DLC Switch incremental cost is applied to new customers only for the purchase and installation of the programmable thermostat.

Table 33. Demand-Side Rate Measure Inputs

Sector	Measure	Unit	Measure Life	Per Unit Gross Peak kW Savings	Per Unit Incremental Cost
Residential	AC DLC Switch	per unit	10	0.838	$150
C&I	AC DLC Switch	per unit	10	1.000	$150
C&I	Curtailable Rate	per kW	1	1.000	$1.00

4.4.2 INTERACTION OF MULTIPLE DEMAND-SIDE RATES

2. An assessment of how the interactions between multiple potential demand-side rates, if offered simultaneously, would affect the impact estimates; —

KCP&L engaged Navigant to conduct a DSM Resource Potential. In the study, demand-side rates were bundled and assessed by customer class and type such that multiple demand-side rates would not be offered simultaneously to the same customer. Navigant modeled the end-use interactions through application of HVAC interaction factors for lighting measures, which account for increased heating and/or decreased cooling loads resulting from reduced lighting wattages. In addition, impacts for New Construction/Major Rehab projects account for bundles of end-use measures needed to meet targeted energy efficiency levels.

4.4.3 INTERACTION OF POTENTIAL DEMAND-SIDE RATES AND PROGRAMS

3. An assessment of how the interactions between potential demand-side rates and potential demand-side programs would affect the impact estimates of the potential demand side programs and potential demand-side rates; —

Navigant modeled the end-use interactions through application of HVAC interaction factors for lighting measures, which account for increased heating and/or decreased cooling loads resulting from reduced lighting wattages. In addition, impacts for New Construction/Major Rehab projects account for bundles of end-use measures needed to meet targeted energy efficiency levels.

KCP&L engaged AEG to design an additional DSM portfolio (Option C) for the KCP&L-MO service territory. AEG reviewed the end-use measures developed in the Navigant potential study and the measures in KCP&L's MEEIA portfolio. Based on research and industry best practices, AEG updated the measure inputs and added additional end-use measures to reflect changes in technology that have emerged since the potential study was completed.

The end-use measures identified were screened for cost-effectiveness on a stand-alone basis. Measures that were cost-effective on a stand-alone basis were bundled into programs and re-screened for cost-effectiveness. Except for the low-income programs, the DSM programs were designed to be cost-effective. Measures were bundled based on end-use and implementation.

4.4.4 DEMAND AND REDUCTION ENERGY SAVINGS

4. For each year of the planning horizon, an estimate of the incremental and cumulative demand reduction and energy savings due to the potential demand-side rate; and —

There are no energy savings currently assumed with the programs as designed, although studies are currently underway to evaluate this potential. The estimated incremental and cumulative demand reduction savings due to the potential demand-side rates can be found in the work paper “KCPL IRP Filing Tables.xlsx.”

4.4.5 COST OF DEMAND-SIDE RATES

5. For each year of the planning horizon, an estimate of the costs of each potential demand-side rate, including: —

A. The cost of incentives to customers to participate in the potential demand side rate paid by the utility. The utility shall consider multiple levels of incentives to achieve customer participation in each potential demand-side rate, with corresponding adjustments to the maximum achievable potential and the realistic achievable potentials of that potential demand-side rate; —

The cost of incentives to customers can be found in the work paper “KCPL IRP Filing Tables.xlsx.” The Residential and Commercial Programmable Thermostat incentives apply only to new customers.

B. The cost to the customer and to the utility of technology to implement the potential demand-side rate; —

The cost to the customer and the utility to implement the potential demand-side rates can be found in the work paper “KCPL IRP Filing Tables.xlsx.” The Residential and Commercial Programmable Thermostat participant incremental costs apply only to new customers.

C. The utility’s cost to administer the potential demand-side rate; and —

The utility’s cost to administer the potential demand-side rates can be found in the work paper “KCPL IRP Filing Tables.xlsx.”

D. Other costs identified by the utility; —

No other costs were identified.

4.5 TABULATION OF NUMBER OF PARTICIPANTS

(E) A tabulation of the incremental and cumulative number of participants, load impacts, utility costs, and program participant costs in each year of the planning horizon for each potential demand-side program; —

The incremental and cumulative participants, load impacts, utility costs and program participant costs for each potential demand-side rate can be found in the work paper "KCPL IRP Filing Tables.xlsx." Cumulative participants does not equal the sum of all incremental participants because some customers will participate in multiple programs. The analysis assumes that there will be a 25% overlap.

4.6 SPP DR ELIGIBILITY

(F) Evaluate how each demand-side rate would be considered by the utility's Regional Transmission Organization (RTO) in resource adequacy determinations, eligibility to participate as a demand response resource in RTO markets for energy, capacity, and ancillary services; and —

On March 1, 2014, the Southwest Power Pool (SPP) launched its new Integrated Marketplace. Included in SPP's new market design is the enabling of demand response resources to compete with traditional generators in the energy market. To offer a Demand Response Resource (DRR) into the SPP market, market participants must register as either a Dispatchable Demand Response (DDR) Resource or a Block Demand Response (BDR) Resource. As a part of this registration, the Asset Owner must also identify a corresponding Demand Response Load Asset and the associated PNode or APNode at which the load will be reduced. The Demand Response Load Asset is used by SPP to identify the actual load reduction to verify DDR and BDR compliance with Dispatch Instructions and Operating Reserve deployment instructions.

A DDR resource is a special type of resource created to model demand reduction associated with controllable load and/or a behind-the-meter generator that is dispatchable on a 5-minute basis and must have a corresponding Demand Response Load (DRL). DRL is a measurable load capable of being increased or reduced at the instruction of the SPP operator identified in the registration and must have telemetering installed. A DDR must submit the real-time value of the DRL to SPP via SCADA on a 10-second basis. A DDR resource has two alternatives for reporting its output; Submitted Resource Production Option or Calculated Production Option.

For DDR resources utilizing the Submitted Resource Option, the Market Participant must determine the real-time resource production and submit the value to SPP via SCADA on a 10-second basis. The meter agent will submit after-the-act integrated meter values directly to SPP.

For DDR resources utilizing the Calculated Resource Production Option, a baseline hourly load profile must be submitted for the DRL prior to the hour for which the DDR resource has been committed that represents the forecast consumption for the hour assuming no load reduction. SPP will take a snapshot of the demand MW at the start of the operating hour. The Real-Time Resource output is calculated as the difference between 1) the minimum of (hourly Load Profile of the DRL, Snapshot of the DRL SCADA interval prior to deployment) and 2) the Real-Time SCADA value for the DRL.

DDR resources must submit energy offer curves similar to generators. The offer curve represents how much the DDR resource can reduce load by in a given hour and at what price. DDR resources specify the maximum and minimum amount of demand reduction that can be achieved. DDR resources would also submit all associated costs no-load costs, start-up costs, etc. A DDR resource can also be compensated for some but not all ancillary services. DDR resources have the opportunity to be compensated for spinning and supplemental reserves but not for regulation up or regulation down.

A BDR is a special type of resource that is not dispatchable on a 5-minute basis but can be dispatched and committed in hourly blocks. A BDR resource must also have a corresponding DRL. The DRL must have telemetering installed and have the real-time load consumption sent to SPP SCADA via ICCP on a 10-second basis. A BDR resource is required to submit an hourly load profile prior to the hour for which the BDR resource has been committed which represents the forecast assuming no load reduction. SPP will take a snapshot of the demand MW at the start of the operating hour.

There are certain operational differences that apply to BDR resources. First, a BDR resource will only use two operating limits, minimum economic capacity operating limit and maximum economic capacity operating limit. The minimum economic operating limit represents the MW amount of demand reduction associated with the first price block identified in the energy price offer curve. The maximum economic capacity limit represents the maximum amount of demand reduction that can be achieved. Second, in the Real Time Balancing Market (RTBM), if the BDR is committed and dispatched in the Day-Ahead market or Reliability Unit Commitment (RUC), the BDR resource minimum economic capacity operating limit will be increased to match the dispatched amount.

A limiting factor for the use of DRRs in the SPP market are the metering requirements. SPPs requirements stipulate that the DRRs must be metered at the individual meter level. Therefore, the company cannot register a DR program as a whole, but would have to register each individual participating customer as a separate resource, because each customer has their own meter. This would greatly increase the amount of work required to manage the program and would also increase the cost, with unclear benefits.

Further, SPP does not have a capacity market and thus the DRRs only receive compensation for the energy and ancillary provided and do not receive capacity payments. This potentially reduces the value of the DRRs because the utility does not control the dispatch of the resource. DRRs are included in the must offer requirements of the SPP market, meaning that the company is required to offer all available resources into the market. The utility does retain some capability to self-commit the resource, but if there are a limited number of times we can call on a particular DR program and SPP has already utilized all those times, then we will have nothing left to use.

Finally, SPP does not recognize demand response as a resource equal to a generator in the capacity margin requirements. If the DRR does not get dispatched, the utility does not realize a reduction in its peak demand and therefore does not avoid the capacity need. For the time being, it would appear that the company may have greater ability to control and manage its peak demand by self-dispatching its DRRs rather than submitting demand response offers into the SPP market. This will help to maximize the value of DRR by capturing the value of avoided capacity by reducing its overall system load from SPP's perspective. At the time of this writing, KCP&L-MO is not aware of any registered DRRs in the SPP market. The company will continue to evaluate and monitor SPPs DR market options for the best way to maximize the value of DRRs.

4.7 DOCUMENT HOW ASSESMENTS WERE PERFORMED

(G) The utility shall describe and document how it performed the assessments and developed the estimates pursuant to subsection (4)(D) and shall document its sources and quality of information. —

KCP&L engaged AEG to design an additional DSM portfolio (Option C) for the KCP&L-MO service territory. AEG began with the *Demand-Side Resource Potential Study Report – Demand Response* completed by Navigant in August 2013. Navigant conducted the analysis using its DRSim™ model. The model is designed to identify the critical component variables of peak demand impact, avoided cost estimates, program administration and evaluation costs, one-time startup costs, any incentive costs, and the appropriate population of potential participants. Navigant mirrored the model's approach after the methodology that the Federal Energy Regulatory Commission used in its *National Assessment of Demand Response Potential,*[28] with a number of customizations added to specifically tailor the framework and inputs to KPC&L.

Navigant estimated the participant peak reduction as a percentage of the average load profile for that rate class. For Interruptible Tariffs and Direct Load Control, Navigant used actual 2012 peak demand reduction values from the KCP&L programs. Navigant conservatively assumed there were no significant energy savings. Demand-side rate resources referenced by Navigant include:

[28] Federal Energy Regulatory Commission, *A National Assessment of Demand Response Potential*. Prepared by The Brattle Group, June 2009.

- KEMA Consulting (March 4, 2011). Missouri Statewide DSM Potential Study – Final Report.
- Global Energy Partners (January 2010). AmerenUE Demand-side Management (DSM) market Potential Study, Volume 3.
- Electric Power Research Institute (October 2012). Understanding Electric Utility Customers – Summary Report. Report #1025856.
- Federal Energy Regulatory Commission (December 2012). 2012 Survey on Demand Response and Advanced Metering. Demand Response Survey Data.
- The Brattle Group (June 2009). A National Assessment of Demand Response Potential. Prepared for Federal Energy Regulatory Commission.
- The Brattle Group (June 2009). National Demand Response Potential Model Guide. Prepared for Federal Energy Regulatory Commission.

AEG updated the measure inputs to reflect KCP&L's 2014 Residential and Commercial Programmable Thermostat Programs. There are no energy savings currently assumed with the programs as designed, although studies are currently underway to evaluate this potential. The AC DLC Switch incremental cost is applied to new customers only for the purchase and installation of the programmable thermostat.

SECTION 5: DEMAND-SIDE PROGRAM COST EFFECTIVENESS

(5) The utility shall describe and document its evaluation of the cost effectiveness of each potential demand-side program developed pursuant to section (3) and each potential demand-side rate developed pursuant to section (4). All costs and benefits shall be expressed in nominal dollars. —

KCP&L engaged AEG to design an additional DSM portfolio (Option C) for the KCP&L-MO service territory. AEG began with the *Demand-Side Resource Potential Study Report* and the *Demand-Side Resource Potential Study Report – Demand Response* completed by Navigant in August 2013. Navigant developed a comprehensive measure list of 500 measures, 300 of which were characterized for the final model. Navigant employed a variety of analytical approaches to estimate measure-level energy savings and coincident peak demand savings, including standard engineering algorithms, calibrated simulation models, and secondary resources. AEG reviewed the end-use measures developed in the Navigant potential study and the measures in KCP&L's MEEIA portfolio. Based on research and industry best practices, AEG updated the measure inputs and added additional end-use measures to reflect changes in technology that have emerged since the potential study was completed.

AEG performed the industry standard cost-effectiveness tests to gauge the economic merits of the measures, programs and portfolio. Each test compares the benefits of a DSM program to its costs using its own unique perspectives and definitions. The definitions for the four standard tests most commonly used are described below.

- *Total Resource Cost Test (TRC).* The benefits include the lifetime avoided energy costs and avoided capacity costs while the costs include the participant and utility administrative costs associated with the program. The TRC test represents the combination of the effects of a program on both participating and non-participating customers.

– *Utility Cost Test (UCT).* The benefits include the lifetime avoided energy costs and avoided capacity costs while the costs include the utility's incentive and administrative costs.

– *Participant Cost Test (PCT).* The benefits include lost utility revenues (i.e. the lifetime value of retail rate savings). The costs include the participant incremental measure costs minus the value of incentives.

– *Rate Impact Measure Test (RIM).* The test measures what happens to customer's rates due to changes in utility revenues and operating costs. Therefore, if the benefits are greater than the costs, rates will decrease on average and subsidies will be minimized or avoided. The benefits are the same as the TRC benefits and the costs include all utility costs associated with the program, including lost utility revenue as well as incentive and administrative costs.

The software used to perform the cost-effectiveness has been adapted from Minnesota Office of Energy Security "BenCost" software and is consistent with the California Standard Practice Manual. The input data gathered for the model included:

Table 34. Cost-Effectiveness Model Inputs

General Inputs	Specific-Project Inputs
Retail Rate ($/kWh)	Utility Project Costs (Administrative & Incentives)
Commodity Cost ($/kWh)	Direct Participant Project Costs ($/Participant)
Demand Cost ($/kW-Year)	Project Life (Years)
Environmental Damage Cost ($/kWh)	kWh/Participant Saved (Net and Gross)
Discount Rate (%)	kW/Participant Saved (Net and Gross)
Growth Rate (%)	Number of Participants
Line Losses (%)	

Measures that were cost-effective on a stand-alone basis were bundled into programs and re-screened for cost-effectiveness. Except for the low-income programs, the DSM programs were designed to be cost-effective. Measures were bundled based on end-use and implementation.

Table 35. DSM Program Measure Offerings

Residential Programs	
Home Lighting Rebate	CFL and LED Bulbs
Appliance Recycling	Recycle inefficient refrigerators, freezers, dehumidifiers or room air conditioners.
Home Energy Report	Behavior program utilizing customized energy reports sent periodically to households.
Online Home Energy Audit	Online energy audit tool.

Whole House Efficiency	The program has three tiers. To participate in Tier 2, customers must complete Tier 1.
	– Tier 1. Audit and direct install of CFL/LED bulbs, low flow faucet aerators, low flow showerheads, hot water pipe insulation, water heater tank wrap, and smart power strips.
	– Tier 2. Air Sealing, Insulation (ceiling/wall) and ENERGY STAR Windows
	– Tier 3. HVAC Equipment
	  – Heat Pump Water Heater
	  – Efficient ECM Fan
	  – Central Air Conditioners (SEER 15, 16)
	  – Central Air Conditioner Early Retirement (SEER 15, 16)
	  – Air Source Heat Pump (SEER 15, 16 and 17)
	  – Air Source Heat Pump Early Retirement (SEER 15, 16)
	  – Air Source Heat Pump Replace Electric Resistance Heat (SEER 15, 16)

Income-Eligible Multi-Family	The program is comprised of two tiers. – Tier 1. Home Kit (includes CFL/LED bulbs, low flow faucet aerators, low flow showerheads, hot water pipe insulation, water heater tank wrap, and smart power strip). – Tier 2. Common Area Lighting
Income-Eligible Weatherization	The program is comprised of two tiers. – Tier 1. Home Kit (includes CFL/LED bulbs, low flow faucet aerators, low flow showerheads, hot water pipe insulation, water heater tank wrap, and smart power strip). Tier 2. Weatherization (ceiling, duct or wall insulation)
Residential Programmable Thermostat	Direct load control program that cycles and curtails central air conditioners by way of a remote-controlled switch.
Commercial Programs	
Business Energy Efficiency Rebate – Standard	Customers may receive incentives by installing efficient measures from a pre-qualified list of options.
Business Energy Efficiency Rebate – Custom	Customers may receive incentives for non-prescriptive measures.
Strategic Energy Management	Provides energy education, technical assistance, and coaching for large commercial and industrial customers in order to drive behavioral change and transformation of the company culture.
Block Bidding	Purchase blocks of electricity savings representing reduced electric usage from eligible customers or third parties working with eligible customers.
Online Building Energy Audit	Online energy audit tool.
Small Business Direct Install	Small customers receive 70% of the full cost of qualifying measures.
Commercial Programmable Thermostat	Direct load control program that cycles and curtails central air conditioners by way of a remote-controlled switch.
Demand Response Incentive	Interruptible tariff program for customers that can reduce load by at least 25 kW during times of system peak congestion.

5.1 CUMULATIVE BENEFITS

(A) In each year of the planning horizon, the benefits of each potential demand-side program and each potential demand-side rate shall be calculated as the cumulative demand reduction multiplied by the avoided demand cost plus the cumulative energy savings multiplied by the avoided energy cost. These calculations shall be performed both with and without the avoided probable environmental costs. The utility shall describe and document the methods, data, and assumptions it used to develop the avoided costs. —

5.1.1 AVOIDED DEMAND COST

1. The utility avoided demand cost shall include the capacity cost of generation, transmission, and distribution facilities, adjusted to reflect reliability reserve margins and capacity losses on the transmission and distribution systems, or the corresponding market-based equivalents of those costs. The utility shall describe and document how it developed its avoided demand cost, and the capacity cost chosen shall be consistent throughout the triennial compliance filing. —

The calculation of avoided demand cost is provided in the table below.

Table 36. Avoided Demand Cost Development **Highly Confidential**

Technology Type	CT (F-Class)
Capital Cost Source	[redacted]
Net Capacity (MW)	[redacted]
Capacity Factor	[redacted]
Fixed O&M ($/kW-Yr)	[redacted]
Var O&M ($/MWh)	[redacted]
Technology Cost ($/kW)	[redacted]
AFUDC	[redacted]
Technology Cost w AFUDC	[redacted]
Technology Capital (w AFUDC)	[redacted]
Levelized FCR for construction projects	[redacted]
Annual Technology Carrying Cost	[redacted]
Transmission Cost ($/kW)	[redacted]
Transmission Capital	[redacted]
Transmission FCR	[redacted]
Annual Transmission Carrying Cost	[redacted]
Total Annual Carrying Cost	[redacted]
Total Fixed O&M	[redacted]
Total Variable O&M	[redacted]
Total Fixed Cost Per Year	[redacted]
Total Fixed Cost Per Year ($/MWh) {1}	[redacted]
Ht Rt (Btu/KWh)	[redacted]
Fuel Cost $/mmbtu	[redacted]
Fuel Cost $/MWh	[redacted]
All-In ($/MWh)	[redacted]
All-in $/kW-year (2012$)	[redacted]
Annual Inflation Rate	[redacted]
All-In $/MWh (2015$)	[redacted]
All-in $/kW-year (2015$)	[redacted]

At the outset of the time horizon considered by the analysis, the avoided demand costs are set at $20 per kW to reflect the prevailing price of short-term capacity contracts available on the market. The avoided demand cost is then assumed to ramp up to $152.22 linearly over the intervening years. For this particular input of the DSM analysis, we assume the year in which capacity needs are anticipated for KCP&L-MO is 2021, based on a holistic assessment of current and prior information. This, of course, is an output of the current IRP's multiple cases, but the above represents a reasonable, simplifying assumption based on the best available information in order to avoid

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circularity in the analysis. The corresponding values of avoided demand costs by year are provided in the table below.

Table 37. Avoided Demand Costs by Year **Highly Confidential**

Year	Capacity Cost ($/kW)
2016	[redacted]
2017	[redacted]
2018	[redacted]
2019	[redacted]
2020	[redacted]
2021	[redacted]
2022	[redacted]
2023	[redacted]
2024	[redacted]
2025	[redacted]
2026	[redacted]
2027	[redacted]
2029	[redacted]
2030	[redacted]
2031	[redacted]
2032	[redacted]
2033	[redacted]
2034	[redacted]

5.1.2 AVOIDED ENERGY COST

2. The utility avoided energy cost shall include the fuel costs, emission allowance costs, and other variable operation and maintenance costs of generation facilities, adjusted to reflect energy losses on the transmission and distribution systems, or the corresponding market-based equivalents of those costs. The utility shall describe and document how it developed its avoided energy cost, and the energy costs shall be consistent throughout the triennial compliance filing. —

The avoided energy costs are market-based equivalents that account for all of these costs and are provided by the MIDAS Market Model. The corresponding values by year are provided in the table below.

Table 38. Avoided Energy Costs by Year **Highly Confidential**

Year	Avoided Cost ($/MWh)
2016	[redacted]
2017	
2018	
2019	
2020	
2021	
2022	
2023	
2024	
2025	
2026	
2027	
2029	
2030	
2031	
2032	
2033	
2034	

5.1.3 AVOIDED ENVIRONMENTAL COST

3. The avoided probable environmental costs include the effects of the probable environmental costs calculated pursuant to 4 CSR 240-22.040(2)(B) on the utility avoided demand cost and the utility avoided energy cost. The utility shall describe and document how it developed its avoided probable environmental cost. —

The probable environmental costs were developed as described in the response to 4 CSR 240-22.040(2)(B) and included in the calculation of avoided energy costs.

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5.2 TOTAL RESOURCE COST TEST (TRC)

(B) The total resource cost test shall be used to evaluate the cost effectiveness of the potential demand-side programs and potential demand-side rates. In each year of the planning horizon —

5.2.1 DEMAND-SIDE PROGRAM COSTS

1. The costs of each potential demand-side program shall be calculated as the sum of all incremental costs of end-use measures that are implemented due to the program (including both utility and participant contributions) plus utility costs to administer, deliver, and evaluate each potential demand-side program; —

The TRC costs include the incremental participant cost and utility administrative costs associated with the program.

5.2.2 DEMAND-SIDE RATE COSTS

2. The costs of each potential demand-side rate shall be calculated as the sum of all incremental costs that are due to the rate (including both utility and participant contributions) plus utility costs to administer, deliver, and evaluate each potential demand-side rate; and —

The TRC costs include the incremental participant cost and the utility administrative costs associated with the program.

5.2.3 COSTS NOT TO INCLUDE

3. For purposes of this test, the costs of potential demand-side programs and potential demand-side rates shall not include lost revenues or utility incentive payments to customers. —

The TRC costs do not include lost revenues or incentive payments.

5.3 UTILITY COST TEST (UCT)

(C) The utility cost test shall also be performed for purposes of comparison. In each year of the planning horizon —

5.3.1 TEST COSTS

1. The costs of each potential demand-side program and potential demand-side rate shall be calculated as the sum of all utility incentive payments plus utility costs to administer, deliver, and evaluate each potential demand-side program or potential demand-side rate; —

The UCT costs include the utility's incentive and administrative costs.

5.3.2 COSTS NOT TO INCLUDE

2. For purposes of this test, the costs of potential demand-side programs and potential demand-side rates shall not include lost revenues; and —

The UCT costs do not include lost revenues.

5.3.3 RATE OF RETURN OR INCENTIVE COSTS

3. The costs shall include, but separately identify, the costs of any rate of return or incentive included in the utility's recovery of demand-side program costs. — .

The analysis did not assume a rate of return or utility incentive.

5.4 TRC MUST BE GREATER THAN ONE

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

impacts or avoided costs, including programs required to comply with legal mandates. —

Except for the low-income programs, the DSM programs were designed to be cost-effective.

5.5 TRC AND UCT TEST RESULTS

(E) The utility shall provide results of the total resource cost test and the utility cost test for each potential demand-side program evaluated pursuant to subsection (5)(B) and for each potential demand–side rate evaluated pursuant to subsection (5)(C) of this rule, including a tabulation of the benefits (avoided costs), demand-side resource costs, and net benefits or costs. —

The TRC and UCT results for each potential DSM program and demand side rate are presented in the work paper "KCPL IRP Filing Tables.xlsx."

5.6 OTHER COST BENEFIT TEST RESULTS

(F) If the utility calculates values for other tests to assist in the design of demand-side programs or demand-side rates, the utility shall describe and document the tests and provide the results of those tests. —

AEG also analyzed cost-effectiveness for the following two standard tests:

- *Participant Cost Test (PCT).* The benefits include lost utility revenues (i.e. the lifetime value of retail rate savings). The costs include the participant incremental measure costs minus the value of incentives.
- *Rate Impact Measure Test (RIM).* The test measures what happens to customer's rates due to changes in utility revenues and operating costs. Therefore, if the benefits are greater than the costs, rates will decrease on average and subsidies will be minimized or avoided. The benefits are the same as the TRC benefits and the costs include all utility costs associated with the

program, including lost utility revenue as well as incentive and administrative costs.

The PCT and RIM results for each potential DSM program and demand side rate are presented in the work paper “KCPL IRP Filing Tables.xlsx.”

5.7 DESCRIBE AND DOCUMENT COST EFFECTIVENESS TESTS

(G) The utility shall describe and document how it performed the cost effectiveness assessments pursuant to section (5) and shall describe and document its methods and its sources and quality of information. —

KCP&L engaged AEG to design an additional DSM portfolio (Option C) for the KCP&L-MO service territory. AEG began with the *Demand-Side Resource Potential Study Report* and the *Demand-Side Resource Potential Study Report – Demand Response* completed by Navigant in August 2013. Navigant developed a comprehensive measure list of 500 measures, 300 of which were characterized for the final model. Navigant employed a variety of analytical approaches to estimate measure-level energy savings and coincident peak demand savings, including standard engineering algorithms, calibrated simulation models, and secondary resources.

AEG reviewed the end-use measures developed in the Navigant potential study and the measures in KCP&L’s MEEIA portfolio. Based on research and industry best practices, AEG updated the measure inputs and added additional end-use measures to reflect changes in technology that have emerged since the potential study was completed.

In addition to the Navigant potential study, AEG gathered the end-use measure data from multiple sources including:

- Southwest Energy Efficiency Project (March 2013). Utility Strategic Energy Management Programs.
- United States Energy Information Administration. Form EIA-826. Monthly Electric Utility Sales and Revenue Report with State Distributions.

- State of Illinois. (2012). Energy Efficiency Technical Reference Manual.
- U.S. Department of Energy. Building Technologies Program: Residential Products.
- Michigan Public Service Commission (2013). Michigan Energy Measures Database. Prepared by Morgan Marketing Partners.
- Northeast Energy Efficiency Partnerships (June 2014). Mid-Atlantic Technical Reference Manual. Version 4. Prepared by Shelter Analytics.
- Navigant Consulting, Inc. (July 2014). GMO Evaluation, Measurement, & Verification Report – Final Draft. Program Year 2013. Highly Confidential. Prepared for KCP&L.
- The Cadmus Group, Inc. (August 2013). Nonresidential Block Bidding Program Evaluation Report. Prepared for New York State Electric & Gas and Rochester Gas and Electric Corporations.

The table below presents the source documentation by measure.

Table 39. DSM Measure Documentation

Sector	Measure	Source(s)
Residential	Screw In - CFLs	Illinois/Mid-Atlantic
Residential	Screw In - LEDs	Illinois/Mid-Atlantic
Residential	Low Flow Faucet Aerator	Navigant Potential Study
Residential	Low Flow Showerhead	Navigant Potential Study
Residential	AC DLC Switch	KCP&L Inputs
Residential	Air Conditioner	DOE/Illinois/Michigan
Residential	Air Sealing	Illinois/Michigan
Residential	Dehumidifier Recycle	Navigant Evaluation
Residential	Efficient ECM Fan	Illinois
Residential	ENERGY STAR Windows	Mid-Atlantic
Residential	Freezer Recycle	Navigant Evaluation
Residential	Heat Pump Ductless Mini Split	DOE/Energy Star/Illinois/Michigan
Residential	Heat Pump	DOE/Illinois/Michigan
Residential	Heat Pump Water Heater	Illinois
Residential	Home Energy Reports	Opower

Sector	Measure	Source(s)
Residential	Increased Ceiling Insulation	Illinois/Michigan
Residential	Increased Duct Insulation	Illinois/Michigan
Residential	Increased Wall Insulation	Illinois/Michigan
Residential	Pipe Insulated	Navigant Potential Study
Residential	Refrigerator Recycle	Navigant Evaluation
Residential	Room A/C Recycle	Navigant Evaluation
Residential	Smart Power Strip	Navigant Potential Study
Residential	Water Heater Tank Wrap	Navigant Potential Study
C&I	80 PLUS Power Supply Desktop Derived Server	Navigant Potential Study
C&I	AC DLC Switch	KCP&L Inputs
C&I	Air Source Heat Pump 65<135 kBtuh	Illinois/Mid-Atlantic/CEE
C&I	Block Bidding	NYSEG/RGE
C&I	Ceramic Metal Halide	Navigant Potential Study
C&I	Chilled/Hot Water Temp Reset	Navigant Potential Study
C&I	Comp Air	Navigant Potential Study
C&I	Curtailable Rate	KCP&L Inputs
C&I	Drive	Navigant Potential Study
C&I	Efficient Pumps/Fan	Navigant Potential Study
C&I	Efficient Transformers	Navigant Potential Study
C&I	ENERGY STAR Beverage Machine	Navigant Potential Study
C&I	Fans	Navigant Potential Study
C&I	Geothermal Heat Pump	Navigant Potential Study
C&I	Heat Pump Water Heater	Navigant Potential Study/Mid-Atlantic
C&I	High Bay T5	Navigant Potential Study
C&I	High Bay T8	Navigant Potential Study
C&I	High Efficiency PTAC/PTHP	Navigant Potential Study
C&I	High Efficiency Reach-In Refrigerator/Freezer	Navigant Potential Study
C&I	LED Display Lighting	Navigant Potential Study
C&I	LED Exit Sign (replace CFL)	Navigant Potential Study/Mid-Atlantic
C&I	LED Exit Sign (replace Incandescent)	Navigant Potential Study/Illinois
C&I	LED Linear Fluorescent	Navigant Potential Study/EIA
C&I	Low Flow Faucet Aerator	Navigant Potential Study
C&I	Make Up/Exhaust - Separate/Optimized	Navigant Potential Study
C&I	Occupancy Sensors	Illinois
C&I	Pipe Wrap/Insulation	Navigant Potential Study
C&I	Pool Pump	Navigant Potential Study
C&I	Premium T8 Linear Fluorescent	Navigant Potential Study
C&I	Pre-Rinse Spray Valves	Illinois
C&I	Programmable Thermostat Controls	Navigant Potential Study
C&I	Pumps	Navigant Potential Study
C&I	Reduced Lighting Power Density	Navigant Potential Study

Sector	Measure	Source(s)
C&I	Screw In - CFLs	Navigant Potential Study
C&I	Screw In - LEDs	Navigant Potential Study
C&I	Strategic Energy Management	SWEEP/EIA
C&I	Strip Curtains	Navigant Potential Study
C&I	T8 Linear Fluorescent with Reflector/Delamping	Navigant Potential Study
C&I	VSD Compressor	Navigant Potential Study
C&I	VSD Pumps/Fan	Navigant Potential Study
C&I	Water Heater - Heat Recovery	Navigant Potential Study

The demand and energy reduction impacts of each end-use measure included in the additional DSM portfolio (Option C) are presented below.

Residential Measures

In 2007, the United States Congress passed the Energy Independence and Security Act (EISA) which set efficiency standards for 'general service' light bulbs, implemented in two phases. From 2012 to 2014, standard light bulbs manufactured were be required to use approximately 20 to 30 percent less energy than current incandescent light bulbs. By 2020, there must be a 60 percent reduction in light bulb energy use.[29] The effective dates of the EISA legislation pertain to newly manufactured bulbs, not existing stock.

Table 40. Residential Lighting Measures

Measure	Measure Life	Gross kWh Savings	Gross kW Savings	Incremental Cost
CFL pre-2020	5	28	0.003	$1.70
CFL 2020	5	6	0.001	$1.00
LED pre-2020	20	31	0.003	$15.00
LED 2020	20	9	0.001	$10.00

KCP&L proposes to offer measures to multi-family and single family customers. The energy and demand savings vary for low-flow faucet aerator or hot water pipe insulation depending on whether the customer resides in a multi-family or single family residence.

[29] See Database of State Incentives for Renewables & Efficiency (DSIRE). *Federal Appliance Standards*. Available at: www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US04R&re=1&ee=1

Table 41. Residential Low-Flow Faucet Aerator & Pipe Insulation

Measure	Measure Life	Gross kWh Savings	Gross kW Savings	Incremental Cost
Faucet Aerator – Multi-Family	9	42	0.005	$3
Family	9	65	0.010	$3
Pipe Insulated – Multi-Family	10	236	0.017	$15
Pipe Insulated – Single Family	10	273	0.024	$15

The remaining residential measure inputs are presented in the table below.

Table 42. Residential Measures

Measure	Unit	Measure Life	Gross kWh Savings	Gross kW Savings	Incremental Cost
A/C SEER 15	per ton	18	69	0.016	$93
A/C SEER 15, Early Retirement	per ton	6	486	0.234	$642
A/C SEER 16	per ton	18	130	0.016	$185
A/C SEER 16, Early Retirement	per ton	6	547	0.234	$642
A/C SEER 17	per ton	18	184	0.041	$278
A/C SEER 17, Early Retirement	per ton	6	600	0.259	$642
Air Sealing	per sq. ft.	15	0	0	$0.12
Dehumidifier Recycle	per unit	4	139	0.035	$49
Efficient ECM Fan	per unit	20	644	0.36	$97
ENERGY STAR Windows	per sq. ft.	25	2	0.001	$1.5
Freezer Recycle	per unit	8	1201	0.191	$93
Heat Pump Ductless Mini Split	per ton	18	1285	0.817	$716
HP SEER 15	per ton	18	173	0.054	$98
HP SEER 15, Early Retirement	per ton	6	1195	0.502	$729
HP SEER 15, Replace Electric Resistance Heat	per ton	6	4838	1.765	$729
HP SEER 16	per ton	18	234	0.054	$196
HP SEER 16, Early Retirement	per ton	6	1256	0.502	$729
HP SEER 16, Replace Electric Resistance Heat	per ton	6	4891	1.765	$729
HP SEER 17	per ton	18	321	0.093	$294
HP SEER 17, Early Retirement	per ton	6	1342	0.54	$729
Heat Pump Water Heater	per unit	13	1766	0.084	$1,000
Home Energy Reports	per home	1	145	0.028	$0
Increased Ceiling Insulation	per sq. ft.	25	1	0	$0.76
Increased Duct Insulation	per home	20	210	0.118	$720
Increased Wall Insulation	per sq. ft.	25	1	0	$1.32
Pipe Insulated	per unit	15	74	0.008	$2.81
Refrigerator Recycle	per unit	8	1190	0.19	$93
Room A/C Recycle	per unit	4	121	0.114	$49
Smart Power Strip	per unit	5	74	0.005	$15
Water Heater Tank Wrap	per unit	5	131	0.015	$18

C&I End-Use Measures

In 2007, the United States Congress passed EISA which set efficiency standards for ‘general service’ light bulbs, implemented in two phases. From 2012 to 2014, standard light bulbs manufactured were be required to use approximately 20 to 30 percent less energy than current incandescent light bulbs. By 2020, there must be a 60 percent reduction in light bulb energy use. The effective dates of the EISA legislation pertain to newly manufactured bulbs, not existing stock.

Table 43. C&I Lighting Measures

Measure	Measure Life	Gross kWh Savings	Gross kW Savings	Incremental Cost
CFL pre-2020	5	188	0.006	$3.30
CFL 2020	5	82	0.003	$1.00
LED pre-2020	20	200	0.006	$25.00
LED 2020	20	94	0.003	$39.00

The remaining C&I measures are presented in the table below.

Table 44. C&I Measures

Efficient Description	Unit	Measure Life	Gross kWh Savings	Gross kW Savings	Incremental Cost
80 PLUS Power Supply Desktop Derived Server	per unit	5	334	0.038	$2
AC DLC Switch	per unit	10	-	1.000	$0
Air Source Heat Pump 65<135 kBtuh	per ton	15	91	0.124	$100
Air Sourced Air Conditioner <65 kBtuh	per ton	15	82	0.066	$120
Air Sourced Air Conditioner >240 kBtuh	per ton	15	71	0.057	$100
Air Sourced Air Conditioner 135<240 kBtuh	per ton	15	81	0.065	$100
Air Sourced Air Conditioner 65<135 kBtuh	per ton	15	57	0.046	$100
Block Bidding	per Bid	10	2,514,850	436	$496,331
Ceramic Metal Halide (replace HID HPS)	per unit	15	712	0.024	$104
Ceramic Metal Halide (replace HID MH)	per unit	15	697	0.023	$106
Chilled/Hot Water Temp Reset	per ton	5	82	0.003	$2.06
Comp Air - ASD (100+ HP)	per HP	6	693	0.167	$132
Comp Air - ASD (1-5 HP)	per HP	14	693	0.167	$385
Comp Air - ASD (6-100 HP)	per HP	10	693	0.167	$147
Comp Air - Controls	per HP	10	454	0.160	$20
Comp Air - Dryer Cycling	per HP	10	47	0.011	$11
Comp Air - Eliminate In-Efficient Uses	per HP	8	333	0.080	$67
Comp Air - Leaks Repaired	per HP	10	666	0.160	$133
Comp Air - Motor Practices (100+ HP)	per HP	6	56	0.010	$7.86
Comp Air - Motor Practices (1-5 HP)	per HP	14	180	0.034	$79
Comp Air - Motor Practices (6-100 HP)	per HP	10	90	0.017	$20
Comp Air - No Loss Drains	per HP	5	13	0.003	$3
Comp Air - Pressure Reduction	per HP	6	100	0.024	$1
Comp Air - Replace Motor (100+ HP)	per HP	15	31	0.007	$8
Comp Air - Replace Motor (6-100 HP)	per HP	15	46	0.011	$8
Comp Air - Sizing	per HP	10	100	0.024	$15
Comp Air - Storage/Air Receivers	per HP	10	292	0.070	$20
Curtailable Rate	per kW	1	-	1.000	$1
Drive - Custom	per HP	15	29	0.006	$10

Efficient Description	Unit	Measure Life	Gross kWh Savings	Gross kW Savings	Incremental Cost
Drive - Direct Drive	per HP	15	146	0.031	$25
Drive - VFD (Other)	per HP	15	512	0.082	$355
Efficient Pumps/Fan	per HP	15	3	0.002	$1.77
Efficient Transformers	per kVA	25	14	0.002	$2.06
ENERGY STAR Beverage Machine	per unit	14	1754	0.116	$140
Fans - ASD (100+ HP)	per HP	15	948	0.147	$133
Fans - ASD (1-5 HP)	per HP	15	1037	0.161	$460
Fans - ASD (6-100 HP)	per HP	15	973	0	$155
Fans - Controls	per HP	15	57	0.012	$20
Fans - Improve Components	per HP	15	142	0.030	$49
Fans - Motor Practices (100+ HP)	per HP	15	62	0.013	$21
Fans - Motor Practices (1-5 HP)	per HP	15	67	0.014	$23
Fans - Motor Practices (6-100 HP)	per HP	15	63	0.013	$22
Fans - Power Recovery	per HP	15	283	0.060	$98
Fans - System Optimization	per HP	15	283	0.060	$98
Geothermal Heat Pump	per ton	15	443	0.781	$379
Heat Pump Water Heater	per unit	10	1993	0.298	$925
High Bay T5 (replace HID HPS)	per unit	15	443	0.032	$104
High Bay T5 (replace HID MH)	per unit	15	390	0.028	$102
High Bay T8 (replace HID HPS)	per unit	15	325	0.023	$100
High Efficiency PTAC/PTHP	per kBtuh	15	30	0.012	$12
High Efficiency Reach-In Refrigerator/Freezer	per unit	12	3026	0.129	$263
LED Display Lighting	per unit	8	731	0.071	$256
LED Exit Sign (replace CFL)	per unit	13	65	0.008	$23
LED Exit Sign (replace Incandescent)	per unit	13	258	0.031	$30
LED Linear Fluorescent	per unit	15	225	0.062	$45
Low Flow Faucet Aerator	per unit	9	131	0.196	$8.35
Make Up/Exhaust - Separate/Optimized	per HP	15	568	0.285	$116
Occupancy Sensors	per Watt	8	2	0.001	$0.12
Pipe Wrap/Insulation	per unit	6	224	0.278	$47
Pool Pump - High Efficiency	per unit	10	1301	0.149	$273
Pool Pump - VSD	per unit	10	2461	0.281	$579
Premium T8 Linear Fluorescent	per unit	15	55	0.004	$10
Pre-Rinse Spray Valves	per unit	5	2671	-	$100
Programmable Thermostat Controls	per ton	8	126	-	$6
Pumps - ASD (100+ HP)	per HP	15	1002	0.085	$133
Pumps - ASD (1-5 HP)	per HP	15	1096	0.092	$460
Pumps - ASD (6-100 HP)	per HP	15	1028	0.087	$155
Pumps - Controls	per HP	15	239	0.062	$85
Pumps - Motor Practices (100+ HP)	per HP	15	87	0.022	$31
Pumps - Motor Practices (1-5 HP)	per HP	15	95	0.024	$34

Efficient Description	Unit	Measure Life	Gross kWh Savings	Gross kW Savings	Incremental Cost
Pumps - Motor Practices (6-100 HP)	per HP	15	89	0.023	$32
Pumps - Power Recovery	per HP	15	227	0.059	$81
Pumps - Replace Motor (1-5 HP)	per HP	15	33	0.008	$19
Pumps - Sizing	per HP	15	162	0.042	$58
Reduced Lighting Power Density	per sq. ft.	13	0.46	0.000	$0.14
Screw In - CFLs	per unit	5	188	0.006	$3.33
Screw In - LEDs	per unit	25	200	0.006	$25
Strategic Energy Management	per Customer	3	150,454	34	$3,009
Strip Curtains	per sq. ft.	6	129	0.015	$10
T8 Linear Fluorescent with Reflector/Delamping	per unit	15	67	0.005	$8
VSD Compressor	per HP	10	234	0.038	$78
VSD Pumps/Fan	per HP	15	478	0.145	$305
Water Heater - Heat Recovery from Air Source HP	per unit	18	1923	0.133	$900
Water Heater - Heat Recovery from Geothermal HP	per unit	18	1923	0.127	$900

AEG performed the industry standard cost-effectiveness tests in order to gauge the economic merits of the measures, programs and portfolio. Each test compares the benefits of a DSM program to its costs using its own unique perspectives and definitions*.* The definitions for the four standard tests most commonly used are described below.

- *TRC*. The benefits include the lifetime avoided energy costs and avoided capacity costs while the costs include the participant and utility administrative costs associated with the program. The TRC test represents the combination of the effects of a program on both participating and non-participating customers.

- *UCT*. The benefits include the lifetime avoided energy costs and avoided capacity costs while the costs include the utility's incentive and administrative costs.

- *PCT*. The benefits include lost utility revenues (i.e. the lifetime value of retail rate savings). The costs include the participant incremental measure costs minus the value of incentives.

- *RIM*. The test measures what happens to customer's rates due to changes in utility revenues and operating costs. Therefore, if the benefits are greater than the costs, rates will decrease on average and subsidies will be minimized or avoided. The benefits are the same as the TRC benefits and the costs include all utility costs associated with the program, including lost utility revenue as well as incentive and administrative costs.

The software used to perform the cost-effectiveness has been adapted from Minnesota Office of Energy Security "BenCost" software and is consistent with the California Standard Practice Manual. The input data gathered for the model included:

Table 45. Cost-Effectiveness Model Inputs

General Inputs	Specific-Project Inputs
Retail Rate ($/kWh)	Utility Project Costs (Administrative & Incentives)
Commodity Cost ($/kWh)	Direct Participant Project Costs ($/Participant)
Demand Cost ($/kW-Year)	Project Life (Years)
Environmental Damage Cost ($/kWh)	kWh/Participant Saved (Net and Gross)
Discount Rate (%)	kW/Participant Saved (Net and Gross)
Growth Rate (%)	Number of Participants
Line Losses (%)	

Measures that were cost-effective on a stand-alone basis were bundled into programs and re-screened for cost-effectiveness. Except for the low-income programs, the programs were designed to be cost-effective. Measures were bundled based on the end-use, sector and implementation.

SECTION 6: TOTAL RESOURCE COST TEST

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

Potential demand-side programs and demand-side rates that passed the total resource cost test (a benefit-cost ratio of at least 1.0) were considered as a demand-side candidate resource option.

6.1 BUNDLING OF PORTFOLIOS

(A) The utility may bundle demand-side candidate resource options into portfolios, as long as the requirements pursuant to section (1) are met and as long as multiple demand side candidate resource options and portfolios advance for consideration in the integrated resource analysis in 4 CSR 240-22.060. The utility shall describe and document how its demand-side candidate resource options and portfolios satisfy these requirements. —

KCP&L engaged Navigant to conduct a DSM Resource Potential Study and AEG to design an additional DSM portfolio (Option C) for the KCP&L-MO service territory.

Navigant developed a set of efficiency programs designed to deliver the savings in the realistic achievable potential scenario. While the potential model is run at the level of the measure and customer segment, Navigant mapped measures and customer segments to programs, thereby allocating the realistic achievable potential to a suite of efficiency programs. The potential model is therefore effectively an integrated potential and program design model, as the results are internally consistent.

AEG took a number of steps to prepare Option C, these included:

Review Existing DSM Portfolio. AEG reviewed the existing DSM portfolio and held two collaborative DSM program design workshops with KCP&L program managers and staff to discuss the program design process and gain insight into the existing DSM programs. The insights included, but were not limited to, the following:

- How are the programs implemented? What program modifications are anticipated for 2015?
- What is working well? What is not working well? What is missing?

- How well are the current programs suited to address the portfolio objectives?
- What are the implications of the potential study on existing programs?

Review DSM Potential Study. AEG reviewed the *Demand-Side Resource Potential Study Report* and the *Demand-Side Resource Potential Study Report – Demand Response* completed by Navigant Consulting, Inc. in August 2013. AEG compared the existing KCP&L portfolios with the potential study and best practice programs from industry research, primarily using information from utilities that are similar in size and customer composition as KCP&L. At this stage, AEG updated measure inputs and incorporated additional measures on an as-needed basis to reflect more recent program developments, evaluations, and new technology developments.

Review Stakeholder Input and Regulatory Requirements. AEG reviewed KCP&L stakeholder input on the DSM programs provided through written comments and prior collaborative workshops. Similarly, AEG reviewed reporting and filing requirements. AEG attempted to design the portfolio and programs in such a way to address and satisfy all of these concerns.

AEG screened the measures identified. Measures that were cost-effective on a stand-alone basis were bundled into programs and re-screened for cost-effectiveness. Except for the low-income programs, the programs were designed to be cost-effective. Measures were bundled based on end-use, sector and implementation while considering stakeholder input and regulatory requirements.

6.2 LOAD IMPACT ESTIMATES

(B) For each demand-side candidate resource option or portfolio, the utility shall describe and document the time-differentiated load impact estimates over the planning horizon at the level of detail required by the supply system simulation model that is used in the integrated resource analysis, including a tabulation of the estimated annual change in energy usage and in diversified demand for each year in the planning horizon due to the implementation of the candidate demand-side resource option or portfolio. —

KCP&L engaged Navigant to conduct a DSM Resource Potential Study and AEG to design an additional DSM portfolio (Option C) for the KCP&L-MO service territory.

Navigant developed a comprehensive measure list through a review of potential studies, technical reference manuals, and demand-side management program evaluations as well as regional and national sources. Navigant employed a variety of analytical approaches to estimate annual energy savings and coincident peak demand savings for each measure including: engineering algorithms, building energy computer simulation models, and secondary resources. The measure characterization values are aligned with national codes and standards assumptions for 2013. To accurately assess future impacts and cost effectiveness from these measures, both the energy/demand and costs of certain measures must be adjusted to account for codes and standards changes. Navigant identified the following measures as affected by future codes and standards: The adjustments to the baseline and efficient annual energy and demand savings as well as costs can be found in Appendix 5A Navigant Demand Side Resource Potential Study Report.

AEG updated measure inputs and incorporated additional measures on an as-needed basis to reflect more recent program developments, evaluations, and new technology developments. Measure assumptions were updated to reflect the most recent national codes and standards.

Lighting measures will experience a federal code change in 2020. In 2007, the United States Congress passed the Energy Independence and Security Act (EISA) which set efficiency standards for 'general service' light bulbs, implemented in two phases. From 2012 to 2014, standard light bulbs manufactured were be required to use approximately 20 to 30 percent less energy than current incandescent light bulbs. By 2020, there must be a 60 percent reduction in light bulb energy use.[30] The effective dates of the EISA legislation pertain to newly manufactured bulbs, not existing stock.

[30] See Database of State Incentives for Renewables & Efficiency (DSIRE). *Federal Appliance Standards*. Available at: www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US04R&re=1&ee=1

Table 46. Residential Lighting Measures

Measure	Measure Life	Gross kWh Savings	Gross kW Savings	Incremental Cost
CFL pre-2020	5	28	0.003	$1.70
CFL 2020	5	6	0.001	$1.00
LED pre-2020	20	31	0.003	$15.00
LED 2020	20	9	0.001	$10.00

Table 47. C&I Lighting Measures

Measure	Measure Life	Gross kWh Savings	Gross kW Savings	Incremental Cost
CFL pre-2020	5	188	0.006	$3.30
CFL 2020	5	82	0.003	$1.00
LED pre-2020	20	200	0.006	$25.00
LED 2020	20	94	0.003	$39.00

6.3 UNCERTAINTY OF LOAD IMPACT ESTIMATES

(C) The utility shall describe and document its assessment of the potential uncertainty associated with the load impact estimates of the demand-side candidate resource options or portfolios. The utility shall estimate —

1. The impact of the uncertainty concerning the customer participation levels by estimating and comparing the maximum achievable potential and realistic achievable potential of each demand-side candidate resource option or portfolio; and —

The potential uncertainty associated with the load impact estimates of the demand-side candidate resource options was accounted for with the 5 scenarios developed by Navigant.

The achievable potential estimates consider market acceptance, technology turn-over and diffusion of technology awareness and product adoption. The only difference between the scenarios is the assumed measure incentive.

- *Maximum Achievable Potential (MAP)*: incentive levels are set at 100% of the incremental cost of the measure. The scenario maximizes savings achieved, but also results in a portfolio cost that far exceeds that typically encountered in efficiency programs for a given level of energy saved.

– *Realistic Achievable Potential (RAP)*: incentive levels are set based upon the efficiency supply curve by limiting the maximum $/kWh paid (calculated on a levelized cost basis) for any given measure.

Additionally, KCP&L engaged AEG to design an additional DSM portfolio (Option C) for the KCP&L-MO service territory. After a review of KCP&L's existing programs and the Navigant potential study and industry research as well as workshops with KCP&L program managers and staff, AEG updated measure inputs and incorporated additional measures on an as-needed basis to reflect more recent program developments, evaluations, and new technology developments. With the existing KCP&L DSM programs and the Navigant potential study as a starting point, the programs were modified to enhance their performance and incorporate the updated measure characteristics. AEG performed the industry standard cost-effectiveness tests in order to gauge the economic merits of the measures, programs and portfolio. The end-use measures most likely to achieve cost-effective savings were then selected and bundled into programs.

2. The impact of uncertainty concerning the cost effectiveness by identifying uncertain factors affecting which end-use resources are cost effective. The utility shall identify how the menu of cost-effective end-use measures changes with these uncertain factors and shall estimate how these changes affect the load impact estimates associated with the demand-side candidate resource options. —

In the Navigant potential study report, the reported energy and demand savings did not account for the roll-off of measures at the end of the measures' life nor did it factor in the opt-out of commercial and industrial customers. At KCP&L's request, Navigant provided additional spreadsheets that take measure roll-off into account. KCP&L then used the new energy and demand savings and factored in an estimated 10% opt-out of commercial and industrial customers. In addition, KCP&L adjusted the Navigant potential study RAP and MAP scenarios to match the time period needed for the IRP.

The potential study included the years 2014 through 2033. KCP&L already has existing programs through 2015. Thus, the effects of programs in 2014 and 2015 were removed and the savings were extended to 2034. The impacts of these adjustments are shown in Table 48, Table 49, and Table 50. These calculations and adjustments can be found in the KCP&L workpapers[31].

The tables below present the cumulative energy and demand savings for the combined energy efficiency and demand response programs for the adjusted Navigant MAP and RAP scenarios as well as Option C.[32]

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[31] MO IRP Output - Maximum, FINAL - Program Totals IRP HC.xlsx
MO IRP Output - Realistic, FINAL - Program Totals IRP HC.xlsx
KS IRP Output - Maximum, FINAL - Program Totals IRP HC.xlsx
KS IRP Output - Realistic, FINAL - Program Totals IRP HC.xlsx

[32] The Navigant potential study runs from 2014 through 2033. The AEG additional DSM portfolio runs from 2016 through 2034.

Table 48. Cumulative Energy Savings Potential (MWh) – KCP&L-MO[33]

Year	Option C	RAP	MAP
2016	68,782	113,259	147,686
2017	122,446	245,023	324,785
2018	176,168	386,550	518,940
2019	226,837	513,318	702,822
2020	269,941	642,534	889,820
2021	302,208	766,066	1,069,225
2022	333,479	878,946	1,234,937
2023	364,793	978,749	1,382,363
2024	392,059	1,058,780	1,504,823
2025	427,581	1,123,883	1,606,023
2026	454,893	1,177,265	1,692,079
2027	482,171	1,215,175	1,755,330
2028	509,000	1,244,211	1,806,816
2029	535,436	1,253,693	1,831,914
2030	560,088	1,251,401	1,839,705
2031	570,408	1,241,142	1,834,834
2032	581,833	1,222,401	1,816,888
2033	593,171	1,199,740	1,791,421
2034	604,314	1,177,764	1,766,638

[33] Note that the RAP and MAP estimates reflect the adjustments for measure roll-off, commercial and industrial opt-outs, and the shift in the time period to meet the IRP needs.

Table 49. Cumulative Peak Demand Potential (MW) – KCP&L-MO[34]

Year	Option C	RAP	MAP
2016	39	44	91
2017	51	89	184
2018	63	136	281
2019	71	181	376
2020	88	225	468
2021	103	265	555
2022	118	301	638
2023	133	331	714
2024	143	356	782
2025	155	366	819
2026	165	373	832
2027	169	377	845
2028	174	379	856
2029	179	380	864
2030	184	379	871
2031	185	378	876
2032	188	376	879
2033	190	374	882
2034	192	370	878

[34] Note that the RAP and MAP estimates reflect the adjustments for measure roll-off, commercial and industrial opt-outs, and the shift in the time period to meet the IRP needs.

Table 50. Cumulative Budget – KCP&L-MO **Highly Confidential[35]**

Year	Option C	RAP	MAP
2016	[redacted]		
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			

[35] Note that the RAP and MAP estimates reflect the adjustments for measure roll-off, commercial and industrial opt-outs, and the shift in the time period to meet the IRP needs.

HC

SECTION 7: DEVELOPMENT OF EVALUATION PLANS

(7) For each demand-side candidate resource option identified in section (6), the utility shall describe and document the general principles it will use to develop evaluation plans pursuant to 4 CSR 240-22.070(8). The utility shall verify that the evaluation costs in subsections (5)(B) and (5)(C) are appropriate and commensurate with these evaluation plans and principles. —

Program evaluation supports the need for public accountability, oversight, validation of program performance and cost-effective program improvements. The performance of DSM portfolios in regulated jurisdictions is almost universally evaluated by third-party independent contractors. KCP&L has designated approximately 5% of its portfolio budget for Evaluation, Measurement and Verification (EM&V) activities.

KCP&L will engage an EM&V contractor(s) to conduct process and impact evaluations of the DSM programs. The EM&V Contractor will meet with KCP&L program staff to discuss evaluation objectives, establish a schedule of deliverables and set up a communications protocol. The EM&V Contractor will develop a high level timeline of evaluation strategies and objectives.

Process Evaluations

Process evaluations ensure that a program is operating as intended and provides information that can enable improvements in both the program design and implementation. Process evaluations are typically conducted within six months to a year from a program’s implementation.

A good process evaluation will:

- Assist KPC&L staff and implementation contractors structure programs to achieve cost-effective savings while maintaining high levels of customer satisfaction.
- Determine awareness levels to refine marketing strategies and reduce barriers to participation.

- Provide recommendations for changing the program's structure, management, administration, design, delivery, operations or targets.
- Determine if specific best practices should be incorporated.

Process evaluations assess customer understanding, attitudes about, and satisfaction with the program and other educational activities. The EM&V contractor will assess the effectiveness of the marketing and outreach, trade ally involvement, and whether implementation milestones are met adequately and on schedule. These evaluations will use sales and promotion data maintained by the tracking system as well as customer survey data.

Evaluation Plans

The EM&V Contractor will develop evaluation plans for each program, identifying the program objectives, key researchable issues, data collection requirements, sampling plan, budget and timeline. The sampling plan will describe the sample design, interview methodology and stratification. The interview methodology will range depending on the market actor being interviewed, from on-site interviews, in-depth interviews or telephone interviews. The EM&V Contractor will identify key market actors, such as KCP&L staff, third-party implementation contractors, participation trade allies, and participation customers. The sample size of each group will be calculated at a 90% confidence interval with an error margin of +/- 10%. KCP&L will review and approve the evaluation plans and subsequent data collection instruments.

Document Review

The EM&V Contractor will collect program materials, including, but not limited to, process flowcharts, third-party implementation contractor agreements (redacted as necessary), trade ally agreements, rebate applications, and marketing and outreach materials.

The EM&V Contractor will also evaluate the program tracking system(s), including initial data validation (application processing, measure and savings capture and validation, audit trail, and system location), security, and data granularity (types of data being captured, QA/QC processes, data thresholds and back-up data capture, refresh rate and automated validations).

Market Actor Interviews

Interviews with key market actors will focus on understanding the program history and objectives as well as program implementation, including, but not limited to:

- Marketing and outreach activities
- Third-party implementation contractor responsibilities and management, if applicable
- Customer acquisition and participation process
- Trade Ally participation
- Rebate application processing
- Program tracking and reporting

Interview questions will be based on portfolio- and program-level activities and achievements to identify process improvements to improve program efficiency.

Customer Surveys

Participating customer surveys will seek to understand the customer experience with the program and awareness of the KPC&L portfolio. The surveys will identify barriers to participation, spillover, and areas of improvement.

Trade Ally Surveys/Interviews

Trade allies will be asked about clarity of program rules, support from KPC&L staff and/or third-party implementation contractor, marketing efforts, and rebate applications. The surveys/interviews will identify barriers to participation, free-ridership, spillover, and opportunities to improve program processes.

Non-Participating Customer and Trade Ally Interviews/Surveys

Where appropriate, interviews with non-participating customers and trade allies will be conducted to better understand the free ridership, spillover, barriers to participation and marketing messages.

Impact Evaluations

Impact evaluations estimate gross and net demand, energy savings and the cost-effectiveness of installed systems. They are used to verify measure installations, identify key energy assumptions and provide the research necessary to calculate defensible and accurate savings attributable to the program. Impact evaluations are typically conducted one year after the program is implemented because program results may not be accessible or apparent before then.

The EM&V Contractor will develop evaluation plans that ensure the appropriate measurement of savings in compliance with the appropriate International Performance Measurement and Verification Protocol as well as the State of Missouri EM&V protocols. The evaluation will verify measure installations and identify key assumptions for equipment life, incremental equipment cost, free ridership and spillover. The evaluation will also provide the necessary research to calculate defensible and accurate savings attributable to the program.

The EM&V Contractor will evaluate program cost-effectiveness using the standard tests including Total Resource Cost, Societal Cost Test, Participant Test, Utility Test and Rate Impact Measure Test.

SECTION 8: DEMAND-SIDE RESOURCES AND LOAD-BUILDING PROGRAMS

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

KCP&L did not include load-building programs.

VOLUME 6

INTEGRATED RESOURCE ANALYSIS

KANSAS CITY POWER & LIGHT COMPANY (KCP&L)

INTEGRATED RESOURCE PLAN

4 CSR 240-22.060

APRIL, 2015

energizing life

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VOLUME 6: INTEGRATED RESOURCE ANALYSIS

PURPOSE: This rule requires the utility to design alternative resource plans to meet the planning objectives identified in 4 CSR 240-22.010(2) and sets minimum standards for the scope and level of detail required in resource plan analysis, and economically equivalent analysis of alternative resource plans. This rule also requires the utility to identify the critical uncertain factors that affect the performance of alternative resource plans and establishes minimum standards for the methods used to assess the risks associated with these uncertainties.

SECTION 1: RESOURCE PLANNING OBJECTIVES

(1) Resource Planning Objectives. The utility shall design alternative resource plans to satisfy at least the objectives and priorities identified in 4 CSR 240-22.010(2). The utility may identify additional planning objectives that alternative resource plans will be designed to meet. The utility shall describe and document its additional planning objectives and its guiding principles to design alternative resource plans that satisfy all of the planning objectives and priorities.

The fundamental objective of all the alternative resource plans is to provide the public with energy services that are safe reliable and efficient. The plans comply with current legal mandates in a manner that serves the public interest and is consistent with state energy and environmental policies.

All of the Alternative Resource Plans developed are based upon the impact of future renewable generation requirements for KCP&L. In Missouri, these requirements are based on Rule 4 CSR 240-20.100 which requires that an electric utility's compliance with the Renewable Energy Standard (RES) is based on total retail electric sales, or total retail electric energy usage, delivered in each year to its Missouri retail customers. For the state of Kansas, pursuant to Kansas statues and standards, an affected utility is required to provide net renewable generation capacity based on its Kansas retail one-hour peak demand for each of the previous three calendar years and the average for these years. The specific renewable portfolio and RES requirements are provided in Section 3.1 below.

Other items that drove plan selection for this filing are the impact of demand side management (DSM) programs, potential coal unit retirements, choice of alternative generation, natural gas conversion, imposition of environmental rules, and the Southwest Power Pool's capacity margin requirements. Other factors were also analyzed, but were determined not critical to the selection of alternative resource plans. Details of these additional factors and how they were examined are given in Section 5: of this document.

As required by Rule 22.010(2), demand-side resources were analyzed on an equivalent basis with supply-side resources.

Net present value of revenue requirements (NPVRR) of each plan including probable environmental costs (PEC) was calculated. Minimization of NPVRR with PEC was used as the primary criteria for determination of the ordinal preference of a particular plan. Risks associated with critical uncertain factors, those associated with new or more stringent legal mandates are included in the integrated analysis of the resource planning process. Rate increases associated with the alternative resource plans are determined in the analysis as well. All performance measures are detailed in Section 2: of this document.

SECTION 2: PERFORMANCE MEASURES

(2) Specification of Performance Measures. The utility shall specify, describe, and document a set of quantitative measures for assessing the performance of alternative resource plans with respect to resource planning objectives.

(A) These performance measures shall include at least the following:

1. Present worth of utility revenue requirements, with and without any rate of return or financial performance incentives for demand-side resources the utility is planning to request;

Annual Revenue Requirement is calculated by totaling all expenses of the company in a year plus the return on rate base. The rate base increases as capital expenditures grow and plant is placed into service, but is reduced by depreciation and amortization of assets. This measure includes the total cost of operation of the company and any costs associated with probable environmental compliance.

The NPVRR is calculated by applying the discount rate consistent with rule 4 CSR 240-22.060 (2) (B) to the future estimated Annual Revenue Requirement to estimate the total future requirement on a present value basis. This value is the primary measure of plan financial performance.

DSM expenditures have been expensed in the year that they are incurred, so there is no increase to rate base for these outlays. The impact of DSM assumed financial performance incentives has been shown in the performance measures.

2. Present worth of probable environmental costs;

The Present Worth of Probable Environmental Costs are determined by removing all capital and O&M costs from future environmental retrofits to estimate the cost of utility operations absent environmental expenditures. These results are compared to the NPVRR of the plans with environmental costs to determine the cost of these laws on total company operation and financial performance.

CO_2 credits are assumed to be a market risk. In the integrated analysis, endpoints contain different assumptions of CO_2 credit prices or no CO_2 market at all. Therefore the analysis of plans without PEC is calculated both with and without a CO_2 market.

3. Present worth of out-of-pocket costs to participants in demand-side programs and demand-side rates;

The cost of DSM programs is an input to the integrated analysis. As such it is an exogenous driver of each plan and does not exhibit variability within the analysis of an individual plan. The present value of these programs is calculated using the estimated future costs of the programs and applying the discount rate consistent with rule 4 CSR 240-22.060 (2) (B).

4. Levelized annual average rates;

Annual average rates are calculated by dividing the total estimated annual revenue requirement, calculated as described earlier in this section, by the forecasted total retail energy sales volume. The levelized value is the simple average of the 20-year estimate of annual rates.

5. Maximum single-year increase in annual average rates;

Single year increases (and decreases) in rates are developed as year-over-year percent change to the rate calculation as described earlier in this section. The Maximum value is determined from the highest year-over-year percent change.

6. Financial ratios (e.g., pretax interest coverage, ratio of total debt to total capital, ratio of net cash flow to capital expenditures) or other credit metrics indicative of the utility's ability to finance alternative resource plans; and

The company uses three financial metrics; pretax times interest earned, total debt to total capital and internal cash to construction expense.

7. Other measures that utility decision makers believe are appropriate for assessing the performance of alternative resource plans relative to the planning objectives identified in 4 CSR 240-22.010(2).

The Company finds that the required financial measures provide an appropriate indication of financial performance. No additional measures are proposed

(B) All present worth and levelization calculations shall use the utility discount rate and all costs and benefits shall be expressed in nominal dollars.

For all purposes in this analysis, a discount rate of 8.090% has been utilized.

SECTION 3: ALTERNATIVE RESOURCE PLANS

(3) Development of Alternative Resource Plans. The utility shall use appropriate combinations of candidate demand-side resources and supply-side resources to develop a set of alternative resource plans, each of which is designed to achieve one (1) or more of the planning objectives identified in 4 CSR 240-22.010(2). Demand-side resources are the demand-side candidate resource options and portfolios developed in 4 CSR 240-22.050(6). Supply-side resources are the supply-side candidate resource options developed in 4 CSR 240-22.040(4). The goal is to develop a set of alternative plans based on substantively different mixes of supply-side resources and demand-side resources and variations in the timing of resource acquisition to assess their relative performance under expected future conditions as well as their robustness under a broad range of future conditions.

Alternative Resource Plans were developed using a combination of various capacities of supply-side resources, demand-side resources, and various resource addition timing.

3.1 DEVELOPMENT OF ALTERNATIVE RESOURCE PLANS

(A) The utility shall develop, and describe and document, at least one (1) alternative resource plan, and as many as may be needed to assess the range of options for the choices and timing of resources, for each of the following cases. Each of the alternative resource plans for cases pursuant to paragraphs (3)(A)1.–(3)(A)5. shall provide resources to meet at least the projected load growth and resource retirements over the planning period in a manner specified by the case. The utility shall examine cases that—

1. Minimally comply with legal mandates for demand-side resources, renewable energy resources, and other mandated energy resources. This constitutes the compliance benchmark resource plan for planning purposes;

All Alternative Resource Plans comply with the respective State renewable energy mandates (Missouri Renewable Energy Standard and Kansas Renewable Energy Standard) and demand-side mandates excluding the Persistence DSM found in alternative resource plan KAADA. KCP&L is compliant with Missouri RES requirements; the wind additions included in this filing are driven by Kansas RES requirements.

A recap of the Renewable Energy Standard (RES) model supporting renewable non-solar additions is provided in Table 1 below:

Table 1: KCP&L Non-Solar Renewable Requirements

Year	3-Year Average Retail Peak	KS RES Requirement	KCP&L KS Requirement	KS Share of Installed Capacity	Future Renewable Additions
	MW		MW	MW	MW
2015	1,617	10%	162	239	
2016	1,589	15%	238	402	350
2017	1,604	15%	241	529	300
2018	1,603	15%	240	529	
2019	1,598	15%	240	529	
2020	1,595	20%	319	529	
2021	1,591	20%	318	529	
2022	1,590	20%	318	529	
2023	1,592	20%	318	529	
2024	1,598	20%	320	467	
2025	1,606	20%	321	467	
2026	1,616	20%	323	467	
2027	1,627	20%	325	467	
2028	1,640	20%	328	467	
2029	1,655	20%	331	467	
2030	1,671	20%	334	467	
2031	1,687	20%	337	467	
2032	1,705	20%	341	406	
2033	1,723	20%	345	359	
2034	1,741	20%	348	359	

2. Utilize only renewable energy resources, up to the maximum potential capability of renewable resources in each year of the planning horizon, if that results in more renewable energy resources than the minimally compliant plan. This constitutes the aggressive renewable energy resource plan for planning purposes;

Alternative Resource Plan KAACW was developed to meet this rule.

3. Utilize only demand-side resources, up to the maximum achievable potential of demand-side resources in each year of the planning horizon, if that results in more demand-side resources than the minimally compliant plan. This constitutes the aggressive demand-side resource plan for planning purposes;

Any Alternative Resource Plan that has a letter "A" as the fourth character is utilized Maximum Achievable Potential DSM.

4. In the event that legal mandates identify energy resources other than renewable energy or demand-side resources, utilize only the other energy resources, up to the maximum potential capability of the other energy resources in each year of the planning horizon, if that results in more of the other energy resources than the compliance benchmark resource plan. For planning purposes, this constitutes the aggressive legally-mandated other energy resource plan;

No other legal mandates have been identified.

5. Optimally comply with legal mandates for demand-side resources, renewable energy resources, and other targeted energy resources. This constitutes the optimal compliance resource plan, where every legal mandate is at least minimally met, but some resources may be optimally utilized at levels greater than the mandated minimums;

All Alternative Resource Plans comply with the renewable energy mandates (Missouri RES) and demand-side mandates excluding the Persistence DSM Alternative Resource Plan KAADA.

6. Any other plan specified by the commission as a special contemporary issue pursuant to 4 CSR 240-22.080(4);

No Alternative Resource Plans were required to evaluate any special contemporary issues.

7. Any other plan specified by commission order; and

There are no other plans specified by commission order.

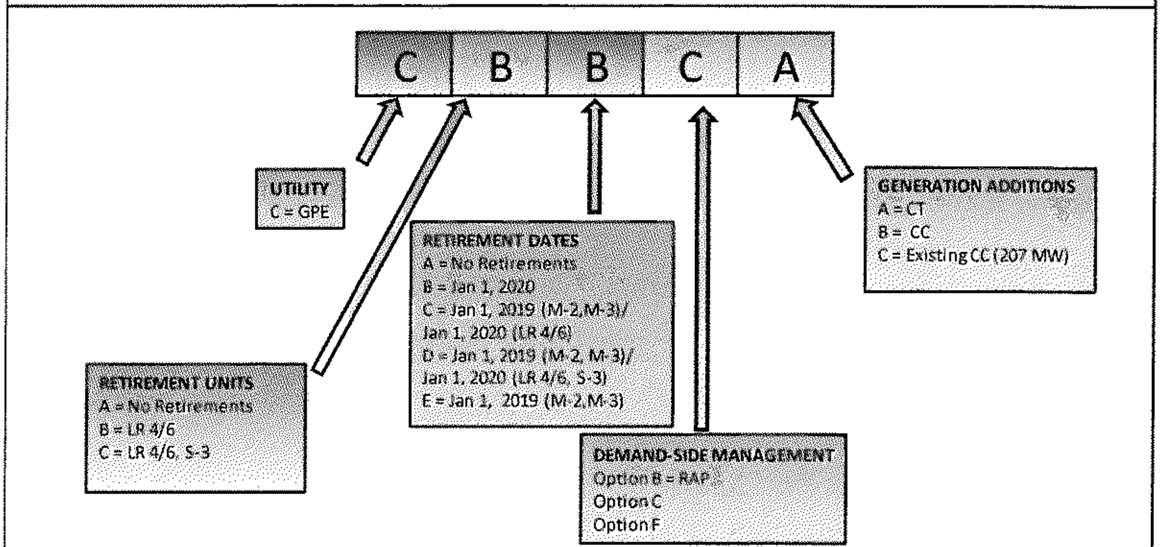
8. Any additional alternative resource plans that the utility deems should be analyzed.

KCP&L also considers it prudent resource planning to develop and analyze alternative resource plans that are based upon KCP&L and GMO combining resources. Evaluating alternative resource plans on a joint planning basis can provide a platform to determine if joint planning "serves the public interest" as mandated in 4 CSR 240-22.010 Policy Objectives.

Alternative resource plans were developed using a combination of various capacities of supply-side resources, demand-side resources and various resource addition timing. The plan-naming convention utilized for the joint planning Alternative Resource Plans developed is shown in Table 2 below:

Table 2: Joint Planning Alternative Resource Plan Naming Convention

NAMING CONVENTION FOR ALTERNATIVE RESOURCE PLANS
FOR THE 2015 GPE TRIENNIAL IRP



Definitions:		S-3 - Sibley -3
RAP - Realistic Achievable Potential	M-2 - Montrose-2	CT - Combustion Turbine
MAP - Maximum Achievable Potential	M-3 - Montrose-3	CC - Combined Cycle

Various joint company Alternative Resource Plans were derived and an overview of each is provided in the tables below. It should be noted that each joint planning Alternative Resource Plan assumes cease burning coal at Montrose Units 1, 2, and 3, and Sibley Units 1 and 2.

Table 3: Overview of Joint Planning Alternative Resource Plans

Plan Name	DSM Level	Facility	Year to Cease Burning Coal	Renewable Additions		Generation Addition (if needed)
CAEFA	Option F	Sibley-1 Sibley-2 Lake Road 4/6 Montrose-1 Montrose-2 Montrose-3	2019 2019 Convert to Gas 2016 2019 2019	Solar: 2016 - 8 MW 2026 - 12 MW	Wind: 2016 - 350 MW 2017 - 560 MW 2019 - 50 MW	207 MW CT in 2031
CBBFA	Option F	Sibley-1 Sibley-2 Lake Road 4/6 Montrose-1 Montrose-2 Montrose-3	2019 2019 2020 2016 2021 2021	Solar: 2016 - 8 MW 2026 - 12 MW	Wind: 2016 - 350 MW 2017 - 560 MW 2019 - 50 MW	207 MW CT in 2029 207 MW CT in 2033
CBCFA	Option F	Sibley-1 Sibley-2 Lake Road 4/6 Montrose-1 Montrose-2 Montrose-3	2019 2019 2020 2016 2019 2019	Solar: 2016 - 8 MW 2026 - 12 MW	Wind: 2016 - 350 MW 2017 - 560 MW 2019 - 50 MW	207 MW CT in 2020 207 MW CT in 2033
CBCFC	Option F	Sibley-1 Sibley-2 Lake Road 4/6 Montrose-1 Montrose-2 Montrose-3	2019 2019 2020 2016 2019 2019	Solar: 2016 - 8 MW 2026 - 12 MW	Wind: 2016 - 350 MW 2017 - 560 MW 2019 - 50 MW	207 MW Existing CC in 2016 207 MW CT in 2033
CCDFC	Option F	Sibley-1 Sibley-2 Sibley-3 Lake Road 4/6 Montrose-1 Montrose-2 Montrose-3	2019 2019 2020 2020 2016 2019 2019	Solar: 2016 - 8 MW 2026 - 12 MW	Wind: 2016 - 350 MW 2017 - 560 MW 2019 - 50 MW	207 MW Existing CC in 2016 414 MW CT in 2020 207 MW CT in 2034

Table 4: Overview of Joint Alternative Resource Plans (continued)

Plan Name	DSM Level	Facility	Year to Cease Burning Coal	Renewable Additions		Generation Addition (if needed)
CBCCA	Option C	Sibley-1 Sibley-2 Lake Road 4/6 Montrose-1 Montrose-2 Montrose-3	2019 2019 2020 2016 2019 2019	Solar: 2016 - 8 MW 2026 - 12 MW	Wind: 2016 - 350 MW 2017 - 560 MW 2019 - 50 MW	207 MW CT in 2019 207 MW CT in 2026 207 MW CT in 2030 207 MW CT in 2034
CBCCC	Option C	Sibley-1 Sibley-2 Lake Road 4/6 Montrose-1 Montrose-2 Montrose-3	2019 2019 2020 2016 2019 2019	Solar: 2016 - 8 MW 2026 - 12 MW	Wind: 2016 - 350 MW 2017 - 560 MW 2019 - 50 MW	207 MW Existing CC in 2016 207 MW CT in 2026 207 MW CT in 2030 207 MW CT in 2034
CCDCC	Option C	Sibley-1 Sibley-2 Sibley-3 Lake Road 4/6 Montrose-1 Montrose-2 Montrose-3	2019 2019 2020 2020 2016 2019 2019	Solar: 2016 - 8 MW 2026 - 12 MW	Wind: 2016 - 350 MW 2017 - 560 MW 2019 - 50 MW	207 MW Existing CC in 2016 414 MW CT in 2020 207 MW CT in 2027 207 MW CT in 2031

All plans assuming joint planning were each subjected to similar analysis as the integrated analysis for each of the stand-alone company plans. The resulting expected value NPVRR for each of the joint planning Alternative Resource Plans is detailed in the table below.

Table 5: Joint Planning Alternative Resource Plan Results

Total Revenue Requirement			
Rank	Plan	NPVRR ($mm)	Delta
1	CBBFA	29,106.38	0.00
2	CAEFA	29,153.90	47.53
3	CCDFC	29,181.08	74.70
4	CBCFA	29,195.77	89.39
5	CBCFC	29,216.81	110.43
6	CCDCC	29,229.79	123.42
7	CBCCA	29,274.40	168.02
8	CBCCC	29,281.86	175.49

(B) The alternative resource plans developed at this stage of the analysis shall not include load-building programs, which shall be analyzed as required by 4 CSR 240-22.070(5).

No load-building programs have been included as a resource in any alternative resource plan.

(C) The utility shall include in its development of alternative resource plans the impact of—

1. The potential retirement or life extension of existing generation plants;

KCP&L modeled ceasing burning coal at Montrose Unit 1 by 2017, and Montrose Units 2 and 3 by 2022 or by 2020. An Alternative Resource Plan which included retiring LaCygne Unit 2 was also evaluated.

2. The addition of equipment and other retrofits on generation plants to meet environmental requirements; and

Retrofits and other actions potentially expected to comply with currently proposed environmental regulations and assumed compliance dates are modeled for KCP&L's remaining coal units. The following table provides current assumptions regarding these expected environmental regulations and the retrofits and actions being presumed to meet compliance.

Table 6: Retrofits and Actions due to Environmental Regulations

Environmental Driver	Emittant	Compliance Year (Expected)	Status	Retrofit
Mercury and Air Toxics Standards (MATS)	Mercury, PM, HCl	April, 2016	Judicial review ongoing.	ACI, ESP Improvements, Low Chlorine Coal
Ozone National Ambient Air Quality Standards (O_3 NAAQS)	NO_x	(2021)	Under revision by EPA, final rule October 2015	SNCR
PM National Ambient Air Quality Standards (PM NAAQS)	PM, SO_2, NO_x	(2023)	Final rule issued - KC area in attainment	SCR (on all units)
SO_2 National Ambient Air Quality Standards (SO_2 NAAQS)	SO_2	(2020-2023)	Final Rule issued - KC area attainment/nonattainment currently undetermined	Scrubber/BH (on all units)
Clean Water Act 316(b) (Fish Impingment)	-	(2016-2020)	Final rule issued, judicial review ongoing	Fish Friendly Screens
Clean Water Act 316(b) (Fish Entrainment)	-	(2020)	Final rule issued, judicial review ongoing	Cooling Towers
Clean Water Act 316(a) (Thermal Discharge)	-	(2019-2024)	KCP&L in discussion with MDNR/EPA	Cooling Towers (river units earlier, lake units later)
Effluent Guidelines	Wastewater Constituents	(2018-2023)	Final Rule September 2015	Cease Wet Sluicing
Coal Combustion Residual (CCR)	Ash/Water	(2018-2019)	Final Rule December 2014	Cease Wet Sluicing/Increased Dust Controls

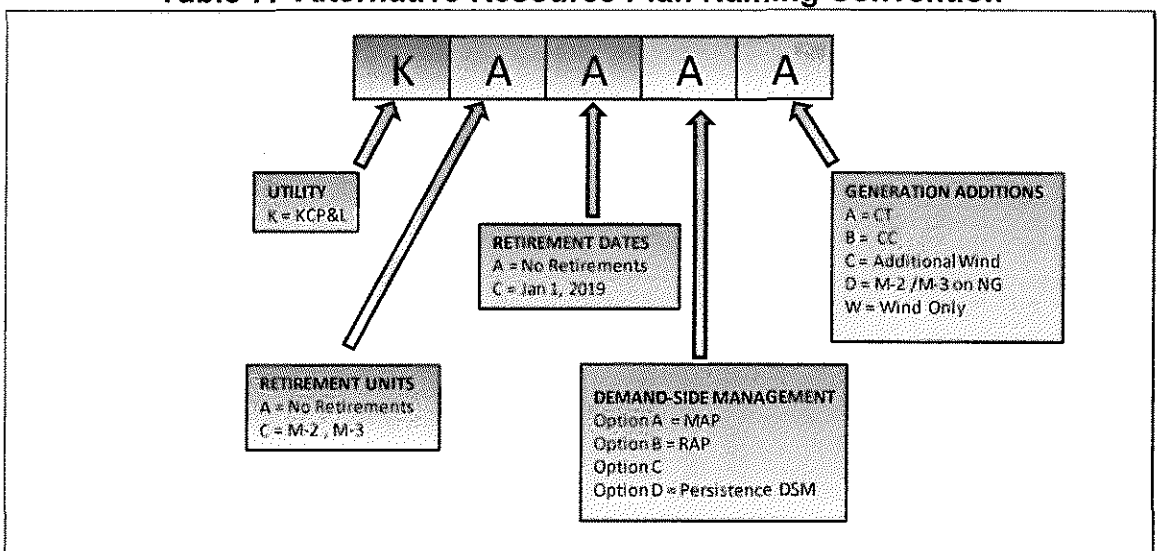
3. The conclusion of any currently implemented demand-side resources.

Alternative Resource Plan KAADA was developed to evaluate this rule.

(D) The utility shall provide a description of each alternative resource plan including the type and size of each demand-side resource and supply-side resource addition and a listing of the sequence and schedule for the end of life of existing resources and for the acquisition of each new resource.

Alternative Resource Plans were developed using a combination of various capacities of supply-side resources, demand-side resources, retrofit and resource addition quantities and timing differences. The plan-naming convention utilized for KCP&L's Alternative Resource Plans developed is shown in Table 7 below:

Table 7: Alternative Resource Plan Naming Convention



Definitions:		
RAP - Realistic Achievable Potential	M-2 - Montrose-2	CT - Combustion Turbine
MAP - Maximum Achievable Potential	M-3 - Montrose-3	CC - Combined Cycle

In total, fifteen Alternative Resource Plans were developed for the integrated resource analysis. The following tables provide an overview of the Alternative Resource Plans. Note that wind and solar additions shown are based on nameplate capacity. Each individual plan is shown in Table 12 through Table 26 below.

Table 8: Overview of Alternative Resource Plans

<table>
<tr><th>Plan Name</th><th>DSM Level</th><th>Facility</th><th>Year to Cease Burning Coal</th><th colspan="2">Renewable Additions</th><th>Generation Addition (if needed)</th></tr>
<tr><td>KAAAA</td><td>Option A - MAP</td><td>Montrose-1
Montrose-2
Montrose-3</td><td>2016
2021
2021</td><td>Solar:
2016 - 3 MW
2026 - 7 MW</td><td>Wind:
2016 - 350 MW
2017 - 300 MW</td><td>n/n</td></tr>
<tr><td>KAAAC</td><td>Option A - MAP</td><td>Montrose-1
Montrose-2
Montrose-3</td><td>2016
2021
2021</td><td>Solar:
2016 - 3 MW
2026 - 7 MW</td><td>Wind:
2016 - 350 MW
2017 - 400 MW</td><td>n/n</td></tr>
<tr><td rowspan="2">KAAAD</td><td rowspan="2">Option A - MAP</td><td>Montrose 1</td><td>2016</td><td rowspan="2">Solar:
2016 - 3 MW
2026 - 7 MW</td><td rowspan="2">Wind:
2016 - 350 MW
2017 - 300 MW</td><td rowspan="2">n/n</td></tr>
<tr><td>Convert to NG:
Montrose-2
Montrose-3</td><td>2019</td></tr>
</table>

Table 9: Overview of Alternative Resource Plans (continued)

Plan Name	DSM Level	Facility	Year to Cease Burning Coal	Renewable Additions		Generation Addition (if needed)
KAABA	Option B - RAP	Montrose-1 Montrose-2 Montrose-3	2016 2021 2021	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 300 MW	n/n
KAABC	Option B - RAP	Montrose-1 Montrose-2 Montrose-3	2016 2021 2021	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 400 MW	n/n
KAABD	Option B - RAP	Montrose 1 Convert to NG: Montrose-2 Montrose-3	2016 2019	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 300 MW	n/n
KCCBA	Option B - RAP	Montrose-1 Montrose-2 Montrose-3	2016 2019 2019	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 300 MW	n/n

Table 10: Overview of Alternative Resource Plans (continued)

Plan Name	DSM Level	Facility	Year to Cease Burning Coal	Renewable Additions		Generation Addition (if needed)
KAACA	Option C	Montrose-1 Montrose-2 Montrose-3	2016 2021 2021	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 300 MW	207 MW CT in 2029
KAACB	Option C	Montrose-1 Montrose-2 Montrose-3	2016 2021 2021	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 300 MW	200 MW CC in 2029
KAACC	Option C	Montrose-1 Montrose-2 Montrose-3	2016 2021 2021	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 400 MW	207 MW CT in 2030
KAACD	Option C	Montrose 1 Convert to NG: Montrose-2 Montrose-3	2016 2019	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 300 MW	n/n
KAACW	Option C	Montrose-1 Montrose-2 Montrose-3	2016 2021 2021	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 300 MW	670 MW Wind in 2029

Table 11: Overview of Alternative Resource Plans (continued)

Plan Name	DSM Level	Facility	Year to Cease Burning Coal	Renewable Additions		Generation Addition (if needed)
KBBCA	Option C	Montrose-1 LaCygne-2 Montrose-2 Montrose-3	2016 2019 2021 2021	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 300 MW	414 MW CT in 2021 207 MW CT in 2032
KCCCA	Option C	Montrose-1 Montrose-2 Montrose-3	2016 2019 2019	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 300 MW	207 MW CT in 2029
KAADA	Option D - Persistence	Montrose-1 Montrose-2 Montrose-3	2016 2021 2021	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 300 MW	207 MW CT in 2021 207 MW CT in 2025 207 MW CT in 2031

These individual plans are shown in the following tables:

Table 12: Alternative Resource Plan KAAAA

Year	CT's (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)	Existing Capacity (MW)
2015	0			29		4572
2016	0	350	3	166		4387
2017	0	300		337		4432
2018	0			513		4432
2019	0			686		4442
2020	0			851		4442
2021	0			1005		4102
2022	0			1149		4102
2023	0			1281		4117
2024	0			1401		4056
2025	0			1475		4056
2026	0		7	1497		4056
2027	0			1518		4056
2028	0			1538		4056
2029	0			1552		4056
2030	0			1564		4056
2031	0			1574		4056
2032	0			1582		4056
2033	0			1589		4056
2034	0			1583		4056

Plan KAAAA assumes M-1, and M-2 and M-3 cease burning coal in 2016 and 2021, respectively. DSM: A Resource additions (if needed): CT's

Table 13: Alternative Resource Plan KAAAC

Year	CT's (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)	Existing Capacity (MW)
2015	0			29		4572
2016	0	350	3	166		4387
2017	0	400		337		4432
2018	0			513		4432
2019	0			686		4442
2020	0			851		4442
2021	0			1005		4102
2022	0			1149		4102
2023	0			1281		4117
2024	0			1401		4056
2025	0			1475		4056
2026	0		7	1497		4056
2027	0			1518		4056
2028	0			1538		4056
2029	0			1552		4056
2030	0			1564		4056
2031	0			1574		4056
2032	0			1582		4056
2033	0			1589		4056
2034	0			1583		4056

Plan KAAAC assumes M-1, and M-2 and M-3 cease burning coal in 2016 and 2021, respectively. DSM: A Additional wind, and resource additions (if needed): CT's

Table 14: Alternative Resource Plan KAAAD

Year	Balance	CT's (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)	Existing Capacity (MW)
2015	235	0			29		4572
2016	189	0	350	3	166		4387
2017	410	0	300		337		4432
2018	597	0			513		4432
2019	786	0			686		4442
2020	954	0			851		4442
2021	1106	0			1005		4442
2022	1244	0			1149		4442
2023	1385	0			1281		4457
2024	1431	0			1401		4396
2025	1483	0			1475		4396
2026	1476	0		7	1497		4396
2027	1464	0			1518		4396
2028	1449	0			1538		4396
2029	1429	0			1552		4396
2030	1403	0			1564		4396
2031	1376	0			1574		4396
2032	1347	0			1582		4396
2033	1316	0			1589		4396
2034	1268	0			1583		4396

Plan KAAAD assumes M-1 ceases burning coal in 2016 and M-2 and M-3 are converted to NG in 2021. DSM: A Resource additions (if needed): CT's

Table 15: Alternative Resource Plan KAABA

Year	CT's (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)	Existing Capacity (MW)
2015	0			29		4572
2016	0	350	3	79		4387
2017	0	300		160		4432
2018	0			245		4432
2019	0			325		4442
2020	0			400		4442
2021	0			466		4102
2022	0			524		4102
2023	0			574		4117
2024	0			611		4056
2025	0			628		4056
2026	0		7	639		4056
2027	0			645		4056
2028	0			649		4056
2029	0			648		4056
2030	0			647		4056
2031	0			645		4056
2032	0			643		4056
2033	0			641		4056
2034	0			633		4056

Plan KAABA assumes M-1, and M-2 and M-3 cease burning coal in 2016 and 2021, respectively. DSM: B Resource additions (if needed): CT's

Table 16: Alternative Resource Plan KAABC

Year	CT's (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)	Existing Capacity (MW)
2015	0			29		4572
2016	0	350	3	79		4387
2017	0	400		160		4432
2018	0			245		4432
2019	0			325		4442
2020	0			400		4442
2021	0			466		4102
2022	0			524		4102
2023	0			574		4117
2024	0			611		4056
2025	0			628		4056
2026	0		7	639		4056
2027	0			645		4056
2028	0			649		4056
2029	0			648		4056
2030	0			647		4056
2031	0			645		4056
2032	0			643		4056
2033	0			641		4056
2034	0			633		4056

Plan KAABC assumes M-1, and M-2 and M-3 cease burning coal in 2016 and 2021, respectively. DSM: B Additional wind, and resource additions (if needed): CT's

Table 17: Alternative Resource Plan KAABD

Year	CT's (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)	Existing Capacity (MW)
2015	0			29		4572
2016	0	350	3	79		4387
2017	0	300		160		4432
2018	0			245		4432
2019	0			325		4442
2020	0			400		4442
2021	0			466		4442
2022	0			524		4442
2023	0			574		4457
2024	0			611		4396
2025	0			628		4396
2026	0		7	639		4396
2027	0			645		4396
2028	0			649		4396
2029	0			648		4396
2030	0			647		4396
2031	0			645		4396
2032	0			643		4396
2033	0			641		4396
2034	0			633		4396

Plan KAABD assumes M-1 ceases burning coal in 2016 and M-2 and M-3 are converted to NG in 2021. DSM: B Resource additions (if needed): CT's

Table 18: Alternative Resource Plan KCCBA

Year	CT's (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)	Existing Capacity (MW)
2015	0			29		4572
2016	0	350	3	79		4387
2017	0	300		160		4432
2018	0			245		4432
2019	0			325		4102
2020	0			400		4102
2021	0			466		4102
2022	0			524		4102
2023	0			574		4117
2024	0			611		4056
2025	0			628		4056
2026	0		7	639		4056
2027	0			645		4056
2028	0			649		4056
2029	0			648		4056
2030	0			647		4056
2031	0			645		4056
2032	0			643		4056
2033	0			641		4056
2034	0			633		4056

Plan KCCBA assumes M-1, and M-2 and M-3 cease burning coal in 2016 and 2019, respectively. DSM: B. Resource additions (if needed): CT's.

Table 19: Alternative Resource Plan KAACA

Year	CT's (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)	Existing Capacity (MW)
2015	0			29		4572
2016	0	350	3	71		4387
2017	0	300		103		4432
2018	0			124		4432
2019	0			139		4442
2020	0			176		4442
2021	0			206		4102
2022	0			228		4102
2023	0			248		4117
2024	0			266		4056
2025	0			284		4056
2026	0		7	299		4056
2027	0			308		4056
2028	0			316		4056
2029	207			325		4056
2030	0			333		4056
2031	0			337		4056
2032	0			341		4056
2033	0			345		4056
2034	0			349		4056

Plan KAACA assumes M-1, and M-2 and M-3 cease burning coal in 2016 and 2021, respectively. DSM: C Resource additions (if needed): CT's

Table 20: Alternative Resource Plan KAACB

Year	CC's (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)	Existing Capacity (MW)
2015	0			29		4572
2016	0	350	3	71		4387
2017	0	300		103		4432
2018	0			124		4432
2019	0			139		4442
2020	0			176		4442
2021	0			206		4102
2022	0			228		4102
2023	0			248		4117
2024	0			266		4056
2025	0			284		4056
2026	0		7	299		4056
2027	0			308		4056
2028	0			316		4056
2029	200			325		4056
2030	0			333		4056
2031	0			337		4056
2032	0			341		4056
2033	0			345		4056
2034	0			349		4056

Plan KAACB assumes M-1, and M-2 and M-3 cease burning coal in 2016 and 2021, respectively. DSM: C Resource additions (if needed): CC's

Table 21: Alternative Resource Plan KAACC

Year	CT's (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)	Existing Capacity (MW)
2015	0			29		4572
2016	0	350	3	71		4387
2017	0	400		103		4432
2018	0			124		4432
2019	0			139		4442
2020	0			176		4442
2021	0			206		4102
2022	0			228		4102
2023	0			248		4117
2024	0			266		4056
2025	0			284		4056
2026	0		7	299		4056
2027	0			308		4056
2028	0			316		4056
2029	0			325		4056
2030	207			333		4056
2031	0			337		4056
2032	0			341		4056
2033	0			345		4056
2034	0			349		4056

Plan KAACC assumes M-1, and M-2 and M-3 cease burning coal in 2016 and 2021, respectively. DSM: C Additional wind, and resource additions (if needed): CT's

Table 22: Alternative Resource Plan KAACD

Year	CT's (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)	Existing Capacity (MW)
2015	0			29		4572
2016	0	350	3	71		4387
2017	0	300		103		4432
2018	0			124		4432
2019	0			139		4442
2020	0			176		4442
2021	0			206		4442
2022	0			228		4442
2023	0			248		4457
2024	0			266		4396
2025	0			284		4396
2026	0		7	299		4396
2027	0			308		4396
2028	0			316		4396
2029	0			325		4396
2030	0			333		4396
2031	0			337		4396
2032	0			341		4396
2033	0			345		4396
2034	0			349		4396

Plan KAACD assumes M-1 ceases burning coal in 2016 and M-2 and M-3 are converted to NG in 2021. DSM: C. Resource additions (if needed): CT's.

Table 23: Alternative Resource Plan KAACW

Year	CT's (MW)	Wind Only (MW)	Solar (MW)	DSM (MW)	Retire (MW)	Existing Capacity (MW)
2015	0			29		4572
2016	0	350	3	71		4387
2017	0	300		103		4432
2018	0			124		4432
2019	0			139		4442
2020	0			176		4442
2021	0			206		4102
2022	0			228		4102
2023	0			248		4117
2024	0			266		4056
2025	0			284		4056
2026	0		7	299		4056
2027	0			308		4056
2028	0			316		4056
2029	0	670		325		4056
2030	0			333		4056
2031	0			337		4056
2032	0			341		4056
2033	0			345		4056
2034	0			349		4056

Plan KAACW assumes M-1, and M-2 and M-3 cease burning coal in 2016 and 2021, respectively. DSM: C. Resource additions (if needed): Wind Only

Table 24: Alternative Resource Plan KBBCA

Year	CT's (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)	Existing Capacity (MW)
2015	0			29		4572
2016	0	350	3	71		4387
2017	0	300		103		4432
2018	0			124		4432
2019	0			139	329	4113
2020	0			176		4113
2021	414			206		3773
2022	0			228		3773
2023	0			248		3788
2024	0			266		3727
2025	0			284		3727
2026	0		7	299		3727
2027	0			308		3727
2028	0			316		3727
2029	0			325		3727
2030	0			333		3727
2031	0			337		3727
2032	207			341		3727
2033	0			345		3727
2034	0			349		3727

Plan KBBCA assumes M-1, LC-2, and M-2 and M-3 cease burning coal in 2016, 2019, and 2021, respectively. DSM: C Resource additions (if needed): CT's.

Table 25: Alternative Resource Plan KCCCA

Year	CT's (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)	Existing Capacity (MW)
2015	0			29		4572
2016	0	350	3	71		4387
2017	0	300		103		4432
2018	0			124		4432
2019	0			139		4102
2020	0			176		4102
2021	0			206		4102
2022	0			228		4102
2023	0			248		4117
2024	0			266		4056
2025	0			284		4056
2026	0		7	299		4056
2027	0			308		4056
2028	0			316		4056
2029	207			325		4056
2030	0			333		4056
2031	0			337		4056
2032	0			341		4056
2033	0			345		4056
2034	0			349		4056

Plan KCCCA assumes M-1, and M-2 and M-3 cease burning coal in 2016 and 2019, respectively. DSM: C. Resource additions (if needed): CT's.

Table 26: Alternative Resource Plan KAADA

Year	CT's (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)	Existing Capacity (MW)
2015	0			29		4572
2016	0	350	3	0		4387
2017	0	300		0		4432
2018	0			0		4432
2019	0			0		4442
2020	0			0		4442
2021	207			0		4102
2022	0			0		4102
2023	0			0		4117
2024	0			0		4056
2025	207			0		4056
2026	0		7	0		4056
2027	0			0		4056
2028	0			0		4056
2029	0			0		4056
2030	0			0		4056
2031	207			0		4056
2032	0			0		4056
2033	0			0		4056
2034	0			0		4056

Plan KAADA assumes M-1, and M-2 and M-3 cease burning coal in 2016 and 2021, respectively. DSM: D Resource additions (if needed): CT's.

SECTION 4: ANALYSIS OF RESOURCE PLAN

(4) Analysis of Alternative Resource Plans.

The utility shall describe and document its assessment of the relative performance of the alternative resource plans by calculating for each plan the value of each performance measure specified pursuant to section (2). This calculation shall assume values for uncertain factors that are judged by utility decision makers to be most likely. The analysis shall cover a planning horizon of at least twenty (20) years and shall be carried out on a year by year basis in order to assess the annual and cumulative impacts of alternative resource plans. The analysis shall be based on the assumption that rates will be adjusted annually, in a manner that is consistent with Missouri law. The analysis shall treat supply-side and demand-side resources on a logically-consistent and economically-equivalent basis, such that the same types or categories of costs, benefits, and risks shall be considered and such that these factors shall be quantified at a similar level of detail and precision for all resource types. The utility shall provide the following information:

(A) A summary tabulation that shows the performance of each alternative resource plan as measured by each of the measures specified in section (2) of this rule;

The expected value of each plan's performance measures is provided below:

Table 27: Expected Value Plan Performance Measures ** Highly Confidential **

[redacted]

(B) For each alternative resource plan, a plot of each of the following over the planning horizon:

1. The combined impact of all demand-side resources on the base-case forecast of summer and winter peak demands;

The combined impact of all demand-side resources on the base-case forecast of summer and winter peak demands is shown in the following three charts. Note that Option D is Persistence DSM and therefore does not have any impact on Peak Demand.

HC

Chart 1: Demand Side Impact - DSM Option A ** Highly Confidential **

[redacted]

Chart 2: Demand Side Impact - DSM Option B Highly Confidential ****

[redacted]

HC

Chart 3: Demand Side Impact - DSM Option C ** Highly Confidential **

[redacted]

HC

2. The composition, by program and demand-side rate, of the capacity provided by demand-side resources;

The following three charts illustrate the combined capacity supplied by the three levels of DSM programs associated with the Alternative Resource Plans. It should be noted that Option D is Persistence DSM and is included in each of the three DSM levels.

Chart 4: Capacity Composition – DSM Option A

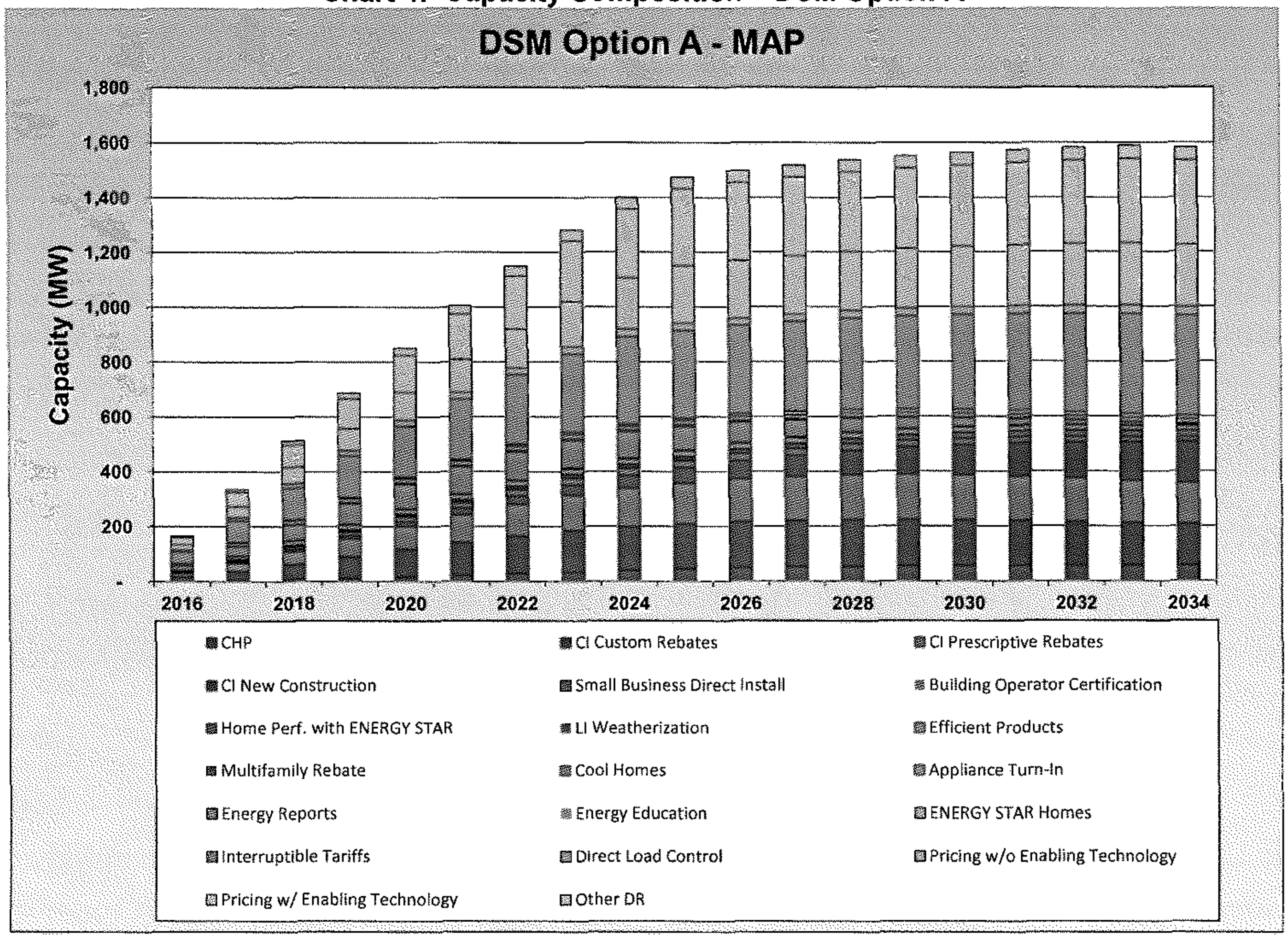


Chart 5: Capacity Composition – DSM Option B

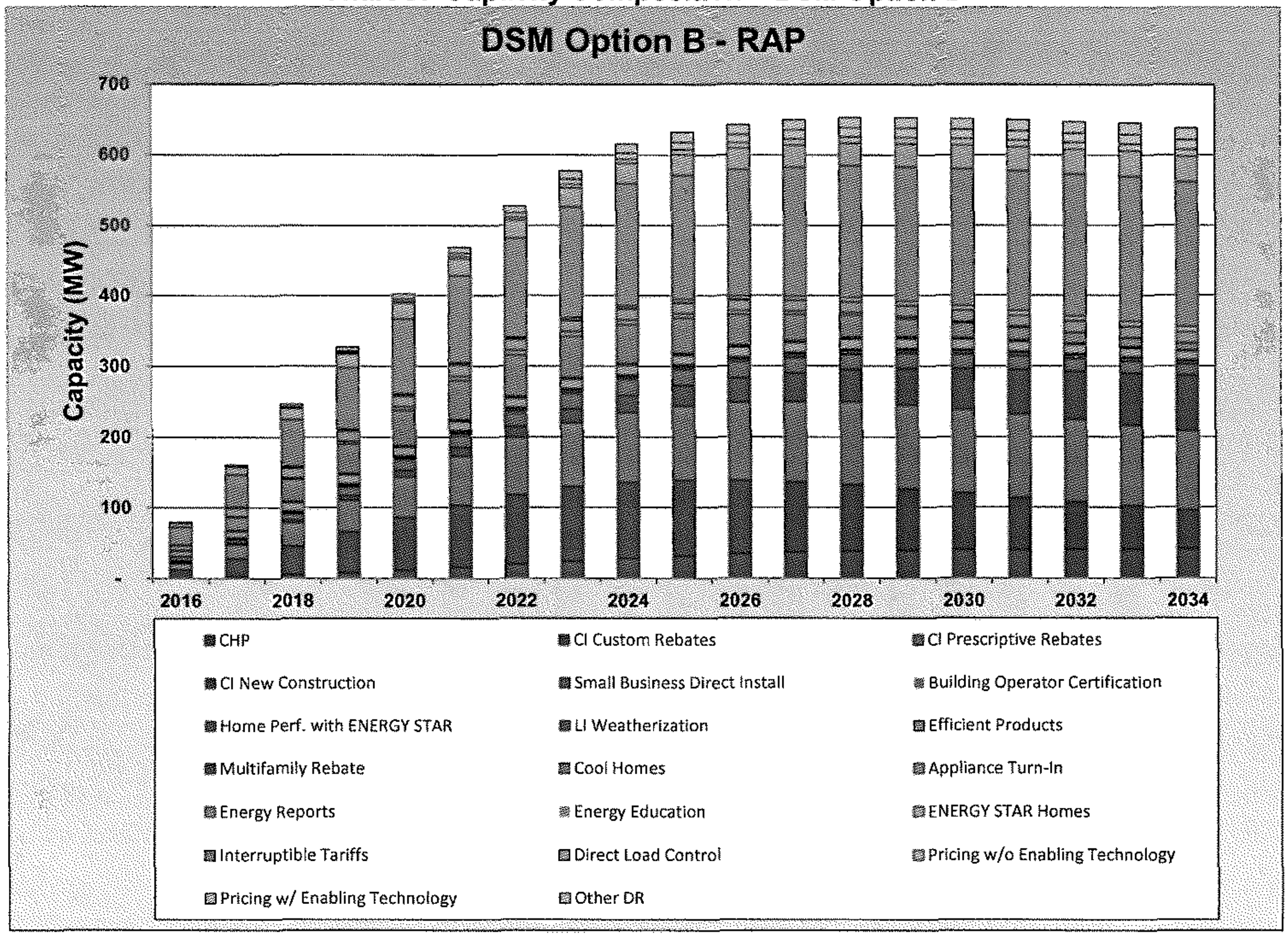
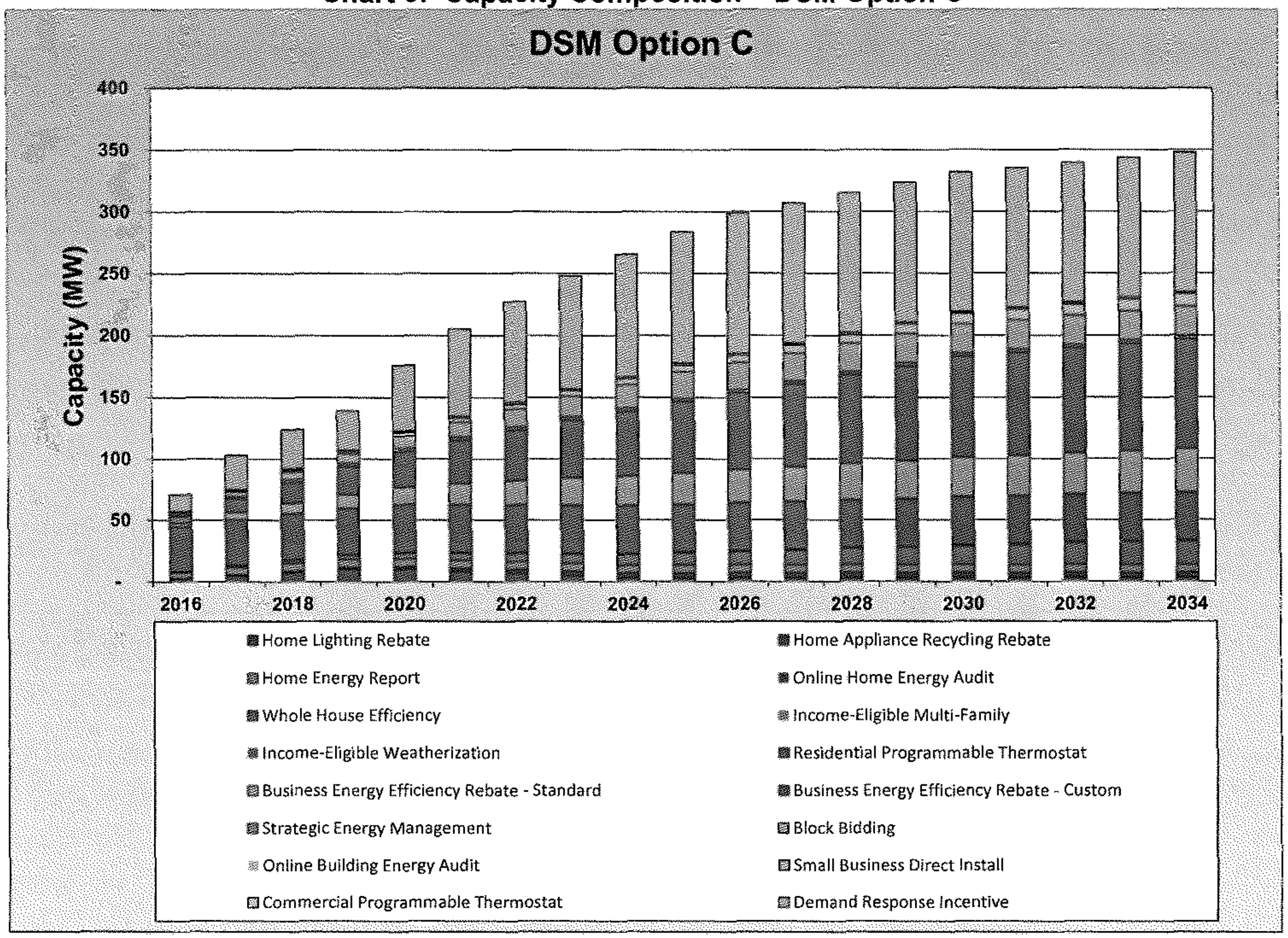


Chart 6: Capacity Composition – DSM Option C



3. The composition, by supply-side resource, of the capacity supplied to the transmission grid provided by supply-side resources. Existing supply-side resources may be shown as a single resource;

The following charts provide the supply-side resource composition for each Alternative Resource Plan.

Chart 7: Alternative Resource Plan KAAAA - Capacity

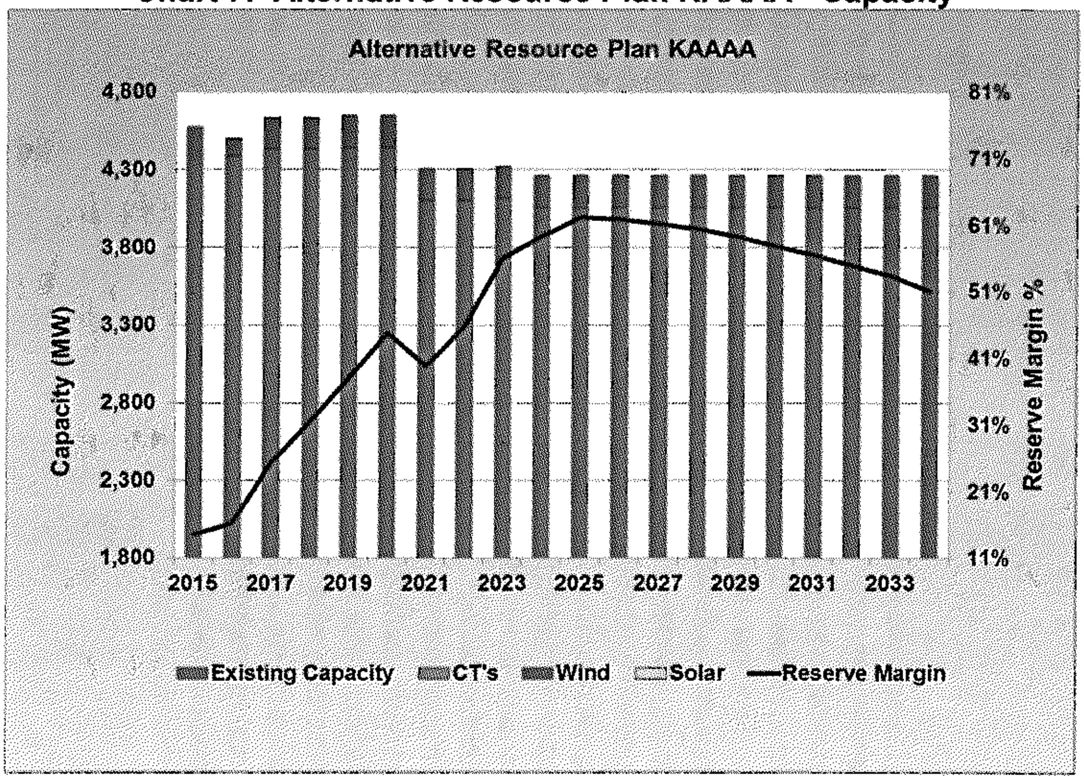


Chart 8: Alternative Resource Plan KAAAC - Capacity

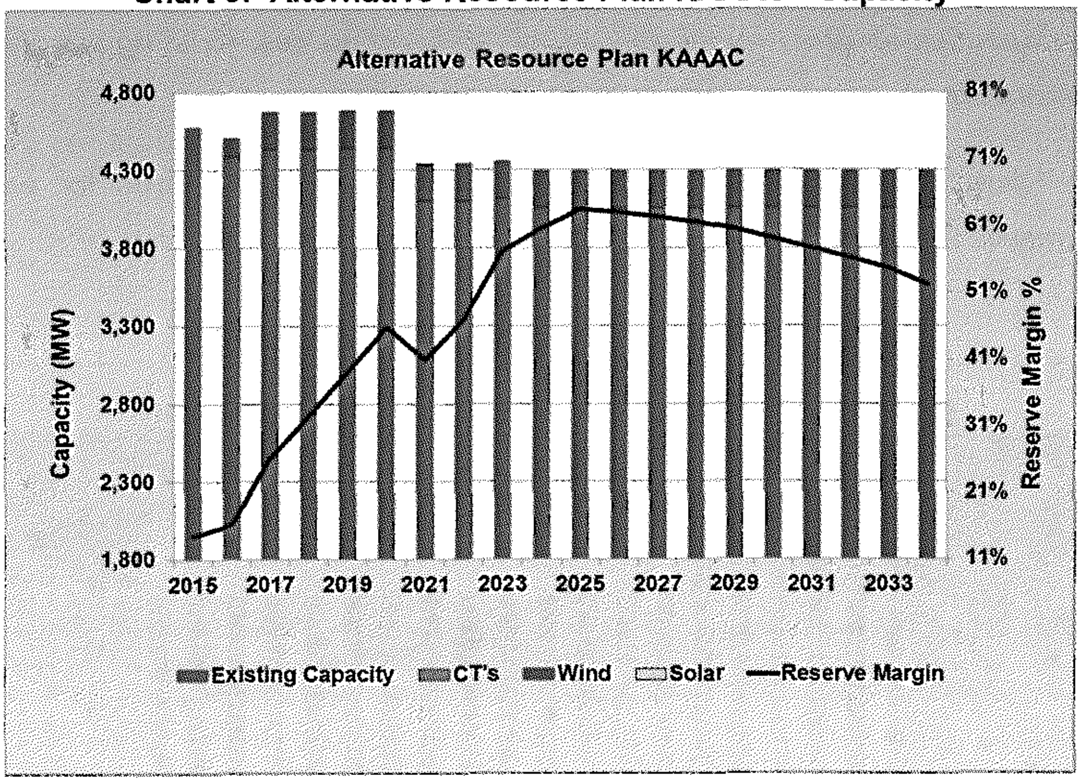


Chart 9: Alternative Resource Plan KAAAD – Capacity

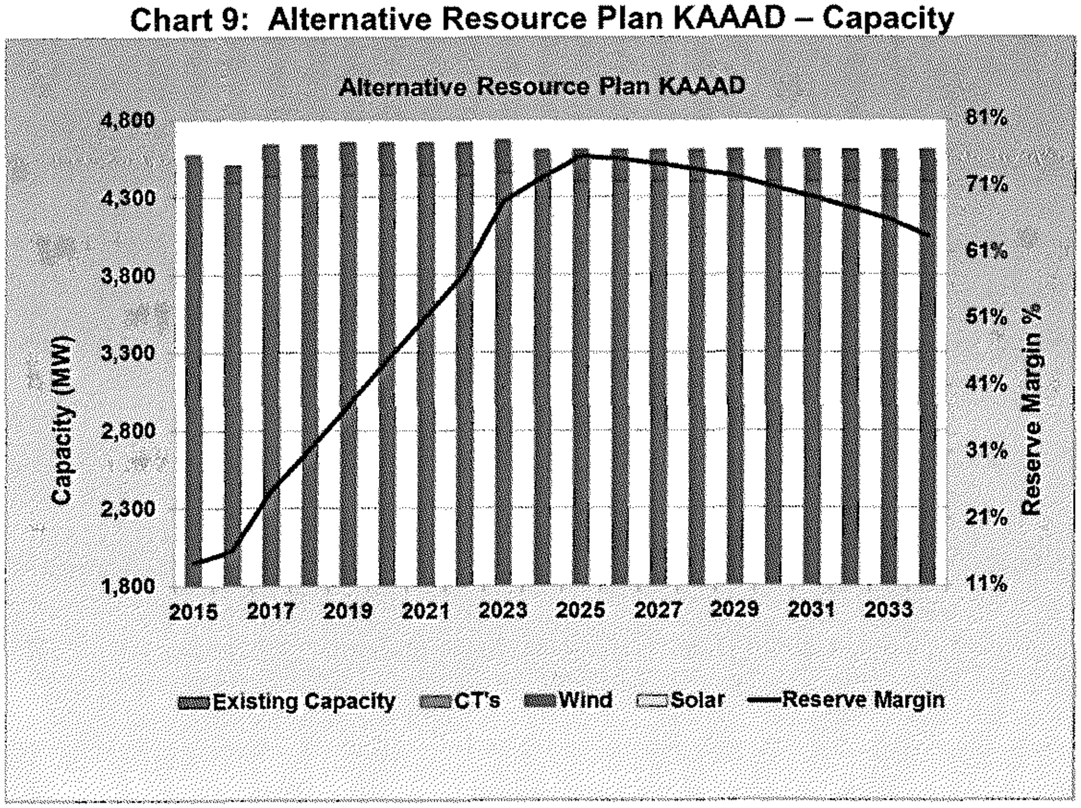


Chart 10: Alternative Resource Plan KAABA - Capacity

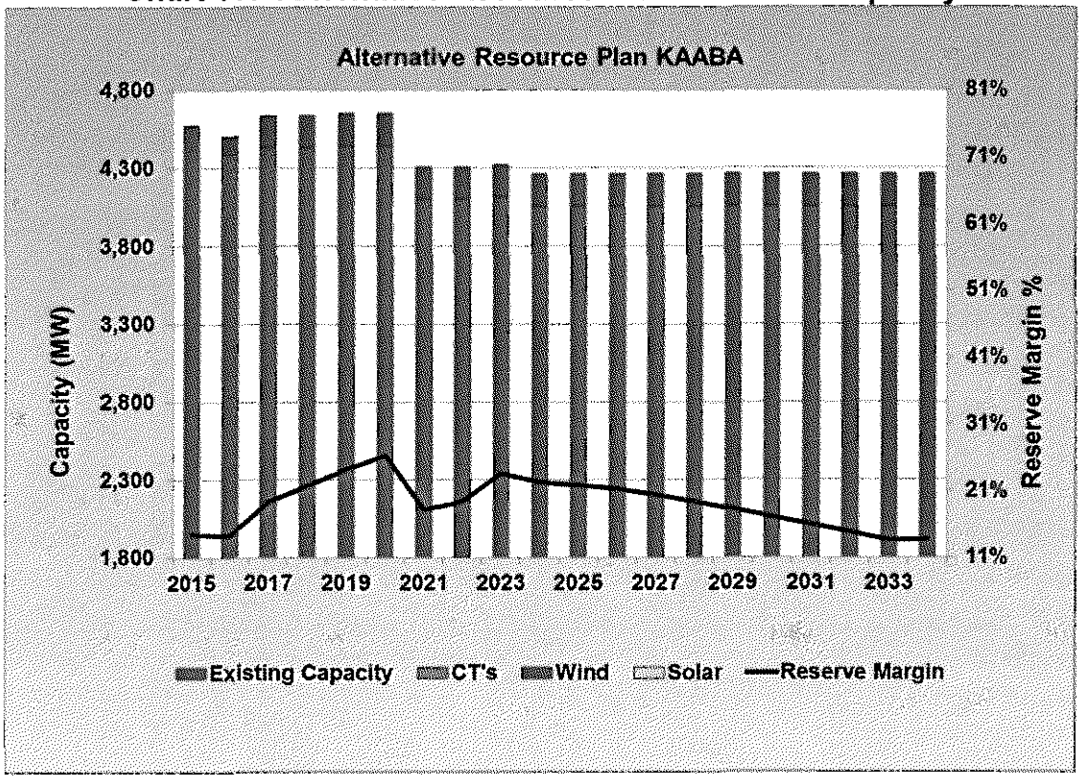


Chart 11: Alternative Resource Plan KAABC - Capacity

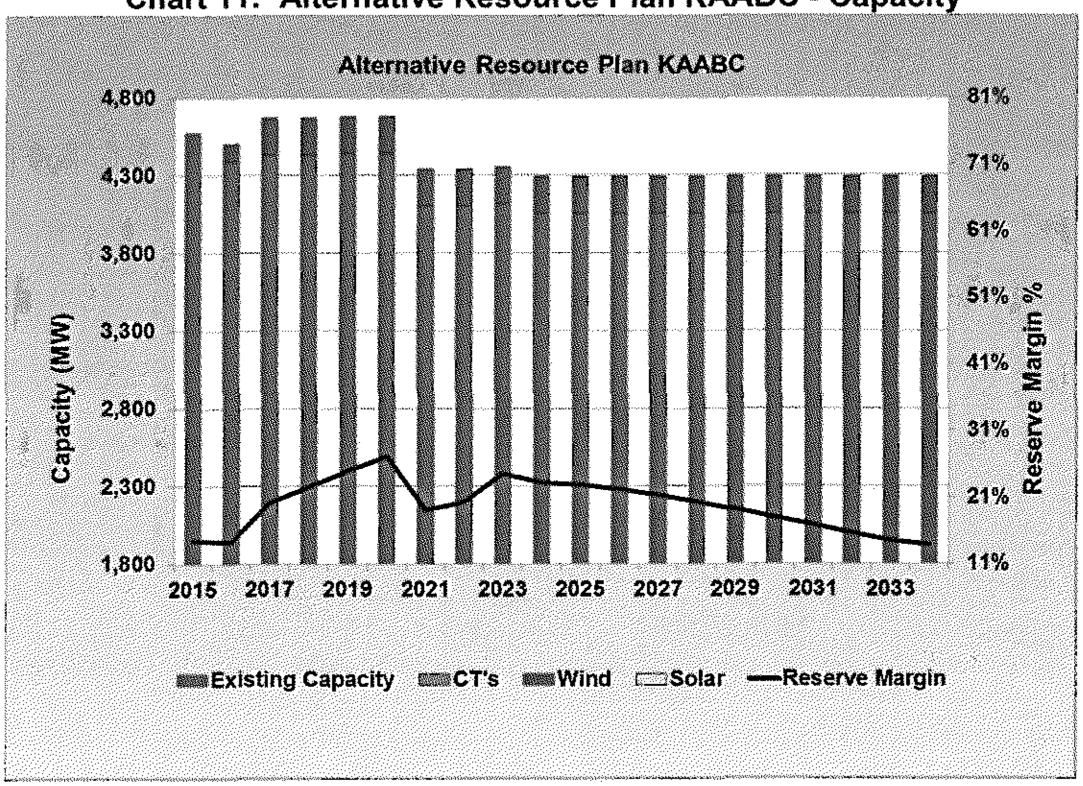


Chart 12: Alternative Resource Plan KAABD - Capacity

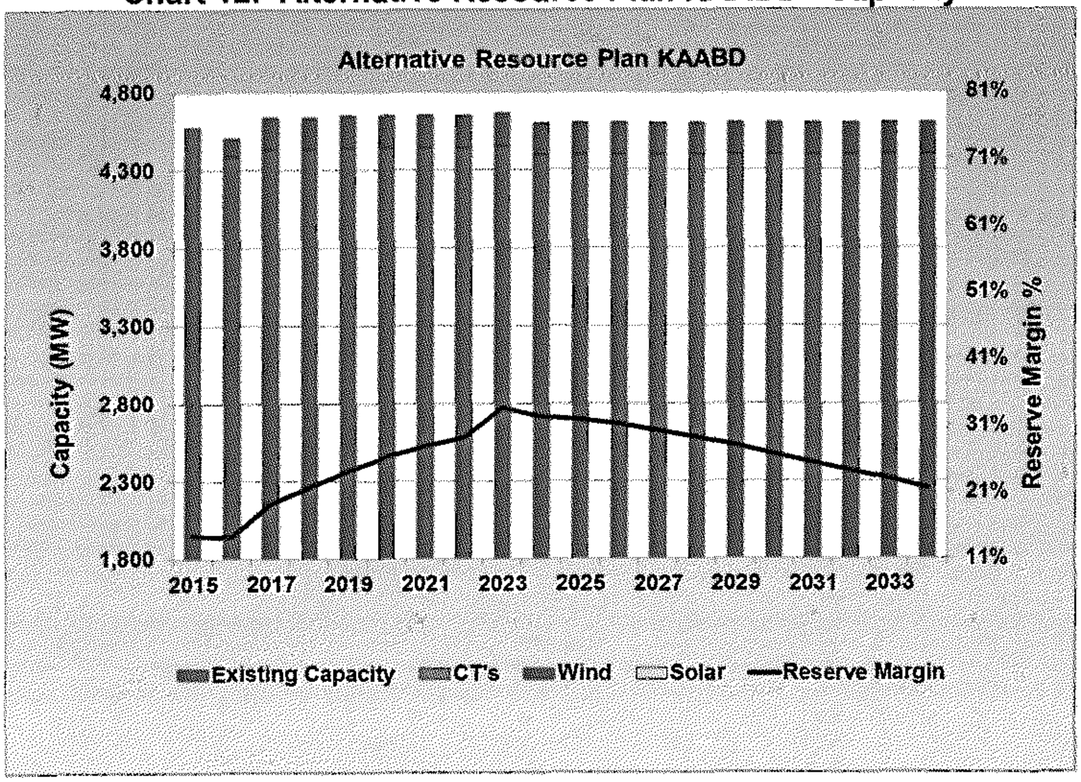


Chart 13: Alternative Resource Plan KCCBA - Capacity

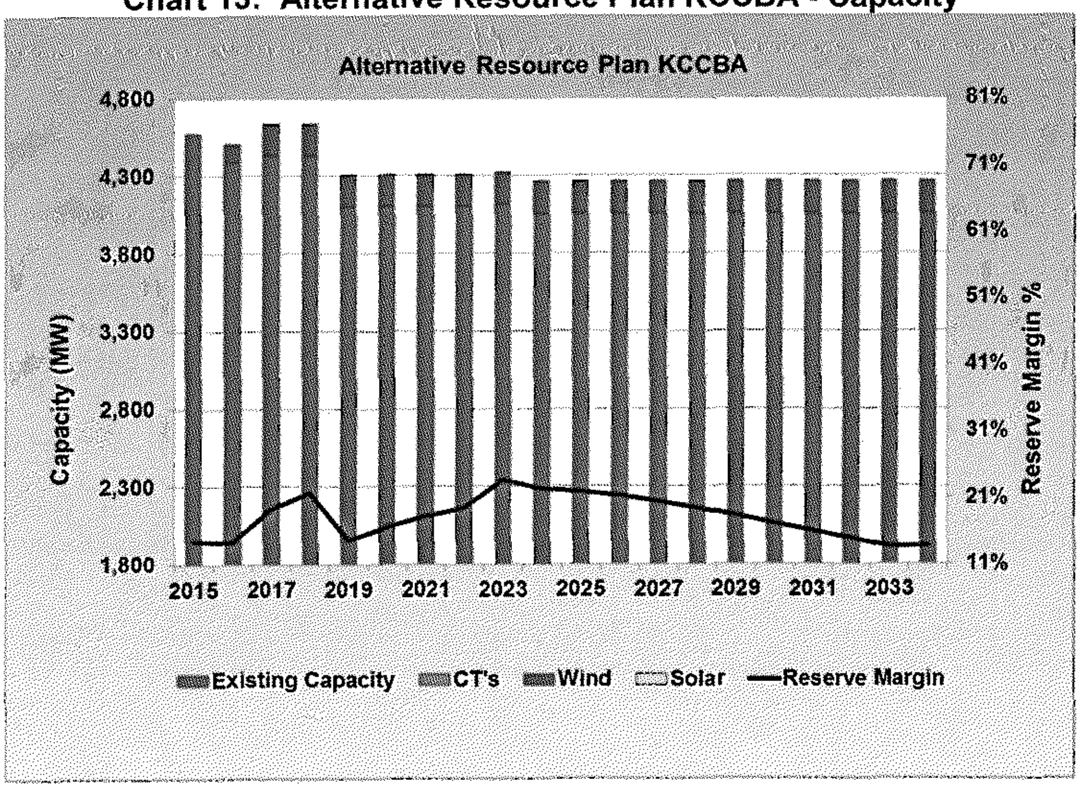


Chart 14: Alternative Resource Plan KAACA - Capacity

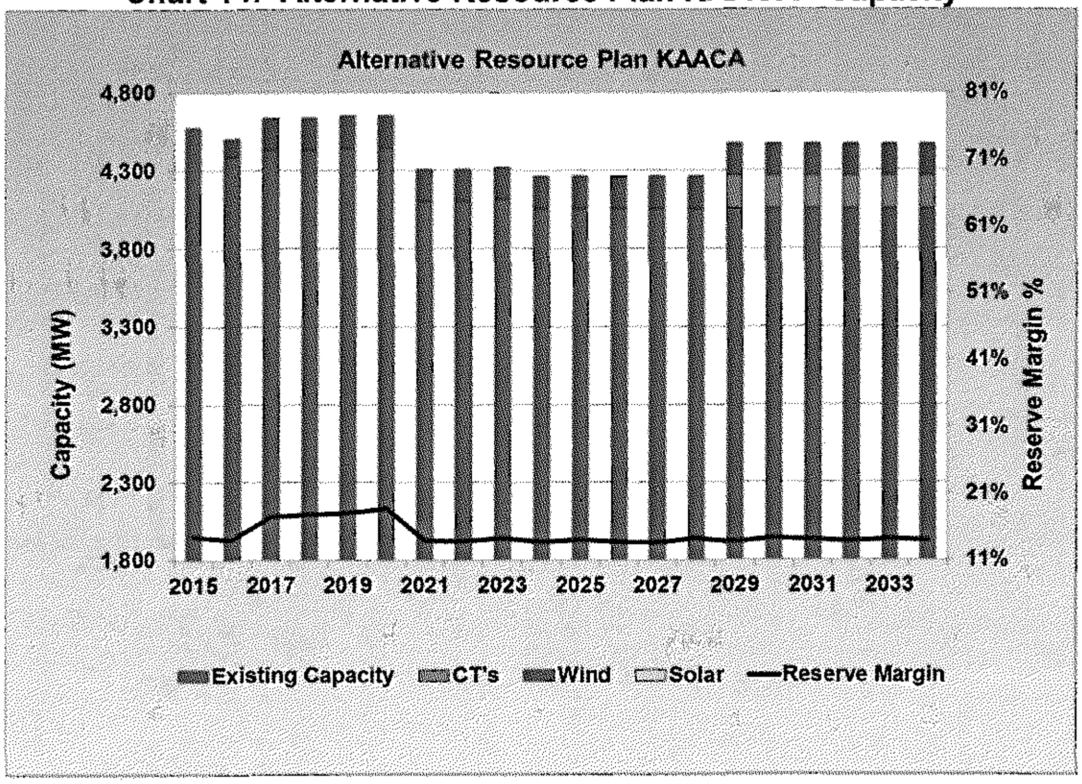


Chart 15: Alternative Resource Plan KAACB - Capacity

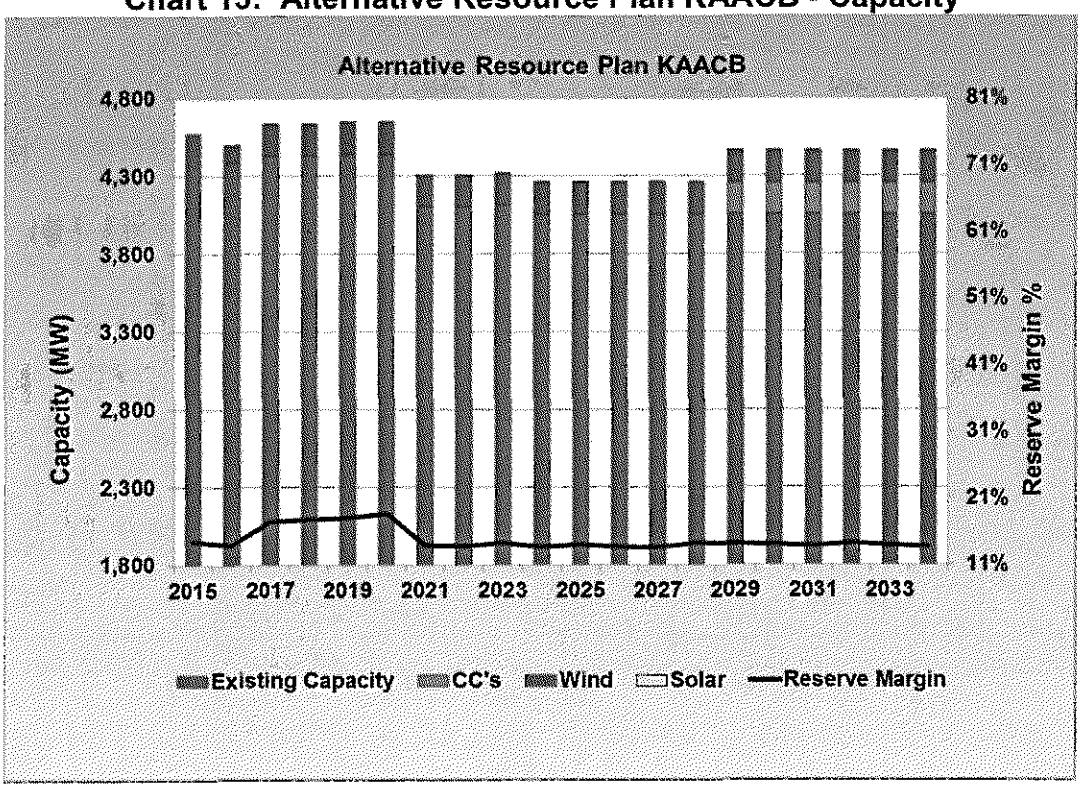


Chart 16: Alternative Resource Plan KAACC - Capacity

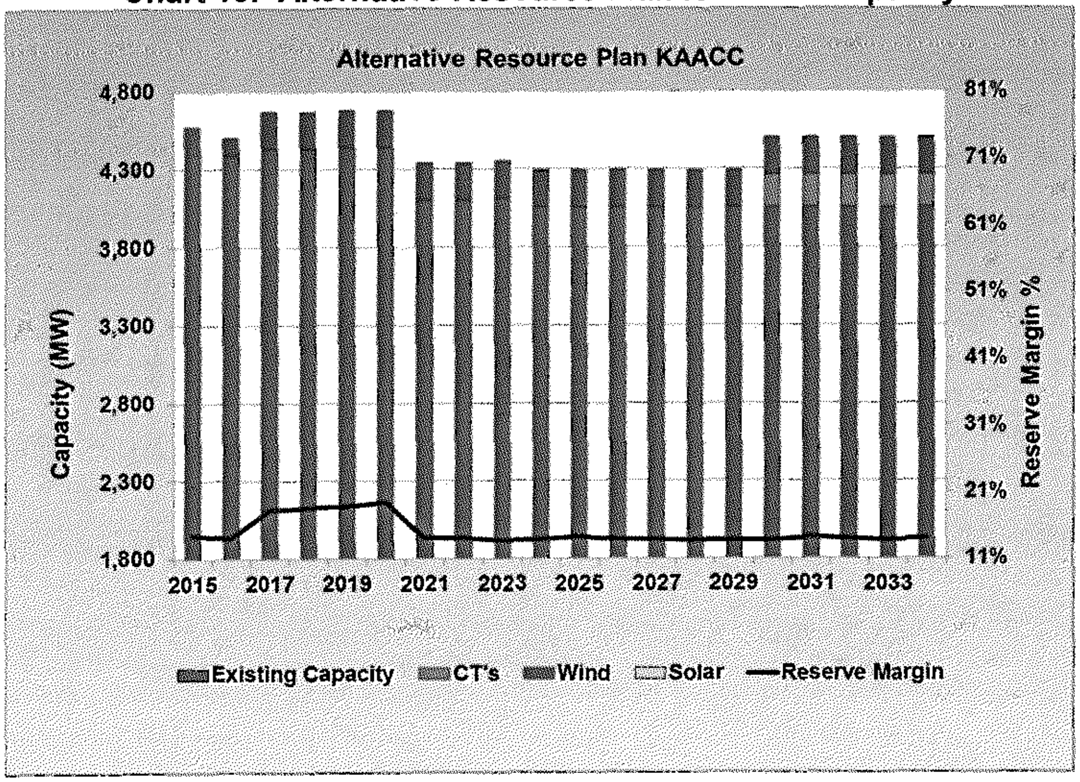


Chart 17: Alternative Resource Plan KAACD - Capacity

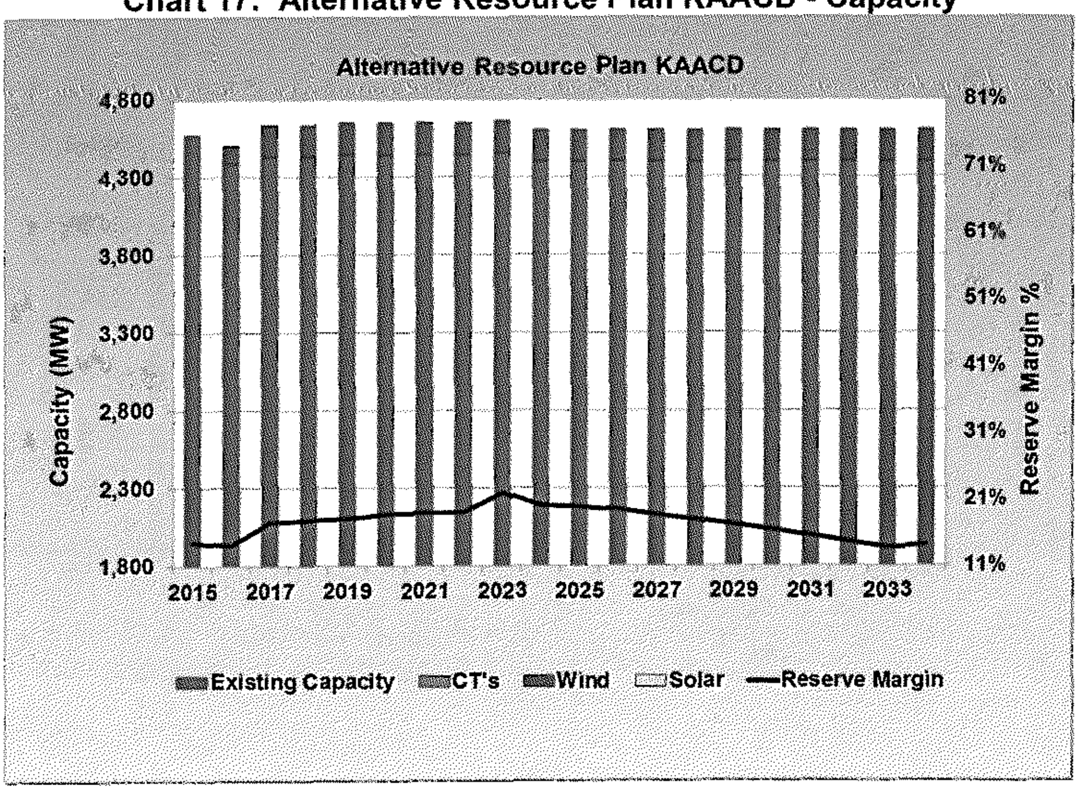


Chart 18: Alternative Resource Plan KAACW – Capacity

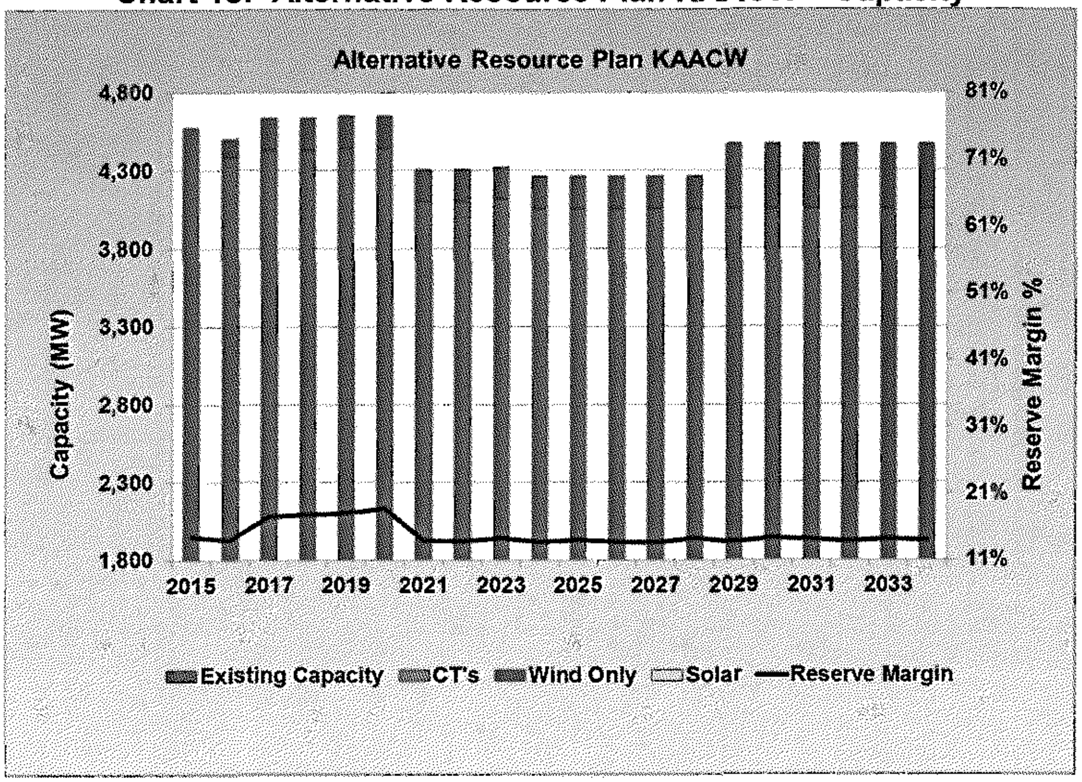


Chart 19: Alternative Resource Plan KBBCA – Capacity

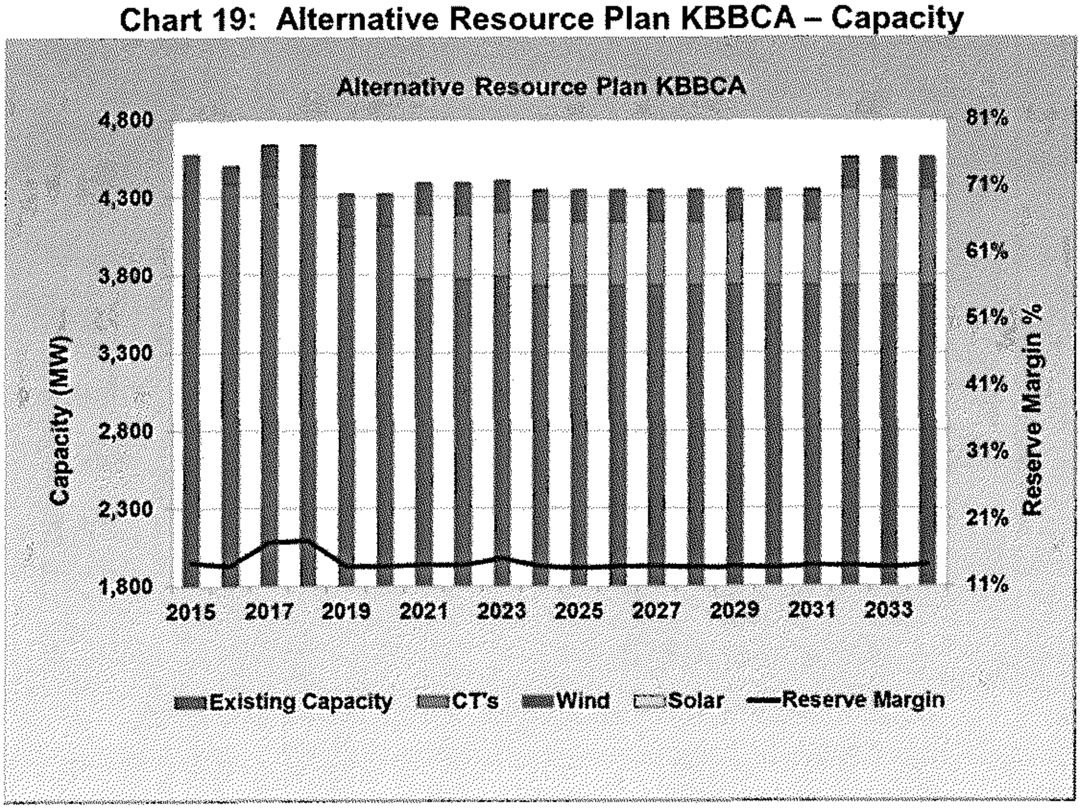


Chart 20: Alternative Resource Plan KCCCA - Capacity

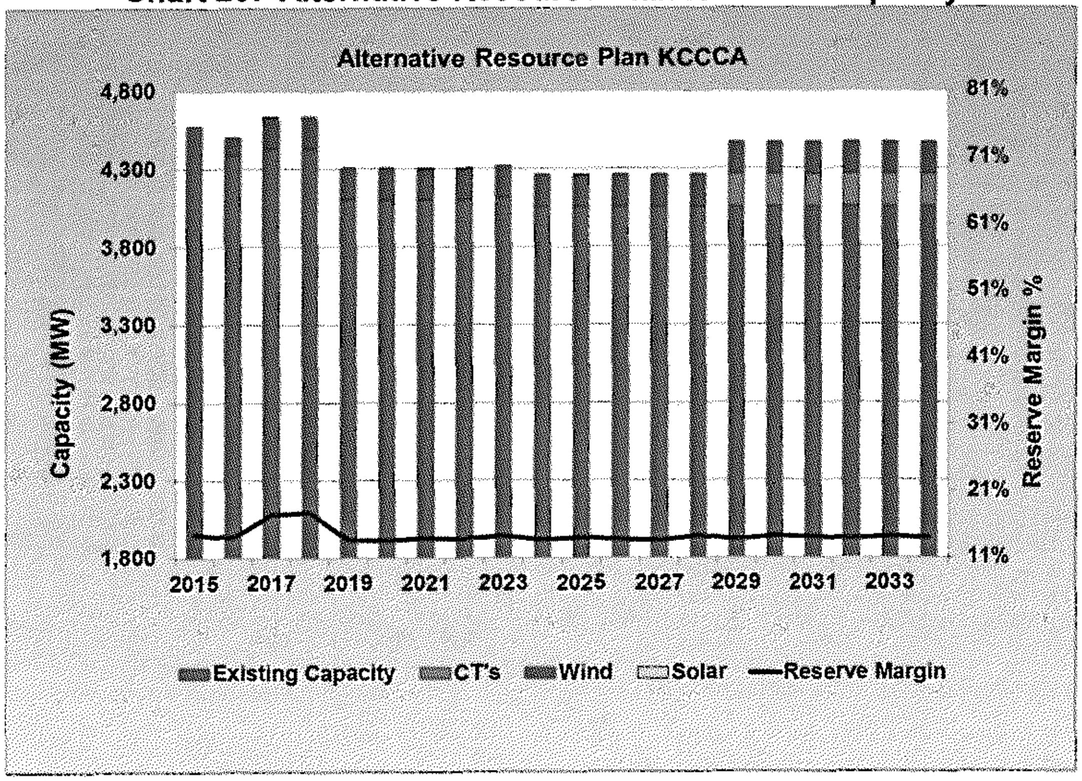
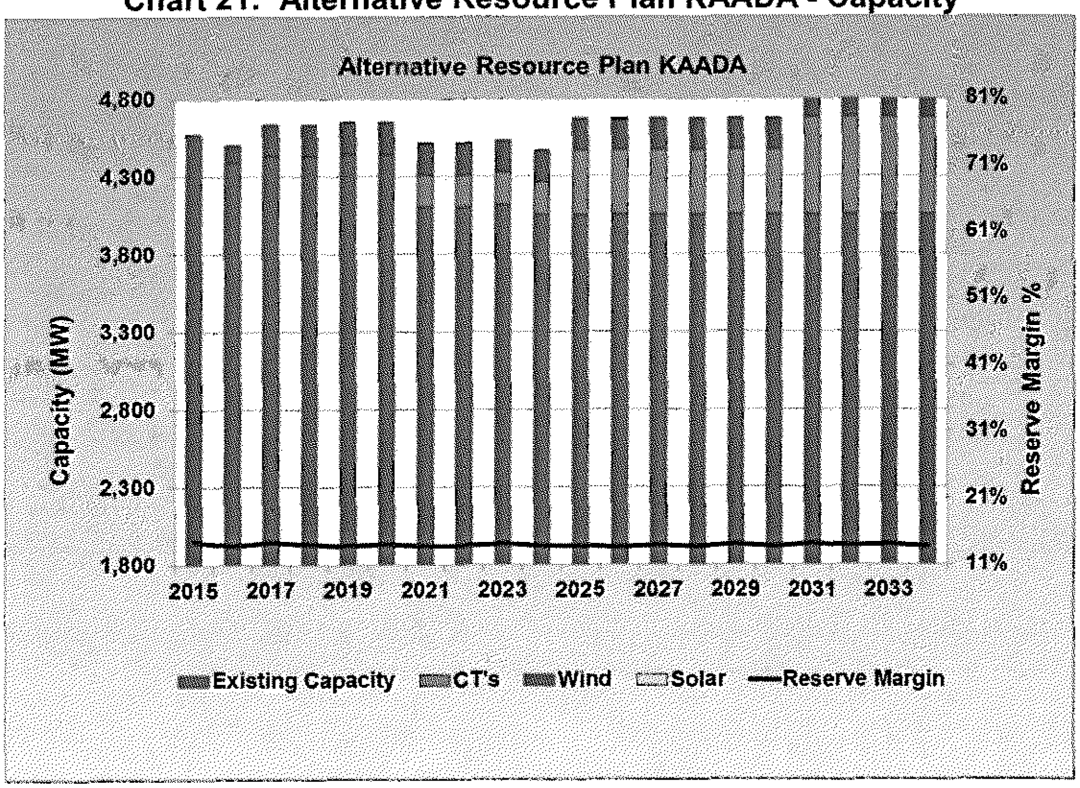


Chart 21: Alternative Resource Plan KAADA - Capacity



4. The combined impact of all demand-side resources on the base-case forecast of annual energy requirements;

The following three charts illustrate the combined energy supplied by the three levels of DSM programs associated with the alternative resource plans. It should be noted that Option D is Persistence DSM and therefore does not have any impact on Peak Demand.

Chart 22: Annual Energy Impact – DSM Option A

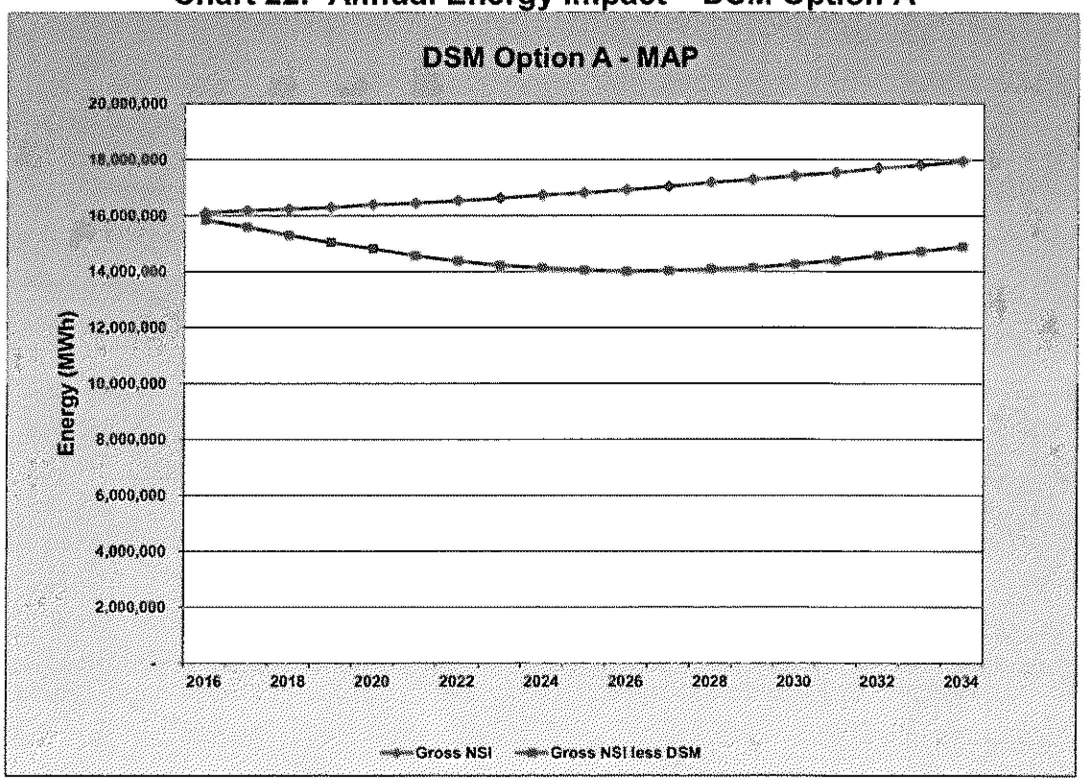


Chart 23: Annual Energy Impact – DSM Option B

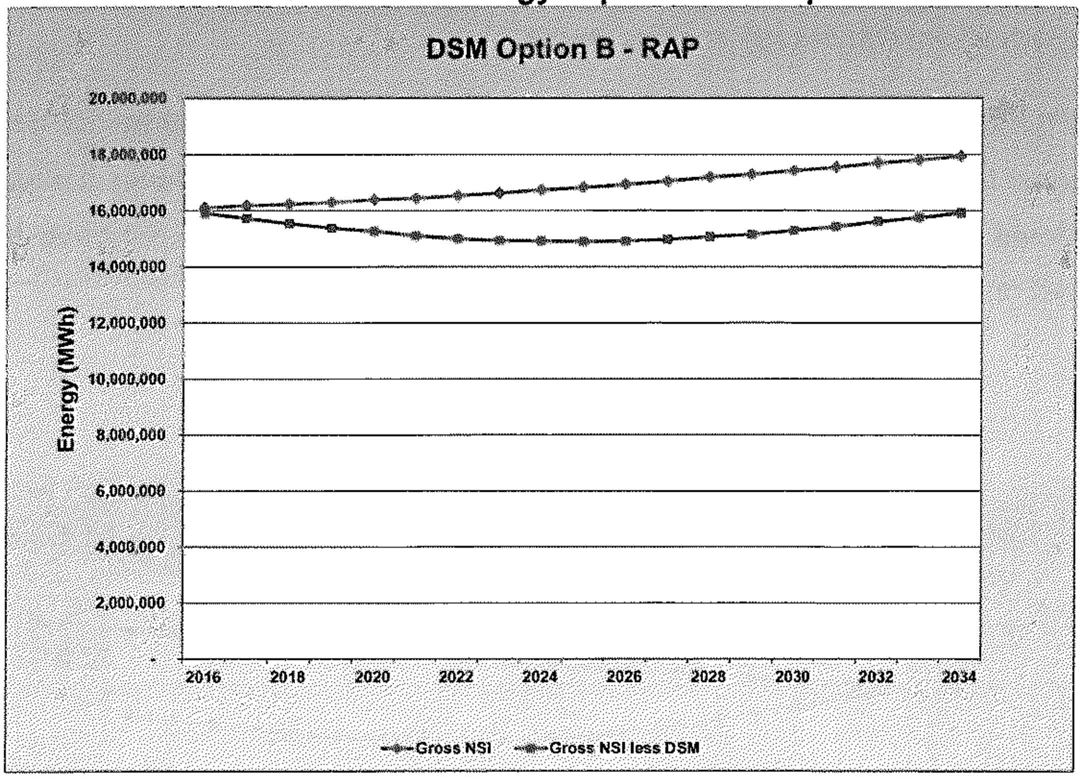
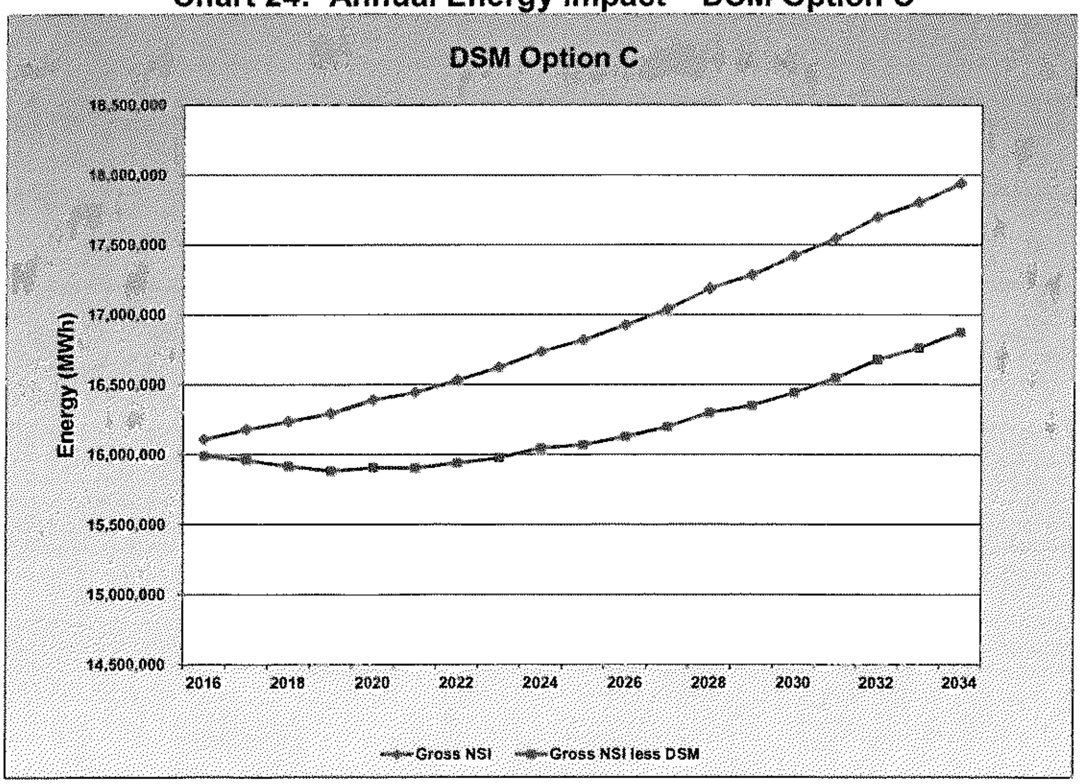


Chart 24: Annual Energy Impact – DSM Option C



5. The composition, by program and demand-side rate, of the annual energy provided by demand-side resources;

The following three charts illustrate the combined energy supplied by the three levels of DSM programs associated with the Alternative Resource Plans. It should be noted that Option D is Persistence DSM and is included in each of the three DSM levels.

Chart 25: Energy Composition – DSM Option A

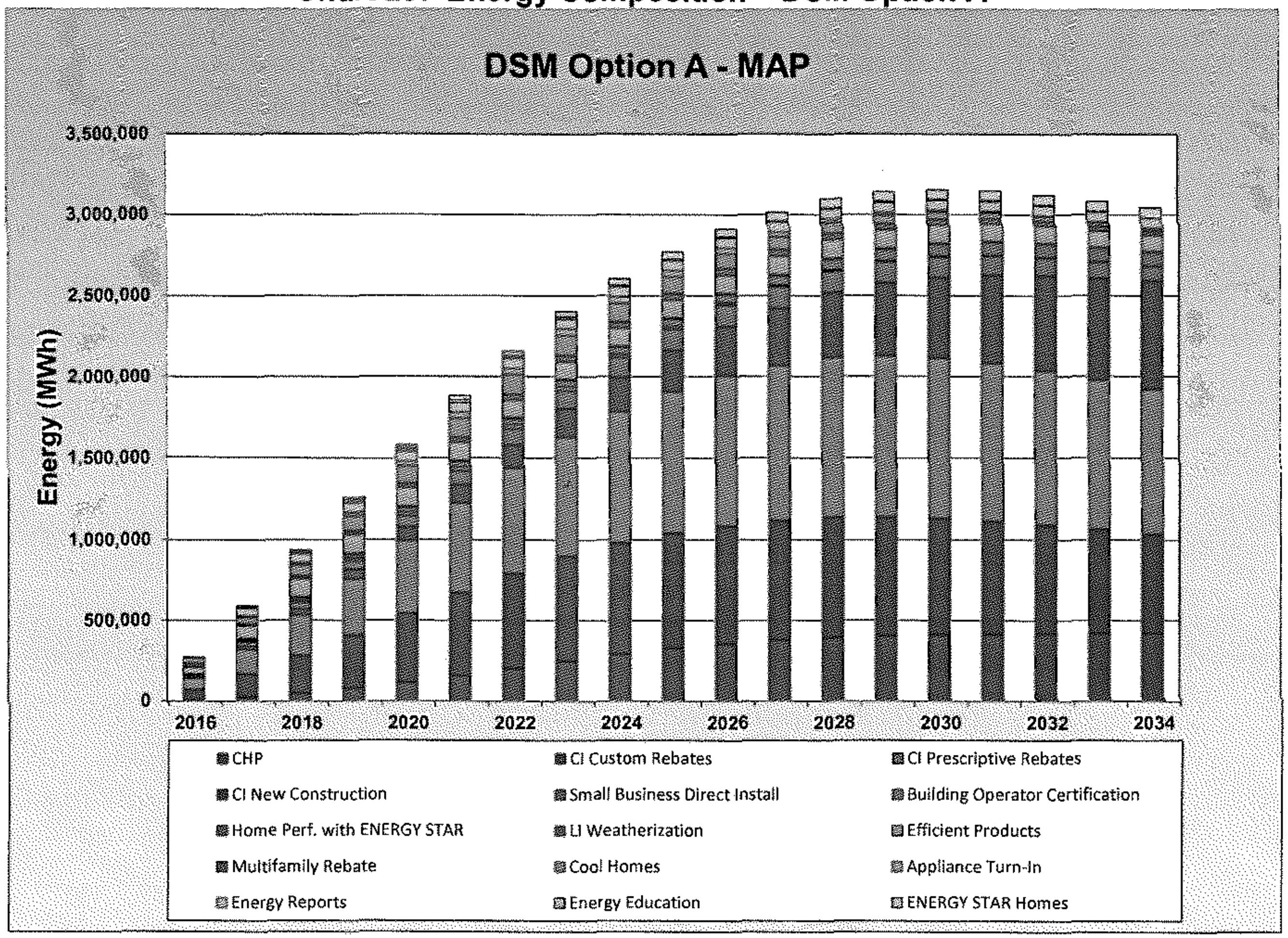


Chart 26: Energy Composition – DSM Option B

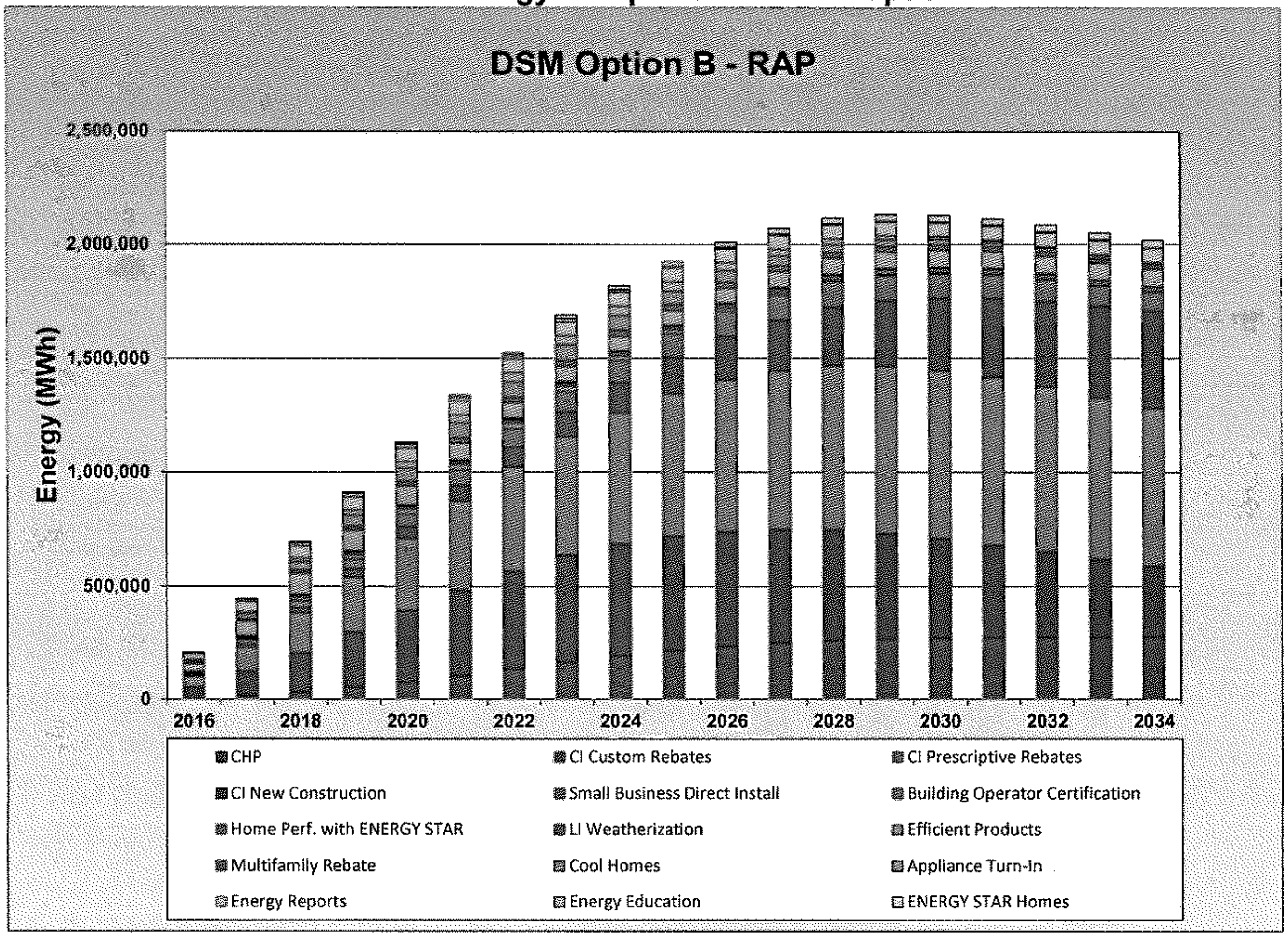
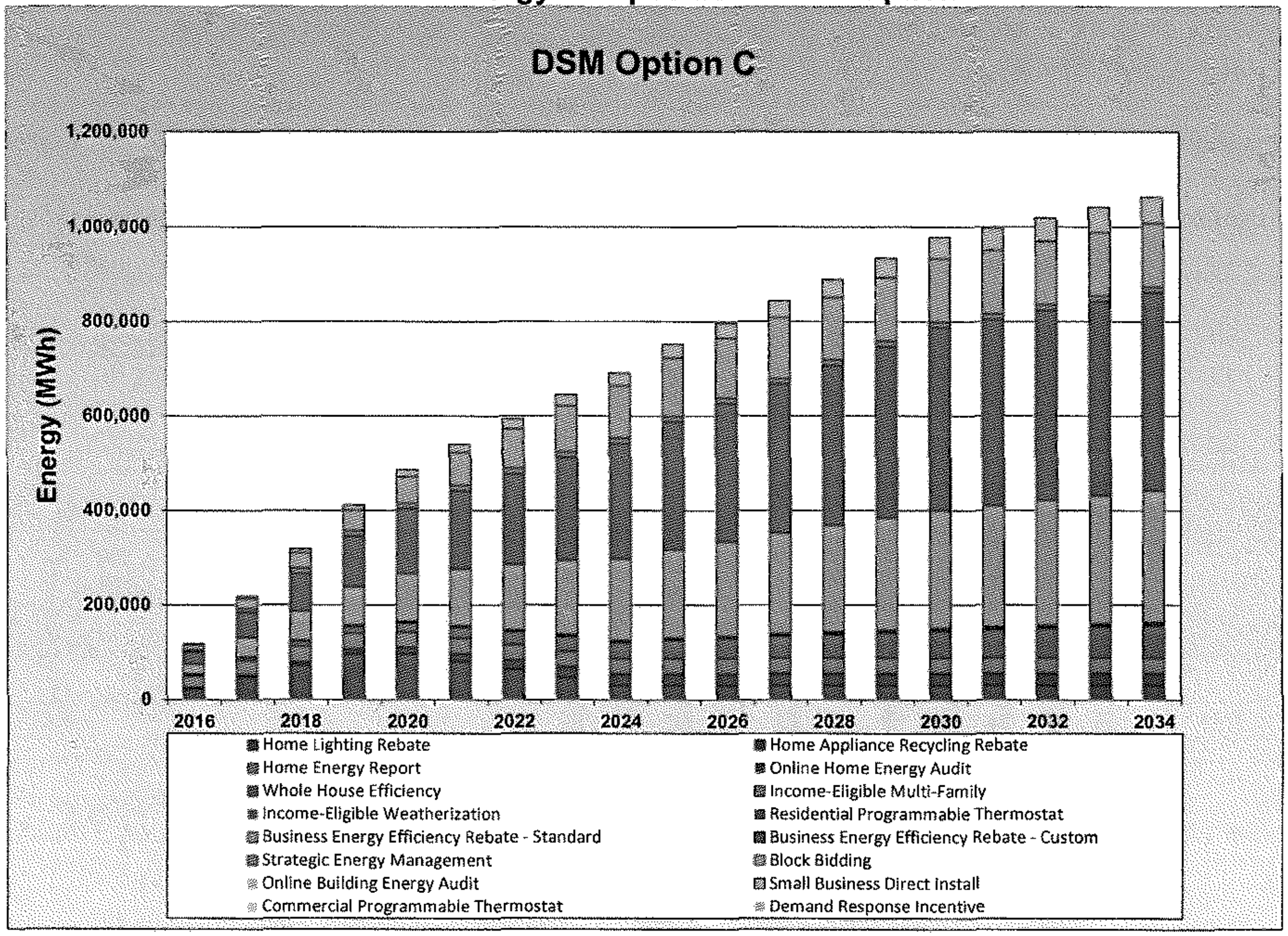


Chart 27: Energy Composition – DSM Option C



6. The composition, by supply-side resource, of the annual energy supplied to the transmission grid, less losses, provided by supply-side resources. Existing supply-side resources may be shown as a single resource;

The following charts detail the expected-value composition by supply-side resource of all energy generated by the assets and supplied to the transmission grid included in each plan. No allowances are developed for "losses" as it is not possible to determine the exact source of energy for a particular lost megawatt-hour of energy.

Chart 28: Annual Generation KAAAA

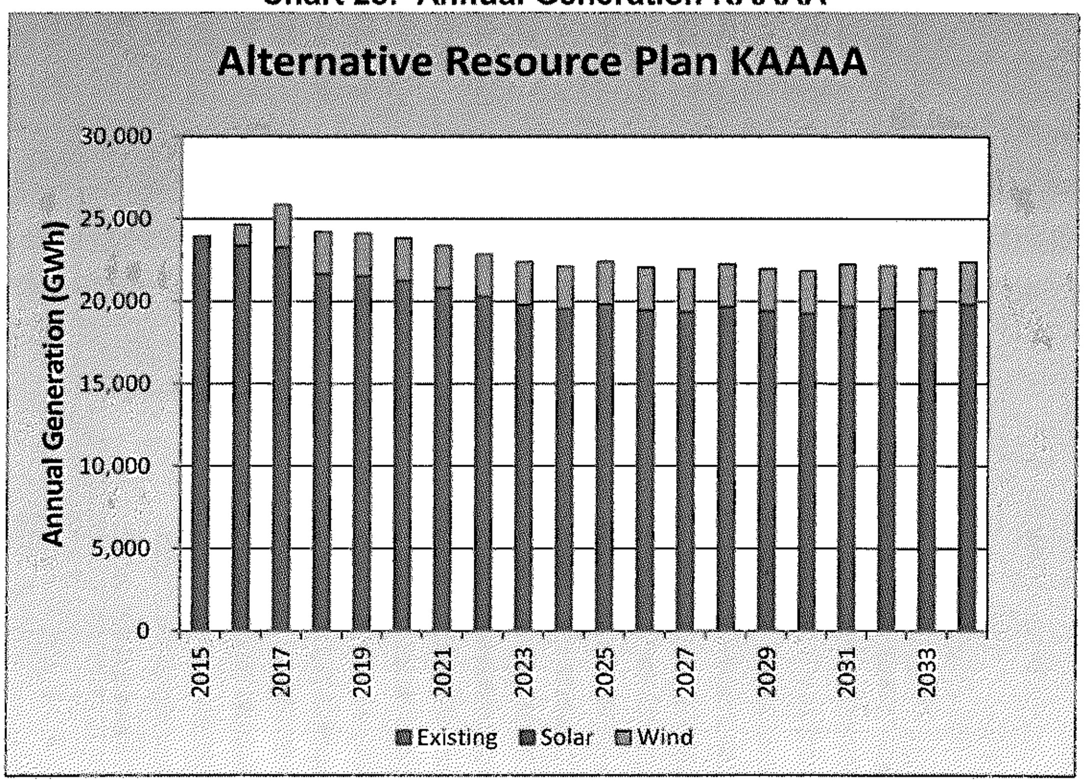


Chart 29: Annual Generation KAAAC

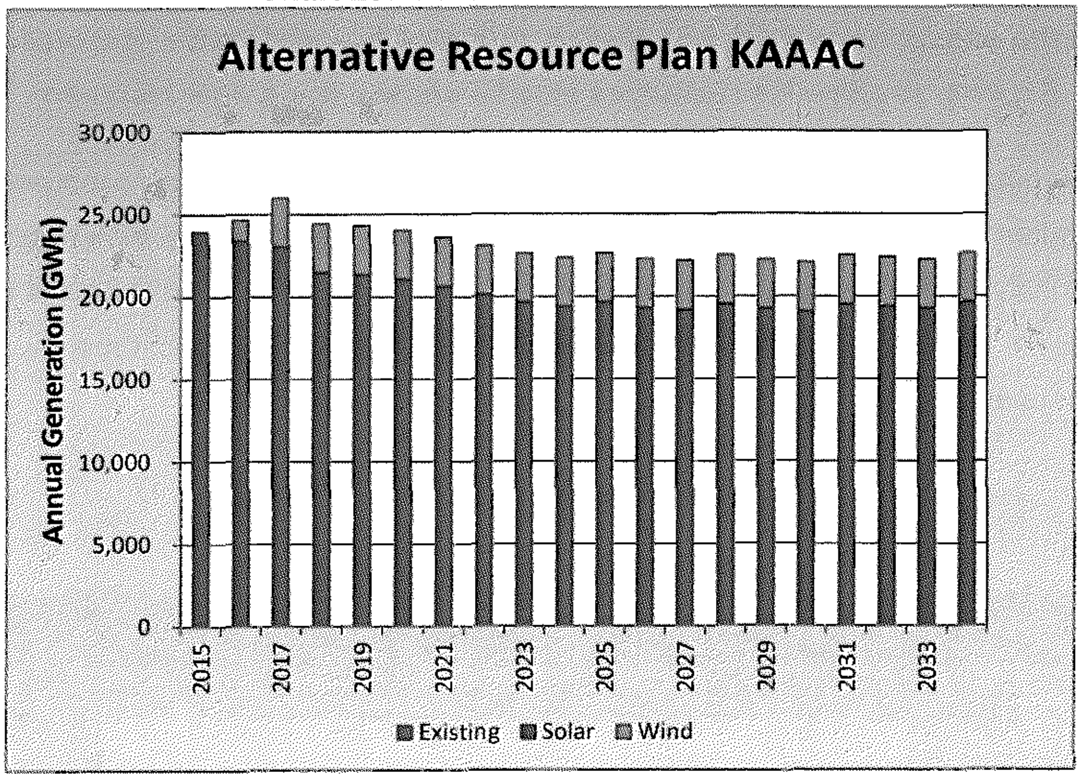


Chart 30: Annual Generation KAAAD

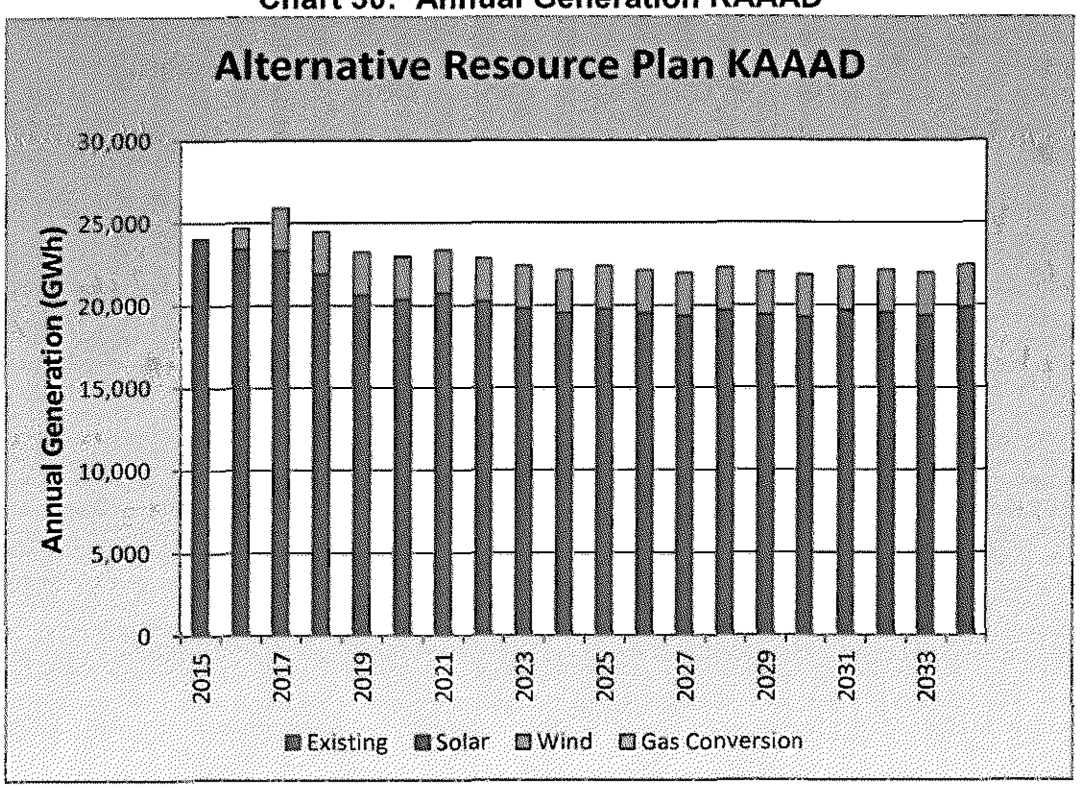


Chart 31: Annual Generation KAABA

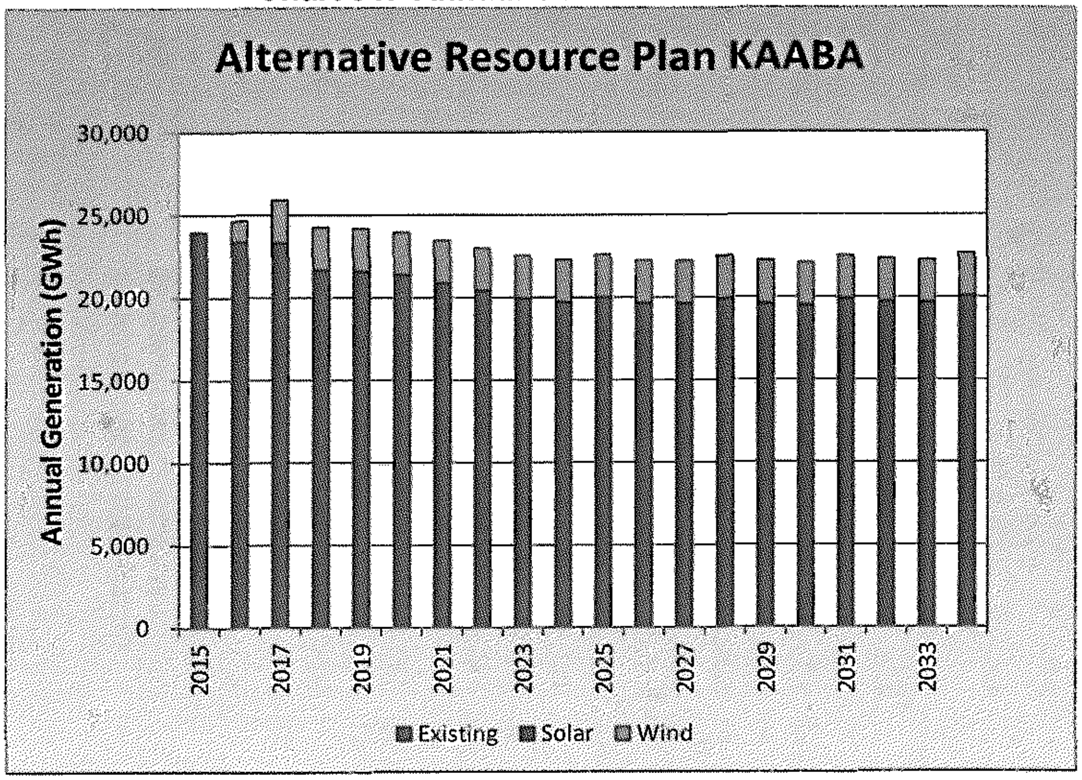


Chart 32: Annual Generation KAABC

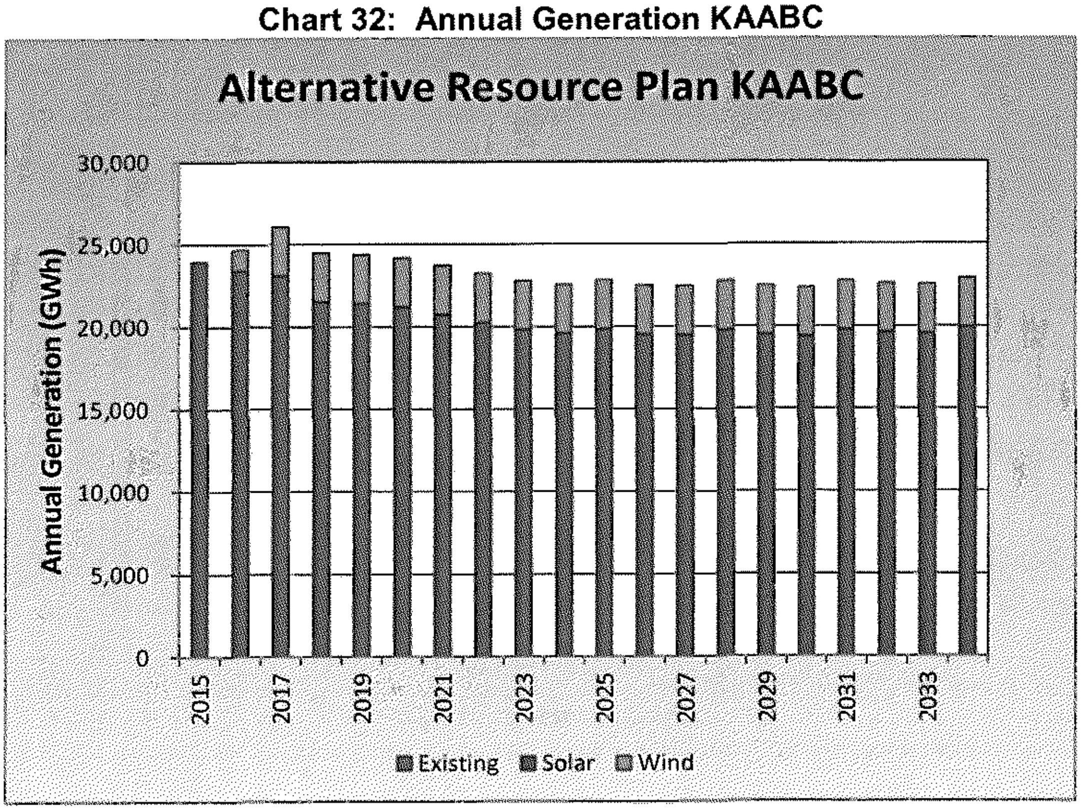


Chart 33: Annual Generation KAABD

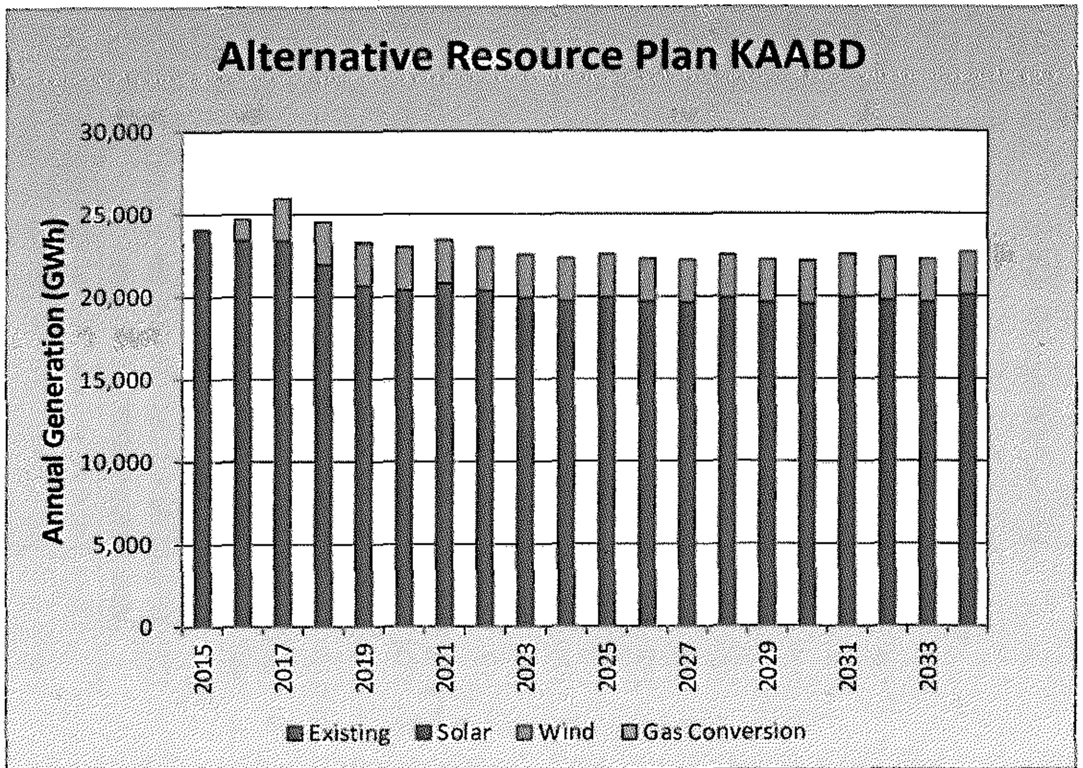


Chart 34: Annual Generation KCCBA

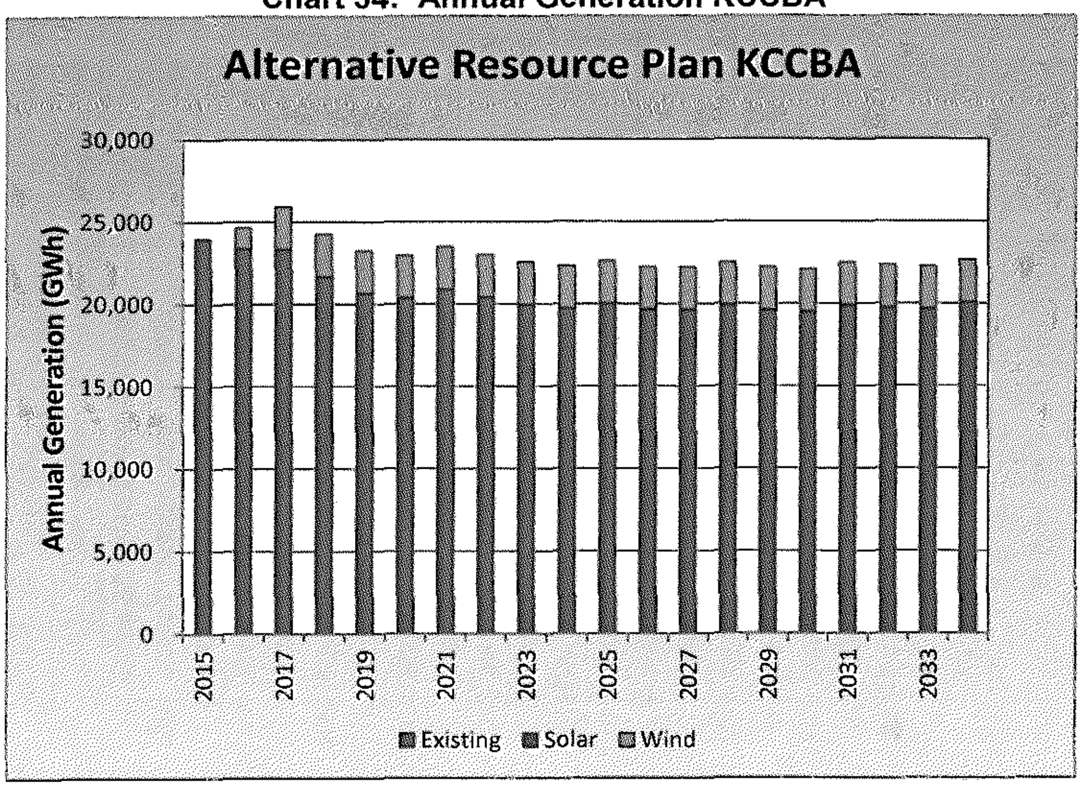


Chart 35: Annual Generation KAACA

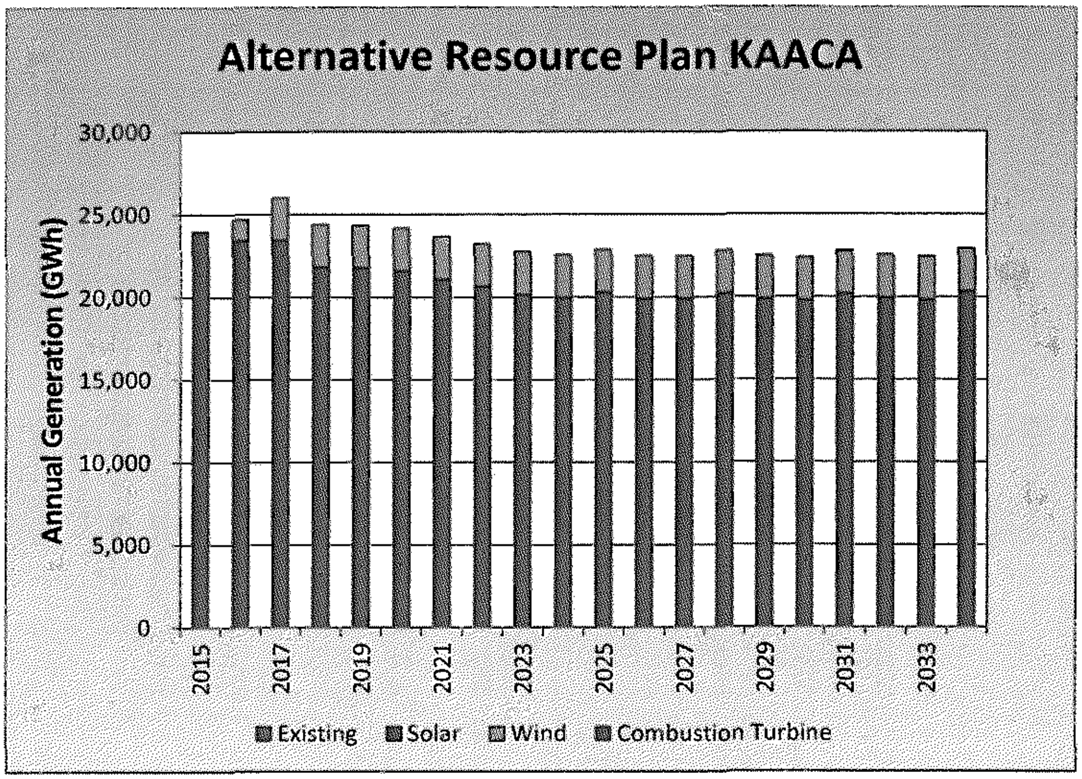


Chart 36: Annual Generation KAACB

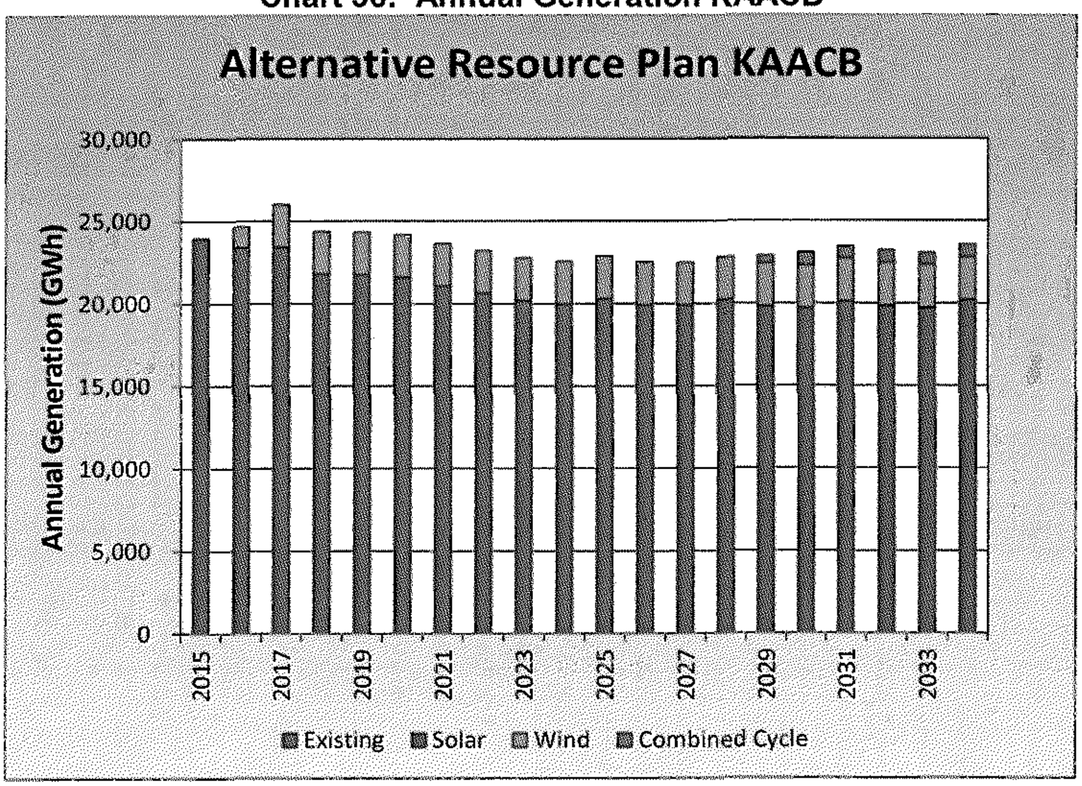


Chart 37: Annual Generation KAACC

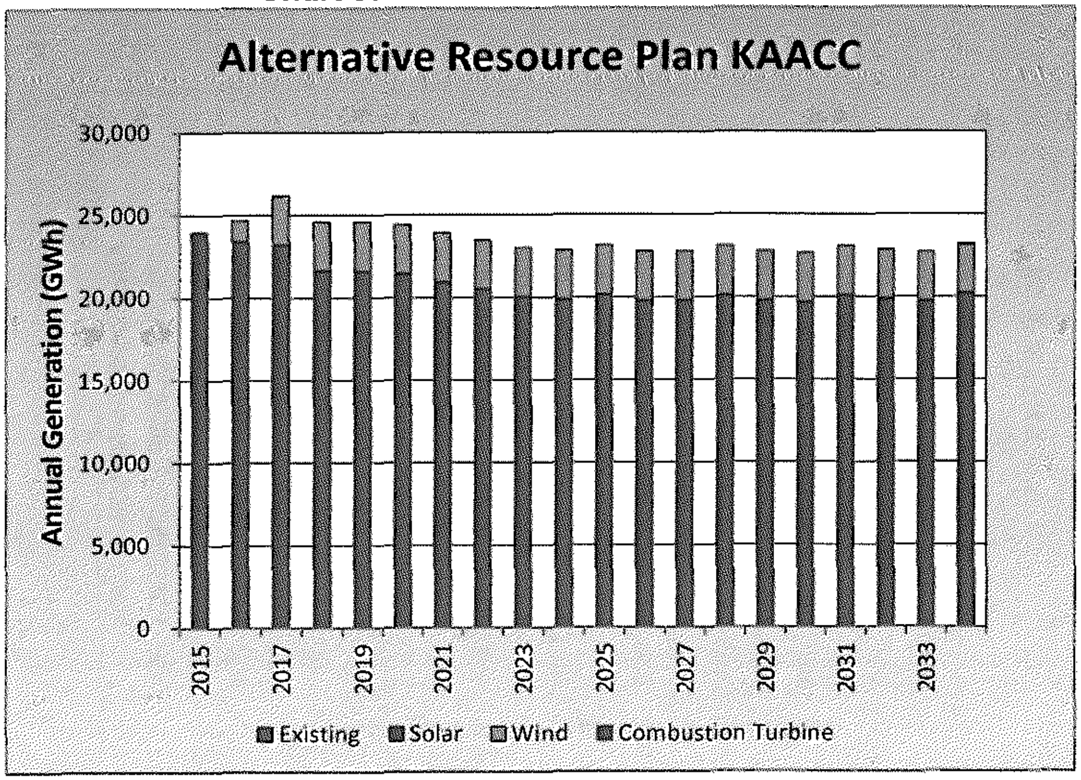


Chart 38: Annual Generation KAACD

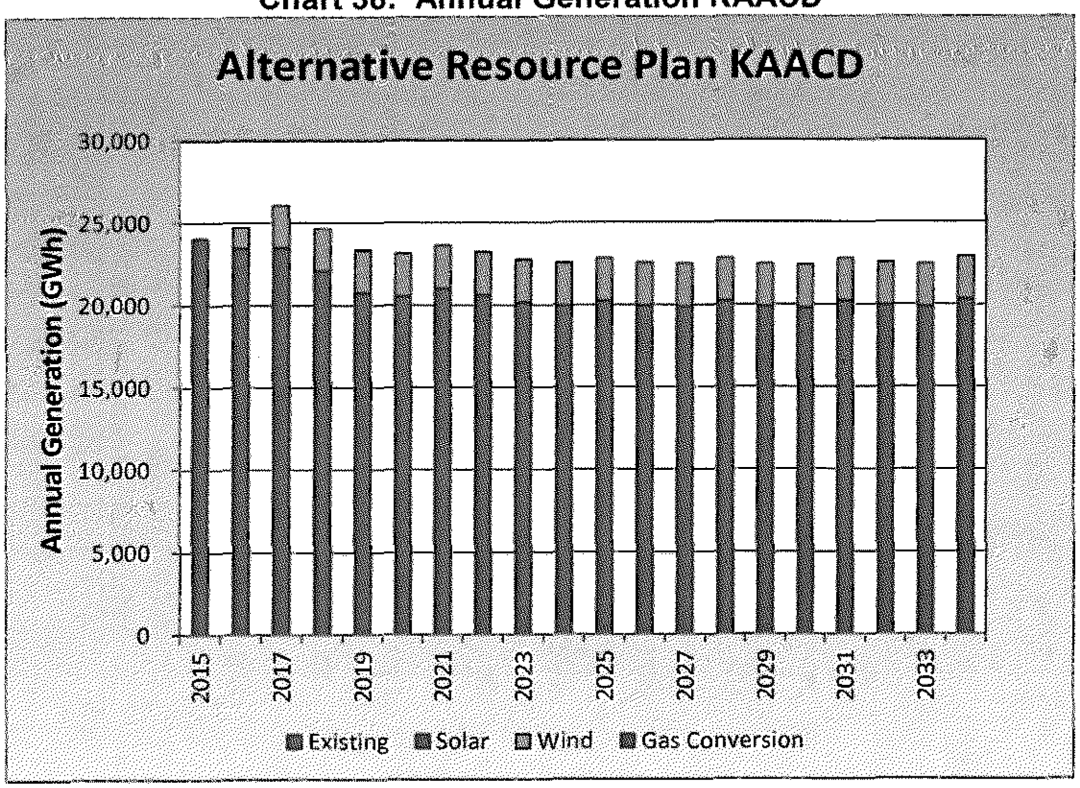


Chart 39: Annual Generation KAACW

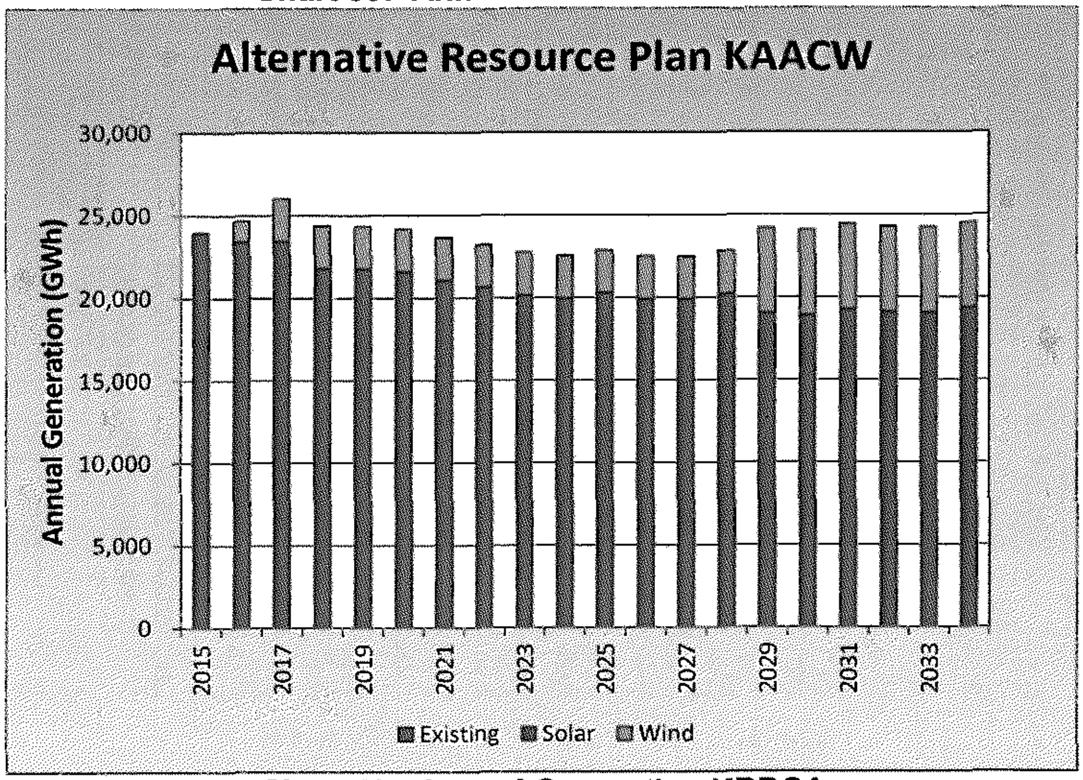


Chart 40: Annual Generation KBBCA

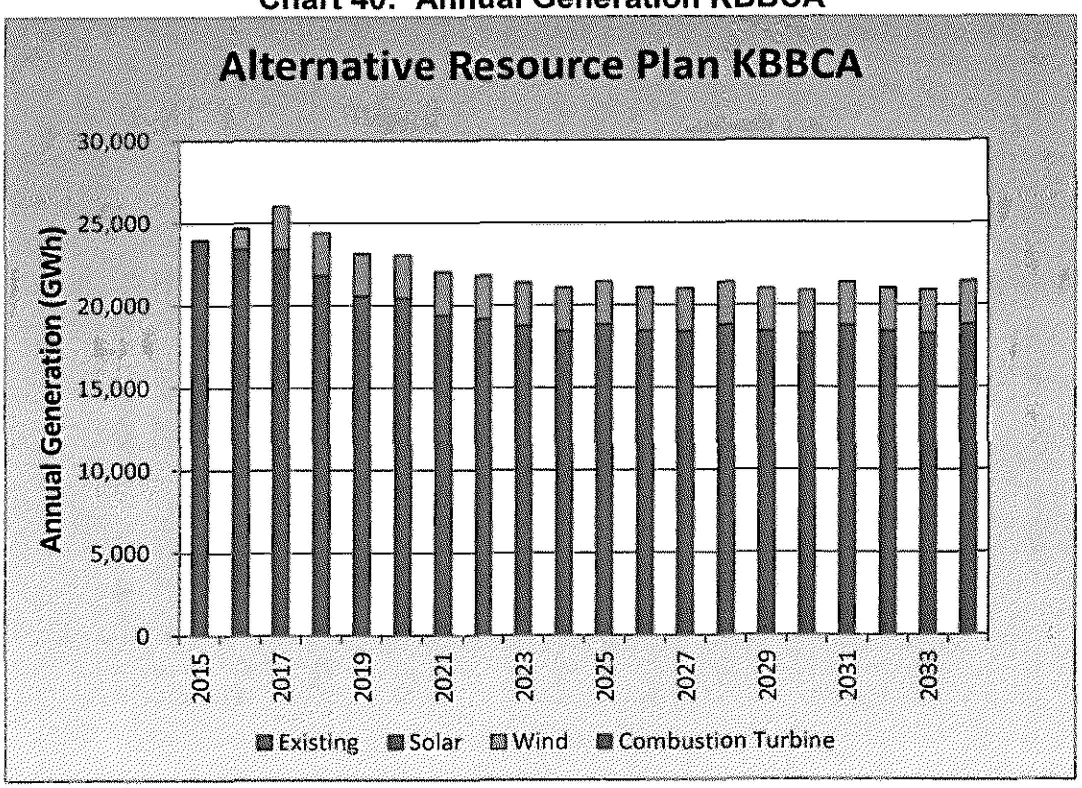


Chart 41: Annual Generation KCCCA

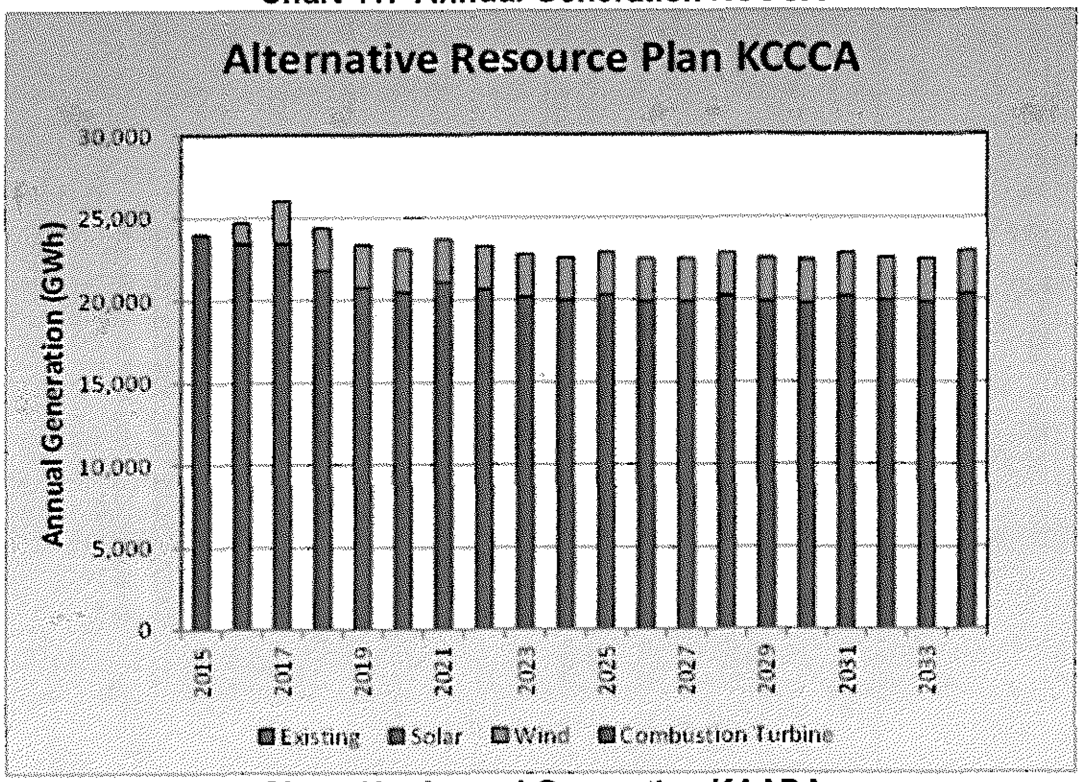
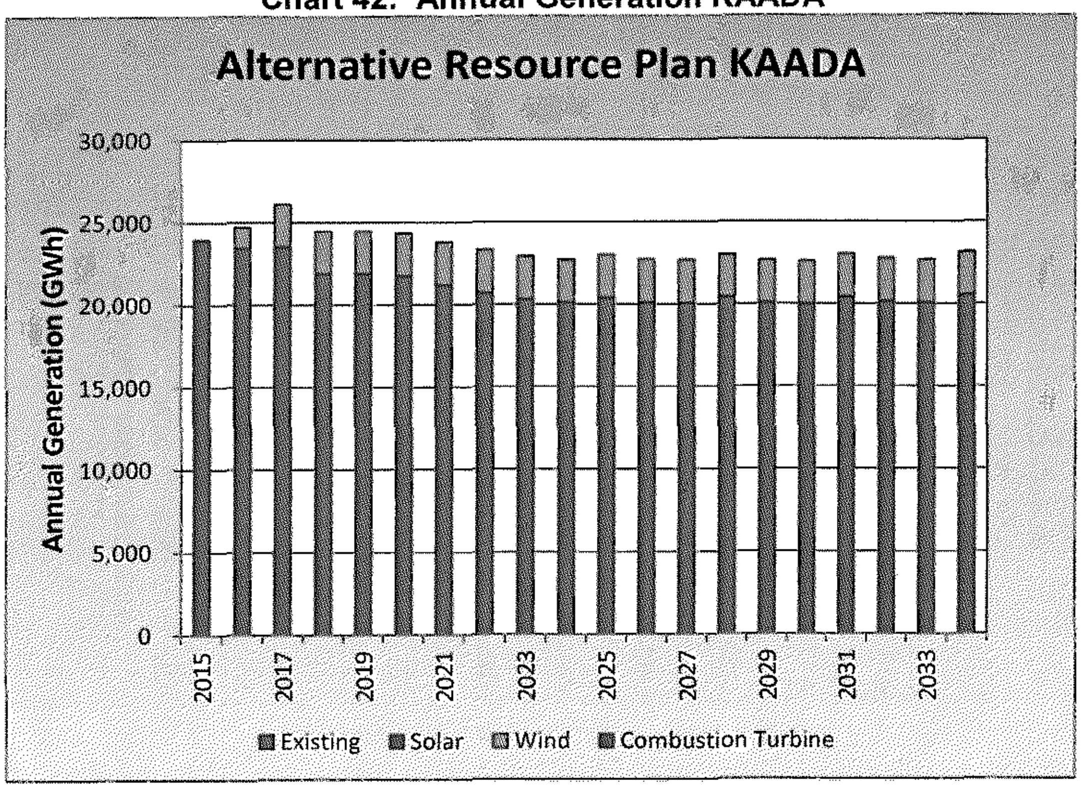


Chart 42: Annual Generation KAADA



7. Annual emissions of each environmental pollutant identified pursuant to 4 CSR 240-22.040(2)(B);

The following charts detail the expected value of annual emissions in each Alternative Resource Plan.

Chart 43: Annual Emissions - KAAAA

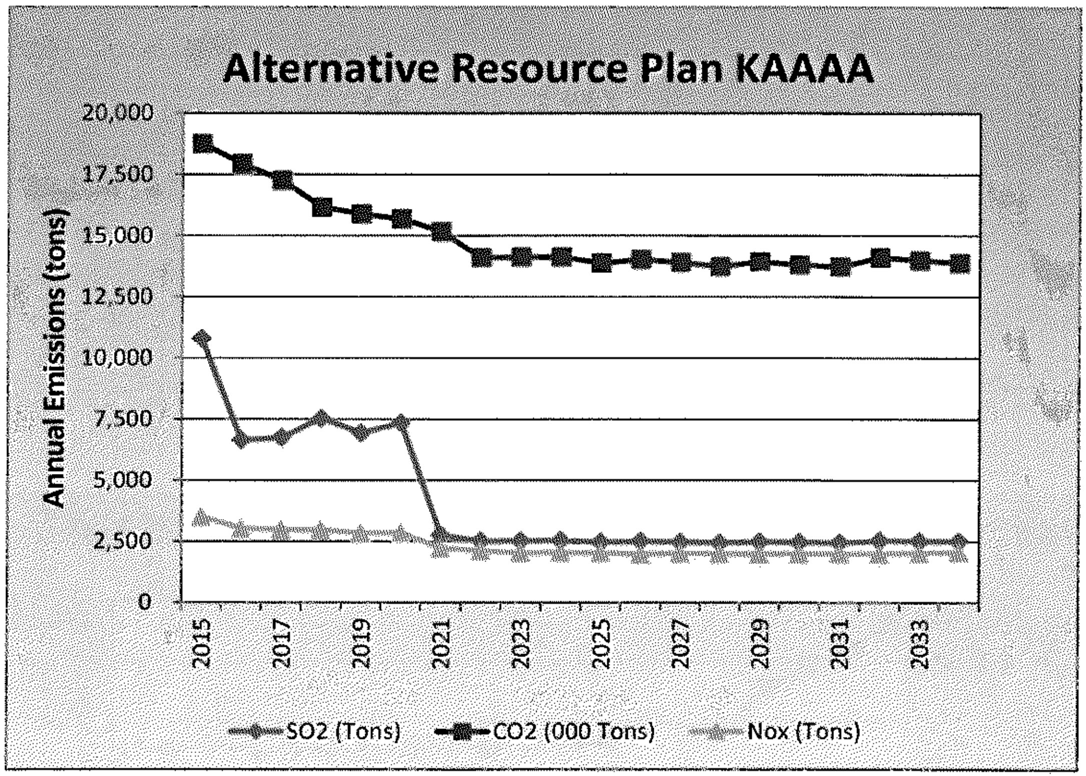


Chart 44: Annual Emissions KAAAC

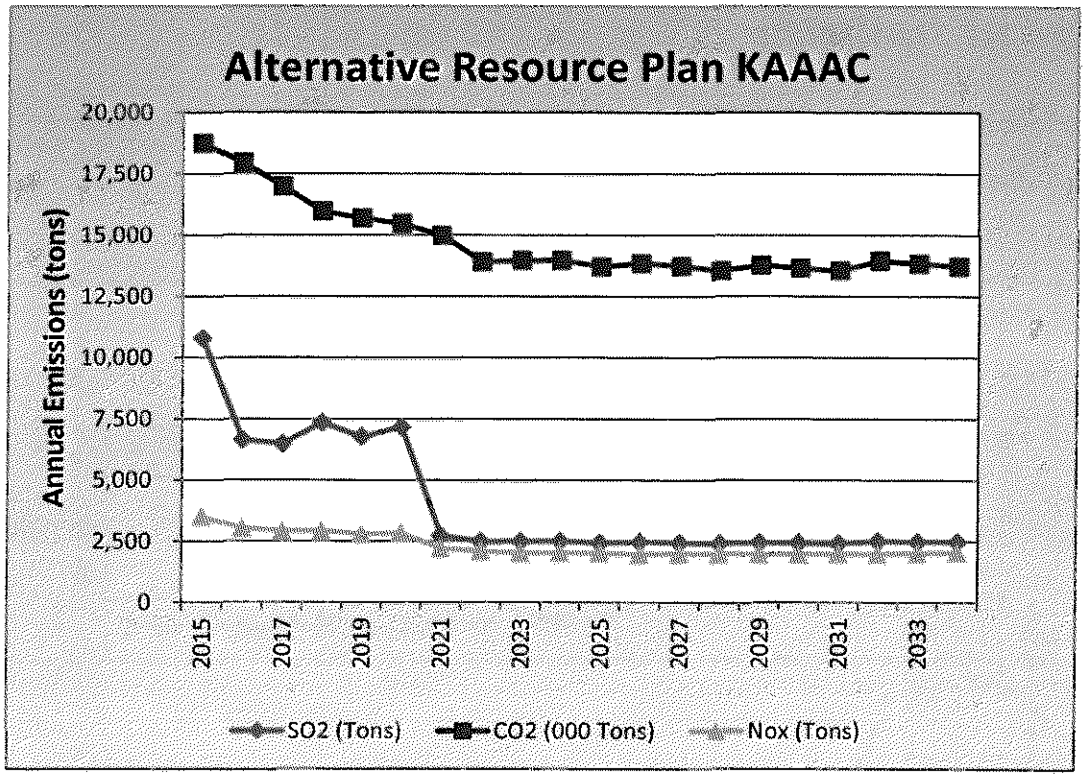


Chart 45: Annual Emissions KAAAD

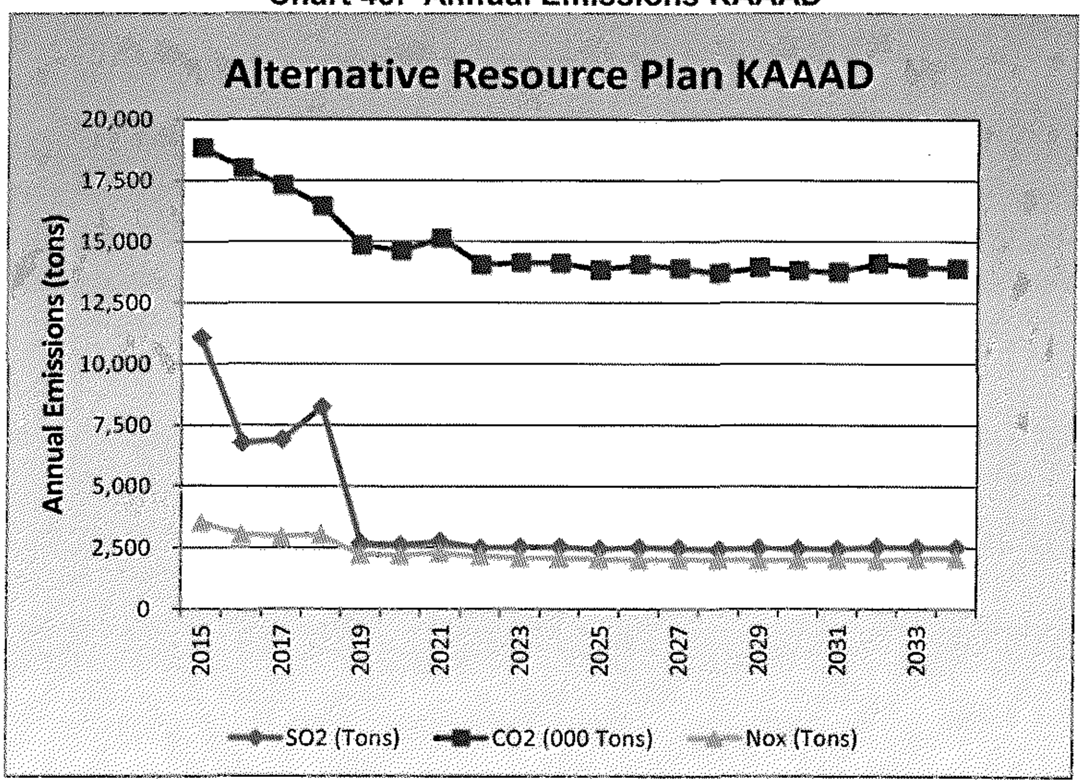


Chart 46: Annual Emissions KAABA

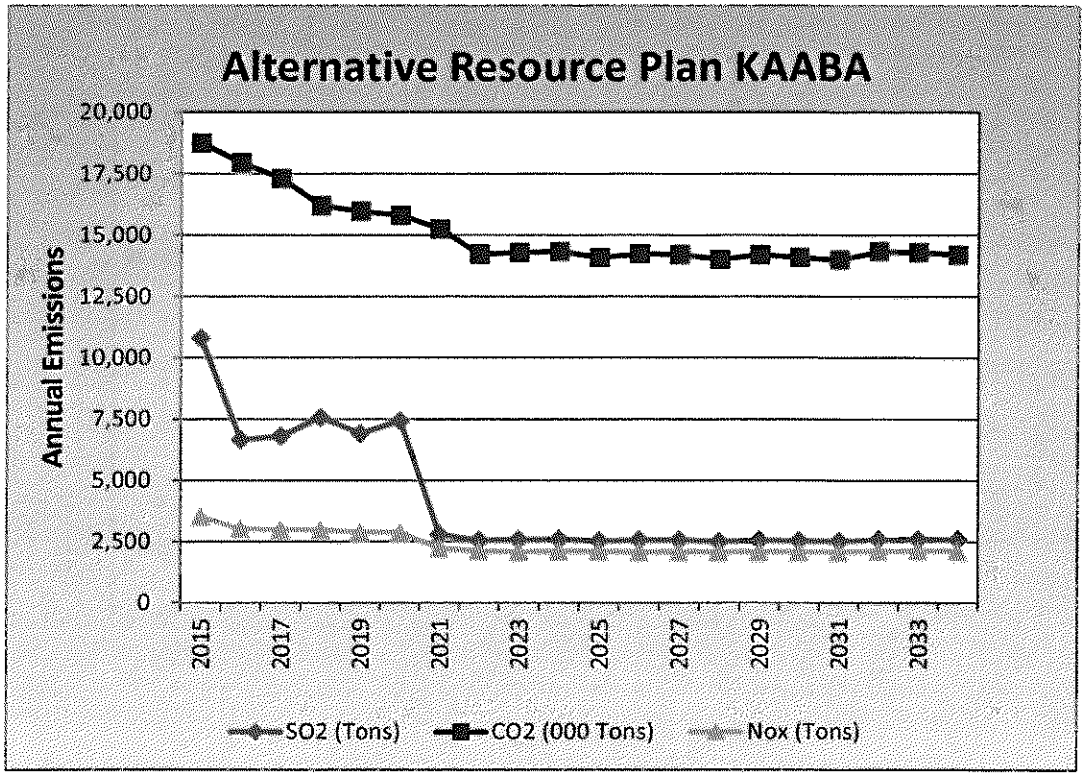


Chart 47: Annual Emissions KAABC

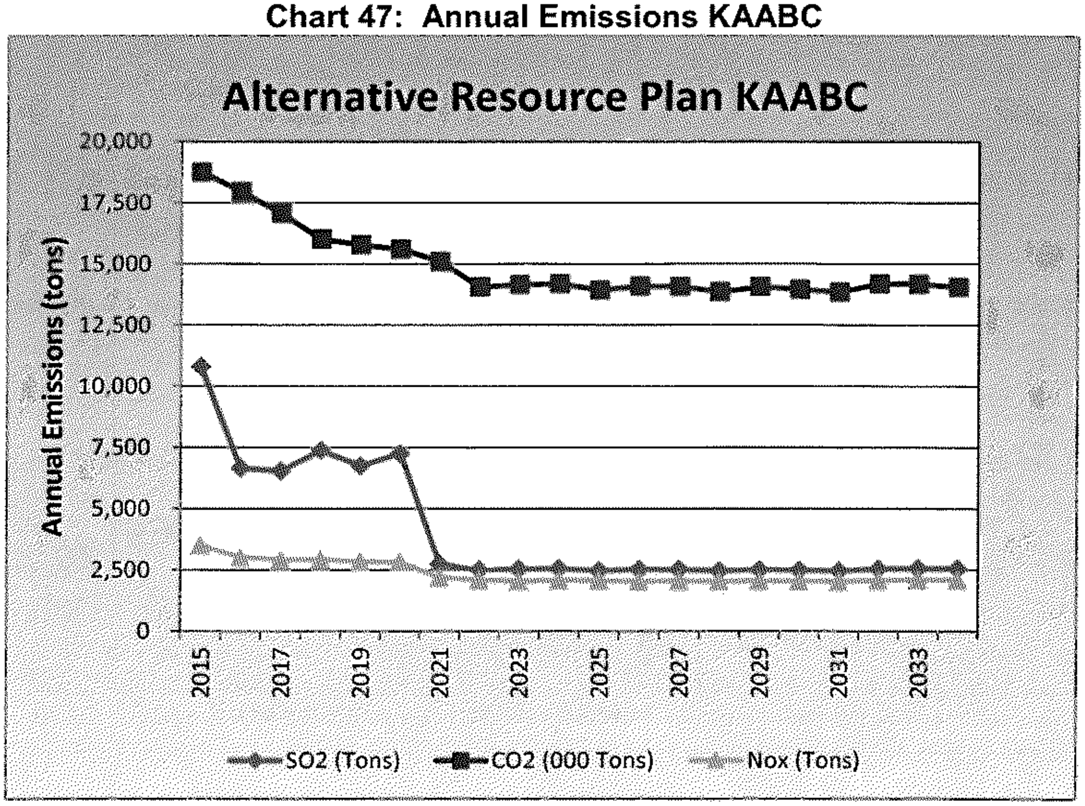


Chart 48: Annual Emissions KAABD

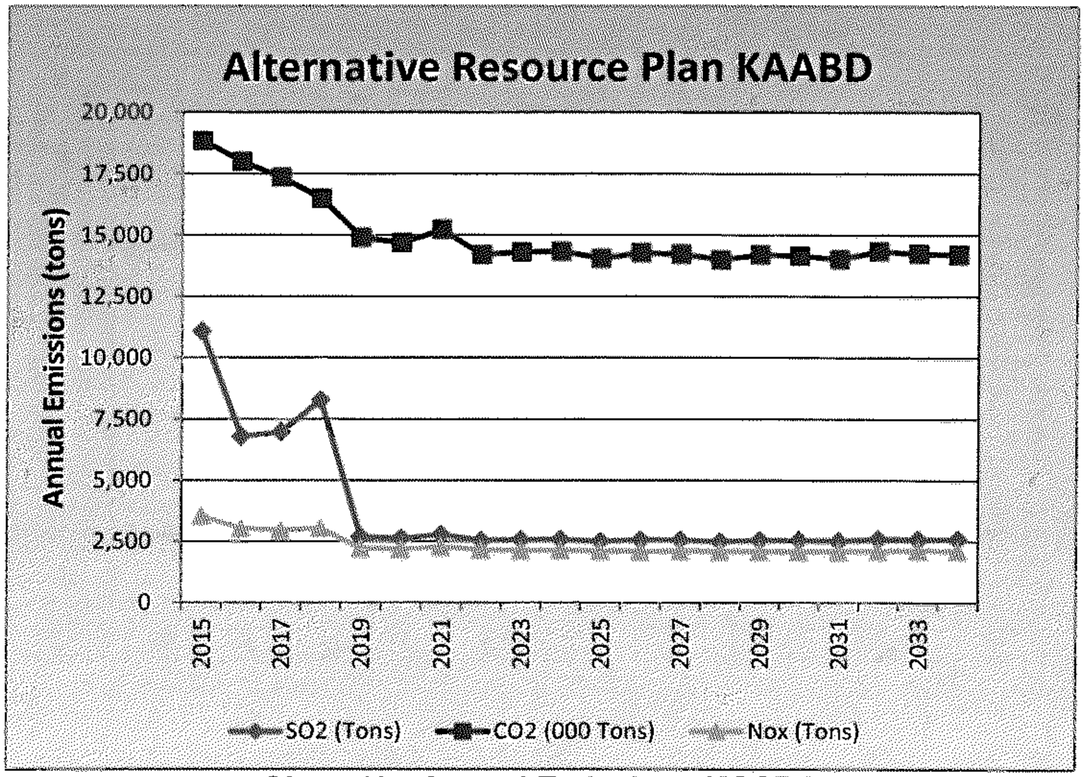


Chart 49: Annual Emissions KCCBA

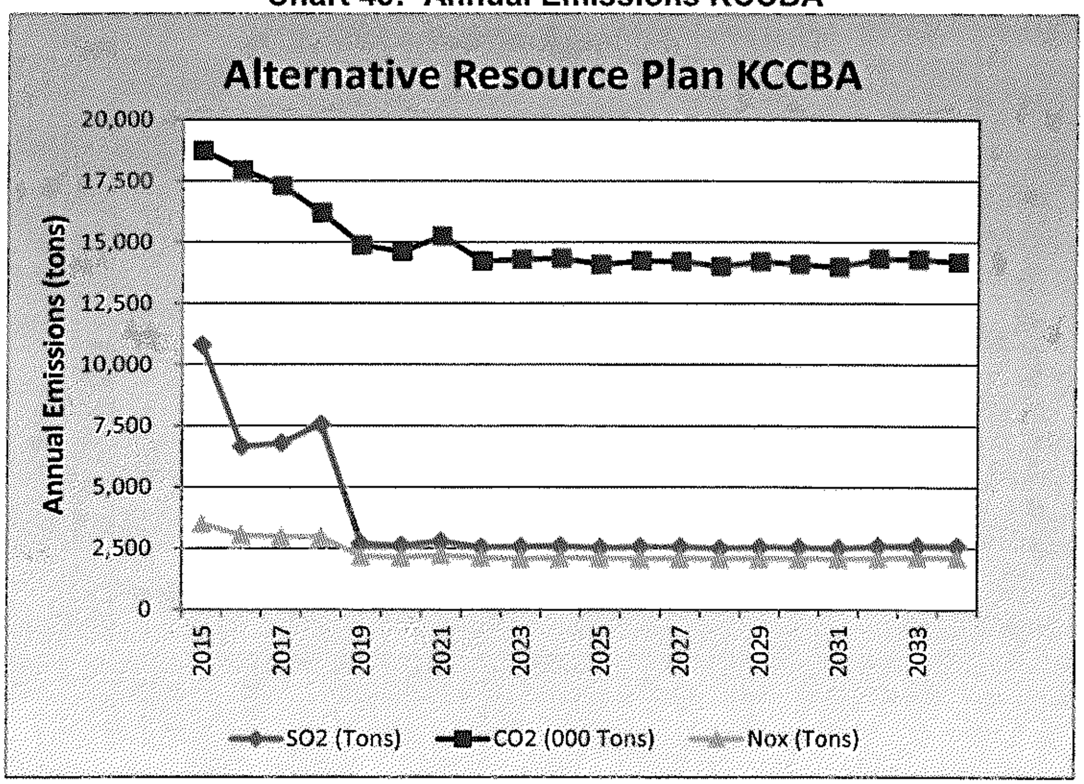


Chart 50: Annual Emissions KAACA

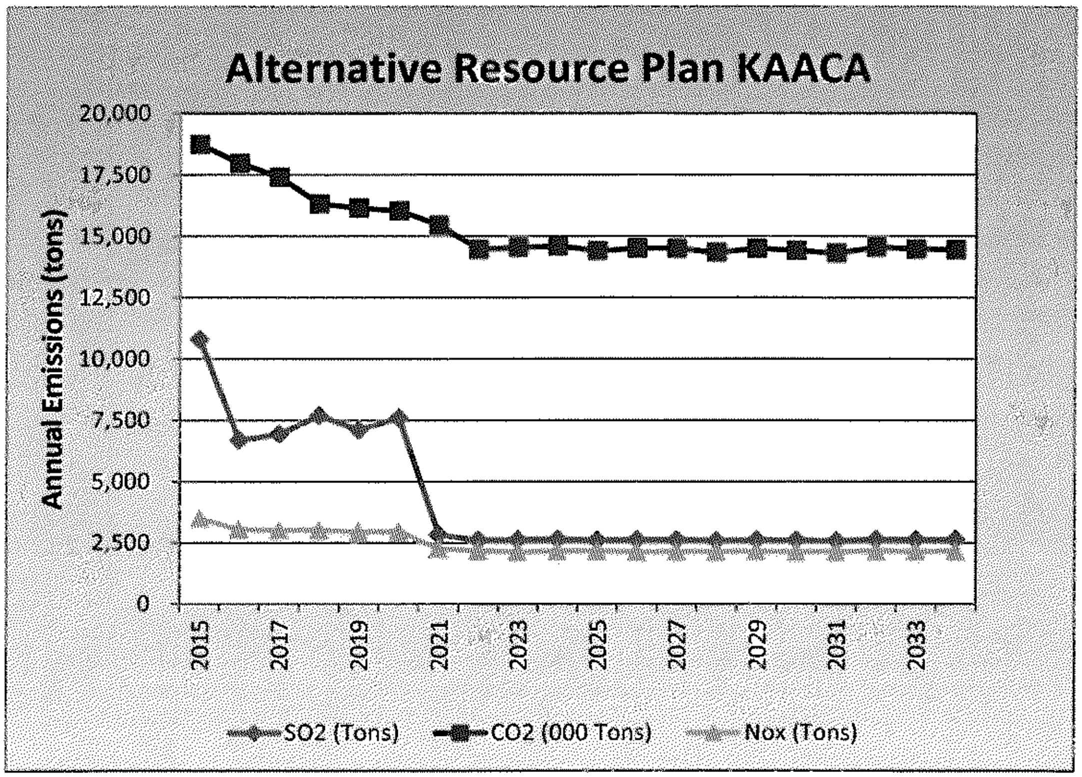


Chart 51: Annual Emissions KAACB

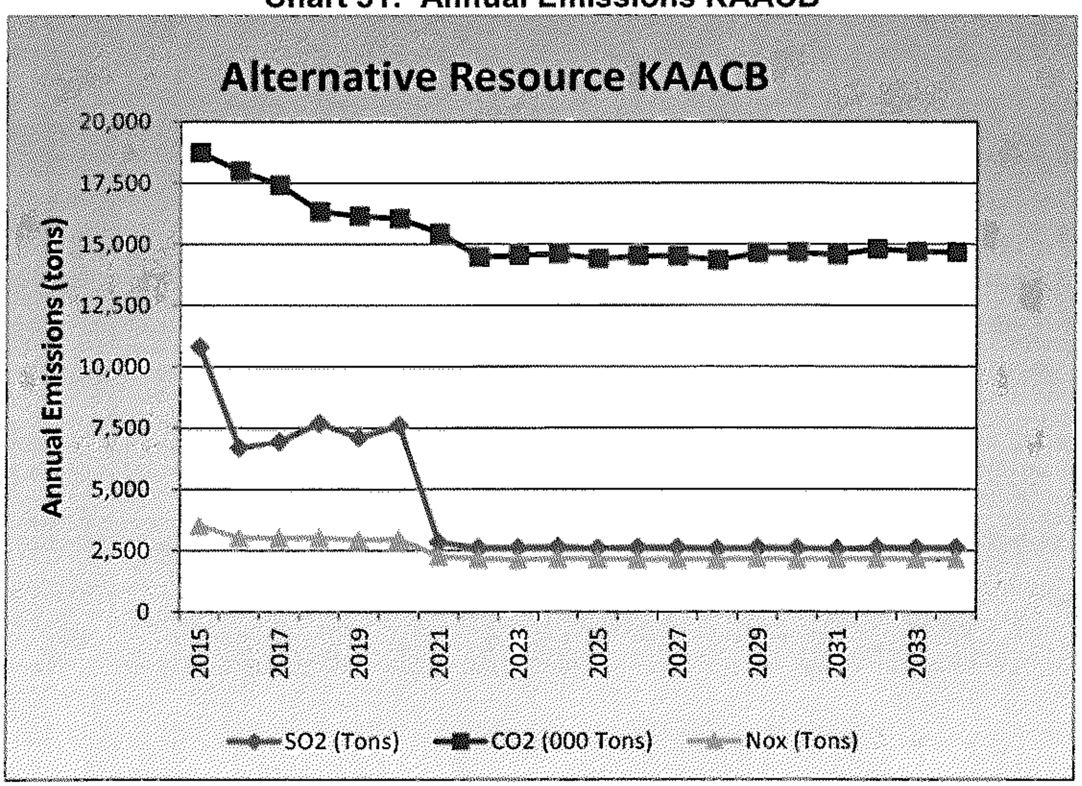


Chart 52: Annual Emissions KAACC

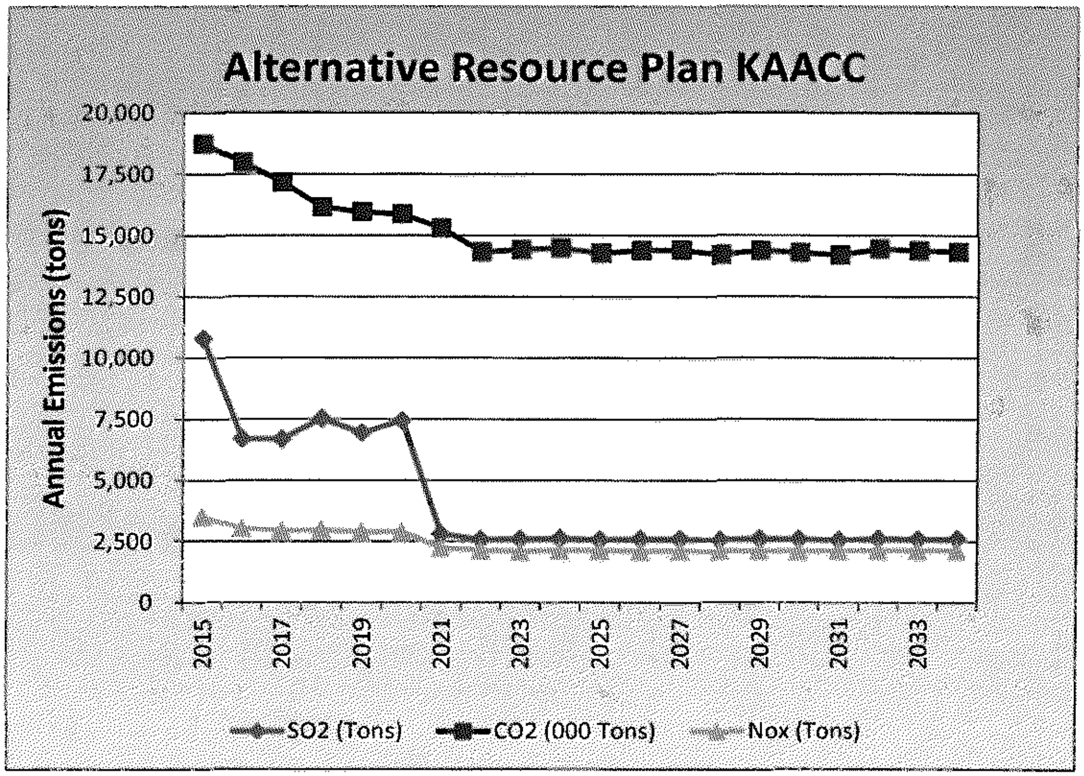


Chart 53: Annual Emissions KAACD

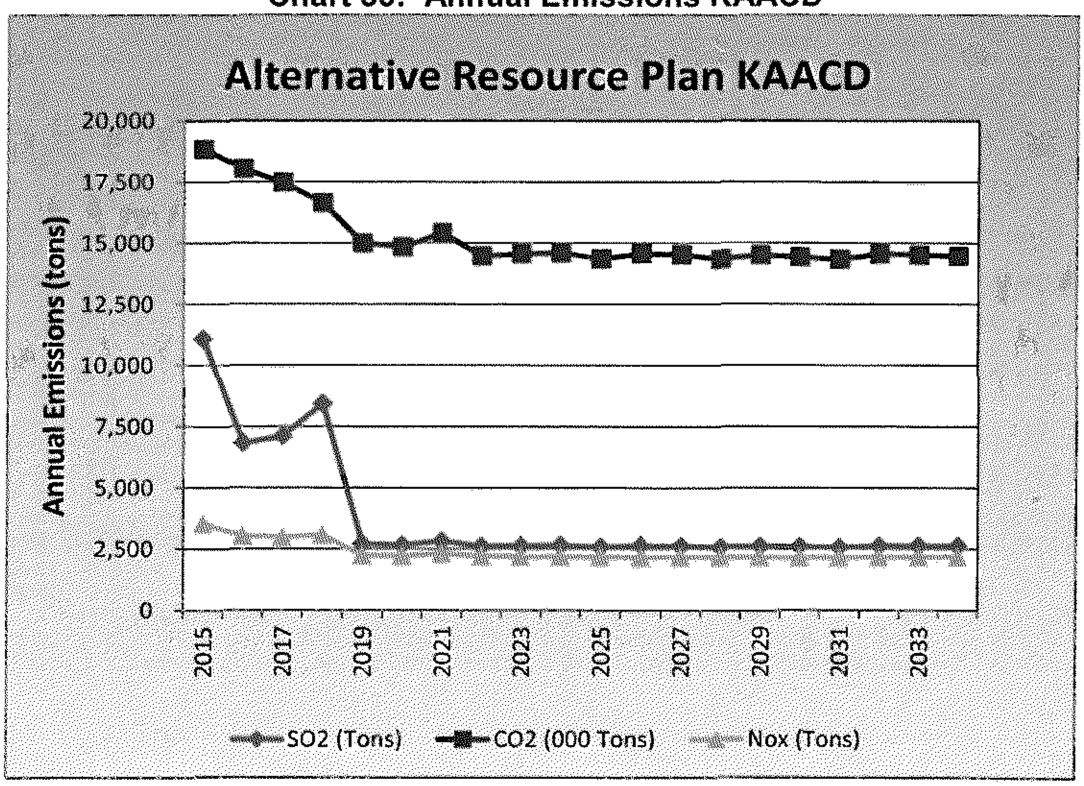


Chart 54: Annual Emissions KAACW

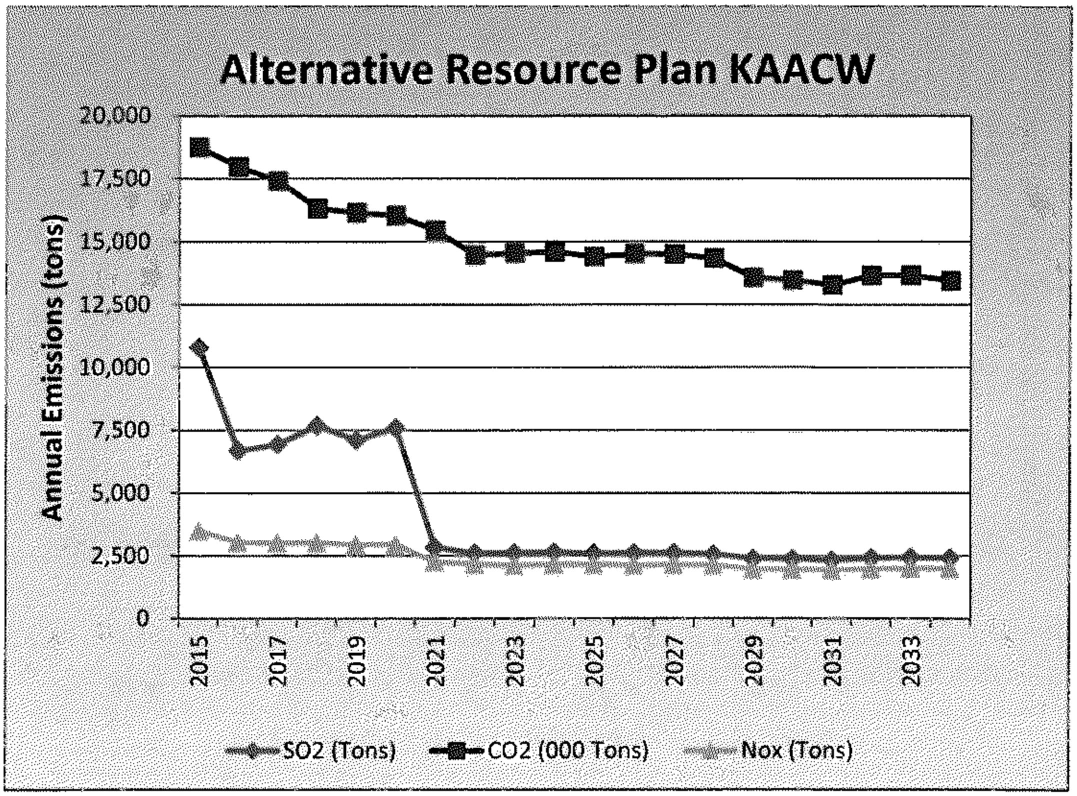


Chart 55: Annual Emissions KBBCA

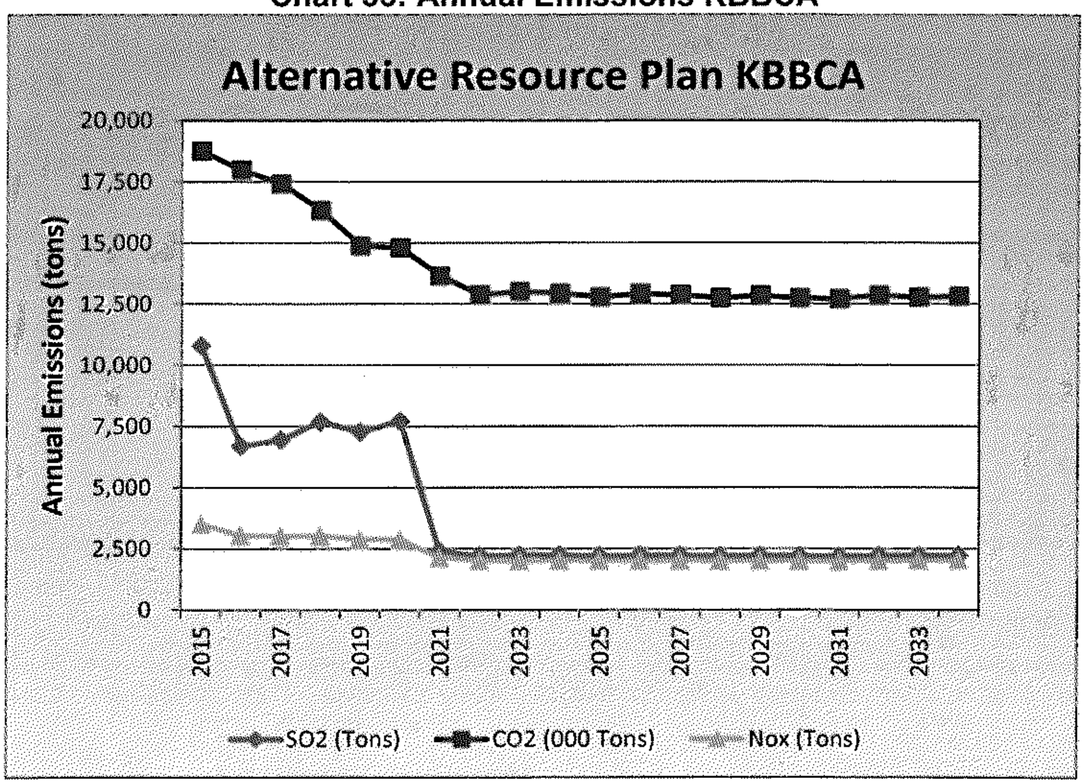


Chart 56: Annual Emissions KAADA

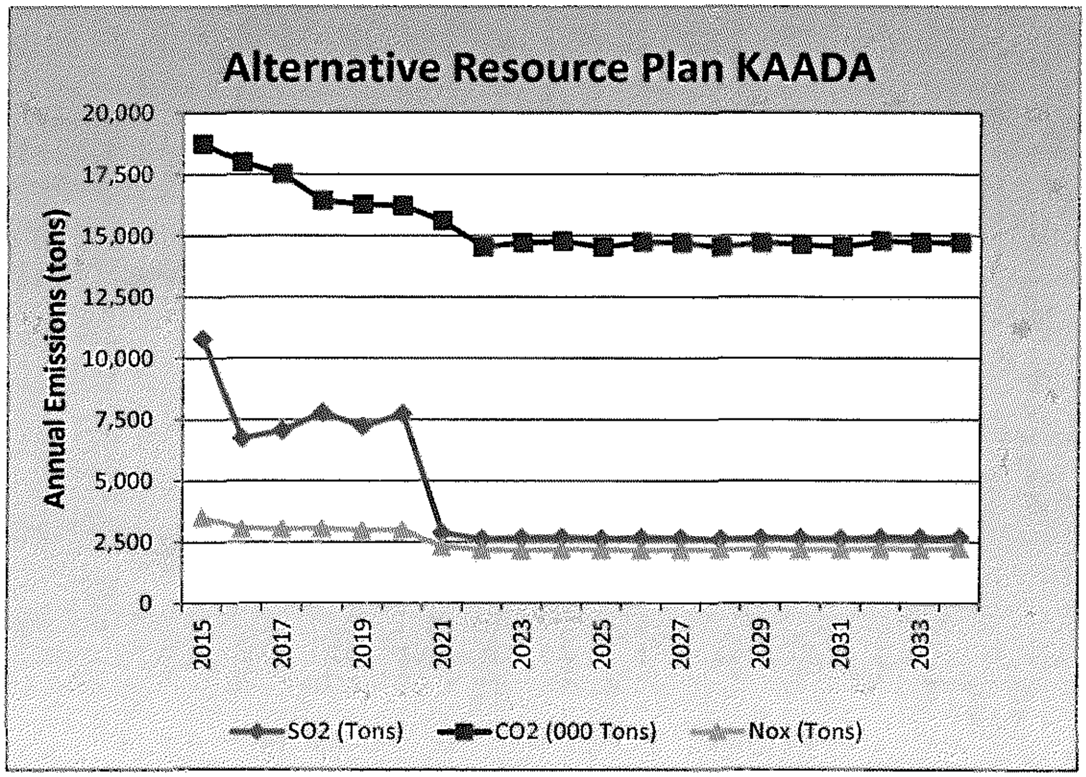
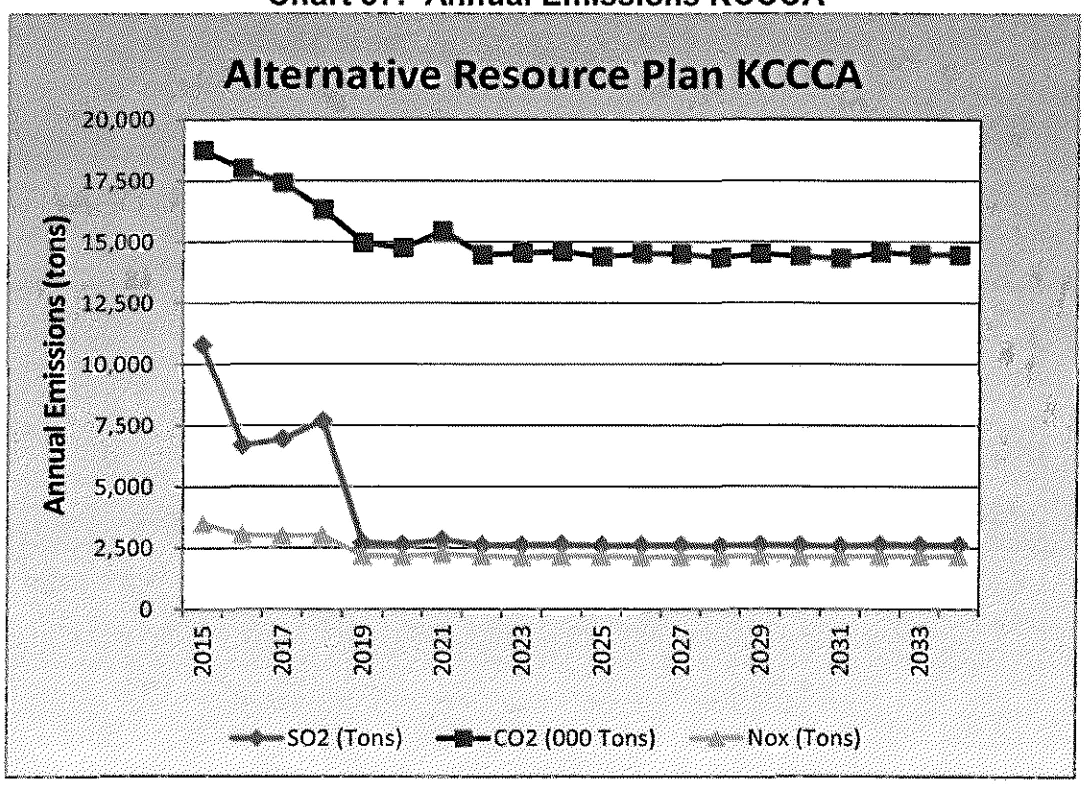


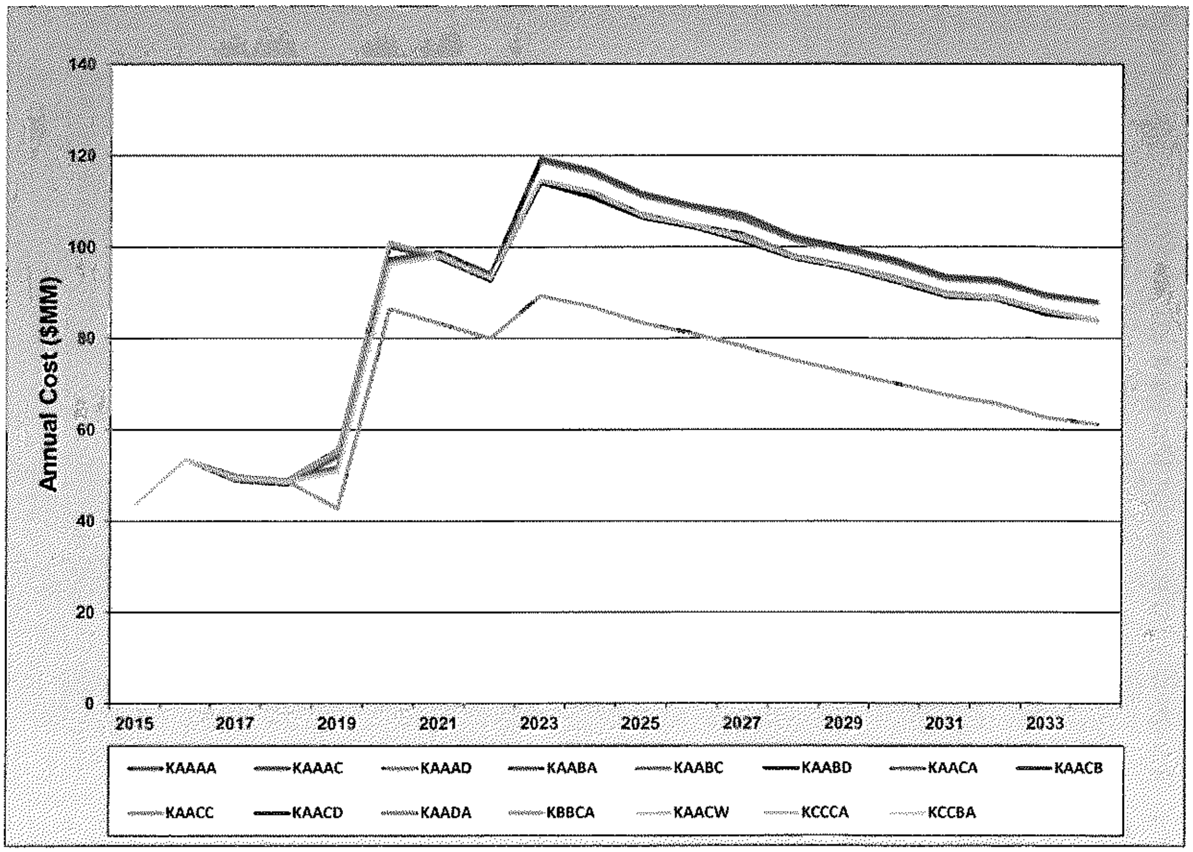
Chart 57: Annual Emissions KCCCA



8. Annual probable environmental costs; and

The following table shows the annual probable environmental cost of each plan on an expected value basis.

Chart 58: Probable Environmental Costs



9. Public and highly-confidential forms of the capacity balance spreadsheets completed in the specified format;

The following tables provide the KCP&L forecast of capacity balance for the next 20 years for each of the Alternative Resource Plans discussed elsewhere in this document.

Table 28: Capacity Forecast - Alternative Resource Plan KAAAA **Highly Confidential**

[redacted]

HC

Table 29: Capacity Forecast - Alternative Resource Plan KAAAC **Highly Confidential**

[redacted]

HC

Table 30: Capacity Forecast - Alternative Resource Plan KAAAD **Highly Confidential**

[redacted]

HC

Table 31: Capacity Forecast - Alternative Resource Plan KAABA **Highly Confidential**

[redacted]

HC

Table 32: Capacity Forecast - Alternative Resource Plan KAABC **Highly Confidential**

[redacted]

HC

Table 33: Capacity Forecast - Alternative Resource Plan KAABD **Highly Confidential**

[redacted]

HC

Table 34: Capacity Forecast - Alternative Resource Plan KCCBA **Highly Confidential**

[redacted]

HC

Table 35: Capacity Forecast - Alternative Resource Plan KAACA **Highly Confidential**

[redacted]

HC

Table 36: Capacity Forecast - Alternative Resource Plan KAACB **Highly Confidential**

[redacted]

HC

Table 37: Capacity Forecast - Alternative Resource Plan KAACC **Highly Confidential**

[redacted]

Table 38: Capacity Forecast - Alternative Resource Plan KAACD **Highly Confidential**

[redacted]

HC

Table 39: Capacity Forecast - Alternative Resource Plan KAACW **Highly Confidential**

[redacted]

HC

Table 40: Capacity Forecast - Alternative Resource Plan KBBCA **Highly Confidential**

[redacted]

HC

Table 41: Capacity Forecast - Alternative Resource Plan KCCCA **Highly Confidential**

[redacted]

Table 42: Capacity Forecast - Alternative Resource Plan KAADA **Highly Confidential**

[redacted]

HC

(C) The analysis of economic impact of alternative resource plans, calculated with and without utility financial incentives for demand-side resources, shall provide comparative estimates for each year of the planning horizon—

Each year of the planning period, all alternative plans are simulated with DSM expensed in the year spent. Summary results for this analysis are provided in the following Section.

1. For the following performance measures for each year:

A. Estimated annual revenue requirement;

B. Estimated annual average rates and percentage increase in the average rate from the prior year; and

C. Estimated company financial ratios and credit metrics; and

The following tables detail performance measures of each Alternative Resource Plan, with and without incentive payments for DSM expenditures on an expected value basis.

Table 43: Economic Impact of Alternative Resource Plan KAAAA **Highly Confidential **

[redacted]

Table 44: Economic Impact of Alternative Resource Plan KAAAC ** Highly Confidential **

[redacted]

HC

Table 45: Economic Impact of Alternative Resource Plan KAAAD ** Highly Confidential **

[redacted]

Table 46: Economic Impact of Alternative Resource Plan KAABA ** Highly Confidential **

[redacted]

HC

Table 47: Economic Impact of Alternative Resource Plan KAABC ** Highly Confidential **

[redacted]

Table 48: Economic Impact of Alternative Resource Plan KAABD ** Highly Confidential **

[redacted]

HC

Table 49: Economic Impact of Alternative Resource Plan KCCBA ** Highly Confidential **

[redacted]

Table 50: Economic Impact of Alternative Resource Plan KAACA ** Highly Confidential **

[redacted]

HC

Table 51: Economic Impact of Alternative Resource Plan KAACB ** Highly Confidential **

[redacted]

Table 52: Economic Impact of Alternative Resource Plan KAACC ** Highly Confidential **

[redacted]

HC

Table 53: Economic Impact of Alternative Resource Plan KAACD ** Highly Confidential **

[redacted]

Table 54: Economic Impact of Alternative Resource Plan KAACW ** Highly Confidential **

[redacted]

HC

Table 55: Economic Impact of Alternative Resource Plan KBBCA ** Highly Confidential **

[redacted]

Table 56: Economic Impact of Alternative Resource Plan KCCCA ** Highly Confidential **

[redacted]

HC

Table 57: Economic Impact of Alternative Resource Plan KAADA ** Highly Confidential **

[redacted]

HC

2. If the estimated company financial ratios in subparagraph (4)(C)1.C. are below investment grade in any year of the planning horizon, a description of any changes in legal mandates and cost recovery mechanisms necessary for the utility to maintain an investment grade credit rating in each year of the planning horizon and the resulting performance measures in subparagraphs (4)(C)1.A.–(4)(C)1.C. of the alternative resource plans that are associated with the necessary changes in legal mandates and cost recovery mechanisms.

The expected values of alternative plan performance ratios do not materially change below current conditions. The expectations would be that the investment rating of the company is not at risk from the choice of any particular alternative resource plan.

(D) A discussion of how the impacts of rate changes on future electric loads were modeled and how the appropriate estimates of price elasticity were obtained;

Rate calculation is performed in this analysis on a perfect rate making basis. Total revenue requirement is calculated which requires exogenous load forecast(s) as an input. In other words, rates are an output of the perfect rate making process.

Where rate elasticity is used in the IRP process is in the development of the load forecast. This is documented in the response to rule 22.030(7)(A)1 in Volume 3 of this filing.

(E) A discussion of the incremental costs of implementing more renewable energy resources than required to comply with renewable energy legal mandates;

Rule 060(3)(A)2 requires the company to study a larger build of renewable resources beyond the current Missouri RES requirement. To meet this requirement and review the potential impact of a proposal to increase RES requirements in Missouri, the company included a plan which increased the renewable portfolio for the company and is described in detail in Section 3 of this volume.

The results of this analysis are detailed throughout this Volume and in Volume 7. A summary review shows that increasing the amount of wind in the current company portfolio generally increases the NPVRR of the alternative resource plan.

(F) A discussion of the incremental costs of implementing more energy efficiency resources than required to comply with energy efficiency legal mandates;

At the current time, there is no specifically target legal mandate for energy efficiency. However this analysis reviews different levels of energy efficiency. These alternative plans are included in the integrated analysis results presented elsewhere in this Volume.

(G) A discussion of the incremental costs of implementing more energy resources than required to comply with any other energy resource legal mandates; and

At this time no other legal resource mandates exist. None are contemplated in this analysis.

(H) A description of the computer models used in the analysis of alternative resource plans.

The MIDAS™ model provides hourly chronological dispatch of all system generating assets including unit commitment logic that simulation the actual operation of the utility system resources. The model contains all unit operating variables required to simulate the units. These variables include but are not limited to, heat rates, fuel costs, variable operation and maintenance costs, sulfur dioxide emission allowance costs, scheduled maintenance outages, forced and de rate outages rates each on a per unit basis.

The model can also simulate capacity and energy purchases from or sales to a market in either a firm transaction or as a spot market transaction. In the case of market based transactions, all can be conducted with the impact of environmental credits factored in. The level of purchases or sales can also be limited to any range desired. For this IRP, the Company has limited the ability to purchase firm sales to a level consistent with the company's current operating methods and market conditions.

This model met all conditions of previous rule 22.070 (7) (B), and was used for all previous IRP integrated analysis filings.

SECTION 5: UNCERTAIN FACTORS

(5) The utility shall describe and document its selection of the uncertain factors that are critical to the performance of the alternative resource plans. The utility shall consider at least the following uncertain factors:

The company began developing a list of potential critical uncertain factors to consider in the alternative resource plans by including items required per Rule 4 CSR 240-22.060(5). In addition, the selection of critical uncertain factors considered previously filed IRP stipulations and agreements, the order from the Contemporary Issues process in Case EO-2015-0041, and internal company management concerns. The following table shows the consolidated list of uncertain factors considered by the company.

Table 58: Uncertain Factors

UNCERTAIN FACTOR	RULE	DEFAULT STATE	TEST STATES
Load Growth	060(5)(A)	MID	HIGH, LOW
Interest Rates/Credit Market Conditions	060(5)(B)	MID	HIGH, LOW
Legal Mandate Changes	060(5)(C)	RES	STANDARD
Relative Fuel Prices	060(5)(D)		
Natural Gas		MID	HIGH, LOW
Coal		MID	HIGH, LOW
Siting and Permitting Costs	060(5)(E)	MID	HIGH, LOW
Construction Capital Costs	060(5)(F)	MID	HIGH, LOW
Purchased Power Costs	060(5)(G)	MID	HIGH, LOW
Emission Allowance Markets	060(5)(H)		
CO2		NONE	MARKET EXISTS
SO2		MID	HIGH, LOW
NOX		MID	HIGH, LOW
Fixed O&M	060(5)(I)	MID	HIGH, LOW
Expected Forced Outage Rate (EFOR)	060(5)(J)	MID	HIGH, LOW
DSM Load Impacts	060(5)(K)	MID	HIGH, LOW
DSM Utility Marketing & Delivery Costs	060(5)(L)	MID	HIGH, LOW
Market Import/Export Limits		MID	HIGH, LOW

The Company compiled information concerning the risks listed in 22.060 (5) from subject matter experts within the company. The experts were requested to provide mid, high and low scenario forecasts for their particular risk.

The company utilized the Ventyx System Optimizer Model™[CapEx™] to provide a preliminary test of each state of the uncertain factors. CapEx™ is a linear program based model that chooses the least-cost expansion plan given a known load growth and other fixed market factors. Once a load growth forecast and market is defined, the model is allowed to pick from the available supply, DSM and retirement options to develop the least-cost expansion plan.

The company executed test runs for each sensitivity to determine if the resulting least-cost expansion plan constituted different choices of DSM, supply or retirements. If the model did not materially change its expansion plan by changing sensitivity, that factor was not deemed to be a Critical Uncertain Factor. However, if the model chose different options, such as different technologies or foregoing DSM programs, then that factor would be deemed a Critical Uncertain Factor and was incorporated within the Risk Analysis Decision Tree.

(A) The range of future load growth represented by the low-case and high-case load forecasts;

The high, mid and low load growth cases compliant with and described in Rule 22.030 (7) and 22.030(8) were used in the CapEx™ model. The CapEx™ results demonstrated that load growth is a critical uncertain factor. Load growth sensitivity was passed onto the integrated analysis.

(B) Future interest rate levels and other credit market conditions that can affect the utility's cost of capital and access to capital;

The company tested high and low long term cost of capital to model the sensitivity of CapEx™ plans to changes in these factors. When the adjusted cost of capital rates were input into the CapEx™ model, no material changes occurred to the optimal expansion plan. Therefore the cost of capital was not deemed to be a critical uncertain factor and not included in the integrated analysis.

(C) Future changes in legal mandates;

Future changes to legal mandates would include the potential of a Federal Renewable Energy Standard. For the purposes of modeling, the company assumed the federal requirements would be similar to the Missouri Renewable Energy Standard (RES) requirements except that they would apply on a national level. The Federal standard would not require the Company to acquire additional renewable resources beyond the requirements of the Missouri rules. However, the entire country would be required to acquire additional renewable resources causing an adjustment to power market prices. When adjusted market prices were input into the CapEx™ model, no material changes occurred to the optimal expansion plan. Therefore the Federal renewable standard was not deemed to be a critical uncertain factor and not included in the integrated analysis.

(D) Relative real fuel prices;

NATURAL GAS PRICES

High and low natural gas price forecast scenarios were developed as inputs into the CapEx™ model. The optimized expansion plans for the high and low cases are sufficiently different to require adding natural gas price risk as a critical uncertain factor. Natural gas price forecast development is detailed in Volume 4, Supply-Side Analysis.

COAL PRICES

High and low delivered coal price forecast scenario was modeled in CapEx™. No material changes were identified in the model's optimal expansion plans. This risk was not included in the integrated analysis. Coal price forecast development is detailed in Volume 4, Supply-Side Analysis.

(E) Siting and permitting costs and schedules for new generation and generation-related transmission facilities for the utility, for a regional transmission organization, and/or other transmission systems;

Siting and permitting costs are incorporated into the cost of construction risk detailed in 22.060 (5) (F).

(F) Construction costs and schedules for new generation and generation-related transmission facilities for the utility, for a regional transmission organization, and/or other transmission systems;

The company determined high and low construction cost estimates for each supply technology that passed the preliminary screening process and was moved into the integrated resource analysis. These high and low construction costs scenarios were modeled in CapEx™. The resulting optimal expansion plans did not materially change for either the high or the low construction cost estimates. Construction cost was not identified as a critical uncertain factor, and this risk was not included in the integrated analysis.

Construction cost risks vary by technology. Detailed information for each of the resource options identified can be viewed in Volume 4.

(G) Purchased power availability, terms, cost, optionality, and other benefits;

High and low purchased power availability was simulated with a high and low cost for the capacity terms of the contracts. High and low purchased power availability scenarios were modeled in CapEx™. No material changes were identified in the model's optimal expansion plans. Purchased power availability was not identified as a critical uncertain factor. This risk was not included in the integrated analysis.

(H) Price of emission allowances, including at a minimum sulfur dioxide, carbon dioxide, and nitrogen oxides;

SO_2 credit price forecast development is detailed in Volume 4, Supply-Side Analysis. High and low SO_2 credit price forecasts were simulated in the CapEx™ model. Resulting optimal expansion plans did not change as this cost was varied. SO_2 credit prices are not considered a critical resource factor and were not used as part of the integrated analysis.

NO_X credit price forecast development is detailed in Volume 4, Supply-Side Analysis. High and low NO_X credit price forecasts were simulated in the CapEx™ model. Resulting optimal expansion plans did not change as this cost was varied. NO_X credit prices are not considered a critical resource factor and were not used as part of the integrated analysis.

CO_2 credit price forecast development is detailed in Volume 4, Supply-Side Analysis. The default assumption is that there will be no CO_2 emissions credit market over the 20-year integrated resource planning period. The impact of including a cost for a CO_2 emission credits market was tested in the CapEx™ model. The resulting optimal expansion plan showed sensitivity to having a CO_2 emissions credit market. Therefore, CO_2 credit prices were included in the integrated analysis as a critical uncertain factor.

(I) Fixed operation and maintenance costs for new and existing generation facilities;

High and low Fixed O&M costs were simulated in the CapEx™ model. Resulting optimal expansion plans did not change as this cost was varied. Therefore, fixed O&M costs were not considered a critical resource factor and were not used as part of the integrated analysis.

(J) Equivalent or full- and partial-forced outage rates for new and existing generation facilities;

High and low equivalent forced outage rates were simulated in the CapEx™ model. Resulting optimal expansion plans did not change as this factor was varied. Therefore, equivalent forced outage rates were not considered a critical resource factor and were not used as part of the integrated analysis.

(K) Future load impacts of demand-side programs and demand-side rates:

High and low load impacts of DSM were simulated in the CapEx™ model. Resulting optimal expansion plans did not materially change as this factor was varied. Therefore, load impacts of DSM were not considered a critical resource factor and were not used as part of the integrated analysis.

(L) Utility marketing and delivery costs for demand-side programs and demand-side rates; and

High and low marketing costs of DSM were simulated in the CapEx™ model. Resulting optimal expansion plans did not change as this factor was varied. Therefore, marketing costs of DSM were not considered a critical resource factor and were not used as part of the integrated analysis.

(M) Any other uncertain factors that the utility determines may be critical to the performance of alternative resource plans.

The MIDAS ™ Model assumes interregional transfers of power are possible and power is allowed to flow freely in the model to help lower overall system costs and reduce the resultant market clearing price for wholesale power. The constraint of this power flow was simulated in the CapEx™ model to determine if a reduction in transfers of power would impact the expansion plan. The resulting optimal expansion plans did not materially change as this factor was varied. Therefore, interregional transfers of power were not considered a critical resource factor and were not used as part of the integrated analysis.

SECTION 6: CRITICAL UNCERTAIN FACTORS ASSESSMENT

(6) The utility shall describe and document its assessment of the impacts and interrelationships of critical uncertain factors on the expected performance of each of the alternative resource plans developed pursuant to 4 CSR 240-22.060(3) and analyze the risks associated with alternative resource plans. This assessment shall explicitly describe and document the probabilities that utility decision makers assign to each critical uncertain factor.

To summarize the results described in Section 5 above, the company determined three risks to be critical uncertain factors that would be used in the risk sensitivities of the integrated analysis; load growth, natural gas prices and CO_2 credit prices. These risks, and the associated probabilities used to model this IRP Filing are represented in this figure 1 below. The probabilities for both load and natural gas are the same as used on all filings since the last triennial filing in 2012 – with Mid 50% and High and Low states at 25% weighted probabilities. For CO2, the decision states are now modeled as a 40% probability there will be a CO2 credit market and 60% probability that no CO2 credit market will exist. The weighted endpoint probability is the product these three weighted probabilities

Figure 1: Decision Tree Probabilities

Endpoint	Load Growth	Natural Gas	CO_2	Endpoint Probability
1	High	High	Yes	2.5%
2	High	High	No	3.8%
3	High	Mid	Yes	5.0%
4	High	Mid	No	7.5%
5	High	Low	Yes	2.5%
6	High	Low	No	3.8%
7	Mid	High	Yes	5.0%
8	Mid	High	No	7.5%
9	Mid	Mid	Yes	10.0%
10	Mid	Mid	No	15.0%
11	Mid	Low	Yes	5.0%
12	Mid	Low	No	7.5%
13	Low	High	Yes	2.5%
14	Low	High	No	3.8%
15	Low	Mid	Yes	5.0%
16	Low	Mid	No	7.5%
17	Low	Low	Yes	2.5%
18	Low	Low	No	3.8%

In order to assess the full range of risks, each possible combination of covariant risk is simulated. Subject matter experts within the company have assigned risk distributions to each of the three drivers. These risks are used to develop an overall distribution of risk using every combination of risk factors. A cumulative risk distribution is then derived from the joint probability calculation of each scenario component risk that defines the scenario.

The Company has used all combinations of identified risk drivers in its analysis. This includes scenarios that exhibited both strong positive and strong negative correlations among risk drivers. By using regression methods, the Company tested the effects of all extreme risk drivers and the cases of strong positive and strong negative correlations. The results of the regression studies are conclusive. Even if strong correlations existed in the long run [either positive or negative], they have no statistically significant impact on plan performance results.

Results of the company correlation study are presented in the following table of regression results.

Table 59: Regression Study Results

Regression Statistics	
Multiple R	0.89
R Square	0.80
Adjusted R Square	0.79
Standard Error	581.16
Observations	270.00

	df	*SS*	*MS*	*F*
Regression	8	346,259,187.46	43,282,398.43	128.15
Residual	261	88,153,035.45	337,751.09	
Total	269	434,412,222.92		

	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	18,584.52	114.61	162.16	0.00
CO2	1,889.68	86.63	21.81	0.00
HGas	(832.55)	156.18	(5.33)	0.00
LGas	488.53	136.98	3.57	0.00
HLoad	304.19	136.98	2.22	0.03
LLoad	(242.61)	136.98	(1.77)	0.08
Load/Gas(+)	47.30	167.77	0.28	0.78
Load/Gas(-)	(48.18)	167.77	(0.29)	0.77
GAS/CO2	336.62	150.06	2.24	0.03

SECTION 7: CRITICAL UNCERTAIN FACTOR PROBABILITIES

(7) The utility decision-makers shall assign a probability pursuant to section (5) of this rule to each uncertain factor deemed critical by the utility. The utility shall compute the cumulative probability distribution of the values of each performance measure specified pursuant to 4 CSR 240-22.060(2). Both the expected performance and the risks of each alternative resource plan shall be quantified. The utility shall describe and document its risk assessment of each alternative resource plan.

Each risk factor has a probability distribution developed by the company subject matter expert. These probability distributions have been combined to produce overall joint probabilities for critical factor combinations.

(A) The expected performance of each resource plan shall be measured by the statistical expectation of the value of each performance measure.

Table 60: Expected Value Plan Performance Measures ** Highly Confidential **

[redacted]

(B) The risk associated with each resource plan shall be characterized by some measure of the dispersion of the probability distribution for each

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performance measure, such as the standard deviation or the values associated with specified percentiles of the distribution.

Table 61: Standard Deviation Plan Performance Measures ** Highly Confidential **

[redacted]

Note: Several performance measures are not affected by the individual scenario risk and therefore exhibits no standard deviation.

(C) The utility shall provide—

1. A discussion of the method the utility used to determine the cumulative probability—

For the overall risk analysis, the company assumed independence of the three critical uncertain factors for this long term analysis. The individual scenarios utilized a joint probability of the probabilistic occurrence of each risk component that defined the scenario. This method and its statistical performance is described in Section 6 of this Volume.

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A. An explanation of how the critical uncertain factors were identified, how the ranges of potential outcomes for each uncertain factor were determined, and how the probabilities for each outcome were derived; and

The method for determining whether or not a risk was an uncertain factor is detailed in Section 5 of this Volume. The risk distribution for the load forecast and natural gas forecast was determined by the company subject matter expert. The risk distribution for CO_2 was vetted and set by the KCP&L executive team.

B. Analyses supporting the utility's choice of ranges and probabilities for the uncertain factors;

Supporting documentation for the choice of probabilistic range is in Volume 3 for the load growth risk and Volume 4 for Natural Gas and CO_2 credit price risk.

2. Plots of the cumulative probability distribution of each distinct performance measure for each alternative resource plan;

Chart 59: Cumulative Probability - NPVRR

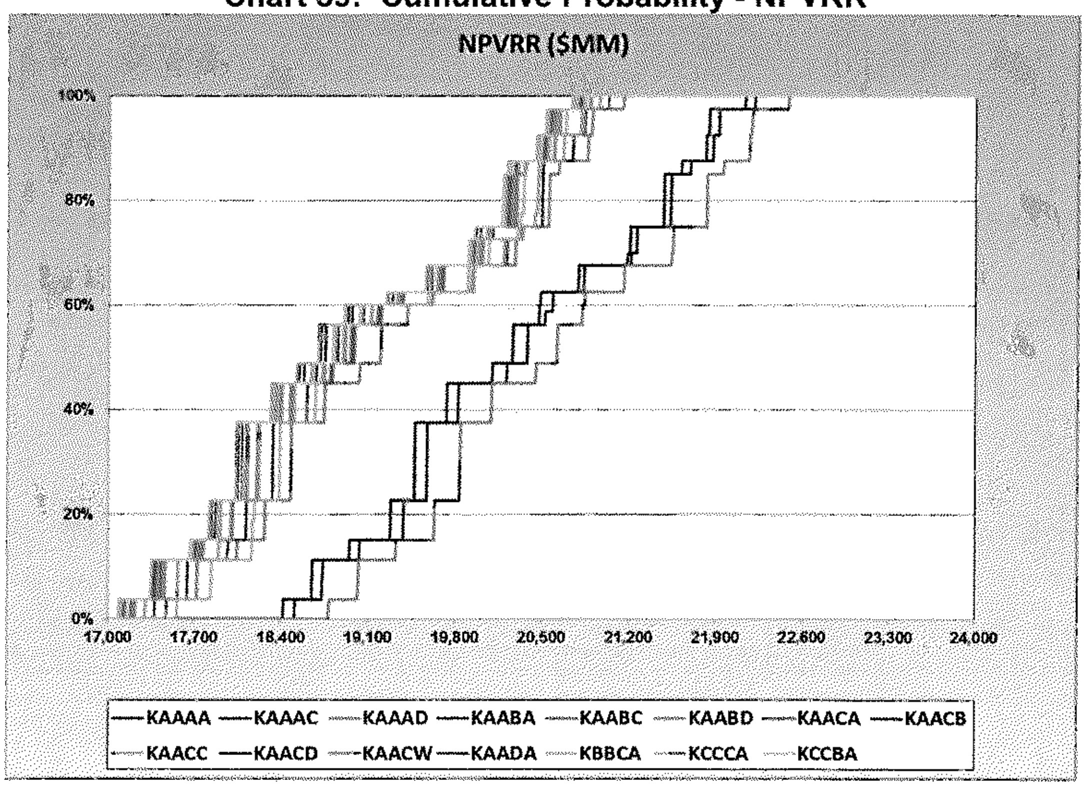


Chart 60: Cumulative Probability - PEC

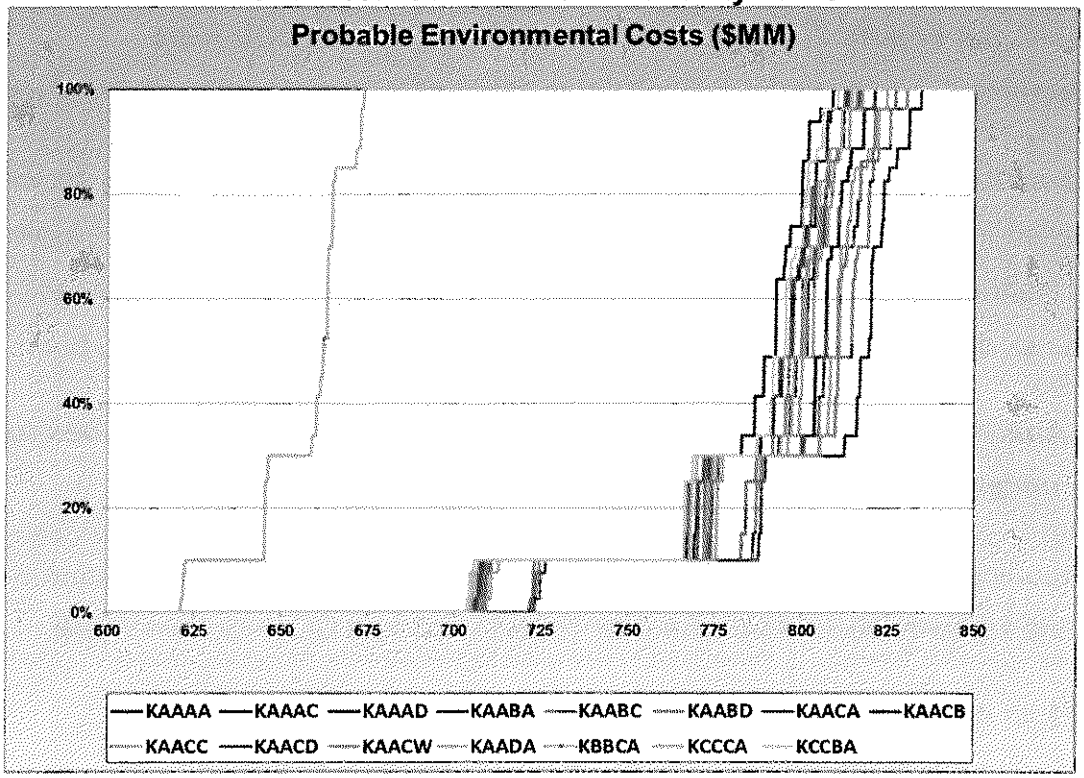


Chart 61: Cumulative Probability - Average Rates

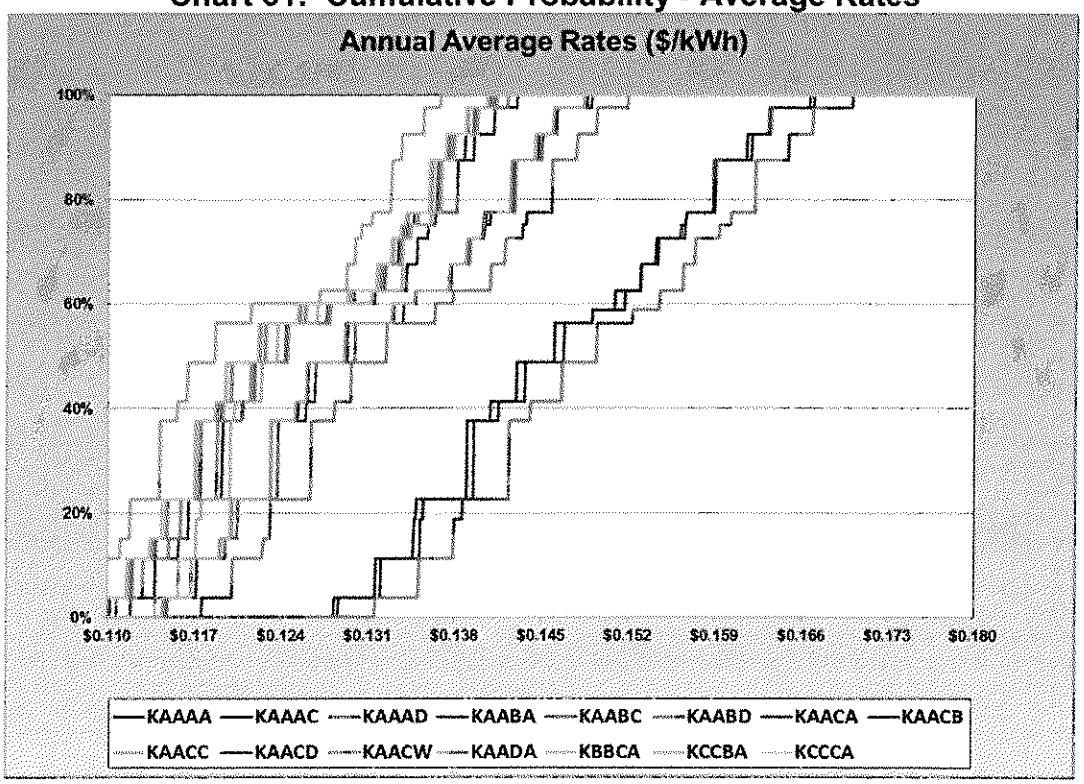
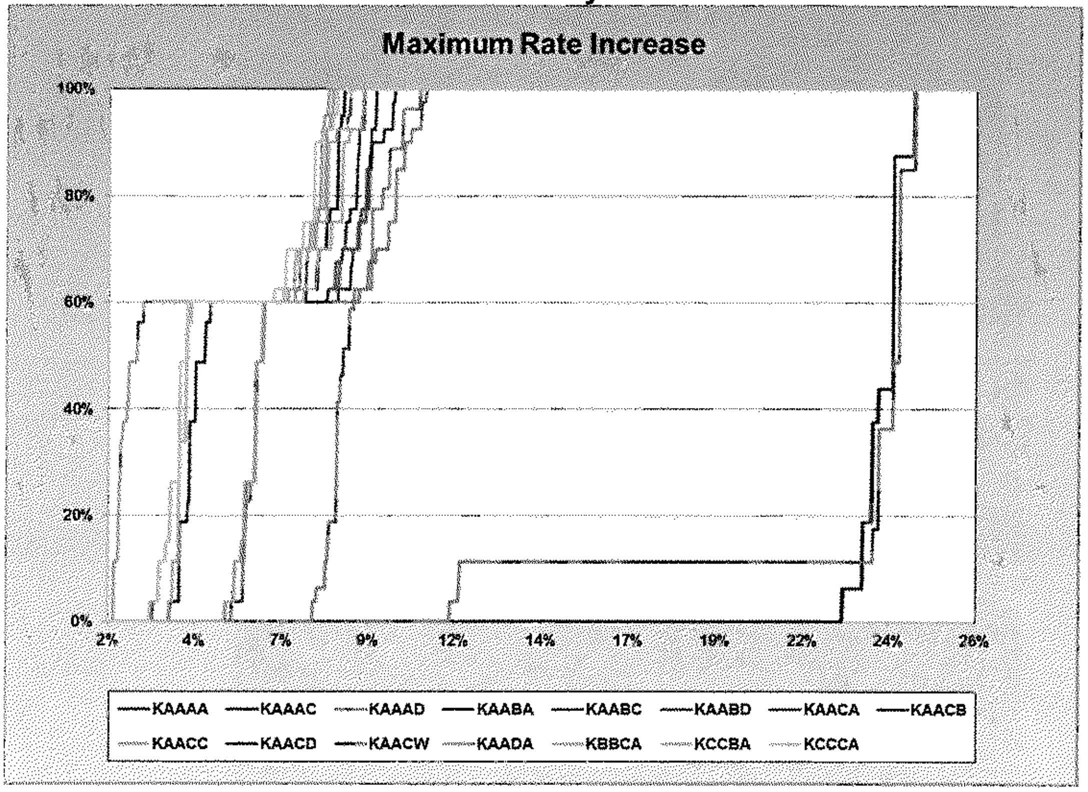


Chart 62: Cumulative Probability - Maximum Rate Increase



Values for all other performance measures do not vary enough over the range of scenarios to allow for graphical display.

3. For each performance measure, a table that shows the expected value and the risk of each alternative resource plan; and

Table 62: Expected Value Plan Performance Measures ** Highly Confidential **

[redacted]

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Table 63: Standard Deviation Plan Performance Measures ** Highly Confidential **

[redacted]

Note: Several performance measures are not affected by the individual scenario risk and therefore exhibits no standard deviation.

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4. A plot of the expected level of annual unserved hours for each alternative resource plan over the planning horizon.

There was no unserved energy in any of the alternative resource plans.

VOLUME 7

RESOURCE ACQUISITION STRATEGY SELECTION

KANSAS CITY POWER & LIGHT COMPANY (KCP&L)

INTEGRATED RESOURCE PLAN

4 CSR 240-22.070

APRIL, 2015

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VOLUME 7: RESOURCE ACQUISITION STRATEGY SELECTION

PURPOSE: This rule requires the utility to select a preferred resource plan, develop an implementation plan, and officially adopt a resource acquisition strategy. The rule also requires the utility to prepare contingency plans and evaluate the demand-side resources that are included in the resource acquisition strategy.

SECTION 1: PREFERRED RESOURCE PLAN

The utility shall select a preferred resource plan from among the alternative resource plans that have been analyzed pursuant to the requirements of 4 CSR 240-22.060. The utility shall describe and document the process used to select the preferred resource plan, including the relative weights given to the various performance measures and the rationale used by utility decision makers to judge the appropriate tradeoffs between competing planning objectives and between expected performance and risk. The utility shall provide the names, titles, and roles of the utility decision–makers in the preferred resource plan selection process. The preferred resource plan shall satisfy at least the following conditions:

(A) In the judgment of utility decision makers, strike an appropriate balance between the various planning objectives specified in 4 CSR 240-22.010(2);

See response in Rule 070(1)(D)

(B) Invest in advanced transmission and distribution technologies unless, in the judgment of the utility decision-makers, investing in those technologies to upgrade transmission and/or distribution networks is not in the public interest;

See response in Rule 070(1)(D)

(C) Utilize demand-side resources to the maximum amount that comply with legal mandates and, in the judgment of the utility decision-makers, are consistent with the public interest and achieve state energy policies; and

See response in Rule 070(1)(D)

(D) In the judgment of the utility decision makers, the preferred plan, in conjunction with the deployment of emergency demand response measures and access to short-term and emergency power supplies, has sufficient resources to serve load forecasted under extreme weather conditions pursuant to 4CSR 240-22.030(8)(B) for the implementation period. If the utility cannot affirm the sufficiency of resources, it shall consider an alternative resource plan or modifications to its preferred resource plan that can meet extreme weather conditions.

The Preferred Plan that has been selected for KCP&L is shown in Table 1 below:

Table 1: KCP&L Preferred Plan

Year	CT's (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)	Existing Capacity (MW)
2015	0			29		4572
2016	0	350	3	71		4387
2017	0	300		103		4432
2018	0			124		4432
2019	0			139		4442
2020	0			176		4442
2021	0			206		4102
2022	0			228		4102
2023	0			248		4117
2024	0			266		4056
2025	0			284		4056
2026	0		7	299		4056
2027	0			308		4056
2028	0			316		4056
2029	207			325		4056
2030	0			333		4056
2031	0			337		4056
2032	0			341		4056
2033	0			345		4056
2034	0			349		4056

Based in part upon current Missouri RPS rule requirements, the Preferred Plan includes 10 MW of solar additions and 650 MW of wind additions over the twenty-year planning period. It should be noted that the solar resource addition in 2016 is expected to consist of ownership of 3 MW of Commercial and Industrial rooftop installations. A 350 MW wind addition is expected to be in service in 2016. An additional 300 MW of wind is expected to be in service in 2017. DSM resources consist of a suite of thirteen Energy Efficiency and three Demand Response programs that KCP&L considers the capacity and energy estimated from these programs comprise realistically achievable levels. The Preferred Plan reflects Montrose Unit 1 ceasing to burn coal by 2017 and Montrose Units 2 and 3 ceasing to burn coal by 2022. The environmental drivers that contributed to the discontinuing of burning of coal includes Mercury and Air Toxics Standards Rule, Ozone National Ambient Air Quality Standards (NAAQS), PM NAAQS, Clean Water Act Section 316(a) and (b), Effluent Guidelines, Coal Combustion Residuals Rule, and Clean Power Plan.

The Preferred Plan was not the lowest cost plan from a Net Present Value of Revenue Requirement (NPVRR) perspective. One Alternative Resource Plan, KCCCA, had the lowest expected NPVRR of all modeled plans. This plan included the same DSM level as the Preferred Plan, Option C, but Montrose Units 2 and 3 ceased burning coal by the year 2020. The plan producing the next lowest expected value of NPVRR, Alternative Resource Plan KAACA, was chosen as the Preferred Plan.

It should be noted that the selection of the KCP&L Preferred Plan is based upon resource planning in tandem with KCP&L-Greater Missouri Operations Company (GMO) and provides benefit to Missouri retail customers by planning on a joint basis. The lowest cost joint Alternative Resource Plan CBBFA includes Alternative Resource Plan KAACA.

The Preferred Plan also meets the fundamental planning objectives as required by Rule 22.010(2) to provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies. The Preferred Plan was reviewed and approved by Terry D. Bassham, President and Chief Executive Officer and Kevin Noblet, Vice President – Generation.

The Forecast of Capacity Balance worksheet associated with the KCP&L Preferred Plan is shown in Table 2 below. It should be noted that the “Peak Forecast” data is based upon an extreme weather forecast. The Capacity Balance shows that reserve obligations are met each year.

.

Table 2: KCP&L Forecast of Capacity Balance - Preferred Plan **Highly Confidential**

[redacted]

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The Preferred Plan was tested under extreme weather conditions as defined by Rule 240-22.030(8)(B). There was no unserved energy under this extreme condition. The performance measure effects and annual amount of unserved energy given extreme weather conditions are provided below.

Table 3: Performance Measure Impact - Extreme Weather ** Highly Confidential **

[redacted]

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Table 4: Extreme Weather Unserved Energy

Year	Unserved Energy (MWh) Extreme Weather
2015	0
2016	0
2017	0
2018	0
2019	0
2020	0
2021	0
2022	0
2023	0
2024	0
2025	0
2026	0
2027	0
2028	0
2029	0
2030	0
2031	0
2032	0
2033	0
2034	0

SECTION 2: RANGES OF CRITICAL UNCERTAIN FACTORS

The utility shall specify the ranges or combinations of outcomes for the critical uncertain factors that define the limits within which the preferred resource plan is judged to be appropriate and explain how these limits were determined. The utility shall also describe and document its assessment of whether, and under what circumstances, other uncertain factors associated with the preferred resource plan could materially affect the performance of the preferred resource plan relative to alternative resource plans.

The ranges of critical uncertain factors are calculated by finding the value at which the critical uncertain factor needs to change in order for the Preferred Plan to no longer be preferred. The values of the NPVRR for the Preferred Resource Plan and the lowest cost plan under extreme conditions are compared and by using linear interpolation a crossover point value is found and expressed as a percent of the range of the critical uncertain factor. These percentages are superimposed on the high, mid and low forecasts for each critical uncertain factor to develop the resulting ranges.

The Company has selected its Preferred Plan based in part on the results of the joint planning for KCP&L and GMO. Details on the joint plans can be found in Volume 6, Section 3.1. In the joint planning analysis, the overall lowest cost plan on an expected value NPVRR basis, CBBFA and two other plans, CCDCC and CCDFC proved to be the lowest cost plans under different risk scenarios. The values of these plans' NPVRR under each of the risks are detailed in the following table.

Table 5: Risk Scenario NPVRR

Assuming Low CO2						
NPVRR ($MM)	High Load	High NG	Low CO2	EV	Low NG	Low Load
CCDCC	28,446	27,661	28,028	29,230	28,332	27,674
CBBFA	28,236	27,258	27,831	29,106	28,367	27,490
Assuming High CO2						
NPVRR ($MM)	High Load	High NG	High CO2	EV	Low NG	Low Load
CCDFC	31,520	30,748	31,026	29,181	30,972	30,603
CBBFA	31,577	30,676	31,085	29,106	31,120	30,663

Based on joint planning, the uncertain factors which may cause the Company to modify the KCP&L Preferred Plan are limited to high CO_2 and low natural gas prices.

2.1 CRITICAL UNCERTAIN FACTOR: CO_2

The uncertain factor range calculation is detailed in Table 6 below. As assumptions on the cost of future CO_2 increase toward the high scenario, Alternative Resource Plan CCDFC becomes the lower cost plan.

Table 6: CO_2 Uncertain Factor Range

CO2		
Plan	Low	High
CCDFC	27,994	31,026
CBBFA	27,831	31,085
Percent	from Low	
Upper %	73.4%	

The resulting limits of the range of this critical uncertain factor are detailed in Figure 1 below:

Figure 1: CO_2 Uncertain Factor Range Limits ** Highly Confidential **

[redacted]

2.2 <u>CRITICAL UNCERTAIN FACTOR: LOAD</u>

The uncertain factor range calculation is detailed in Table 7 below. Note the load growth forecast does not cause any other plan to out-perform the lowest-cost joint plan.

Table 7: Load Uncertain Factor Range

Load		
Plan	Mid	High
CBBFA	27,831	28,236
CBBFA	27,831	28,236
Percent	from Mid	from Low
Upper %	N/A	N/A

Plan	Mid	Low
CBBFA	27,831	27,490
CBBFA	27,831	27,490
Percent	from Mid	from Low
Lower %	N/A	N/A

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2.3 CRITICAL UNCERTAIN FACTOR: NATURAL GAS

The uncertain factor range calculation is detailed in Table 8 below. As assumptions on the cost of future natural gas decrease towards the low scenario, Alternative Resource Plan CCDCC becomes a lower cost plan. .

Table 8: Natural Gas Uncertain Factor Range

Natural Gas		
Plan	**Mid**	**High**
CBBFA	27,831	27,258
CBBFA	27,831	27,258
Percent	**from Mid**	**from Low**
Upper %	N/A	N/A

Plan	Mid	Low
CCDCC	28,028	28,332
CBBFA	27,831	28,367
Percent	**from Mid**	**from Low**
Lower %	-84.7%	7.7%

The resulting limits of the range of this critical uncertain factor are detailed in Figure 2 below:

Figure 2: Natural Gas Uncertain Factor Range Limit **Highly Confidential**

[redacted]

SECTION 3: BETTER INFORMATION

The utility shall describe and document its quantification of the expected value of better information concerning at least the critical uncertain factors that affect the performance of the preferred resource plan, as measured by the present value of utility revenue requirements. The utility shall provide a tabulation of the key quantitative results of that analysis and a discussion of how those findings will be incorporated in ongoing research activities.

The Company calculated the value of better information for each of the critical uncertain factors identified in the preliminary sensitivity test. For each uncertainty, the Preferred Plan NPVRR for the specific uncertainty scenarios (or endpoints) was compared to the better plan under each extreme uncertainty condition. The comparison was made on an expected value basis assuming that only those three particular scenarios (high value uncertainty, mid value and low value uncertainty) would occur. Baye's Theorem was applied to the endpoint probabilities to develop conditional probabilities for the calculation scenarios. The difference between the expected value of the Preferred Plan and the expected value of the better information results is the expected value of better information.

These values represent the maximum amount the company should be willing to spend to study each of these uncertainties. It must be noted that should a Preferred Plan out-perform all alternatives across the range of a critical risk, the calculation for better information will yield a value of zero.

The results for these calculations are shown in below.

Table 9: Better Information - CO_2

CO2						
Preferred Plan	**Endpoint**	**Plan**	**NPVRR**	**EP Prob**	**Cond. Prob**	**Expected Value**
High CO2	9	CBBFA	31,085	10.00%	40.0%	29,133
Low CO2	10	CBBFA	27,831	15.00%	60.0%	
						-
Better Information	**Endpoint**	**Plan**	**NPVRR**	**EP Prob**	**Cond. Prob**	**Expected Value**
High CO2	9	CCDFC	31,026	10.00%	40.0%	29,109
Low CO2	10	CBBFA	27,831	15.00%	60.0%	
Expected Value of Better Information			24	Million		

Table 10: Better Information - Load

Load						
Preferred Plan	**Endpoint**	**Plan**	**NPVRR**	**EP Prob**	**Cond. Prob**	**Expected Value**
High Load	4	CBBFA	28,236	7.50%	25.00%	27,847
Mid	10	CBBFA	27,831	15.00%	50.00%	
Low Load	16	CBBFA	27,490	7.50%	25.00%	
Better Information	**Endpoint**	**Plan**	**NPVRR**	**EP Prob**	**Cond. Prob**	**Expected Value**
High Load	4	CBBFA	28,236	7.50%	25.00%	27,847
Mid	10	CBBFA	27,831	15.00%	50.00%	
Low Load	16	CBBFA	27,490	7.50%	25.00%	
Expected Value of Better Information			-	Million		

Table 11: Better Information - Natural Gas

Natural Gas						
Preferred Plan	**Endpoint**	**Plan**	**NPVRR**	**EP Prob**	**Cond. Prob**	**Expected Value**
High Natural Gas	8	CBBFA	27,258	7.50%	25.00%	27,822
Mid	10	CBBFA	27,831	15.00%	50.00%	
Low Natural Gas	12	CBBFA	28,367	7.50%	25.00%	
Better Information	**Endpoint**	**Plan**	**NPVRR**	**EP Prob**	**Cond. Prob**	**Expected Value**
High Natural Gas	8	CBBFA	27,258	7.50%	25.00%	27,813
Mid	10	CBBFA	27,831	15.00%	50.00%	
Low Natural Gas	12	CCDCC	28,332	7.50%	25.00%	
Expected Value of Better Information			9	Million		

SECTION 4: CONTINGENCY RESOURCE PLANS

The utility shall describe and document its contingency resource plans in preparation for the possibility that the preferred resource plan should cease to be appropriate, whether due to the limits identified pursuant to 4 CSR240-22.070(2) being exceeded or for any other reason.

(A) The utility shall identify as contingency resource plans those alternative resource plans that become preferred if the critical uncertain factors exceed the limits developed pursuant to section (2).

KCP&L has identified a contingency plan should the critical uncertain factors exceed the limits specified. The Contingency Resource Plan is shown in the table below:

Table 12: Contingency Resource Plan

Plan Name	DSM Level	Facility	Year to Cease Burning Coal	Renewable Additions		Generation Addition (if needed)
KCCCA	Option C	Montrose-1 Montrose-2 Montrose-3	2016 2019 2019	Solar: 2016 - 3 MW 2026 - 7 MW	Wind: 2016 - 350 MW 2017 - 300 MW	207 MW CT in 2029

The contingency plan was identified through evaluation of the relative cost performance of each alternative resource plan under different combinations of the critical uncertain factors. The combination of the critical uncertain factors under which this contingency plan is projected to be lower cost than the Preferred Plan is as follows:

Low Gas, Low CO_2 Price Scenario: Under this scenario, the Alternative Resource Plan shown in Table 12 above is the Contingency Plan.

Low or Mid Gas, High CO_2 Price Scenario: Under this scenario, the Alternative Resource Plan shown in Table 12 above is the Contingency Plan.

(B) The utility shall develop a process to pick among alternative resource plans, or to revise the alternative resource plans as necessary, to help ensure reliable and low cost service should the preferred resource plan no longer be appropriate for any reason. The utility may also use this process to confirm the viability of contingency resource plans identified pursuant to subsection (4)(A).

The process used to select alternative resource plans was derived from the analysis of the joint KCP&L/GMO planning results under identical risks imposed on the KCP&L stand-alone system. The KCP&L Preferred Plan was chosen as the resource plan that exhibited the lowest expected value of NPVRR found in the joint plans. The Contingency Plan was chosen as the plan that could perform better than the Preferred Plan, should certain extreme conditions of risk factors arise. These factors are described in the response to Rule 240-22.070(2) in this Volume.

(C) Each contingency resource plan shall satisfy the fundamental objective in 4 CSR240-22.010(2) and the specific requirements pursuant to 4 CSR 240-22.070(1).

The Contingency Plan KCCCA meets the considerations of Rule 240.22.010(2) as one of the alternative resource plans developed and conformed in the response to Rule 240-22.060(3) in Volume 6 of this filing.

As for concurrence with Rule 240.070(1), Plan KCCCA conforms by meeting Rule 240.010(2), considers investments in advanced transmission and distribution technologies, utilizes the amount of DSM that conforms to legal mandates and demonstrates adequate access to emergency short-term power supply.

SECTION 5: LOAD –BUILDING PROGRAMS

Analysis of Load-Building Programs. If the utility intends to continue existing load building programs or implement new ones, it shall analyze these programs in the context of one (1) or more of the alternative resource plans developed pursuant to 4 CSR 240- 22.060(3) of this rule, including the preferred resource plan selected pursuant to 4 CSR240-22.070(1). This analysis shall use the same modeling procedure and assumptions described in 4 CSR 240-22.060(4). The utility shall describe and document—

(A) Its analysis of load building programs, including the following elements:

1. Estimation of the impact of load building programs on the electric utility's summer and winter peak demands and energy usage;

2. A comparison of annual average rates in each year of the planning horizon for the resource plan(s) with and without the load building program;

3. A comparison of the probable environmental costs of the resource plan(s) in each year of the planning horizon with and without the proposed load-building program;

4. A calculation of the performance measures and risk by year; and

5. An assessment of any other aspects of the proposed load-building programs that affect the public interest; and

(B) All current and proposed load-building programs, a discussion of why these programs are judged to be in the public interest, and, for all resource plans that include these programs, plots of the following over the planning horizon:

1. Annual average rates with and without the load-building programs; and

2. Annual utility costs and probable environmental costs with and without the load-building programs.

At this time, KCP&L does not have any load-building programs.

SECTION 6: IMPLEMENTATION PLAN

(6) The utility shall develop an implementation plan that specifies the major tasks, schedules, and milestones necessary to implement the preferred resource plan over the implementation period. The utility shall describe and document its implementation plan, which shall contain—

6.1 LOAD ANALYSIS - SCHEDULE AND DESCRIPTION

(A) A schedule and description of ongoing and planned research activities to update and improve the quality of data used in load analysis and forecasting;

KCP&L plans to conduct its next Residential Appliance Saturation Survey in 2016-2017. KCP&L is also looking at the option of expanding the survey to the commercial sector in 2016-2017. The last residential survey was completed in 2013. The results were used to calculate appliance saturations and these saturations were used to calibrate DOE forecasts of appliance saturations for use in KCP&L's load forecasting models. KCP&L also plans to match the responses with the customers' billing records and to conduct a conditional demand study to measure the unit energy consumption (UEC) for each major appliance.

KCP&L is in the process of developing a framework for incorporating photovoltaic (PV) impacts into the energy forecast in order to capture PV energy impacts. The goal would be for inclusion in the next IRP update.

KCP&L is developing a new industrial model that will accommodate the creation of an industrial intensity index which would be calibrated to our service area based on employment. It will be implemented in the 2016 update.

The timeline currently expected for the Residential Appliance Saturation Survey is shown in the following table:

Table 13: Appliance Saturation Survey Initiative

Appliance Saturation Survey Initiative	Date Range
Issue Appliance Saturation Survey Request for Proposal (RFP)	06/2015 - 12/2015
Evaluate Conducting a C&I Survey	1/2015 - 12/2015
Conduct Residential Appliance Saturation Survey	01/2016-06/2016
Tabulation Appliance Saturation Survey Results	06/2016-12/2016
Conduct Conditional Demand Study	01/2017-5/2017
Implement Survey Result in Load Forecast	05/2017-7/2017

6.2 DEMAND-SIDE PROGRAMS – SCHEDULE AND DESCRIPTION

(B) A schedule and description of ongoing and planned demand-side programs and demand-side rates, evaluations, and research activities to improve the quality of demand-side resources;

The current schedule for ongoing and planned DSM programs is shown in the two tables below:

Table 14: DSM Program Schedule – Existing Programs

Program Name	Program Type	Status	Segment	Program Implemented	Annual Report	EM&V Completed and draft report available
Income Eligible Weatherization	Energy Efficiency	Existing	Residential	Jul. 6, 2014	90-days following Plan Year	1-Yr following Plan Year
Air Conditioning Upgrade Rebate	Energy Efficiency	Existing	Residential	Jul. 6, 2014	90-days following Plan Year	1-Yr following Plan Year
Business Energy Efficiency Rebate-Custom	Energy Efficiency	Existing	C&I	Jul. 6, 2014	90-days following Plan Year	1-Yr following Plan Year
Mpower	Demand Response	Existing	C&I	Jul. 6, 2014	90-days following Plan Year	1-Yr following Plan Year
Residential Programmable Thermostat	Demand Response	Existing	Residential	Jul. 6, 2014	90-days following Plan Year	1-Yr following Plan Year
Building Operator Certification	Educational	Existing	C&I	Jul. 6, 2014	90-days following Plan Year	1-Yr following Plan Year
Home Energy Analyzer	Educational	Existing	Residential	Jul. 6, 2014	90-days following Plan Year	1-Yr following Plan Year
Business Energy Analyzer	Educational	Existing	C&I	Jul. 6, 2014	90-days following Plan Year	1-Yr following Plan Year
Home Appliance Recycling Rebate	Energy Efficiency	Existing	Residential	Jul. 6, 2014	90-days following Plan Year	1-Yr following Plan Year
Business Energy Efficiency Rebate - Prescriptive	Energy Efficiency	Existing	C&I	Jul. 6, 2014	90-days following Plan Year	1-Yr following Plan Year
Home Energy Reports	Energy Efficiency	Existing	Residential	Jul. 6, 2014	90-days following Plan Year	1-Yr following Plan Year
Home Lighting Rebate	Energy Efficiency	Existing	Residential	Jul. 6, 2014	90-days following Plan Year	1-Yr following Plan Year

Table 15: DSM Program Schedule – Existing Programs

Program Name		New or Existing	Segment	Tariff Filing Date	MEEIA and DSM program approved	Program Implemented	Annual Report	EM&V Completed and draft report available
Home Lighting Rebate	Energy Efficiency	New	Residential	Jun., 2015	Oct., 2015	Jan., 2016	90-days following Plan Year	1-Yr following Plan Year
Home Appliance Recycling Rebate	Energy Efficiency	New	Residential	Jun., 2015	Oct., 2015	Jan., 2016	90-days following Plan Year	1-Yr following Plan Year
Home Energy Report	Energy Efficiency	New	Residential	Jun., 2015	Oct., 2015	Jan., 2016	90-days following Plan Year	1-Yr following Plan Year
Online Home Energy Audit	Educational	New	Residential	Jun., 2015	Oct., 2015	Jan., 2016	90-days following Plan Year	1-Yr following Plan Year
Whole House Efficiency	Energy Efficiency	New	Residential	Jun., 2015	Oct., 2015	Jan., 2016	90-days following Plan Year	1-Yr following Plan Year
Income-Eligible Multi-Family	Energy Efficiency	New	Residential	Jun., 2015	Oct., 2015	Jan., 2016	90-days following Plan Year	1-Yr following Plan Year
Income-Eligible Weatherization	Energy Efficiency	New	Residential	Jun., 2015	Oct., 2015	Jan., 2016	90-days following Plan Year	1-Yr following Plan Year
Residential Programmable Thermostat	Demand Response	New	Residential	Jun., 2015	Oct., 2015	Jan., 2016	90-days following Plan Year	1-Yr following Plan Year
Business Energy Efficiency Rebate - Prescriptive	Energy Efficiency	New	C&I	Jun., 2015	Oct., 2015	Jan., 2016	90-days following Plan Year	1-Yr following Plan Year
Business Energy Efficiency Rebate - Custom	Energy Efficiency	New	C&I	Jun., 2015	Oct., 2015	Jan., 2016	90-days following Plan Year	1-Yr following Plan Year
Strategic Energy Management	Energy Efficiency	New	C&I	Jun., 2015	Oct., 2015	Jan., 2016	90-days following Plan Year	1-Yr following Plan Year
Block Bidding	Energy Efficiency	New	C&I	Jun., 2015	Oct., 2015	Jan., 2016	90-days following Plan Year	1-Yr following Plan Year
Online Building Energy Audit	Educational	New	C&I	Jun., 2015	Oct., 2015	Jan., 2016	90-days following Plan Year	1-Yr following Plan Year
Small Business Direct Install	Energy Efficiency	New	C&I	Jun., 2015	Oct., 2015	Jan., 2016	90-days following Plan Year	1-Yr following Plan Year
Commercial Programmable Thermostat	Demand Response	New	C&I	Jun., 2015	Oct., 2015	Jan., 2016	90-days following Plan Year	1-Yr following Plan Year
Demand Response Incentive	Demand Response	New	C&I	Jun., 2015	Oct., 2015	Jan., 2016	90-days following Plan Year	1-Yr following Plan Year

Additional detail regarding the implementation plan for the DSM Preferred Plan can be found in Volume 5. It includes the descriptions of the programs, the implementation strategy, a discussion of risk management, the incentive levels used for planning purposes, energy and peak demand savings goals, and budget estimates. KCP&L will file an application under the Missouri Energy Efficiency Investment Act (MEEIA) requesting Commission approval of demand-side programs for a program implementation period of 2016 to 2018 in mid-2015.

6.3 SUPPLY-SIDE – SCHEDULES AND DESCRIPTIONS

(C) A schedule and description of all supply-side resource research, engineering, retirement, acquisition, and construction activities, including research to meet expected environmental regulations;

Based on the 2015 Preferred Plan, limited environmental retrofits are anticipated to be required for Montrose Units 2 & 3 prior to cease burning coal in 2021. These retrofits are required to operate the units through year 2020. Other projects anticipated to begin within the three year implementation period are Hawthorn 5 Cooling Tower and Spray Dry Absorber water reduction, Iatan 1 Cooling Tower, and LaCygne 2 Submerged Flight Conveyer. A draft schedule of major milestones for expected retrofit projects are provided in Table 16 below:

Table 16: Retrofit Milestone Schedule

Retrofit Project	Milestone Description	Date Range
Hawthorn 5 Cooling Tower	Studies/Specification/Bid/Award	01/2016 - 4/2018
Hawthorn 5 SDA water reduction	Study/Design/Construction	01/2015 - 07/2015
Iatan 1 Cooling Tower	Studies/Specification/Bid/Award	01/2016 - 4/2018
La Cygne 2 SFC	Design/Procurement/Construction	04/2015 - 09/2018
Montrose 2 & 3 ACI	Engineering/Procurement/Construction	01/2015 - 4/2015
Montrose 2 & 3 ACI	Checkout/Startup/Tuning/Testing	04/2015 - 02/2016
Montrose 2 & 3 ESP Improvements	Engineering/Procurement/Construction	01/2015 - 4/2015
Montrose 2 & 3 ESP Improvements	Checkout/Startup/Tuning/Testing	04/2015 - 02/2016
Montrose 2 & 3 sluiced ash modifications	Study/Design/Procurement/Construction	01/2015 - 12/2018
Montrose 2 & 3 new fly ash pug mill	Study/Design/Procurement/Construction	04/2015 - 04/2016

ACI : Activated Carbon Injection ESP: Electrostatic Precipitator
SDA: Spray Dry Absorber SFC: Submerged Flight Conveyor

Also, the Preferred Plan includes solar resource additions in 2016 consisting of ownership in 3 MW of Commercial and Industrial solar rooftop installations. A draft schedule of the major milestones for this solar initiative is provided in the following table:

Table 17: Solar Initiative

Solar Initiative	Date Range
Evaluate/Select Developer(s)	04/2015 - 07/2015
Site Designs/Obtain Permits	8/2015 - 12/2015
Rooftop Installations Mobilization/Construction	01/2016 - 5/2016
Commercial Operation for Rooftop Installations	05/2016 - 06/2016

In addition, KCP&L is working towards procuring additional wind resources.

6.4 MILESTONES AND CRITICAL PATHS

(D) Identification of critical paths and major milestones for implementation of each demand-side resource and each supply-side resource, including decision points for committing to major expenditures;

Critical paths and major milestones for implementation of each demand-side resource are shown above, in Section 6.2.

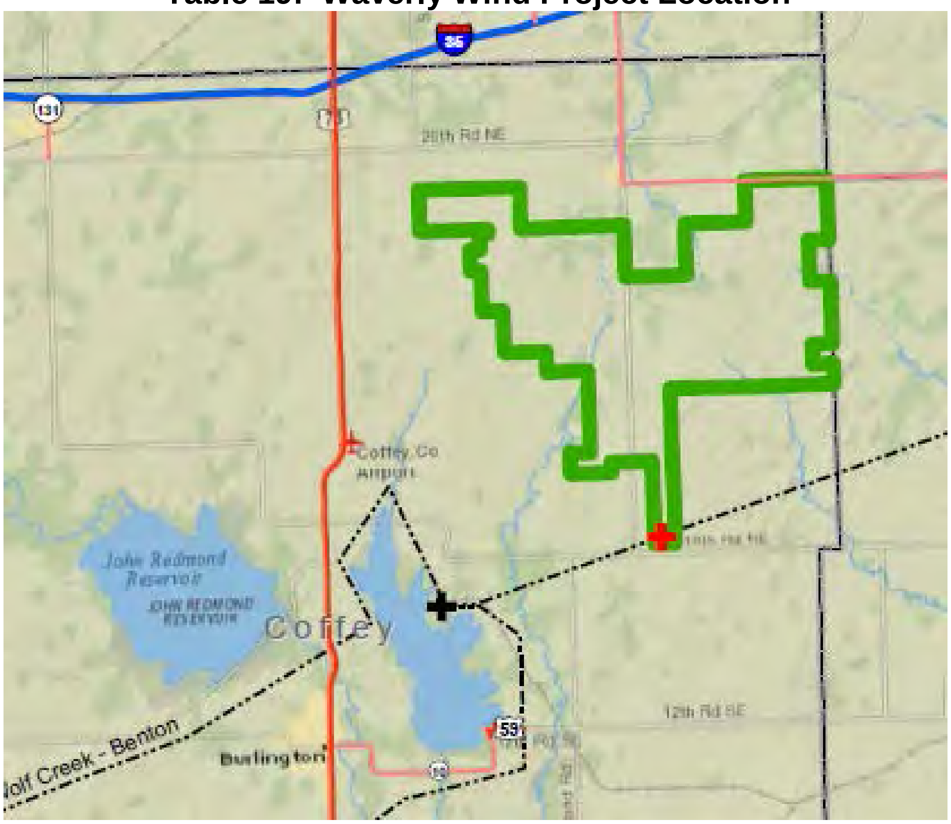
On November 18, 2013, KCP&L entered into a PPA agreement with EDP Renewables, to purchase energy from Waverly, a 200 MW wind project located near Waverly, in Coffey County, Kansas. The facility is expected to be in-service by December 31, 2015. Table 18 provides a milestone schedule of activities.

Table 18: Waverly Wind Schedule

Milestone Description	Milestone Dates
Site Mobilization for O&M Building, and Substation and Transmission Line	March. 2015
Site Mobilization for Balance of Plant	March, 2015
Main Power Transfomer Delivered	June, 2015
Turbine Deliveries and Erection Begin and Main Power Transformer Energized	September, 2015
Mechanical Completion of Turbines Begins and Commencement of Turbine Commissioning	October, 2015
Mechanical Completion of Turbines Complete	November, 2015
Commercial Operation Date[1]	December, 2015
[1] Delays may be possible due to adverse weather	

Table 19 shows the location of the Waverly wind project:

Table 19: Waverly Wind Project Location



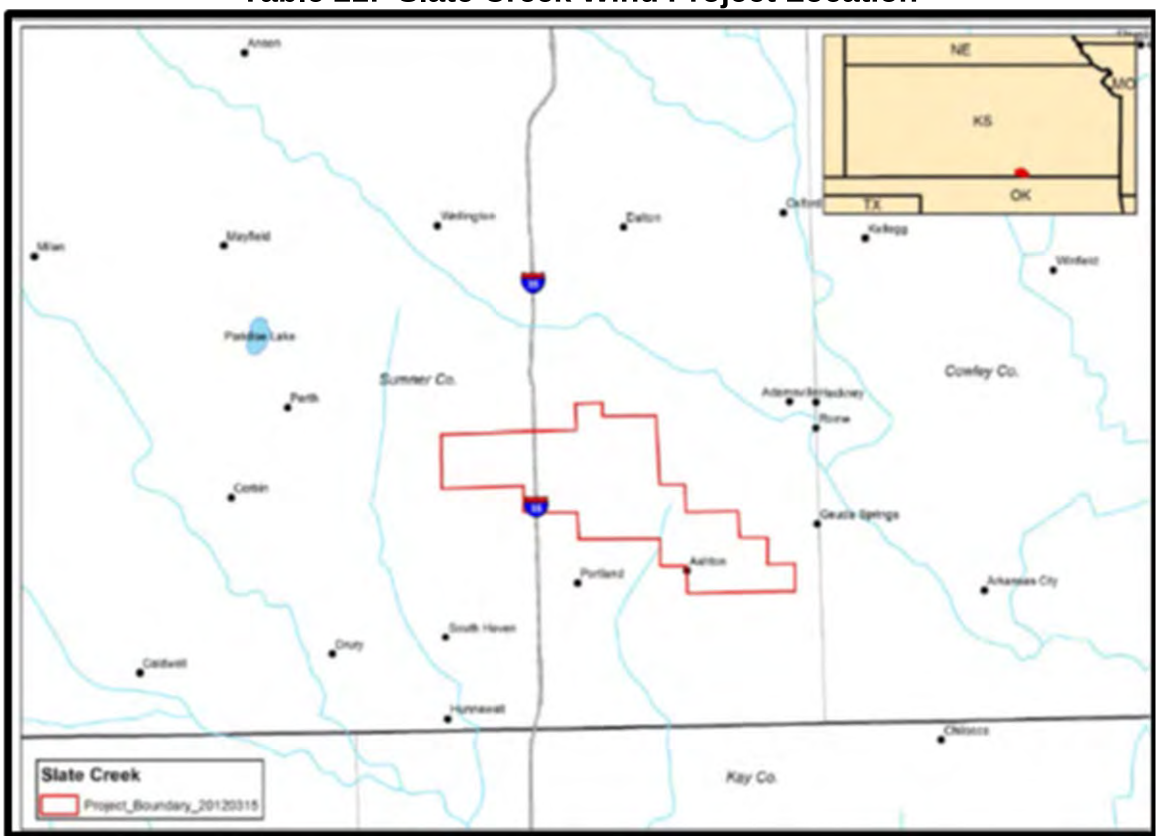
On June 11, 2014, Great Plains Energy Inc., the parent company of KCP&L, entered into a PPA agreement with EDF to purchase energy from Slate Creek, a 150 MW wind project located in south central Kansas. The facility is expected to be in-service by December 31, 2015. Table 20 provides a milestone schedule of activities.

Table 20: Slate Creek Wind Schedule

2015 WIND ACQUISITION MAJOR MILESTONE SCHEDULE	
Milestone Description	**Milestone Dates**
Site Mobilization for O&M Building, and Substation and Transmission Line	March. 2015
Site Mobilization for Balance of Plant	May, 2015
Main Power Transfomer Delivered	July, 2015
Turbine Deliveries and Erection Begin and Main Power Transformer Energized	August, 2015
Mechanical Completion of Turbines Begins and Commencement of Turbine Commissioning	September, 2015
Mechanical Completion of Turbines Complete and Turbine Commissioning Complete	November, 2015
Commercial Operation Date[1]	December, 2015
[1] Delays may be possible due to adverse weather	

Table 21 shows the location of this wind project:

Table 21: Slate Creek Wind Project Location



6.5 COMPETITIVE PROCUREMENT POLICIES

(E) A description of adequate competitive procurement policies to be used in the acquisition and development of supply-side resources;

KCP&L has an extensive review and analysis process for the acquisition of supply-side resources. In the 2015-2018 Implementation Period it is anticipated that KCP&L will evaluate and select one or more contractors for development of up to 3 MW of Commercial and Industrial solar rooftop installations. A team from several departments in the company will evaluate and select contractors that will provide the most beneficial services to KCP&L. Additionally, KCP&L plans to obtain 300 MW's of wind resources with commercial operation occurring in 2017.

6.6 MONITORING CRITICAL UNCERTAIN FACTORS

(F) A process for monitoring the critical uncertain factors on a continuous basis and reporting significant changes in a timely fashion to those managers or officers who have the authority to direct the implementation of contingency resource plans when the specified limits for uncertain factors are exceeded; and

Each critical uncertain factor is reviewed on an individual basis due to the varied nature of the information sources used in its review. This IRP analysis will be updated on an annual basis reflecting any changes to these critical uncertain factors. Results will be distributed to the Vice President, Generation.

Critical Uncertain Factor: CO_2

CO_2 credit prices are reviewed on a continual basis. The data sources used are third party views predicting the price of the credits. Most of these third party studies are sparked by proposed legislation or are updated up to a quarterly basis. This review and update is conducted by the Fuels department with a full review conducted on an annual basis.

Critical Uncertain Factor: Load

Load forecasts are updated on an annual basis as part of the company's annual budgeting process.

Critical Uncertain Factor: Natural Gas

Natural Gas forecasts are updated weekly with executive updates provided on a monthly basis.

6.7 MONITORING PREFERRED RESOURCE PLAN

(G) A process for monitoring the progress made implementing the preferred resource plan in accordance with the schedules and milestones set out in the implementation plan and for reporting significant deviations in a timely fashion to those managers or officers who have the authority to initiate corrective actions to ensure the resources are implemented as scheduled.

KCP&L has processes in place to monitor its Demand-Side Management programs and track and report their performance compared to the planned implementation schedule.

Wind development activities are reported to the Vice President, Generation on an ongoing basis and weekly meetings have been established for the solar initiatives.

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SECTION 7: RESOURCE ACQUISITION STRATEGY

The utility shall develop, describe and document, officially adopt, and implement a resource acquisition strategy. This means that the utility's resource acquisition strategy shall be formally approved by an officer of the utility who has been duly delegated the authority to commit the utility to the course of action described in the resource acquisition strategy. The officially adopted resource acquisition strategy shall consist of the following components:

7.1 PREFERRED RESOURCE PLAN

(A) A preferred resource plan selected pursuant to the requirements of section (1) of this rule;

The Preferred Resource Plan is outlined in Section 1 above per Rule 240-22.070(1).

7.2 IMPLEMENTATION PLAN

(B) An implementation plan developed pursuant to the requirements of section (6) of this rule; and

The Implementation Plan is outlined in Section 6 above per Rule 240-22.070(6).

7.3 CONTINGENCY RESOURCE PLANS

(C) A set of contingency resource plans developed pursuant to the requirements of section (4) of this rule and identification of the point at which the critical uncertain factors would trigger the utility to move to each contingency resource plan as the preferred resource plan.

The Contingency Resource Plan is outlined in Section 4 above per Rule 240-22.070(4).

KANSAS CITY POWER & LIGHT COMPANY

INTEGRATED RESOURCE PLAN – 2015 TRIENNIAL FILING

CORPORATE APPROVAL AND STATEMENT OF COMMITMENT FOR RESOURCE ACQUISITION STRATEGY

In accordance with Missouri Public Service Commission rules found in 4 CSR 240-22 and 4 CSR 240-22.080(3), Kansas City Power & Light Company ("KCP&L") now officially adopts for implementation the resource acquisition strategy contained in this Triennial filing.

With the objective of providing the public with energy services that are safe, reliable, and efficient at just and reasonable rates, KCP&L is committed to the full implementation of the Resource Acquisition Strategy contained herein.

Kevin Noblet

Vice President Generation

Terry D. Bassham

President and Chief Executive Officer

SECTION 8: EVALUATION OF DEMAND-SIDE PROGRAMS AND DEMAND-SIDE RATES

The utility shall describe and document its evaluation plans for all demand-side programs and demand-side rates that are included in the preferred resource plan selected pursuant to 4 CSR 240-22.070(1). Evaluation plans required by this section are for planning purposes and are separate and distinct from the evaluation, measurement, and verification reports required by 4 CSR 240-3.163(7) and 4 CSR 240-20.093(7); nonetheless, the evaluation plan should, in addition to the requirements of this section, include the proposed evaluation schedule and the proposed approach to achieving the evaluation goals pursuant to 4 CSR 240-3.163(7) and 4 CSR 240-20.093(7). The evaluation plans for each program and rate shall be developed before the program or rate is implemented and shall be filed when the utility files for approval of demand-side programs or demand-side program plans with the tariff application for the program or rate as described in 4 CSR 240-20.094(3). The purpose of these evaluations shall be to develop the information necessary to evaluate the cost-effectiveness and improve the design of existing and future demand-side programs and demand-side rates, to improve the forecasts of customer energy consumption and responsiveness to demand-side programs and demand-side rates, and to gather data on the implementation costs and load impacts of demand-side programs and demand-side rates for use in future cost-effectiveness screening and integrated resource analysis.

KCP&L will prepare a request for proposal (“RFP”) to conduct an evaluation, measurement and verification (“EM&V”) of all demand-side programs and demand-side rates that are approved by the Commission.

<u>EM&V Process Evaluation</u>

The scope of work for the RFP will require that the Vendor conduct a process evaluation pursuant to requirements of 4 CSR 240-22.070 (8) (A) and require the

Vendor to provide answers to questions 1 through 5 of this rule section in the EM&V final report ("Report").

EM&V Impact Evaluation

The scope of work for the EM&V RFP will require that the Vendor conduct the impact evaluation pursuant to requirements of 4 CSR 240-22.070 (8) (B) and require the Vendor to provide answers to questions 1 and 2 of this rule section in the Report.

EM&V Data Collection

The scope of work for the EM&V RFP will require that the Vendor collect EM&V participation rate data, utility cost data, participant cost data and total cost data pursuant to requirements of 4 CSR 240-22.070 (8) (C).

EM&V Reporting Requirements

The scope of work for the EM&V RFP will also require that the Vendor perform, and report EM&V of each commission-approved demand-side program in accordance with 4 CSR 240-3.163 (7).

KCP&L will provide the Missouri Public Service Commission ("Commission") Staff and other stakeholders with an opportunity to review and comment on the RFP prior to issuance of the EM&V RFP.

The proposed EM&V RFP will be available for Commission staff and stakeholder review three months after Commission approval of these demand-side resources pursuant to 4 CSR 240-20.094 and the approval KCP&L's demand-side program investment mechanism ("DSIM") pursuant to 4 CSR 240-20.093 ("Approval Date"). The proposed RFP may be modified to incorporate any important issues or concerns raised by the Commission staff or stakeholders. The EM&V RFP will be issued five months after the Commission Approval Date. Vendor selection will be seven months after the Commission Approval Date.

An EM&V for all demand-side programs and demand-side rates that are included in KCP&L's Preferred Plan will begin after the completion of each program year.

The EM&V RFP will require the selected vendor to evaluate and prepare an annual program performance report. Preliminary EM&V reports will be available by August 1 following the program year. Commission Staff and stakeholders will be provided with an opportunity to review, and comment on the preliminary report. The final EM&V report will be available by October 1 following the completion of each program year.

EM&V Schedule and Budget

The EM&V budget shall not exceed five percent (5%) of the total budget for all approved demand-side program costs. A tentative EM&V schedule is shown in Table 22 below. This schedule will be updated when KCP&L files for new programs under MEEIA.

Table 22: Evaluation Schedule[i]

Estimated EM&V Schedule	
Commission Approval of Programs	**Estimated Dec, 2015**
EM&V RFP ready for review	4/1/2016
Issue EM&V RFP	6/1/2016
EM&V Vendor Selected	8/1/2016
1st Annual EM&V Begins	1/1/2017
1st Annual Draft Report	8/1/2017
1st Annual Program Report	10/1/2017
2nd Annual EM&V Begins	1/1/2018
2nd Annual Draft Report	8/1/2018
2nd Annual Program Report	10/1/2018
3rd Annual EM&V Begins	1/1/2019
3rd Annual Draft Report	8/1/2019
3rd Annual Program Report	10/1/2019

8.1 PROCESS EVALUATION

(A) Each demand-side program and demand-side rate that is part of the utility's preferred resource plan shall be subjected to an ongoing evaluation process which addresses at least the following questions about program design.

1. What are the primary market imperfections that are common to the target market segment?

See the response to Section 8, above.

2. Is the target market segment appropriately defined, or should it be further subdivided or merged with other market segments?

See the response to Section 8, above.

3. Does the mix of end-use measures included in the program appropriately reflect the diversity of end-use energy service needs and existing end-use technologies within the target market segment?

See the response to Section 8, above.

4. Are the communication channels and delivery mechanisms appropriate for the target market segment?

See the response to Section 8, above.

5. What can be done to more effectively overcome the identified market imperfections and to increase the rate of customer acceptance and implementation of each enduse measure included in the program?

See the response to Section 8, above.

8.2 IMPACT EVALUATION

(B) The utility shall develop methods of estimating the actual load impacts of each demand-side program and demand-side rate included in the utility's preferred resource plan to a reasonable degree of accuracy.

1. Impact evaluation methods. At a minimum, comparisons of one (1) or both of the following types shall be used to measure program and rate impacts in a manner that is based on sound statistical principles:

A. Comparisons of pre-adoption and post-adoption loads of program or demand-side rate participants, corrected for the effects of weather and other intertemporal differences; and

See the response to Section 8, above.

B. Comparisons between program and demand-side rate participants' loads and those of an appropriate control group over the same time period.

See the response to Section 8, above.

2. The utility shall develop load-impact measurement protocols that are designed to make the most cost-effective use of the following types of measurements, either individually or in combination:

A. Monthly billing data, hourly load data, load research data, end-use load metered data, building and equipment simulation models, and survey responses; or

See the response to Section 8, above.

B. Audit and survey data on appliance and equipment type, size and efficiency levels, household or business characteristics, or energy-related building characteristics.

See the response to Section 8, above.

8.3 DATA COLLECTION PROTOCOLS

(C) The utility shall develop protocols to collect data regarding demand-side program and demand-side rate market potential, participation rates, utility costs, participant costs, and total costs.

See the response to Section 8, above.

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[i] Dates are estimated based on a December 2015 Commission approval of the programs.

VOLUME 8

FILING SCHEDULE, FILING REQUIREMENTS, AND STAKEHOLDER PROCESS

KANSAS CITY POWER & LIGHT COMPANY (KCP&L)

INTEGRATED RESOURCE PLAN

4 CSR 240-22.080

APRIL, 2015

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VOLUME 8: FILING SCHEDULE, FILING REQUIREMENTS, AND STAKEHOLDER PROCESS

This rule specifies the requirements for electric utility filings to demonstrate compliance with the provisions of this chapter. The purpose of the compliance review required by this chapter is not commission approval of the substantive findings, determinations, or analyses contained in the filing. The purpose of the compliance review required by this chapter is to determine whether the utility's resource acquisition strategy meets the requirements of Chapter 22. However, if the commission determines that the filing substantially meets these requirements, the commission may further acknowledge that the preferred resource plan or resource acquisition strategy is reasonable in whole or in part at the time of the finding. This rule also establishes a mechanism for the utility to solicit and receive stakeholder input to its resource planning process.

SECTION 1: IRP REQUIREMENTS

(1) Each electric utility which sold more than one (1) million megawatt-hours to Missouri retail electric customers for calendar year 2009 shall make a filing with the commission every three (3) years on April 1. The electric utilities shall submit their triennial compliance filings on the following schedule:

(A) Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company, or their successors, on April 1, 2012, and every third year thereafter;

KCP&L will file the required triennial compliance filing by April 1, 2015.

SECTION 2: TRIENNIAL COMPLIANCE REQUIREMENTS

(2) The utility's triennial compliance filings shall demonstrate compliance with the provisions of this chapter and shall include at least the following items:

(A) Letter of transmittal expressing commitment to the approved preferred resource plan and resource acquisition strategy and signed by an officer of the utility having the authority to bind and commit the utility to the resource acquisition strategy;

A Corporate Approval Statement signed by officers of KCP&L has been included in Volume 7, Resource Acquisition Strategy Selection per Rule 4 CSR 240-22.070(7).

(B) If the preferred resource plan is inconsistent with the utility's business plan, an explanation of the differences and why the differences exist;

The Preferred Resource Plan is not inconsistent with KCP&L's business plan.

(C) Technical volume(s) that fully describe and document the utility's analysis and decisions in selecting its preferred resource plan and resource acquisition strategy.

Volume 7, "Resource Strategy Selection Strategy" is included in this filing pursuant to 4 CSR 240-22.070.

1. The technical volume(s) shall include all documentation and information specified in 4 CSR 240-22.030–4 CSR 240-22.070 and any other information considered by the utility to analyze and select its resource acquisition strategy.

2. The technical volume(s) shall be organized by chapters corresponding to 4 CSR 240-22.030–4 CSR 240-22.070.

Volumes 3 through Volumes 8 correspond to 4 CSR 240-22.030 through 4 CSR 240-22.080.

3. A separate chapter shall be designated in the technical volume(s) to address special contemporary issues pursuant to 4 CSR 240-22.080(4) and input from the stakeholder group pursuant to 4 CSR 240-22.080(5). The chapter shall identify the issues raised, how the utility addressed them, and where in the technical volume(s) the reports, analyses, and all resulting actions are presented.

Volume 8 herein, addresses the special contemporary issues pursuant to rule 4 CSR 240-22.080(4).

(D) The forecast of capacity balance spreadsheet completed in the specified form, included herein, for the preferred resource plan and each candidate resource plan considered by the utility.

The capacity balance spreadsheet for the preferred resource plan and each candidate resource plan has been included in Volume 6 Rule (4)(B)9.

(E) An executive summary, separately bound and suitable for distribution to the public in paper and electronic formats. The executive summary shall be an informative non-technical description of the preferred resource plan and resource acquisition strategy. This document shall summarize the contents of the technical volume(s) and shall be organized by chapters corresponding to 4 CSR 240-22.030–4 CSR 240-22.070. The executive summary shall include:

1. A brief introduction describing the utility, its existing facilities, existing purchase power arrangements, existing demand-side programs, existing demand-side rates, and the purpose of the resource acquisition strategy;

2. For each major class and for the total of all major classes, the base load forecasts for peak demand and for energy for the planning horizon, with and without utility demand-side resources, and a listing of the economic and demographic assumptions associated with each base load forecast;

3. A summary of the preferred resource plan to meet expected energy service needs for the planning horizon, clearly showing the demand-side resources and

supply-side resources (both renewable and non-renewable resources), including additions and retirements for each resource type;

4. Identification of critical uncertain factors affecting the preferred resource plan;

5. For existing legal mandates and approved cost recovery mechanisms, the following performance measures of the preferred resource plan for each year of the planning horizon:

A. Estimated annual revenue requirement;

B. Estimated level of average retail rates and percentage of change from the prior year; and

C. Estimated company financial ratios;

6. If the estimated company financial ratios in subparagraph (2)(E)5.C. of this rule are below investment grade in any year of the planning horizon, a description of any changes in legal mandates and cost recovery mechanisms necessary for the utility to maintain an investment grade credit rating in each year of the planning horizon and the resulting performance measures of the preferred resource plan;

7. Actions and initiatives to implement the resource acquisition strategy prior to the next triennial compliance filing; and

8. A description of the major research projects and programs the utility will continue or commence during the implementation period; and

(F) Such other information or format as the commission may determine.

An Executive Summary has been included in this compliance filing and is entitled Volume 1 “Executive Summary”.

SECTION 3: ANNUAL UPDATE WORKSHOP

(3) Beginning in 2012, on or about April 1 of every year in which the utility is not required to submit a triennial compliance filing, each electric utility shall host an annual update workshop with the stakeholder group. The utility at its discretion may host additional update workshops when conditions warrant. Any additional update workshops shall follow the same procedures as the annual update workshop.

(A) The purpose of the annual update workshop is to ensure that members of the stakeholder group have the opportunity to provide input and to stay informed regarding the—

1. Utility's current preferred resource plan;

2. Status of the identified critical uncertain factors;

3. Utility's progress in implementing the resource acquisition strategy;

4. Analyses and conclusions regarding any special contemporary issues that may have been identified pursuant to 4 CSR 240-22.080(4);

5. Resolution of any deficiencies or concerns pursuant to 4 CSR 240-22.080(16); and

6. Changing conditions generally.

KCP&L will host an annual workshop with the Stakeholders in the years a triennial filing is not due.

(B) The utility shall prepare an annual update report with both a public version and a highly-confidential version to document the information presented at the annual update workshop and shall file the annual update reports with the commission no less than twenty (20) days prior to the annual update workshop. The depth and detail of the annual update report shall generally be

commensurate with the magnitude and significance of the changing conditions since the last filed triennial compliance filing or annual update filing. If the current resource acquisition strategy has changed from that contained in the most-recently-filed triennial compliance filing or annual update filing, the annual update report shall describe the changes and provide updated capacity balance spreadsheets required pursuant to 4 CSR 240-22.080(2)(D). If the current resource acquisition strategy has not changed, the annual update report shall explicitly verify that the current resource acquisition strategy is the same as that contained in the most-recently filed triennial compliance filing or annual update filing.

KCP&L will prepare a public and highly confidential annual update report documenting the information presented at an annual update workshop.

(C) The utility shall prepare a summary report that shall list and describe any action items resulting from the workshop to be undertaken by the utility prior to next triennial compliance filing or annual update filing. The summary shall be filed within ten (10) days following the workshop. If there are no changes as a result of the workshop, the utility is required to file a notice that it will not be making any changes to its annual update report.

KCP&L will prepare a summary report listing and describing any action items resulting from an annual update workshop.

(D) Stakeholders may file comments with the commission concerning the utility's annual update report and summary report within thirty (30) days of the utility's filing of the summary report.

SECTION 4: SPECIAL CONTEMPORARY ISSUES

(4) It is the responsibility of each utility to keep abreast of evolving electric resource planning issues and to consider and analyze these issues in a timely manner in the triennial compliance filings and annual update reports. An order containing a list of special contemporary issues shall be issued by the commission for each utility to analyze and document in its next triennial compliance filing or next annual update report. The purpose of the special contemporary issues lists is to ensure that evolving regulatory, economic, financial, environmental, energy, technical, or customer issues are adequately addressed by each utility in its electric resource planning. Each special contemporary issues list will identify new and evolving issues but may also include other issues such as unresolved deficiencies or concerns from the preceding triennial compliance filing. To develop the list of special contemporary issues—

(A) No later than September 15, staff, public counsel, and parties to the last triennial compliance filing of each utility may file suggested special contemporary issues for each utility to consider;

(B) Not later than October 1, the utilities, staff, public counsel, and parties to the last triennial compliance filings may file comments regarding the special contemporary issues filed on September 15; and

(C) No later than November 1, an order containing a list of special contemporary issues shall be issued by the commission for each utility to analyze and document in its next triennial compliance filing or annual update report. The commission shall not be limited to only the filed suggested special contemporary issues. If the commission determines that there are no special contemporary issues for a utility to analyze, an order shall be issued by the commission stating that there are no special contemporary issues.

Order EO-2015-0041 was received by KCP&L with an effective date of November 1, 2014 providing a list of special contemporary issues to be analyzed and documented: The following submittal is the list of issues provided in the Order and KCP&L's responses:

a. Review the impact of foreseeable emerging energy efficiency technologies throughout the 20-year planning period;

KCP&L engaged Navigant Consulting, Inc. (Navigant) to conduct a Demand Side Management (DSM) Resource Potential Study which was completed in August 2013. As part of the study, Navigant developed a comprehensive list of energy efficiency measures based on conventional and emerging technologies. The study also included the effects of improved technologies expected over the 20-year planning horizon. Overall, 500 measures were considered across the sectors and end uses with 300 characterized for analysis in the final model. The final list of measures, including detailed measure characterization results, can be found in Appendix A of the 2013 Navigant 'Demand-Side Resource Potential Study Report'. KCP&L will continue to monitor energy efficiency technology developments and include and assess new and emerging energy efficiency technologies and measures in all future DSM Potential Studies.

For this IRP, our end-use level load forecasts were developed using both primary data collected by KCP&L and secondary data and projections produced by the U.S. Department of Energy (DOE) for the West North Central region of the U.S. DOE projections used in our models include projections of saturations for household appliances and equipment used in commercial buildings and projections of efficiencies for appliances, buildings and equipment. DOE's projections are designed to account for changes in consumer preferences, technology and building design practices. Their projections also account for the impacts of appliance and equipment standards. DOE updates its projections at least once a year and we use the most recently available projections whenever we update our models.

b. Review the impact of foreseeable emerging energy storage technologies throughout the 20-year planning period;

The role of energy storage technologies as a potential supply-side resource alternative is expected to be minimal over the 20-year planning period. While energy storage technologies utilized for frequency regulation have become commercially viable, the majority of supply-side energy storage technologies remain in the developmental or early demonstration stages. In addition, most energy storage technologies remain cost-prohibitive in comparison with other existing supply-side technologies considered in this resource planning process. In the pre-screening of supply side technologies, KCP&L did consider Compressed Air Energy Storage (CAES), Pumped Hydro, and Sodium Sulfur Battery technologies, but these were not advanced into the integrated resource analysis due to a lack of proven commercial operations, higher costs, and/or siting limitations. The KCP&L SmartGrid Demonstration project incorporated the demonstration and operational testing of the lithium-ion battery storage technology in a 1.0 MW/1.0 MWh Bulk Energy Storage System (BESS) and a 6.0 kW/11.2 kWh Premise Energy Storage System (PESS). KCP&L will continue to track the development and costs of these technologies, as well as the potential to use energy storage with renewable integration, for future resource planning.

c. Analyze and document the future capital and operating costs faced by each KCP&L coal-fired generating unit in order to comply with the following environmental standards:

(1) Clean Air Act New Source Review provisions;

(2) 1-hour Sulfur Dioxide National Ambient Air Quality Standard;

(3) National Ambient Air Quality Standards for ozone and fine particulate matter;

(4) Cross-State Air Pollution Rule, in the event that the rule is reinstated;

(5) Clean Air Interstate Rule;

(6) Mercury and Air Toxics Standards;

(7) Clean Water Act Section 316(b) Cooling Water Intake Standards;

(8) Clean Water Act Steam Electric Effluent Limitation Guidelines;

(9) Coal Combustion Waste rules;

(10) Clean Air Act Section 111(d) Greenhouse Gas standards for existing sources; and

(11) Clean Air Act Regional Haze requirements.

(1) Clean Air Act New Source Review provisions: The Company reviews proposed generation projects and permits these projects, as necessary, to comply with rule.

(2) 1-hour Sulfur Dioxide National Ambient Air Quality Standard: Iatan Station, LaCygne Station, and Hawthorn-5 are currently equipped to comply with this environmental rule. It is anticipated that the remaining KCP&L coal units will cease burning coal before this rule goes into effect.

(3) National Ambient Air Quality Standards for ozone and fine particulate matter: Iatan Station, LaCygne Station, and Hawthorn-5 are currently equipped to comply with this environmental rule. It is anticipated that the remaining KCP&L coal units will cease burning coal before this rule goes into effect.

(4) Cross-State Air Pollution Rule: The Company will comply through a combination of trading allowances within or outside its system in addition to changes in operations as necessary.

(5) Clean Air Interstate Rule: This Rule was replaced by the Cross-State Air Pollution Rule as of 1/1/2015

(6) Mercury and Air Toxics Standards: See Table 1, Table 2, and Table 3 below.

(7) Clean Water Act Section 316 Cooling Water Intake Standards: See Table 1, Table 2, and Table 3 below.

(8) Clean Water Act Steam Electric Effluent Limitation Guidelines: See Table 1, Table 2, and Table 3 below.

(9) Coal Combustion Residuals rules: See Table 1, Table 2, and Table 3 below.

(10) Clean Air Act Section 111(d) Greenhouse Gas standards for existing sources: The impacts of this rule will not be known until after the rule is ultimately finalized.

On June 2, 2014, EPA signed a notice of proposed rulemaking entitled, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" (Proposal). The Proposal, which EPA calls the "Clean Power Plan," (CPP) would require each state with fossil fuel-fired electric generating units (EGUs) to meet a rate, expressed in weighted average pounds of carbon dioxide (CO2) per net megawatt hour (MWh), by 2030 pursuant to section 111(d) of the Clean Air Act (CAA). The Proposal also sets an "interim" reduction target for each state with fossil generation, which is an average that the state must meet over the period 2020 to 2029.

EPA has identified four building blocks as BSER for CO2 emissions from existing EGUs:

1. Reducing the carbon intensity of generation at individual affected EGUs through heat rate improvements.

2. Reducing emissions of the most carbon-intensive affected EGUs in the amount that results from substituting generation at those EGUs with generation from less carbon-intensive affected EGUs (including natural gas combined cycle (NGCC) units that are under construction).

3. Reducing emissions of affected EGUs in the amount that results from substituting generation at those EGUs with expanded low- or zero-carbon generation.

4. Reducing emissions from affected EGUs in the amount that results from the use of demand-side energy efficiency that reduces the amount of generation required.

EPA's Proposal sets out proposed state-specific CO2 emission performance goals to guide states in development of their state plans. The proposed goals reflect EPA's quantification of the average emission rate from affected EGUs within each state that could be achieved by 2030 (and sustained thereafter) through implementation of EPA's selected BSER, taking into consideration the unique circumstances of each individual state. The goals also include interim goals that would apply over a 2020-2029 phase-in period and would need to be met on an average basis over that period of time

Based on a number of high-level assumptions on how Missouri and Kansas may implement the CPP (assuming it became a final rule similar to the proposed rule), KCP&L has estimated what its emission rate goals would be and the emission rate produced by the Preferred Plan. This was done for both the 2020-2029 phase-in period as well as the final 2030 goal.

The high-level assumptions in this analysis include:

- KCP&L's Missouri and Kansas emission rate targets are based on same percent reduction in emission rates EPA proposed for Missouri and Kansas.
- KCP&L is able to utilize a portion of its Kansas wind resources to comply with the Missouri emission rate targets.

The phase-in and final emission rate targets along with the Preferred Plan projected emission rates are included in the table below. Note that the Preferred Plan would be in compliance with proposed CPP requirements in both the 2020-2029 phase-in period as well as the final 2030 target in Missouri. However, it would not be in compliance in Kansas with the 2030 target. Therefore, should the CPP become final, it is projected that KCP&L would need to add approximately 75 MW of additional wind resources to meet CPP requirements.

	Target: 2020-29 Average lbs/MWh	Projected: 2020-29 Average lbs/MWh	Target: 2030 Average lbs/MWh	Projected: 2030 Average lbs/MWh
Missouri	**1691**	**1633**	**1611**	**1604**
Kansas	**1457**	**1446**	**1384**	**1453**

(11) Clean Air Act Regional Haze Requirements. The Company is installing BART at its LaCygne Generating Station for compliance with this rule.

Table 1: Retrofit Fixed O&M Estimates ** Highly Confidential **

[redacted]

Table 2: Retrofit Fixed O&M Estimates ** Highly Confidential **

[redacted]

HC

Table 3: Retrofit Variable O&M Estimates ** Highly Confidential **

[redacted]

d. Analyze and document the cost of any transmission grid upgrades or additions needed to address transmission grid reliability, stability, or voltage support impacts that could result from the retirement of any existing KCP&L coal-fired generating unit in the time period established in the IRP process.

The only KCP&L coal units identified for ceasing burning coal in the IRP plan are Montrose units 1, 2, and 3. The transmission grid impact of retirement of the Montrose units should be minimal. Retirement of any of the larger KCP&L coal fired generators would necessitate the replacement of that supply with some other resource. It is not possible to identify all the necessary transmission upgrades that might be associated with retirement of a specific generating unit without knowing the specific location of the replacement generation. From the transmission perspective, the most advantageous location for replacement generation is the site of the retired generation where the transmission capacity utilized by the retired generation would be available for new resources.

e. Analyze and document the range of potential levels of distributed generation in KCP&L's service territory for the 20-year planning horizon and the potential impacts of each identified level of distributed generation, and in particular distributed solar generation, on KCP&L's preferred resource plan. The potential impacts should quantify both the amount of electrical energy the distributed generation is expected to provide to the grid and the amount of electrical energy that the distributed generation customers are expected to consume on site that will offset the amount that the company would normally provide to those customers.

There is a substantial amount of uncertainty regarding distributed solar generation over a 20 year planning horizon. Nearly 100% of KCP&L's existing distributed solar generation is attributed to the Missouri law in which KCP&L paid up to $2.00/watt in rebates for customer installed solar generation. Pursuant to that Missouri law, a one-time rebate cap was established not to exceed $36.5M. KCP&L has approximately $2M in remaining funds at $1.00/watt. Distributed solar generation as a result of the rebates realized its peak in 2014, with approximately 9 MW of installed capacity. Subsequent to the rebate level decline from $1.50 to $1.00 KCP&L has only received 4 Net Metering applications YTD. Currently, there is a lack of relevant data, particularly in the Midwest to support any representative forecast that has a measurable impact. KCP&L will continue to track the development and cost of distributed generation as well as the intake of Net Metering applications for future resource planning.

SECTION 5: STAKEHOLDER GROUP MEETINGS

(5) Each electric utility shall convene a stakeholder group to provide the opportunity for public input into electric utility resource planning in a timely manner that may affect the outcome of the utility resource planning efforts. The utility may choose to not incorporate some, or all, of the stakeholder group input in its analysis and decision-making for the triennial compliance filing.

(A) The utility shall convene at least one (1) meeting of the stakeholder group prior to the triennial compliance plan filing to present a draft of the triennial compliance filing corresponding to 4 CSR 240-22.030–4 CSR 240-22.050 and to present an overview of its proposed alternative resource plans and intended procedures and analyses to meet the requirements of 4 CSR 240-22.060 and 4 CSR 240-22.070. The stakeholders shall make a good faith effort to provide comments on the information provided by the utility, to identify additional alternative resource plans, and to identify where the utility's analyses and intended approaches may not meet the objectives of the rules.

KCP&L presented draft information corresponding to Rules 4 CSR 240-22.030 through 4 CSR 240-22.050 on January 21, 2015 at the Missouri Public Service Commission, 200 Madison, Room 130, Jefferson City, Missouri. The material presented at the stakeholder meeting is attached as Appendix 8A.

(B) Within thirty (30) days of the last stakeholder group meeting pursuant to subsection (5)(A) of this rule, any stakeholder may provide the utility and other stakeholders with a written statement summarizing any potential deficiencies in or concerns with the utility's proposed compliance with the electric resource planning rules. The utility has the opportunity to address the potential deficiencies or concerns identified by any stakeholder in its preparation of the triennial compliance filing.

In response to NRDC and Renew Missouri's joint comments on KCP&L's draft presentation of the filing on January 21, 2015, KCP&L fully modeled multiple scenarios in the integrated analysis including RAP and MAP. In addition, the RAP and MAP scenarios also included the achievable potential from demand-side rates as was determined by the potential study conducted by Navigant.

(C) Any stakeholder input through the process described in section (5) of this rule does not preclude the stakeholder from filing reports in accordance with section (7) or (8) of this rule.

SECTION 6: COMMISSION DOCKETS

(6) The commission will establish dockets for the purpose of receiving the triennial compliance filings. Unless the commission specifies otherwise, the docket of the triennial compliance filing of each affected utility shall remain open to receive annual update reports including workshop summary reports, notifications of changes to the preferred plan, and other relevant documents submitted between triennial compliance filings. The commission will issue orders that establish an intervention deadline and provide for notice.

SECTION 7: TRIENNIAL COMPLIANCE FILING - STAFF REVIEW

(7) The staff shall conduct a limited review of each triennial compliance filing required by this rule and shall file a report not later than one hundred fifty (150) days after each utility's scheduled triennial compliance filing date. The report shall identify any deficiencies in the electric utility's compliance with the provisions of this chapter, any major deficiencies in the methodologies or analyses required to be performed by this chapter, and any other deficiencies and shall provide at least one (1) suggested remedy for each identified deficiency. Staff may also identify concerns with the utility's triennial compliance filing, may identify concerns related to the substantive reasonableness of the preferred resource plan or resource acquisition strategy, and shall provide at least one (1) suggested remedy for each identified concern. Staff shall provide its workpapers related to each deficiency or concern to all parties within ten (10) days of the date its report is filed. If the staff's limited review finds no deficiencies or no concerns, the staff shall state that in the report. A staff report that finds that an electric utility's filing is in compliance with this chapter shall not be construed as acceptance or agreement with the substantive findings, determinations, or analysis contained in the electric utility's filing.

SECTION 8: TRIENNIAL COMPLIANCE FILING - OTHER PARTIES REVIEW

(8) Also within one hundred fifty (150) days after an electric utility's triennial compliance filing pursuant to this rule, the public counsel and any intervenor may file a report or comments. The report or comments, based on a limited review, may identify any deficiencies in the electric utility's compliance with the provisions of this chapter, any major deficiencies in the methodologies or analyses required to be performed by this chapter, and any other deficiencies. The report may also identify concerns with the utility's triennial compliance filing and may identify concerns related to the substantive reasonableness of the preferred resource plan or resource acquisition strategy. Public counsel or intervenors shall make a good faith effort to provide at least one (1) suggested remedy for each identified deficiency or concern. Public counsel or any intervenor shall provide its workpapers, if any, related to each deficiency or concern to all parties within ten (10) days of the date its report is filed.

SECTION 9: JOINT AGREEMENT TIMELINE

(9) If the staff, public counsel, or any intervenor finds deficiencies in or concerns with a triennial compliance filing, it shall work with the electric utility and the other parties to reach, within sixty (60) days of the date that the report or comments were submitted, a joint agreement on a plan to remedy the identified deficiencies and concerns. If full agreement cannot be reached, this should be reported to the commission through a joint filing as soon as possible but no later than sixty (60) days after the date on which the report or comments were submitted. The joint filing should set out in a brief narrative description those areas on which agreement cannot be reached. The resolution of any deficiencies and concerns shall also be noted in the joint filing.

SECTION 10: ESTABLISHMENT OF HEARING

(10) If full agreement on remedying deficiencies or concerns is not reached, then, within sixty (60) days from the date on which the staff, public counsel, or any intervenor submitted a report or comments relating to the electric utility's triennial compliance filing, the electric utility may file a response and the staff, public counsel, and any intervenor may file comments in response to each other. The commission will issue an order which indicates on what items, if any, a hearing will be held and which establishes a procedural schedule.

SECTION 11: SUBMISSION OF DOCUMENTATION

(11) All workpapers, documents, reports, data, computer model documentation, analysis, letters, memoranda, notes, test results, studies, recordings, transcriptions, and any other supporting information relating to the filed resource acquisition strategy within the electric utility's or its contractors' possession, custody, or control shall be preserved and submitted within two (2) days of its triennial compliance or annual update filings in accordance with any protective order to the staff and public counsel, and to any intervenor within two (2) days of the intervenor signing and filing a confidentiality agreement, for use in its review of the periodic filings required by this rule. All information shall be labeled to reference the sections of the technical volume(s) to which it is related, and all spreadsheets shall have all formulas intact. Each electric utility shall retain at least one (1) readable copy of the officially adopted resource acquisition strategy and all supporting information for at least the prior three (3) triennial compliance filings.

KCP&L will submit workpapers, documents, reports, data, computer model documentation, analysis, letters, memoranda, notes, test results, studies, recordings, transcriptions, and any other supporting information within two days of submitting the triennial filing.

SECTION 12: NOTICE OF CHANGE TO PREFERRED PLAN

(12) If, between triennial compliance filings, the utility's business plan or acquisition strategy becomes materially inconsistent with the preferred resource plan, or if the utility determines that the preferred resource plan or acquisition strategy is no longer appropriate, either due to the limits identified pursuant to 4 CSR 240-22.070(2) being exceeded or for other reasons, the utility, in writing, shall notify the commission within sixty (60) days of the utility's determination and shall serve notice on all parties to the most recent triennial compliance filing. The notification shall include a description of all changes to the preferred plan and acquisition strategy, the impact of each change on the present value of revenue requirement, and all other performance measures specified in the last filing pursuant to 4 CSR 240-22.080 and the rationale for each change.

(A) If the utility decides to implement any of the contingency resource plans identified pursuant to 4 CSR 240-22.070(4), the utility shall file for review a revised resource acquisition strategy. In this filing, the utility shall specify the ranges or combinations of outcomes for the critical uncertain factors that define the limits within which the new alternative resource plan remains appropriate.

(B) If the utility decides to implement a resource plan not identified pursuant to 4 CSR 240-22.070(4) or changes its acquisition strategy, it shall give a detailed description of the revised resource plan or acquisition strategy and why none of the contingency resource plans identified in 4 CSR 240-22.070(4) were chosen. In this filing, the utility shall specify the ranges or combinations of outcomes for the critical uncertain factors that

define the limits within which the new alternative resource plan remains appropriate.

SECTION 13: GRANTING OF WAIVER OR VARIANCE

(13) Upon written application made at least twelve (12) months prior to a triennial compliance filing, and after notice and an opportunity for hearing, the commission may waive or grant a variance from a provision of 4 CSR240-22.030–4 CSR 240-22.080 for good cause shown. The commission may grant an application for waiver or variance filed less than twelve (12) months prior to the triennial compliance filing upon a showing of good cause for the delay in filing the application for waiver or variance.

A variance was requested regarding Rule 4 CSR 240-22.045(3)(B)2 and Rule 4 CSR 240-22.045(3)(B)3 requiring a Regional Transmission Organizations (RTO) expansion plan analysis specific to its Missouri customers. The Commission granted the variance.

(A) The granting of a variance to one (1) electric utility which waives or otherwise affects the required compliance with a provision of this chapter does not constitute a waiver respecting, or otherwise affect, the required compliance of any other electric utility with a provision of these rules.

(B) The commission will not waive or grant a variance from this chapter in total.

SECTION 14: WAIVER FOR ANNUAL UPDATE WORKSHOP

(14) An electric utility which sells less than seven (7) million megawatt-hours to Missouri retail electric customers for the previous calendar year may apply for a waiver allowing it to conduct an annual update workshop

pursuant to section (3) of this rule in place of its scheduled triennial compliance filing pursuant to section (1) of this rule, if the utility has no unresolved deficiencies or concerns from its prior triennial plan filing or annual update filing that materially affect its resource acquisition strategy. Upon written application made at least twelve (12) months prior to a triennial compliance filing, and after notice and an opportunity for hearing, the commission may allow the utility to conduct the annual update workshop process in lieu of submitting its triennial compliance filing. No more than one (1) such waiver may be granted consecutively between triennial compliance filings.

SECTION 15: EXTENDING OR REDUCING TIME PERIODS

(15) The commission may extend or reduce any of the time periods specified in this rule for good cause shown.

SECTION 16: COMMISSION ISSUED ORDER

(16) The commission will issue an order which contains its findings regarding at least one (1) of the following options:

(A) That the electric utility's filing pursuant to this rule either does or does not demonstrate compliance with the requirements of this chapter, and that the utility's resource acquisition strategy either does or does not meet the requirements stated in 4CSR 240-22.

(B) That the commission approves or disapproves the joint filing on the remedies to the plan deficiencies or concerns developed pursuant to section (9) of this rule;

(C) That the commission understands that full agreement on remedying deficiencies or concerns is not reached and pursuant to section (10) of this rule, the commission will issue an order which indicates on what items, if any, a hearing(s) will be held and which establishes a procedural schedule; and

(D) That the commission establishes a procedural schedule for filings and a hearing(s), if necessary, to remedy deficiencies or concerns as specified by the commission.

SECTION 17: COMMISSION ACKNOWLEDGEMENT OF PREFERRED RESOURCE PLAN

(17) If the commission finds that the filing achieves substantial compliance with the requirements outlined in section (16), the commission may acknowledge the utility's preferred resource plan or resource acquisition strategy as reasonable at a specific date. The commission may acknowledge the preferred resource plan or resource acquisition strategy in whole, in part, with exceptions, or not at all. Acknowledgment shall not be construed to mean or constitute a finding as to the prudence, pre-approval, or prior commission authorization of any specific project or group of projects. In proceedings where the reasonableness of resource acquisitions are considered, consistency with an acknowledged preferred resource plan or resource acquisition strategy may be used as supporting evidence but shall not be considered any more or less relevant than any other piece of evidence in the case. Consistency with an acknowledged preferred resource plan or resource acquisition strategy does not create a rebuttable presumption of prudence and shall not be considered to be dispositive of the issue. Furthermore, in such proceedings, the utility bears the burden of proof that past or proposed actions are consistent with an acknowledged preferred resource plan or resource acquisition strategy

and must explain and justify why it took any actions inconsistent with an acknowledged preferred resource plan or resource acquisition strategy.

(A) The utility shall notify the commission pursuant to 4 CSR 240-22.080(12) in the event there is material reason why any plan acknowledged by the commission is no longer viable.

(B) Any interested stakeholder group may file a notice in the utility's most recent Chapter 22 compliance file with the commission if a substantial change in circumstances has occurred that it believes may result in the invalidation of any aspect of a preferred resource plan or portion of a resource acquisition strategy previously acknowledged by the commission.

(C) The utility about which a stakeholder group files a notice described in the previous section may file its response within fifteen (15) working days of the date the notice is filed.

SECTION 18: CERTIFICATION OF CONSISTANCY OF PREFERRED PLAN TO FUTURE CASE

(18) In all future cases before the commission which involve a requested action that is affected by electric utility resources, preferred resource plan, or resource acquisition strategy, the utility must certify that the requested action is substantially consistent with the preferred resource plan specified in the most recent triennial compliance filing or annual update report. If the requested action is not substantially consistent with the preferred resource plan, the utility shall provide a detailed explanation.