KANSAS CITY POWER & LIGHT COMPANY (KCP&L)

INTEGRATED RESOURCE PLAN

2017 ANNUAL UPDATE

JUNE, 2017

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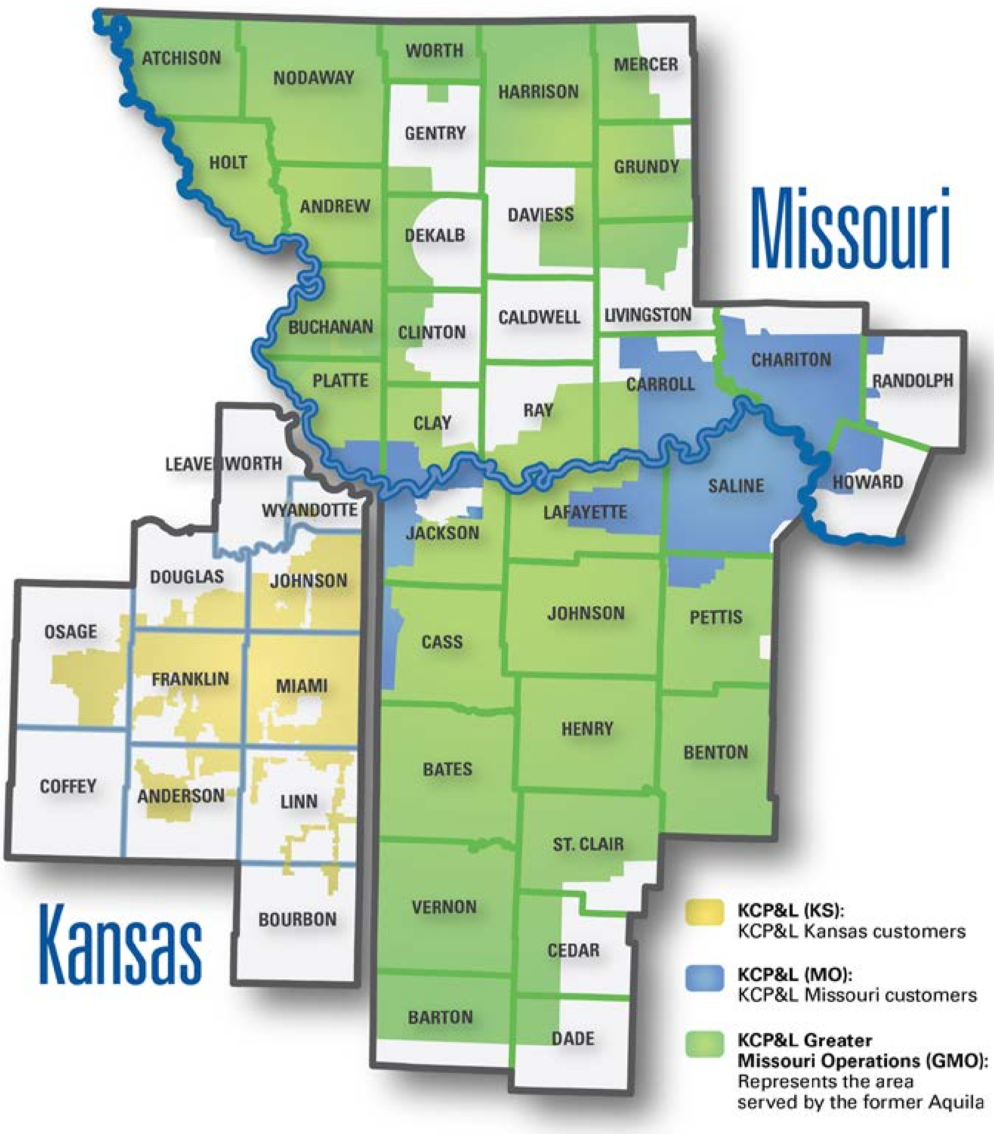
SECTION 1: EXECUTIVE SUMMARY

1.1 UTILITY INTRODUCTION

Kansas City Power & Light ("KCP&L" or "Company") 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: Great Plains Energy 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 for 2016.

Table 1: KCP&L Customers, Retail Sales and Peak Demand

Jurisdiction	Number of Retail Customers	Retail Sales (MWh)	Net Peak Demand (MW)
KCP&L-Missouri	279,786	8,435,167	1,842
KCP&L-Kansas	251,845	6,370,266	1,700
KCP&L	531,631	14,805,433	3,542

KCP&L owns and operates a diverse generating portfolio and Power Purchase Agreements (PPA) to meet customer energy requirements. Two recent renewable generation projects that KCP&L has 20-year PPAs with are the Osborn and Rock Creek wind farms. The 120 MW Osborn wind farm achieved commercial operation on December 14, 2016 and 180 MW Rock Creek wind farm is currently under construction and expected to be commercially operating by December 31, 2017. Table 2, Figure 2, and Figure 3 reflect KCP&L's generation assets including PPAs in place by 2018.

Table 2: KCP&L Capacity and Energy by Resource Type

Capacity By Fuel Type	Capacity (MW)	% of Total Capacity	Estimated Energy (MWh)	% of Annual Energy
Coal	2,569	48%	13,745,925	61%
Nuclear	549	10%	4,056,184	18%
Oil	401	7%	-	0%
Nat. Gas	782	15%	129,325	1%
Wind	1,031	19%	4,035,565	18%
Hydro	60	1%	383,400	2%
Solar	0.2	0.003%	240	0.001%
Total	5,392	100.0%	22,350,639	100.0%

* Wind capacity is based upon nameplate capacity

Figure 2: KCP&L Capacity by Resource Type

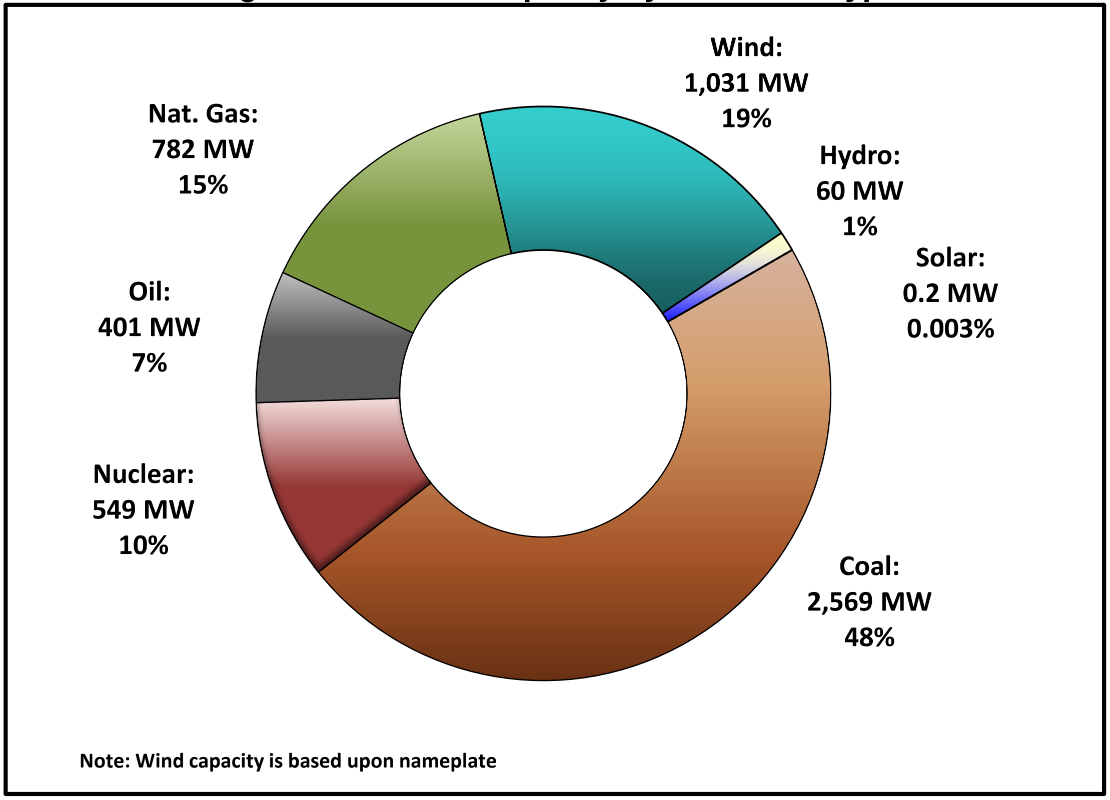
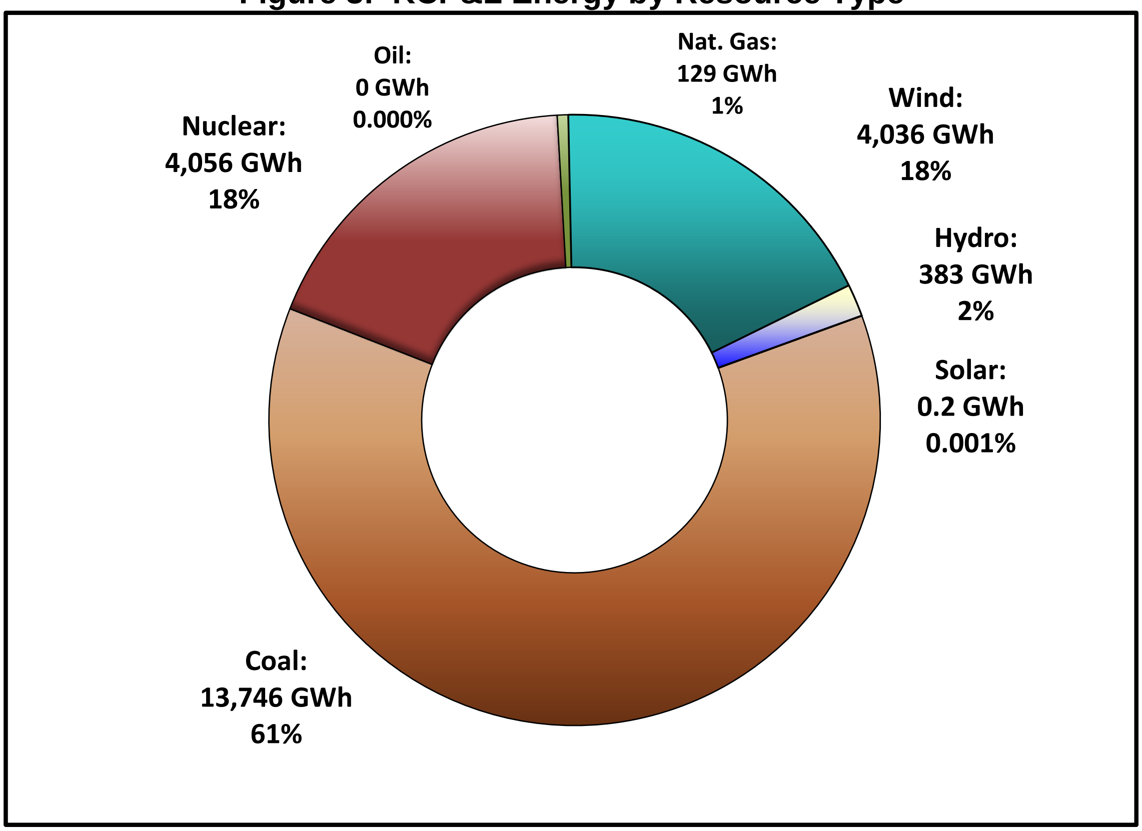


Figure 3: KCP&L Energy by Resource Type



1.2 CHANGES FROM THE 2015 TRIENNIAL IRP

Since the filing of the 2015 Triennial IRP, changing conditions, or major drivers, were refreshed to reflect the latest information and forecasts available to determine if the Preferred Plan and associated Resource Acquisition Strategy identified in 2015 Triennial IRP continue to be the company's path forward. The changing conditions, or major drivers, that have contributed to KCP&L's need to develop new Alternative Resource Plans and selection of a new Preferred Plan include:

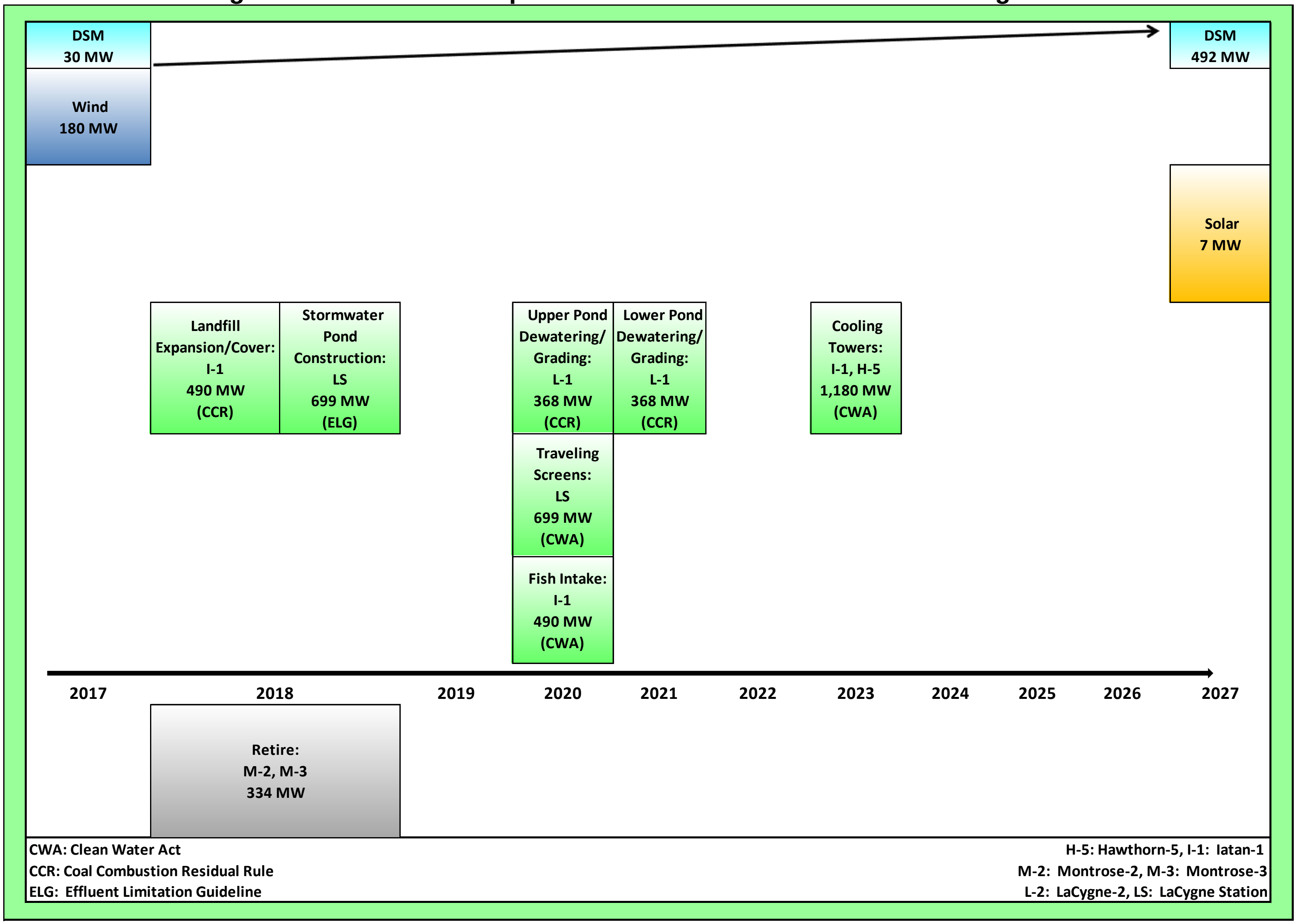
- Proposed and Potential Environmental Regulations
- Load, Fuel, and Emissions Forecast Projections
- Demand-Side Management (DSM) Program levels
- Significant changes to the SPP reserve margin requirements. In addition to lowering the reserve margin requirement from 13.6% to 12%, the requirement is going to be based on projected normal weather peak load rather than actual peal load. SPP also changed their wind accreditation requirements which effectively increased the accreditable wind capacity.

1.3 2017 ANNUAL UPDATE PREFERRED PLAN

The 2017 Annual Update analysis has resulted in material changes to the Preferred Plan outlined in the 2015 Triennial IRP. The new Preferred Plan is comprised of the following components for years 2017 – 2027 shown in Figure 4 below. Based in part upon current Missouri RPS rule requirements, the Preferred Plan includes a 7 MW solar addition currently expected to be in-service by 2028 and a 180 MW portion of a Missouri wind facility expected to be commercially operational by 2018. The DSM resources that were modeled consisted of a suite of eight residential and eight commercial programs three of which are demand response programs, two are educational programs, and eleven are energy efficiency programs. Additionally, six demand-side rate (DSR) programs are currently modeled to commence in 2019. The six DSR programs are: Time of Use, Time of Use with Electric Vehicle, Demand Rate, Demand Rate with Electric Vehicle, Real Time Pricing, and Inclining Block Rate.

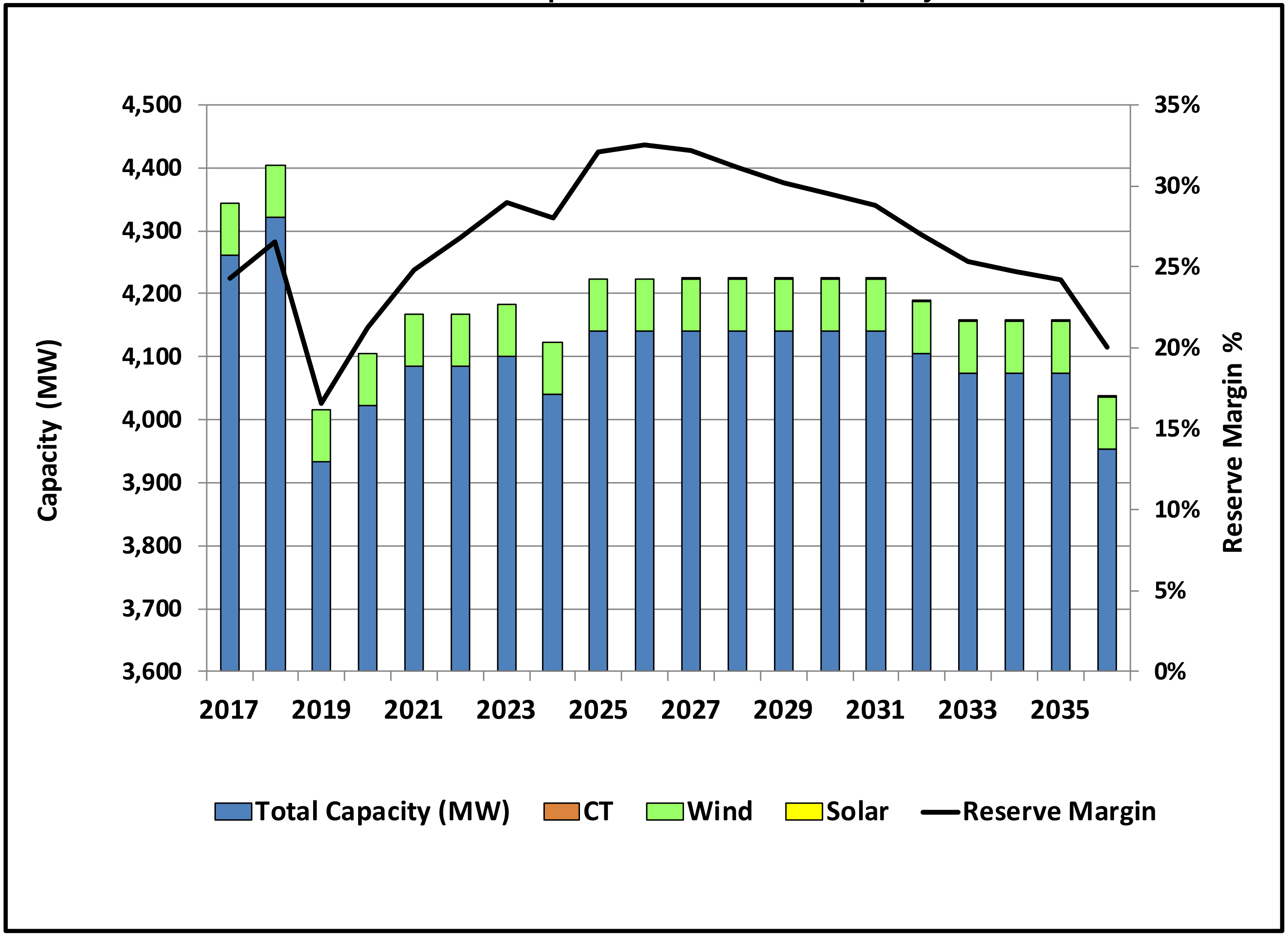
The Preferred Plan also includes Montrose Units 2 and 3 retiring by 2019. Key drivers that contribute to these retirement decisions are a lower SPP reserve margin requirement which has been reduced from 13.6% to 12%, higher wind resource accreditations, and peak load based upon normal weather rather than actual peak. Additionally, continued low long-term gas price forecasts, low long-term peak load forecasts, and more wind capacity additions in the SPP region have reduced the economic value of these units. Also, environmental regulations including Ozone National Ambient Air Quality Standards (NAAQS), PM NAAQS, Clean Water Act Section 316(a) and (b), Coal Combustion Residuals Rule, Effluent Guidelines, Clean Power Plan increase the cost of operating these units, further reducing their economic value Vs. other generating options.

Figure 4: 2017 Annual Update Preferred Plan - Years 2017 through 2027



Existing and new capacity additions for the 2017 Annual Update Preferred Plan are shown in Table 3 below:

Table 3: 2017 Annual Update Preferred Plan Capacity Outlook



The 2017 Annual Update Preferred Plan for the 20-year planning period is shown in Table 4 below:

Table 4: 2017 Annual Update Preferred Plan

Year	CT's (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)	Existing Capacity (MW)
2017	0	180		30		4,461
2018	0			60	334	4,522
2019	0			113		4,133
2020	0			175		4,223
2021	0			228		4,285
2022	0			300		4,285
2023	0			361		4,300
2024	0			411		4,240
2025	0			448		4,240
2026	0			475		4,240
2027	0		7	492		4,240
2028	0			500		4,240
2029	0			501		4,240
2030	0			504		4,240
2031	0			507		4,240
2032	0			510		4,204
2033	0			513		4,173
2034	0			517		4,173
2035	0			526		4,173
2036	0			538		4,053

SECTION 2: LOAD ANALYSIS AND LOAD FORECASTING UPDATE

2.1 CHANGES FROM THE 2016 ANNUAL UPDATE

Several inputs to the load forecasting models were updated for this filing.

- The economic forecasts for the KC metro area were updated. In the 2015 Triennial filing, KCP&L used forecasts produced by Moody's Analytics in July 2014. In this 2017 Annual Update filing, the forecasts were produced in July 2016.

- Billing statistics were updated through July 2016 for this filing. In the 2015 Triennial filing, the statistics were current through July 2014. These statistics include the number of customers, kWh sales and dollars per kWh.

- Forecasts of saturations and appliance use are updated annually by the US Department of Energy (DOE). In this filing, KCP&L used the results from DOE's 2016 models. In the 2015 Triennial filing, KCP&L used results from the 2014 models.

- The industial models structure in the 2015 Triennial has changed to an industrial based Statistically Adjusted Employment-Intensity Model in the 2016 and 2017 Annual Updates. This structure utilizes a framework that incorporates sector employment, price and sector intensities (MWh/Employee). This results in a sector weighted employment index used within the regression model.

- The methodology used to calculate peak load in the 2015 Triennial has changed from a bottom up approach to standalone jurisdictional peak models which incorporates the energy end use forecast by class in to the model. The models are also designed to weather normalize peak loads. This approach was adopted in the 2016 and 2017 Annual Updates.

- Historical weather normalized kWh sales are no longer derived within the forecasting models as in the 2015 Triennial filing. Historical weather normalized results for billed kWh sales, calendar kWh sales and unbilled kWh sales are now calculated in a seperate weather normalzation model for the 2016 and 2017 Annual Updates.

- Class models in the 2017 Annual Update are the same as the 2015 Triennial filing: residential, small commercial (small general service commercial), big commercial (medium general service commercial, large general service commercial, and large power commercial), and industrial (small general service industrial, medium general service industrial, large general service industrial, and large power industrial).

- The Company also re-evaluated the output elasticities used in the commercial and industrial models and the elasticity used in the residential model. Adjustments made were to increase the R^2.

- The mid-case load forecast is shown in Table 5 below:

Table 5: KCP&L Mid-Case Annual NSI and Peak Forecast ** Highly Confidential **

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SECTION 3: SUPPLY-SIDE RESOURCE ANALYSIS UPDATE

3.1 FUEL AND EMISSION FORECAST CHANGES FROM THE 2016 ANNUAL UPDATE

The forecasts for coal, natural gas, fuel oil, SO_2, NO_x, NO_x Seasonal, and CO_2 have been updated for the 2017 Annual Update. Note that the methodology used in determining the forecast range has not changed from the 2016 Annual Update. The data is presented in graphical and tabular form on the next pages.

Table 6: Coal Forecasts – 2017 Annual Update Vs. 2016 Annual Update Graphic ** Highly Confidential **

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Table 7: Coal Forecasts - 2017 Annual Update Vs. 2016 Annual Update ** Highly Confidential **

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Table 8: Natural Gas Forecasts - 2017 Annual Update Vs. 2016 Annual Update Graphic ** Highly Confidential **

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Table 9: Natural Gas Forecasts – 2017 Annual Update Vs. 2016 Annual Update ** Highly Confidential **

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Table 10: Fuel Oil Forecasts – 2017 Annual Update Vs. 2016 Annual Update Graphic ** Highly Confidential **

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Table 11: Fuel Oil Forecasts - 2017 Annual Update Vs. 2016 Annual Update ** Highly Confidential **

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Table 12: SO_2 Forecasts - 2017 Annual Update Vs. 2016 Annual Update Graphic ** Highly Confidential **

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Table 13: SO_2 Forecasts - 2017 Annual Update Vs. 2016 Annual Update ** Highly Confidential **

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Table 14: NO_x Annual Forecasts - 2017 Annual Update Vs. 2016 Annual Update Graphic ** Highly Confidential **

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Table 15: NO_x Annual Forecasts – 2017 Annual Update Vs. 2016 Annual Update ** Highly Confidential **

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Table 16: NO_x Seasonal Forecasts - 2017 Annual Update Vs. 2016 Annual Update Graphic ** Highly Confidential **

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Table 17: NO_x Seasonal Forecasts - 2017 Annual Update Vs. 2016 Annual Update ** Highly Confidential **

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Table 18: CO_2 Forecast - 2017 Annual Update Vs. 2016 Annual Update Graphic ** Highly Confidential **

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Table 19: CO_2 Forecast - 2017 Annual Update Vs. 2016 Annual Update Table ** Highly Confidential **

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The following two tables provide the sources of the fuel and emission forecasts reflected in the above charts.

Table 20: Fuel Forecast Sources

Forecast Source	Coal	Natural Gas	Fuel Oil
IHS	x	x	x
EIA	x	x	x
PIRA		x	x
Energy Ventures Analysis	x	x	x
JD Energy	x		
Hanou Energy Consulting	x		

Table 21: Emission Forecast Sources

Forecast Source	SO_2	NO_x	CO_2
IHS	x	x	x
PIRA	x	x	x
Energy Ventures Analysis	x	x	x
JD Energy	x	x	
Synapse			x

3.1.1 SUPPLY-SIDE TECHNOLOGY CANDIDATE RESOURCE OPTIONS

Supply-side technology candidates reviewed for potential integrated resource analysis in the 2017 Annual Update are shown in Table 22 below. The cost and operating data sources for these technologies were obtained from Electric Power Research Institute Technical Assessment Guide (EPRI-TAG®), the Energy Information Administration, and recently obtained market intelligence. These supply-side options include natural gas, coal, nuclear and renewable alternatives. The following table compares the all-in cost of the supply side options on a 2017 dollar per MWh basis which includes capital cost, fixed O&M, variable O&M, fuel, and emissions.

Table 22: Supply-Side Technology Candidates ** Highly Confidential **

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3.1.2 LIFE ASSESSMENT & MANAGEMENT PROGRAM

The 2017 Annual Update included an update of the Life Assessment and Management Program (LAMP) data for the KCP&L coal-fired generating units. The LAMP 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-fired generating units.

SECTION 4: TRANSMISSION AND DISTRIBUTION UPDATE

4.1 CHANGES FROM THE 2015 TRIENNIAL IRP

Transmission and Distribution-related changes and updates are provided below:

4.1.1 RTO EXPANSION PLANNING

KCP&L assessment of RTO expansion plans is an ongoing process that occurs throughout the various regional planning processes conducted by SPP. These assessments include review and approval of plan scope documents, review and approval of plan input assumptions, review of plan study analysis and results with feedback from KCP&L staff, and review and approval of final plan reports. All transmission projects for the KCP&L service territory are included in SPP's annual Transmission Expansion Plan Report and Project List. By meeting the performance standards established for transmission planning the assessment ensures that adequate transmission is available in the near term and long term to meet the firm load and transmission service requirements included in the SPP Regional Plan for the Company. These documents are attached as Appendix A 2017 SPP Transmission Expansion Plan Report.pdf and Appendix A1 2017 SPP Transmission Expansion Plan Project List.xls.

4.1.2 ADVANCED DISTRIBUTION TECHNOLOGIES DISCUSSION

Having completed the SmartGrid Demonstration project in 2015, KCP&L has been implementing targeted Advanced Distribution Technologies (ADT).

Main initiatives in the near-term ADT plan include:

- Implementing SCADA-like monitoring and control into the Company's recently implemented Operations Management System (OMS).
- Fault Isolation and System Restoration (FISR) pilots for proof of concept.
- Fault Location functionality with the new OMS system.
- Pilots and proof of concept for Communicating Faulted Circuit Indicators (CFCI).
- Replace "2G" vintage distribution end-device cellular communications equipment.
- Pilot new "4G" distribution end-point communications equipment.
- Develop a multi-year Distribution Automation Roadmap.

4.1.2.1 SCADA-like Monitoring and Control via OMS

KCP&L has over ten years of experience using cellular communications for monitoring, operating, controlling and maintaining Intelligent End Devices (IEDs) on the distribution system. Up through mid-2015, this technology has been limited to internet-based web applications. This required company distribution dispatchers to utilize a separate system to operate this communicating equipment. This added complexity to the dispatcher role and there was a desire to consolidate as much functionality as possible into the new OMS system. Phase 2 of the company's OMS implementation project included integration of the internet-based system directly into the OMS. This project was placed in service in 2015.

Distribution dispatchers now monitor and operate the communicating IEDs directly from the OMS system without the need to swap between systems with very different interfaces. The internet-based web applications still underlie the OMS integration, providing an emergency back-up system to operate this equipment in the event of issues with the OMS system.

KCP&L's vendor for the internet-based web applications is changing their web platform and plans to decommission the existing system that is integrated to the Company's OMS system. The Company is planning to transition from the existing web platform to the new platform over the next several years. The vendor has not provided a definitive date to decommission the existing platform. Final transition planning will be built around this date, once known. In the meantime, integration to the new platform will continue and both platforms will be used in parallel until the old system is decommissioned or until all field devices are transitioned to the new platform. These changes should be relatively transparent to system operators.

Engineering and other non-dispatch organizations mainly utilize the web applications to manage and maintain the fleet of communicating IEDs in the field. Users will need to become familiar with the new web application platform.

4.1.2.2 Fault Isolation and Service Restoration (FISR)

KCP&L is piloting two schemes for FISR: one using peer-to-peer communications between smart switching devices and a second one with a loop scheme (without peer-to-peer communications).

4.1.2.2.1 FISR Using Peer-to-Peer (PTP) Communications

The Company initiated a pilot (Phase 1) for FISR with PTP communications for proof of concept located in Roeland Park, Kansas. A second phase of pilots is planned on the heels of the first two, but locations have not been selected as this point.

The switching devices chosen for this pilot are S&C Electric's Intellirupter Pulseclosers. PTP is a term meaning that there is specific communications between the switches on the feeder so these intelligent devices share information before performing any automated switching operations. The PTP communications will be provided by S&C Electric's Speednet radio system. The intelligent switching and restoration in this scheme is managed by S&C Electric's Intelliteam distributed control system embedded into the switching device controls.

In essence, switches will be placed at middle points on adjacent circuits as well as the normally open switch points between these circuits. This is similar to historical system design where field personnel are dispatched to patrol the circuit and manually operate the switches to isolate a faulted section as well as using the tie switch to restore circuit sections not directly affected by the fault.

In the FISR pilot, the Intelliteam system and the PTP communications will automatically identify a faulted circuit section (without requiring a human patrol), perform switching to isolate the faulted section and perform switching to restore sections not affected by the fault. The Company anticipates this will all occur in less than five (5) minutes and involves little to no human intervention.

After the automated switching is completed, the Intelliteam system will communicate the results via cellular communications to Company operators informing them of the faulted section and the restoration switching already performed. Dispatchers will then have information to dispatch crews directly to the faulted section to identify the physical problem and make repairs. Field crews will not need to patrol non-faulted sections, reducing patrol times.

After repairs are completed, dispatchers can remotely switch the system back to its normal configuration without requiring a field crew to perform the switching.

If the Company determines that the initial Phase 1 pilot is successful over an estimated nine month period, the next set of circuits will be piloted (Phase 2). After this second phase of pilot circuits is observed, the Company will complete a study of the performance and make recommendations whether to proceed with this scheme as a standard solution and establish criteria for its application.

4.1.2.2.2 FISR Using Loop Scheme

The Company is planning two initial pilots (Phase 1) for FISR using a Loop Scheme for proof of concept. Potential locations are being studied but final locations have not been selected as yet. The first pilot location is planned for field installation in 2017. These pilots are now dependent upon implementation of 4G cellular communications and the new web platform discussed in Section 4.1.2.1 above

The switching devices chosen for this pilot are G&W Electric's Viper Recolser using a Sweitzer Engineering Labs control. A Loop Scheme is based on conditions measured at each intelligent switch as well as coordinated timing between the switches. PTP is not required for Loop Scheme. Each individual switch will communicate via 4G cellular communications back to the Company's OMS. This is also a distributed intelligence system since switching decisions are made locally by the switches, not by a centralized control system (such as a Distribution Management System).

In essence, switches will be placed at middle points on adjacent circuits as well as the normally open switch points between these circuits. This is similar to historical system design where field personnel are dispatched to patrol the circuit and manually operate the switches to isolate a faulted section as well as using the tie switch to restore circuit sections not directly affected by the fault.

In the Loop Scheme FISR pilot, each switch will sense fault current and voltage conditions, while allowing sufficient time for upstream equipment to complete an operational sequence. Using this local data/sensing, switches decide to open or close in order to automatically isolate a faulted circuit section (without requiring a human patrol), and perform switching to restore sections not affected by the fault. The Company anticipates this will all occur in less than ten (10) minutes (and possibly less than five minutes) and involves little or no human intervention.

After the automated switching is completed, each switch will communicate the results via 4G cellular communications to Company OMS informing dispatchers of the faulted section and the restoration switching already performed. Dispatchers will then have information to dispatch crews directly to the faulted section to identify the physical problem and make repairs. Field crews will not need to patrol non-faulted sections, reducing patrol times.

After repairs are completed, dispatchers can remotely switch the system back to its normal configuration without requiring a field crew to perform the switching.

If the Company finds the initial pilots successful, another set of circuits will be piloted (Phase 2). After this second phase of pilot circuits is observed, the Company will complete a study of the performance and make recommendations whether to proceed with this scheme as a standard solution and establish criteria for its application.

4.1.2.3 OMS Fault Location Functionality

The supplier of the Company's new OMS system claims it has an advanced application for predicting Fault Location. The concept is fairly simple in nature. The OMS will use data from communicating field equipment to predict sections of a feeder where a fault may be physically located. The more fault sensors (such as communicating faulted circuit indicators, or communicating switches) on the circuit, the more accurately the OMS will be able to predict the fault location.

Benefits anticipated from Fault Location prediction are mainly reduced patrol time for field crews. Dispatchers can direct field crews to focus on predicted faulted sections vs. patrolling an entire circuit to identify a fault.

If this proves to be highly accurate, communicating switches could be added to circuits to enable dispatchers to isolate the faulted section before a field patrol is completed as well as restoring as many customers as possible via remote switching. This would in essence be a human-supervised form of FISR.

No specific timeline has been established to pilot and study this function. It is now dependent on successful integration and testing of the the new web platform discussed in Section 4.1.2.1 above.

4.1.2.4 Communicating Faulted Circuit Indicator (CFCI) Pilots

KCP&L is working with suppliers to pilot current technologies for CFCIs. The usefulness of CFCIs to Company dispatchers has escalated due to the new functionality discussed previously outlined in Section 4.1.2.1 above.

Dispatchers will now have the ability to receive alarms in OMS and to “see” the CFCI indication on the OMS One-line diagram while troubleshooting an outage within OMS. This will greatly enhance the “visability” and usefulness of CFCIs to dispatchers, vs. having to go to a web application as in the past.

CFCIs are also anticipated to be a cost-effective way to enhance the OMS Fault Location functionality discussed previously. Although CFCIs cannot perform switching operations, they can enhance the effectiveness of dispatching and manual switching. It should be noted that specific pilot locations have yet to be determined for the KCP&L service territory.

Vendor development of CFCI has been slow to progress and deployment of CFCI is now dependent on successful integration and testing of the the new web platform discussed in Section 4.1.2.1 above. Alternative web platforms and cellular communication mechanisms are also being reviewed for integration into the Company’s OMS.

4.1.2.5 2G Cellular Communications Replacement

KCP&L has cellular-based communications to field devices that utilize AT&T 2G generation communications. As planned, AT&T began to retire its 2G network in early 2017. The Company replaced all critical 2G endpoints with 3G cellular or private cellular in 2016. Additional replacements of less critical devices will continue and is currently dependent on successful integration and testing of the the new web platform discussed in Section 4.1.2.1 above as well as continued development of 4G cellular communications.

4.1.2.6 4G Cellular Communications Pilot

KCP&L's cellular communications provider recently introduced a series of endpoint devices using "4G" cellular communications. The Company has continued bench testing this equipment and installed pilot equipment in the field in 2016.

This new 4G equipment is not compatible with the vendor's existing web platform. The 4G pilot will also include integration of the 4G equipment into the OMS platform as discussed in Section 4.1.2.1 above.

4.1.2.7 Develop a Multiyear Distribution Automation Roadmap

KCP&L developed a framework of potential scenarios for a multiyear Distribution Automation Roadmap in 2016. In early 2017, the Company selected scenarios to be further vetted into a first iteration of a Distribution Automation Roadmap. The roadmap will include aspects across the entire Company.

SECTION 5: DEMAND-SIDE RESOURCE ANALYSIS UPDATE

Because of the voluminous nature of the Demand-Side Resources analysis update, please refer to the separate document entitled “Kansas City Power & Light Demand-Side Resource Analysis”.

SECTION 6: INTEGRATED RESOURCE PLAN AND RISK ANALYSIS UPDATE

6.1 CHANGES FROM THE 2015 TRIENNIAL IRP

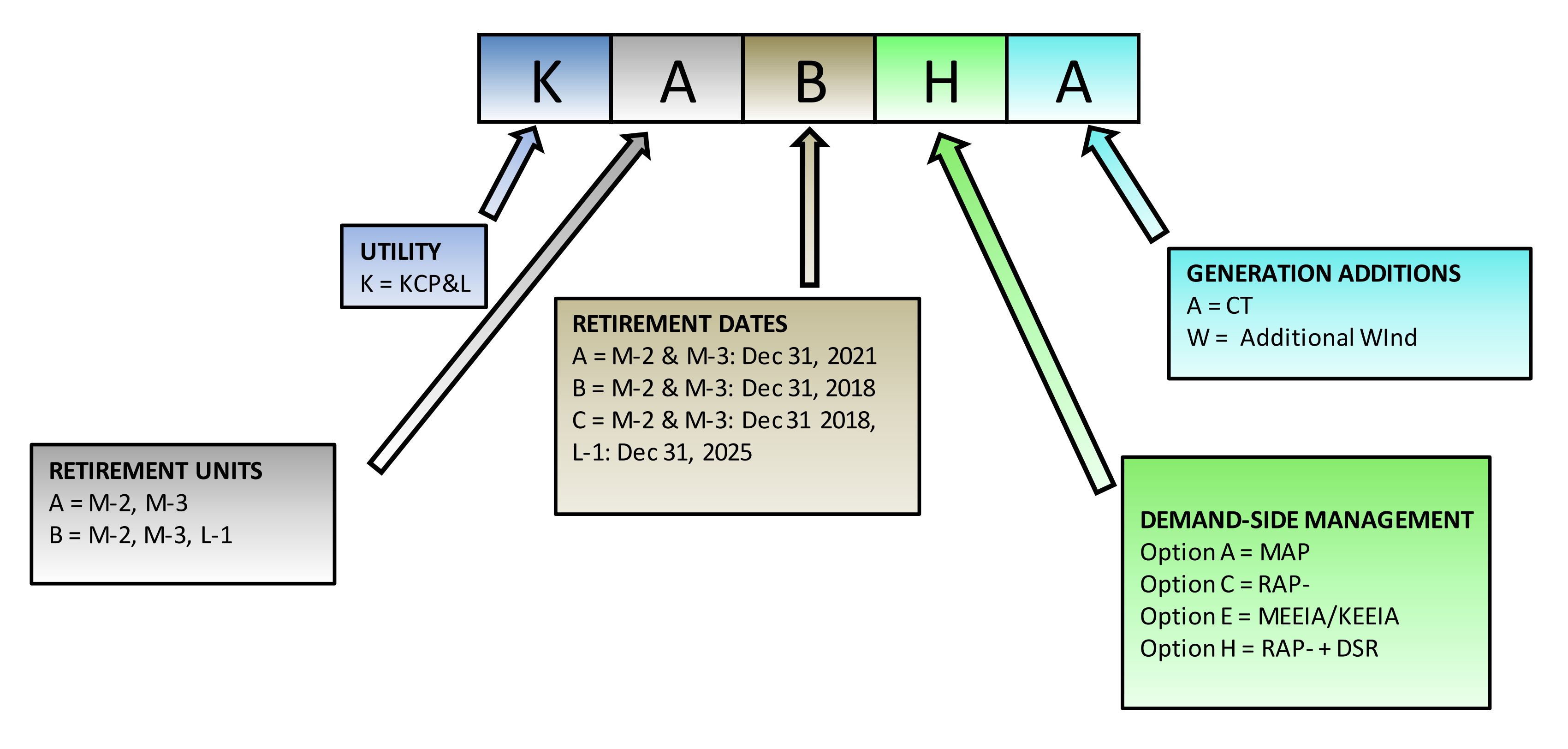
Since the filing of the 2015 Triennial IRP, changing conditions, or major drivers, were refreshed to reflect the latest information and forecasts available to determine if the Preferred Plan and associated Resource Acquisition Strategy identified in 2015 Triennial IRP continue to be the company's path forward. The information and forecasts that have been updated for the 2017 Annual Update included:

- Proposed and Potential Environmental Regulations
- Load Forecast Projections
- Demand-Side Management Program levels
- Significant changes to the SPP reserve margin requirements. In addition to lowering the reserve margin requirement from 13.6% to 12%, the requirement is going to be based on projected normal weather peak load rather than actual peal load. SPP also changed their wind accreditation requirements which effectively increased the accreditable wind capacity.

6.2 ALTERNATIVE RESOURCE PLAN DEVELOPMENT

Alternative Resource Plans (ARPs) were developed using a combination of supply-side resources, demand-side resources, various resource addition timings, as well as generation retirement options and timings. Because some of the supply-side technology candidates were either considerably more costly in comparison to other technologies considered and/or permitting is currently expected to be extremely difficult to achieve, only a portion of the candidates were utilized in development of ARPs. The plan-naming convention utilized for the ARPs developed is shown in Table 23**Error! Reference source not found.** and an overview of the ARPs is shown in Table 24 below:

Table 23: Alternative Resource Plan Naming Convention



Definitions:

M-2: Montrose-2	**CT - Combustion Turbine**	**MAP: Maximum Achievable Potential**
M-3: Montrose-3	**MEEIA: Missouri Energy Efficiency Investment Act Cycle II**	**RAP-: Realistic Achievable Potential Minus**
L-1: LaCygne-1	**KEEIA: Kansas Energy Efficiency Investment Act**	**DSR: Demand-Side Rates**

Table 24: Alternative Resource Plan Overview

Plan Name	DSM Level	Retire	Renewable Additions		Generation Addition (if needed)
KAACA	Option C	Montrose-2: Dec, 2021 Montrose-3: Dec, 2021	Solar: 2027 - 7 MW	Wind: 2017 - 180 MW	n/n
KABAA	Option A	Montrose-2: Dec 31, 2018 Montrose-3: Dec 31, 2018	Solar: 2027 - 7 MW	Wind: 2017 - 180 MW	n/n
KABBA	Option B	Montrose-2: Dec 31, 2018 Montrose-3: Dec 31, 2018	Solar: 2027 - 7 MW	Wind: 2017 - 180 MW	n/n
KABCA	Option C	Montrose-2: Dec 31, 2018 Montrose-3: Dec 31, 2018	Solar: 2027 - 7 MW	Wind: 2017 - 180 MW	n/n
KABCW	Option C	Montrose-2: Dec 31, 2018 Montrose-3: Dec 31, 2018	Solar: 2027 - 7 MW	Wind: 2017 - 180 MW	200 MW of Additional Wind in 2018
KABEA	Option E	Montrose-2: Dec 31, 2018 Montrose-3: Dec 31, 2018	Solar: 2027 - 7 MW	Wind: 2017 - 180 MW	n/n
KABHA	Option H	Montrose-2: Dec 31, 2018 Montrose-3: Dec 31, 2018	Solar: 2027 - 7 MW	Wind: 2017 - 180 MW	n/n
KBCCA	Option C	Montrose-2: Dec 31, 2018 Montrose-3: Dec 31, 2018 LaCygne-1: Dec 31, 2025	Solar: 2027 - 7 MW	Wind: 2017 - 180 MW	n/n

Refer to Appendix B, Capacity Balance Spreadsheets, for tables which provide the KCP&L forecast of capacity balance over the twenty-year planning period for each of the Alternative Resource Plans outlined above. These capacity forecasts include renewable and generation additions. The capacity for wind facilities is based on SPP's criteria for calculating wind net capability using actual generation or wind data. Solar capacity is based on SPP criteria indicating that absent a net capability calculation, 10% of the facility's nameplate rating be used.

6.3 REVENUE REQUIREMENT

For each of the Alternative Resource Plans developed, integrated analysis yielded an expected value of the Net Present Value of Revenue Requirement shown in Table 25 below:

Table 25: Twenty-Year Net Present Value Revenue Requirement

Rank (L-H)	Plan	NPVRR ($MM)	Delta ($MM)
1	KABHA	$ 21,623	$ -
2	KABCA	$ 21,700	$ 77
3	KBCCA	$ 21,705	$ 82
4	KABEA	$ 21,719	$ 97
5	KAACA	$ 21,722	$ 99
6	KABBA	$ 21,725	$ 103
7	KABCW	$ 21,809	$ 186
8	KABAA	$ 21,811	$ 188

6.4 PERFORMANCE MEASURES

A summary tabulation of the expected value of all performance measures is provided in Table 26 below. Plan detail results behind this summary tabulation are attached in Appendix D, Economic Impact for Each Alternative Resource Plan HC.

Table 26: Expected Value of Performance Measures ** Highly Confidential **

Plan	NPVRR ($MM)	Levelized Annual Rates ($/KW-hr)	Maximum Rate Increase
KABHA	21,586		
KABCA	21,700		
KBCCA	21,705		
KABEA	21,719		
KAACA	21,722		
KABBA	21,725		
KABCW	21,809		
KABAA	21,811		

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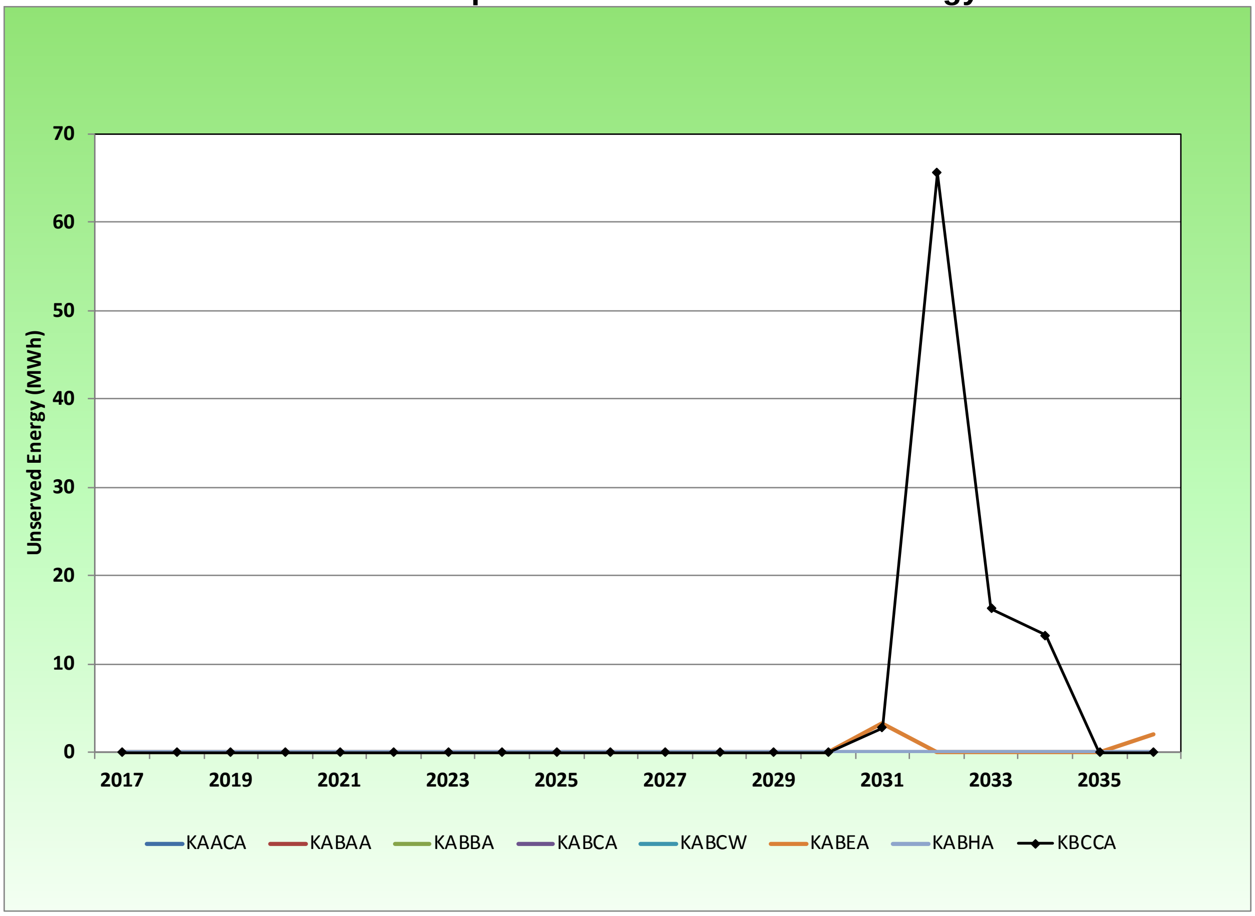
6.5 UNSERVED ENERGY

The expected value of unserved energy for all KCP&L Alternative Resource Plans is provided in Table 27 below:

Table 27: Expected Value of Unserved Energy



6.6 JOINT-PLANNING KCP&L/GMO RESOURCE PLANS

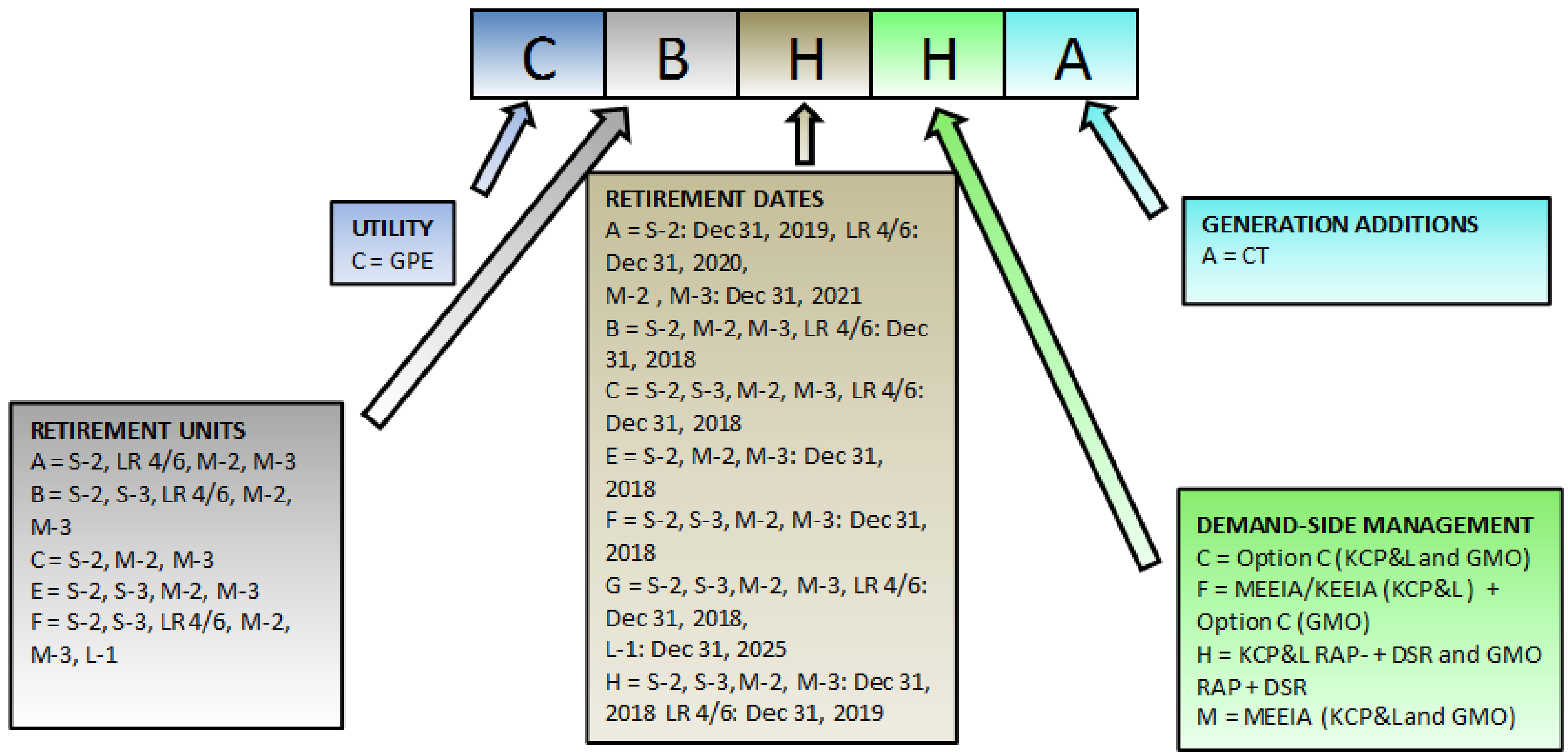
KCP&L also considers it prudent resource planning to develop and analyze alternative resource plans that are based upon KCP&L and GMO combining resources. Evaluating alternative resource plans on a joint planning basis can provide a platform to determine if joint planning "serves the public interest" as mandated in 4 CSR 240-22.010 Policy Objectives.

Joint-planning Alternative Resource Plans were developed to reflect combinations of the KCP&L and GMO Alternative Resource Plans. For example, combined company plan CBHHA is the combination of KCP&L Alternative Resource Plan KABHA (retire Montrose-2 and Montrose-3 by 2019 and DSM Option H) and GMO Alternative Resource Plan GCGHP (retire Sibley-2 and Sibley-3 retire by 2019, Lake Road 4/6 retire by 2020 and DSM Option H). . It should be noted that Sibley-1 is being retired from electric service in June, 2017 and not considered as having accredited capacity due to a safety-related boiler issue. However, the Sibley-1 boiler will remain in service to provide start-up steam to Sibley- 3 until the station is retired.

The NPVRR for each joint-planning alternative resource plan was determined under the same 18 scenarios analyzed for the stand alone companies. For example, electricity market prices, natural gas prices, CO_2 allowance prices, etc. were unchanged from the stand-alone company scenarios.

The plan-naming convention utilized for the joint-planning Alternative Resource Plans developed is shown in Table 28. The Alternative Resource Plans were developed using various capacities of supply-side resources and demand-side resources. In total, eleven joint-planning Alternative Resource Plans were developed for the integrated resource analysis for the 2017 Annual Update. An overview of the Alternative Resource Plans is shown in Table 29 and Table 30 below:

Table 28: Joint-Planning Alternative Resource Plan Naming Convention



Definitions:

S-2: Sibley-2	M-2: Montrose-2	MEEIA: Missouri Energy Efficiency Investment Act Cycle II	CT - Combustion Turbine
S-3: Sibley-3	M-3: Montrose-3	KEEIA: Kansas Energy Efficiency Investment Act	
LR 4/6: Lake Road 4/6	L-1: LaCygne-1	DSR: Demand-Side Rates	

Table 29: Overview of Joint-Planning Resource Plans

Plan Name	DSM Level	Retire	Renewable Additions		Generation Addition (if needed)
CAACA	Option C	Sibley-2: Dec 31, 2019 Lake Road 4/6: Dec 31, 2020 Montrose-2: Dec 31, 2021 Montrose-3: Dec 31,2021	Solar: 2027 - 12 MW	Wind: 2018 - 300 MW	n/n
CABCA	Option C	Sibley-2: Dec 31, 2018 Montrose-2: Dec 31, 2018 Montrose-3: Dec 31, 2018 Lake Road 4/6: Dec 31, 2018	Solar: 2027 - 12 MW	Wind: 2018 - 300 MW	n/n
CABFA	Option F	Sibley-2: Dec 31, 2018 Montrose-2: Dec 31, 2018 Montrose-3: Dec 31, 2018 Lake Road 4/6: Dec 31, 2018	Solar: 2027 - 12 MW	Wind: 2018 - 300 MW	207 MW of CT in 2033 207 MW of CT in 2036
CBCCA	Option C	Sibley-2: Dec 31, 2018 Sibley-3: Dec 31, 2018 Montrose-2: Dec 31, 2018 Montrose-3: Dec 31, 2018 Lake Road 4/6: Dec 31, 2018	Solar: 2027 - 12 MW	Wind: 2018 - 300 MW	207 MW of CT in 2033 207 MW of CT in 2036
CBCFA	Option F	Sibley-2: Dec 31, 2018 Sibley-3: Dec 31, 2018 Montrose-2: Dec 31, 2018 Montrose-3: Dec 31, 2018 Lake Road 4/6: Dec 31, 2018	Solar: 2027 - 12 MW	Wind: 2018 - 300 MW	207 MW of CT in 2027 207 MW of CT in 2030 207 MW of CT in 2033 207 MW of CT in 2036

Table 30: Overview of Joint-Planning Resource Plans (continued)

Plan Name	DSM Level	Retire	Renewable Additions		Generation Addition (if needed)
CBHCA	Option C	Sibley-2: Dec 31, 2018 Sibley-3: Dec 31, 2018 Montrose-2: Dec 31, 2018 Montrose-3: Dec 31, 2018 Lake Road 4/6: Dec 31, 2019	Solar: 2027 - 12 MW	Wind: 2018 - 300 MW	207 MW of CT in 2033 207 MW of CT in 2036
CBHHA	Option H	Sibley-2: Dec 31, 2018 Sibley-3: Dec 31, 2018 Montrose-2: Dec 31, 2018 Montrose-3: Dec 31, 2018 Lake Road 4/6: Dec 31, 2019	Solar: 2027 - 12 MW	Wind: 2018 - 300 MW	n/n
CBHMA	Option M	Sibley-2: Dec 31, 2018 Sibley-3: Dec 31, 2018 Montrose-2: Dec 31, 2018 Montrose-3: Dec 31, 2018 Lake Road 4/6: Dec 31, 2019	Solar: 2027 - 12 MW	Wind: 2018 - 300 MW	207 MW of CT in 2020 207 MW of CT in 2025 207 MW of CT in 2029 207 MW of CT in 2032 414 MW of CT in 2036
CCECA	Option C	Sibley-2: Dec 31, 2018 Montrose-2: Dec 31, 2018 Montrose-3: Dec 31, 2018	Solar: 2027 - 12 MW	Wind: 2018 - 300 MW	n/n
CEFCA	Option C	Sibley-2: Dec 31, 2018 Sibley-3: Dec 31, 2018 Montrose-2: Dec 31, 2018 Montrose-3: Dec 31, 2018	Solar: 2027 - 12 MW	Wind: 2018 - 300 MW	207 MW of CT in 2036
CFGCA	Option C	Sibley-2: Dec 31, 2018 Sibley-3: Dec 31, 2018 Montrose-2: Dec 31, 2018 Montrose-3: Dec 31, 2018 Lake Road 4/6: Dec 31, 2018 LaCygne-1: Dec 31, 2025	Solar: 2027 - 12 MW	Wind: 2018 - 300 MW	207 MW of CT in 2027 207 MW of CT in 2032 207 MW of CT in 2035

Revenue requirement results for each of the combined company Alternative Resource Plans are shown in Table 31 below:

Table 31: Joint-Planning Twenty-Year Net Present Value Revenue Requirement

Rank (L-H)	Plan	NPVRR ($MM)	Delta ($MM)
1	CBHHA	$ 31,223	$ -
2	CBCCA	$ 31,430	$ 207
3	CBHCA	$ 31,432	$ 209
4	CEFCA	$ 31,461	$ 238
5	CFGCA	$ 31,563	$ 340
6	CBCFA	$ 31,623	$ 400
7	CABCA	$ 31,669	$ 446
8	CAACA	$ 31,691	$ 468
9	CABFA	$ 31,720	$ 497
10	CCECA	$ 31,745	$ 522
11	CBHMA	$ 31,842	$ 619

The joint-planning Alternative Resource Plan (ARP) CBHHA provided the lowest Net Present Value Revenue Requirement (NPVRR). This plan consists of retiring Sibley-2, Sibley-3, Montrose-2, and Montrose-3 by 2019 and retiring Lake Road 4/6 by 2020. The next lowest NPVRR plan was ARP CBCCA consisting of retiring Sibley-2, Sibley-3, Lake Road 4/6, Montrose-2, and Montrose-3 by 2019. The lowest NPVRR plan, CBHHA, included RAP level DSM programs for GMO, RAP- level DSM programs for KCP&L as well as Demand-Side Rates for both utilities. This plan also included retaining Lake Road 4/6 until December, 2019 to provide additional capacity until DSM programs implementation plans materialized as expected. As stated earlier, Sibley-1 will be retired from electric service in June, 2017. However, the Sibley-1 boiler will remain in service to provide start-up steam to Sibley- 3 until the station is retired.

Table 32 and Table 33 show the expected value of NPVRR for the joint plans with and without CO_2 restrictions. The “Without” CO_2 restrictions shows the expected value over the nine scenarios that have $0 CO_2 emission allowance cost. The “With” CO_2 restrictions shows the expected value over the nine scenarios that include the Company’s non-zero CO_2 emission allowance forecast. Under the scenarios with CO_2 restrictions, ARP

CBHHA which includes retirement of Sibley-2, Sibley-3, Montrose-2 and Montrose-3 is the lowest cost plan. Under scenarios without CO_2 restrictions, the same ARP, CBHHA, was the lowest cost plan as well. Given the results of the joint plans, no changes to the GMO or KCP&L Preferred Plans were warranted.

Table 32: Joint Plan Results With CO_2 Restrictions

Total Revenue Requirement - EV 9EPs (CO_2 - Yes)						
Rank (L-H)	Plan	NPVRR ($mm)	Delta	Retirements	Additions	DSM level
1	CBHHA	$32,363	$0	S1: Mar 20, 2017, S2, S3, M2, M3: Dec 31, 2018; LR 4/6: Dec 31, 2019	None	GMO RAP w DSR / KCPL RAP- w DSR
2	CBCCA	$32,588	$225	S1: Mar 20, 2017, S2, S3, M2, M3, LR 4/6: Dec 31, 2018	207 MW CT in 2033 and 2036	GMO - RAP / KCPL - RAP-
3	CBHCA	$32,589	$226	S1: Mar 20, 2017, S2, S3, M2, M3: Dec 31, 2018; LR 4/6: Dec 31, 2019	207 MW CT in 2033 and 2036	GMO - RAP / KCPL - RAP-
4	CEFCA	$32,619	$256	S1: Mar 20, 2017, S2, S3, M2, M3: Dec 31, 2018	207 MW CT in 2036	GMO - RAP / KCPL - RAP-
5	CFGCA	$32,656	$293	S1: Mar 20, 2017, S2, S3, M2, M3, LR 4/6: Dec 31, 2018, LC1: Dec 31, 2025	207 MW CT in 2027 and 2032 and 2035	GMO - RAP / KCPL - RAP-
6	CBCFA	$32,798	$435	S1: Mar 20, 2017, S2, S3, M2, M3, LR 4/6: Dec 31, 2018	207 MW CT in 2027, 2030, 2033 and 2036	GMO - RAP / KCPL - MEEIA/KEEIA
7	CABCA	$32,913	$550	S1: Mar 20, 2017, S2, M2, M3, LR 4/6: Dec 31, 2018	None	GMO - RAP / KCPL - RAP-
8	CAACA	$32,936	$573	S1: Mar 20, 2017, S2: Dec 31, 2019, LR 4/6: Dec 31, 2020, M2, M3: Dec 31, 2021	None	GMO - RAP / KCPL - RAP-
9	CABFA	$32,980	$617	S1: Mar 20, 2017, S2, M2, M3, LR 4/6: Dec 31, 2018	207 MW CT in 2033 and 2036	GMO - RAP / KCPL - MEEIA/KEEIA
10	CCECA	$32,990	$627	S1: Mar 20, 2017, S2, M2, M3: Dec 31, 2018	None	GMO - RAP / KCPL - RAP-
11	CBHMA	$33,033	$670	S1: Mar 20, 2017, S2, S3, M2, M3: Dec 31, 2018; LR 4/6: Dec 31, 2019	207 MW CT in 2020, 2025, 2029, 2032; 414 MW CT in 2036	GMO - MEEIA / KCPL - MEEIA

Table 33: Joint Plan Results Without CO_2 Restrictions

Total Revenue Requirement - EV 9EPs (No CO_2)						
Rank (L-H)	Plan	NPVRR ($mm)	Delta	Retirements	Additions	DSM level
1	CBHHA	$30,463	$0	S1: Mar 20, 2017, S2, S3, M2, M3: Dec 31, 2018; LR 4/6: Dec 31, 2019	None	GMO RAP w DSR / KCPL RAP- w DSR
2	CBCCA	$30,659	$196	S1: Mar 20, 2017, S2, S3, M2, M3, LR 4/6: Dec 31, 2018	207 MW CT in 2033 and 2036	GMO - RAP / KCPL - RAP-
3	CBHCA	$30,660	$197	S1: Mar 20, 2017, S2, S3, M2, M3: Dec 31, 2018; LR 4/6: Dec 31, 2019	207 MW CT in 2033 and 2036	GMO - RAP / KCPL - RAP-
4	CEFCA	$30,690	$227	S1: Mar 20, 2017, S2, S3, M2, M3: Dec 31, 2018	207 MW CT in 2036	GMO - RAP / KCPL - RAP-
5	CFGCA	$30,834	$371	S1: Mar 20, 2017, S2, S3, M2, M3, LR 4/6: Dec 31, 2018, LC1: Dec 31, 2025	207 MW CT in 2027 and 2032 and 2035	GMO - RAP / KCPL - RAP-
6	CABCA	$30,839	$376	S1: Mar 20, 2017, S2, M2, M3, LR 4/6: Dec 31, 2018	None	GMO - RAP / KCPL - RAP-
7	CBCFA	$30,840	$377	S1: Mar 20, 2017, S2, S3, M2, M3, LR 4/6: Dec 31, 2018	207 MW CT in 2027, 2030, 2033 and 2036	GMO - RAP / KCPL - MEEIA/KEEIA
8	CAACA	$30,861	$398	S1: Mar 20, 2017, S2: Dec 31, 2019, LR 4/6: Dec 31, 2020, M2, M3: Dec 31, 2021	None	GMO - RAP / KCPL - RAP-
9	CABFA	$30,879	$417	S1: Mar 20, 2017, S2, M2, M3, LR 4/6: Dec 31, 2018	207 MW CT in 2033 and 2036	GMO - RAP / KCPL - MEEIA/KEEIA
10	CCECA	$30,915	$452	S1: Mar 20, 2017, S2, M2, M3: Dec 31, 2018	None	GMO - RAP / KCPL - RAP-
11	CBHMA	$31,048	$585	S1: Mar 20, 2017, S2, S3, M2, M3: Dec 31, 2018; LR 4/6: Dec 31, 2019	207 MW CT in 2020, 2025, 2029, 2032; 414 MW CT in 2036	GMO - MEEIA / KCPL - MEEIA

A summary tabulation of the expected value of all performance measures is provided in Table 34 below. Detailed results behind this summary tabulation are attached in Appendix D.

Table 34: Joint-Planning Expected Value of Performance Measures ** Highly Confidential **

Plan	NPVRR ($MM)	Levelized Annual Rates ($/KW-hr)	Maximum Rate Increase
CBHHA	31,223		
CBCCA	31,430		
CBHCA	31,432		
CEFCA	31,461		
CFGCA	31,563		
CBCFA	31,623		
CABCA	31,669		
CAACA	31,691		
CABFA	31,720		
CCECA	31,745		
CBHMA	31,842		

The Joint-Planning Alternative Resource Plan that reflects the combination of the KCP&L Preferred Plan, KABHA and GMO's Preferred Plan, GCGHA is Alternative Resource Plan CBHHA. The joint-planning ARP is comprised of the following components for years 2017 – 2027 and shown in Figure 5 below:

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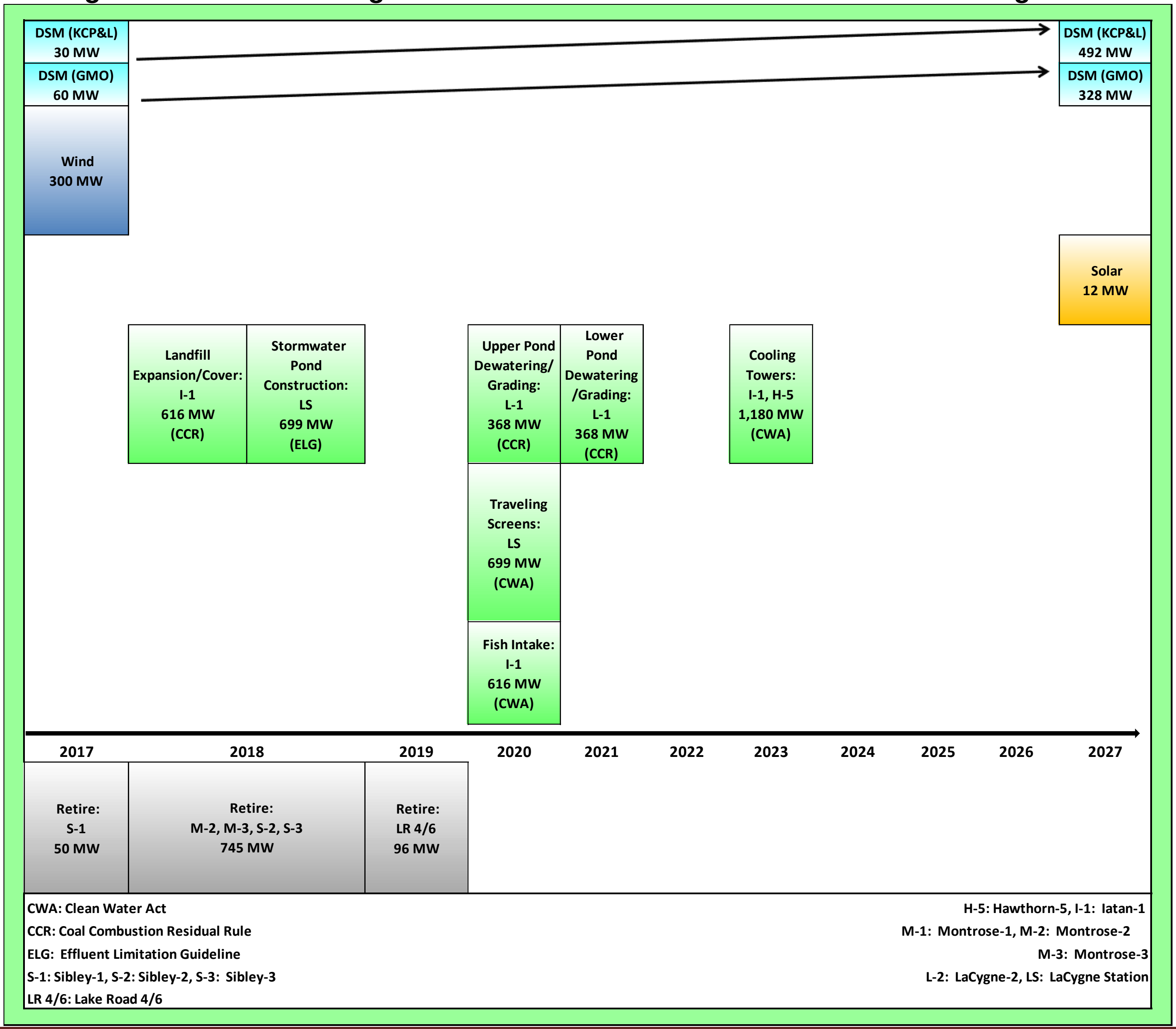
Figure 5: Joint Planning Alternative Resource Plan CBHHA - 2017 through 2027



The Joint-Planning Alternative Resource Plan CBHHA for the 20-year planning period is shown in Table 35 below:

Table 35: Joint-Planning Alternative Resource Plan

Year	CT	Wind	Solar	DSM	Retire	Existing Capacity
2017	0	300		90	50	6,612
2018	0			154	745	6,672
2019	0			236	96	5,937
2020	0			361		5,841
2021	0			451		5,868
2022	0			558		5,868
2023	0			642		5,883
2024	0			707		5,823
2025	0			758		5,828
2026	0			796		5,828
2027	0		12	820		5,828
2028	0			831		5,828
2029	0			830		5,828
2030	0			835		5,828
2031	0			839		5,828
2032	0			839		5,783
2033	0			846		5,721
2034	0			856		5,721
2035	0			873		5,721
2036	0			894		5,601

6.7 JOINT-PLANNING ECONOMIC IMPACT

The economic impact by year of the Joint-Planning Alternative Resource Plan CBHHA is represented in Table 36 below. The economic impact of all plans can be found in Appendix D.

Table 36: Joint-Planning Alternative Resource Plan CBHHA - Economic Impact
**** Highly Confidential ****

Year	Revenue Requirement ($MM)	Levelized Annual Rates ($/kW-hr)	Rate Increase
2017	2,774		
2018	2,902		
2019	2,889		
2020	2,934		
2021	2,961		
2022	3,085		
2023	3,153		
2024	3,187		
2025	3,190		
2026	3,199		
2027	3,261		
2028	3,307		
2029	3,322		
2030	3,404		
2031	3,443		
2032	3,486		
2033	3,559		
2034	3,622		
2035	3,675		
2036	3,778		

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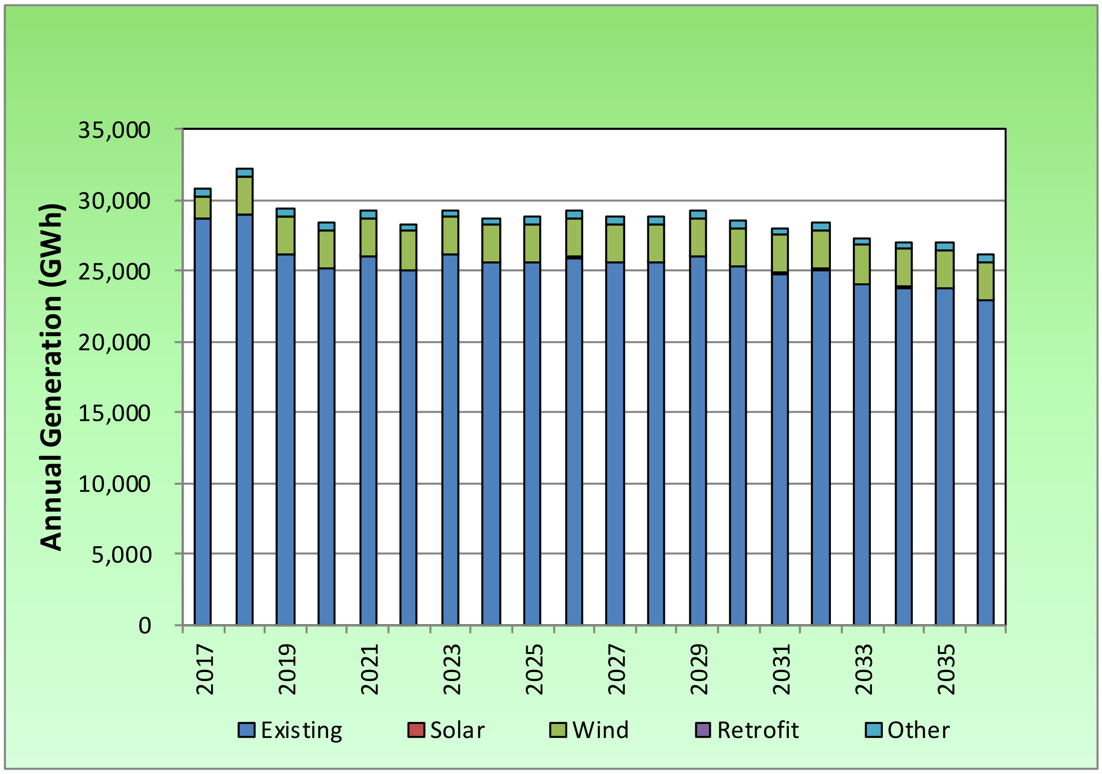
6.8 JOINT-PLANNING ANNUAL GENERATION

The expected value of annual generation of the Joint-Planning Alternative Resource Plan CBHHA is represented in Table 37 below. The annual generation of all Joint-Planning plans can be found in Appendix C, Generation and Emissions for Each Alternative Resource Plan.

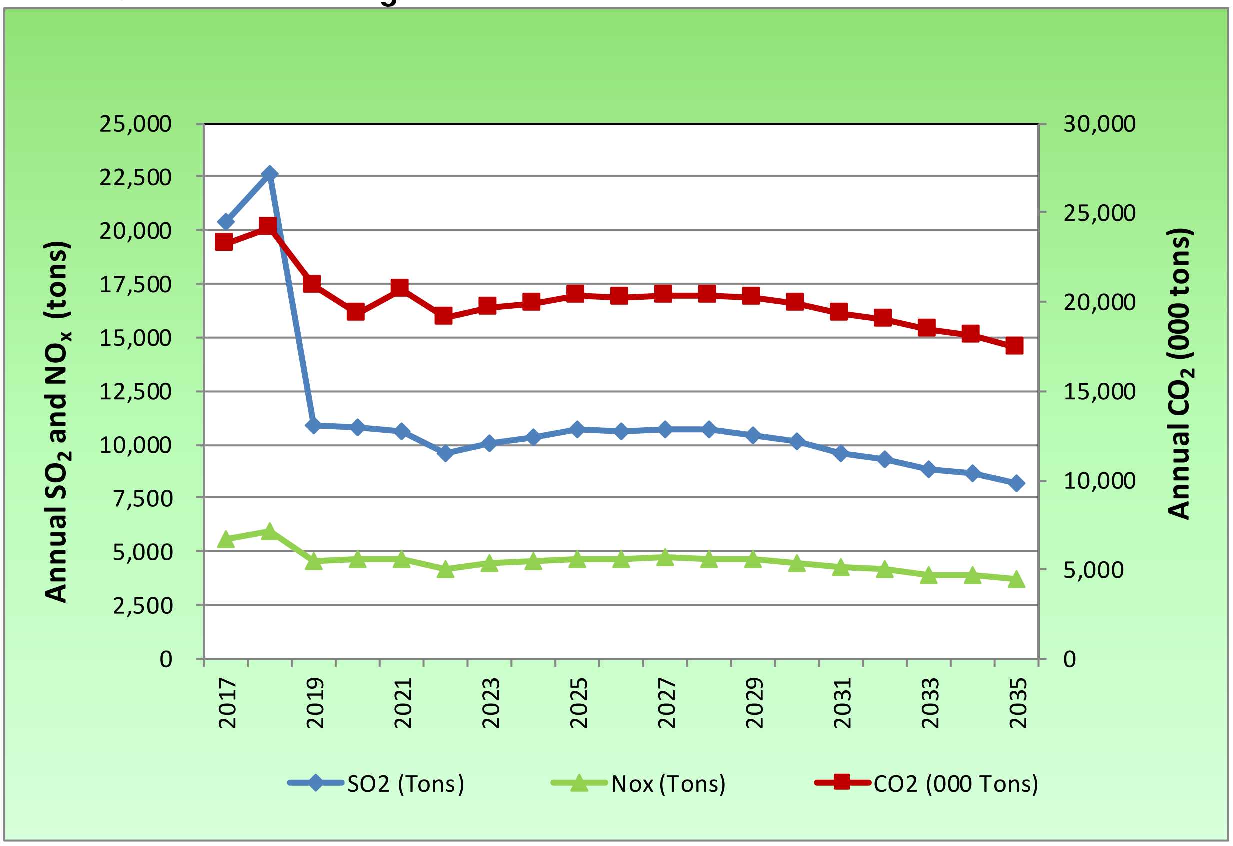
Table 37: Joint-Planning Alternative Resource Plan CBHHA Annual Generation



6.9 JOINT-PLANNING ANNUAL EMISSIONS

The expected values of annual emissions of the Joint-Planning Alternative Resource Plan CBHHA are represented in Table 38 below. The annual emissions of all Joint-Planning plans can be found in Appendix C.

Table 38: Joint-Planning Alternative Resource Plan CBHHA Annual Emissions



SECTION 7: RESOURCE ACQUISITION STRATEGY

7.1 2017 ANNUAL UPDATE PREFERRED PLAN

The 2017 Annual Update Preferred Plan for the 20-year planning period is shown in Table 39 below:

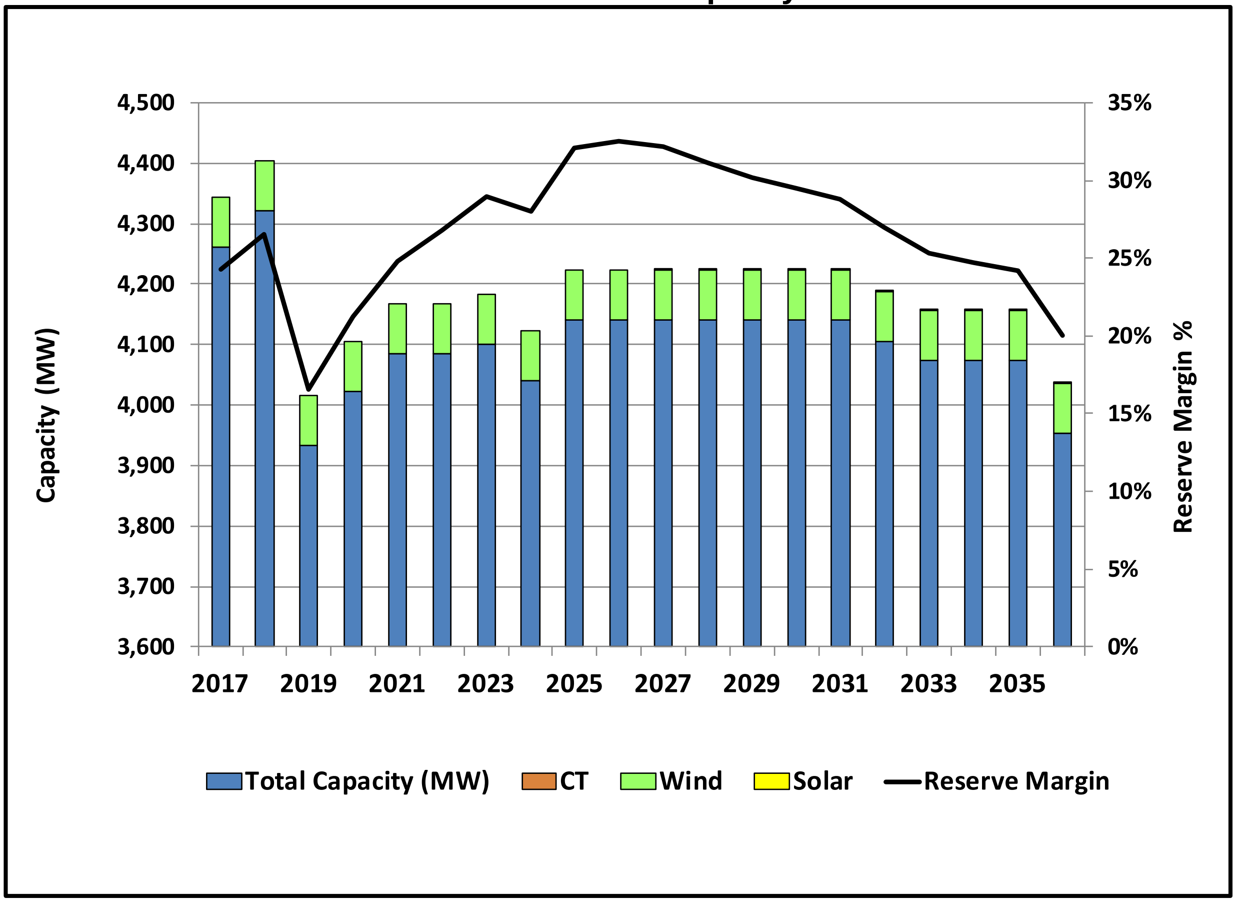
Table 39: 2017 Annual Update Preferred Plan

Year	CT's (MW)	Wind (MW)	Solar (MW)	DSM (MW)	Retire (MW)	Existing Capacity (MW)
2017	0	180		30		4,461
2018	0			60	334	4,522
2019	0			113		4,133
2020	0			175		4,223
2021	0			228		4,285
2022	0			300		4,285
2023	0			361		4,300
2024	0			411		4,240
2025	0			448		4,240
2026	0			475		4,240
2027	0		7	492		4,240
2028	0			500		4,240
2029	0			501		4,240
2030	0			504		4,240
2031	0			507		4,240
2032	0			510		4,204
2033	0			513		4,173
2034	0			517		4,173
2035	0			526		4,173
2036	0			538		4,053

7.1.1 PREFERRED PLAN COMPOSITION

Existing and new capacity additions for the 2017 Annual Update Preferred Plan are shown in Table 40 below:

Table 40: Preferred Plan Capacity Additions



Based in part upon current Missouri RPS rule requirements, the Preferred Plan includes a 7 MW solar addition by 2028 and a 180 MW wind addition over the twenty-year planning period. The 180 MW wind addition is KCP&L's portion of the Rock Creek wind project located in Atchison County, Missouri is expected to be in-service by 2018. The DSM resources that were modeled consisted of a suite of eight residential and eight commercial programs three of which are demand response programs, two are educational programs, and eleven are energy efficiency programs. Additionally, six demand-side rate (DSR) programs are currently expected to commence in 2019. The six DSR programs are: Time of Use, Time of Use with Electric Vehicle, Demand Rate, Demand Rate with Electric Vehicle, Real Time Pricing, and Inclining Block Rate. The Preferred Plan reflects retiring Montrose Units 2 and 3 by 2019. Drivers that contributed to these retirements include 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, Clean Power Plan as well as long term forecasts of low priced natural gas. These drivers will be monitored by KCP&L to determine if and when retiring these generating units continues to be prudent decisions.

7.1.2 PREFERRED PLAN ECONOMIC IMPACT

The expected value of economic impact by year of the Preferred Plan KABHA is represented in Table 41 below. The economic impact of all plans can be found in Appendix D.

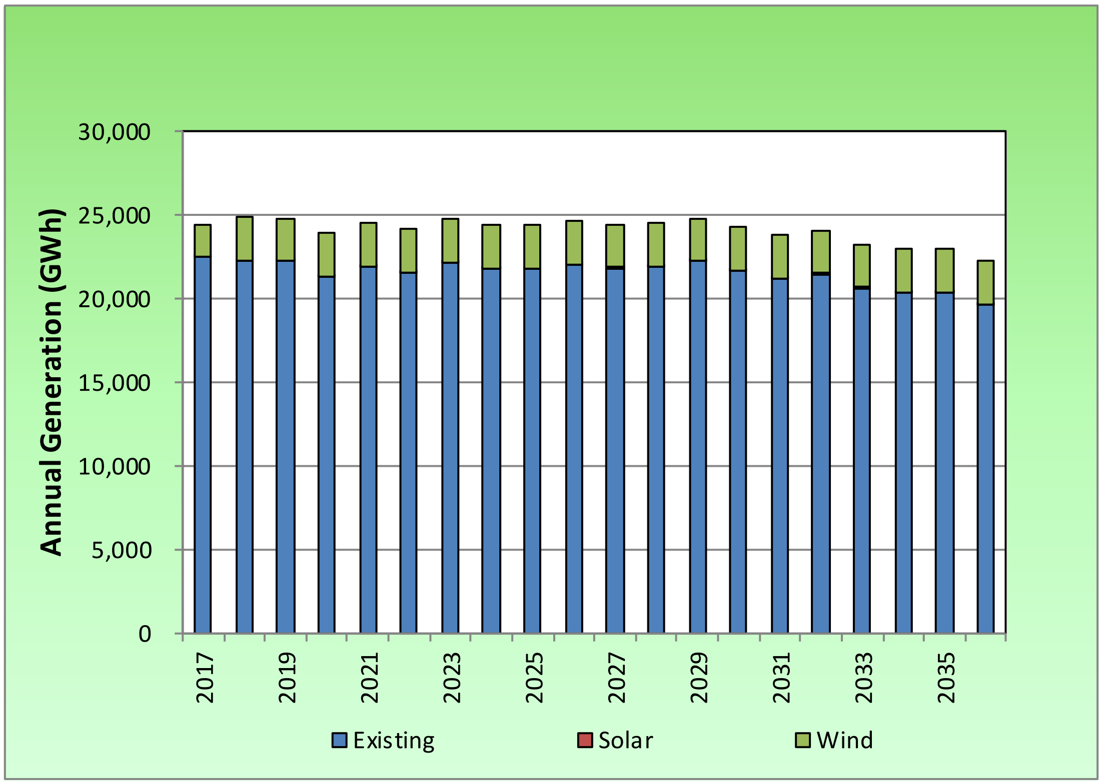
Table 41: Preferred Plan Economic Impact ** Highly Confidential **

Year	Revenue Requirement ($MM)	Levelized Annual Rates ($/kW-hr)	Rate Increase
2017	1,922		
2018	2,037		
2019	1,996		
2020	2,036		
2021	2,068		
2022	2,141		
2023	2,187		
2024	2,202		
2025	2,199		
2026	2,206		
2027	2,251		
2028	2,277		
2029	2,284		
2030	2,343		
2031	2,372		
2032	2,391		
2033	2,442		
2034	2,478		
2035	2,505		
2036	2,577		

7.1.3 PREFERRED PLAN ANNUAL GENERATION

The expected value of annual generation for the Preferred Plan is shown in Table 42 below. The annual generation for all plans is included in Appendix C.

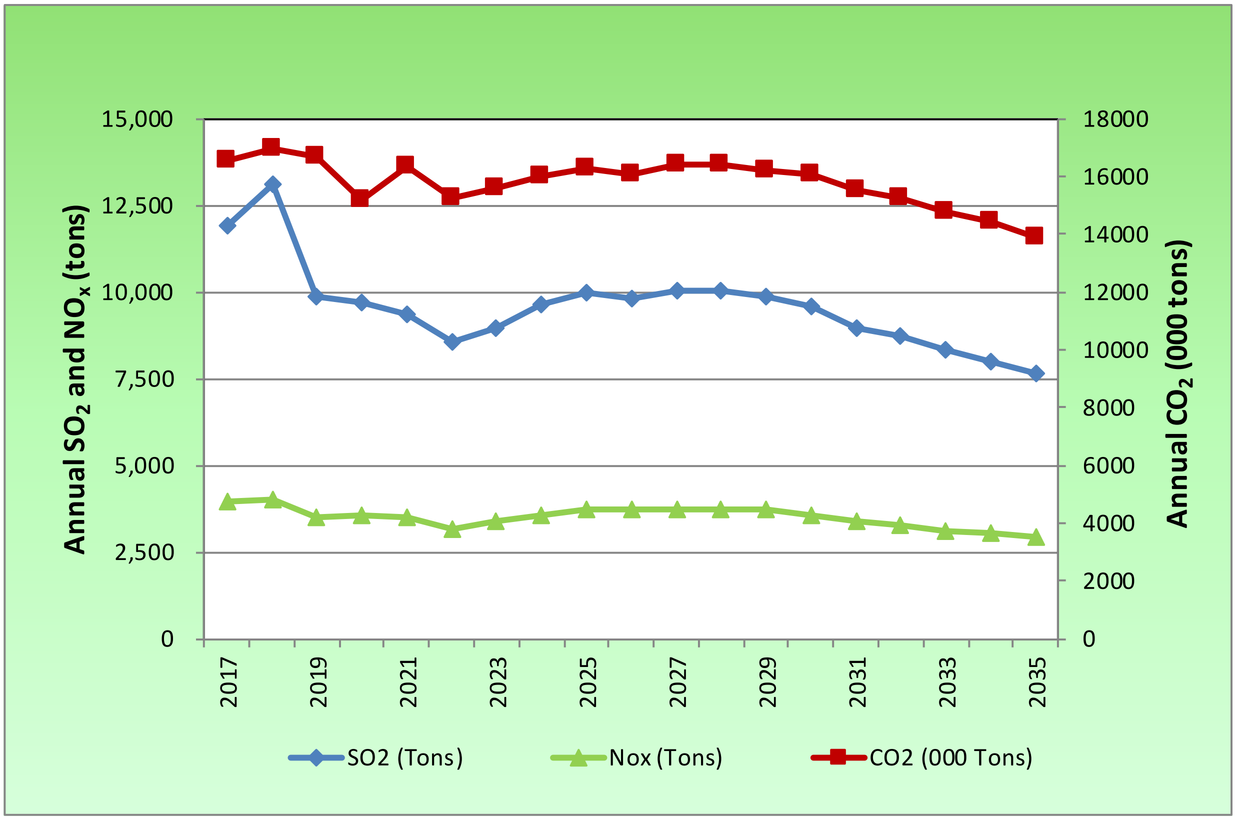
Table 42: Preferred Plan Annual Generation



7.1.4 PREFERRED PLAN ANNUAL EMISSIONS

The expected value of annual emissions for the Preferred Plan are shown in Table 43 below. The annual emissions for all plans is included in Appendix C.

Table 43: Preferred Plan Annual Emissions



7.1.5 PREFERRED PLAN DISCUSSION

Based in part upon current Missouri RPS rule requirements, the Preferred Plan includes a 7 MW solar addition currently expected to be in-service by 2028 and a 180 MW portion of a Missouri wind facility expected to be commercially operational by 2018. The DSM resources that were modeled consisted of a suite of eight residential and eight commercial programs three of which are demand response programs, two are educational programs, and eleven are energy efficiency programs. The Preferred Plan also includes Montrose Units 2 and 3 retiring by 2019. It is anticipated that these retirements will not cause transmission-related constraints on the KCP&L system.

The Preferred Plan selected was the lowest cost plan from a Net Present Value of Revenue Requirement (NPVRR) perspective. The Preferred Plan therefore meets 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.

It should be noted that the 2015 Triennial IRP Preferred Plan was modeled as an Alternative Resource Plan, KAACA, and determined to have a higher NPVRR than the 2017 Annual Update Preferred Plan. The NPVRR difference between the 2017 Annual Update Preferred Plan, KABHA and the 2015 Triennial IRP Preferred Plan, KAACA, was $99MM as shown in Table 44 below. The difference in the levelized annual rates and maximum rate increase performance measures between the 2015 Triennial IRP Preferred Plan and the 2017 Annual Update Preferred Plan are provided in Table 44 as well. A significant factor in the 2017 Annual Update was the inclusion of the DSM from the just-completed DSM Potential Study. The integrated analysis results determined that retirement of Montrose-2 and Montrose-3 three years earlier than the 2015 Triennial IRP Preferred Plan resulted in a lower NPVRR.

Table 44: 2017 Annual Update Preferred Plan Vs. 2015 Triennial Preferred Plan
**** Highly Confidential ****

Rank (L-H)	Plan	NPVRR ($MM)	Delta ($MM)	Levelized Annual Rates ($/KW-hr)	Maximum Rate Increase
1	KABHA	$ 21,586	$ -		
2	KABCA	$ 21,700	$ 114		
3	KBCCA	$ 21,705	$ 119		
4	KABEA	$ 21,719	$ 133		
5	KAACA	$ 21,722	$ 136		
6	KABBA	$ 21,725	$ 139		
7	KABCW	$ 21,809	$ 223		
8	KABAA	$ 21,811	$ 225		

From the 2015 Triennial IRP filing, the contingency plan consisted of retiring Montrose-2 and Montrose-3 by 2020. The 2017 Annual Update Preferred Plan retires Montrose-2 and Montrose-3 by 2019 as these earlier retirement dates have shown to reduce NPVRR. Regarding DSM, the 2015 Triennial IRP filing contingency plan utilized a 2013 DSM Potential Study whereas the 2017 Annual Update Preferred Plan utilized the recently completed DSM Potential Study.

7.2 CRITICAL UNCERTAIN FACTORS

The Critical Uncertain Factors for the 2017 Annual Update are identical to those in the 2015 Triennial IRP. 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. The probabilities for both load growth and natural gas are the same as used on all filings since the 2012 Triennial IRP – with Mid 50% and High and Low states at 25% weighted probabilities. Consistent with the 2015 Triennial IRP the decision states for CO_2 are modeled as a 40% probability there will be a CO_2 credit market and 60% probability that no CO_2 credit market will exist. The weighted endpoint probability is the product these three weighted probabilities

The Critical Uncertain Factors identified were incorporated into a decision tree representation of the risks that will impact the performance of the alternative resource plans. A graphical representation of the decision tree risks is provided in Figure 6 below:

Figure 6: Critical Uncertain Factors With 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%

The company performed an analysis to address the impact of the critical uncertain factors on Preferred Plan selection. This analysis ranks how plans perform relative to the representation of the eighteen endpoint tree. The results of the analysis are represented in the following tables.

7.2.1 CRITICAL UNCERTAIN FACTOR – HIGH LOAD GROTH

HIGH LOAD GROWTH														
	CO2 - Yes		CO2 - No			CO2 - Yes		CO2 - No			CO2 - Yes		CO2 - No	
HIGH GAS	Endpoint	1	Endpoint	2	MID GAS	Endpoint	3	Endpoint	4	LOW GAS	Endpoint	5	Endpoint	6
	PLAN	NPVRR	PLAN	NPVRR		PLAN	NPVRR	PLAN	NPVRR		PLAN	NPVRR	PLAN	NPVRR
	KABHA	22,434	KABHA	21,075		KABHA	22,619	KABHA	21,301		KABHA	22,767	KABHA	21,491
	KBCCA	22,540	KAACA	21,185		KBCCA	22,698	KABCA	21,405		KBCCA	22,821	KABCA	21,585
	KABCA	22,576	KABCA	21,186		KABCA	22,753	KABEA	21,414		KABCA	22,894	KABEA	21,585
	KAACA	22,576	KABEA	21,205		KABBA	22,773	KAACA	21,428		KABBA	22,916	KBCCA	21,611
	KABBA	22,593	KABBA	21,212		KAACA	22,776	KABBA	21,433		KABEA	22,922	KABBA	21,616
	KABEA	22,622	KBCCA	21,263		KABEA	22,791	KBCCA	21,456		KAACA	22,933	KAACA	21,624
	KABCW	22,633	KABCW	21,295		KABCW	22,827	KABAA	21,522		KABCW	22,987	KABAA	21,710
	KABAA	22,667	KABAA	21,297		KABAA	22,850	KABCW	21,531		KABAA	22,997	KABCW	21,730

7.2.2 CRITICAL UNCERTAIN FACTOR – LOW LOAD GROWTH

LOW LOAD GROWTH

	CO2 - Yes		CO2 - No			CO2 - Yes		CO2 - No			CO2 - Yes		CO2 - No	
	Endpoint	13	Endpoint	14		Endpoint	15	Endpoint	16		Endpoint	17	Endpoint	18
	PLAN	NPVRR	PLAN	NPVRR		PLAN	NPVRR	PLAN	NPVRR		PLAN	NPVRR	PLAN	NPVRR
HIGH GAS	KABHA	21,873	KABHA	20,617	MID GAS	KABHA	22,088	KABHA	20,876	LOW GAS	KABHA	22,268	KABHA	21,099
	KBCCA	21,973	KABCA	20,724		KBCCA	22,162	KABCA	20,976		KBCCA	22,318	KABEA	21,187
	KABCA	22,013	KAACA	20,725		KABCA	22,220	KABEA	20,982		KABCA	22,394	KABCA	21,190
	KAACA	22,015	KABEA	20,740		KABBA	22,241	KAACA	21,000		KABBA	22,417	KBCCA	21,205
	KABBA	22,031	KABBA	20,751		KAACA	22,244	KABBA	21,005		KABEA	22,419	KABBA	21,222
	KABEA	22,056	KBCCA	20,787		KABEA	22,255	KBCCA	21,015		KAACA	22,433	KAACA	21,229
	KABCW	22,074	KABAA	20,838		KABCW	22,298	KABAA	21,096		KABCW	22,489	KABAA	21,316
	KABAA	22,106	KABCW	20,844		KABAA	22,319	KABCW	21,111		KABAA	22,499	KABCW	21,342

7.2.3 CRITICAL UNCERTAIN FACTOR – HIGH NATURAL GAS PRICES

HIGH NATURAL GAS PRICES

	CO2 - Yes		CO2 - No			CO2 - Yes		CO2 - No			CO2 - Yes		CO2 - No	
	Endpoint	1	Endpoint	2		Endpoint	7	Endpoint	8		Endpoint	13	Endpoint	14
	PLAN	NPVRR	PLAN	NPVRR		PLAN	NPVRR	PLAN	NPVRR		PLAN	NPVRR	PLAN	NPVRR
HIGH LOAD	KABHA	22,434	KABHA	21,075	MID LOAD	KABHA	22,155	KABHA	20,847	LOW LOAD	KABHA	21,873	KABHA	20,617
	KBCCA	22,540	KAACA	21,185		KBCCA	22,259	KAACA	20,955		KBCCA	21,973	KABCA	20,724
	KABCA	22,576	KABCA	21,186		KABCA	22,296	KABCA	20,955		KABCA	22,013	KAACA	20,725
	KAACA	22,576	KABEA	21,205		KAACA	22,297	KABEA	20,973		KAACA	22,015	KABEA	20,740
	KABBA	22,593	KABBA	21,212		KABBA	22,314	KABBA	20,981		KABBA	22,031	KABBA	20,751
	KABEA	22,622	KBCCA	21,263		KABEA	22,342	KBCCA	21,027		KABEA	22,056	KBCCA	20,787
	KABCW	22,633	KABCW	21,295		KABCW	22,355	KABCW	21,069		KABCW	22,074	KABAA	20,838
	KABAA	22,667	KABAA	21,297		KABAA	22,389	KABAA	21,069		KABAA	22,106	KABCW	20,844

7.2.4 CRITICAL UNCERTAIN FACTOR – LOW NATURAL GAS PRICES

LOW NATURAL GAS PRICES														
	CO2 - Yes		CO2 - No			CO2 - Yes		CO2 - No			CO2 - Yes		CO2 - No	
HIGH LOAD	Endpoint	5	Endpoint	6	MID LOAD	Endpoint	11	Endpoint	12	LOW LOAD	Endpoint	17	Endpoint	18
	PLAN	NPVRR	PLAN	NPVRR		PLAN	NPVRR	PLAN	NPVRR		PLAN	NPVRR	PLAN	NPVRR
	KABHA	22,767	KABHA	21,491		KABHA	22,519	KABHA	21,295		KABHA	22,268	KABHA	21,099
	KBCCA	22,821	KABCA	21,585		KBCCA	22,572	KABEA	21,387		KBCCA	22,318	KABEA	21,187
	KABCA	22,894	KABEA	21,585		KABCA	22,646	KABCA	21,387		KABCA	22,394	KABCA	21,190
	KABBA	22,916	KBCCA	21,611		KABBA	22,668	KBCCA	21,409		KABBA	22,417	KBCCA	21,205
	KABEA	22,922	KABBA	21,616		KABEA	22,673	KABBA	21,419		KABEA	22,419	KABBA	21,222
	KAACA	22,933	KAACA	21,624		KAACA	22,685	KAACA	21,427		KAACA	22,433	KAACA	21,229
	KABCW	22,987	KABAA	21,710		KABCW	22,740	KABAA	21,514		KABCW	22,489	KABAA	21,316
	KABAA	22,997	KABCW	21,730		KABAA	22,751	KABCW	21,536		KABAA	22,499	KABCW	21,342

7.2.5 CRITICAL UNCERTAIN FACTOR –CO_2 - YES

CO_2 CREDIT PRICES - Yes

HIGH LOAD

HIGH GAS		MID GAS		LOW GAS	
Endpoint	1	Endpoint	3	Endpoint	5
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
KABHA	22,434	KABHA	22,619	KABHA	22,767
KBCCA	22,540	KBCCA	22,698	KBCCA	22,821
KABCA	22,576	KABCA	22,753	KABCA	22,894
KAACA	22,576	KABBA	22,773	KABBA	22,916
KABBA	22,593	KAACA	22,776	KABEA	22,922
KABEA	22,622	KABEA	22,791	KAACA	22,933
KABCW	22,633	KABCW	22,827	KABCW	22,987
KABAA	22,667	KABAA	22,850	KABAA	22,997

MID LOAD

HIGH GAS		MID GAS		LOW GAS	
Endpoint	7	Endpoint	9	Endpoint	11
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
KABHA	22,155	KABHA	22,355	KABHA	22,519
KBCCA	22,259	KBCCA	22,432	KBCCA	22,572
KABCA	22,296	KABCA	22,489	KABCA	22,646
KAACA	22,297	KABBA	22,509	KABBA	22,668
KABBA	22,314	KAACA	22,512	KABEA	22,673
KABEA	22,342	KABEA	22,525	KAACA	22,685
KABCW	22,355	KABCW	22,564	KABCW	22,740
KABAA	22,389	KABAA	22,587	KABAA	22,751

LOW LOAD

HIGH GAS		MID GAS		LOW GAS	
Endpoint	13	Endpoint	15	Endpoint	17
PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
KABHA	21,873	KABHA	22,088	KABHA	22,268
KBCCA	21,973	KBCCA	22,162	KBCCA	22,318
KABCA	22,013	KABCA	22,220	KABCA	22,394
KAACA	22,015	KABBA	22,241	KABBA	22,417
KABBA	22,031	KAACA	22,244	KABEA	22,419
KABEA	22,056	KABEA	22,255	KAACA	22,433
KABCW	22,074	KABCW	22,298	KABCW	22,489
KABAA	22,106	KABAA	22,319	KABAA	22,499

7.2.6 CRITICAL UNCERTAIN FACTOR – CO_2 - NO

CO2 CREDIT PRICES - No

HIGH LOAD	HIGH GAS		MID GAS		LOW GAS	
	Endpoint	2	Endpoint	4	Endpoint	6
	PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
	KABHA	21,075	KABHA	21,301	KABHA	21,491
	KAACA	21,185	KABCA	21,405	KABCA	21,585
	KABCA	21,186	KABEA	21,414	KABEA	21,585
	KABEA	21,205	KAACA	21,428	KBCCA	21,611
	KABBA	21,212	KABBA	21,433	KABBA	21,616
	KBCCA	21,263	KBCCA	21,456	KAACA	21,624
	KABCW	21,295	KABAA	21,522	KABAA	21,710
	KABAA	21,297	KABCW	21,531	KABCW	21,730

MID LOAD	HIGH GAS		MID GAS		LOW GAS	
	Endpoint	8	Endpoint	10	Endpoint	12
	PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
	KABHA	20,847	KABHA	21,089	KABHA	21,295
	KAACA	20,955	KABCA	21,190	KABEA	21,387
	KABCA	20,955	KABEA	21,199	KABCA	21,387
	KABEA	20,973	KAACA	21,214	KBCCA	21,409
	KABBA	20,981	KABBA	21,219	KABBA	21,419
	KBCCA	21,027	KBCCA	21,237	KAACA	21,427
	KABCW	21,069	KABAA	21,310	KABAA	21,514
	KABAA	21,069	KABCW	21,321	KABCW	21,536

LOW LOAD	HIGH GAS		MID GAS		LOW GAS	
	Endpoint	14	Endpoint	16	Endpoint	18
	PLAN	NPVRR	PLAN	NPVRR	PLAN	NPVRR
	KABHA	20,617	KABHA	20,876	KABHA	21,099
	KABCA	20,724	KABCA	20,976	KABEA	21,187
	KAACA	20,725	KABEA	20,982	KABCA	21,190
	KABEA	20,740	KAACA	21,000	KBCCA	21,205
	KABBA	20,751	KABBA	21,005	KABBA	21,222
	KBCCA	20,787	KBCCA	21,015	KAACA	21,229
	KABAA	20,838	KABAA	21,096	KABAA	21,316
	KABCW	20,844	KABCW	21,111	KABCW	21,342

7.2.7 CRITICAL UNCERTAIN FACTORS – SUMMARY AND EVALUATION

This summary table, Table 45 provides the expected value for NPVRR across the eighteen endpoint tree by plan and the value for NPVRR for the mid-load, mid-gas and CO_2 – Yes scenario, Endpoint 9.

Table 45: Alternative Resource Plan NPVRRs

Expected Value			Endpoint 9		
PLAN	NPVRR ($MM)	DELTA ($MM)	PLAN	NPVRR ($MM)	DELTA ($MM)
KABHA	21,586	-	KABHA	22,355	-
KABCA	21,700	114	KBCCA	22,432	77
KBCCA	21,705	119	KABCA	22,489	133
KABEA	21,719	133	KABBA	22,509	153
KAACA	21,722	136	KAACA	22,512	157
KABBA	21,725	139	KABEA	22,525	170
KABCW	21,809	223	KABCW	22,564	209
KABAA	21,811	225	KABAA	22,587	232

7.2.8 RANGES OF CRITICAL UNCERTAIN FACTORS

The ranges of critical uncertain factors are calculated by finding the value at which the critical uncertain factor needs to change to affect the preferred ranking among plans. 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.

Excluding the impact of Demand-Side Rates, in the integrated planning analysis, the overall lowest cost plan on an expected value NPVRR basis was KABCA. Other plans proved to be the lowest cost plans under different risk scenarios. Demand Side Rate programs were added later to KABCA to come up with the overall preferred plan KABHA.

Any of the other plans would have benefitted from the addition of Demand Side Rate programs similarly.

The values of these plans' NPVRR under each of the risks are detailed in Table 46 below:

Table 46: Risk Scenario NPVRR

Assuming Low CO2						
NPVRR ($MM)	**High Load**	**High NG**	**Low CO2**	**EV**	**Low NG**	**Low Load**
KBCCA	21,456	21,027	21,237	21,705	21,409	21,015
KABCA	21,405	20,955	21,190	21,700	21,387	20,976
Assuming High CO2						
NPVRR ($MM)	**High Load**	**High NG**	**High CO2**	**EV**	**Low NG**	**Low Load**
KBCCA	22,698	22,259	22,432	21,705	22,572	22,162
KABCA	22,753	22,296	22,489	21,700	22,646	22,220

Based on this planning, the uncertain factors which may cause the Company to modify the KCP&L Preferred Plan are limited to high CO_2 and natural gas prices.

CRITICAL UNCERTAIN FACTOR: CO_2

The CO_2 uncertain factor range calculation is detailed in Table 47 below. As assumptions on the cost of future CO_2 increase toward the high scenario, Alternative Resource Plan KBCCA becomes the lower cost plan.

Table 47: CO_2 Uncertain Factor Range

CO2		
Plan	**Low**	**High**
KBCCA	21,237	22,432
KABCA	21,190	22,489
Percent	**from Low**	
Upper %	45.2%	

The resulting limits of the range of this critical uncertain factor are detailed in Table 48 below:

Table 48: CO_2 Uncertain Factor Range Limits ** Highly Confidential **

[redacted]

CRITICAL UNCERTAIN FACTOR: LOAD

The load uncertain factor range calculation is detailed in Table 49 below. Note the load growth forecast does not cause any other plan to out-perform the lowest-cost joint plan.

Table 49: Load Uncertain Factor Range

Load		
Plan	**Mid**	**High**
KABCA	21,190	21,405
KABCA	21,190	21,405
Percent	**from Mid**	**from Low**
Upper %	N/A	N/A

Plan	**Mid**	**Low**
KABCA	21,190	20,976
KABCA	21,190	20,976
Percent	**from Mid**	**from Low**
Lower %	N/A	N/A

CRITICAL UNCERTAIN FACTOR: NATURAL GAS

The uncertain factor range calculation is detailed in Table 50 below. As assumptions on the cost of future natural gas decrease towards the low scenario, Alternative Resource Plan KABEA becomes a lower cost plan. As assumptions on the cost of future natural gas increase towards the high scenario, Alternative Resource Plan KAACA becomes a lower cost plan.

Table 50: Natural Gas Uncertain Factor Range

Natural Gas		
Plan	Mid	High
KAACA	21,214	20,955
KABCA	21,190	20,955
Percent	from Mid	from Low
Upper %	98.62%	99.31%

Plan	Mid	Low
KABEA	21,199	21,387
KABCA	21,190	21,387
Percent	from Mid	from Low
Lower %	-93.7%	3.1%

The resulting limits of the range of this critical uncertain factor are detailed in Table 51 below:

Table 51: Natural Gas Uncertain Factor Range Limit **Highly Confidential**

[redacted]

7.2.9 BETTER INFORMATION

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 provided below. Note that these do not include the impact of Demand-Side Rates.

Better Information - CO_2

CO2						
Preferred Plan	**Endpoint**	**Plan**	**NPVRR**	**EP Prob**	**Cond. Prob**	**Expected Value**
High CO2	9	KABCA	22,489	10.00%	40.0%	21,709
Low CO2	10	KABCA	21,190	15.00%	60.0%	
						-
Better Information	**Endpoint**	**Plan**	**NPVRR**	**EP Prob**	**Cond. Prob**	**Expected Value**
High CO2	9	KBCCA	22,432	10.00%	40.0%	21,687
Low CO2	10	KABCA	21,190	15.00%	60.0%	
Expected Value of Better Information			23	Million		

Better Information - Load

Load						
Preferred Plan	**Endpoint**	**Plan**	**NPVRR**	**EP Prob**	**Cond. Prob**	**Expected Value**
High Load	4	KABCA	21,405	7.50%	25.00%	21,190
Mid	10	KABCA	21,190	15.00%	50.00%	
Low Load	16	KABCA	20,976	7.50%	25.00%	
Better Information	**Endpoint**	**Plan**	**NPVRR**	**EP Prob**	**Cond. Prob**	**Expected Value**
High Load	4	KABCA	21,405	7.50%	25.00%	21,190
Mid	10	KABCA	21,190	15.00%	50.00%	
Low Load	16	KABCA	20,976	7.50%	25.00%	
Expected Value of Better Information			-	Million		

Better Information - Natural Gas

Natural Gas - Under Low CO2						
Preferred Plan	**Endpoint**	**Plan**	**NPVRR**	**EP Prob**	**Cond. Prob**	**Expected Value**
High Natural Gas	8	KABCA	20,955	7.50%	25.00%	21,181
Mid	10	KABCA	21,190	15.00%	50.00%	
Low Natural Gas	12	KABCA	21,387	7.50%	25.00%	
Better Information	**Endpoint**	**Plan**	**NPVRR**	**EP Prob**	**Cond. Prob**	**Expected Value**
High Natural Gas	8	KAACA	20,955	7.50%	25.00%	21,180
Mid	10	KABCA	21,190	15.00%	50.00%	
Low Natural Gas	12	KABEA	21,387	7.50%	25.00%	
Expected Value of Better Information			0.23	Million		

Table 52 below provides the Alternative Resource Plan that had the lowest NPVRR for each endpoint scenario.

Table 52: Endpoint/Lowest NPVRR Alternative Resource Plan

EP	Plan	Value	Conditional Probability
1	KABHA	22,434	2.50%
2	KABHA	21,075	3.75%
3	KABHA	22,619	5.00%
4	KABHA	21,301	7.50%
5	KABHA	22,767	2.50%
6	KABHA	21,491	3.75%
7	KABHA	22,155	5.00%
8	KABHA	20,847	7.50%
9	KABHA	22,355	10.00%
10	KABHA	21,089	15.00%
11	KABHA	22,519	5.00%
12	KABHA	21,295	7.50%
13	KABHA	21,873	2.50%
14	KABHA	20,617	3.75%
15	KABHA	22,088	5.00%
16	KABHA	20,876	7.50%
17	KABHA	22,268	2.50%
18	KABHA	21,099	3.75%

The sum of the joint probabilities and the count of the number of times an Alternative Resource Plan is the low cost scenario endpoint is shown in Table 53 below:

Table 53: Cumulative Probability of Lowest NPVRR Plan

Plan	Cumulative Probability	Count
KABHA	100%	18

7.3 IMPLEMENTATION PLAN

The Implementation Plan provided in the 2015 KCP&L Triennial IRP is materially changing primarily due to a change in the timing of previously announced plant retirements. In the 2015 Triennial IRP and the 2016 Annual Update Implementation Plans, it was disclosed that Montrose Units 2 and 3 would be retired by 2022. The current plan is to retire both units by 2019. Based on this updated retirement date occurring within the next three years, KCP&L will be utilizing previous KCP&L-specific retirement studies to determine next steps and upcoming major milestones required to proceed with unit retirements.

Additionally, there was 300 MW of new wind generation disclosed in the 2015 Triennial IRP and 2016 Annual Update that was expected to be in-service by 2018. On December 14^{th}, 2016, KCP&L's 120 MW portion of the Osborn wind project located near Osborn, Missouri reached commercial operation. KCP&L's 180 MW portion of the Rock Creek wind project located in Atchison County, Missouri is expected to be in-service by 2018. Also, the 3 MW of Commercial and Industrial solar rooftop installations that were expected to be installed in 2016 have been put on hold.

It should also be noted that KCP&L is exploring and has tested a behind-the-meter demand response (DR) system as a pilot project. The DR system, which is an automated demand response (ADSM) product, enables two-way, real time communication and load control between the utility and customers, feeders, or substations.

The Demand-Side Management program schedule has been updated and the current schedules for ongoing and future DSM programs are provided in Table 54 and Table 55 below.

7.3.1 DEMAND-SIDE MANAGEMENT SCHEDULE

Table 54: DSM Program Schedule – Existing Programs

Program Name	Program Type	Segment	Program Implemented	Annual Report	Program Duration	EM&V Completed and draft report available
Home Lighting Rebate	Energy Efficiency	Residential	Apr., 2016	90-days following Plan Year	3-years	1-Yr following Plan Year
Home Appliance Recycling Rebate	Energy Efficiency	Residential	Apr., 2016	90-days following Plan Year	3-years	1-Yr following Plan Year
Home Energy Report	Energy Efficiency	Residential	Apr., 2016	90-days following Plan Year	3-years	1-Yr following Plan Year
Income-Eligible Home Energy Report	Energy Efficiency	Residential	Apr., 2016	90-days following Plan Year	3-years	1-Yr following Plan Year
Online Home Energy Audit	Educational	Residential	Apr., 2016	90-days following Plan Year	3-years	1-Yr following Plan Year
Whole House Efficiency	Energy Efficiency	Residential	Apr., 2016	90-days following Plan Year	3-years	1-Yr following Plan Year
Income-Eligible Multi-Family	Energy Efficiency	Residential	Apr., 2016	90-days following Plan Year	3-years	1-Yr following Plan Year
Residential Programmable Thermostat	Demand Response	Residential	Apr., 2016	90-days following Plan Year	3-years	1-Yr following Plan Year
Business Energy Efficiency Rebate - Standard	Energy Efficiency	C&I	Apr., 2016	90-days following Plan Year	3-years	1-Yr following Plan Year
Business Energy Efficiency Rebate - Custom	Energy Efficiency	C&I	Apr., 2016	90-days following Plan Year	3-years	1-Yr following Plan Year
Strategic Energy Management	Energy Efficiency	C&I	Apr., 2016	90-days following Plan Year	3-years	1-Yr following Plan Year
Block Bidding	Energy Efficiency	C&I	Apr., 2016	90-days following Plan Year	3-years	1-Yr following Plan Year
Online Business Energy Audit	Educational	C&I	Apr., 2016	90-days following Plan Year	3-years	1-Yr following Plan Year
Small Business Direct Install	Energy Efficiency	C&I	Apr., 2016	90-days following Plan Year	3-years	1-Yr following Plan Year
Commercial Programmable Thermostat	Demand Response	C&I	Apr., 2016	90-days following Plan Year	3-years	1-Yr following Plan Year
Demand Response Incentive	Demand Response	C&I	Apr., 2016	90-days following Plan Year	3-years	1-Yr following Plan Year

Table 55: DSM Program Schedule – Planned Programs

Program Name	Program Type	Segment	Tariff Filing Date	Projected Approval Date	Projected Implementation Date	Annual Report
Home Lighting Rebate	Energy Efficiency	Residential	May., 2018	Oct., 2018	Jan., 2019	90-days following Plan Year
Home Energy Report	Energy Efficiency	Residential	May., 2018	Oct., 2018	Jan., 2019	90-days following Plan Year
Income-Eligible Home Energy Report	Energy Efficiency	Residential	May., 2018	Oct., 2018	Jan., 2019	90-days following Plan Year
Online Home Energy Audit	Educational	Residential	May., 2018	Oct., 2018	Jan., 2019	90-days following Plan Year
Whole House Efficiency	Energy Efficiency	Residential	May., 2018	Oct., 2018	Jan., 2019	90-days following Plan Year
Income-Eligible Multi-Family	Energy Efficiency	Residential	May., 2018	Oct., 2018	Jan., 2019	90-days following Plan Year
Income-Eligible Weatherization	Energy Efficiency	Residential	May., 2018	Oct., 2018	Jan., 2019	90-days following Plan Year
Residential Smart Thermostat w DLC	Demand Response	Residential	May., 2018	Oct., 2018	Jan., 2019	90-days following Plan Year
Central AC DLC Switch	Energy Efficiency	Residential	May., 2018	Oct., 2018	Jan., 2019	90-days following Plan Year
Water Heating DLC Switch	Energy Efficiency	Residential	May., 2018	Oct., 2018	Jan., 2019	90-days following Plan Year
Business Energy Efficiency Rebate - Standard	Energy Efficiency	C&I	May., 2018	Oct., 2018	Jan., 2019	90-days following Plan Year
Business Energy Efficiency Rebate - Custom	Energy Efficiency	C&I	May., 2018	Oct., 2018	Jan., 2019	90-days following Plan Year
Strategic Energy Management	Educational	C&I	May., 2018	Oct., 2018	Jan., 2019	90-days following Plan Year
Retrocommissioning	Energy Efficiency	C&I	May., 2018	Oct., 2018	Jan., 2019	90-days following Plan Year
Block Bidding	Demand Response	C&I	May., 2018	Oct., 2018	Jan., 2019	90-days following Plan Year
Online Business Energy Audit	Demand Response	C&I	May., 2018	Oct., 2018	Jan., 2019	90-days following Plan Year
Small Business Targeted	Demand Response	C&I	May., 2018	Oct., 2018	Jan., 2019	90-days following Plan Year
Business Smart Thermostat w DLC	Demand Response	C&I	May., 2018	Oct., 2018	Jan., 2019	90-days following Plan Year
Demand Response Incentive	Demand Response	C&I	May., 2018	Oct., 2018	Jan., 2019	90-days following Plan Year

Additional detail regarding the implementation plan for the DSM Preferred Plan can be found in the separate volume entitled “Kansas City Power & Light Demand-Side Resource Analysis”. 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 2019 to 2021 in mid-2018.

7.3.2 EVALUATION, MEASUREMENT AND VERIFICATION

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.

EM&V Process Evaluation

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 approximately five months after the Commission Approval Date. Vendor selection will be approximately seven months after the Commission Approval Date.

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 full EM&V will be conducted over the three-year cycle with annual performance reports delivered each year. 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 56 below. This schedule will be updated when KCP&L files for new programs under MEEIA.

Table 56: Evaluation Schedule[i]

Estimated EM&V Schedule	
EM&V RFP Ready for Review	4/1/2019
Issue EM&V RFP	6/1/2019
EM&V Vendor Selected	8/1/2019
1st Annual EM&V Begins	1/1/2019
1st Annual Draft Report	8/1/2019
1st Annual Program Report	10/1/2019
2nd Annual EM&V Begins	1/1/2020
2nd Annual Draft Report	8/1/2020
2nd Annual Program Report	10/1/2020
3rd Annual EM&V Begins	1/1/2021
3rd Annual Draft Report	8/1/2021
3rd Annual Program Report	10/1/2021

SECTION 8: SPECIAL CONTEMPORARY ISSUES

From the Commission Order, EO-2017-0074, the following Special Contemporary Resource Planning Issues are addressed as follows:

8.1 AMI METER IMPLEMENTATION

Document GMO's most recent economic analysis for its system-wide implementation of AMI meters. Provide projected implementation dates and annual budgets for AMI implementation.

Response:

The most recent economic analysis was completed in 2016 for the implementation of the remaining ~200,000 AMI meters. The analysis was completed as a combined study for GMO, KCP&L-MO, and KCP&L-KS. GMO accounts for approximately 157,000 meters, KCP&L-MO 12,000 meters, and KCP&L-KS for 31,000 meters of the 200,000 meters. The analysis showed an 11-year payback and would result in full implementation of AMI metering for both GMO and KCP&L.

This project is currently projected to commence in 2019 as shown in Table 57 below:

Table 57: AMI Metering Schedule

Service Territory	Number of Meters	Deployment Year
Missouri - North District: St. Joseph, Mound City, Trenton	70,000	2019
Missouri - East District: Brunswick	22,000	2019
Missouri - Southeast District: Warrensburg, Sedalia, Nevada	77,000	2019/2020
Kansas - South District: Paola, Ottawa	31,000	2020

The project budget is provided in Table 58 below:

Table 58: AMI Metering Budget

	2018	2019	2020	Project Total
Meters and Installation Cost (includes other non-IT costs)	$ 250,000	$ 16,667,000	$ 16,667,000	$ 33,584,000
IT Cost	$ 400,000	$ 50,000	$ 50,000	$ 500,000
Budget	$ 650,000	$ 16,717,000	$ 16,717,000	$ 34,084,000

8.2 ENVIRONMENTAL CAPITAL AND OPERATING COSTS FOR COAL-FIRED GENERATING UNITS

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:

Response:

(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:*** See Table 59, Table 60, and Table 61 below.

(3) ***National Ambient Air Quality Standards for ozone and fine particulate matter:*** See Table 59, Table 60, and Table 61 below.

(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) ***Mercury and Air Toxics Standards:*** See Table 59, Table 60, and Table 61 below.

(6) ***Clean Water Act Section 316(b) Cooling Water Intake Standards:*** See Table 59, Table 60, and Table 61 below.

(7) ***Clean Water Act Steam Electric Effluent Limitation Guidelines:*** See Table 59, Table 60, and Table 61 below.

(8) ***Coal Combustion Waste rules:*** See Table 59, Table 60, and Table 61 below.

(9) ***Clean Air Act Section 111(d) Greenhouse Gas standards for existing sources:*** See "Clean Power Plan" discussion below.

(10) ***Clean Air Act Regional Haze Requirements:*** The Company is in compliance with this rule.

Table 59: Environmental Capital Cost Estimates ** Highly Confidential **

[redacted]

Table 60: Environmental Fixed O&M Estimates ** Highly Confidential **

[redacted]

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Table 61: Retrofit Variable O&M Estimates ** Highly Confidential **

[redacted]

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(11) *Clean Power Plan:* Issued by the EPA in August 2015, the Clean Power Plan ("CPP") regulations seek to reduce CO_2 emissions from certain power plants by 32% from 2005 levels by 2030. It does so by imposing CO_2 reduction obligations on existing power plants based on what EPA identified as the "Best System of Emission Reductions". States are expected to develop State Implementation Plans ("SIPs") that will ensure that the state meets its CO_2 reduction obligations. Reductions are to start in 2022 with further reductions phased in through 2030. States may choose a mass-based or rate-based compliance structure. A mass-based structure sets state CO_2 emission targets in terms of total tons emitted from covered resources. A rate-based structure sets state targets based on pounds of CO_2 emitted per MWh generated. On February 9, 2016, the Supreme Court issued a stay of the CPP until legal challenges can be addressed. Since the stay by the Supreme Court, neither MDNR nor KDHE have had any meetings or provided any analysis of the CPP or the Clean Energy Incentive Plan ("CEIP"). Pursuant to the stay, KCP&L has not taken any actions in preparation for compliance since all obligations have been stayed.

Since the 2016 Annual IRP Update filing, a new US President and a new Administrator of the Environmental Protection Agency have taken office and created more uncertainty as to the future of the Clean Power Plan. This uncertainty is covered in more detail in Special Contemporary Resource Planning Issues and related documents.

For the purpose of this filing, KCP&L has maintained the same analysis approach as presented in the 2015 Triennial and the 2016 Annual IRP Updates, for the selection of the 2017 Annual Update preferred plan.

KCP&L has attempted to analyze the potential CPP impacts on its resource plans. Since the CPP State Implementation Plans have yet to be developed and approved, a number of important assumptions were required to perform this analysis. These assumptions include:

- A mass-based compliance structure

- When CO_2 emission allowances are allocated, the allocations are based on a utility's share of 2012 emissions relative to state total emissions from covered resources

- No emission allowance set-asides for new renewable generation, new non-renewable generation or energy efficiency programs

- A CO_2 emission allowance trading market is established

- Regional wholesale electric market prices based on CO_2 emission allowances applied to covered resources

KCP&L CPP Analysis Results – CO_2 emissions

The following chart shows the expected value of CO_2 produced each year (in tons) for each KCP&L alternative resource plan modeled. This is the expected value over the nine scenarios that include CO_2 emission costs. The chart also shows the assumed amount of CO_2 emission allowances allocated to KCP&L (labeled "EPA Targets"). Where the emissions from alternative resource plans exceed the EPA targets, the cost of these excess emissions is included in the NPVRR results. The modeled CO_2 cost for the integrated analysis is based upon a composite of forecasts (PIRA, CERA, EVA & Synapse), and it is included in the production cost on all covered resources and the power market price forecasts for these scenarios.

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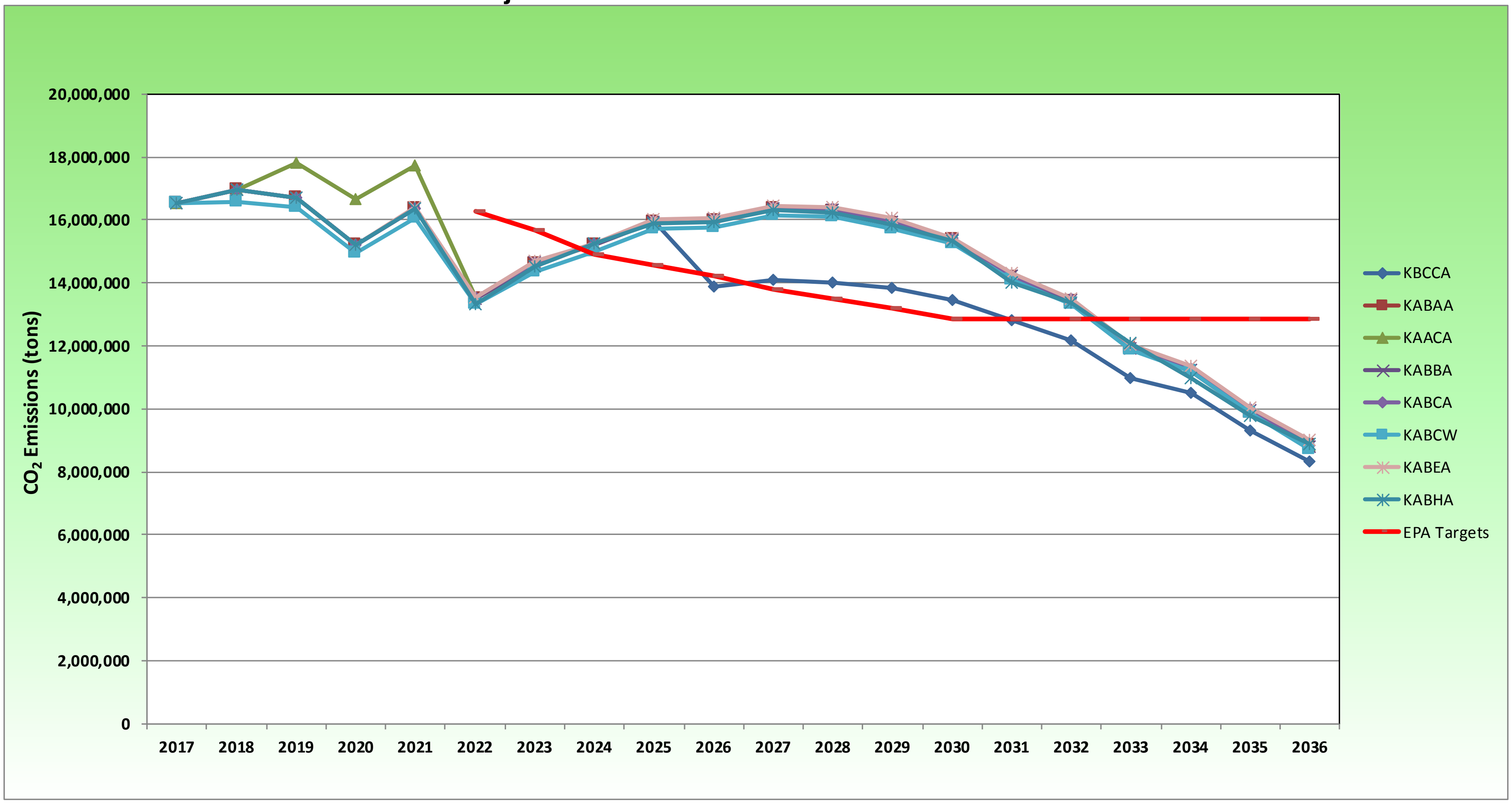
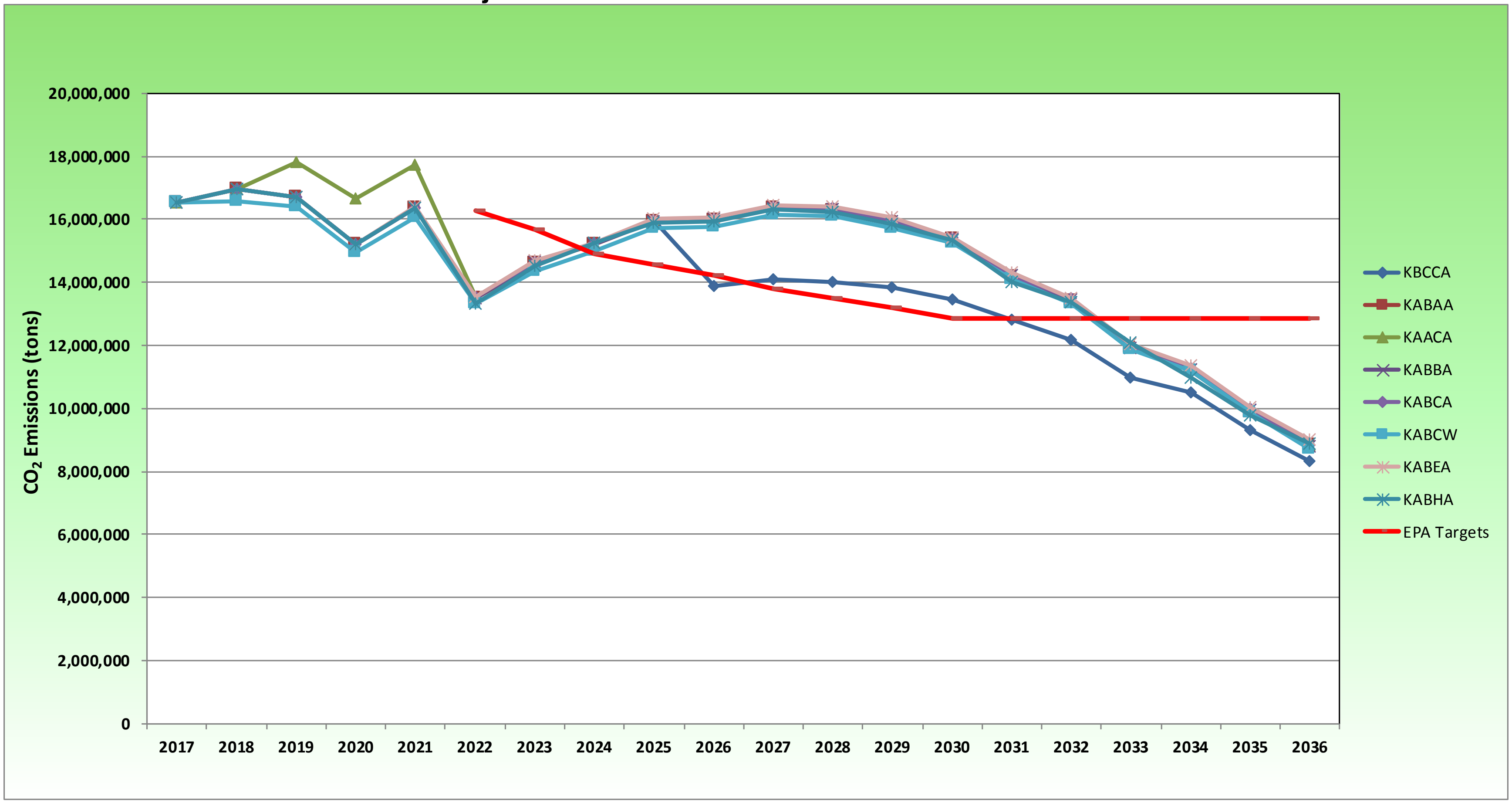
Table 62: Projected Annual CO_2 Emissions With CO_2 Restrictions



For comparison purposes, the following chart shows the expected value of CO_2 produced each year (in tons) for each of the KCP&L alternative resource plans modeled under the 9 scenarios without CO_2 costs applied.

Table 63: Projected Annual CO_2 Emissions Without CO_2 Restrictions



(11) Clean Power Plan (continued):

Estimated CPP Cost Impact

Based on analysis to date, the 20-year net present value of CPP compliance costs are estimated to be approximately ** [redacted]**, where emission allowances are auctioned by Missouri and Kansas rather than allocated to the utilities.

Economic dispatch including an explicit CO_2 cost on KCP&L's covered resources shows a significant increase in gas generation as compared to historic operation. Given this increase in gas generation, the alternative resource plans modeled include additional cost for KCP&L's gas turbine fleet for increased O&M, year-round firm gas service, and the costs necessary to operate KCP&L's combined cycle unit (Hawthorn 6/9) on a year-round basis.

This analysis is based on several major assumptions that could ultimately be proved incorrect. For example, the assumed state CO_2 emission allowances allocation could be different from what KCP&L has assumed in this analysis. Given the Supreme Court CPP stay, it is uncertain as to when Missouri and Kansas will develop their SIPs specifying how the emission allowance would be allocated, if allocated at all. In addition, it appears that the CO_2 emission forecast used in this analysis may result in a regional shift of coal-based generation to gas-based generation greater than that required to meet the CPP mass-based CO_2 targets. Given this, more work is needed to refine the CO_2 emission allowance forecast.

In addition to actions previously taken by the company to reduce CO_2 emissions related to retail load, (renewable generation additions, DSM program development and implementation, coal use reductions, plant efficiency improvements, etc.) current modeling indicates additional CO_2 reduction would come from increased existing combustion turbine utilization. Existing combustion turbines are not "covered resources" so their CO_2 emissions do not count towards the state's CO_2 limits. While this shift in generation to existing combustion turbine resource would be permissible under the

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current CPP, EPA did not anticipate such a shift. As such, actual national CO_2 levels could exceed EPA's intended targets under such a scenario.

8.3 CUSTOMER FINANCING OPTIONS

Review the options available to KCP&L for providing customer financing for energy efficiency measures. Discuss KCP&L's current, near term (next three years) and long-term activities and plans for providing customer financing for energy efficiency measures.

Response:

8.3.1 CURRENT

KCP&L currently does not provide on-bill financing for energy efficiency measures. The Company's Customer Information System (CIS) platform is not designed to support this financing process functionality. We are, however, in development of a new CIS platform (planned for a 2018 launch) that could potentially handle such processes. If our ongoing exploration and program evaluation indicates this offering is advantageous, the financing option will be investigated further.

However, as stated in proceeding ER-2016-0285 (rebuttal testimony of Brian A File), KCP&L has been involved with the purveyors of PACE financing in the KCP&L's Missouri service territory over the last 3-4 years for commercial properties and within the last year for residential properties. While the commercial PACE loans have been available for a few years, there have only been a couple of companies that jointly pursued a rebate from the Company's energy efficiency programs and PACE financing for their project. The offering of PACE financing programs in KCP&L's Missouri service area should provide synergistic benefits to a customer who combines the financing with KCP&L's energy efficiency programs. Currently our website, KCPL.com, presents how PACE financing can be a solution to overcoming up-front cost barriers to commercial energy efficiency projects.

In addition to PACE funding mentioned above, a few additional options for commercial customers that we have seen in the marketplace include:

- Energy Service Company ("ESCO") financing
- Manufacturer direct financing for various energy efficient appliances
- Local distributors and contractors loans through private outside lenders
- Energy Loan Program (sponsored by the DOE) – Available to public schools, colleges, city/county government buildings, public water and wastewater treatment facilities and public/private non-profit hospitals; 2016 FY interest rate set at 2.75%.

Most recently, the Company partnered with an agency, Renovate America - who offers residential PACE financing, to educate and inform our Trade Ally (heating, ventilation, and air conditioning ("HVAC") and insulation professionals) partners of the options available to offer PACE financing to residential customers for qualified projects. KCP&L has also invited commercial PACE lenders to various customer and Trade Ally events (including Strategic Energy Management cohorts, Trade Ally Forums and other customer education series) promoting KCP&L programs and presenting PACE financing as an option for overcoming barriers.

Now that PACE is gaining more traction with additional counties/cities joining in to offer this financing option, KCP&L will be evaluating next best steps such as cobranded marketing, potential system integrations, etc.

Properly developed financing vehicles should have a positive impact on the participation of energy efficiency programs as well as increasing the overall customer value. However, the ultimate benefits may not outweigh the costs and risks associated with setting up utility on-bill financing programs, especially when there are additional options for funding that are available to all customers.

8.3.2 NEAR-TERM (NEXT 3 YEARS)

KCP&L will monitor the marketplace and our program offerings and if it is determined that the market needs something more, perhaps a financing option, to meet our goals; we will then research steps to incorporate this mechanism into our process and program offerings, including an deeper assessment of the new CIS platform functionality.

8.3.3 LONG-TERM

KCP&L will continue as listed above, under item 2 (Near Term) and will keep current on market trends and how/if we need to adjust our current program offerings, including the offering of a customer financing option.

8.4 TRANSMISSION GRID IMPACTS

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.

Response: The KCP&L coal units identified for retirement in the IRP plan are Montrose Units 2 and 3. The approximate cost estimate for switching cap banks and reactors to replace the generators reactive capability would be $3-5 million. Other 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 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.

8.5 CLEAN POWER PLAN COMPLIANCE

Describe and document how the preferred plan of the Company's Integrated Resource Plans (IRPs) positions the utility for full or partial compliance with the U.S. Environmental Protection Agency's (EPA) Clean Power Plan (CPP) under Section 111(d) of the Clean Air Act, as released in final form on August 3, 2015, assuming that the rule is upheld by the courts in its current form, except as compliance timelines may need to be modified as a result of the delay in implementation resulting from the U.S. Supreme Court's stay. Please include in this regard:

Response:

(1) *Qualitative and quantitative evaluations of how renewable energy, energy efficiency and other demand-side resources (including combined heat and power) deployed by the Company after January 1, 2013 could contribute to compliance;*

Renewables, energy efficiency initiatives and other DSM resources play an important role in contributing to CPP compliance. As shown in the Executive Summary, Table 64 below illustrates the importance of renewables in the make-up of KCP&L capacity and energy resources. Load served by renewable energy reduces CO_2 emissions, as does load displaced by energy efficiency and other DSM programs employed by KCP&L.

Table 64: KCP&L Capacity and Energy by Resource Type

Capacity By Fuel Type	Capacity (MW)	% of Total Capacity	Estimated Energy (MWh)	% of Annual Energy
Coal	2,569	48%	13,745,925	61%
Nuclear	549	10%	4,056,184	18%
Oil	401	7%	-	0%
Nat. Gas	782	15%	129,325	1%
Wind	1,031	19%	4,035,565	18%
Hydro	60	1%	383,400	2%
Solar	0.2	0.003%	240	0.001%
Total	5,392	100.0%	22,350,639	100.0%

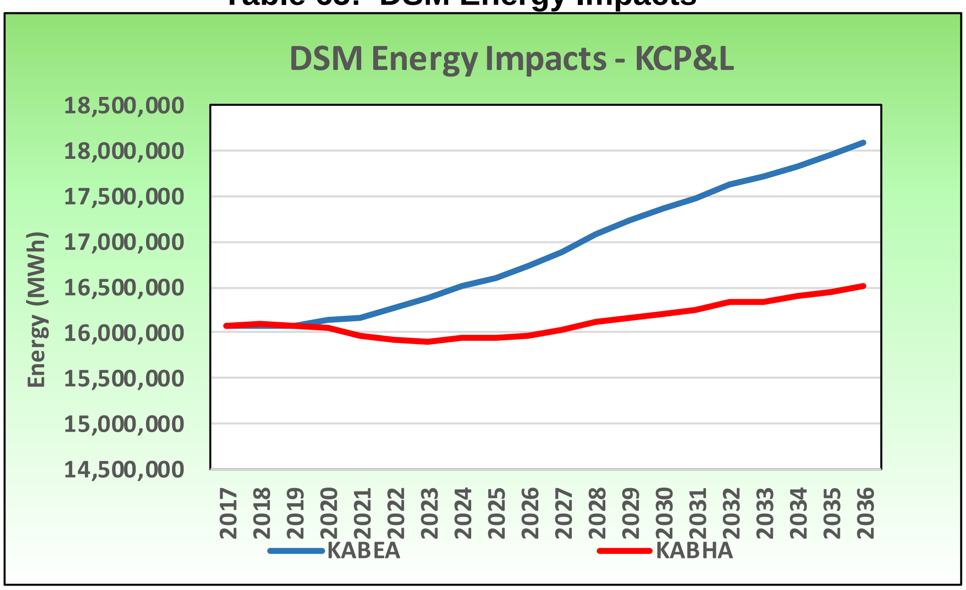
The post-2012 renewables resources are illustrated by eliminating post-2012 renewable resources in the KCP&L Preferred Plan KABHA. By comparing the mid load, mid gas, w/CO_2 scenario (EP#9) performed in the KCP&L integrated analysis to the scenario that eliminates the post-2012 renewables we came up with these results:

a. These renewables average over 2,640 GWh of energy annually over the 20-year IRP.

b. These provide for over $300mm NPVRR benefit during that 20-year IRP.

The energy impact of the energy efficiency and other demand-side resource programs on preferred plan KABHA is illustrated Table 65 below. This compares the preferred plan KABHA to plan KABEA, which has no new programs. The NPVRR benefit of comparing the mid load, mid gas, w/CO_2 scenarios (EP#9) for these plans is just under $170mm for the 20-year IRP.

Table 65: DSM Energy Impacts



The results of this analysis will be included in workpapers as E1_Post2012Renewables.xlsx.

(2) *Qualitative and quantitative evaluations of how renewable energy, energy efficiency and other demand-side resources (including combined heat and power) deployed by the Company after the submission of a final State Implementation Plan could qualify under EPA's proposed Clean Energy Investment Program (CEIP);*

The final State Implementation Plan has yet to be filed.

(3) *A description and quantification of additional investments (in fiscal, capacity, and energy terms by year) which will be required by the Company to meet the targets in the CPP under a trading-ready "mass-based" approach, with and without participation in the CEIP;*

Clean Power Plan may significantly increase KCP&L reliance on gas generation units and this would require approximately $4.9mm in capital expenditures at Hawthorn 6 & 9 combined cycle units, along with approximately $1.3mm in annual O&M costs to achieve year-round operating potential. Hawthorn combustion turbines #7 & 8 would have $26mm in infrastructure upgrades and $6.26mm in annual gas transportation capacity charges. West Gardner and Osawatomie combustion turbine units would require approximately $12.5mm and $1.7mm annually in gas transportation capacity charges . There is also anticipated need for 2 FTE's to provide additional maintenance for increased combustion turbine production volume.

(4) *Qualitative and quantitative descriptions of the barriers to achieving these additional investments;*

At this time, no significant barriers are anticipated to meet the items discussed in item (3) above.

(5) *The price of carbon used by the Company in the analyses above and a justification for this price;*

The modeled CO_2 cost for the integrated analysis is based upon a composite of forecasts (PIRA, CERA, EVA & Synapse), and it is included in the production cost on all covered resources and the power market price forecasts for these scenarios. This forecast was previously presented in Table 19 above.

CO_2 Forecast	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
2017 - Yes	0.00	0.00	0.00	0.00	0.00	15.76	16.12	16.42	13.49	13.43
2017 - No	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO_2 Forecast	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
2017 - Yes	13.59	14.80	16.42	18.60	20.13	21.99	23.94	25.98	28.11	30.21
2017 - No	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO_2 Forecast	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
2016 - Yes	0.00	0.00	0.00	0.00	0.00	8.10	14.32	15.76	23.35	24.67
2016 - No	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO_2 Forecast	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
2016 - Yes	25.42	27.67	29.15	30.71	32.16	34.77	36.68	37.70	39.67	
2016 - No	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	

KCP&L is studying an alternative approach to develop CO_2 prices in a CPP world, that would be based upon extrapolating an effective CO_2 price that would represent CPP compliance across the entire Eastern Interconnect Region. This approach relies on the assumptions stated in (6) below are implemented for the Eastern Interconnect region, and that this CO_2 effective price represents the equilibrium price for the emission allowance trading market for that region.

(6) *A description and explanation of the Company's preferences regarding specific compliance options under a state implementation plan; and*

KCP&L has attempted to analyze the potential CPP impacts on its resource plans. Since the CPP State Implementation Plans have yet to be developed and approved, a number of important assumptions were required to perform this analysis. These assumptions include:

- A mass-based compliance structure
- When CO_2 emission allowances are allocated, the allocations are based on a utility's share of 2012 emissions relative to state total emissions from covered resources
- No emission allowance set-asides for new renewable generation, new non-renewable generation or energy efficiency programs

- A CO_2 emission allowance trading market is established
- Regional wholesale electric market prices based on CO_2 emission allowances applied to covered resources

(7) *A description of all meetings, analyses, or other efforts made towards preparation for compliance with the CPP (and CEIP, as applicable).*

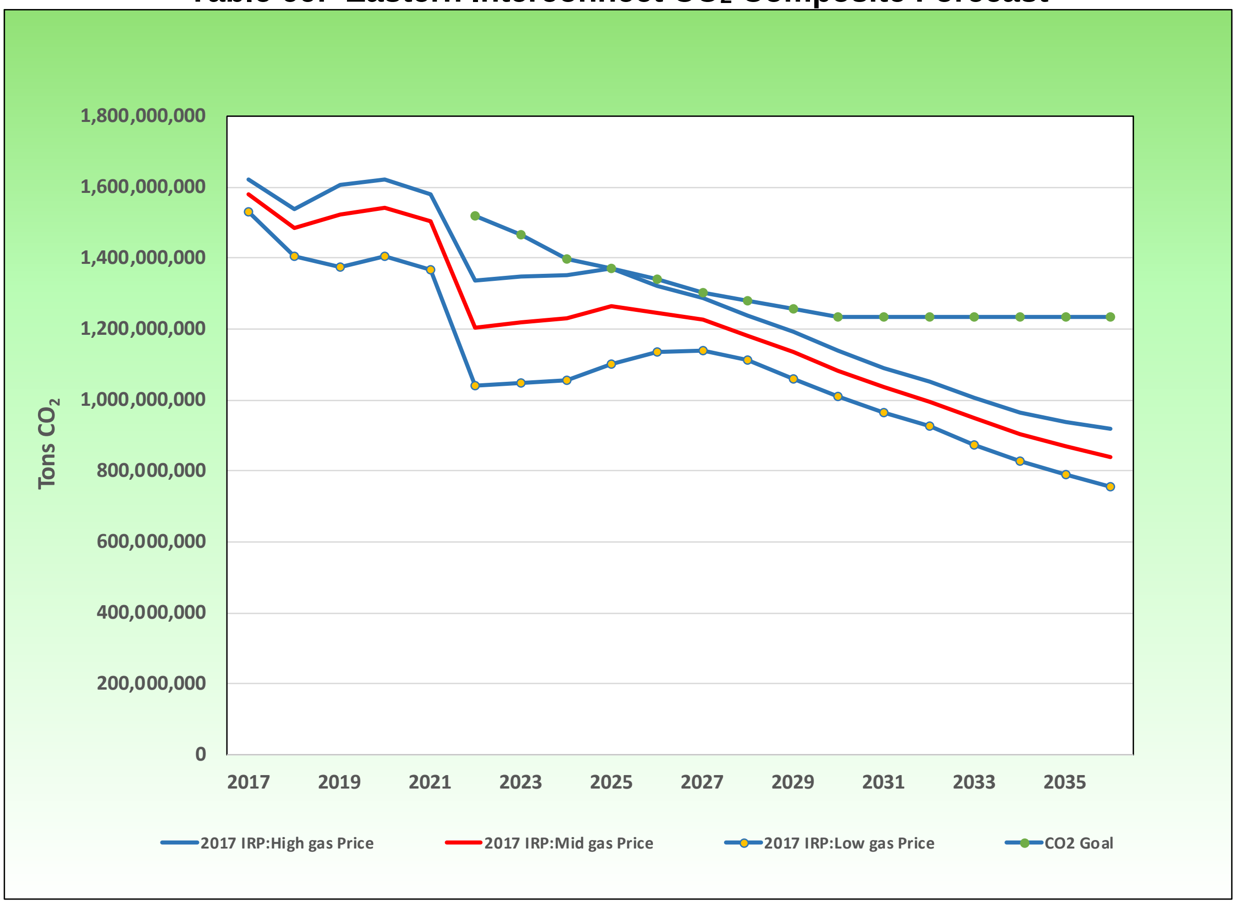
On February 9, 2016, the Supreme Court issued a stay of the CPP until legal challenges can be addressed. Some states have indicated that no further work will be done on SIP development until the stay is lifted. Since the stay by the Supreme Court, neither MDNR nor KDHE have had any meetings or provided any analysis of the CPP or the Clean Energy Incentive Plan ("CEIP"). Pursuant to the stay, KCP&L has not taken any actions in preparation for compliance since all obligations have been stayed. On March 28, 2017, the President issued an executive order regarding the CPP that resulted in an abeyance of the litigation while EPA reviews the rule.

To the extent that any uncertainty is involved in determining compliance pathways under the CPP (and CEIP, as applicable) based on the scenarios provided above, please describe and document the Company's choices under the most probable compliance scenarios, with an explanation of why the Company believes these scenarios are the most probable.

Many pathways may help lead to compliance with the EPA CO_2 targeted goals, including coal unit retirements, increased renewable energy sources, and energy efficiency and other demand-side resource programs. Allowance trading markets are another critical compliance tool. Broad regional allowance trading markets would no doubt have some states in an over, or under, compliance positions relative to their specific EPA targeted goal, but these should be balanced by the market dynamics of allowance (auction prices) and energy power prices.

Table 66 below represents the CO_2 emission tons for the Eastern Interconnect as modeled in this 2017 IRP Annual Update. These emissions were output from the energy market pricing model that produced the energy power price curves for the integrated analysis simulations. These emissions are output from the same natural gas and CO_2 forecasted price input assumptions that are used to generate the hourly energy power prices. The EPA CO_2 goal represents the summation of the state goals within the Eastern Interconnect Region. This chart shows that based upon these assumptions, the entire Eastern Interconnect appears to be in over compliance relative to the EPA CO_2 goal. If there is over compliance, the trade value of CO_2 allowance prices should decrease.

Table 66: Eastern Interconnect CO_2 Composite Forecast



8.6 JOINT DSM POTENTIAL WITH WATER UTILITIES

Evaluate, describe, and document the feasibility, cost-reduction potential, and potential benefits of joint DSM programs, marketing, and outreach with water utilities.

Response:

On January 30, 2017, KCP&L contracted with Aiqueous to conduct Water Energy Nexus research in their Missouri territories. This research is intended to identify potential energy savings that could be realized though water savings measures/strategies in three specific vertical market segments: water/wastewater treatment and distribution, irrigated agriculture and C&I water use. This research is being conducted under the current the MEEIA Cycle 2 Pilot and Research portion of the Commission approved Stipulation and Agreement. Because MEEIA Cycle 2 runs for three program years, April 1, 2016 - March 31, 2019, this Water Energy Nexus research is planned to conclude by early in Program Year 2 in order to leverage any potential research learnings to the existing DSM business program portfolio.

The primary research questions are:

- What is the total volume of water use, water production, water distribution, and water treatment within KCP&L's service territory?
- What is the electric energy use and demand associated with that water use, production, distribution, and treatment?
- What technologies or strategies could drive energy efficiency improvements, both directly and through the reduction of water use, production, distribution, and treatment?
- What technologies or strategies have interactive effects between water and electricity, and how could KCP&L approach these technologies or strategies?
- What has been the historical KCP&L program participation and customer engagement around the water-energy nexus?

- What opportunities exist to jointly engage on the water-energy nexus with water utilities and other water authorities?
- How have other energy utilities in the United States addressed the water-energy nexus?
- How could KCP&L integrate the water-energy nexus into its existing programs, and what could be an associated budget and savings target?

The deliverables of this research are:

- Table(s) by market segment summarizing number of entities by type, size categories by type, energy and water use by size category and type, and estimated end use breakdowns
- List of recommended measure(s) by market segment
- Measure summary table(s) by market segment including measure name, measure description, baseline assumption, end use affected, savings estimate, relative cost-effectiveness, notes, and other data sources
- Case studies providing concrete examples of water-energy nexus projects and savings for each of the 3 vertical markets explored.
- One-page program profile per utility surveyed discussing their utility program designs and applicable market segment approaches.
- Measures to include in existing C&I programs, with associated assessment and measurement and verification (M&V) approaches, savings potential, and incentive structures;
- Recommendation for a new Strategic Energy Management (SEM) Program segment focusing on agriculture

- Strategies to jointly promote energy efficiency and water conservation programs with water utilities and other water authorities in KCP&L service territory
- Trade ally segments to be targeted to promote water-energy nexus measures
- Estimated incremental budget to capture budget-constrained, achievable water-energy nexus savings
- Program design recommendations and budget per market segment

8.7 DSM OPT-OUT AVOIDANCE

Describe, document, and evaluate potential DSM programs which could address the needs of customers that might otherwise "opt out" of participation in MEEIA.

Response:

KCP&L as part of their MEEIA Cycle 2 filing implemented two programs; Strategic Energy Management and Block Bidding which address the needs of customers that might otherwise "opt out" of participation in MEEIA.

The Strategic Energy Management program is designed for high energy use customers with unique operational characteristics provides hands on training by aligning these customers with similar customers in a co-hort. The program offers in depth curriculum on a variety of different energy related topics over a two year period. During this span of time each customer develops models of their facilities to track their predicted usage based on weather or production against their actual usage as a result of the sustainability efforts initiated. Each organization has an executive sponsor and energy champion which are responsible for driving change management throughout their organization. The objective for this program is to not only impact change through capital side investments but through culture and behavioral modifications of those that utilize the systems. See the complete program description at: https://www.efis.psc.mo.gov/mpsc/commoncomponents/view_itemno_details.asp?caseno=EO-2015-0240&attach_id=2016003617 , pages 111-113.

Block Bidding is a program that encourages the development and implementation of high volume energy savings projects. Local, regional and national third party suppliers are recruited through an RFQ to identify opportunities for customers and bid for incremental rebate incentives that exceed the programs annual cap at a reduced rate. Through this approach large customers are eligible for large incentive values that provide a compelling case for energy efficiency investments and participation in the utilities DSM programs. See the complete program description at https://www.efis.psc.mo.gov/mpsc/commoncomponents/view_itemno_details.asp?caseno=EO-2015-0240&attach_id=2016003617 . pages 115-116.

In short the Strategic Energy Management and Block Bidding programs address the needs of customers that might not see the value or are able to make the financial case for participating in DSM programs. Strategic Energy Management offers a comprehensive educational and training engagement which provides a top down approach for sustainability within participating organizations and Block Bidding provides the incremental financial incentives to help projects which may not meet paybacks or hurdle rates by aligning cost effective incentives with energy savings which benefits all customers.

8.8 ELECTRIC VEHICLE EVALUATION AND INITIATIVES

Evaluate the potential demand and energy load associated with electric vehicles within the Company's Missouri service territory, discuss how the preferred addresses the additional demand and energy load requirements, and evaluate potential means for shifting the additional demand and energy load to off-peak periods. Describe all current and planned electric vehicle initiatives undertaken by the Company.

Response:

The KCP&L load forecast includes a projection of the potential demand and energy associated with electric vehicles within Company's Missouri service territory throughout the 20 year planning horizon. The end-use load forecasts were developed using both EV data collected by KCP&L and secondary data and projections of EV adoption produced by the U.S. Department of Energy (DOE) for the West North Central Region of the U.S. DOE updates its projections at least once a year and we use the most recently available projections whenever we update our models.

Due to the uncertainty of future EV adoption rates, KCP&L has engaged EPRI in a supplemental research project to perform an Analysis and Valuation of KCP&L's Clean Charge Network. The '*Preliminary Scoping Analysis of the Effects of Transportation Electrification in the KCP&L Service Territory'*, completed in 2016, (see Attachment A) developed High/Med/Low EV adoption scenarios for the combined KCP&L/GMO service territories across both KS and MO. There is a wide range between the low and high adoption cases with the low case showing approximately 5500 PEVs (16,000 MWh) in the service territory in 2025 and the high case reaching approximately 73,500 PEVs (225,000 MWh) in 2020. The preliminary scoping analysis found that, if charging is managed properly, KCP&L/GMO has more than enough capacity available to support a large fleet of PEVs in its service territory. To minimize any potential impact on system peak loading, all CCN charge stations are configure to reduce charge levels in response to Company initiated DR events. However, the preliminary EPRI analysis did not analyze the potential impact on localized distribution grid facilities and that further study was in this area is needed. Previous EPRI studies have shown that TOU rates for EV drivers charging at home can be effective at minimizing the localized impact to distribution equipment.

In Phase 2 of the analysis, that is currently underway, EPRI will confirm the number of EVs registered in each KCP&L jurisdiction and develop enhanced High/Med/Low adoption scenarios with anticipated EV miles and kWh charging requirements for each jurisdiction. Additionally, this phase of the study will develop anticipated charge profiles for managed and unmanaged charging at home, workplace, and public charging locations and perform an analysis of the potential impact to the distribution grid. The Phase 2 analysis will be completed in 2017 and the results will be incorporated into future load forecasts and IRP analysis.

Multiple studies are underway within the KCP&L and GMO companies to explore TOU and other dynamic rates and evaluate their demand side management ("DSM") potential. To be more specific, in ER-2016-0156, the Commission ordered GMO to study TOU rates for GMO including EV TOU rates for stand-alone charging stations and TOU rates applicable to EV charging associated with an existing account. These studies will provide more understanding of the role of dynamic rates and help determine an appropriate path forward for these rate options.

KCP&L's current and planned electric vehicle initiatives include:

Clean Charge Network ("CCN") – Is a Company initiative to install and operate more than 1,000 EV charging stations throughout the Greater Kansas City region within the KCP&L (both Missouri and Kansas) and GMO service territories. The CCN will install approximately 1000 Level 2 AC (7.2 kW) charge stations and 16 Fast DC (50kW) charge stations at an estimated 350 host site locations.

Missouri Department of Transportation (MODOT) Road to Tomorrow -The Company has committed to participate and collaborate with MODOT and other Missouri electric utilities to add several Fast DC charging stations in combination with Level 2 charging along the I-70 corridor between St Louis and Kansas City. EV charging islands will be conveniently located right off the highway in communities across the state. Location planning is currently underway.

EV Group Buy – KCP&L partnered with the City of Kansas City MO, Kansas City Regional Clean Cities and Nissan to extend special Nissan group buy incentives to Kansas City residents and KCP&L customers and employees.

8.9 ENERGY STORAGE AND VOLTAGE REDUCTIONS

Describe and document the roles which energy storage and conservation voltage reductions could play in the Company's system planning, particularly with regards to DSM and distributed energy resources.

Response:

KCP&L views energy storage as having the potential for a significant role in system planning beyond the 20 year horizon, and the company monitors industry trends in this arena. However, near term energy storage development is anticipated to be contained to mostly pilot projects. The most prevalent energy storage option in the company's Missouri territories is currently battery storage. Although costs are declining, battery storage remains cost prohibitive in Missouri and remains a fringe-level solution. It is unlikely to gain significantly increased adoption without financial incentives, significant cost reductions or significant technological improvements.

Although these limitations are real, the Company remains active through its work on several pilots. KCP&L deployed a 1.0 MWhr grid storage battery in our KCP&L-Missouri territory as part of the Green Impact Zone SmartGrid Demonstration Project. GMO plans to pilot three 375 kWh storage batteries as part of a Grid Power Balancing System near Liberty, MO. This system is designed to operate with single-phase inverters intended to provide real-time load balancing between the source feeder's phases on the pilot feeder/circuit. These pilots are intended to provide insights into the potential impacts for battery storage on the distribution system.

Storage could play another role in the Company's capacity planning. If the storage is company-owned and can be appropriately located in the distribution system, it can be programmed to provide system support during peak hours. However, the footprint for storage that can last through a peak of several hours is significant. The 1.0 MWhr battery consumes space of approximately two semi-trailers and is only capable of providing 1 MW for less than one hour. It is very difficult to site a location for such large footprint equipment to shave peak on a distribution circuit. Readiness of a battery for discharge relies not only on the battery technology and control systems, but also on continuous system maintenance. Before battery systems can be firmly included in in system planning, reliability of these system required improvement or there must be a high enough penetration to allow for a percentage of the capacity to be modeled as unavailable. If the storage is not charged for any reason, it will not cover the anticipated load and result in customer outages.

Customer-owned storage has the similar physical limitations, but the contribution to Company planning is further restricted if KCP&L is not able to control the charge and discharge cycles. Another limitation to use in Company planning is performance of required maintenance of customer-owned systems. If equipment is not well maintained, it will not be available for the modeled scenarios.

Given these limitations, KCP&L still believes that storage will eventually play a role in enabling additional DSM. TOU or other pricing models could make DSM investments that include storage more attractive. Storage can enable customers to capture energy from a variety of distributed resources and release the energy at a time beneficial to the customer and the utility. If these type systems reach significant penetration levels, they can be modeled and the level of availability could become reliable enough to include them as resources in distribution planning models, but not in the near-term.

KCP&L implemented a system called Dynamic Voltage Control (DVC) under the Comprehensive Energy Plan. In simplest terms, it is a semi-manual and semi-automated system to reduce voltage on distribution circuits by approximately 2% during summer peak conditions when temperatures exceed 95 degrees F and when KCP&L is generation short. During these conditions, this system reduces system demand by approximately 50 MW. Distribution system voltage is monitored manually by operations personnel during a DVC event to ensure customer voltage remains within acceptable regulatory limits.

Although DVC has been successfully implemented in KCP&L's metropolitan territory in Missouri and Kansas, the same system is not practical outside the metro area. This is due to circuits outside this footprint being significantly longer and having line regulators as an additional technical complication. The ability to utilize voltage reduction (commonly called Volt-VAR Optimization or VVO) for demand management in these areas will require implementation of a Distribution Management System (DMS) that provides centralized and automated monitoring and control. Deployment of a DMS is not currently part of the KCP&L Information Technology plan.

8.10 DELIVERY INFRASTRUCTURE

Evaluate the need to upgrade and enhance the utility's delivery infrastructure in order to ensure and advance system resiliency, reliability and sustainability.

Response:

As it is KCP&L's responsibility to provide safe, reliable and efficient power for all of our customers, KCP&L is continuously monitoring performance of its delivery infrastructure. As with any electric utility, delivery infrastructure continuously ages. KCP&L is an expert at maintaining aging infrastructure to maximize the lifespan of delivery equipment while maintaining high levels of service reliability. The Grid, like the internet, does not have a defined final state. It is a continuously evolving process of varying grid modernization steps. KCP&L approaches grid modernization from a portfolio and business case perspective. Modernization efforts are evaluated on the merits of their business case and balanced against alternatives to select the best option for KCP&L stakeholders. KCP&L has been forward thinking in many grid modernization efforts related to system resiliency, reliability and sustainability. KCP&L typically approaches new technology infusion with a pilot for proof of concept before developing a final business case for enterprise-wide deployment. Frequently the business case calls for "surgical" application of technologies to specific portions of the system: areas with poor circuit reliability or areas in need of load reduction, for example. KCP&L has been engaged in various demand-side management programs, distributed energy and renewable resources, electric vehicle charging, grid automation, and information technology (IT) systems and infrastructure to support grid modernization and operational efforts. Since this is an on-going process that is a core responsibility of the company, there is no need for any separate evaluation.

8.11 GRID MODERNIZATION, DSM, AND RENEWABLE ENERGY INVESTMENTS

Separately describe and document how the utility's investments in grid modernization, DSM (as evaluated in the current or most recent IRP) and renewable energy will ensure that the public interest is adequately served and that other policy objectives of the state are met (see 4 CSR 240-22.010).

Response:

8.11.1 GRID MODERNIZATION

As described in the response to Section 8.10, KCP&L approaches grid modernization from a portfolio and business case perspective. Modernization efforts are evaluated on the merits of their business case and balanced against alternatives to select the best option for KCP&L stakeholders. KCP&L has been forward thinking in many grid modernization efforts related to system resiliency, reliability and sustainability. KCP&L typically approaches new technology infusion with a pilot for proof of concept before developing a final business case for enterprise-wide deployment. KCP&L business cases for grid modernization must pass the basic test in 4 CSR 240-22-010 to provide "energy services that are safe, reliable and efficient, at just and reasonable rates."

As described in the response to Section 8.10, grid modernization is an ongoing process. It includes both tried and true asset management and maintenance programs as well as infusion of new technology and resources to ensure KCP&L meets the test of providing energy services that are safe, reliable and efficient, at just and reasonable rates. One way to ensure KCP&L meets these goals is by measuring and monitoring several reliability indices. These indices are reported annually to the Missouri Public Service Commission in accordance with 4 CSR 240-23.010. KCP&L also complies with the Electrical Corporation Service Standards and associated reporting requirement s found in 4 CSR 240-23.020.

8.11.2 DSM

The Company's investment in DSM insures that the public interest is served because DSM is evaluated on an equivalent basis to other supply-side and renewable resources in choosing the preferred resource plan. The potential demand-side resources are identified and the potential demand-side programs developed in accordance with 4 CSR 240-22.050 and can be found in Volume 5 of the Company's 2015 triennial integrated resource plan filing. The potential demand-side programs that pass the total resource cost test are then advanced for consideration in the integrated resource analysis as described in 4 CSR 240-22.060 which is detailed in Volume 6 of the Company's filing.

8.11.3 RENEWABLE ENERGY

KCP&L is in full compliance with the Electric Utility Renewable Energy Standard (RES) Requirements as described in 4 CSR 240-20.100 and reported in the annual report filed with the MPSC Commission. Additionally, KCP&L has invested in renewable energy projects above the prescribed amount mandated in the RES requirements due to the economic benefits of wind facilities.

8.12 DISTRIBUTED GENERATION AND MICROGRIDS

Describe and document how the utility's standby rates, cogeneration tariffs, and interconnection standards facilitate the development of customer-owned distributed generation resources and microgrids.

Response:

The form, size, and details that define customer-owned generation resources can vary dramatically from case to case. Within that variation, the Company must ensure safe and reliable service for all customers. To achieve this balance the Company offers a range of tariffs and an interconnection standard to define how a customer may interconnect their distributed generation. The interconnection-related Company tariffs currently available are Stand-by Service for Self-Generating Customers (KCP&L-MO), Special Isolated Generating Plant Service (GMO), Parallel Generation Contract Service

(KCP&L-MO), Cogeneration Purchase Schedule (GMO), and Net Metering Interconnection (KCP&L-MO & GMO). These tariffs outline the terms and conditions associated with service for generation that is, or could be considered distributed generation. Additionally, the Company publishes a Transmission Facility Connection Requirement document to outline the conditions that must be met to interconnect to the company transmission system safely. These documents allow the company to achieve compliance with State statutes, regulations, and Federal PURPA laws.

In whole or in part, these documents form the structure to facilitate interconnection with customer owned distributed generation resources and microgrids. In the event the customer situation is unique and not covered by these documents, the Company can enter into a custom Interconnection Agreement that draws from these documents to accommodate service.

In a recent rate proceeding (ER-2014-0370) the standby rates were discussed and the Commission ultimately ordered KCP&L to complete a study reviewing the standby rate within two years of the effective date of this order. KCP&L is in the process of completing that review and expects it to be completed in September 2017.

8.13 PROVIDING INTERVAL METER DATA

Study feasibility of providing all customers with interval meter data. Review the options available to provide customers with real-time, building level data, sub-meter, line and device level data.

Response:

The Company has plans to make interval usage data available to the majority of our residential and commercial customers There are three technology projects underway within the Company that need to be in place to support the presentation of interval usage data to customers; Automated Metering Infrastructure ("AMI"), Meter Data Management ("MDM"), and Customer Care & Billing ("CC&B") system.

AMI - KCP&L deployed approximately 500,000 AMI meters in its KS and MO jurisdictions during 2014 & 2015 leaving approximately 15,000 customers with non-AMI meters. The customers without AMI meters are predominately located in rural portions of the service territory and there are there are approved plans to deploy AMI meters to these areas in 2019 and 2020. The Company's AMI deployment is described in more detail in Section 8.1 above.

MDM - The MDM system implementation has been completed in preparation for the upgrade of the legacy Customer Information System ("CIS") to CC&B. All AMI meters have been programmed to collect and report interval usage data to the MDM. The MDM system performs validation, verification, and estimation ("VEE") of the meter usage data and becomes the system of record for usage data for all meter reading data.

CC&B – The project is underway to replace two existing CIS systems, one from legacy KCP&L and one from legacy Aquila, with one CC&B system. The CC&B system will implement a new customer web portal that will provide customers access to their usage data. The replacement is a multi-year project and is targeted to be in-service in the first half of 2018.

Once the CC&B customer web portal is implemented, customers with AMI (or other interval) meters will have on-line access to their historical interval usage data provided by the MDM system. The usage data available to customer will typically be 'prior day' usage as there will have some latency due to communicating the data through the AMI system and performing the required MDM VVE processes.

KCP&L currently provides larger commercial customer the capability to receive real-time building level usage data in the form of KYZ pulse data directly from a special meter. This pulse data service is provided with a one-time upfront charge. The customer's building or energy manage system would convert the pulse data into energy usage data for its use.

There are a growing number of options for both residential and commercial customers to obtain real-time, building level, sub-meter, line and device level usage data. Major companies are taking on the smart home market from different angles and products, which is leading to a wide range of smart home capabilities.

Several companies provide low cost energy monitoring products, like The Energy Detective "TED" (http://www.theenergydetective.com/) and Eyedro (http://eyedro.com/) for residential and commercial customers to monitor whole building and branch circuit level usage. Current transformers (CTs) are clamped around the main incoming wires and branch circuits to measure usage. The CTs communicate via power line carrier or WIFI to an energy monitoring hub connected to the internet. The energy usage data can typically be viewed by the customer on any computer or mobile device.

With the advent of Internet of Things ("IOT"), home automation technology represents an enormous emerging market and major companies are competing for automation dominance. This technology is not only accelerating the adoption of home automation, but also energy management technology. Homeowners can now efficiently monitor and regulate their own energy usage and new innovative technologies and applications keep emerging. Nest continues to lead the industry with it 'Rush Hour Rewards' demand response program and 'Time of Savings' energy management based on TOU rate plans. But Apple (Home app), Google (Home) Amazon (Echo) and others are rapidly developing their own systems and devices and integrating with 3rd party devices to allow customers to monitor and control energy usage at a personal level. (http://www.cleantech.com/new-advancements-in-home-energy-management/)

8.14 TIME OF USE RATE AVAILABILITY

Review plans to make Time of Use rates available to all customers.

Response:

The Company believes that appropriately designed time-of-use ("TOU") or other time-variant rate should be part of our portfolio of rates offered to all customers. Making appropriately designed time-variant rates available to all Customers will be dependent on completion of multiple rate studies currently underway and completion of the technology infrastructure needed to implement the new rate structures.

There are three technology projects underway within the Company that need to be in place to support the implementation of TOU and other time-variant rates; Automated Metering Infrastructure ("AMI"), Meter Data Management ("MDM"), and Customer Care & Billing ("CC&B") system.

AMI - KCP&L deployed approximately 500,000 AMI meters in its KS and MO jurisdictions during 2014 & 2015 leaving approximately 15,000 customers with non-AMI meters. The customers without AMI meters are predominately located in rural portions of the service territory and there are approved plans to deploy AMI meters to these areas in 2019 and 2020. The Company's AMI deployment is described in more detail in Section 8.1 of this report.

MDM - The MDM system implementation has been completed in preparation for the upgrade of the legacy Customer Information System ("CIS") to CC&B. More information about the MDM system is provided in Section 8.13 of this report.

CC&B – The project is underway to replace two existing CIS systems, one from legacy KCP&L and one from legacy Aquila, with one CC&B system. The replacement will be a multi-year project and is targeted to be in-service in the first half of 2018.

Multiple studies are underway within the KCP&L and GMO companies to explore TOU and other dynamic rates and evaluate their demand side management ("DSM") potential. These studies will provide more understanding of the role of dynamic rates and help determine an appropriate path forward for these rates.

To be more specific, in ER-2014-0370 the Commission ordered KCP&L to complete a study regarding the redesign of its time-of-use rates within two years of the effective date of that order. That date would be September 15, 2017.

Similarly, in ER-2016-0156, the Commission ordered GMO to study time-of-use rates for GMO including time-of-use residential and SGS rates, critical peak rates, Electric Vehicle time-of-use rates for stand-alone charging stations, time-of-use rates applicable to Electric Vehicle charging associated with an existing account, Real Time Pricing, Peak Time Rebates, and other rate types which could encourage load shifting/efficiency. GMO will propose rates based on this study no later than its next rate case or rate design case.

Finally, there is work is underway in the DSM Potential Study being performed for the next triennial IRP filing. The Potential Study is evaluating residential TOU as well as other rate designs that could be used by the Company a means to provide additional energy efficiency and peak load management.

As these studies have not been completed, it is unclear what the appropriate path forward will be for making TOU rates available to all KCP&L customers. KCP&L plans to use the findings of these studies to develop TOU and other rate options for consideration in future rate or rate design cases that could be implemented after CC&B go-live in 2018.

8.15 DISTRIBUTED GENERATION RESOURCES

Discuss plans to increase deployment of distributed generation resources, including, but not limited to, net metering limitations, interconnection procedures, and billing practices for solar customers.

Response:

In its 2015 Triennial IRP analysis the Company evaluated several supply side resources technologies (including solar, wind, biomass, landfill gas, and fuel cells) that have varying potential to be deployed as utility initiated, distributed generation resources. Through the planning process, distributed generation resources must prove to be cost effective or provide benefit to customers. To meet the solar requirements of the MO RES, the Company did pass on the solar photovoltaic (PV) fixed flat-plate technology to the integrated resource analysis.

In 2016 and as directed by the IRP preferred plan, GMO completed construction of the Greenwood solar generation facility, a small utility scale (3MW) facility connected to the GMO distribution grid. In addition to furthering the Company's commitment to renewable energy, the facility is providing the Company hands-on solar operation and maintenance experience while gaining a better understanding of how larger penetrations of distributed solar generation will impact the distribution grid.

As discussed in Section 8.12, the Company offers a range of tariffs and an interconnection standard to define how a customer may interconnect their distributed generation. While the Company is committed to renewable energy and understands the potential benefits of distributed generation, customer deployment is driven by customer choice and is commonly driven by factors outside of the Company's control. Therefore, the Company's policies and procedures are in place to comply with relevant MO rules and regulations and to be ready to help guide customer interconnection to the Company system.

Missouri regulations 4 CSR 240-20.060, Cogeneration, establishes the requirements for utility programs pertaining to small power producers and cogeneration facilities as defined by the Public Utility Regulatory Policies Act ("PURPA"). KCP&Ls current standby (Schedule SGC) and parallel generation (Schedule PG) tariffs and interconnection requirements comply with these regulations.

Missouri regulations 4 CSR 240-20.065, Net Metering, establishes the standards for interconnection of qualified renewable generating units of 100kW or less. KCP&L's current Net Metering Interconnection Application Agreement (Schedule NM) complies with these regulations.

Missouri regulations 4 CSR 393-1030, Renewable Energy Standard, establishes the portfolio requirement for all electric utilities to generate or purchase electricity generated from renewable energy resources with at least two percent of each requirement being derived from solar. Subsection 3 of this rule specifies the requirements for solar rebates for new or expanded solar electric systems sited on customers' premises. KCP&L's current Solar Photovoltaic Rebate Program tariff complies with these regulations. However, KCP&L is expected to reach the rebate commitment cap by the end of the year.

Multiple rate studies are underway within the KCP&L and GMO companies to explore rate-related topics. To be more specific, in ER-2014-0370, the Commission acknowledged that standby rates are important to combined heat and power ("CHP") projects and ordered KCP&L to complete a study of issues regarding standby rate tariffs within two years of the effective date of that order. That date would be September 15, 2017. As these studies have not been completed, it is unclear what the appropriate path forward will be for KCP&L's standby and other distributed generation related tariffs. KCP&L is committed to promote policies to achieve cost effective DG and will utilize the information gleamed from these studies to inform the best path forward.

8.16 UNCERTAIN FACTORS INCLUSION

For purposes of its triennial IRP filing to be made in 2018, include the following as uncertain factors that may be critical to the performance of alternative resource plans in accordance with 4 CSR 240-22.060(5)(M):

(1) Foreseeable emerging energy efficiency technologies;

(2) Foreseeable energy storage technologies; and

(3) Foreseeable distributed generation, including, but not limited to, distributed

solar generation, combined heat and power (CHP) and micro-grid formation.

Response:

These factors will be addressed in the 2018 Triennial filing.

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[i] Dates are estimated based on a December 2015 Commission approval of the programs.