KANSAS ELECTRIC POWER COOPERATIVE, INC.

600 S.W. CORPORATE VIEW

TOPEKA, KS. 66615

INTEGRATED RESOURCE PLAN

SUBMITTED AUGUST 22, 2016

TO THE

WESTERN AREA POWER ADMINISTRATION

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Executive Summary

Overview of KEPCo

In compliance with Western Area Power Administration's (WAPA) Planning and Management Program, Kansas Electric Power Cooperative, Inc. (KEPCo) respectfully submits the following Integrated Resource Plan (IRP).

KEPCo is a not-for-profit generation and transmission cooperative (G&T), headquartered in Topeka, Kansas. KEPCo was incorporated in 1975 to provide its nineteen Member distribution cooperatives with a reliable power supply at a reasonable cost.

KEPCo provides the total power requirements for seventeen Member Cooperatives and total power requirements for specific delivery points for two Member Cooperatives. These two cooperatives are also members of Sunflower Electric Power Corporation, a G&T in Hays, Kansas. KEPCo Member Cooperatives provide service to approximately 130,000 member meters and maintain nearly 46,000 miles of electric distribution line.

The combined service territory of the KEPCo Member Cooperatives covers most of the rural area in the eastern two-thirds of Kansas, stretching 350 miles from east to west and 200 miles from north to south, and covering a wide range of physiographic regions.

KEPCo would like to emphasize that 52% of its generation resource mix does not emit any greenhouse gas. This percentage will increase even more as KEPCo's new solar generation comes on-line and as KEPCo continues to share in the attributes of additional renewable energy investment made by the area utilities for which KEPCo has purchase power contracts with. This percentage of non-greenhouse emitting resources will prove to be valuable and advantageous to KEPCo as the industry continues upon its current carbon-constrained pathway.

KEPCo's power supply resources include a six percent ownership in the Wolf Creek Generating Station. Wolf Creek is a reliable nuclear power plant that has provided dependable base load power since it began commercial operation in 1985. The unit has a total rated reliable capacity of 1164 megawatts (MW). KEPCo's share of power to the grid is 70 MW. The plant has a lifetime capacity factor of approximately 85% and furnishes approximately 23% of KEPCo's energy requirements. KEPCo solely owns the Sharpe Generating Station, a peaking facility that is comprised of ten, 2 MW Caterpillar diesel generators that can be remotely operated from KEPCo headquarters. KEPCo also owns a 3.5% ownership interest (30 MW) of latan 2, a supercritical850 MW coal-fired generating facility located in Weston, MO. KEPCo is in the early stages of constructing a one megawatt solar facility that is located in Benton, Kansas. The solar facility is expected to be operational by December 2016. KEPCo has hydropower purchases equivalent to 100 MW from the Southwestern Power Administration, and 13 MW from the Western Area Power Administration, plus partial requirement power purchases from regional utilities. KEPCo uses the transmission system of the Southwest Power Pool (SPP) to deliver the power. KEPCo is a member of the SPP and participates in the planning and expansion of the system within Kansas.

The economy of the service territory is primarily agricultural, with the wide variety in the physical landscape of the service territory resulting in a considerable diversity in the type of agriculture and commercial load that each Member Cooperative serves. The growth that was realized in previous years in the oil and gas industry has been greatly diminished. The per barrel price of oil has reached a level that has caused many producers to decrease, or in some cases, cease operations, thus decreasing the associated loads at many of KEPCo's Member cooperatives.

Several years ago, the geology of southeastern Kansas led to the development of coal bed methane extraction, a form of natural gas, in that region. At that time, there was a benefit to those Member cooperatives in areas where pipelines and compressor stations were located. Today, as stated earlier, the decline in the price of oil and natural gas is also accompanied by a decrease in the production of methane.

The growth in energy sales over the next ten years is forecasted to be an average of 0.7% annually. The somewhat slight degree of increase is influenced by two factors; continued production price pressure on the oil and natural gas industry, thus limiting load growth in these industries; and further expansion and growth of residential renewable energy and energy efficiency products and services.

In January 2021, two current KEPCo Member cooperatives will no longer receive energy from KEPCo, due to their decision not to renew their respective all requirements power contracts. These two cooperatives account for 29 MW of demand and 175,500 MWh of energy sales.

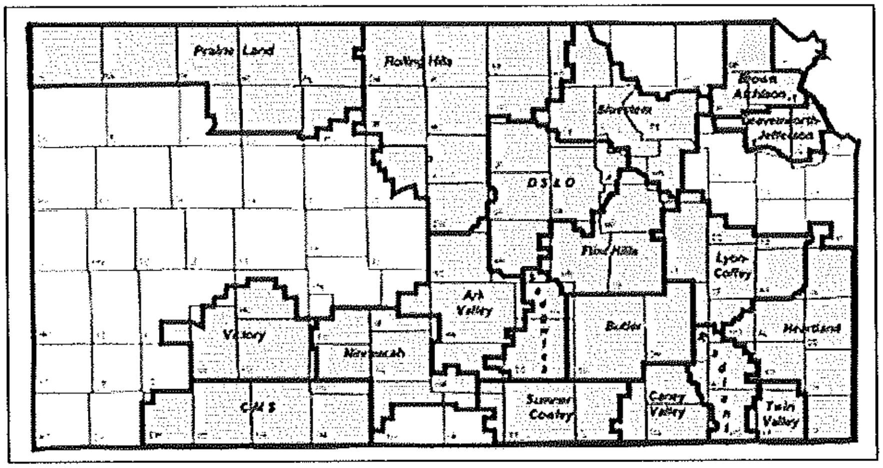
The graphs of the KEPCo Demand Forecast and the KEPCo Energy Forecast on page 6-19 of the Burns & McDonnell Resource Planning Study illustrate the two Member cooperatives not renewing their respective all requirements power contracts. After a decline in both load and energy sales in January 2021, which is depicted in the graphs, both graphs show a demand increase and energy sales increase of 0.7% annually.

KEPCo Board of Trustees

KEPCo is governed by a Board of Trustees representing each of its nineteen members The KEPCo Board of Trustees meets regularly to establish policies and act on issues that often include recommendations from working committees of the Board and KEPCo staff. The Board also elects a seven-person Executive Committee which includes the President, Vice President, Secretary, Treasurer, and three additional Executive Committee members.

KEPCo Member Distribution Cooperatives

The following are the nineteen Member cooperatives that receive service from KEPCo and a map illustrating each of the nineteen Members service territories.



Ark Valley Electric Cooperative Association, Inc.
10 E. 10th Street
South Hutchinson, KS 67505
Miles of Line: 2,083

Bluestem Electric Cooperative, Inc.
614 E. U.S. Highway 24
Wamego, KS 66547
Miles of Line: 2,846

Brown-Atchison Electric Cooperative Association, Inc.
1712 Central
Horton, KS 66439
Miles of Line: 1,107

Butler Rural Electric Cooperative Association, Inc.
216 S. Vine Street
El Dorado, KS 67042
Miles of Line: 2,038

Caney Valley Electric Cooperative Association, Inc.
401 Lawrence
Cedar Vale, KS 67024
Miles of Line: 1,749

CMS Electric Cooperative, Inc.
509 East Carthage
Meade, KS 67864
Miles of Line: 2,615

DS&O Rural Electric Cooperative Association, Inc.
129 W. Main Street
Solomon, KS 67480
Miles of Line: 2,460

Flint Hills Rural Electric Cooperative Association, Inc.
1564 S. 1000 Road
Council Grove, KS 66846
Miles of Line: 2,551

Heartland Rural Electric Cooperative, Inc.
110 N. Enterprise Drive
Girard, KS 66743
Miles of Line: 3,810

LJEC
507 N. Union
McLouth, KS 66054
Miles of Line: 1,574

Lyon-Coffey Electric Cooperative, Inc.
1013 N. 4th Street
Burlington, KS 66839
Miles of Line: 2,493

Ninnescah Electric Cooperative Association, Inc.
20112 W. U.S. 54
Pratt, KS 67124
Miles of Line: 2,120

Prairie Land Electric Cooperative, Inc.
1101 West Hwy. 36
Norton, KS 67654
Miles of Line: 6,968

Radiant Electric Cooperative, Inc.
100 N. 15th
Fredonia, KS 66736
Miles of Line: 1,489

Rolling Hills Electric Cooperative, Inc.
122 W. Main
Mankato, KS 66956
Miles of Line: 6,383

Sedgwick County Electric Cooperative Association, Inc.
1355 S. 383rd Street West
Cheney, KS 67025
Miles of Line: 1,158

Sumner-Cowley Electric Cooperative, Inc.
2223 North A Street
Wellington, KS 67152
Miles of Line: 2,000

Twin Valley Electric Cooperative, Inc.
501 Huston
Altamont, KS 67330
Miles of Line: 960

Victory Electric Cooperative Association, Inc.
3230 N. 14th
Dodge City, KS 67801
Miles of Line: 2,795

Wholesale Rate Competitiveness
KEPCo's wholesale rate, per the 2016 G&T Accounting & Finance Association annual directory (2015 data), was 73.68 mills. Sunflower Electric Power Corporation, a G&T headquartered in Hays, KS. had an average rate of 53.92 mills. Corn Belt Power Cooperative, a G&T headquartered in Humbolt, IA. had an average rate of 64.50 mills. Oglethorpe Power, a G&T headquartered in Tucker, GA. had an average rate of 66.36 mills.

The following are KEPCo's wholesale rates for the years 2010 thru 2014.
2010 – 66.33 mills
2011 – 74.52 mills
2012 – 80.43 mills
2013 – 75.77 mills
2014 – 76.57 mills

Load Growth
KEPCo's load forecast was based on a recent projection for KEPCo's demand and energy requirements through 2025. During this ten-year time period, KEPCo energy sales are projected to increase at an average annual rate of 0.7% over the next ten years, based on normal weather conditions. As stated earlier, the slight degree of increase is influenced by price pressure in the oil and gas industry and the continued growth of energy efficiency measures and residential renewable energy.

Coincident Peak (CP) demand is expected to increase 0.7% between 2016 and 2020 and then the "baseline" CP resets in 2021 as a result of the two cooperatives not renewing their respective all requirements power contracts, and then continues to increase by 0.7% over the remaining forecast period.

KEPCo realized 2.2 million MWh of energy sales in 2015 with a peak demand of 433 MW. Approximately 47% of KEPCo Member Cooperative 2015 energy sales were in the Residential customer class. This class is expected to increase by an average of 0.3% annually over the forecast period.

The Small Commercial class accounted for approximately 23.9% of Member Cooperative energy sales in 2015. Small Commercial energy sales are expected to increase at an average rate of 0.7% annually.

Large Commercial sales accounted for 21% of 2016 energy sales.

Sales in the Irrigation, Street Lighting and Public Authority customer classes accounted for approximately 4.3% of total sales in 2016.

Load Forecast
A load forecast was performed in 2015 using an Econometric Method. The load forecast was incorporated in the Resource Planning Study conducted by Burns & McDonnell which is substantial part of KEPCo's IRP.

Peak Reduction Programs
KEPCo operates a Load Management program designed to reduce peak load. In 1990, KEPCo adopted rates to encourage peak demand reduction and also began a Load Management program that involves issuing peak alerts to Member Cooperatives, who in turn provide incentives to large and small commercial customers to reduce usage during peak periods.

In some cases, Member cooperatives use remotely controlled devices to cycle irrigation pumps, oil well pumping, electric water heaters and central air-conditioners to reduce peak demand. In 2001, KEPCo implemented a state-of-the-art Energy Management and Supervisory Control and Data Acquisition (EMS/SCADA) System which has enabled KEPCo to provide real time monitoring of load data to its Member Cooperatives. KEPCo's current rate design defines CP as a week-day peak. Depending on weather patterns, load management efforts can reduce week-day demand by as much as 30 to 34 MW.

Beginning in 2015 and continuing into 2016, nine KEPCo Member cooperatives installed distributed generation resources to decrease the peak demand on KEPCo's system. The number of Member cooperatives utilizing distributed generation is expected to increase over the next few years.

Demand-Side Management

KEPCo continues to employ its Demand-Side Management Program for peak MW reduction. The following are the MW saved, savings in purchase power costs (PPC), and expenditures to achieve those savings, for 2011 thru 2015.

	2011	2012	2013	2014	2015
MW Saved	34	31	33	31	30
PPC Saved	$1,905,000	$1,723,000	$1,956,000	$1,928,000	$1,870,000
Cost of Savings	$319,000	$235,000	$238,000	$298,000	$247,000

As stated earlier, it is important to note that approximately 52% of KEPCo's energy resource mix does not produce any greenhouse gas emissions (nuclear, wind and hydroelectric). However, KEPCo recognizes the heightened political pressure and environmental concerns to reduce greenhouse gas emissions. One of the simplest and most cost effective ways to reduce emissions, for a utility, is to reduce energy consumption. KEPCo's HVAC rebate program follows the guidelines and thresholds established by Energy Star. And in 2015, the Department of Energy raised the efficiency factor for electric water heaters to .95. KEPCo's rebate program follows the efficiency guidelines under Energy Star and The Department of Energy. KEPCo, on average, provides rebates for 687 water heaters and 289 heat pumps (air source and ground source combined) annually. To date, KEPCo has provided rebates for over 6,300 heat pumps and over 18,500 water heaters.

Renewable Energy Considerations

Kansas has been identified as one of the windiest areas in the United States and thus has a potential for substantial wind energy development. The state of Kansas was under a Renewable Portfolio Standard (RPS) for approximately six years. Through 2015 legislation, the RPS was abolished and the utilities in Kansas agreed voluntarily to develop renewable resources totaling 20% nameplate capacity of each electric utilities peak load by 2020.

Since KEPCo is a relatively small power supplier without a 24-hour system operation and real-time scheduling capability, KEPCo contracts with a third party for energy management services. Since wind is an intermittent resource, the most economical and reliable method for KEPCo to participate in developing wind resources has historically been through the integrated mix of wind energy in its purchase power agreements. KEPCo, in its agreements with Westar and Sunflower, includes the ability to receive energy generated from wind resources as a part of the power supply mix. This partnering ensures that KEPCo is able to help contribute to the development of wind resources in Kansas in an economical and responsible manner.

KEPCo is also in the early stages on constructing its first utility-scale solar array, a one megawatt solar facility in Benton, KS. The facility is scheduled to be operational by December 2016.

Regulatory Oversight
KEPCo was granted a limited certificate of authority in 1980 to act as a Generation & Transmission public utility.

In 2009, afforded by a law passed the same year, the KEPCo Board of Trustees voted unanimously for KEPCo to self-regulate its rates through its member-owner Board. KEPCo continues to be regulated by the KCC as it pertains to the wholesale transaction of electricity from one utility to another.

KEPCo is also subject to requirements of the Rural Utilities Service (RUS), a department of the United States Department of Agriculture. RUS is KEPCo's primary lender and mortgage holder and as such, must approve changes in rates, loans, and other significant aspects of KEPCo's operation. KEPCo must also meet financial matrix thresholds to remain in compliance with RUS' mortgage requirements.

Plan Components
In March of 2016, Burns & McDonnell completed KEPCo's Resource Planning Study. This plan evaluates KEPCo's future power supply requirements and satisfies the majority of requirements set forth in the regulations regarding information to be included in the IRP. The plan is included in its entirety under Tab 1.

Environmental Impact of KEPCo Solar Facility
This project is a one megawatt (ac) nameplate capacity electricity generating facility that uses solar irradiance as a fuel source (solar farm). As such, there will not be a release or consumption of any material, substances or waste that would be considered dangerous or hazardous. The project has an expected life of at least 25 years. At the end of the useful life of the facility, KEPCo may elect to replace the exhausted panels with new panels and continue to operate the solar farm. If KEPCo does not elect to continue operation but rather decommission the facility, KEPCo will restore the property to its original condition.

Intergovernmental review was initiated by KEPCo as it pertains to the construction and operation of the solar array. KEPCo has received a letter from the Kansas State Historic Preservation Office (KHPO) in accordance with the Kansas Department of Health and Environment's (KDHE) requirement for a Notice of Intent for Stormwater Runoff from Industrial Activity. KHPO states that there are no historic properties within the boundaries of the project site and KHPO has no objection to the implementation of the project.

A letter was submitted to the United States Department of the Interior Fish and Wildlife Service and a response was received back from the Department. To address the questions posed by the Department in their response letter, KEPCo submits that KEPCo has retained the services of Bartlett and West Engineers to develop a Stormwater Pollution Prevention Plan, per KDHE guidelines, that will be implemented during the construction of the array. In addition, the aforementioned letter from KHPO states there is no concern as it relates to stormwater runoff. The amount of heat generated by a panel will be the equivalent of the heat generated from an automobile sitting under sunlight. Although the letter from Fish and Wildlife references questions about migratory birds and birds mistaking the array for a body of water, Fish and Wildlife did not express an objection. KEPCo is currently researching method(s) to mitigate the possibility of birds mistaking the array for a body of water. The Fish and Wildlife letter also questions water usage. Water is not used in the production of electricity from a solar array. KEPCo will rely upon natural occurrences (rain and snow) to clean the solar panels. In the event that the panels need to be manually cleaned, KEPCo will rent a truck with a water container to clean the panels. Water usage, if there is any, will not affect stream flow and the panels will not affect rainfall runoff.

KEPCo submitted a letter to the Kansas Department of Wildlife, Parks, and Tourism regarding the construction and operation of the array and received a response stating that the Department finds no significant impacts to crucial wildlife habitats and therefore, no special mitigation measures are recommended. The project will not impact any public recreational areas, nor could the Department document any potential impacts to currently-listed threatened or endangered species or species in need of conservation.

Public Participation

KEPCo solicited public involvement in the IRP by placing an ad in the Kansas Country Living magazine and 27 newspapers within and surrounding KEPCo's service territory. The Kansas Country Living magazine is distributed to all KEPCo Member Cooperatives. Please see Tab 2 for a copy of the ad and a list of the selected newspapers.

KEPCo did not receive any public comments regarding the IRP. However, KEPCo has and continues to seek the recommendations from its Board of Trustees, in regards to power supply and generation resources. KEPCo's Board of Trustees is comprised of a manager from each Member cooperative and a Trustee from each cooperative. The Trustees serve on their respective Member cooperative board and are owners (customers) of each respective cooperative. In addition, the energy consulting company Energy+Environmental Economics, or "E3", was retained to facilitate a Strategic Planning meeting with KEPCo staff and the Board of Trustees at KEPCo's July 2016 Board meeting. Many topics were discussed, such as generation choices, energy efficiency, and purchase power agreements, among others

At KEPCo's August 2016 Board meeting, a formal strategic plan was delivered to the Board of Trustees for their review and recommendations.

On August 18, 2016, the KEPCo Board of Trustees approved the WAPA IRP. See Tab 3 for the Board Resolution approving the IRP.

Goals and Implementation

Consistent with KEPCo's mission statement is the goal for KEPCo to continue to provide the most economical and reliable power supply possible. To this end, KEPCo has chosen to manage market exposure and fuel volatility by securing a diverse mix of purchase power agreements with local and regional suppliers to supplement its owned resources. The contract with Westar Energy runs until 2045; the contract with Sunflower runs until 2020, and the contracts with SWAPA and WAPA run until 2031 and 2054 respectively. KEPCo, through energy management services provided by Westar, also participates in the SPP Integrated Market.

As a wholesale provider of electricity to member distribution cooperatives that ultimately supply electricity to retail members, KEPCo's efforts toward energy conservation and energy efficiency must be in concert with its member cooperatives. KEPCo works with its Member Cooperatives collectively and on an individual basis to create and administer beneficial programs.

Specific goals include:

Given the efficiency requirements to qualify for a rebate have increased, and KEPCo subsequently predicting the amount of rebates will level off, KEPCo has established a benchmark of 575 water heaters and 215 heat pump rebates annually as its goal.

KEPCo will continue to pursue additional improvements to its Load Management Program. Over the past five years, KEPCo has been able to shed an average of 32 MW each year and KEPCo will use this figure as a benchmark for subsequent years.

KEPCo will continue to evaluate the incremental increase of renewable energy into its energy portfolio on an economic and reliability basis.

KEPCo will continue to evaluate the feasibility of acquiring additional cost effective generation resources as opportunities are presented.

KEPCo will continue to support initiatives introduced by the Kansas Legislature that promote energy efficiency, as long as the initiatives do not adversely economically impact the consumers in the rural areas of Kansas.

BURNS McDONNELL

Resource Planning Study

KEPCo

Kansas Electric Power Cooperative, Inc.

Project No. 87230

August 2016

August 15, 2016

Mr. Les Evans
Senior Vice President and COO
Kansas Electric Power Cooperative
600 SW Corporate View
Topeka, KS 66615

Re: Resource Planning Study

Dear Mr. Evans:

Kansas Electric Power Cooperative (KEPCo) retained Burns & McDonnell Engineering Co. (Burns & McDonnell) to conduct a Resource Planning Study (Study). The objective of this Study was to investigate long range supply options while taking into account expiration dates of current contracts. In addition, this Study presented the potential impacts of the Clean Power Plan and other regulations on KEPCo's power supply.

A specific focus of this Study was to evaluate potential power supply options at the expiration of the Sunflower Power Purchase Agreements (PPA) in 2020. Results from the Study indicate that there are other power supply alternatives, such as combined cycle or peaking resources, that may be more economical than the current pricing available under the existing Westar PPA or Sunflower PPA. KEPCo may consider further investigation of potential power supply options to replace the Sunflower PPA.

Burns & McDonnell is pleased to submit our report to KEPCo detailing the results of the Study. It has been a pleasure to assist KEPCo with this evaluation. If you have any questions regarding the information presented herein, please feel free to contact me at 816-822-3459 or mborgstadt@burnsmcd.com.

Sincerely,

Mike Borgstadt, PE
Project Manager

Resource Planning Study

prepared for

Kansas Electric Power Cooperative, Inc.

Topeka, Kansas

Project No. 87230

August 2016

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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LIST OF FIGURES

LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
§	section
AEO	Annual Energy Outlook
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BAT	Best Available Technology Economically Achievable
BLR	balance of loads and resources
BMcD	Burns & McDonnell Engineering Company, Inc.
BPT	best practicable control technology currently available
BTA	best technology available
Btu	British thermal unit
BYOD	Bring Your Own Device
CAIR	Clean Air Interstate Rule
CATR	Clean Air Transport Rule
CCGT	combined cycle gas turbine
CCR	Coal Combustion Residue
CEIP	Clean Energy Incentive Program
CEMS	continuous emissions monitoring system
CFR	Code of Federal Regulations
cm	centimeter
CO	carbon monoxide
CO_2	carbon dioxide
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
CWIS	cooling water intake structures
DC	District of Columbia
DLN	Dry Low NO_x

Abbreviation	Term/Phrase/Name
DOE	Department of Energy
DVC	dynamic voltage control
EE	energy efficiency
EGU	Electric Generating Unit
EIA	Energy Information Administration
ELG	effluent limitation guidelines
EPA	Environmental Protection Agency
EPC	Engineer, Procure, Construct
ERCs	emission reduction credits
FGD	flue gas desulfurization
FGMC	flue gas mercury control
FIP	Federal Implementation Plan
fps	feet per second
FTE	full time equivalent
g	Earth's gravitational pull
GE	General Electric
GHG	Greenhouse Gas
GT	gas turbine
GTG	gas turbine generators
GW	gigawatt
GWh	gigawatt hour
HDPE	high-density polyethylene
HHV	higher heating value
hr	hour
HRSG	heat recovery steam generator
HVAC	heating, ventilation, and air conditioning
IDC	interest during construction
IM	impingement mortality

Abbreviation	Term/Phrase/Name
IRR	internal rate of return
KDHE	Kansas Department of Health and Environment
KEPCo	Kansas Electric Power Cooperative, Inc.
kW	kilowatt
kWh	kilowatt hour
L	liter
lb	pound
LCS	load control switch
LED	light emitting diode
LHV	lower heating value
LTSA	Long Term Service Agreement
m	meter
MATS	Mercury and Air Toxics Standards
MDNR	Missouri Department of Natural Resources
mg	milligram
MGD	million gallons per day
MM	million
MMBtu	million British thermal units
MW	megawatt
MWh	megawatt hour
N/A	not applicable
NAAQS	National Ambient Air Quality Standards
NESHAPs	National Ambient Air Quality Standards
ng	nanogram
NLT	no later than
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NPDES	National Pollutant Discharge Elimination System

Abbreviation	Term/Phrase/Name
NPV	net present value
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standards
O&M	operation and maintenance
O_2	oxygen
O_3	ozone
OEM	original equipment manufacturer
PCT	programmable communicating thermostat
PE	Professional Engineer
PM	particulate matter
$PM_{2.5}$	fine particulate matter
POTWs	publicly owned treatment works
PPA	power purchase agreement
ppb	parts per billion
ppm	parts per million
PSES	Pretreatment Standards for Existing Sources
PSNS	Pretreatment Standards for New Sources
PV	photovoltaic
PW	Pratt & Whitney
RACT	Reasonably Available Control Technology
RE	renewable energy
RH	relative humidity
RHR	Regional Haze Rule
SCGT	simple cycle gas turbine
SCR	selective catalytic reduction
sec	second
SEC	Securities and Exchange Commission
SIP	State Implementation Plan

Abbreviation	Term/Phrase/Name
SO_2	sulfur dioxide
SPP	Southwest Power Pool
Study	Resource Planning Study
Sunflower	Sunflower Electric Power Corporation
SWPA	Southwestern Power Administration
T&D	transmission and distribution
U.S.	United States
ug	microgram
USD	United States Dollar
VOC	volatile organic compounds
WAPA	Western Area Power Administration
Westar	Westar Energy

STATEMENT OF LIMITATIONS

In preparation of this Study, Burns & McDonnell Engineering Company, Inc. (BMcD) has relied upon information provided by Kansas Electric Power Cooperative, Inc. (KEPCo). While BMcD has no reason to believe that the information provided, and upon which BMcD has relied, is inaccurate or incomplete in any material respect, BMcD has not independently verified such information and cannot guarantee its accuracy or completeness.

Estimates and projections prepared by BMcD relating to performance, construction costs and operating and maintenance costs are based on experience, qualifications, and judgment as a professional consultant. Since BMcD has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractor's procedures and methods, unavoidable delays, construction contractor's method of determining prices, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding, and market conditions or other factors affecting such estimates or projections, BMcD does not guarantee the accuracy of its estimates or predictions. Actual rates, costs, performance, schedules, etc., may vary from the data provided.

1.0 EXECUTIVE SUMMARY

1.1 Introduction

Kansas Electric Power Cooperative, Inc. (KEPCo) is an electric power cooperative providing 19 members capacity and energy. KEPCo's members cover approximately two-thirds of the state of Kansas. KEPCo provides energy and capacity to its members through owned resources and power supply contracts. KEPCo has power purchase agreements with Westar and Sunflower. The Westar contract is set to expire in 2045. The Sunflower contract is set to expire in 2020. The goal of this effort was to evaluate mid-term to long-term power supply options that may be available to KEPCo after expiration of the Sunflower contract. New build resources, owned partially or solely by KEPCo, were considered. Additionally, impacts of environmental regulations were evaluated to determine potential impacts to KEPCo's existing power supply resources.

KEPCo requested that Burns & McDonnell Engineering Company, Inc. (BMcD) perform a resource planning study to assess the options that may be available to KEPCo for providing reliable, low cost, and environmentally compliant power to its members (Study).

1.2 Study Organization

This Study is organized into several sections as follows:

- Section 1.0 Executive Summary: Provides an executive summary and an introduction of the Study.
- Section 2.0 Electric Power Industry Review: Provides a general review of the overall electric power industry.
- Section 3.0 Regulatory Review: Provides a detailed discussion of the environmental regulations that are promulgated or proposed regarding air, water, and waste by-products from power plants.
- Section 4.0 Demand Side Management Analysis: Summarizes existing demand side programs currently being implemented by KEPCo's members and examines other potential programs that may further reduce load requirements.
- Section 5.0 Technology Assessment: Provides detailed discussion and costs associated with the development and construction of new power generation resources.
- Section 6.0 Economic Evaluation: Assesses the overall power supply costs to KEPCo over a 30-year period from 2016 to 2045, and evaluates varying power supply options and futures.

1.3 Conclusions

Based on the analysis conducted herein, BMcD provides the following conclusions:

1. Electric Power Industry Review
   a. The electric power industry continues to be a target of increased regulations regarding water, coal combustion by-products, and air emissions.
   b. Overall, the power industry has experienced continued interest in wind and solar development. This interest is driven by technological advancements, which have lowered costs and increased energy production, as well as subsidies through tax incentives and renewable standards. The development of wind has been particularly robust the Southwest Power Pool.
   c. Specific to KEPCo's power supply, the most immediate area of need will be fulfilling load requirements that are currently served by the Sunflower contract when the contract expires at the end of 2020.

2. Regulatory Review
   a. KEPCo has significant diversity within its power supply portfolio through owned resources and power purchase agreements including coal-fired resources, gas-fired resources, hydroelectric facilities, nuclear generation, and renewables. The units, specifically coal-fired resources, will likely continue to be the target of more stringent environmental regulations associated with water, coal combustion by-products, and air emissions.
   b. Carbon dioxide emission regulations for fossil fueled units, both coal and natural gas, will likely continue to become more stringent over current regulations. Notwithstanding the stay of the Clean Power Plan rule by the U.S. Supreme Court, further regulation is expected regarding carbon dioxide emissions over current rules regardless of the outcome of court rulings on the Clean Power Plan.
   c. As currently written, the Clean Power Plan will require existing fossil fuel fired resources to reduce carbon dioxide by 35 percent in Kansas and 37 percent in Missouri.
   d. Overall utilities are taking a more "holistic" approach to regulatory compliance for current and potential regulations. Westar Energy and Kansas City Power & Light, the operators of KEPCo's major power supply resources, are actively evaluating the impacts of proposed regulations on their units.
3. Demand Side Management Analysis
   a. KEPCo's members already implement several demand and energy conservation programs such as irrigation incentive rates and rebates for heat pumps and water heaters.

   b. Programmable controllable thermostats and electric water heater control switches, two programs that KEPCo's members are not currently implementing, were specifically evaluated regarding the cost and benefits to control demand. The overall payback for these programs is close to 10 years, based on the assumptions herein. The power industry typically focuses on demand programs with a payback period closer to 5 years, but some programs with longer paybacks have been implemented.

4. Technology Assessment
   a. A new resource technology assessment was conducted, evaluating the following new resources:
      i. Natural gas-fired combined cycle, simple cycle, and reciprocating engine power plants
      ii. Renewables consisting of wind and solar
      iii. Battery energy storage
   b. Resources were considered in which KEPCo may have the opportunity to self-develop and build or participate in a larger facility as a minority owner or power off-taker.
5. Economic Analysis
   a. Utilizing the information above, BMcD and KEPCo developed several scenarios to evaluate impacts to KEPCo's power supply. The scenarios focused on near-term and mid-term requirements driven by the expiration of the Sunflower contract. Additionally, potential impacts of the Clean Power Plan were also investigated.
   b. The economic analysis indicates that a new power supply resource would be more economical for KEPCo's power supply portfolio than extending the current Sunflower contract (if available to do so) or expanding the current Westar contract under the current pricing terms to provide power to the load that was once served by the Sunflower contract.
      i. After the expiration of the Sunflower contract, KEPCo will have the need for approximately 45 MW of capacity and energy requirements.
      ii. All three new resources; a combined cycle unit, a simple cycle unit, and a reciprocating engine plant; evaluated were more economical than either of the two power purchase contracts from Westar or Sunflower. The combined cycle resource was the most economical with the simple cycle and reciprocating engine plant following as the second and third most economical, respectively. The combined cycle and simple cycle plants reflect participation in a larger unit, likely developed by others. The reciprocating engine plant would provide KEPCo the opportunity to self-develop the project.
   c. Westar provides a large amount of power to KEPCo under a long-term power supply contract (through 2045). As currently written, the Clean Power Plan will affect the overall power

supply in the state of Kansas, and specifically Westar. Two futures were developed for Westar compliance focusing on the installation of a combined cycle unit or the installation of wind generation and simple cycle capacity.

d. Based on the assumptions herein, compliance with the Clean Power Plan appears to increase KEPCo's overall power supply costs by approximately 10 percent.

6. Recommendations
   a. KEPCo should continue to monitor regulations that have potential to impact their power supply portfolio regarding water, coal combustion by-products, and air emissions.
   b. KEPCo may consider inquiring with its members about implementation of additional demand and energy reduction programs that may be able to reduce costs associated with power supply. If desired, a more robust cost/benefit evaluation, that includes a thorough investigation of potential participation and a customer survey, would be required.
   c. KEPCo may consider next steps in regards to replacing the Sunflower contract including starting development of a new build power plant and/or gathering information or proposals from power producers for capacity and/or energy.

2.0 ELECTRIC POWER INDUSTRY REVIEW

The following provides a review of overall electric power industry trends, the Southwest Power Pool (SPP) energy market, and Kansas Electric Power Cooperative, Inc.'s (KEPCo) current power supply.

2.1 Overall Electricity Industry Trends

The electricity industry continues to be impacted by numerous trends. The following provides a brief discussion of the overall trends that are currently impacting electric utilities and generators.

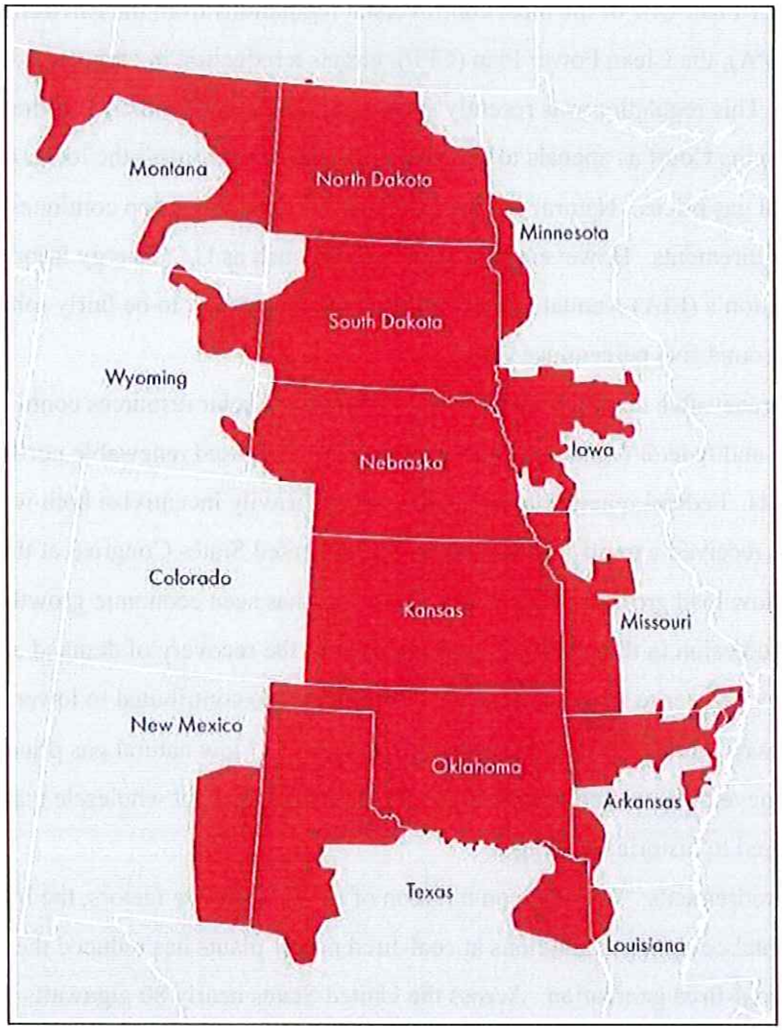
- Environmental regulations: Both federal and state environmental regulating agencies continue to pursue more stringent environmental regulations regarding emissions from power generating facilities, specifically coal-fired power plants.
- Clean Power Plan: One of the most controversial regulations from the Environmental Protection Agency (EPA), the Clean Power Plan (CPP), targets a reduction in carbon dioxide (CO_2) emissions. This regulation was recently stayed (postponed indefinitely) by the United Sates (U.S.) Supreme Court as appeals to the rule work their way through the lower court system.
- Low natural gas prices: Natural gas prices remain low as production continues to outpace demand requirements. However, industry forecasts, such as U.S. Energy Information Administration's (EIA) Annual Energy Outlook (AEO), appear to be fairly robust with price increases around five percent per year.
- Continued renewable development: The use of wind and solar resources continues to increase. Many state and federal regulators continue to pursue increased renewable portfolio and energy requirements. Federal renewable tax credits, which heavily incentivize both wind and solar generation, received a multi-year extension by the United States Congress at the end of 2015.
- Relatively low load growth: While much of the U.S. has seen economic growth since the economic recession in the 2008 and 2009 timeframe, the recovery of demand and energy has been much slower. Increased conservation programs have also contributed to lower load growth.
- Low wholesale market energy prices: The combination of low natural gas prices, increased renewable development, and relatively low load growth has kept wholesale market energy prices low compared to historical averages.
- Coal-fired retirements: With the combination of all of the above factors, the investment in costly environmental compliance solutions at coal-fired power plants has reduced the overall economic benefit of coal-fired generation. Across the United States nearly 80 gigawatts (GW) of coal-fired retirements have occurred, are pending, or have been announced; representing approximately 25 percent of the total coal fleet.

- Increased interest in "firm" natural gas pipeline capacity: A number of factors including coal-fired retirements, recent extreme winter weather, and increased dependence of natural gas for the electric industry have led to increased interest in firm capacity. If firm natural gas transport contracts are required for power generators, it could increase the cost of production significantly.

2.1.1 Southwest Power Pool Energy Market

Southwest Power Pool initiated its integrated marketplace on March 1, 2014. On October 1, 2015, Western Area Power Administration (WAPA), Basin Electric Cooperative, and Heartland Consumers Power District officially joined SPP and were integrated into SPP's transmission system. The SPP market is made up of numerous utilities operating in 14 states as presented in Figure 2-1.

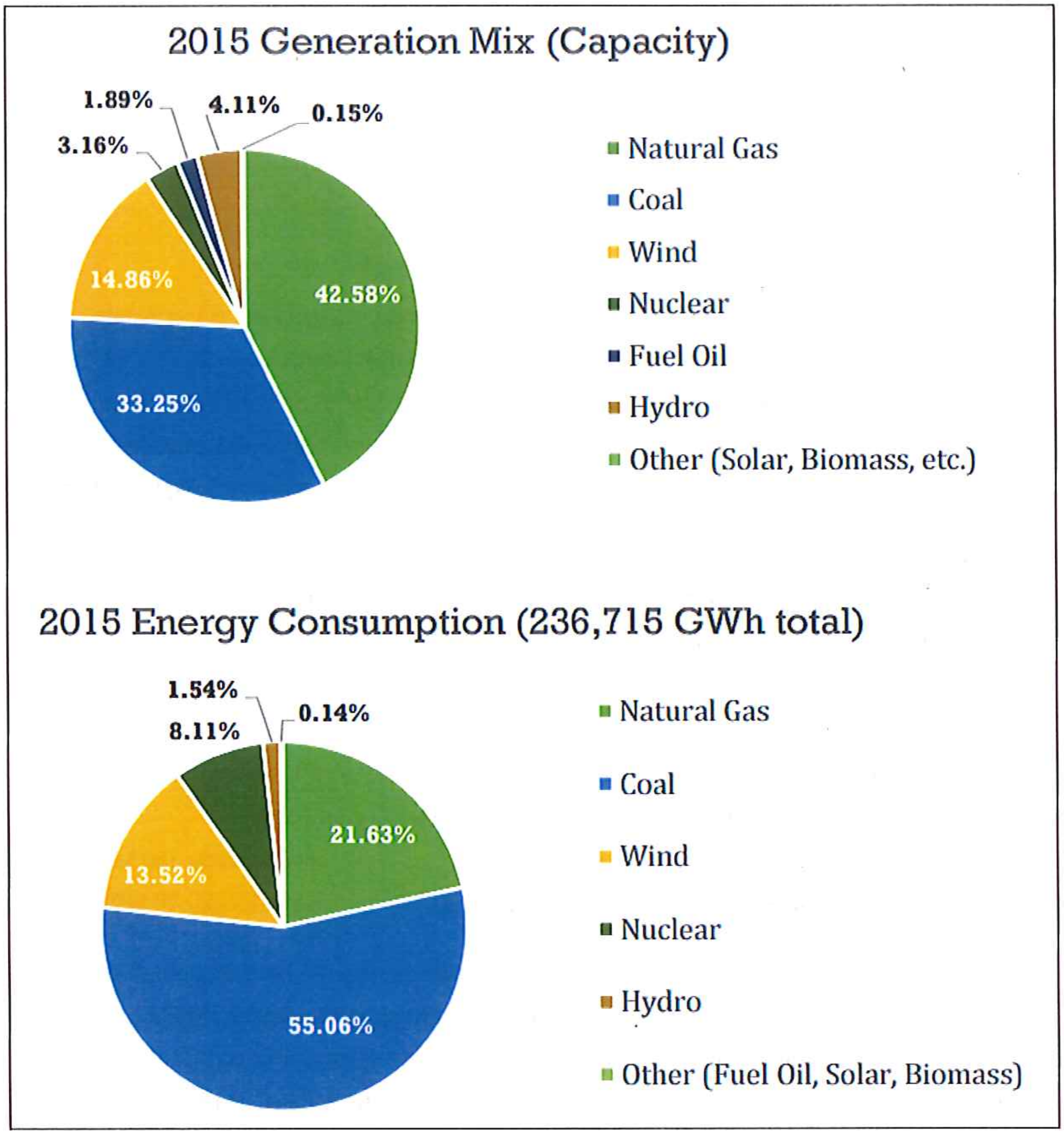
Figure 2-1: SPP Market Area



Source: Intro to SPP Presentation

The SPP market has a wide range of capacity and energy resources including fossil fuel, renewable, and nuclear generation. The 2015 capacity and energy mix of resources within SPP is presented in Figure 2-2.

Figure 2-2: SPP Capacity and Energy Resource Mix



Source: SPP Fast Facts

Wholesale electricity markets are increasingly more mature and utilities are becoming more comfortable with market operations. It is common for utilities today to acquire all of their energy from the market and sell energy from their resources into the market when it is accepted for dispatch. The past few years have seen wholesale energy prices decline significantly when compared to the 2000 to 2008 timeframe. The decline in pricing is due to several factors including:

- Economic downturn and relatively slow economic and load growth
- Significant addition of wind resources (approximately 2 GW in 2007 and approximately 12 GW in 2015)
- Low pricing of natural gas

2.1.2 KEPCo Power Supply Review

KEPCo provides energy and capacity to its members through owned resources and power supply contracts. KEPCo's total coincident peak demand is approximately 430 megawatts (MW) to 440 MW (excluding planning reserve requirements). KEPCo is currently forecasting long-term load growth around 0.7 percent, which is consistent with other utilities' load forecasts in the region. The following summarizes KEPCo's existing power supply portfolio for meeting its load and energy requirements:

- Owned resources
  - Wolf Creek Generation Station (nuclear) 70 MW
  - Iatan 2 Generating Plant (coal) 31 MW
  - Sharpe Generating Station (diesel) 20 MW
- Power purchase agreements
  - Southwestern Power Administration (hydroelectric) 100 MW
  - Western Area Power Administration (hydroelectric) 13 MW
  - Westar Energy (expires 2045) approximately 180 MW
  - Sunflower Electric Power Corporation (expires 2020) approximately 70 MW

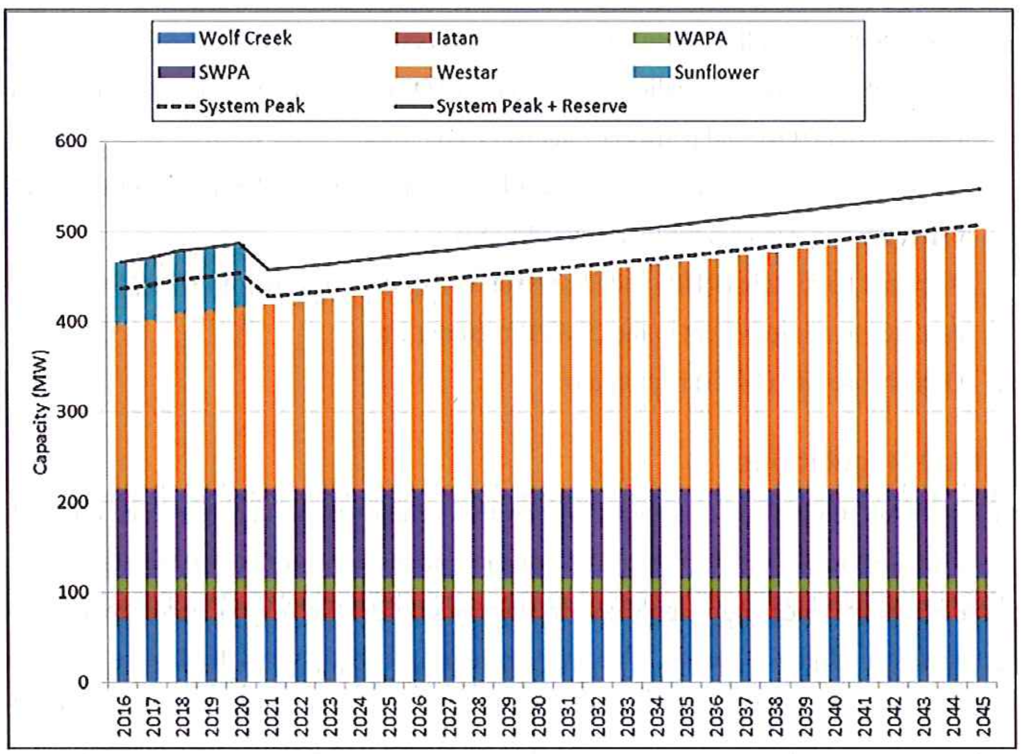
As illustrated by the list above, KEPCo has a diverse power supply portfolio consisting of nuclear, coal, peaking, and hydroelectric resources. Both the Southwestern Power Administration (SWPA) and Western Area Power Administration (WAPA) power purchase agreements (PPA) consist of hydroelectric resources, which are anticipated to operate through the current planning horizon. Furthermore, the Westar Energy (Westar) and Sunflower Electric Power Corporation (Sunflower) PPAs are sourced from energy from each of those utilities fleets, which include coal, natural gas, and renewable resources.

At the expiration of the Sunflower PPA, two of KEPCo's members, which currently purchase power from both KEPCo and Sunflower, are expected to no longer purchase power from KEPCo.

A balance of loads and resources (BLR) based on the load forecast and resources that KEPCo will have available to meet its obligations are presented in Figure 2-3. The reduced load is illustrated in 2021 when the two members are expected to no longer purchase power from KEPCo. Based on existing resources and current load projections, KEPCo will be capacity deficient both in the mid-term and long-term, after the expiration of the Sunflower PPA.

A key objective of this Study was to determine the power supply alternatives available to KEPCo to meet capacity and energy requirements after the expiration of the Sunflower PPA.

Figure 2-3: KEPCo Balance of Loads and Resources



Note: Sharpe Generating Station is assumed to reduce reserve requirements and is not presented as a capacity resource.

3.0 REGULATORY REVIEW

The purpose of the Regulatory Review was to evaluate and summarize the promulgated and proposed environmental regulations that are currently, and may have the potential, to significantly impact the power generation industry in the coming years. Each of these regulations have varying degrees of impact on KEPCo and should be considered in context.

The environmental regulations that were explicitly considered included:

- Effluent limitation guidelines (ELG)
- Coal Combustion Residue (CCR) regulations
- Clean Water Act (CWA) Section 316(b)
- Air regulations
  - Cross-State Air Pollution Rule (CSAPR) requirements
  - National Ambient Air Quality Standards (NAAQS) for sulfur dioxide (SO_2), nitrogen oxides (NO_x), ozone (O_3), and particulate matter (PM)
  - National Emissions Standards for Hazardous Air Pollutants (NESHAPs) for power plants (Mercury and Air Toxics Standards (MATS))
  - Regional Haze Rule (RHR) and Best Available Retrofit Technology (BART) which was assumed to be equivalent to the CSAPR requirements
  - Greenhouse Gas (GHG) regulations

3.1 ELG Regulations

The Clean Water Act (CWA) was enacted in 1972 (with several revisions thereafter) and establishes procedures and requirements for discharges of pollutants into the waters of the United States and regulates water quality standards for surface water discharges. The CWA is applicable to all wastewater discharges regardless of industry sector. The previous revision to the CWA affecting the electric utility industry occurred in 1982 and has since become out of date with the current processes employed by utilities as well as inadequate in regards to its discussion of toxic pollutant discharges of concern.

3.1.1 Background

The EPA is required by the CWA to establish national technology-based effluent limitations guidelines and standards (ELGs) and to periodically review all ELGs to determine whether revisions are warranted. In 2005, the EPA's annual ELG review identified the Steam Electric Power Generating industry for study due to pollutant discharges from power plants utilizing fossil-type fuels and the expectation that these discharges will increase significantly in the next few years as new air pollution controls are installed. A detailed study was conducted and the results were compiled into a report titled "Steam Electric Power Generating Point Source Category: Final Detailed Study" (October 2009). A summary of the findings of the report is as follows:

- The current regulations do not adequately address the pollutants being discharged and have not kept pace with changes that have occurred in the electric power industry over the last three decades.
- Steam electric power plants are responsible for a significant amount of the toxic pollutant loadings discharged to surface waters by point sources.
- Coal ash ponds and flue gas desulfurization (FGD) systems are the source of many of these pollutants.

Upon completion of the study in the fall of 2009, the EPA announced its intent to update the effluent guidelines for the Steam Electric Power Generating Point Source Category. The proposed guidelines were published in the Federal Register on June 7, 2013, the pre-published final regulations were released on September 30, 2015, and the final regulations were published in the Federal Register on November 3, 2015. The final regulation is effective on January 4, 2016. Therefore, the 2016 to 2021 National Pollutant Discharge Elimination System (NPDES) Permit renewal cycle will be the first to contain provisions from the new rulemaking. In general, all facilities are required to be in compliance between November 1, 2018, and December 31, 2023.

Iatan utilizes a zero liquid discharge technology, so compliance with ELG does not appears to be significant. However, as the overall regulations for water-related compliance continue to increase, utilities are beginning to conduct more holistic evaluations of the overall water system at their plants in order to gauge compliance with current regulations and potential concerns in the future. Based on BMcD's understanding, both Westar and Kansas City Power & Light are currently evaluating their respective water systems with this type of holistic approach.

3.1.2 Scope/Applicability of the Final Rule

The finalized ELGs establish new or additional effluent limitations for certain plants within the steam electric industry. The requirements would apply to discharges of wastewater associated with the following processes and byproducts:

- FGD wastewater
- Fly ash transport water

- Bottom ash transport water
- Combustion residuals leachate from landfills and surface impoundments
- Gasification of fuels such as coal and petroleum coke
- Flue gas mercury control (FGMC) wastewater

EPA has established Best Available Technology Economically Achievable (BAT) for existing sources, New Source Performance Standards (NSPS), Pretreatment Standards for Existing Sources (PSES), and Pretreatment Standards for New Sources (PSNS) that apply to discharges of pollutants for the waste streams listed above. These limits will apply to the following facility and discharge types:

- BAT limits established for discharges directly to surface water from existing facilities (except oil-fired and <50 MW)
- NSPS limits established for discharges directly to surface water from new sources
- PSES limits established for discharges to publicly owned treatment works (POTWs) from existing facilities (except oil-fired and <50 MW)
- PSNS limits established for discharges to POTWs from new sources

The discharge requirements would apply to all plants whose generation of electricity is the predominant source of revenue or principal reason for operation, including plants fired by fossil-type fuel (coal, oil, or gas), fuel derived from fossil fuel (petroleum coke, synthetic gas), or nuclear fuel. As stated above, the rules do not apply to existing small generating units (defined as 50 MW or less), existing oil-fired units (units that are fired solely on oil and that do not burn coal or petroleum coke), or generating units owned and operated by industrial facilities not traditionally regulated by the steam electric ELGs. BAT effluent limits will not be added as part of the rule for these units, and the existing discharge limits based on the best practicable control technology currently available (BPT) will remain in place.

For the purposes of this report, Burns & McDonnell will focus only on the impacts resulting from the BAT limits that are being established for existing facilities. The evaluated sites are not believed to currently discharge pollutants to POTWs (other than sanitary wastewater, which is not covered under the ELGs), and the development of any new plants or new sources is beyond the scope of the current study.

3.1.3 ELG Regulations

The final ELGs establish new definitions for FGD wastewater, FGMC wastewater, gasification wastewater, and combustion residual leachate. The final rule also establishes BAT for six waste streams:

fly ash transport water, bottom ash transport water, FGMC wastewater, FGD wastewater, gasification wastewater, and combustion residual leachate.

The final BAT limitation for fly ash transport water, bottom ash transport water, and FGMC wastewater is zero discharge. This limitation is based on dry handling or in the instance of bottom ash transport water, the use of a closed-loop system. A notable exception to this discharge limitation is the allowable use of fly ash or bottom ash transport water as FGD absorber makeup water (untreated). This exception does not apply to FGMC wastewater, so the location of any activated carbon injection, and waste collection, is critical to determine if the wastewater can be used in the scrubber.

The following tables (Table 3-1 through Table 3-4) present the final ELG limits for existing discharges of FGD wastewater, gasification wastewater, and combustion residual leachate, along with the technology basis for each of the limits:

Table 3-1: FGD Wastewater – Chemical Precipitation plus Biological Treatment

Pollutant or pollutant property		BAT effluent limitations	
		Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total	(ug/L)	11	8
Mercury, total	(ng/L)	788	356
Selenium, total	(ug/L)	23	12
Nitrate/nitrite as N	(mg/L)	17	4.4

Table 3-2: Gasification Wastewater - Evaporation

Pollutant or pollutant property		BAT effluent limitations	
		Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total	(ug/L)	4	---
Mercury, total	(ng/L)	1.8	1.3
Selenium, total	(ug/L)	453	227
Total dissolved solids	(mg/L)	38	22

Table 3-3: Combustion Residual Leachate - Surface Impoundments

Pollutant or pollutant property		BAT effluent limitations	
		Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Total suspended solids	(mg/L)	100.0	30.0
Oil and grease	(mg/L)	20.0	15.0

Table 3-4: FGD Wastewater Voluntary Option – Thermal Evaporation

Pollutant or pollutant property		BAT effluent limitations	
		Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total	(ug/L)	4[a]	---[b]
Mercury, total	(ng/L)	39	24
Selenium, total	(ug/L)	5	---
Total dissolved solids	(mg/L)	50	24

a. Limitation is set equal to the quantitation limit
b. Monthly average limitation is not established when the daily maximum limitation is based on the quantitation limit

3.1.4 Prohibition of Co-mingling (Anti-Circumvention Provisions)

The only anti-circumvention provision the EPA included in the final ELGs is in regard to streams that have a zero discharge provision. These streams may not be mixed with any other stream that results in an eventual discharge. As noted previously, the only exception to this anti-circumvention provision is the use of fly ash or bottom ash transport water as FGD makeup water.

While the anti-circumvention provisions do not apply to other waste streams, the ELGs make clear that when any two streams are mixed, the resulting discharge limits should be prorated to account for any dilution effect mixing the streams could have. In essence, mixing is allowed but the eventual discharge limit will be reduced to ensure the resulting discharge will contain the same amount of contaminants as if the mixing had not occurred.

3.1.5 Legacy Wastewater

The final ELGs do not apply to wastewater generated before the compliance date (legacy wastewater). If a new treatment system is added for a particular waste stream to comply with the final rules, such as a tank-based system for FGD wastewater, the effluent from the tank-based treatment system (in compliance with numeric limits outlined in the final rules) could be combined with legacy FGD wastewater and then discharged to surface waters under the prior BPT limits that apply to FGD wastewater. If a utility chooses to combine new FGD wastewater (generated after the compliance date required by the permitting agency) with legacy wastewater prior to treatment in a tank-based system, then the legacy wastewater would have to meet the new discharge limits as well. This same example would apply to all legacy wastewater. Specific state water regulations should also be considered in the ELG evaluation. Some states may have more stringent regulations than the federal ELG rule.

3.1.6 Implementation Schedule

The final rule indicates these limitations do not apply until a date determined by the permitting authority that is as soon as possible beginning November 1, 2018 (approximately three years following promulgation of the final rule), but that is also no later than December 31, 2023 (approximately eight years following promulgation). The rule further describes 'as soon as possible' is November 1, 2018 unless the permitting agency determines otherwise taking into account: 1) time to implement the project, 2) impacts of other regulations, 3) commissioning period (FGD only), 4) or other factors as appropriate.

An exception to the 'as soon as possible' limit application is if prior to the next permit the utility informs the permitting agency it intends to comply with the voluntary alternative FGD limitations (based on evaporation). In this instance the more stringent limit will be deferred until December 31, 2023. Additionally, it is possible that different waste streams may have different compliance dates (40 CFR 423.11(t)).

3.1.7 State and Local Considerations

In addition to the federal ELG rule, some states can have more stringent regulations or regulatory interpretations of the federal ELG rule. Additional discussion with the state agency is recommended to ensure all requirements are known.

3.2 CCR Regulations

In January 2009, the EPA began activity to develop federal rules to regulate Coal Combustion Residuals (CCRs). For the purposes of the regulations, CCRs means fly ash, bottom ash, boiler slag, and flue gas desulfurization materials generated from burning coal for the purpose of generating electricity. After gathering information from a number of utilities across the country, the EPA developed the proposed draft federal CCR rules and published them to the Federal Register on June 21, 2010. In response to numerous comments, the EPA revised the rule and issued a pre-publication final version on December 19, 2014. The final rule was published in the Federal Register on April 17, 2015, and was effective on October 19, 2015.

The final rule establishes a federal minimum standard for disposal of CCR material in surface impoundments and landfills. The rule establishes a framework to address risks of groundwater contamination, structural failures of CCR impoundments, locational issues, and fugitive dust emissions. Any of these CCR units posing an unacceptable risk are subject to closure. Unlike other regulations issued by the EPA, enforcement will be completed under a citizen suit approach. The rule does not require permits, does not require states to adopt or implement these requirements, and EPA cannot enforce the requirements. Instead citizens, environmental groups, or states will enforce the requirements of the rule through lawsuits brought against utilities. Ultimately, the states will likely adopt the regulations into their solid waste management plans and issue permits for new disposal facilities or closure of existing facilities; however, the compliance requirements and schedules for the state program are unknown and for the purposes of this study, the discussion will be focused on the recently issued federal minimum standards. The individual criteria and general requirements are discussed further in the following subsections of this report; however, the applicability of the CCR rule to specific site conditions and impoundments should be reviewed with legal counsel when determining the overall compliance plan for each site.

3.2.1 Applicability

The new regulation applies to new and existing CCR landfills, new and existing CCR surface impoundments, and any lateral expansion of these facilities that engage in the disposal of CCR generated by electric utilities and independent power producers. These requirements affect CCR units both on-site and off-site. In addition, the rule applies to inactive surface impoundments (units no longer receiving CCR but still containing both CCR and water) at active electric utility sites.

The CCR regulation does not apply to:

- CCR landfills that ceased receiving CCR prior to the effective date of the rule
- CCR units at facilities that have ceased producing electricity prior to the effective date of the rule
- CCR generated at facilities that are not part of an electric utility or independent power producer, such as manufacturing facilities, universities, and hospitals
- Fly ash, bottom ash, boiler slag, and flue gas desulfurization materials generated from the combustion of fossil fuels other than coal or from a fuel blend with less than 50 percent coal
- CCR material that is beneficially used
- CCR placement at active or abandoned underground and surface coal mines
- Municipal solid waste landfills that receive CCR material

Inactive units that are closed no later than April 17, 2018, are not subject to any other requirements of the rule, including location restrictions, groundwater monitoring, structural integrity assessment/inspections, and post-closure care.

Impoundments that receive the following flows, but not large volume CCR streams such as fly ash, bottom ash/boiler slag, and FGD wastewater, would not generally be classified as CCR impoundments. Each of these flows are called out in Section 261.4(b)(4)(ii) as uniquely associated low volume wastes and are clearly listed separately from the CCR flows (large volume wastes) identified in Section 261.4(b)(4)(i) in the proposed text for the final rule. These flows could be considered to generally deliver de minimis amounts of CCR material to the receiving body.

- Coal pile runoff
- Boiler cleaning solutions (metal cleaning waste – chemical or nonchemical)
- Boiler blowdown
- Process water treatment and demineralizer regeneration wastes
- Cooling tower blowdown
- Air heater and precipitator washes
- Effluents from floor and yard drains and sumps
- Wastewater treatment sludges

CCR impoundments do not include units generally referred to as cooling water ponds, process water ponds, wastewater treatment ponds, storm water holding ponds, or aeration ponds. These units are not designed to hold an accumulation of CCR.

3.2.2 Location Restrictions

The EPA requires CCR disposal facilities to comply with the following five location restrictions. For existing CCR units, the owner or operator must demonstrate that the specific criteria are met no later than October 17, 2018. These demonstrations must be certified by a qualified professional engineer, and, if these criteria cannot be met, the owner must cease placing CCR in the CCR unit and begin closure within six months, unless the facility can demonstrate that no alternative disposal capacity exists and show progress toward developing alternative disposal capacity.

3.2.2.1 Placement above the Uppermost Aquifer

New CCR landfills, existing and new surface impoundments, and lateral expansions of existing facilities, must be constructed with a base that is located a minimum of five feet above the upper limit of the uppermost aquifer, or demonstrate that there will not be an intermittent, recurring, or sustained hydraulic connection between any portion of the base of the CCR facility and the aquifer due to normal fluctuations groundwater level (including the seasonal high water table).

3.2.2.2 Wetlands

New CCR landfills, existing and new surface impoundments, and lateral expansions of existing facilities should not be located in wetlands unless the owner can demonstrate that the disposal unit design mitigates any potential adverse impact on existing wetlands.

3.2.2.3 Fault Areas

New CCR landfills, existing and new surface impoundments, and lateral expansions of existing facilities shall not be located within 200 feet of faults that have experienced displacement during the Holocene Epoch unless the owner can demonstrate that a smaller setback distance will not affect the structural integrity of the unit.

3.2.2.4 Seismic Impact Zones

New CCR landfills, existing and new surface impoundments, and lateral expansions of existing facilities must not be located in a seismic impact zone unless it is demonstrated that the unit is designed to resist the maximum horizontal acceleration in lithified earth material for the site. Seismic impact zones are defined as areas having a 2 percent or greater probability that the maximum expected horizontal acceleration, expressed as a percentage of Earth's gravitational pull, will exceed 0.1 g in 50 years.

3.2.2.5 Unstable Areas

All CCR landfills and surface impoundments (and lateral expansions of existing facilities) would not be allowed to be located in unstable areas unless it is demonstrated that the integrity of the structural components of the unit will not be disrupted. This is the only location restriction that would apply for existing CCR landfills. Unstable areas include locations susceptible to natural or human-induced events or forces capable of impairing the integrity, including structural components of part or all of the CCR unit, that are responsible for preventing releases from such unit. Unstable areas can include poor foundation conditions, areas susceptible to mass movements, and karst terrains.

3.2.3 Design Criteria

The final rule establishes liner design criteria to help prevent groundwater contamination associated with materials leaching out of CCR disposal units. All new CCR landfills, new CCR surface impoundments, and lateral expansions of CCR facilities must be lined with a composite liner. New CCR landfills must be equipped with a leachate collection and removal system.

The bottom liner technology requirement is a composite liner system consisting of two components: a lower minimum two-foot layer of compacted soil with a maximum hydraulic conductivity of 1x10-7 cm/sec, overlain by an upper minimum 30-mil flexible membrane liner (minimum 60-mil thickness if high-density polyethylene (HDPE) is used). The upper membrane component must be installed in direct and uniform contact with the lower soil component. Alternative liner systems can be used. For those applications, the upper membrane requirements are the same; however, the lower soil layer may be replaced with other components that have the same maximum hydraulic conductivity, such as a geosynthetic clay liner. A qualified professional engineer must certify that the performance of this liner will match that of the specified composite liner. For new landfills, the leachate collection and removal system must be designed and constructed to maintain less than a 12-inch depth of leachate over the composite liner.

The CCR rule does not require existing CCR landfills to be retrofitted for these bottom liner and leachate collection system requirements. Under the CCR rule, existing CCR surface impoundments would have been required to retrofit with composite liners; however, to comply with the final version of the rule the owners must demonstrate their liner status no later than October 17, 2016.

An existing impoundment is considered to be lined if it has one of the following:

- A liner consisting of a minimum of two feet of compacted soil with a maximum hydraulic conductivity of $1x10^{-7}$ cm/sec;
- A composite liner as specified in the previous paragraph; or
- An alternative composite liner system.

If an owner cannot demonstrate that an existing CCR impoundment is lined, the facility will be allowed to continue operation; however, the facility will be subject to the groundwater protection standards identified in the rule. Any statistical exceedance of groundwater constituents of concern above the background levels will require closure of unlined CCR impoundments to begin within six months of identifying the condition, unless the facility can demonstrate that no alternative disposal capacity exists and show progress toward developing alternative disposal capacity. If the existing impoundment is demonstrated to be lined, then the facility will be subject to additional monitoring and potentially corrective action; however, closure will not be required immediately.

3.2.4 Structural Integrity Criteria

All CCR surface impoundments (except for incised and inactive units) are required to comply with technical requirements to maintain the structural integrity of the units. All facilities must be marked with a permanent marker no later than December 17, 2015. All facilities must also conduct a hazard potential classification every five years, with the initial classification completed no later than October 17, 2016. For facilities that are classified with a high or significant hazard potential, an emergency action plan must be prepared to define the areas that would be impacted by a structural failure and to prepare emergency responders and other parties for their responsibilities during a safety emergency. This plan must be established no later than April 17, 2017, and should be updated every five years, with an annual meeting to discuss the plan with the first responders.

For impoundments with dike heights of five feet or more and a total storage volume of 20 acre-feet, or with a dike height of 20 feet or more, the owner must also prepare the following information no later than October 17, 2016:

- History of construction, including an engineering description of the facility size, location, design, etc.
- Periodic structural stability assessment (every five years)
- Periodic safety factor assessments (every five years)

These documents must be certified by a qualified professional engineer and placed in both the operating record and on the CCR website. If the owner does not demonstrate that the required factors of safety are present by the required date, the impoundment must cease receiving CCR and non-CCR flows within six months and begin closure. This deadline is not allowed to extend on the basis of no alternative disposal capacity.

3.2.5 Operating Standards

The following subsections of this report summarize the operational changes required by the CCR rule.

3.2.5.1 Fugitive Dust Control

Owners or operators of CCR units must adopt measures that will minimize CCR from becoming airborne at their facility. Per the CCR rule, an owner or operator will be required to prepare and operate in accordance with a fugitive dust control plan that is updated annually, with the initial plan published no later than October 19, 2015. The owner must identify the fugitive dust control measures that are most appropriate for their site conditions and provide an explanation for how the measures selected are applicable and appropriate. Examples of control measures that may be appropriate include:

- Locating CCR inside an enclosure or partial enclosure
- Operating a water spray or fogging system
- Reducing fall distances at material drop points
- Using wind barriers, compaction, or vegetative covers
- Establishing and enforcing reduced vehicle speed limits
- Paving and sweeping roads
- Covering trucks transporting CCR
- Reducing or halting operations during high wind events
- Applying a daily cover

If the owner operates a landfill, the dust control plan must include procedures to place the material as conditioned CCR, which requires wetting the CCR with water to a moisture content that will prevent wind dispersal and facilitate compaction but not result in free liquids. The plan must also log any citizen complaints received by the owner or operator of the facility and must be certified by a qualified professional engineer.

3.2.5.2 CCR Pile Containerization

CCR piles are defined as any non-containerized accumulation of solid, non-flowing CCR that is placed on the land. Temporary stockpiles must be "containerized" or they will be subject to the requirements for CCR landfills, including the requirements to prepare run-on/runoff control plans, provide fugitive dust control plans, install groundwater monitoring, complete inspections, and meet the unstable areas location restriction. Containerization is not clearly defined in the rule itself; however, the preamble of the rule states "this could include placement of the CCR on an impervious base such as asphalt, concrete, or a geomembrane; leachate and runoff collection; and walls or wind barriers." CCR material that is beneficially used offsite is not a CCR pile; however, any material that is onsite and may be used beneficially in the future would be subject to either containerization requirements or the disposal requirements in the CCR rule.

Burns & McDonnell believes that conveyor stack out areas and other temporary stockpiles of material destined for disposal should be stored on a concrete or similar surface, with walls to control overflow of solids, prevent stormwater run-on across the pile area, and control stormwater runoff. If these and similar measures are implemented, and the material is stored and maintained with adequate moisture to control fugitive dust emissions, then the requirements and the intent of the rule would be satisfied.

3.2.5.3 Run-on/Runoff Controls

All CCR landfills must prepare and implement run-on/runoff control plans no later than October 17, 2016. These controls will prevent flow onto the active portion of the landfill during the peak discharge of the 25-year, 24-hour storm and collect the runoff from the active portion from the same design storm. The plans must document the system design and construction, including engineering calculations and certification by a qualified professional engineer that the requirements of the rule have been met. The plans must be updated every five years at a minimum, and the current copy must be maintained in the facility's operating record and on the CCR website.

3.2.5.4 Hydraulic Capacity Assessments

All CCR surface impoundments (except inactive impoundments closed no later than April 17, 2018) must prepare and implement hydrologic and hydraulic capacity assessments no later than October 17, 2016. The owner must design, construct, operate, and maintain an inflow design flood control system to adequately manage flow into the unit during the peak discharge of the design flood event and collect and control runoff from the CCR unit during the same design storm. The design flood is based on the hazard potential rating:

- For high hazard potential, the design flood is the probable maximum flood
- For significant hazard potential, the design flood is the 1,000-year flood
- For low hazard potential, the design flood is the 100-year flood
- For incised impoundments, the design flood is the 25-year flood

The design flood control system plan must document the system design and construction, including engineering calculations and certification by a qualified professional engineer that the requirements of the rule have been met. The plans must be updated every five years at a minimum, and the current copy must be maintained in the facility's operating record and on the CCR website.

3.2.5.5 Inspection Requirements

The CCR rule requires weekly inspections of all CCR units (except inactive surface impoundments closed no later than April 17, 2018) by a person qualified to recognize specific signs of structural instability and other hazardous conditions by visual observation. These weekly inspections must begin no later than October 19, 2015. Inspections of any CCR unit instrumentation are required at intervals not exceeding 30 days. Further, these facilities (except for incised CCR impoundments or impoundments with berm heights less than 5 feet and/or smaller than 20 acre-feet) are subject to annual inspections by a qualified professional engineer to ensure the design, construction, and operation and maintenance of the impoundment is consistent with generally accepted good engineering standards. The first annual inspection must be completed no later than January 18, 2016. The weekly inspection reports need to be placed in the operating record, while the annual inspection reports must be placed both in the operating record and on the CCR website.

3.2.5.6 Vegetation Maintenance

Existing and new CCR surface impoundments that have vegetated slopes must be maintained so that the vegetation height does not exceed six inches. The intent of this requirement is to prevent the growth of shrubs and other woody plant materials and to improve the reliability of the weekly visual inspections. This will require changes to current operations at many sites, with more frequent mowing efforts required. If the impoundment slopes are not vegetated, they need to be protected with an alternate form of slope protection.

3.2.6 Groundwater Monitoring

All existing CCR landfills and surface impoundments will need to be retrofit with groundwater monitoring networks and have eight samples taken from each well no later than October 17, 2017. These initial samples need to include results for all constituents listed in Appendix III and IV of the rule, as required by Section 257.94(b). The results from Appendix III constituents must be compiled using one of the statistical analysis methods identified in the rule, and the first annual groundwater monitoring report must be prepared and published by January 31, 2018. If there is a statistical exceedance of Appendix III constituents, then further assessments are required to be completed by July, 2018.

If the statistical analysis shows concentrations above the groundwater protection standard, then any unlined impoundments will be required to cease sluicing within six months and either retrofit or close, unless the facility can demonstrate that no alternative disposal capacity exists and show progress toward developing alternative disposal capacity. Landfills and existing lined impoundments would be required to continue assessment monitoring (Appendix III and IV constituents) and potentially initiate corrective action. If contamination is not found, then detection monitoring (Appendix III constituents only) must continue until the completion of clean closure or the end of the post-closure care period.

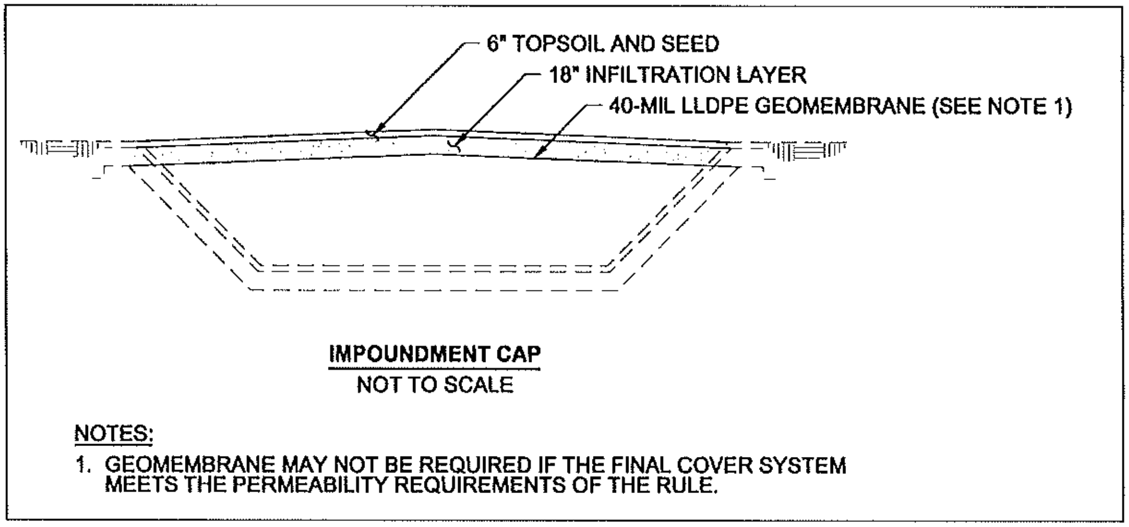
3.2.7 Closure Requirements

The following subsections of this report summarize the closure requirements included in the federal CCR rule.

3.2.7.1 Closure Methods

Closure of CCR units can occur in one of two ways. Clean closure involves removal of CCR solids and decontamination of the CCR unit by eliminating constituent concentrations in the impoundment and the groundwater. Alternatively, the CCR unit can be closed with CCR material in place, which requires drainage and stabilization of wastes in surface impoundments and installation of final cover over CCR material to minimize erosion and infiltration. The federal minimum standards for cover include a permeability less than or equal to that of the bottom liner or 1 x 10^{-5} cm/sec, whichever is less. Depending on the cover soils available onsite, the may require the use of a flexible membrane liner. The rule also requires an 18" infiltration layer above the liner and 6" of topsoil to support the growth of vegetation. See Figure 3 1 for a typical section of an impoundment cap over CCR material.

Figure 3-1: Impoundment Cap – Typical Section



In lieu of closure, the CCR rule allows retrofit of unlined CCR units that do not meet the groundwater protection standards outlined in the rule. To retrofit, a written retrofit plan must be prepared no later than 60 days prior to initiating retrofit activities. Retrofit involves removal of CCR materials and installation of a composite liner.

3.2.7.2 Closure Plans

Closure plans must be developed for all existing CCR disposal facilities no later than October 17, 2016, or prior to initial receipt of CCR for new units. These plans must be certified by a qualified professional engineer and must include a narrative description of how the CCR unit will be closed, an estimate of the maximum inventory of CCR expected onsite over the active life of the unit, an estimate of the largest area to receive cover, and a schedule for completing all of the activities required for closure. If the schedule shows that the standard closure timeframes will be exceeded, then the closure plan must include a description of the site specific factors that would support a request for an extension.

3.2.7.3 Closure Schedules

Closure is generally required within six months of beginning closure activities for landfills and five years for impoundments. The closure may be extended for site-specific impacts associated with dewatering, weather, borrow locations, permits, or other factors. For landfills, owners may request up to two one-year extensions. For impoundments less than 40 acres, the closure schedule may be extended by up to two years. For impoundments greater than 40 acres, the closure schedule may be extended in up to five two-year increments.

3.2.7.4 Alternative Closure Requirements

In the event that closure of a CCR unit is required due to a location restriction or a groundwater contamination resulting from an unlined impoundment, but not a safety factor assessment, the CCR unit may continue to receive CCR material beyond the six-month maximum duration specified in the rule if all of the following conditions are met:

- No alternative disposal capacity exists on-site or off-site. An increase in costs or the inconvenience of existing capacity is not sufficient to support qualification.
- The owner or operator has made, and continues to make, efforts to obtain additional disposal capacity.
- The owner or operator must remain in compliance with all other requirements of the rule, including the requirement to conduct necessary corrective action.
- The owner or operator must prepare annual progress reports documenting the continued lack of disposal capacity and the progress towards the development of alternative disposal capacity.

Once alternative disposal capacity is identified and available, the owner or operator must arrange to use such capacity as soon as possible and then begin the required closure of the CCR unit. If no alternative disposal capacity is identified within five years after the initial request for an alternative closure schedule, the CCR unit must cease receiving CCR and close within the timeframes discussed in Section 2.7.3.

This extension will likely only apply to facilities that have wet sluicing systems and that are either in the process of permitting and constructing a new CCR surface impoundment or converting to a dry ash handling system. It will likely be difficult for utilities that must close a landfill to justify this approach, as the CCR material is probably captured dry and can be hauled to a municipal solid waste landfill or other location while a new landfill is permitted and constructed.

3.2.7.5 Post-Closure Care

For CCR units (other than inactive units) closed by capping the CCR material in place, post-closure care will be required for a minimum of thirty years. This requires maintaining the integrity and effectiveness of the final cover system, correcting any settling, preventing erosion, and maintaining the leachate collection system, if applicable. Also, continuous groundwater monitoring would be required. If at the end of the 30-year period the facility is still in an assessment monitoring program, the owner must continue to conduct post-closure care until the facility returns to detection monitoring.

3.2.8 Recordkeeping, Notifications, and Internet Posting

Utilities will be required to create a CCR website and begin posting documents satisfying numerous criteria with respect to each CCR facility in their fleet. Some documents will need to be posted no later than October 19, 2015. Table 2 1 summarizes the documentation and notifications required, as well as the dates for when this information must be published in order to comply with the federal CCR rule.

Table 3-5: CCR Rule Documentation Summary

Requirement	New CCR Landfills[1]	Existing CCR Landfill	New CCR Surface Impoundments[1]	Existing CCR Surface Impoundments	Inactive CCR Impoundments[2]	Documentation Required - Place in Operating Record and on CCR Website/Notify State Director	Prepared by PE	Initial Date Required for Existing Facilities[3]	Subsequent Submittal Intervals
Location Restrictions[4]:									
Placement Above the Uppermost Aquifer	x		x	x		Demonstrate that unit is located 5' above uppermost aquifer	Yes	October 17, 2018	-
Wetlands	x		x	x		Must not be located in wetlands or must demonstrate no impacts	Yes	October 17, 2018	-
Fault Areas	x		x	x		Must not be located within 200' of Holocene era fault or must demonstrate that structural integrity is sufficient	Yes	October 17, 2018	-
Seismic Impact Zones	x		x	x		Demonstrate that unit is not in a seismic impact zone or that design can overcome horizontal movement	Yes	October 17, 2018	-
Unstable Areas	x	x	x	x		Must not be located in an areas with poor foundation conditions, karst terrains, or that are susceptible to mass movements; or, demonstrate that structural integrity is sufficient	Yes	October 17, 2018	-
Design Requirements:									
Composite Liner	x		x	x		New facilities must meet specified liner criteria. Existing facilities must publish liner details & be classified as either lined	Yes	October 17, 2016	-
Leachate Collection and Removal System	x					New landfills must meet specified leachate collection criteria	Yes	Prior to initial receipt	-
Groundwater Monitoring[4]	x	x	x	x		Install groundwater monitoring network, initiate detection monitoring program	Yes	October 17, 2017	Sample every 6 months, prepare initial annual report NLT 1/31/2018
Structural Integrity Criteria:									
Marker[5]			x	x		Place a 6' high marker adjacent to CCR unit showing ID number, name of the unit, and owner of the unit	No	December 17, 2015	-
Hazard Potential Classification Assessments[5]			x	x		Document the basis of the hazard potential classification	Yes	October 17, 2016	every 5 years
Emergency Action Plan[5]			x	x		If a high or significant hazard potential determined, prepare plan that outlines potential affected areas, emergency contacts, define responsibilities, etc.	Yes	April 17, 2017	every 5 years
History of Construction[6]				x		Publish documentation of location, use, size, and engineering description of existing facility	No	October 17, 2016	with any changes
Construction Plan[6]			x			Publish design documentation with location, use, size, and engineering description of facility	No	Prior to initial receipt	with any changes
Structural Stability Assessments[6]			x	x		Assess and document stability /integrity per specified criteria	Yes	October 17, 2016	every 5 years
Safety Factor Assessments[4,6]			x	x		Calculate safety factors against specified failure conditions	Yes	October 17, 2016	every 5 years
Weekly Inspections	x	x	x	x		Visual inspection of berms/outfalls by a Qualified Person	No	October 19, 2015	weekly
Annual Inspections	x	x	x[6]	x[6]		Visual inspection of berms/outfalls by a Qualified PE, report storage capacity remaining and impounded volumes of water	Yes	January 19, 2016	annually
Other:									
Fugitive Dust Controls	x	x	x	x		Prepare and operate in accordance with fugitive dust control plan	Yes	October 19, 2015	annual report
Run-on, Runoff Controls	x	x				Develop plan to prevent run-on of water into landfill and to capture and treat runoff from landfill during 25-yr 24-hr storm	Yes	October 17, 2016	every 5 years
Hydrologic & Hydraulic Capacity Requirements			x	x		Develop plan/ install system to control inflow from design flood	Yes	October 17, 2016	with any changes
Closure Requirements	x	x	x	x	x[2]	Prepare closure plan with specified narrative, schedule, etc.	Yes	October 17, 2016	with any changes
Post-Closure Care[7]	x	x	x	x		Prepare plan to maintain cover integrity, leachate collection system (if applicable), and groundwater monitoring for 30 years	Yes	October 17, 2016	with any changes

[1]Includes lateral expansions of existing impoundments and landfills

[2]Inactive CCR ponds do not receive additional CCR after October 14, 2015, still contain water and CCR after that date, and must complete closure by April 17, 2018. Intent to close and closure plan must be submitted by December 17, 2015.

[3]Date for new facilities or lateral expansions will generally be required before initial receipt of CCR materials, or within 6 months of sampling efforts beginning

[4]If location restrictions, groundwater protection standards, or specified safety factors cannot be satisfied, impoundments must cease receiving CCR and non-CCR waste streams within 6 months of determination and begin closure/retrofit.

[5]Does not apply to an incised CCR impoundment.

[6]Only required for CCR surface impoundments with a height of 20' or more; or with a height of 5' or more AND a storage volume >20 acre-ft.

[7]Does not apply to CCR surface impoundments that have closed by removing all CCR materials and have verified that groundwater is not contaminated.

Burns & McDonnell has not been engaged to render legal or technical services. The opinions, analysis, and representations made in this attachment should not be construed to be legal advice or legal opinion. Legal advice, opinion, and counsel must be sought from a competent and knowledgeable attorney.

3.2.9 Beneficial Use

With the final CCR regulations, the EPA is not proposing to change the May 2000 Regulatory Determination for beneficially used CCRs. However, the EPA is clarifying what constitutes a beneficial use as follows:

- The CCR must provide a functional benefit;
- The CCR must substitute for the use of virgin material, conserving natural resources that would otherwise need to be obtained through practices such as extraction;
- The use of the CCR must meet relevant product specifications and must not be in excess quantities; and
- For un-encapsulated uses involving more than 12,400 tons of CCR placed on land (in non-roadway applications), the user must demonstrate that environmental releases to the groundwater, surface water, soil, and air are similar to those associated with the use of non-CCR material.

This definition essentially only allows for encapsulated beneficial uses, such as the use of fly ash in concrete or gypsum in wallboard. Un-encapsulated uses for non-roadway applications, such as fills in sand and gravel pits and other mass fills, however, would be considered as disposal and would effectively be prohibited. The EPA is also not proposing to address the placement of CCRs in mines, or non-minefill uses of CCRs at coal mine sites with these regulations. Rather, the EPA will be working with the Office of Surface Mining to develop federal regulations to ensure that the placement of CCRs in minefill operations is adequately controlled.

3.3 Section 316(b) Regulations

Section 316(b) of the Clean Water Act specifies that cooling water intake structures (CWIS) will be located, designed, and operated, and incorporate the best technology available (BTA) to minimize adverse impacts to the aquatic environment. Over the decades since enactment, the adverse impacts have become defined as mortality of fish and shellfish caused by impingement and entrainment. The Final Rule for existing facilities (40 CFR 125 Subpart J) applies to facilities that withdraw more than 2 million gallons per day (MGD) from waters of the United States, of which 25 percent or more is used for cooling purposes.

The Final Rule requires that existing facilities subject to the rule must comply with one of the following seven impingement mortality (IM) reduction options:

1. Operate a closed-cycle recirculating system as defined by the Final Rule (at §125.92)

2. Operate a CWIS that has a maximum design through-screen design intake velocity of 0.5 feet per second (fps);
3. Operate a CWIS that has an actual through-screen intake velocity of 0.5 fps;
4. Operate an offshore velocity cap that is a minimum of 800 feet offshore;
5. Operate a modified traveling screen that the Director determines meets the definition of the rule (at §125.92(s)) and that the Director determines is the best technology available for impingement reduction;
6. Operate any other combination of technologies, management practices and operational measures that the Director determines is the best technology available for impingement reduction; or
7. Achieve the specified impingement mortality performance standard of less than 24 percent.

IM Option 1, IM Option 2, and IM Option 4 are considered pre-approved technologies that require no demonstration or only a minimal demonstration that the flow reduction and control measures are functioning as EPA envisioned. IM Option 3, IM Option 5, and IM Option 6 require more detailed information be submitted to the Director before the Director may specify it as the requirement to control IM.

- IM Option 3: EPA considers this option to be a streamlined alternative. The facility must submit information to the Director that demonstrates that the maximum intake velocity as water passes through the structural components of a screen measured perpendicular to the screen mesh does not exceed 0.5 feet per second.
- IM Option 5: The facility must submit a site-specific impingement technology performance optimization study that must include two years of biological sampling demonstrating that the operation of the modified traveling screens has been optimized to minimize impingement mortality. If the facility does not already have this technology installed and chooses this option, the Director may postpone this study until the modified traveling screens and fish return system are installed.
- IM Option 6: Similar to IM Option 5, the facility must submit a site-specific impingement study including two years of biological data collection demonstrating that the operation of the system of technologies, operational measures, and best management practices has been optimized to minimize IM. If this demonstration relies in part on a credit for reductions in the rate of impingement already achieved by measures taken at the facility, an estimate of those reductions and any relevant supporting documentation must be submitted. The estimated reductions in rate of impingement must be based on a comparison of the system to a once-through cooling system

with a traveling screen whose point of withdrawal from the surface water source is located at the shoreline of the source waterbody.

- IM Option 7: Requires that a facility must achieve a 12-month impingement mortality performance of all life stages of fish and shellfish of no more than 24 percent mortality, including latent mortality, for all non-fragile species that are collected or retained in a sieve with maximum opening dimension of 0.56 inches and kept for a holding period of 18 to 96 hours. Biological monitoring must be completed at a minimum frequency of monthly.

The pre-approved BTA for entrainment is an intake rate commensurate with closed-cycle cooling. The actual BTA for entrainment at a given facility, however, is to be determined on a site specific basis by the agency that issues the facility's discharge permit. The selection of entrainment BTA is based on a cost/benefit analysis of entrainment compliance technologies, including at a minimum, the options to install fine mesh screens and to convert to closed-cycle cooling.

To justify the selection of impingement and entrainment BTA, all subject facilities must submit seven information reports (40 CFR 122.21(r)(2-8)) that describe the source water body, the current cooling water intake system, the current and future status of the facility, and the chosen impingement compliance method. In addition, facilities that have had an actual average cooling water intake rate greater than 125 MGD over the past three years must also submit studies (§ 122.21(r)(9-13)) that will form the basis of the cost/benefit analysis the permitting agency will use to determine BTA for entrainment. These studies are described in Table 3 1.

Addressing the requirements of the § 316(b) Final Rule could require a substantial commitment of resources.

Table 3-6: Section 316(b) Studies Required Under 40 CFR 122.21(r)

§ 122.21(r) Paragraph	Title	Description
All Facilities		
(2)	Source Water Physical Data	Unchanged from Phase I &II rule. Submit data to characterize facility and evaluate type of water body affected.
(3)	Cooling Water Intake Structures Data	Unchanged from Phase I & II rule. Submit data to characterize cooling water intake and evaluate potential for impingement and entrainment of aquatic organisms.
(4)	Source Water Baseline Biological Characterization	Similar to Phase I rule. Characterize biological community in the vicinity of the cooling water intake structure in terms of species composition, vulnerability to impingement and entrainment, and presence of threatened or endangered species.
(5)	Cooling Water System Data	These data used to determine appropriate standards to be applied to a specific facility. Includes narrative description of the cooling operation system and its relationship to intake structures; proportion of intake flow that is used in the system; a distribution of water re-use.
(6)	Chosen Method(s) of Compliance with Impingement Mortality Standard	New rule provides seven compliance options for meeting requirements. Facility must identify its approach for meeting the mortality requirements. Must identify the method for the entire facility or for each intake structure. EPA has eliminated the requirement for a separate impingement mortality reduction plan. Data collection requirements only apply where the facility must demonstrate performance outcomes as further explained in (r) (6).
(7)	Entrainment Performance Studies	Facilities must submit only previously conducted entrainment related studies. Impingement studies, where relevant, are already part of the permit application at 122.21(r) (6). Applicant must submit a description of biological studies conducted at the facility and summary/conclusions. Studies over 10 years old must include a relevancy explanation. Focuses on previous and current studies rather than requiring new studies.
(8)	Operational Status	Submit description of operational status of each unit for which a cooling water intake structure provides water for cooling. Includes age of unit, capacity utilization for last five years (including any outages) and any major upgrades in last 15 years, any uprates, relicensing, decommissioning or replacement plans, and current and future production schedules.

§ 122.21(r) Paragraph	Title	Description
Facilities > 125 MGD		
(9)	Entrainment Characterization Study	Must develop a study that includes a minimum of two years of entrainment data. Would include documentation of data collection period and frequency, identification of organisms found to lowest taxon. Must be representative of the entrainment at each intake and document how the location of the intake in the water body and water column is accounted for. Must include analysis of data to determine total entrainment and entrainment mortality. Will be used in determination of BTA for entrainment for each site
(10)	Comprehensive Technical Feasibility and Cost Evaluation Study	Must submit an engineering study of technical feasibility and incremental costs of candidate entrainment control technologies. Study must include an evaluation of technical feasibility of closed cycle cooling, use of fine mesh screens, reuse of water or alternate sources of cooling water, and any other entrainment reduction technologies identified by the applicant or requested by the director. Must also include a description of all technologies considered. Cost information in both capital costs and in net present value terms with corresponding annual value are required.
(11)	Benefits Valuation Study	Must submit a detailed discussion of the benefits of the candidate entrainment reduction technologies evaluated in (r) (10) and data from (r) (9). Categories of benefits are to be narrative and quantified in physical or biological units and monetized using economic valuation methods, when possible. Peer review of this study is required.
(12)	Non-Water Quality and Other Environmental Impacts Study	Must submit a discussion of changes in non-water quality environmental studies and other factors attributed to technologies or operational measures. Examples include energy consumption, air and noise impacts, potential for plumes, grid reliability, consumptive water use, etc.
(13)	External Peer Review of Study 9-12	Studies required under (r) (10, 11, 12) must be submitted for peer review. Can be submitted as one combined document and panel must be of appropriate background to conduct a combined and complete technical review.

The determination of the § 122.21(r) studies that need to be conducted for each facility was based on the exceedance of the 125-MGD threshold.

Compliance options are evaluated using the following step-wise process:

1. Determine if the facility is already compliant with BTA for impingement and entrainment under options 1, 2, or 3.

2. Determine if the facility has low rates of impingement that could be considered de minimis by the Director.
3. Determine if the facility is eligible for the capacity exemption. The average capacity factor must be less than 8 percent over the past three years.
4. Evaluate the likely efficacy, technical feasibility, and relative costs of the impingement BTA alternatives applicable to open-cycle cooling systems.
5. Evaluate the technical feasibility, capital costs, and other environmental impacts of the BTA alternatives for entrainment of conversion of closed-cycle cooling or using fine-mesh screens.

3.4 Air Regulations

This section outlines the various defined regulations that could impact air emissions from the KEPCo owned facilities. KEPCo owned facilities are well underway on the Mercury and Air Toxics Standards (MATS) rule implementation so there is no discussion for MATS. Although the Clean Power Plan (CPP) was stayed by the Supreme Court in 2016, its ultimate fate is unknown for the next year or two. For this study, BMcD evaluated the CPP requirements before the stay. For the CPP, the final rule requires the state of Kansas and Missouri to develop either a mass based or rate based emissions rate for carbon dioxide (CO_2). Until the state rule is final, no state can finalize their plans. However, this report discusses the current proposed Federal Implementation Plan attributes.

The applicable air regulations and their histories are summarized in the following sections of this report.

3.4.1 Pollutant Interstate Transport

Section 110(a) (2) (D) of the Clean Air Act addresses the interstate transport of air pollutants. This provision applies to each pollutant covered by NAAQS and to all areas of the country regardless of their attainment designation. This section of the act specifically provides that a State Implementation Plan (SIP) must prohibit statewide air pollutant emissions that significantly contribute to a non-attainment or maintenance problem in another state. To address interstate transport issues, the EPA finalized the Clean Air Interstate Rule (CAIR) on March 10, 2005, which required Electric Generating Units (EGUs) to cut SO_2 and NO_x emissions in 27 states, including Kansas and Missouri. The "cap and trade" CAIR rule was challenged in the District of Columbia (DC) Circuit Court and on July 11, 2008, the court ruled that CAIR should be vacated and remanded back to EPA. However, parties to the litigation were granted a rehearing and on December 28, 2008, the Court changed their July 11 order to the extent that it remanded the rules to EPA without vacating them.

In response to the December 28 Court ruling, the EPA proposed the Clean Air Transport Rule (CATR) on July 6, 2010, to reduce interstate transport of SO_2 and NO_x. These pollutants are precursors to ozone (O_3) and fine particulate matter ($PM_{2.5}$). On July 7, 2011, the EPA finalized the CATR as the CSAPR. The final rule was published in the Federal Register on August 8, 2011.

On December 30, 2011, the U.S. Court of Appeals for the DC Circuit stayed CSAPR. The Court vacated CSAPR in August 2012 and directed EPA to continue to implement the CAIR pending the promulgation of a valid replacement. The decision was appealed to the Supreme Court. As a result of the Supreme Court ruling in 2014, EPA's allowance and cost methodology was affirmed and CSAPR was remanded back to the Court of Appeals. In 2014, the Court of Appeals reinstalled CSAPR. EPA began CSAPR's Phase I beginning in 2015. Phase II will begin in 2017. In July 2015, the U.S. Court of Appeals found the EPA erred in certain SO_2 and ozone season NO_x emissions budgets for several states, including Kansas and Missouri. These issues were sent back to EPA for reconsideration, but upheld the remainder of the rule.

The CSAPR is designed to help states achieve compliance with the following NAAQS:

- $PM_{2.5}$ NAAQS set in 1997 (annual standard)
- $PM_{2.5}$ NAAQS set in 2006 (24-hour standard)
- O_3 NAAQS set in 1997

The EPA found that emissions from Kansas and Missouri impact O_3 and $PM_{2.5}$ concentrations in downwind states, so an ozone-season NO_x budget and annual NO_x and SO_2 budget for Kansas and Missouri has been finalized.

However, EPA has proposed additional ozone season restrictions, under the CSAPR, to meet the O_3 NAAQS finalized in March 2008. No action has taken place on the 70 parts per billion (ppb) O_3 NAAQS finalized in 2015. The EPA may address compliance with these NAAQS in a follow-up rule (the "Transport Rule II").

CSAPR does not address the current $PM_{2.5}$ NAAQS finalized in 2012. The EPA may address compliance with these NAAQS in a follow up rule.

3.4.1.1 CSAPR Allowance Allocations

In the CSAPR, the EPA's approach is based on state-wide SO_2 and NO_x emission budgets. Each state's budget consists of the emissions that the EPA estimates will remain after the state has made the reductions required to reduce its significant contribution to non-attainment and interference with maintenance of the relevant NAAQS in other states in an average year. The EPA established each state's budget by estimating unit-level allocations, then totaling the unit-level allocations for each state.

The EPA assumes units that are fossil-fuel fired EGUs greater than 25 MW if they reported data for the CAIR program or the Acid Rain Program. For EGUs that report emissions data to the EPA, the reported annual data (SO_2 emissions, NO_x emissions, and heat input) that was used to develop the allowance allocations was the most recent non-null first quarter, second quarter, third quarter, and fourth quarter emissions and heat input, between 2003 and 2010. The reported ozone season NO_x emissions and heat input that was used was the most recent ozone season data reported to EPA between 2006 and 2010.

Both reported and projected emissions were adjusted by EPA to account for the following:

- Some sources installed SO_2 and NO_x control equipment to comply with the CAIR, but might not operate that equipment if they are not covered by the CSAPR.
- Emissions controls that are expected to be built by 2012 but were not in place during the time period for which the data was reported.
- Emissions controls that may not have operated fully in the projections.
- The year-round operation of post-combustion NO_x controls which may only have operated during the ozone season.

Additionally, the CSAPR rule penalizes states whose actual emissions exceed a pre-determined assurance level allocation. The assurance level allocation is roughly 18 percent to 21 percent above the state's base allocations. If the state's actual emissions exceed its assurance levels, then any facility within the state that also exceeds their assurance levels will suffer a penalty. The penalty is surrender of 2 allowances for every 1 ton emitted over the assurance provision number along with potential fines for non-compliance with Title V provisions. Kansas's and Missouri's SO_2 emissions should decrease due to MATS compliance and announced unit retirements. These actions should reduce the potential for assurance levels to be exceeded.

In the CSAPR, the EPA is directing that each state set aside part of its annual SO_2 and NO_x budget and ozone-season NO_x budget for new units. This set-aside is reflected in EPA's unit-level allowance allocations.

3.4.2 National Ambient Air Quality Standards

The EPA is required to set limits on ambient air concentrations for each criteria pollutant (SO_2, nitrogen dioxide (NO_2), carbon monoxide (CO), O_3, lead, and particulate matter) to protect the public's health and welfare. The EPA is required to review these NAAQS and the latest health data periodically, and modify the standards if needed. On January 22, 2010, the EPA finalized a new 1-hour primary NAAQS for NO_2 (100 ppb). On June 2, 2010, the EPA finalized a new 1-hour primary NAAQS for SO_2 (75 ppb). At this time, the EPA also rescinded the 140 ppb 24-hour SO_2 standard and the annual 30 ppb SO_2 standard.

EPA has identified SO_2 non-attainment areas in the state of Missouri. For those areas that are not attaining the new SO_2 and NO_2 NAAQS, compliance is expected to be required as early as 2017 and 2021, respectively. In order to meet the new SO_2 and NO_2 NAAQS by these timeframes, action may be required sooner at sources found to impact concentrations of these pollutants in non-attainment areas. Demonstrating compliance is based on three years' worth of monitoring data or air dispersion modeling, so states may require emissions controls several years before the compliance date. For ambient air monitoring, once three years of data have been collected, a state may decide to start taking action to achieve attainment. Note that the NO_2 standard is expected to be re-reviewed in 2016, so states may wait until after this review to take action.

EPA has developed a procedure for states to follow in determining non-attainment areas by air dispersion modeling. This guidance was issued in the summer of 2015. Certain large SO_2 sources that emit more than 16,000 tons/year and sources that emit more than 2,600 tons/year and have a 0.45 lb/MMBtu rate or greater have to show through air dispersion modeling that they meet the SO_2 NAAQS by July, 2016. If they are unable to meet that determination, it is unknown if EPA will next require ambient air monitoring or require the facility to reduce SO_2 emissions based on the modeling data. For remaining coal-fired sources, they have until 2017 for NAAQS demonstrations by air dispersion modeling or 2020 if ambient air monitoring is used.

In addition to the new NO_2 and SO_2 NAAQS discussed above, the EPA has tightened the NAAQS for O_3 from 75 ppb to 70 ppb. As a result of this change, the EPA is required to make attainment designations for the new standards by October 2017. Ozone formation is impacted by emissions of volatile organic compounds and NO_x. If the plant is deemed to cause or significantly contribute to an ozone non-attainment area, some form of NO_x control (i.e. Reasonably Available Control Technology (RACT)) could be required for the plant in the 2017 to 2019 timeframe; however, absent any detailed regional air dispersion modeling results, it is impossible to determine what, if any, additional controls will be required. If EPA proposes a new O_3 standard in the near future, attainment with the new standard is expected to be required between 2017 and 2034, depending on the severity of the non-attainment issue.

EPA set the current $PM_{2.5}$ standard on September 21, 2006. At that time, the EPA revised the 24-hour standard, but made no changes to the previous annual standard. Pursuant to an order from the DC Circuit Court in December, 2012, EPA finalized a new $PM_{2.5}$ annual standard which lowered the previous 15 ug/m^3 to a 12 ug/m^3 level. The final rule does not recommend changes to the current 24-hour standard. $PM_{2.5}$ primarily consists of sulfate and nitrate particles which are created from SO_2 and NO_x emissions. Therefore, some form of SO_2 and NO_x control could be required for the plants; however, it is impossible to determine what, if any, additional controls will be required without any detailed air dispersion modeling results. Attainment with the new standard is expected to be required between 2015 and 2031, depending on the severity of the non-attainment issue.

Since the plants are currently located in unclassified areas, no NAAQS related reductions are assumed for KEPCo facilities; however, environmental groups have aggressively challenged Title V renewals on the basis that an agency should not issue a permit renewal unless the facility can demonstrate compliance with all regulations, including the new 1-hour SO_2 and NO_2 NAAQS. To date, the environmental groups have not been successful in their challenges; however, sometime in the future, they may be successful and facilities would be required to demonstrate compliance by ambient air monitoring or air dispersion modeling.

3.4.3 National Emissions Standards for Hazardous Air Pollutants for Power Plants

KEPCo owned facilities are well underway on MATS compliance even though the rule was remanded by the Supreme Court back to the U.S. Court of Appeals regarding the need to consider costs to support the rule.

3.4.4 Regional Haze Rule

On July 1, 1999, the EPA issued the Regional Haze Rule (40 CFR Part 51, Subpart P) aimed at protecting visibility in 156 Federal Class I areas. Subsequently, the EPA issued proposed guidelines for determining Best Available Retrofit Technology (BART), which provides guidance to the States in determining the air pollution controls needed to reduce visibility-impairing pollutants. On July 6, 2005, the EPA finalized amendments to its Regional Haze Rule and its BART Guidelines.

BART is defined as "an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant." BART requirements will apply to facilities that were not yet operating on August 7, 1962 but were in existence (or under construction) on August 7, 1977 (the date of enactment of the Clean Air Act Amendments of 1977) and that have the potential to emit more than 250 tons per year of any visibility-impairing pollutant (SO_2, NO_x, or particulate matter). If any visibility-impairing pollutant is emitted above this threshold level, then that source is BART-eligible. Next, it must be determined whether emissions from a BART-eligible facility are reasonably anticipated to contribute to, or cause, visibility impairment in any Federal Class I area. A BART review is required for each visibility-impairing pollutant.

3.4.5 Greenhouse Gases

On October 23, 2015, two final regulations were published for limiting carbon dioxide emissions from power plants. The first regulation is the Carbon Pollution Emission Guidelines for Existing Electric Generating Units, also known as the Clean Power Plan (CPP) rule. In 2016, the Supreme Court granted a stay of the CPP rule. The case will still be heard in the DC Circuit Court in June, 2016. Once the decision is reached, it is likely to be appealed to the Supreme Court. The rule is stayed until the final decision is made by either the DC Circuit Court or Supreme Court (if it decides to hear the case). The CPP discussion below is based on the final rule, before the stay. The CPP analysis discussed below could change significantly after the final court decision. The second regulation is the Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units. A third proposed regulation was published as the Federal Plan Requirements for Greenhouse Gas Emissions from Electric Utility Generating Units Constructed on or before January 8, 2014, also known as the proposed Federal Implementation Plan (FIP). The Clean Power Plan (CPP) for existing units requires a 32 percent carbon emission reduction from 2005 baseline levels by 2030 and requires fossil fuel fired power plants across the nation, including those in the Kansas and Missouri utility fleets, to meet state specific goals to lower carbon levels. The program sets a glide path beginning in 2022 and has three interim goal periods until the final goal is set for 2030 and beyond. States have the option to accept the FIP or develop their own rate or mass based program. Furthermore, the state must use either an emission standards plan with includes source-specific requirement impacting affected power plants or a state measures plan which includes a mixture of measures implemented by the state.

3.4.5.1 State Plans

By September 6, 2016, each state must either submit to the EPA its initial plan with a request for an extension or final plan. If the state receives an extension, the final plan must be submitted by September 6, 2018. States will then implement plans to achieve the progressive CO_2 emissions reduction over the period of 2022 to 2029, with the final CO_2 goal accountability by 2030.

EPA has proposed a template (FIP) for the states to follow in developing their state plans. The intent of the FIP is to show states an acceptable plan that is immediately approvable by the EPA. However, the states are granted some flexibility in developing their own plans.

3.4.5.2 Mass Based Programs

Under a mass based program, existing coal, oil, and gas boilers and combined cycle units greater than 25 MW, are connected to a utility power distribution system, and provide 219,000 MWh/year to the grid or at least 1/3 of annual net-electric sale to the grid are affected units under the program. According to the Kansas Department of Health and Environment (KDHE), 28 facilities (including several Westar facilities) are affected by the CPP and a 35 percent reduction is required by the rule (2012 to 2030 comparison). EPA will issue allowances to each affected state according to Table 3 or Table 4 of Subpart UUUU of Part 60. For Kansas, the total number of allowances under Table 3 (includes only existing sources) is 198,874,664 tons for 2022 to 2029. This allowance tonnage is divided into three interim periods: 2022 to 2024, 2025 to 2027, and 2028 to 2029. For each interim period, the annual tonnage decreases until the final tonnage goals are reached in 2030. For 2030 to 2031 and every two-year period after, Kansas affected sources can emit 43,981,652 tons. According to the Missouri Department of Natural Resources (MDNR), 21 facilities (including Iatan) are affected by the CPP and a 37 percent reduction is required by the rule (2012 to 2030 comparison). EPA will issue allowances to each affected state according to Table 3 or Table 4 of Subpart UUUU of Part 60. For Missouri, the total number of allowances under Table 3 (includes only existing sources) is 500,555,464 tons for 2022 to 2029. This allowance tonnage is divided into three interim periods: 2022 to 2024, 2025 to 2027, and 2028 to 2029. For each interim period, the annual tonnage decreases until the final tonnage goals are reached in 2030. For 2030 to 2031 and every two-year period after, Missouri affected sources can emit 110,925,768 tons. One allowance is equal to one ton of CO_2 emissions. Allowances can be auctioned or given to affected units. The proposed FIP suggests each facility's allocations be based on either percent MWh produced compared to the total state MWh or by heat input. Excess allowances can be banked for future use. EPA recommends that any state implementation plan (SIP) include provisions for Clean Energy Incentive Program (CEIP) or other set asides and under the mass based program, provisions to prevent "leakage." The CEIP is intended to reward investment in certain renewable energy and energy efficiency projects that commence construction of renewable energy (RE) or operation of energy efficiency (EE), following the submission of the final state plan to the EPA and generate MWh or reduce end use energy demand during 2020 and 2021. EPA will match up to 300 million short tons of CO_2 emissions nationwide for eligible projects. Additional set aside allowances are available for:

1. Units that achieve emission rates lower than a specified standard,

2. Renewable and energy efficiency built/operational after Jan 1, 2013,
3. Transferring coal/oil or gas boiler emissions to existing combined cycle units.

Allowances can be traded inter-state and intra-state.

EPA has two concepts to address leakage under the mass based program. The first concept separates new, modified, or reconstructed sources (Section 111(b) of the Clean Air Act) from existing sources (Section 111(d) of the Clean Air Act). Those allowances are shown in Table 3 of 40 CFR 60 Subpart UUUU. EPA, under law, is not allowed to mix Section 111(b) and Section 111(d) sources. Therefore, this leakage concept only addresses existing sources. Under this program, CEIP and set aside emissions are expected to be included along with existing source emissions that will total the allowances given in Table 3 of Subpart UUUU. For existing units that retire in 2020 and beyond, allowances will continue to be given to the retired unit for a period of two to four years depending on when the unit retires. After that period, the retired unit allowances will go back into the state pool for redistribution under the proposed FIP. The second leakage concept assumes that the state will develop a SIP. Since states can be more stringent than the federal regulations, EPA assumes the states will have the ability to regulate both new and existing sources in the same program. Thus, states would prevent leakage by having an allowance pool as shown in Table 4 of 40 CFR 60 Subpart UUUU. Under this program, Kansas will be allocated 200,960,120 allowances from 2022 to 2029 and 44,441,644 allowances from 2030 to 2031. Missouri will be allocated 505,904,560 allowances from 2022 to 2029 and 112,105,626 allowances from 2030 to 2031.

3.4.5.3 Rate Based Plan

In a rate-based plan, Kansas and Missouri will have to meet the emission goals by enacting a carbon intensity emission limit on each unit. In order to meet the rate based goal, units would be required to use emission reduction credits (ERCs), in the form of MWh, to reduce its overall rate. Each generator type has a limit:

- Coal/oil/gas-fired boilers for steam EGUs — 1,305 lbs of CO_2 per MWh
- Gas-fired combine cycle — 771 lbs of CO_2 per MWh

The CO_2 emission rate is determined as illustrated in the formula below:

$$CO_2\ Emission\ Rate\ (\frac{lbs}{MWh}) = \frac{CO_2\ Emissions\ from\ EGUs\ (lbs)}{Generation\ from\ EGUs\ (MWh) + ERCs\ (MWh)}$$

In order to reduce its emission rate, a generating unit would be required to purchase ERCs to increase the denominator of the formula above (ERCs from wind for example would come emission-free and not impact the numerator).

Therefore, in order for a steam EGUs with a CO_2 emission rate of 2,200 lbs/MWh to comply with the limit, it would be required to secure ERCs equal to approximately 70 percent of its generation. For a natural gas combined cycle unit with an assumed CO_2 emission rate of 1,000 lbs/MWh, it would be required to secure ERCs equal to approximately 30 percent of its generation to meet the rate.

A complex system is described to allow renewable energy (primarily wind and solar), transferring hours from existing coal units to existing natural gas combined cycle units, and energy efficiency (demand side management) to earn ERCs that could be sold to the affected units. New units under the rate based plan would have to meet the new unit emission rates only. No ERCs would be required because EPA believes there is no threat for emissions leakage.

3.4.5.4 Additional Considerations

It should be noted that the concepts for the mass and rate based programs described above are based on EPA's proposed FIP. The final FIP could have different requirements. Also, the state can develop its own SIP which can differ from the FIP. At this time, it is unclear what, if any, deviations from the FIP will be acceptable to EPA. Also, numerous court cases have been filed to stay the CPP. It is uncertain what, if any, changes will occur with the pending court decisions.

3.4.5.5 New, Modified and Reconstructed Units

New fossil fuel fired units will be subject to annual emission limits. For a baseloaded combustion turbine, the annual limit is 1,000 lb CO_2/MWh. For non-base loaded combustion turbines, the annual limit is between 120 to 160 lb CO_2/MMBtu depending on the natural gas/fuel oil operating hours. A new coal-fired plant must meet an annual limit of 1,400 lb CO_2/MWh.

There are also CO_2 limits for modified or reconstructed units. Modified coal units are defined as units that make a physical or operation change that results in a 10 percent CO_2 increase in hourly emissions. Those units would be limited to the best historical annual CO_2 rate but no more stringent than 1,800 lb/MWh for units greater than 2,000 MMBtu/hr heat input. For smaller units less than 2,000 MMBtu/hr heat input, the modified unit limit is 2,000 lb/MWh.

Reconstructed units are defined as units that make capital improvements that are 50% or more of the cost of a new unit. Reconstructed coal units have the same limits as modified units. Reconstructed combined cycle units must meet new unit rates (1,000 lb CO_2/MWh).

3.5 Overall Regulator Review Summary

Westar and Great Plains Energy owned facilities are subject to a host of environmental regulations described above. With each of these companies operating in the Southwest Power Pool, decisions have to be made to retrofit, repurpose, or retire units. A significant part of the decision is to determine how competitive the units will be after installation of compliant pollution controls and/or changes in operations. These analyses are complicated and require significant time and effort for each individual fleet unit. Some of the pertinent information may be contained in the company's Securities and Exchange Commission (SEC) disclosures. Burns & McDonnell reviewed both companies' 2015 10-K and 10-Q documents. There is discussion of each of the above mentioned environmental regulations. Some generalized cost information is provided for some of the environmental costs however, some environmental costs have not been included mainly due to the lack of time to evaluate new rules. Additionally, no unit specific costs have been included. Both companies state that the new Clean Power Plan rule compliance costs could be material. However, no specific plans have been discussed in the SEC disclosures.

4.0 DEMAND SIDE MANAGEMENT ANALYSIS

The following section provides a discussion of the demand side management and energy efficiency programs that KEPCo is currently implementing and an evaluation of other programs that may be available to KEPCo to help reduce is peak demand and overall energy consumption.

4.1 Existing Programs

KEPCo's members have implemented several energy efficiency and demand side management programs. These include energy efficiency programs such as heat pump and water heater rebates and demand response programs such as irrigation incentive rates. Further discussion of these programs is provided.

- Heat Pump Rebates – These programs offer various rebates for different heat pump technologies. Air source heat pump rebates are $100 to $200 per ton based on the efficiency of the unit. The installation of geothermal heat pumps offer a bigger rebate due to the greater cost for installing these units. Geothermal heat pump rebates are $250 per ton, with a minimum unit size of 2 tons.
- Water Heater Rebates – KEPCo's members offer a variety of rebates for water heaters, HVAC systems, and smaller appliances. Water heater rebates are $100 to $200 depending on whether the unit has a lifetime warranty or not.
- Other Rebates – A couple of KEPCo's members also offer rebates for heating and cooling systems and smaller appliances. Caney Valley offers $100 rebates for replacing non-electric dryers and ranges with electric appliances. CMS offers rebates for electric heating and cooling systems.
- Irrigation Incentive Rates – These rates have been designed to have a higher demand charge during peak hours. This pricing incentivizes farmers to run their irrigation equipment during off-peak hours.

4.2 Additional Programs for Consideration

Burns & McDonnell considered a number of additional energy efficiency and demand response programs that other utilities have successfully implemented.

Energy efficiency programs involve a reduction in overall energy consumption, typically through the installation of more efficient appliances and devices. These programs typically involve a one-time expense from the utility, in the form of a rebate or other incentives. Possible energy efficiency programs include:

- Lighting replacements or fixture upgrades

- Electric water heater upgrades to more efficient units
- Refrigerators and freezers upgrades to more efficient units
- Heating and cooling (air conditioning) upgrades to more efficient units
- Large motors and irrigation pumps
- Home energy audits – additional insulation/weatherization
- Garage refrigerator removal program

Demand response programs are intended to reduce system or sub-system load during peak demand hours. These programs require control and communications technology along with ongoing administration and management from the utility. Possible demand response programs include:

- Programmable communicating thermostats (PCTs)
- Dynamic rates such as time-of-use rates, critical peak pricing, peak time rebates, etc.
- Voluntary customer load reduction/shifting in response to utility request
- Interruptible rates
- Dynamic voltage control (DVC)
- Energy storage (batteries, compressed air, pumped hydro, etc.)

For this assessment, only demand response programs were considered as a potential option for reducing peak demand. While energy efficiency programs could potentially reduce peak demand in the short term, the lack of control from a utility perspective makes them harder to predict in the long term.

4.3 Potential Demand Side Management Programs

As part of this Study, Burns & McDonnell examined several load control program options that KEPCo may consider or expand upon to reduce peak demand. Programs were evaluated based on potential effectiveness and costs.

4.3.1 Programmable Communicating Thermostats

Residential programmable communicating thermostats (PCTs) can be deployed by a utility for demand response events. Typical programs involve the utility installing a PCT in a customer's home, usually at no charge to the customer. This is the cost model included in this analysis but recently vendors have established models where customers can buy their own device and voluntarily enroll it in a utility demand response program, often referred to as a Bring Your Own Device (BYOD) program. The customer then agrees to participate in a select number of event days per year, where their thermostat is remotely adjusted by the utility. Event days are typically communicated at least 24 hours in advance, and customers have the ability to opt-out of an event at their discretion. This program is best suited for summer applications when air conditioning load is greatest. For the analysis purpose, 15 event days with 4 hours per event is considered.

Table 4-1 presents the potential load reduction based on various participation rates. A participation rate of 10 percent is typically considered a highly successful program.

Table 4-1: PCT Potential Controlled Load

KEPCo Residential Customers (Approx.)	80,000	80,000	80,000
A/C Saturation Rate	84%	84%	84%
No. of Air Conditioners	67,200	67,200	67,200
Participation Rate	5%	10%	15%
No. of Homes Participating	3,360	6,720	10,080
Diversity Rate	60%	60%	60%
No. of Air Conditioners Controlled	2,016	4,032	6,048
Air Conditioner Demand (kW)	1.0	1.0	1.0
Total Controlled Load (kW)	**2,016**	**4,032**	**6,048**

Cash flow analysis was performed on the PCT program. The analysis estimates initial investment costs, ongoing annual costs and all monetary benefits over a 15-year period. Costs estimated for this analysis include both capital and operating costs. The costs considered in this analysis are:

- Device deployment costs
- Marketing and customer education costs
- Vendor administration and maintenance fees

The direct benefits to KEPCo that were considered in this analysis are:

- Wholesale energy savings (conservation)
- Peak demand savings (based on the Westar PPA)

A summary of costs and savings results for direct benefits to KEPCo for the PCT program are presented in Table 4-2. A more detailed results table is included in Appendix A.

Table 4-2: PCT Program Cost-Benefit Evaluation

KEPCO Costs		15-YR TOTAL
PCT Deployment Cost	$	1,612,800
PCT Program Design	$	75,000
PCT Messaging/Network ($/device/year)	$	134,400
PCT Marketing & Education	$	627,617
PCT Vendor Admin & Maintenance Fee	$	537,958
Total Cost	**$**	**2,987,775**
Contingency (15%)	**$**	**448,166**
Total Cost with Contingency	**$**	**3,435,942**
KEPCO Savings		15-YR TOTAL
Peak Demand Savings from Residential PCTs	$	4,696,171
Wholesale Energy Savings from Residential PCTs	$	-
Total KEPCO Direct Benefits	**$**	**4,696,171**
Net Cost/Benefit	**$**	**1,260,230**
IRR ($)		**8.8%**
NPV (2016$)	**$**	**326,994**
Simple Payback Period		**10 yrs**

The PCT program has a positive economic benefit over a 15-year period, with an internal rate of return (IRR) of 8.8 percent and a simple payback of 10 years, assuming an 8 percent participation rate. There is no assumed energy savings from the PCT program. It primarily shifts the energy usage from the event period to after the event period.

4.3.2 Water Heater Load Control Switches

Load control switches (LCSs) can be installed on customer electric water heaters for demand response events. KEPCo currently has a water heater LCS program that could be expanded to achieve greater load reduction for demand response. Electric water heating load control could be applicable in both the summer and winter.

Table 4-3 presents the potential reduction based on various participation rates. A participation rate of 10 percent is typically considered a highly successful program.

Table 4-3: Water Heater LCS Potential Controlled Load

KEPCo Residential Customers (Approx.)	80,000	80,000	80,000
Electric Water Heater Saturation Rate	22%	22%	22%
No. of Electric Water Heaters	17,778	17,778	17,778
Participation Rate	5%	10%	15%
No. of Homes Participating	889	1,778	2,667
Diversity Rate	12%	12%	12%
No. of Electric Water Heaters Controlled	107	213	320
Electric Water Heater Demand (kW)	4.5	4.5	4.5
Total Controlled Load (kW)	**480**	**960**	**1,440**

Cash flow analysis was performed on the Water Heater LCS program. The analysis estimates initial investment costs, ongoing annual costs and all monetary benefits over a 15-year period. Costs estimated for this analysis include both capital and operating costs. The costs considered in this analysis are:

- Device deployment costs
- Marketing and customer education costs
- Vendor administration and maintenance fees

The direct benefits to KEPCo that were considered in this analysis are:

- Wholesale energy savings (conservation)
- Peak demand savings (based on the Westar PPA)

A summary of costs and savings results for direct benefits to KEPCo for the Water Heater LCS program are presented in Table 4-2. A more detailed results table is included in Appendix A.

Table 4-4: Water Heater LCS Program Cost-Benefit Evaluation

KEPCO Costs	15-YR TOTAL
Water Heater LCS Deployment Cost	$ 426,667
Water Heater LCS Program Design	$ 75,000
Water Heater LCS Messaging/Network ($/device/year)	$ 35,556
Water Heater LCS Marketing & Education	$ 627,617
Water Heater LCS Vendor Admin & Maintenance Fee	$ 537,958
Total Cost	**$ 1,702,797**
Contingency (15%)	**$ 255,420**
Total Cost with Contingency	**$ 1,958,217**

KEPCO Savings	15-YR TOTAL
Peak Demand Savings from Water Heater LCSs	$ 2,970,709
Wholesale Energy Savings from Water Heater LCSs	$ -
Total KEPCO Direct Benefits	**$ 2,970,709**
Net Cost/Benefit	**$ 1,012,492**

IRR ($)	**14.6%**
NPV (2016$)	**$ 433,898**
Simple Payback Period	**8.4 yrs**

The Water Heater LCS program has a positive economic benefit over a 15-year period, with an IRR of 14.6 percent and a simple payback of 8.4 years, assuming an 8 percent participation rate. There is no assumed energy savings from the PCT program. It primarily shifts the energy usage from the event period to after the event period.

4.3.3 Other Potential DSM/EE Programs

In addition to the programs evaluated above and the existing programs that KEPCo and its members currently implement, the following provides other potential programs that may be of interest to KEPCo and its members. No specific analysis was conducted on these programs as it is difficult to ascertain specific opportunities and benefits for these programs without detailed survey data. However, these types of programs may provide KEPCo and its members additional energy savings and may warrant further evaluation in the future should KEPCo or its members determine there are sufficient benefits.

4.3.3.1 LED Lightbulb Rebates

Lighting accounts for 11 percent of household energy consumption. Switching from incandescent to light-emitting diode (LED) lightbulbs may result a significant reduction in energy consumption. Residential lighting is one of the most effective contributors for energy efficiency programs. Quality LED lightbulbs are durable, offer better lighting conditions, and have 25 times rated life spans compared to incandescent lightbulbs. Additionally, LED lamps offer dimming capabilities that can provide additional energy savings. KEPCo can encourage residential customers to switch to LED lightbulbs by offering coupons for LEDs.

4.3.3.2 Commercial DSM/EE Program

Commercial lighting is one of the major sources for electricity use. Existing light fixtures in the commercial buildings can be retrofitted with efficient lightbulbs. Similar to a residential LED lightbulb rebate program, a commercial light rebate program can be implemented to reduce energy consumption. KEPCo can provide incentives based on savings ($/kWh) or rebate for each fixture or lightbulb. Around 15 to 55 percent savings can be achieved through commercial lighting programs. The savings varies based on the lighting, usage, etc.

Commercial building operations and performance programs provide another approach for energy efficiency in commercial buildings. Building tune-up, retro-commissioning, monitoring based commissioning, and strategic energy management programs are some ways to reduce energy in commercial buildings. In these programs, the buildings are assessed and adjusted for optimal efficiency. With a real-time monitoring system, the building's energy usage can be monitored and adjusted in real-time. KEPCo can offer building assessments and rebates for energy saved. The savings potential from these programs range from 5 to 12 percent.

Commercial heating, ventilation, and air conditioning (HVAC) programs offer advanced equipment, improved controls, and maintenance program. The existing HVAC system in the commercial building can be replaced with efficient systems such as variable refrigerant flow HVAC, improved chilled water system, ground source heat pump system, natural gas boiler, etc. A "Pay for Performance" program can be implemented where KEPCo can provide incentives per kWh or kW saved. An average up to 20 percent savings can be achieved based on program and technology.

4.3.3.3 Industrial DSM/EE Program

Industrial energy efficiency can provide additional energy savings to the utility. As the transmission and distribution (T&D) system upgrades are somewhat dependent on the industrial load, reducing industrial energy consumption can potentially defer transmission and distribution costs. Industrial operations vary widely based on product, process, facility size, budget, technology, location, etc. One program does not fit all the industrial customers. An incentive-based program can be implemented where KEPCo can provide industrial customers with rate credits in their electricity bill if they reach the pre-set energy saving goals.

KEPCo can also offer technical assessments to the industrial customers. The technical expert visits the industry, assesses the process and technology, and provides feedback on how to reduce energy cost by improving plant processes. This is similar to a home energy audit program for residential customers. This program requires hiring a technical expert for different industrial fields.

4.3.3.4 Agricultural EE Program

Energy efficiency in the agricultural sector can be improved in two ways – increasing awareness about established techniques that increase energy efficiency and implementing efficient technology and solutions where appropriate. There are a variety of technologies that can be implemented to improve agricultural energy efficiency. Programs can be designed to assess on-farm energy use and potential for energy efficiency improvements, helping farmers implement new and efficient technology/solutions, and assisting with funding applications.

Farm Energy Audit tools can be used to assess energy consumption and associated costs to help agricultural producers conserve energy and save money. It can also explore ways to utilize available renewable energy on the farm.

Replacing inefficient light sources with appropriate high-efficiency lights can save energy costs as well as provide better lighting conditions to work. Lighting controls and dimmers can be installed as needed to simulate day-light conditions and get more energy savings.

5.0 TECHNOLOGY ASSESSMENT

5.1 Introduction

As part of the Study, BMcD was tasked with evaluating several power generation technologies for providing capacity to satisfy KEPCo's load requirements after the Sunflower PPA expires in 2020.

The costs and evaluation presented with this technology assessment is screening-level in nature and includes a comparison of technical features, cost, performance, and emissions characteristics of the following technologies. The costs presented herein do not represent budgetary capital costs, rather they focus on the difference between the options and as a comparison against each other and the potential demand charges associated with the PPAs under consideration. Any technology options that appear to be economical should be further screened with more detailed cost estimating studies.

In addition to firm, dispatchable capacity resources, both renewable and energy storage resources were evaluated under this technology assessment and Study. Resources for wind and solar generation were included as well as advanced battery energy storage.

5.2 Technologies Evaluated

BMcD evaluated several resources consisting of simple cycle gas turbines, reciprocating engines, combined cycle, renewables, and energy storage. The following technologies were evaluated within this Study. Based on Burns & McDonnell's experience, the technologies selected for evaluation represent appropriately sized options that are mature technologies and commercially available to KEPCo for its power supply portfolio, either through a self-build development or a power purchase agreement.

- Simple cycle gas turbine (SCGT) technology:
    - One (1) aeroderivative combustion turbine plant that included a single combustion turbine (GE LM6000) with an output of approximately 45 MW in summer conditions.
    - One (1) aeroderivative combustion turbine plant that included a single combustion turbine (GE LMS100) with an output of approximately 100 MW in summer conditions.
    - One (1) frame combustion turbine plant that included a single GE "F-class" combustion turbine with an output of approximately 225 MW in summer conditions.
- Internal combustion reciprocating engine technology: Five (5) reciprocating engines (Wärtsilä 20V34SG engines were the basis), each approximately 9 MW in output for a total of approximately 45 MW.

- Combined cycle gas turbine (CCGT) technology: A 2x1 "F-class" CCGT was evaluated based on GE 7F5 gas turbines. The output is approximately 900 MW in summer conditions (fully fired).
- Renewables technology:
  - Wind: A 200MW wind farm operating with a net capacity factor in excess of approximately 40 percent.
  - Solar photovoltaic: Both a 1 MW and 10 MW facility were considered, with a net capacity factor of approximately 22 percent.
- Energy storage technology: Advanced battery energy storage was evaluated including both a 1 MWh and 40 MWh lithium ion technology.

5.3 Study Basis and Assumptions

The following provides an outline of the general scope basis and assumptions utilized within this technology assessment to develop the capital costs, operation and maintenance (O&M) costs, and performance estimates for each of the technologies evaluated. Appendix B provides a detailed matrix of the results, scope, and assumptions used within this Study for the technology assessment.

5.3.1 General Assumptions

The assumptions below govern the overall approach of the Study:

- All estimates are screening-level in nature and do not reflect guaranteed costs.
- All information is preliminary and should not be used for engineering and construction purposes.
- All capital costs exclude escalation and are presented in "overnight" costs in 2016 U.S. dollars.
- Estimates assume an Engineer, Procure, Construct (EPC) contract basis.
- Performance ratings for a generic site in Kansas based on the following conditions:
  - Elevation: 945 ft.
  - Winter ambient conditions: 35°F and 67 percent relative humidity (RH)
  - Annual average ambient conditions: 55°F and 69 percent RH
  - Summer ambient conditions: 77°F and 65 percent RH
- All performance assumes new and clean equipment.
- The options assume natural gas operation only.
- An allowance for natural gas pipeline costs outside the site boundary are included.
- Fuel gas compression equipment is included for the aeroderivative turbine option. It is assumed that compression is not necessary for the frame turbine or reciprocating engine options.
- Fuel and power consumed during commissioning are included within Owner's costs.

- Piling is included under heavily loaded foundations.
- Water is assumed to be sourced from wells or surface water. An allowance for water infrastructure has been included.
- Waste water is assumed to be discharged off-site. Wastewater treatment facilities are excluded.
- Demolition or removal of hazardous materials is not included.
- Emissions estimates are based on a preliminary review of Best Available Control Technology (BACT) requirements.
  - Based on <10 percent capacity factor, it is assumed that selective catalytic reduction (SCR) and carbon monoxide (CO) catalysts are not required for LM6000 or "F-Class" simple cycle options.
  - SCR and CO catalyst are assumed to be included on the reciprocating engine, LMS1000, and combined cycle options.

5.3.2 EPC Project Indirect Costs

The following project indirect costs are included in capital cost estimates:

- Performance testing and continuous emissions monitoring system (CEMS)/stack emissions testing (where applicable)
- Pre-operational testing, startup, startup management and calibration
- Construction/startup technical service
- Engineering and construction management
- Freight
- Startup spare parts
- EPC fees
- EPC contingency (assumed 5 percent of all EPC costs)

5.3.3 Owner's Costs

Allowances for the following Owner's costs are included in the pricing estimates:

- Project development
- Owner's operations, project management, startup engineering personnel
- Owner's engineering
- Operator training
- Legal fees

- Permitting/licensing
- Construction power, temporary utilities, startup consumables
- Site security
- Operating spare parts
- 230 kV switchyard is included.
- Political concessions and/or area development fees
- Permanent plant equipment and furnishings
- Builder's risk insurance at 0.45 percent of EPC cost.
- Owner's contingency at 5 percent of total costs for screening purposes

5.3.4 Cost Estimate Exclusions

The following costs are excluded from all estimates:

- Financing fees (however, included in the economic evaluation presented later)
- Interest during construction (IDC) (however, included in the economic evaluation presented later)
- Sales tax
- Property tax and property insurance
- Off-site transmission upgrades
- Other off-site infrastructure unless stated above

5.3.5 Operations and Maintenance Assumptions

Operations and maintenance estimates are based on the following assumptions:

- O&M costs are based on typical capacity factors for the technologies.
- O&M costs are in 2016 USD.
- O&M estimates exclude emissions credit costs, property taxes, or insurance.
- Fixed O&M cost estimates include labor, office and administration, training, contract labor, safety, building and ground maintenance, communication, and laboratory expenses.
- Fixed costs assume full time equivalent (FTE) personnel are hired at each site at a fully burdened cost of approximately $115,000 per person.
- Where applicable, variable O&M costs include routine maintenance, makeup water, water disposal, reagents, SCR replacements, and other consumables not including fuel.
- Fuel costs are excluded from O&M estimates.
- Major maintenance costs are shown separately from variable O&M, as applicable.

- Major maintenance assumes that a Long Term Service Agreement (LTSA) is in place with the original equipment manufacturer (OEM).
- Performance estimates do not consider degradation over the operating life of the plant.

5.4 Simple Cycle Gas Turbine Technologies

5.4.1 General Description

A simple cycle gas turbine plant utilizes natural gas to produce power in a gas turbine generator. The gas turbine (Brayton) cycle is one of the most efficient cycles for the conversion of gaseous fuels to mechanical power or electricity. Also, gas turbine manufacturers continue to develop high temperature materials and cooling techniques to allow higher firing temperatures of the turbines, resulting in increased efficiency.

Typically, simple cycle gas turbines are used for peaking power due to their fast load ramp rates and relatively low capital costs. However, the units have high heat rates (lower efficiency) compared to combined cycle and coal-fired technologies. Simple cycle gas turbine generation is a widely used, mature technology.

Typical simple cycle plants operate with natural gas as the primary operating fuel. Often, the ability to operate on fuel oil is also required in case the demand for power exists when the natural gas supply does not. This assessment does not include dual fuel capability as an option.

Evaporative coolers can be used to cool the air entering the gas turbine by evaporating additional water vapor into the inlet air, which increases the mass flow through the turbine and therefore increases the gas turbine output. Evaporative coolers are included with all gas turbines in this assessment.

5.4.1.1 Aeroderivative Gas Turbines

Aeroderivative gas turbine technology is based on aircraft jet engine design, built with materials that allow for increased turbine cycling. The output of commercially available aeroderivative turbines ranges from less than 20 MW to 100 MW in generation capacity. In simple cycle configurations, these machines typically operate more efficiently than larger frame units and are also capable of shorter ramp-up and turndown times, making them ideal for peaking and load following applications.

Aeroderivative turbines are considered mature technology and have been used in power generation applications for decades. These machines are commercially available from several vendors, including

General Electric (GE), Siemens owned Rolls Royce, and Mitsubishi-owned Pratt & Whitney (PW). This assessment bases aeroderivative performance estimations on the GE LM6000 and GE LMS100.

5.4.1.2 Frame Gas Turbines

Frame turbines are typically used in intermediate to baseload applications. In simple cycle configurations, these engines typically have higher heat rates (lower efficiency) when compared to aeroderivative engines. The smaller frame units generally have simple cycle heat rates of more than 10,000 Btu/kWh (higher heating value (HHV)) while the largest proposed units will have heat rates approaching 9,250 Btu/kWh (HHV). However, frame units have higher exhaust temperatures (≈1,200°F) compared to aeroderivative units (≈850°F), making them more suitable for combined cycle operation where exhaust energy is further utilized.

Frame engines are offered in a large range of sizes by multiple suppliers, including GE, Siemens, Mitsubishi, and Alstom. Commercially available frame units range in size from approximately 50 MW to approximately 330 MW. The continued development by gas turbine manufacturers has resulted in the separation of gas turbine technology into various classes, grouped by output and heat rate. For the purposes of this assessment, BMcD is evaluating an "F-class" turbine.

5.4.2 SCGT Performance and Cost Results

The performance and cost estimates are presented in Appendix B for the simple cycle technologies.

5.4.3 SCGT Emissions Controls

Emissions levels and required NO_x and CO controls vary by technology and site constraints. Historically, natural gas SCGT peaking plants have not required post-combustion emissions control systems because they operate at low capacity factors. However, permitting trends suggest post-combustion controls may be required depending on annual number of gas turbine operating hours, proximity of the site to a non-attainment area, and current state regulations.

In addition, there is a New Source Performance Standard (NSPS) limit for NO_x emissions measured in parts per million, independent of operating hours. Per NSPS, units with heat inputs below 850 MMBtu/hr have a NO_x limit of 25 ppm, but units with heat inputs greater than 850 MMBtu/hr have a NO_x limit of 15 ppm.

"F-class" gas turbines use dry low NO_x (DLN) combustors to achieve NO_x emissions of 9 ppm at 15 percent oxygen (O_2) while operating on natural gas fuel. The heat input is greater than 850 MMBtu/hr, but since these units emit less than 15 ppm NO_x, no selective catalytic reduction (SCR) is assumed to be required.

The LM6000 and LMS100 units utilize water injection to achieve NO_x emissions of 25 ppm at 15 percent O_2 while operating on natural gas fuel. Because the LM6000 unit has a heat input below 850 MMBtu/hr, it meets the appropriate 25 ppm NO_x limit and therefore it is assumed that an SCR is not required. The LMS100 requires an SCR since its heat input is greater than 850 MMBtu/hr.

Oxidation catalysts can be used to reduce CO emissions, but they are not expected to be required for the SCGT plant options due to the limited hours of operation. Sulfur dioxide emissions are not controlled and are therefore a function of the sulfur content of the fuel burned in the gas turbines. Outside of good combustion practices, there is no expectation that CO_2, PM, and volatile organic compounds (VOC) levels will require emissions control equipment.

Most turbine manufacturers will guarantee emissions down to a specified minimum load, commonly 40 percent to 60 percent load. Below this load, turbine emissions may spike. As such, emissions on a ppm basis may be significantly higher at low loads.

5.4.4 SCGT Startup Time and Ramp Rates

An attribute commonly desirable of aeroderivative SCGT's is the ability to start and ramp up load quickly. Most manufacturers guarantee 10 minute starts even in cold start conditions, measured from the time the start sequence is initiated to when the unit is at 100 percent load. However, this assumes that all start permissives are met, which can include lube oil temperature, fuel pressure, etc.

A standard start time for an "F-class" turbine is approximately 30 minutes. However, 10 minute "fast start" packages are commonly available from the manufacturer. These control packages allow the frame startup times to compete with the aeroderivative turbines, but the major maintenance costs may also be impacted, depending on the OEM and the conditions of the service agreement.

Aeroderivative turbines generally have higher ramp rates than frame turbines, which means they can increase or decrease load more quickly. For example, an SCGT with a 25 percent per minute ramp rate can ramp up from 50 percent load to full load in two minutes

5.4.5 SCGT O&M Cost Estimate

O&M costs for each SCGT option are presented in Appendix B. General assumptions for fixed and variable O&M costs are listed in Section 5.3.5.

Major maintenance costs for gas turbine generators (GTG) are commonly expressed in terms of dollars per start or dollars per operating hour, depending on how the plant is operated. For frame turbines, the $/GTG-hr costs are assumed to be used if there are more than 27 operating hours per start. If there are fewer than 27 operating hours per start, major maintenance is assumed to be governed by the $/start cost. Aeroderivative units are typically not impacted by the number of starts, so the major maintenance costs are evaluated on a $/GTG-hr basis.

Fixed costs assume additional personnel are required to operate the plant. Variable costs include routine maintenance, makeup water, and other consumables not including fuel. The aeroderivative units consume water for NO_x control and power augmentation. However, the F class units do not require water for emissions control, and do not require evaporative cooling during average ambient conditions, so they consume no water during normal operation.

5.5 Reciprocating Engine

5.5.1 General Description

The internal combustion reciprocating engine operates on the four-stroke Otto cycle (natural gas fuel) or Diesel cycle (diesel fuel) for the conversion of pressure into rotational energy. In the Otto cycle, fuel and air are injected into a combustion chamber prior to its compression by the piston assembly of the engine. A spark ignites the compressed fuel and air mixture causing a rapid pressure increase that drives the piston downward. In the Diesel cycle, the compression stroke is only compressing air. The fuel is then injected into the cylinder and ignition results from the heat of compression, rather than a spark. In both cycles, the piston is connected to an offset crankshaft, thereby converting the linear motion of the piston into rotational motion that is used to turn a generator for power production. By design, cooling systems are typically closed-loop, minimizing water consumption. Emissions controls are generally accomplished with a combination of lean cycle combustion through fuel to air ratio control, as well as secondary control options such as SCR equipment.

Many different vendors, such as Wärtsilä, Fairbanks Morse, Caterpillar, Kawasaki, and Mitsubishi offer reciprocating engines and they are becoming popular as a means to follow renewable generation with their quick start times and operational flexibility. There are slight differences between manufacturers in engine sizes and other characteristics, but all largely share the common characteristics of quick ramp rates and quick start up.

For the Study, the Wärtsilä 20V34SG natural gas engines were evaluated. These heavy duty, medium speed, four-stroke combustion engines are easily adaptable to grid-load variations. The plant is assumed to include five (5) engines for approximately 45 MW total net output.

5.5.2 Reciprocating Engine Performance and Cost Results

The performance and cost estimates are presented in Appendix B for the reciprocating engine technologies. The engines are evaluated based on natural gas operation. Fuel oil backup is not included.

5.5.3 Reciprocating Engine Emissions Controls

In addition to good combustion practices, it is expected that reciprocating engines will require SCR and CO catalysts to control NO_x and CO emissions. For engines operating on natural gas, CO_2 emissions are estimated to be 120 lbs/MMBtu. Sulfur dioxide emissions are not controlled and are therefore a function of the sulfur content of the fuel burned in the gas turbines.

5.5.4 Reciprocating Engine O&M Cost Estimate

O&M costs for reciprocating engines are presented in Appendix B. General assumptions for fixed and variable O&M costs are listed in Section 5.3.5.

O&M costs are derived from vendor-supplied information and BMcD project experience. Variable O&M includes minor maintenance and consumables such as lube oil and SCR reagent. Catalyst replacement costs are embedded within major maintenance costs, which are presented on a per engine basis. There is no water consumption during normal operation except for maintaining water levels in the radiators.

Fixed costs for the option assume additional personnel are added to operate the plant.

5.6 Combined Cycle Technology

Based on recent technological advancements from the turbine manufacturers, large combined cycle units have been able to capture larger economies of scale and improved efficiencies compared to later model combustion turbines. Most likely, a large combined facility would provide KEPCo the most cost effective power supply for an intermediate resource. However, since KEPCo would not be able to specifically self-develop this type of facility, KEPCo would be dependent on a larger utility, third-party independent power producer, or a consortium of power producers to develop the project. BMcD assumed that KEPCo would participate as minority owner in an F-Class CCGT located within the region or a PPA off-taker of the facility.

5.6.1 General Description

The basic principle of the combined cycle gas turbine plant is to utilize natural gas to produce power in a gas turbine which can be converted to electric power by a coupled generator, and to also use the hot exhaust gases from the gas turbine to produce steam in a heat recovery steam generator (HRSG). This steam is then used to drive a steam turbine and generator to produce electric power. Additional natural gas can be fired in the HRSG to increase steam production and associated output for peaking load, a process commonly referred to as duct firing. The heat rate will increase during duct fired operation, though this incremental duct fired heat rate is generally comparable or less than the resultant heat rate from a similarly sized SCGT peaking plant.

The use of both gas and steam turbine cycles (Brayton and Rankine) in a single plant to produce electricity results in high conversion efficiencies and low emissions. Combined cycle facilities have efficiencies typically in the range of 52 percent to 60 percent on a lower heating value (LHV) basis. Gas turbine manufacturers continue to develop high temperature materials and material cooling techniques to raise the firing temperature of the turbines and increase the efficiency.

Continued development by gas turbine manufacturers has resulted in the separation of gas turbine technology into various classes, grouped by output and heat rate. For this assessment, BMcD evaluated a CCGT plant using a representative turbine from the "F-Class" technology.

Combined cycle plants are a mature technology, but technological advances continue, driven by efficiency, output, and competition. Each major OEM has incrementally improved its frame engine technology platforms to increase output and efficiency while lowering heat rate. Improved material design allows for higher firing temperatures and increased output in the emerging advanced class turbines. In addition, recent "F-Class" turbine design modifications have been driven largely toward faster startup times and operational flexibility, including peaking power capabilities and reduced load operation for off-peak turndown.

The 2x1 F-Class CCGT has a nominal output of approximately 900 MW (summer rating). Approximately 700 MW is attributable to baseload operation with the remaining capacity coming from duct firing.

5.6.2 Combined Cycle Performance and Cost Results

The performance and cost estimates are presented in Appendix B for the combined cycle technology. The CCGT is evaluated based on natural gas operation. Fuel oil backup is not included.

5.6.3 Combined Cycle Emissions Controls

The "F-class" gas turbines can achieve NO_x emissions at 9 ppm down to minimum emissions compliant load (MECL).

An SCR will be required for the CCGT options to reduce NO_x emissions to 2 ppm at 15 percent excess O2. With an SCR, the estimated emissions rate for NO_x is 0.01 lb/MMBtu. It is anticipated that a CO catalyst will also be required to reduce CO emissions. This assessment assumes CO emissions will be controlled to 2 ppm CO at 15 percent O_2.

The use of an SCR and CO catalyst requires additional site infrastructure. An SCR system injects ammonia into the exhaust gas to absorb and react with NO_x molecules. This requires on-site ammonia storage and provisions for ammonia unloading and transfer. The costs associated with these requirements have been included in this assessment.

For the CCGT options, CO_2 emissions are estimated to be 120 lb/MMBtu.

Sulfur dioxide emissions are not controlled and are therefore a function of the sulfur content of the fuel burned in the gas turbines. Sulfur dioxide emissions of a CCGT plant are very low compared to coal technologies, and the emission rate of sulfur dioxide for a combined cycle unit is estimated to be less than 0.01 lb/MMBtu.

5.6.4 Combined Cycle O&M Cost Estimate

O&M costs for reciprocating engines are presented in Appendix B. General assumptions for fixed and variable O&M costs are listed in Section 5.3.5.

O&M costs are derived from vendor-supplied information and BMcD project experience. Variable O&M includes minor maintenance and consumables such as lube oil and SCR reagent. Catalyst replacement costs are embedded within major maintenance costs, which are presented on a per combustion turbine basis. Water consumption estimates are included in Appendix B. Water consumption estimates account for evaporative coolers, cycle makeup, and cooling tower makeup. Water costs assume that an on-site water treatment facility is included.

Fixed costs for the option assume additional personnel are added to operate the plant.

5.7 Solar Technology

5.7.1 General Description

The conversion of solar radiation to useful energy in the form of electricity is a mature concept with extensive commercial experience that is continually developing into a diverse mix of technological designs. Photovoltaic (PV) cells consist of a base material (most commonly silicon), which is manufactured into thin slices and then layered with positively (i.e. Phosphorus) and negatively (i.e. Boron) charged materials. At the junction of these oppositely charged materials, a "depletion" layer forms. When sunlight strikes the cell, the separation of charged particles generates an electric field that forces current to flow from the negative material to the positive material. This flow of current is captured via wiring connected to an electrode array on one side of the cell and an aluminum back-plate on the other. Approximately 15 percent of the solar energy incident on the solar cell can be converted to electrical energy by a typical silicon solar cell. As the cell ages, the conversion efficiency degrades at a rate of approximately 0.7 percent per year. At the end of a typical 30-year period, the conversion efficiency of the cell will still be approximately 80 percent of its initial efficiency.

PV system costs are significantly lower now than they were 5 to 10 years ago, but the pace of the reduction has slowed in recent years. Panel technologies and manufacturing process are maturing, but material costs will continue to impact prices. Because PV costs are more competitive in most energy markets, smaller systems are more economically feasible, which has led to increased development across the nation.

5.7.2 Solar Performance and Cost Results

The performance and cost estimates are presented in Appendix B for the solar technology options.

5.7.3 Solar Emissions Controls

Solar is an emissions-free technology.

5.7.4 Solar O&M Cost Estimate

O&M costs for solar generation are presented in Appendix B. General assumptions for fixed and variable O&M costs are listed in Section 5.3.5.

Fixed costs for the option assume additional personnel are added to operate the plant.

5.8 Wind Technology

5.8.1 General Description

Wind turbines convert the kinetic energy of wind into mechanical energy, and are typically used to pump water or generate electrical energy that is supplied to the grid. Wind turbine energy conversion is a mature technology and is generally grouped into two types of configurations:

- Vertical-axis wind turbines, with the axis of rotation perpendicular to the ground.
- Horizontal-axis wind turbines, with the axis of rotation parallel to the ground.

Over 95 percent of turbines over 100 kW are horizontal-axis. Subsystems for either configuration typically include a blade or rotor to convert the energy in the wind to rotational shaft energy; a drive train, usually including a gearbox and a generator; a tower that supports the rotor and drive train; and other equipment, including controls, electrical cables, ground support equipment, and interconnection equipment.

Wind turbine capacity is directly related to wind speed and equipment size, particularly to the rotor/blade diameter. A 10 kW turbine typically has a rotor diameter of over 20 feet, while a 1.5 MW turbine has a rotor diameter of approximately 230 feet. The power generated by a turbine is proportional to the cube of the prevailing wind, that is, if the wind speed doubles, the available power will increase by a factor of eight. Because of this relationship, proper siting of turbines at locations with the highest possible average wind speeds is vital. According to the Department of Energy's (DOE) National Renewable Energy Laboratory (NREL), Class 3 wind areas (wind speeds of 14.5 mph) are generally considered to have suitable wind resources for wind generation development.

5.8.2 Wind Performance and Cost Results

The performance and cost estimates are presented in Appendix B for the wind technology.

5.8.3 Wind Emissions Controls

Wind is an emissions-free technology.

5.8.4 Wind O&M Cost Estimate

O&M costs for wind are presented in Appendix B. General assumptions for fixed and variable O&M costs are listed in Section 5.3.5.

5.9 Energy Storage Technology

5.9.1 General Description

Electrochemical energy storage systems utilize chemical reactions within a battery cell to facilitate electron flow, converting electrical energy to chemical energy when charging and generating an electric current when discharged. Electrochemical technology is continually developing as one of the leading energy storage and load following technologies due to its modularity, ease of installation and operation, and relative design maturity. Development of electrochemical batteries has shifted into three categories, commonly termed "flow," "conventional," and "high temperature" battery designs. Each battery type has unique features yielding specific advantages compared to one another. Flow batteries offer a much longer life than conventional batteries, and do not suffer from degradation due to cycling. However, they are generally more complex systems and not as efficient. Conventional batteries are comparatively cheap, have a good energy density, and are a proven technology. However, conventional batteries degrade after repeated cycling requiring systems to either be overdesigned initially, or to have cells replaced periodically. High temperature batteries are more expensive and less efficient, but are able to tolerate high temperatures and are vibration and shock resistant. As such, these batteries are typically used for downhole applications in oil fields where these features are essential. For this assessment, BMcD selected the "conventional" battery technology, specifically the lithium ion, as the representative energy storage technology.

A conventional battery contains a cathodic and an anodic electrode and an electrolyte sealed within a cell container than can be connected in series to increase overall facility storage and output. During charging, the electrolyte is ionized such that when discharged, a reduction-oxidation reaction occurs, which forces electrons to migrate from the anode to the cathode thereby generating electric current. Batteries are designated by the electrochemicals utilized within the cell; the most popular conventional batteries are lead acid and lithium ion type batteries.

Lead acid batteries are the most mature and commercially available battery technology, with approximately 35 MW installed worldwide. This design has undergone considerable development since conceptualized in the late 1800s. However, though lead acid batteries require relatively lower capital cost, the technology also has inherently high maintenance costs and handling issues associated with toxicity, as well as low energy density (yields higher land and civil work requirements) and a short life cycle of between 5 and 10 years.

Lithium ion batteries contain graphite and metal-oxide electrodes and lithium ions dissolved within an organic electrolyte. The movement of lithium ions during cell charge and discharge generates current. Lithium ion technology has seen a resurgence of development interest due to its high energy density, low self-discharge, and cycling tolerance, but remains mostly developmental for utility generation applications. Life cycle is dependent on cycling (charging and discharging) and depth of charge (charged load depletion), and can range from 2,000 to 3,000 cycles at high discharge rates up to 7,000 cycles at very low discharge rates.

Lithium ion batteries are gaining traction in several markets, including the utility and automotive industries. Continued development is anticipated to reduce production costs, but uncertainty of these developments lends to wide ranges in project costs.

5.9.2 Energy Storage Performance and Cost Results

The performance and cost estimates are presented in Appendix B for the energy storage technology.

This assessment includes performance of a 10 MW/40MWh as well as a 1 MW/1 MWh battery storage system, based on lithium ion batteries. Lithium ion technology is well suited for utility applications that require dynamic frequency response. Lithium ion systems can respond in seconds and exhibit excellent ramp rates and round trip cycle efficiencies. Because the technology is still maturing, there is uncertainty regarding estimates for cycle life, and these estimates vary greatly depending on the application and depth of discharge. This evaluation assumes a frequency response application, which calls for a high volume of short discharge cycles. Lithium-ion batteries in development may be capable of a 100,000 cycle life, but current batteries may only be expected to last 5-7 years in similar applications.

5.9.3 Energy Storage Emissions Controls

Energy storage does not specifically have emissions associated with it. However, the energy utilized to charge the battery may have been sourced from a resource that does have emissions. For the purposes of this evaluation, the battery is assumed to be emissions free.

5.9.4 Energy Storage O&M Cost Estimate

O&M costs for energy storage options are presented in Appendix B. General assumptions for fixed and variable O&M costs are listed in Section 5.3.5.

Due to inherent inefficiencies, battery systems are net electrical consumers over their useful lifespans. This net power draw is estimated similar to the parasitic load of a traditional generation plant, and is modeled as a variable O&M cost.

The fixed O&M costs assume that the end user enters into a full service contract with the OEM that covers routine and unplanned maintenance. It includes an allowance for maintenance costs, a battery cell replacement fund, and administrative costs such as computers and software licenses. The technical life of the project is estimated at 15 years, and battery cells may need to be replaced every 5 to 7 years.

5.10 Technology Assessment Summary

Table 5-1 and Table 5-2 present the technology assessment summary for the natural gas-fired options and the renewable and storage options, respectively. The full details of the technology assessment are presented in Appendix B.

Table 5-1: Technology Assessment Summary – Natural Gas Options

PROJECT TYPE	2x1 F Class Fully Fired	1 x F Class SCGT	1 x LMS100 SCGT	1 x LM6000 SCGT	5 x Wartsila 20V34SG
BASE PLANT DESCRIPTION					
Number of Gas Turbines	2	1	1	1	5
Fuel Design	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Technology Rating	Mature	Mature	Mature	Mature	Mature
PERFORMANCE					
Base Load Performance @ 77°F, 65% RH					
Net Plant Output, kW	688,700	225,900	99,700	45,500	45,800
Net Plant Heat Rate, Btu/kWh (HHV)	6,530	9,760	8,320	9,630	8,450
Heat Input, MMBtu/h (HHV)	4,500	2,210	830	440	390
Incremental Duct Fired Performance @77°F, 65% RH					
Incremental Net Plant Output, kW	201,500	N/A	N/A	N/A	N/A
Incremental Net Plant Heat Rate, Btu/kWh (HHV)	8,540	N/A	N/A	N/A	N/A
Incremental Heat Input, MMBtu/h (HHV)	1,720	N/A	N/A	N/A	N/A
CAPITAL COSTS					
EPC Projects Cost, 2016 MM$ (w/o Owner's Costs)	$529	$106	$117	$60	$60
Owner's Costs, 2016 MM$	$82	$32	$28	$23	$20
Total Project Costs, 2016 MM$	$611	$139	$145	$83	$80
Total Project Costs, 2016 $/Unfired kW	$870	$600	$1,360	$1,720	$1,750
Total Project Costs, 2016 $/Fired kW	$680	N/A	N/A	N/A	N/A
NON-FUEL OPERATION & MAINTENANCE COSTS					
Fixed O&M Cost, 2016$/kW-Yr	$7.70	$6.80	$10.90	$30.10	$22.50
Levelized Major Maintenance Cost, 2016$/GT-hour	$400	$400	$420	$200	$20
Levelized Major Maintenance Cost, 2016$/GT-Start	$15,000	$15,000	N/A	N/A	N/A
Variable O&M Cost, 2016$/MWh (excl. major maint.)	$1.50	$0.90	$4.50	$7.30	$3.90
Incr. Duct Fired Variable O&M, 2016$/MWh (excl. major maint.)	$1.30	N/A	N/A	N/A	N/A

Table 5-2: Technology Assessment Summary – Renewable and Storage Options

PROJECT TYPE	Advanced Battery Energy Storage		Wind Energy Conversion	Solar Photovoltaic	
BASE PLANT DESCRIPTION	**Lithium Ion**	**Lithium Ion**			
Nominal Output	10 MW / 40 MWh	1 MW / 1 MWh	200 MW	1 MW	10 MW
Fuel Design	N/A	N/A	N/A	N/A	N/A
Technology Rating	Developmental	Developmental	Mature	Mature	Mature
PERFORMANCE					
Base Load Performance @ (Annual Average)					
Net Plant Output, kW	10,000	1,000	200,000	3,000	9,000
Round-Trip Efficiency (%)	90%	90%	N/A	N/A	N/A
ESTIMATED CAPITAL AND O&M COSTS					
Project Capital Costs, 2016 MM$ (w/o Owner's Costs)	$25	$1.5	$295	$2.5	$19
Owner's Costs, 2016 MM$	$4	$0.8	$21	$2.9	$6.1
Total Screening Level Project Costs, 2016 MM$	**$29**	**$2.3**	**$316**	**$5**	**$25**
Total Screening Level Project Costs, 2016 $/kW	**$2,860**	**$2,310**	**$1,580**	**$1,790**	**$2,810**
NON-FUEL OPERATION & MAINTENANCE COSTS					
Fixed O&M Cost, 2016$/kW-Yr	$16.20	$40.80	$42.00	$19.50	$19.50
Levelized Major Maintenance Cost, 2016$/MWh	N/A	N/A	Incl. in Fixed O&M	Incl. in Fixed O&M	Incl. in Fixed O&M
Variable O&M Cost, 2016$/MWh (excl. major maint.)	$1.44	$1.44	Incl. in Fixed O&M	Incl. in Fixed O&M	Incl. in Fixed O&M

6.0 ECONOMIC EVALUATION

The following section provides the assumptions, methodology, and results of the economic evaluation.

6.1 General Power Supply Assumptions

The analysis began with the development of baseline assumptions and constraints applicable to KEPCo. The following general assumptions were used:

- The study period covers years 2016 through 2045.
- The hourly load profile used in this Study was based on historical information from 2014.
- KEPCo's interest rate for financing was 4 percent, with resources financed over 30 years.
- The general escalation rate was assumed to be 2.5 percent.
- The discount rate was assumed to be 5.6 percent.

These assumptions, and others described herein, served as a basis for the economic analysis.

6.2 Load Forecast

SPP requires that all members conduct an annual load forecast that has a well-defined methodology. KEPCo's annual forecast was developed internally at KEPCo. The load forecast was based on a recent projection for KEPCo's demand and energy requirements through 2025; thereafter the load forecast was escalated at 0.7 percent. The forecasts for demand and energy are summarized on an annual basis over the study period in Figure 6-1 and Figure 6-2, respectively. The load forecast does include an adjustment after the Sunflower PPA expires in 2021 to reflect the anticipated reduction in load due to two members no longer purchasing power from KEPCo.

Figure 6-1: KEPCo Demand Forecast

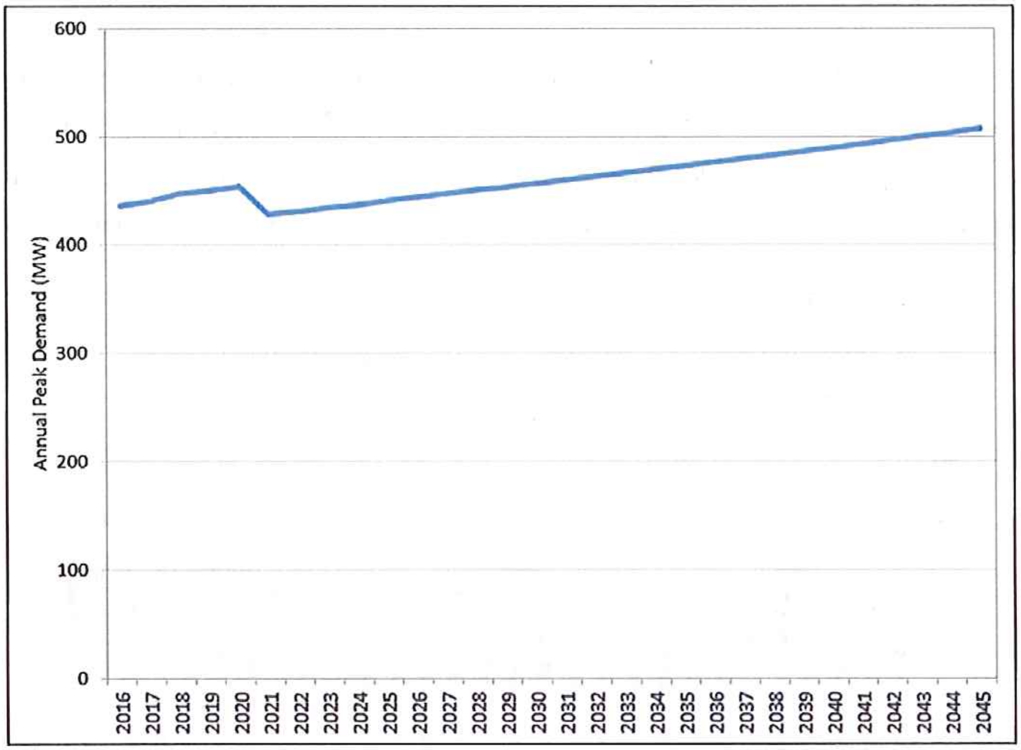
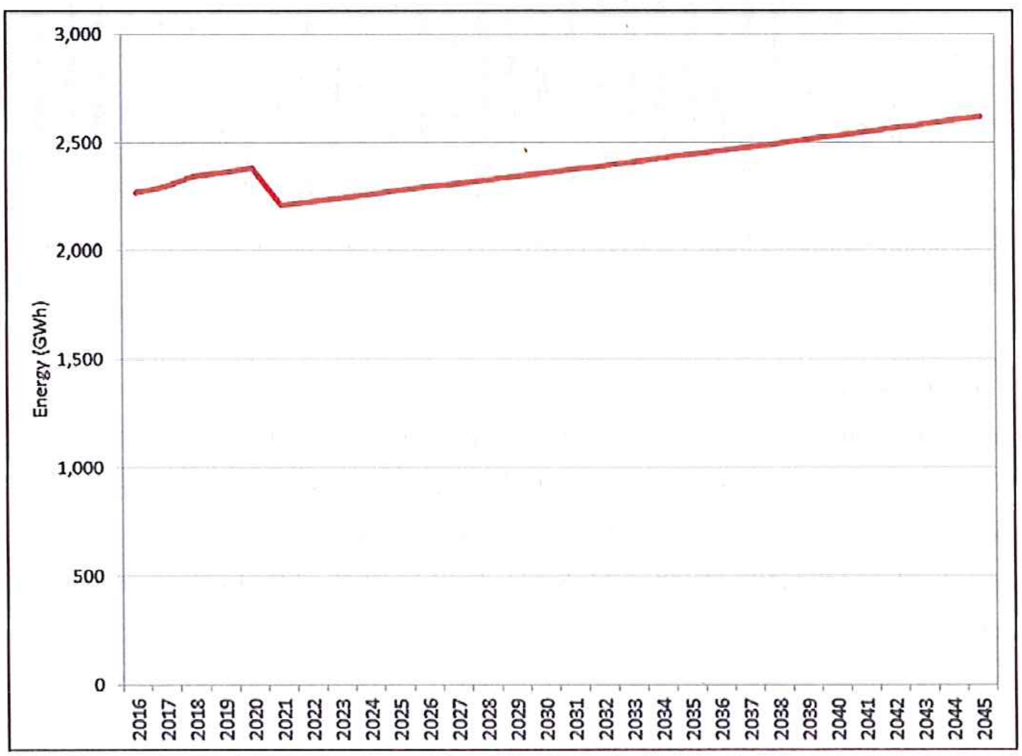


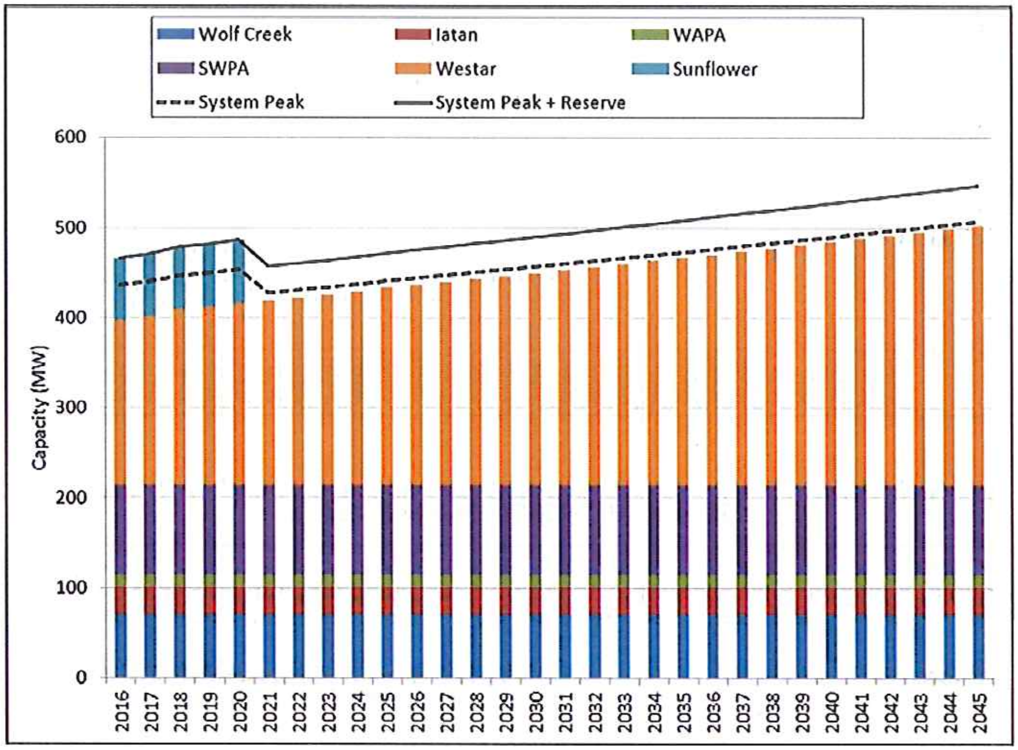
Figure 6-2: KEPCo Energy Forecast



6.3 Balance of Loads and Resources

As described above in Section 2.1.2, KEPCo has a number of resources to meet its capacity reserve margin requirements. A BLR based on the load forecast and resources that KEPCo will have available to meet its obligations are presented in Figure 6-3. KEPCo must maintain a reserve margin of 13.6 percent, a number which is prescribed by SPP. Based on existing resources and current load projections, KEPCo will be capacity deficit after the expiration of the Sunflower PPA. The deficit is approximately 45 MW.

Figure 6-3: KEPCo Balance of Loads and Resources



Note: Sharpe Generating Station is assumed to reduce reserve requirements and is not presented as a capacity resource.

6.4 Forecasts

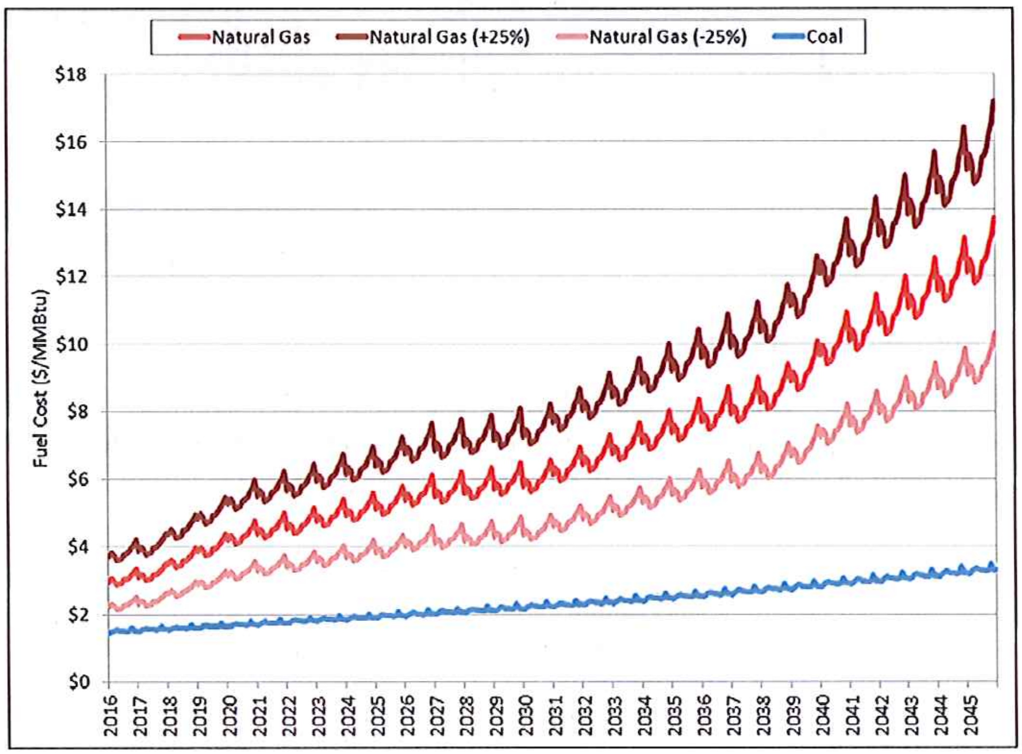
In order to conduct a long-term resource planning assessment for power supply, several forecasts have to be developed for evaluation. For this Study, BMcD developed key forecasts for fuel costs and market energy costs using reputable publicly available sources. The following paragraphs provide a summary of the forecasts developed and utilized within this Study. Further details of the forecasts are presented in Appendix C.

6.4.1 Fuel Cost Forecast

BMcD utilized projected information regarding natural gas fuel cost developed by the U.S. Department of Energy's Energy Information Administration. Utilizing multiple forecasts that are considerably different provides the ability to assess the resource plan under varying assumptions. Varying natural gas prices was performed as a sensitivity analysis and provides for a more robust evaluation to determine whether one resource path appears more favorable under a different set of economic forecasts. Figure 6-4 presents both the base fuel forecast for natural gas and the high (+25 percent) and low (-25 percent) natural gas price sensitivity values.

Since a significant portion of the Westar PPA is supplied from coal-fired resources, and KEPCo is a partial owner of Iatan 2, a coal forecast was also developed. The coal forecast was based on inflation values as developed by the EIA's long-term coal forecast. Figure 6-4 also presents the coal forecast.

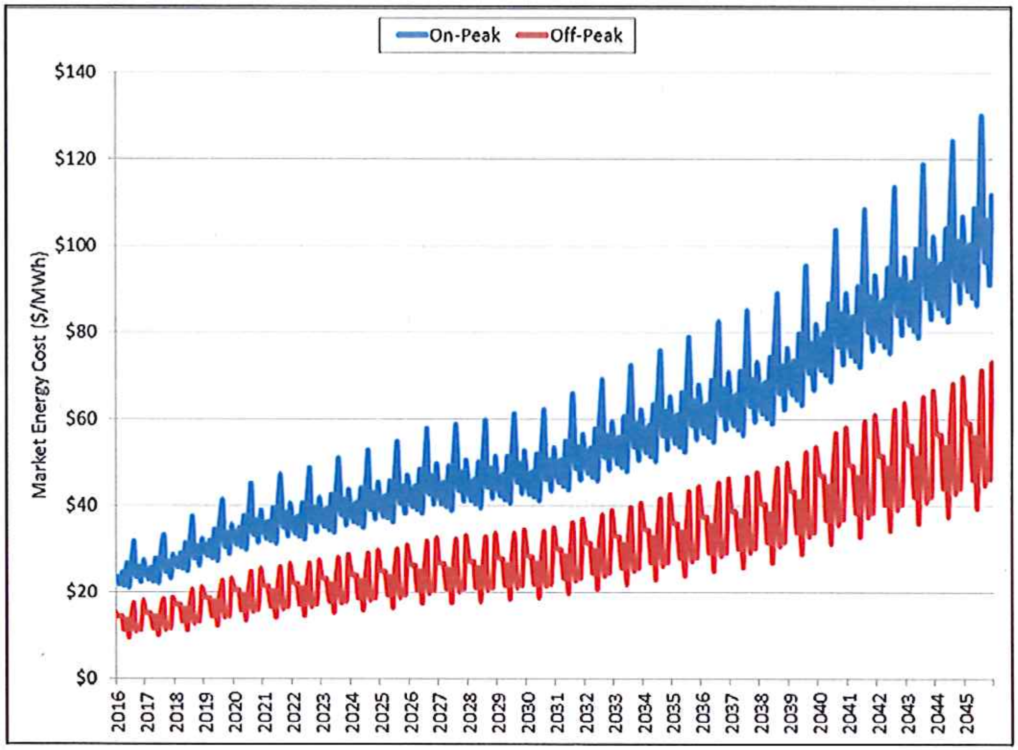
Figure 6-4: Fuel Cost Forecast



6.4.2 Market Energy Cost Forecast

BMcD utilized historical market heat rate information from the SPP wholesale energy market, combined with the natural gas and coal forecasts, to approximate the overall market price of energy. Figure 6-5 presents the market energy cost forecast utilizing the base fuel forecast costs. The market energy price was adjusted for variations in natural gas pricing within the sensitivity evaluation.

Figure 6-5: Market Energy Cost Forecast



6.5 Future Development

When evaluating long-term power supply resource plans, several "futures" are typically developed to account for different assumptions or environments. BMcD and KEPCo developed four futures for consideration within this power supply plan, which are described in Table 6-1.

Table 6-1: Future Summary

Future	Description
Base	Represents the base future and does not include a cost for CO_2 emissions.
Carbon Constrained (CO_2)	Represents a future that does include cost for CO_2 emissions, but no changes to Westar's generation fleet are assumed.
Carbon Constrained with CCGT (CO_2 with CPP 1)	Represents a future that does include cost for CO_2 emissions and assumed Westar constructs a CCGT unit to comply with the Clean Power Plan.
Carbon Constrained with SCGT and Wind (CO_2 with CPP 2)	Represents a future that does include cost for CO_2 emissions and assumed Westar constructs a SCGT unit and wind generation to comply with the Clean Power Plan.

6.6 Scenario Development

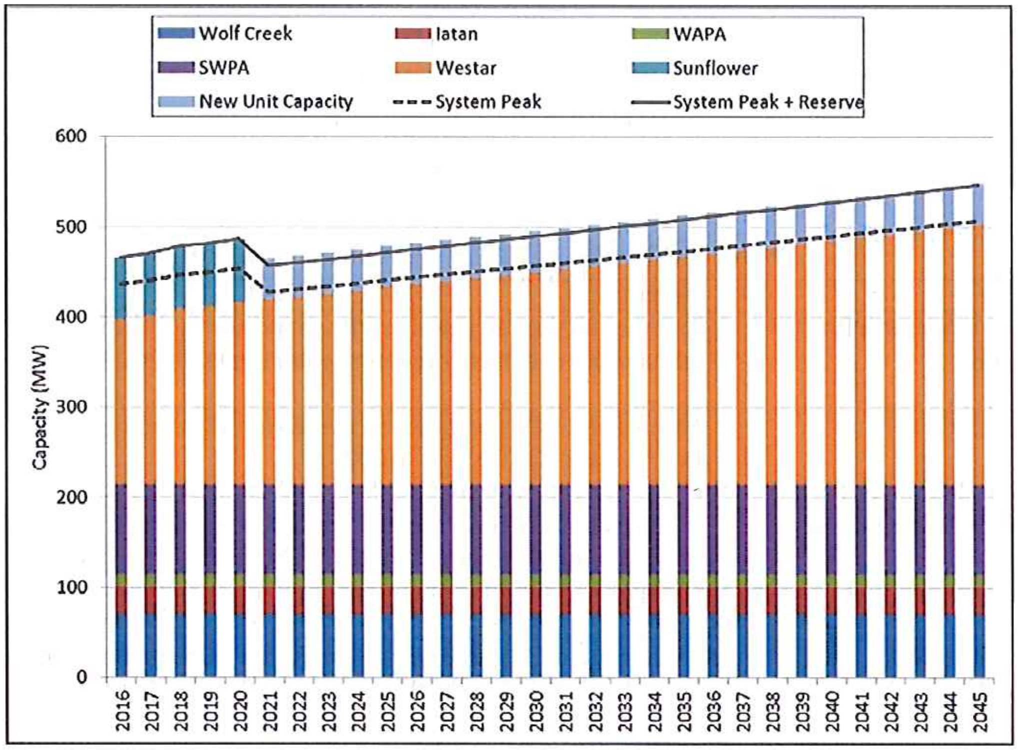
Using the futures described above, BMcD and KEPCo developed distinct scenarios, or power supply paths, with specific options for KEPCo to meet its power supply requirements. These scenarios focused on addressing the capacity deficit which occurs in 2021 after the expiration of the Sunflower PPA. Five specific scenarios were developed and are presented in Table 6-2.

Table 6-2: Scenario Summary

Scenario	Description
Scenario 1: Westar PPA Expansion	Assumes the existing Westar PPA is increased, or expanded, to cover the capacity and energy requirements starting in 2021.
Scenario 2: CCGT	Assumes KEPCo purchases an ownership share of a natural gas-fired 1x1 "F-class" CCGT unit in 2021.
Scenario 3: Recip Engine	Assumes KEPCo develops and constructs a self-build natural gas-fired reciprocating engine facility in 2021 (100 percent owned by KEPCo).
Scenario 4: SCGT	Assumes KEPCo purchases an ownership share of a natural gas-fired "F-class" SCGT unit in 2021.
Scenario 5: Sunflower PPA extension	Assumes the Sunflower PPA is extended at current pricing to cover the capacity and energy requirements in 2021.

A BLR for each of the scenarios was developed and is presented in Appendix C. Figure 6-6 presents the BLR for a self-build scenario (Scenario 2, Scenario 3, or Scenario 4) as an illustrative example.

Figure 6-6: BLR for Scenarios 2, 3, and 4



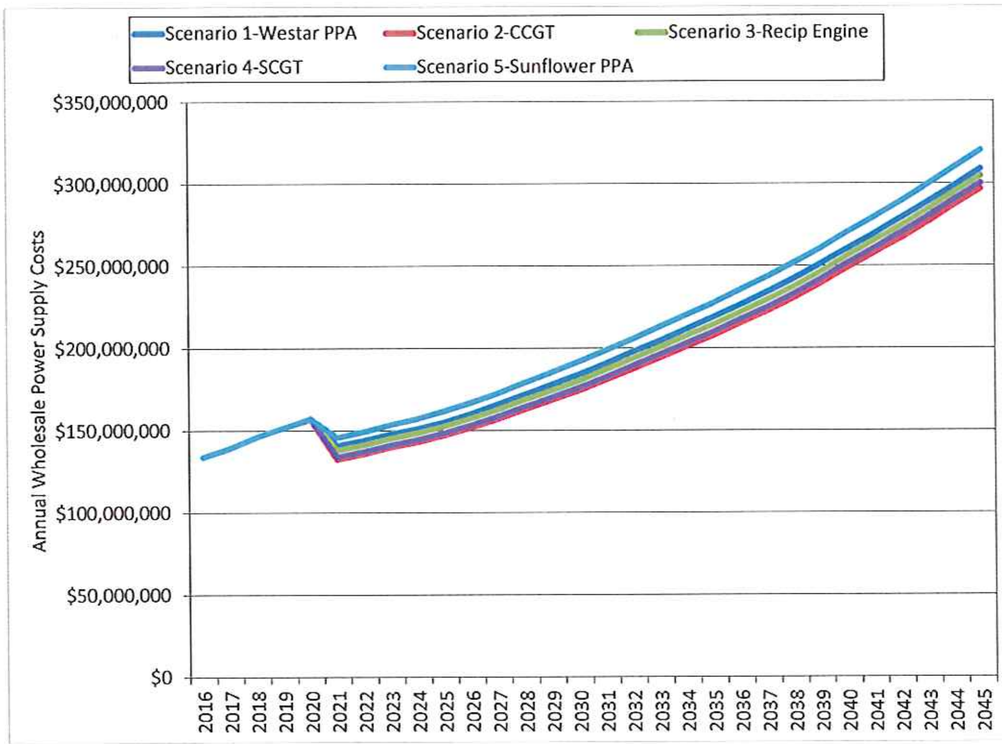
6.7 Power Supply Analysis

For each of the futures and scenarios, BMcD simulated the power supply resources utilizing hourly dispatch software (PROMOD) over the 30-year study period. PROMOD simulates the dispatch of power supply resources available to meet KEPCo's load requirements. The new units, those simulated within Scenario 2, Scenario 3, and Scenario 4, were dispatched against the SPP market energy price. When dispatched, those units would generate energy revenues within the SPP energy market, offsetting their cost of generation. For the existing resources, the cost of generation was considered. The power supply analysis evaluated total cost of generation including fuel, O&M costs, and capital recovery less any market revenues for each scenario under the selected futures (note: existing debt and capital recovery were not included within the analysis as these costs are sunk). The total power supply costs over the 30-year period were brought back to a single net present value for comparison. Table 6-3 presents the net present value for each scenario under the four futures. The percent difference included in Table 6-3 illustrates how much higher cost each scenario is compared to the low cost scenario for that future. Figure 6-7 presents the total annual wholesale power supply costs for each scenario under the Base future. Detailed PROMOD result summaries are included in Appendix D.

Table 6-3: Power Supply Analysis Summary

Future		Scenario 1 (Westar PPA)	Scenario 2 (CCGT)	Scenario 3 (Recip Engine)	Scenario 4 (SCGT)	Scenario 5 (Sunflower PPA)
Base	NPV	$2,561,885,553	$2,464,629,543	$2,526,224,001	$2,483,225,583	$2,638,868,778
	% DIFF	3.95%	0.00%	2.50%	0.75%	7.07%
CO2	NPV	$2,915,748,096	$2,776,908,168	$2,834,423,573	$2,791,668,479	$2,980,823,094
	% DIFF	5.00%	0.00%	2.07%	0.53%	7.34%
CO2 with CPP 1	NPV	$2,890,646,045	$2,757,079,566	$2,814,594,976	$2,771,839,882	$2,960,994,497
	% DIFF	4.84%	0.00%	2.09%	0.54%	7.40%
CO2 with CPP 2	NPV	$2,897,964,743	$2,764,602,115	$2,822,117,524	$2,779,362,430	$2,968,517,046
	% DIFF	4.82%	0.00%	2.08%	0.53%	7.38%

Figure 6-7: Total Annual Wholesale Power Supply Costs for Base Future



As presented in Table 6-3, participation in a large "F-class" combustion turbine technology, whether it is a CCGT or SCGT, provide the lower total power supply costs based on the net present value. The self-build reciprocating engine project is slightly higher cost than the "F-class" technologies, but is lower cost than either of the PPA options.

6.8 Sensitivity Analysis

In order to gauge the robustness of the base assumptions, BMcD conducted a sensitivity analysis by varying several key assumptions, including:

- Natural gas: natural gas prices were fluctuated by +/- 25 percent. This impacted the cost of fuel directly to the natural gas resources, the cost of the energy under the PPAs, and the price of market energy.
- Load: KEPCo's load forecast was adjusted by a lower and higher growth rate than the base 0.7 percent load growth.

The sensitivity analysis was conducted on Scenario 2, Scenario 3, and Scenario 4. Scenario 1 and Scenario 5 were not considered within the sensitivity analysis as those were the higher cost scenarios. Table 6-4 presents net present value for each of the scenarios under each future for the sensitivity analysis. The percent difference included in Table 6-4 illustrate the change in cost for each sensitivity when compared to the Benchmark future. As presented within Table 6-4, the sensitivity analysis illustrates that the CCGT option remains the lowest cost option for all futures under all variations in assumptions.

Table 6-4: Sensitivity Analysis Summary

Sensitivity	Future		Scenario 2 (CCGT)	Scenario 3 (Recip Engine)	Scenario 4 (SCGT)
Benchmark	Base	NPV	$2,464,629,543	$2,526,224,001	$2,483,225,583
	CO2	NPV	$2,776,908,168	$2,834,423,573	$2,791,668,479
	CO2 with CPP 1	NPV	$2,757,079,566	$2,814,594,976	$2,771,839,882
	CO2 with CPP 2	NPV	$2,764,602,115	$2,822,117,524	$2,779,362,430
High Natural Gas	Base	NPV	$2,506,416,215	$2,572,437,340	$2,530,215,410
	(+25% NG)	% DIFF	0.00%	2.63%	0.95%
	CO2	NPV	$2,818,755,233	$2,880,546,284	$2,839,041,351
	(+25% NG)	% DIFF	0.00%	2.19%	0.72%
	CO2 with CPP 1	NPV	$2,793,621,649	$2,855,412,703	$2,813,907,771
	(+25% NG)	% DIFF	0.00%	2.21%	0.73%
	CO2 with CPP 2	NPV	$2,791,480,408	$2,853,271,464	$2,811,766,532
	(+25% NG)	% DIFF	0.00%	2.21%	0.73%
Low Natural Gas	Base	NPV	$2,440,519,683	$2,497,551,349	$2,453,909,166
	(-25% NG)	% DIFF	0.00%	2.34%	0.55%
	CO2	NPV	$2,752,744,709	$2,805,911,540	$2,761,760,511
	(-25% NG)	% DIFF	0.00%	1.93%	0.33%
	CO2 with CPP 1	NPV	$2,720,480,293	$2,773,647,128	$2,729,496,099
	(-25% NG)	% DIFF	0.00%	1.95%	0.33%
	CO2 with CPP 2	NPV	$2,737,691,297	$2,790,858,133	$2,746,707,104
	(-25% NG)	% DIFF	0.00%	1.94%	0.33%
High Load	Base	NPV	$2,560,947,154	$2,622,541,613	$2,579,543,195
	(High Load)	% DIFF	0.00%	2.41%	0.73%
	CO2	NPV	$2,873,225,781	$2,930,741,184	$2,887,986,090
	(High Load)	% DIFF	0.00%	2.00%	0.51%
	CO2 with CPP 1	NPV	$2,853,786,840	$2,911,302,249	$2,868,547,155
	(High Load)	% DIFF	0.00%	2.02%	0.52%
	CO2 with CPP 2	NPV	$2,864,663,504	$2,922,178,912	$2,879,423,817
	(High Load)	% DIFF	0.00%	2.01%	0.52%
Low Load	Base	NPV	$2,373,584,356	$2,435,178,814	$2,392,180,396
	(Low Load)	% DIFF	0.00%	2.59%	0.78%
	CO2	NPV	$2,685,862,982	$2,743,378,386	$2,700,623,291
	(Low Load)	% DIFF	0.00%	2.14%	0.55%
	CO2 with CPP 1	NPV	$2,665,665,696	$2,723,181,105	$2,680,426,011
	(Low Load)	% DIFF	0.00%	2.16%	0.55%
	CO2 with CPP 2	NPV	$2,670,037,893	$2,727,553,302	$2,684,798,207
	(Low Load)	% DIFF	0.00%	2.15%	0.55%

APPENDIX A – DEMAND SIDE MANAGEMENT ANALYSIS

Kansas Electric Cooperative, Inc.
Power Supply Analysis Study
BMcD Project No. 87230

Assumptions

General Assumptions	Values		Comment
PCT Impact per Unit (kW)	1.0	kW	Typical central air conditioner load
Water Heater LCS Impact per Unit (kW)	4.5	kW	Typical electric water heater load
Cycling Ability	50%		
Event Days	15		
Hours per Event	4		
Total Event Hours per year	60		
General Annual Escalation	2.5%		
Population Assumptions			
Total Residential Customers	80,000	Some vendors	Assumed 75% of of total meter count (120,000) was residential
Diversity Rates during Peak Hours			
PCT Diversity Rate	60%		Typical diversity is 50%-70%
Water Heater LCS Diversity Rate	12%		Typical operation is 2-3 hours per day
Rate Assumptions			
Blended Levelized Cost of Energy (kWh)	N/A		
Average Retail Energy Cost (kWh)	N/A		
Demand Charge ($/kW-mo)	$20.16		Westar GFR demand rate
Program Eligible			
PCT Eligible	84%		From *A National Assessment of Demand Response Potential* published by FERC June 2009
PCT Participation Rate	8%		
Water Heater LCS Eligible	22%		From DOE EIA information
Water Heater LCS Particpation Rate	8%		
Cost Assumptions			
PCT Device Deployment Cost	$300	/PCT	PCT with built-in wifi
PCT Program Design	$75,000		
PCT Messaging/Communication Costs	$2	/PCT/year	Assumes annual cost per device per year
PCT Annual Marketing & Education	$35,000		Accounts for collateral and internal labor cost
PCT Annual Vendor Admin & System Maintenance Fee	$30,000		Some vendors may require an administrative fee, may depend on no. of devices involved
Water Heater LCS Device Deployment Cost	$300	/LCS	
Water Heater LCS Program Design	$75,000		
Water Heater LCS Messaging/Communication Costs	$2	/LCS/year	Assumes annual cost per device per year
Water Heater LCS Annual Marketing & Education	$35,000		Accounts for collateral and internal labor cost
Water Heater LCS Annual Vendor Admin & System Maintenance Fee	$30,000		Some vendors may require an administrative fee, may depend on no. of devices involved
Contingency	15%		
Discount rate	5.6%		
Year$	2016		

Assumptions & Explanation

Deployment Cost	Cost to deploy devices/switches; assumed to be completed in first 5 years
Program Design	Cost to design program; includes software, licensing, tests
Messaging/Network	Cost of building and maintaining network; First year includes designing and implementing the network; Second year onwards is the maintenance cost which increases by general annual escalation rate
Marketing & Education	Cost for marketing the product as well as for education & outreach program; Cost increases each year by General Annual Escalation rate; First 3 years marketing cost is high, but the cost significant deceases from fourth year
Vendor Admin & Maintenance Fee	Maintenance cost for switches, devices, system; Cost increases each year by General Annual Escalation rate

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Deployment Expenses

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	TOTAL
Yearly Participation Rate Acquisition	20%	40%	60%	80%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	
PCT Program																
PCT Device Deployment Cost	$300															
Total Number of Participants/Devices (8%)	5,376															
Participants/Devices Deployed per year	1,075	1,075	1,075	1,075	1,075	0	0	0	0	0	0	0	0	0	0	5,376
Active Devices	538	1,613	2,688	3,763	4,838	5,376	5,376	5,376	5,376	5,376	5,376	5,376	5,376	5,376	5,376	
PCT Deployment Cost	$322,560	$322,560	$322,560	$322,560	$322,560	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,612,800
PCT Program Design	$75,000															$75,000
PCT Messaging/Network ($/device/year)	$1,075	$3,226	$5,376	$7,526	$9,677	$10,752	$10,752	$10,752	$10,752	$10,752	$10,752	$10,752	$10,752	$10,752	$10,752	$134,400
PCT Marketing & Education	$35,000	$35,875	$36,772	$37,691	$38,633	$39,599	$40,589	$41,604	$42,644	$43,710	$44,803	$45,923	$47,071	$48,248	$49,454	$627,617
PCT Vendor Admin & Maintenance Fee	$30,000	$30,750	$31,519	$32,307	$33,114	$33,942	$34,791	$35,661	$36,552	$37,466	$38,403	$39,363	$40,347	$41,355	$42,389	$537,958
PCT Program Costs	*$463,635*	*$392,411*	*$396,227*	*$400,084*	*$403,985*	*$84,294*	*$86,132*	*$88,017*	*$89,948*	*$91,928*	*$93,957*	*$96,038*	*$98,170*	*$100,355*	*$102,595*	*$2,987,775*
Water Heater LCS Program																
Water Heater LCS Device Deployment Cost	$300															
Total Number of Participants/Devices (8%)	1,422															
Participants/Devices Deployed per year	284	284	284	284	284	0	0	0	0	0	0	0	0	0	0	1,422
Active Devices	142	427	711	996	1,280	1,422	1,422	1,422	1,422	1,422	1,422	1,422	1,422	1,422	1,422	
Water Heater LCS Deployment Cost	$85,333	$85,333	$85,333	$85,333	$85,333	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$426,667
Water Heater LCS Program Design	$75,000															$75,000
Water Heater LCS Messaging/Network ($/device/year)	$284	$853	$1,422	$1,991	$2,560	$2,844	$2,844	$2,844	$2,844	$2,844	$2,844	$2,844	$2,844	$2,844	$2,844	$35,556
Water Heater LCS Marketing & Education	$35,000	$35,875	$36,772	$37,691	$38,633	$39,599	$40,589	$41,604	$42,644	$43,710	$44,803	$45,923	$47,071	$48,248	$49,454	$627,617
Water Heater LCS Vendor Admin & Maintenance Fee	$30,000	$30,750	$31,519	$32,307	$33,114	$33,942	$34,791	$35,661	$36,552	$37,466	$38,403	$39,363	$40,347	$41,355	$42,389	$537,958
Water Heater LCS Program Costs	*$225,618*	*$152,812*	*$155,046*	*$157,322*	*$159,641*	*$76,386*	*$78,225*	*$80,109*	*$82,041*	*$84,021*	*$86,050*	*$88,130*	*$90,262*	*$92,448*	*$94,688*	*$1,702,797*
TOTAL COSTS	*$689,253*	*$545,222*	*$551,273*	*$557,407*	*$563,626*	*$160,680*	*$164,357*	*$168,126*	*$171,989*	*$175,949*	*$180,007*	*$184,168*	*$188,432*	*$192,803*	*$197,283*	*$4,690,573*

Kansas Electric Cooperative, Inc.
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Energy and Demand Savings

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	TOTAL
Yearly Participation Rate	20%	40%	60%	80%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	
PCT																
Peak Demand Savings from PCTs																
Average Peak Demand Reduction per Device (kW)	1.0															
Active Devices	538	1,613	2,688	3,763	4,838	5,376	5,376	5,376	5,376	5,376	5,376	5,376	5,376	5,376	5,376	
Yearly Peak Demand Reduction from PCTs (kW)	323	968	1,613	2,258	2,903	3,226	3,226	3,226	3,226	3,226	3,226	3,226	3,226	3,226	3,226	
Incurred Demand Charge ($/kW-yr)	$ 80.64	$ 83.04	$ 85.56	$ 89.84	$ 277.56	$ 95.28	$ 97.66	$ 100.10	$ 102.61	$ 105.17	$ 107.80	$ 110.50	$ 113.26	$ 116.09	$ 118.99	
Peak Demand Savings from Residential PCTs	*$26,011*	*$80,356*	*$137,991*	*$202,852*	*$805,768*	*$307,335*	*$315,019*	*$322,894*	*$330,966*	*$339,241*	*$347,722*	*$356,415*	*$365,325*	*$374,458*	*$383,820*	*$4,696,171*
Energy Savings from Residential PCTs																
Energy Savings from PCTs (kWh)																
Blended Levelized Cost of Energy (kWh)																
Wholesale Energy Savings from Residential PCTs	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*
Water Heater LCS																
Peak Demand Savings from Water Heater LCSs																
Average Peak Demand Reduction per Device (kW)	4.5															
Active Devices	142	427	711	996	1,280	1,422	1,422	1,422	1,422	1,422	1,422	1,422	1,422	1,422	1,422	
Yearly Peak Demand Reduction from Water Heater LCSs (kW)	77	230	384	538	691	768	768	768	768	768	768	768	768	768	768	
Incurred Demand Charge ($/kW-yr)	$ 241.92	$ 249.12	$ 256.68	$ 269.52	$ 277.56	$ 285.84	$ 292.99	$ 300.31	$ 307.82	$ 315.51	$ 323.40	$ 331.49	$ 339.77	$ 348.27	$ 356.97	
Peak Demand Savings from Water Heater LCSs	*$18,579*	*$57,397*	*$98,565*	*$144,894*	*$191,849*	*$219,525*	*$225,013*	*$230,639*	*$236,405*	*$242,315*	*$248,373*	*$254,582*	*$260,946*	*$267,470*	*$274,157*	*$2,970,709*
Energy Savings from Water Heater LCSs																
Energy Savings from Water Heater LCSs (kWh)																
Blended Levelized Cost of Energy (kWh)																
Wholesale Energy Savings from Water Heater LCSs	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*
TOTAL																
Total Energy Savings (MWh)	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Total Peak Demand Savings	*$ 44,591*	*$ 137,753*	*$ 236,556*	*$ 347,745*	*$ 997,617*	*$ 526,860*	*$ 540,032*	*$ 553,533*	*$ 567,371*	*$ 581,555*	*$ 596,094*	*$ 610,996*	*$ 626,271*	*$ 641,928*	*$ 657,976*	*$ 7,666,880*
Total Wholesale Energy Savings	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*

Kansas Electric Cooperative, Inc.
Power Supply Analysis Study
BMcD Project No. 87230

Cost/Benefit Evaluation Summary

Programmable Communicating Thermostats

KEPCO Costs	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	15-YR TOTAL
PCT Deployment Cost	$ 322,560	$ 322,560	$ 322,560	$ 322,560	$ 322,560	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,612,800
PCT Program Design	$ 75,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 75,000
PCT Messaging/Network ($/device/year)	$ 1,075	$ 3,226	$ 5,378	$ 7,529	$ 9,677	$ 10,752	$ 10,752	$ 10,752	$ 10,752	$ 10,752	$ 10,752	$ 10,752	$ 10,752	$ 10,752	$ 10,752	$ 134,400
PCT Marketing & Education	$ 35,000	$ 35,875	$ 36,772	$ 37,691	$ 38,633	$ 39,599	$ 40,589	$ 41,604	$ 42,644	$ 43,710	$ 44,803	$ 45,923	$ 47,071	$ 48,248	$ 49,454	$ 627,017
PCT Vendor Admin & Maintenance Fee	$ 30,000	$ 30,750	$ 31,519	$ 32,307	$ 33,114	$ 33,942	$ 34,791	$ 35,661	$ 36,552	$ 37,466	$ 38,403	$ 39,363	$ 40,347	$ 41,355	$ 42,389	$ 537,058
Total Cost	$ 463,635	$ 392,411	$ 396,227	$ 400,084	$ 403,985	$ 84,294	$ 86,132	$ 88,017	$ 89,948	$ 91,928	$ 93,957	$ 96,038	$ 98,170	$ 100,355	$ 102,595	$ 2,987,775
Contingency (15%)	$ 69,545.25	$ 58,862	$ 59,434	$ 60,013	$ 60,598	$ 12,644	$ 12,920	$ 13,202	$ 13,492	$ 13,789	$ 14,094	$ 14,406	$ 14,725	$ 15,053	$ 15,389	$ 448,166
Total Cost with Contingency	$ 533,180	$ 451,272	$ 455,661	$ 460,097	$ 464,582	$ 96,938	$ 99,052	$ 101,219	$ 103,440	$ 105,717	$ 108,051	$ 110,443	$ 112,895	$ 115,409	$ 117,985	$ 3,435,942

KEPCO Savings	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	15-YR TOTAL
Peak Demand Savings from Residential PCTs	$ 26,011	$ 80,356	$ 137,991	$ 202,852	$ 805,768	$ 307,335	$ 315,019	$ 322,894	$ 330,966	$ 339,241	$ 347,722	$ 356,415	$ 365,325	$ 374,458	$ 383,820	$ 4,696,171
Wholesale Energy Savings from Residential PCTs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total KEPCO Direct Benefits	$ 26,011	$ 80,356	$ 137,991	$ 202,852	$ 805,768	$ 307,335	$ 315,019	$ 322,894	$ 330,966	$ 339,241	$ 347,722	$ 356,415	$ 365,325	$ 374,458	$ 383,820	$ 4,696,171
Net Cost/Benefit	$ (507,169)	$ (370,916)	$ (317,669)	$ (257,245)	$ 341,185	$ 210,396	$ 215,967	$ 221,675	$ 227,526	$ 233,523	$ 239,670	$ 245,971	$ 252,430	$ 259,050	$ 265,835	$ 1,260,230
	$ (507,169)	$ (878,085)	$ (1,195,755)	$ (1,453,000)	$ (1,111,815)	$ (901,417)	$ (685,450)	$ (463,775)	$ (236,250)	$ (2,726)	$ 236,944	$ 482,915	$ 735,345	$ 994,395	$ 1,260,230	

IRR ($)	8.8%
NPV (2016$)	$ 325,994
Simple Payback Period	10 yrs

Water Heater Load Control Switches

KEPCO Costs	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	15-YR TOTAL
Water Heater LCS Deployment Cost	$ 85,333	$ 85,333	$ 85,333	$ 85,333	$ 85,333	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 426,667
Water Heater LCS Program Design	$ 75,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 75,000
Water Heater LCS Messaging/Network ($/device/year)	$ 284	$ 853	$ 1,422	$ 1,991	$ 2,560	$ 2,844	$ 2,844	$ 2,844	$ 2,844	$ 2,844	$ 2,844	$ 2,844	$ 2,844	$ 2,844	$ 2,844	$ 35,550
Water Heater LCS Marketing & Education	$ 35,000	$ 35,875	$ 36,772	$ 37,691	$ 38,633	$ 39,599	$ 40,589	$ 41,604	$ 42,644	$ 43,710	$ 44,803	$ 45,923	$ 47,071	$ 48,248	$ 49,454	$ 627,017
Water Heater LCS Vendor Admin & Maintenance Fee	$ 30,000	$ 30,750	$ 31,519	$ 32,307	$ 33,114	$ 33,942	$ 34,791	$ 35,661	$ 36,552	$ 37,466	$ 38,403	$ 39,363	$ 40,347	$ 41,355	$ 42,389	$ 537,058
Total Cost	$ 225,618	$ 152,812	$ 155,046	$ 157,322	$ 159,641	$ 76,386	$ 78,225	$ 80,109	$ 82,041	$ 84,021	$ 86,050	$ 88,130	$ 90,262	$ 92,448	$ 94,688	$ 1,702,797
Contingency (15%)	$ 33,843	$ 22,922	$ 23,257	$ 23,598	$ 23,946	$ 11,458	$ 11,734	$ 12,016	$ 12,306	$ 12,603	$ 12,907	$ 13,220	$ 13,539	$ 13,867	$ 14,203	$ 255,420
Total Cost with Contingency	$ 259,460	$ 175,733	$ 178,303	$ 180,921	$ 183,587	$ 87,844	$ 89,958	$ 92,125	$ 94,347	$ 96,624	$ 98,957	$ 101,350	$ 103,802	$ 106,315	$ 108,891	$ 1,958,217

KEPCO Savings	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	15-YR TOTAL
Peak Demand Savings from Water Heater LCSs	$ 18,579	$ 57,397	$ 98,565	$ 144,894	$ 191,849	$ 219,525	$ 225,013	$ 230,639	$ 236,405	$ 242,315	$ 248,373	$ 254,582	$ 260,946	$ 267,470	$ 274,157	$ 2,970,709
Wholesale Energy Savings from Water Heater LCSs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total KEPCO Direct Benefits	$ 18,579	$ 57,397	$ 98,565	$ 144,894	$ 191,849	$ 219,525	$ 225,013	$ 230,639	$ 236,405	$ 242,315	$ 248,373	$ 254,582	$ 260,946	$ 267,470	$ 274,157	$ 2,970,709
Net Cost/Benefit	$ (240,881)	$ (118,336)	$ (79,738)	$ (36,027)	$ 8,262	$ 131,681	$ 135,055	$ 138,513	$ 142,058	$ 145,691	$ 149,415	$ 153,232	$ 157,145	$ 161,156	$ 165,266	$ 1,012,492
	$ (240,881)	$ (359,217)	$ (438,955)	$ (474,982)	$ (466,720)	$ (335,039)	$ (199,983)	$ (61,470)	$ 80,588	$ 226,279	$ 375,694	$ 528,926	$ 686,071	$ 847,226	$ 1,012,492	

IRR ($)	14.0%
NPV (2016$)	$ 433,808
Simple Payback Period	8.4 yrs

APPENDIX B – TECHNOLOGY ASSESSMENT RESULTS

KEPCO TECHNOLOGY ASSESSMENT SUMMARY TABLE
GREENFIELD NATURAL GAS OPTIONS

BMcD Project Number 87230

PROJECT TYPE	2x1 F Class Fully Fired	1 x F Class SCGT	1 x LMS100 SCGT	1 x LM6000 SCGT	5 x Wartsila 20V34SG
BASE PLANT DESCRIPTION					
Number of Gas Turbines	2	1	1	1	5
Number of Steam Turbines	1	0	0	0	0
Steam Conditions (Main Steam / Reheat)	1050 F/1050 F	N/A	N/A	N/A	N/A
Main Steam Pressure	2200 psia	N/A	N/A	N/A	N/A
Steam Cycle Type	Subcritical	N/A	N/A	N/A	N/A
Capacity Factor (%)	Intermediate (50%)	Peaking (15%)	Peaking (15%)	Peaking (15%)	Peaking (15%)
Startup Time (Cold Start to Unfired Base Load) (Note 3, 4, 11)	140 Minutes	30 Minutes	10 Minutes	10 Minutes	5 Minutes
Startup Time (Warm Start to Unfired Base Load) (Note 3, 4, 11)	100 Minutes	N/A	N/A	N/A	N/A
Startup Time (Hot Start to Unfired Base Load) (Note 3, 4, 11)	70 Minutes	N/A	N/A	N/A	N/A
Startup Time (Cold Start to Stack Emissions Compliance) (See note 7)	60 Minutes	24 Minutes	8 Minutes	8 Minutes	4 Minutes
Startup Time (Warm Start to Stack Emissions Compliance) (See note 7)	30 Minutes	N/A	N/A	N/A	N/A
Startup Time (Hot Start to Stack Emissions Compliance) (See note 7)	30 Minutes	N/A	N/A	N/A	N/A
Maximum Ramp Rate (Online)	10% per minute	20%	33%	25%	50%
Ramp Rate (Duct Firing Online)	10% per minute	N/A	N/A	N/A	N/A
Forced Outage Factor (%) (Note 5)	2.4%	0.7%	5.5%	5.5%	0.2%
Forced Outage Rate (%) (Note 5)	3.6%	10.2%	30.6%	30.6%	0.5%
Equivalent Forced Outage Rate (%) (Note 5)	4.0%	10.2%	30.6%	30.6%	2.5%
Availability Factor (%) (Note 5)	87.5%	95.0%	87.6%	87.6%	97.1%
Fuel Design	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Heat Rejection	Wet Cooling Tower	Fin Fan Heat Exchanger	Wet Cooling Tower	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger
NOx Control	DLN/SCR	DLN	Water Injection/SCR	Water Injection	SCR
CO Control	Oxidation Catalyst	Good Combustion Practice	Oxidation Catalyst	Good Combustion Practice	Oxidation Catalyst
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice
Technology Rating	Mature	Mature	Mature	Mature	Mature
ESTIMATED CCGT PERFORMANCE (Note 1, 2, 8)					
Base Load Performance @ 35°F, 67% RH (Winter)					
Net Plant Output, kW	704,200	232,500	105,000	49,600	45,800
Net Plant Heat Rate, Btu/kWh (HHV)	6,530	9,610	8,350	9,520	8,450
Heat Input, MMBtu/h (HHV)	4,600	2,230	880	470	390
Incremental Duct Fired Performance @ 35°F, 67% RH (Winter)					
Incremental Net Plant Output, kW	193,300	N/A	N/A	N/A	N/A
Incremental Net Plant Heat Rate, Btu/kWh (HHV)	8,320	N/A	N/A	N/A	N/A
Incremental Heat Input, MMBtu/h (HHV)	1,650	N/A	N/A	N/A	N/A
Base Load Performance @ 55°F, 69% RH (Annual Average)					
Net Plant Output, kW	700,600	230,600	106,400	48,200	45,800
Net Plant Heat Rate, Btu/kWh (HHV)	6,510	9,660	8,270	9,690	8,450
Heat Input, MMBtu/h (HHV)	4,560	2,230	880	470	390
Incremental Duct Fired Performance @ 55°F, 69% RH (Annual Average)					
Incremental Net Plant Output, kW	201,000	N/A	N/A	N/A	N/A
Incremental Net Plant Heat Rate, Btu/kWh (HHV)	8,410	N/A	N/A	N/A	N/A
Incremental Heat Input, MMBtu/h (HHV)	1,690	N/A	N/A	N/A	N/A
Minimum Load Performance @ 55°F, 69% RH (Annual Average)					
Net Plant Output, kW	182,600	115,500	53,200	24,100	4,600
Net Plant Heat Rate, Btu/kWh (HHV)	7,440	11,640	10,570	11,390	9,510
Heat Input, MMBtu/h (HHV)	1,360	1,340	560	270	40
Base Load Performance @ 77°F, 65% RH (1% WB - Summer Peak)					
Net Plant Output, kW	688,700	225,900	99,700	45,500	45,600
Net Plant Heat Rate, Btu/kWh (HHV)	6,530	9,760	8,320	9,630	8,450
Heat Input, MMBtu/h (HHV)	4,500	2,210	830	440	390
Incremental Duct Fired Performance @77°F, 65% RH (1% WB - Summer Peak)					
Incremental Net Plant Output, kW	201,500	N/A	N/A	N/A	N/A
Incremental Net Plant Heat Rate, Btu/kWh (HHV)	8,540	N/A	N/A	N/A	N/A
Incremental Heat Input, MMBtu/h (HHV)	1,720	N/A	N/A	N/A	N/A
ESTIMATED CAPITAL AND O&M COSTS					
EPC Projects Cost, 2016 MM$ (w/o Owner's Costs)	**$529**	**$106**	**$117**	**$60**	**$60**
Owner's Costs, 2016 MM$	**$82**	**$32**	**$28**	**$23**	**$20**
Owner's Project Development	$0.9	$0.3	$0.3	$0.3	$0.3
Owner's Operational Personnel Prior to COD	$2.0	$0.3	$0.3	$0.3	$0.3
Owner's Engineer	$2.0	$1.0	$1.0	$1.0	$1.0
Owner's Project Management	$4.5	$0.8	$0.8	$0.8	$0.8
Owner's Legal Costs	$1.0	$0.5	$0.5	$0.5	$0.5
Owner's Start-up Engineering and Training	$0.6	$0.1	$0.2	$0.2	$0.2
Construction Power and Water	$1.7	$0.5	$0.6	$0.5	$0.5
Permitting and Licensing Fees	$0.5	$0.5	$0.5	$0.5	$0.5
Switchyard	$10.0	$4.1	$4.1	$4.1	$4.1
Political Concessions & Area Development Fees	$0.5	$0.5	$0.5	$0.5	$0.5
Startup/Testing (Fuel & Consumables)	$2.6	$0.7	$0.3	$0.1	$0.2
Site Security	$0.5	$0.2	$0.2	$0.2	$0.2
Operating Spare Parts	$7.2	$6.0	$2.5	$2.0	$0.5
Permanent Plant Equipment and Furnishings	$1.3	$0.3	$0.3	$0.3	$0.3
Builders Risk Insurance	$2.4	$0.5	$0.5	$0.3	$0.3
Water supply infrastructure (Note 14)	$3.7	$0.6	$0.6	$0.6	$0.2
Transmission Interconnect for 1 mile (Note 14)	$2.1	$2.1	$2.1	$2.1	$2.1
Natural Gas Line Interconnect for 5 miles (Note 14)	$9.0	$7.0	$5.5	$4.7	$4.5
Owner's Contingency (5% for screening purposes)	$29.1	$6.6	$6.9	$3.9	$3.5
Total Project Costs, 2016 MM$	**$611**	**$139**	**$145**	**$83**	**$80**
Total Project Costs, 2016 $/Unfired kW	**$870**	**$600**	**$1,360**	**$1,720**	**$1,750**
Total Project Costs, 2016 $/Fired kW	**$680**	N/A	N/A	N/A	N/A
O&M COSTS (Note 6, 9, 12, 13)					
Fixed O&M Cost, 2016$/kW-Yr	$7.70	$6.60	$10.90	$30.10	$22.50
Levelized Major Maintenance Cost, 2016$/GT-hour	$400	$400	$420	$200	$20
Levelized Major Maintenance Cost, 2016$/GT-Start	$15,000	$15,000	N/A	N/A	N/A
Variable O&M Cost, 2016$/MWh (excl. major maint.)	$1.50	$0.90	$4.50	$7.30	$3.90
Incr. Duct Fired Variable O&M, 2016$/MWh (excl. major maint.)	$1.30	N/A	N/A	N/A	N/A

KEPCO TECHNOLOGY ASSESSMENT SUMMARY TABLE
GREENFIELD NATURAL GAS OPTIONS

BMcD Project Number 87230

PROJECT TYPE	2x1 F Class Fully Fired	1 x F Class SCGT	1 x LMS100 SCGT	1 x LM6000 SCGT	5 x Wartsila 20V34SG
BASE PLANT DESCRIPTION					
ESTIMATED BASE LOAD OPERATING EMISSIONS, lb/MMBtu (Note 10)					
NO_x	0.007	0.033	0.007	0.092	0.017
CO	0.004	0.020	0.004	0.027	0.035
CO_2	120	120	120	120	120
PM/PM_{10}	0.01	0.01	0.01	0	0.03
ESTIMATED BASE LOAD OPERATING EMISSIONS, lb/MWh					
NO_x	0.050	0.320	0.060	0.690	0.140
CO	0.030	0.190	0.030	0.260	0.300
CO_2	760	1160	990	1160	1010
PM/PM_{10}	0.07	0.10	0.08	0.00	0.25

Notes
Note 1: New and clean performance is assumed. No performance degradation is included.
Note 2. Performance ratings based on elevation of 945 ft above msl.
Note 3. Startup times reflect unrestricted, conventional starts for all gas turbines. GT fast start options are NOT reflected in startup times, capital costs, or O&M costs above. Fast start package options allow 10-15 minute simple cycle starts for F class turbines, however the GT major maintenance $/start cost may increase.
Note 4: Cold start is >72 hours after shutdown. Hot start is <8 hours after shutdown. Simple cycle starts are not affected by hot, warm or cold conditions. Simple cycle starts assume purge credits are available.
Note 5: Outage and availability statistics are collected using the NERC Generating Availability Data System (GADS). Combined cycle data is based on North American units that came online in 2004 or later. Reporting period is 2009-2013.
Note 6. Major maintenance $/hr holds for all aero gas turbines. Major maintenance $/hr holds for frame gas turbines where hours per start is >27. Where hours per start is <27 on frame units, use the $/start value.
Note 7: On combined cycle units, the time to achieve stack emissions compliance is assumed to be driven by the temperature of the CO catalyst in addition to the time for the turbine to achieve MECL. For simple cycle units, this time reflects startup to MECL.
Note 8. GT pricing and performance includes evaporative coolers for inlet air conditioning. For full load ratings at 59°F and up, evaporative coolers are running. For colder ambients and part load conditions, evaporative coolers are turned off.
Note 9. Fixed O&M costs assume 25 full time equivalent (FTE) personnel for 2x1 plants, and 7 FTE for simple cycle plants. FOM costs do not include engine lease fees that may be available with LTSA, depending on OEM. Fixed O&M is based on the unfired output for the CCGT option. There is no incremental FOM for the fired output.
Note 10. Emissions estimates shown for steady state operation at annual average conditions. Estimates account for the impacts of SCR and CO catalysts on combined cycle, LMS100, and reciprocating engine options.
Note 11: For Wartsila engines, if the engine jacket temperature is >165 F, the engine can start in 5 mins. If the engine jacket temperature is between 120 F and 165F, it will take 1-2 hours to get to full load. If the engine jacket is <120 F, the preheaters will need to run to get the engine to 120 F. Once at 120 F, the engine will take 1-2 hours to get to full load, but it could take 6+ hours to get to 120 F.
Note 12: Wartsila engine major maintenance is shown per engine, regardless of plant configuration.
Note 13: VOM for simple cycle options assume the use of temporary trailers for demineralized water treatment.
Note 14: OSBL costs for water, gas will vary widely depending on greenfield site selection. Contingency does not cover these cost items as each of these allowances could increase by well over 100% for a specific site.

Additional Assumptions

General
- All estimates in this table are "screening level," preliminary and are not to be guaranteed.
- Fuel is pipeline quality natural gas with less than 0.5 grains Sulfur/100 scfm. Costs assume natural gas only capabilities.
- All emissions limits are subject to the BACT process.
- All options include an SCR and CO catalyst except LM6000 and F class simple cycle plants.
- Emissions are based on base load performance at 55°F and 69% RH.
- The information presented, including capital costs, start times, start-up fuel, start-up power generation, etc., are based on a conventional designed plant. At this point, no consideration has been given to a plant designed with fast start capabilities.
- All costs or information shown on a per KW basis are based on full load performance at the 55°F and 69% RH case.

Capital Cost Estimates
- An engineer, procure, construct (EPC) contracting method is assumed for this evaluation.
- Capital cost estimates assume overnight costs in 2016 USD. Escalation is excluded.
- Indirect costs include startup, startup management, design engineering/construction management, startup spare parts, overhead, and fees.
- Owner's costs do not include financing fees or AFUDC.
- The plant site is a greenfield site that is clear of trees and wetlands and is reasonably level. There are no existing structures or underground utilities.
- Sufficient laydown area is available.
- Piles are included under heavily loaded foundations.
- Typical buildings are included. Turbines are assumed to be installed outdoors.
- Simple cycle options assume the use of temporary trailers for water treatment. Combined cycle options include a permanent demineralized water system.

Tie-Ins
- Raw water is assumed to be available at the site boundary.
- Natural gas is assumed to be available on site at adequate pressure, flow, and quality. Compression is excluded for frame GTs. Compression is included for aeroderivative turbines only.
- A 230-kV onsite switchyard is included in the Owner's cost section above.

O&M Estimates
- Fuel costs are not included in the O&M analysis.
- The incremental duct fired O&M should only be accounted for over the incremental duct fired output and hours.
- O&M Costs do not include emissions allowances, property tax, or property insurance.
- O&M is estimated based on 100% load performances at the 55°F ambient condition.

KEPCO TECHNOLOGY ASSESSMENT SUMMARY TABLE
RENEWABLE ENERGY & STORAGE OPTIONS

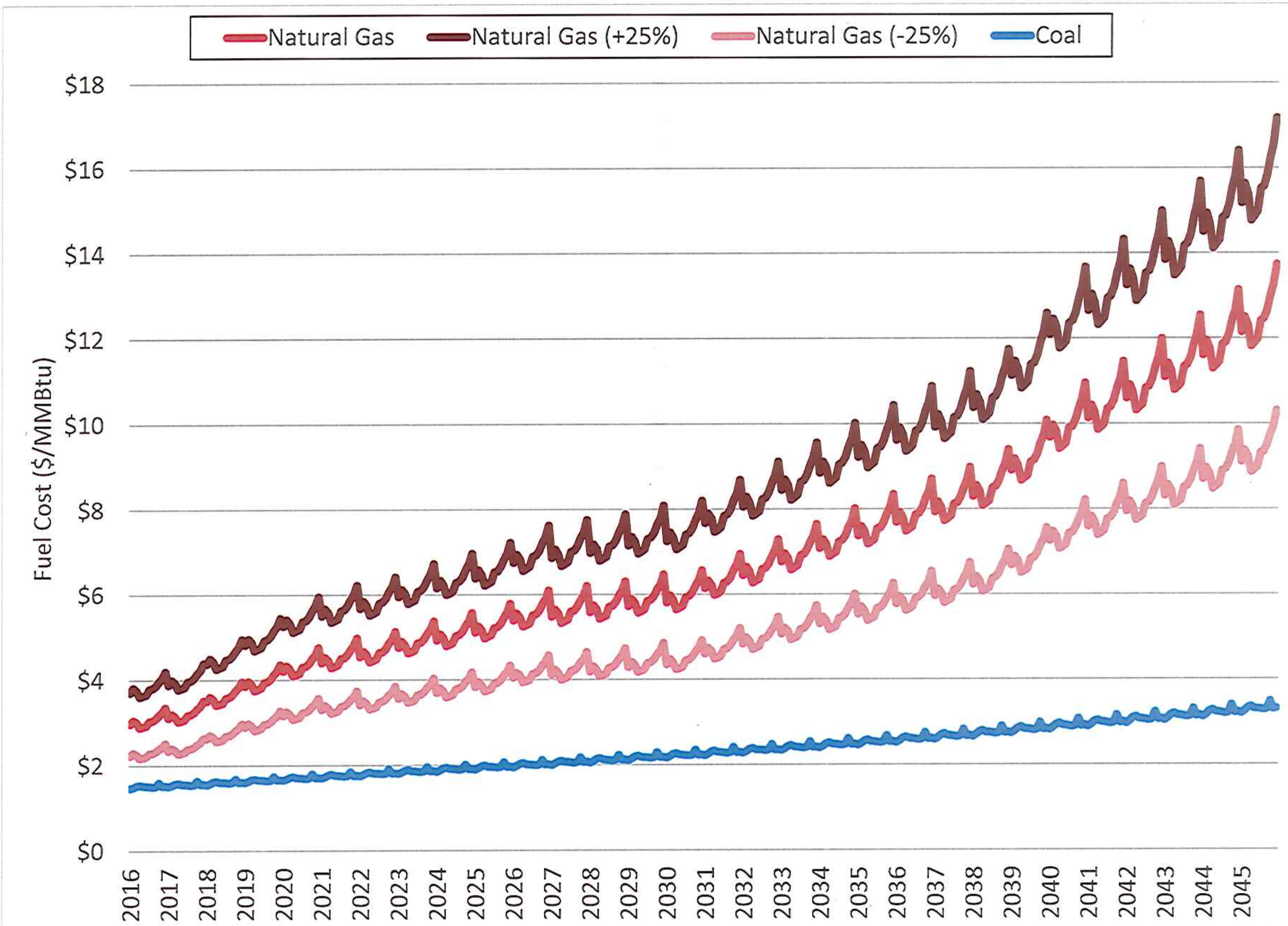
BMcD Project Number 87230

PROJECT TYPE	Advanced Battery Energy Storage		Wind Energy Conversion	Solar Photovoltaic	
BASE PLANT DESCRIPTION	**Lithium Ion**	**Lithium Ion**			
Nominal Output	10 MW / 40 MWh	1 MW / 1 MWh	200 MW	1 MW	10 MW
Number of Boilers/Reactors/Turbines	N/A	N/A	N/A	N/A	N/A
Number of Steam Turbines	N/A	N/A	N/A	N/A	N/A
Capacity Factor (%) (Note 1)	Intermittent (18%)	Intermittent (15%)	37%	22%	22%
Startup Time (Cold Start) (Note 6)	<1 minute	<1 minute	N/A	N/A	N/A
Forced Outage Factor (%)	N/A	N/A	5%	N/A	N/A
Equivalent Forced Outage Rate (%)	N/A	N/A	7%	N/A	N/A
Availability Factor (%) (Note 8)	95%	95%	95%	98%	98%
Fuel Design	N/A	N/A	N/A	N/A	N/A
NO_x Control	N/A	N/A	N/A	N/A	N/A
CO Control	N/A	N/A	N/A	N/A	N/A
SO_2 Control	N/A	N/A	N/A	N/A	N/A
Particulate Control	N/A	N/A	N/A	N/A	N/A
Technology Rating	Developmental	Developmental	Mature	Mature	Mature
Permitting & Construction Schedule (Years from FNTP)	1.5 Years	1.5 Years	2.5 Years	2 Years	2 Years
ESTIMATED PERFORMANCE					
Base Load Performance @ (Annual Average) (Note 4)					
Net Plant Output, kW	10,000	1,000	200,000	3,000	9,000
Round-Trip Efficiency (%)	90%	90%	N/A	N/A	N/A
ESTIMATED CAPITAL AND O&M COSTS					
Project Capital Costs, 2016 MM$ (w/o Owner's Costs) (Note 7)	$25	$1.5	$295	$2.5	$19
Owner's Costs, 2016 MM$ (Notes 5, 7, 9, 10)	$4	$0.8	$21	$2.9	$6.1
Total Screening Level Project Costs, 2016 MM$	**$29**	**$2.3**	**$316**	**$5**	**$25**
Total Screening Level Project Costs, 2016 $/kW	**$2,860**	**$2,310**	**$1,580**	**$1,790**	**$2,810**
Fixed O&M Cost, 2016$/kW-Yr (Note 2)	$16.20	$40.80	$42.00	$19.50	$19.50
Levelized Major Maintenance Cost, 2016$/MWh (Note 3)	N/A	N/A	Incl. in Fixed O&M	Incl. in Fixed O&M	Incl. in Fixed O&M
Variable O&M Cost, 2016$/MWh (excl. major maint.)	$1.44	$1.44	Incl. in Fixed O&M	Incl. in Fixed O&M	Incl. in Fixed O&M
ESTIMATED BASE LOAD OPERATING EMISSIONS, lb/MMBtu (HHV)					
NO_X	N/A	N/A	N/A	N/A	N/A
SO_2	N/A	N/A	N/A	N/A	N/A
CO_2	N/A	N/A	N/A	N/A	N/A
PM/PM_{10}	N/A	N/A	N/A	N/A	N/A
VOC	N/A	N/A	N/A	N/A	N/A
ESTIMATED BASE LOAD OPERATING EMISSIONS, lb/MWh					
NO_X	N/A	N/A	N/A	N/A	N/A
SO_2	N/A	N/A	N/A	N/A	N/A
CO_2	N/A	N/A	N/A	N/A	N/A
PM/PM_{10}	N/A	N/A	N/A	N/A	N/A
VOC	N/A	N/A	N/A	N/A	N/A

Notes

Note 1. Wind capacity factor represents Net Capacity Factor (NCF), which accounts for typical system losses.
Note 2. Fixed O&M for PV is $16.25 per kW DC, and adjusted for AC output.
Note 3. For wind, it is assumed that 20% of fixed O&M budget is set aside for unscheduled maintenance not covered by service and maintenance agreement. For battery systems, fixed O&M includes allowance for inverter maintenance and a battery replacement fund. PV O&M assumes fixed contract for all maintenance activities.
Note 4. Per typical warranty information. Assuming factory recommended maintenance is performed, PV performance is estimated to degrade ~3% in the first year and 0.7% each remaining year.
Note 5. Battery system assumes interconnection at distribution voltage and therefore excludes GSU and switchyard.
Note 6. Battery systems are theoretically capable of ramping 0% to 100% load in under one second. However, control schemes commonly manipulate startup times due to site infrastructure or monitoring characteristics.
Note 7. PV system assumes 1.2 AC-DC ratio. Project costs for PV and wind include medium voltage transformer. Owner's costs include allowances for switchyard, transmission interconnection, land, development, legal costs, spare parts, and permits.
Note 8. GADS data is unavailable for wind, PV, and battery storage. Availability is estimated.

APPENDIX C – ECONOMIC EVALUATION ASSUMPTIONS



Natural Gas
Natural Gas (+25%)
Natural Gas (-25%)
Coal
Fuel Cost ($/MMBtu)
$18
$16
$14
$12
$10
$8
$6
$4
$2
$0
2016
2017
2018
2019
2020
2021
2022
2023
2024
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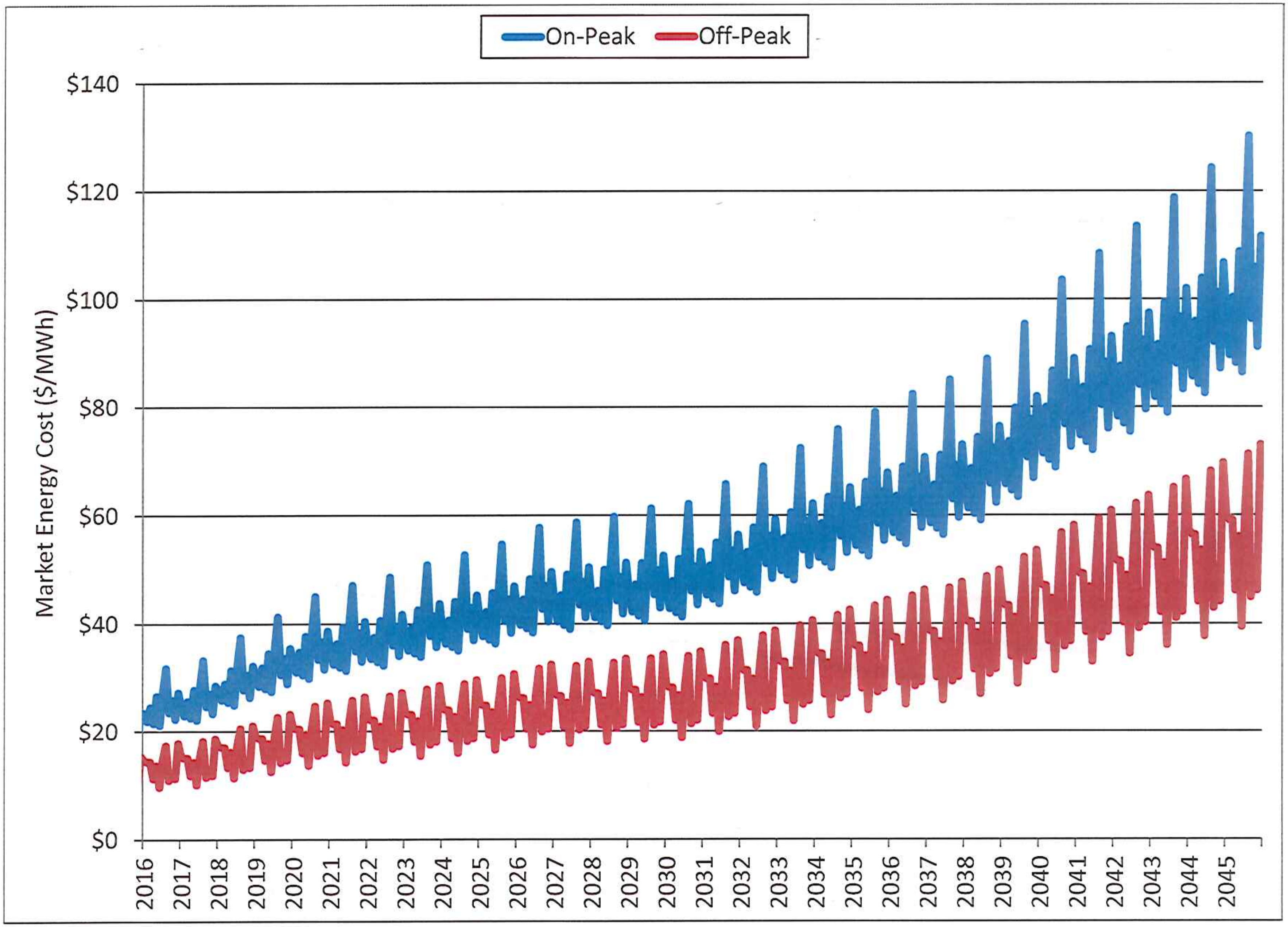
On-Peak
Off-Peak
Market Energy Cost ($/MWh)
$140
$120
$100
$80
$60
$40
$20
$0
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
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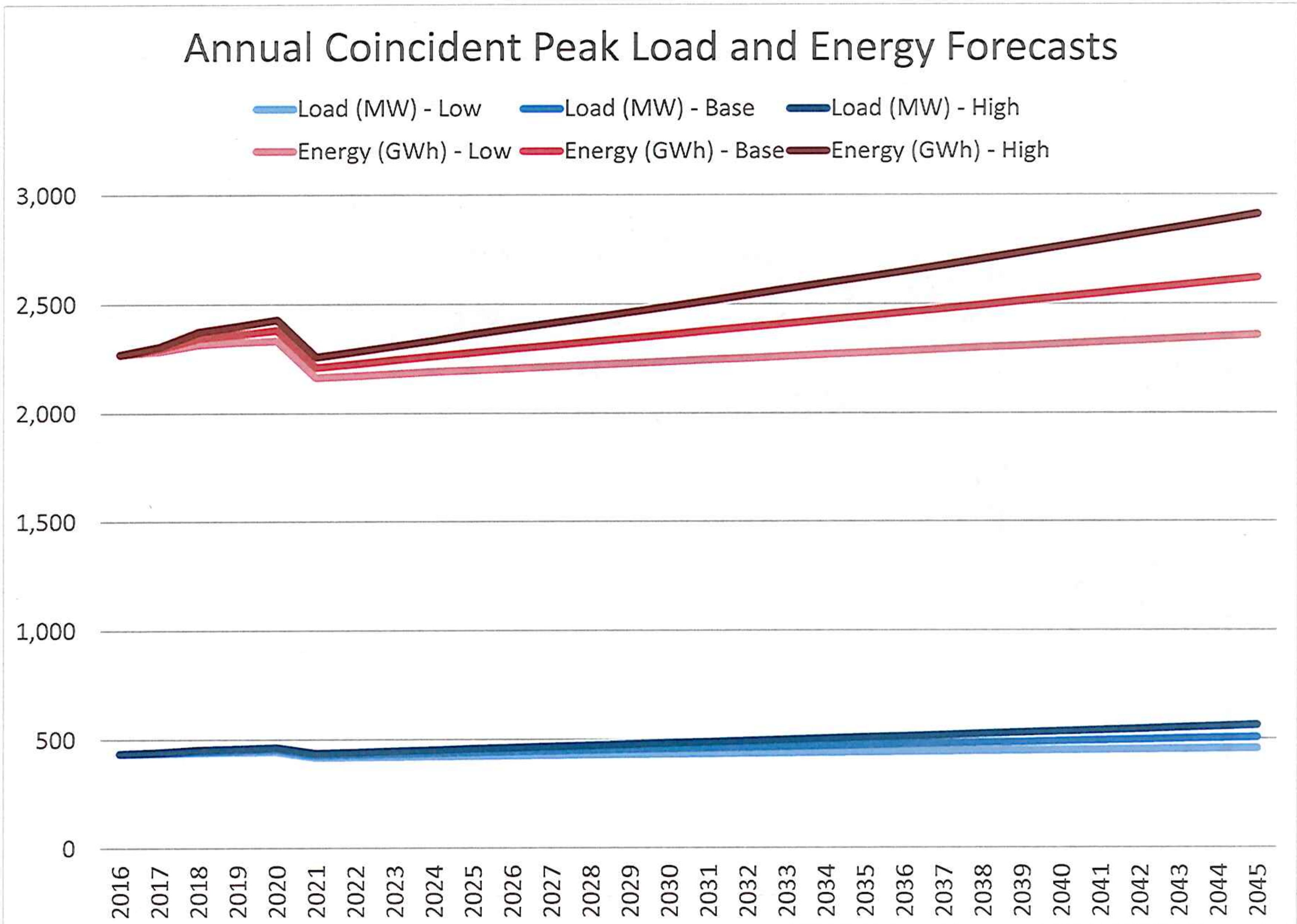
Annual Coincident Peak Load and Energy Forecasts
Load (MW) - Low
Load (MW) - Base
Load (MW) - High
Energy (GWh) - Low
Energy (GWh) - Base
Energy (GWh) - High
3,000
2,500
2,000
1,500
1,000
500
0
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
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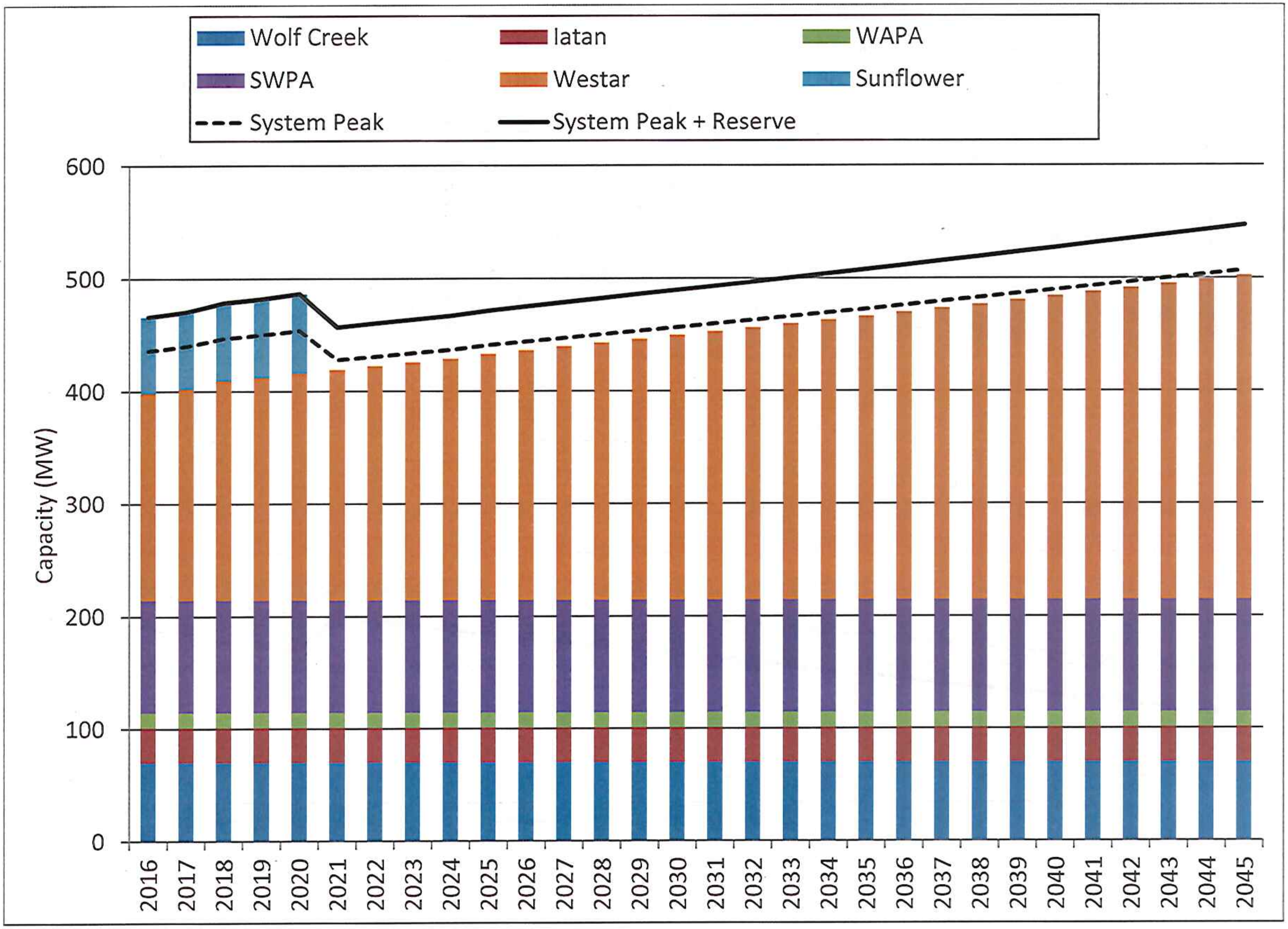
Wolf Creek
Iatan
WAPA
SWPA
Westar
Sunflower
System Peak
System Peak + Reserve
Capacity (MW)
600
500
400
300
200
100
0
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
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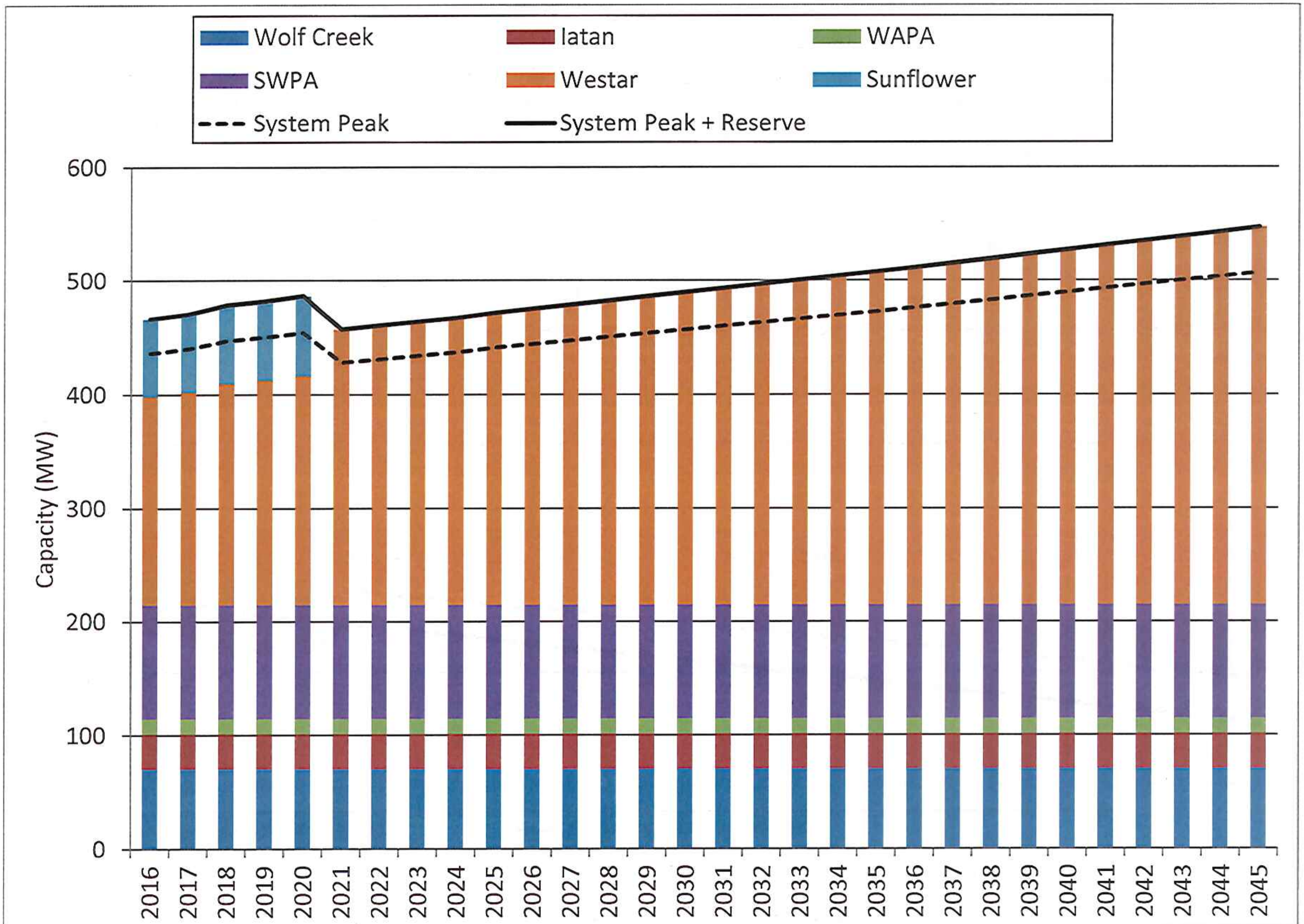
2045



Wolf Creek
Iatan
WAPA
SWPA
Westar
Sunflower
System Peak
System Peak + Reserve
Capacity (MW)
0
100
200
300
400
500
600
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
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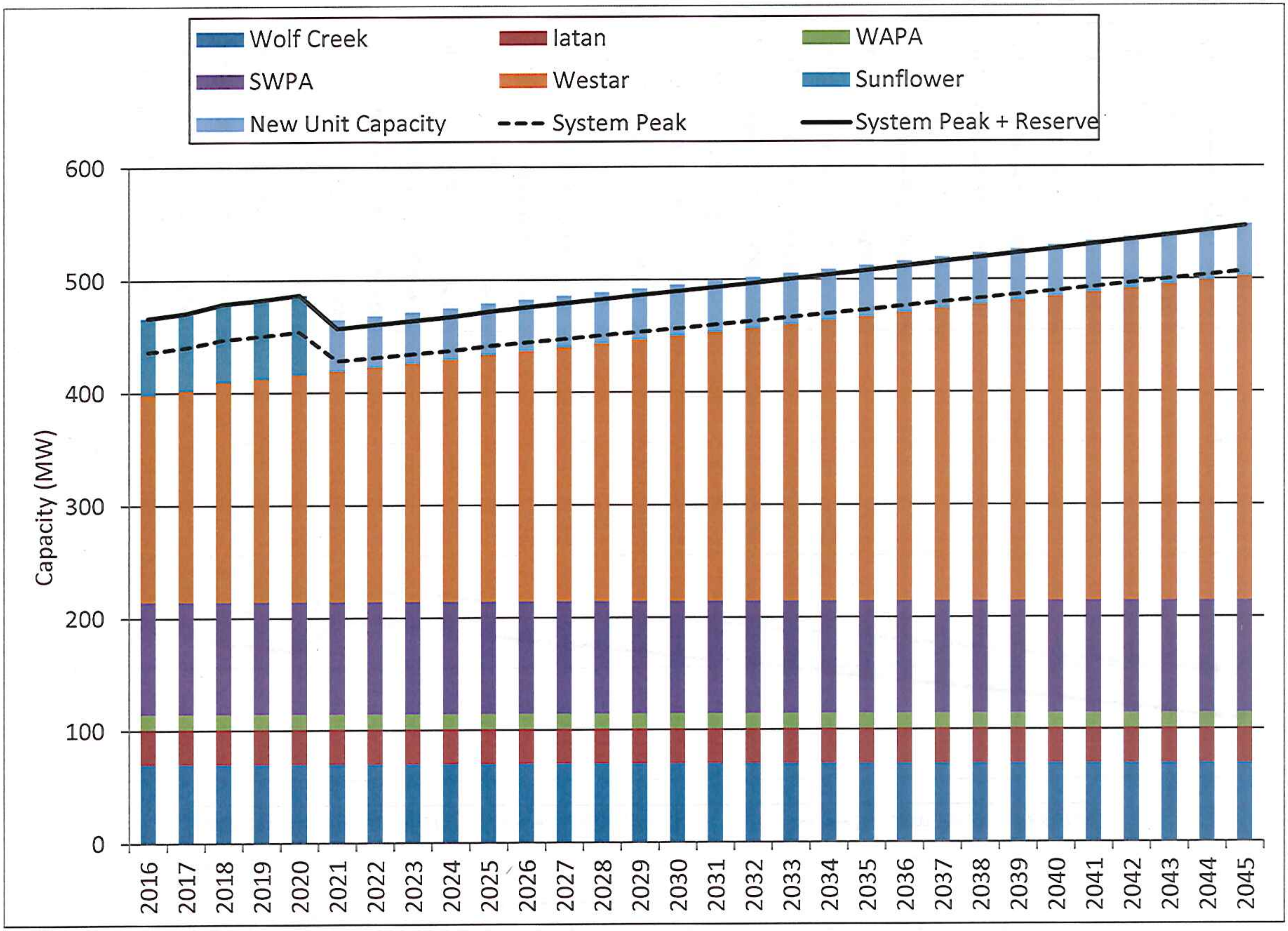

Wolf Creek
Iatan
WAPA
SWPA
Westar
Sunflower
New Unit Capacity
System Peak
System Peak + Reserve
Capacity (MW)
0
100
200
300
400
500
600
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
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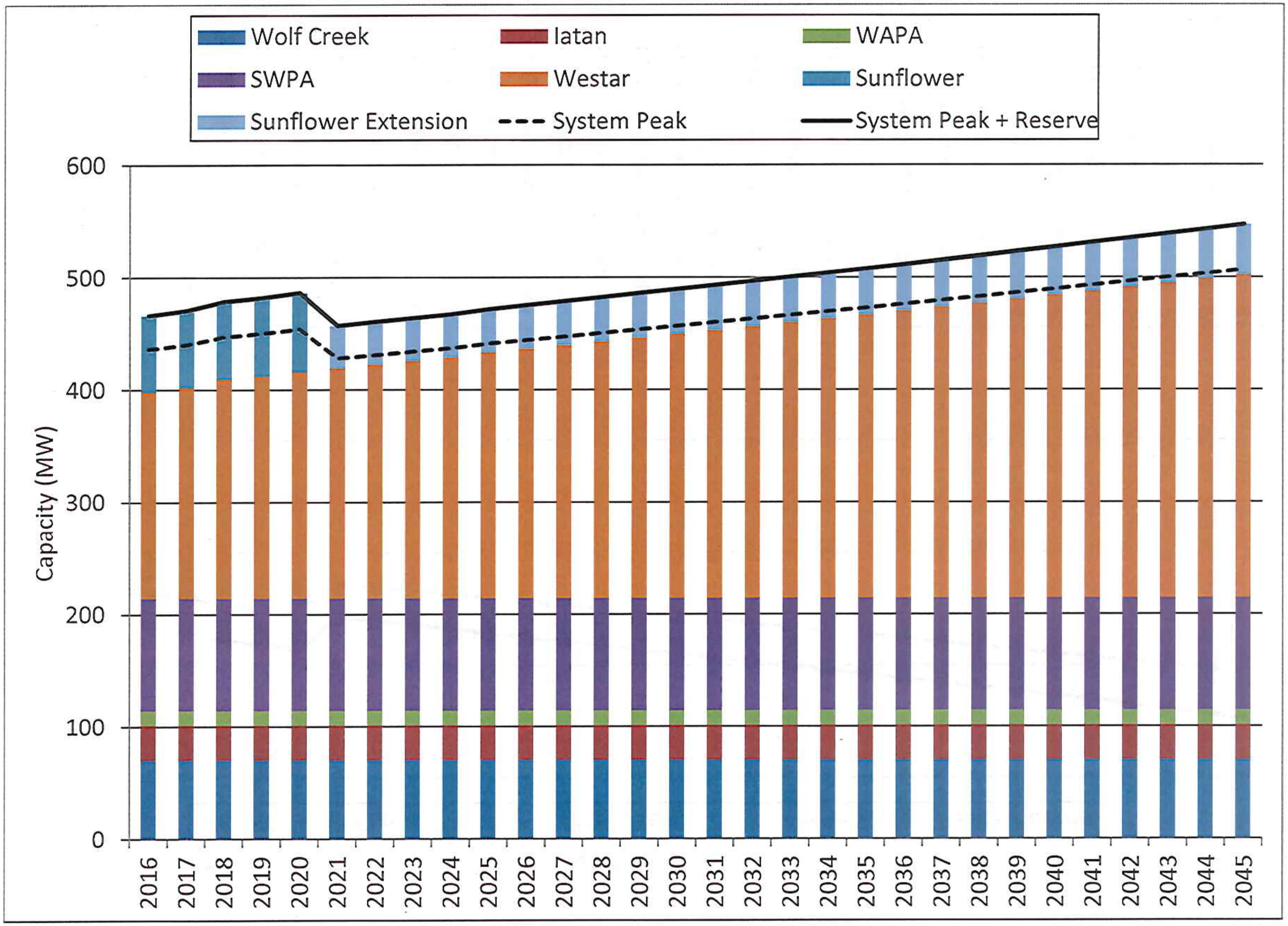
Wolf Creek
Iatan
WAPA
SWPA
Westar
Sunflower
Sunflower Extension
System Peak
System Peak + Reserve
Capacity (MW)
600
500
400
300
200
100
0
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
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PUBLIC NOTICE

Kansas Electric Power Cooperative, Inc. (KEPCo), headquartered in Topeka, is a not-for-profit generation and transmission utility serving the wholesale electric requirements of its nineteen member rural electric cooperatives in Kansas. KEPCo receives 13 MW of hydroelectric power from the Western Area Power Administration (WAPA). Every fifth year, KEPCo is required by WAPA to submit an Integrated Resource Plan (IRP). The IRP is a written evaluation of KEPCo's range of power supply alternatives, including new generation capacity, power purchases, energy conservation and efficiency, environmental impacts, and renewable energy resources, to provide economical and reliable service to KEPCo's nineteen member cooperatives.

WAPA requires that KEPCo solicit public comment as part of the IRP process. Accordingly, KEPCo invites comments or suggestions pertaining to the power supply alternatives mentioned in the above paragraph to be e-mailed to kepcoirp@kepco.org. Comments will be accepted from June 1, 2016 thru July 15, 2016. After the comments have been evaluated and incorporated, KEPCo will post the completed IRP on its web site (www.kepco.org).

Clay Center Dispatch
5 5th Street
Clay Center, KS 67432

Herington Times
7 North Broadway
Herington, KS 67449

Independence Daily Reporter
320 North 6th
Independence, KS 67301

Council Grove Republican
208 West Main Street
Council Grove, KS 66846

Wichita Eagle
825 East Douglas
Wichita, KS 67201

Times-Sentinel
101 N. Main
Cheney, KS 67025

South Haven New Era
309 W. Spring Ave
Conway Springs, KS 67031

Wellington Daily News
113 West Harvey
Wellington, KS 67152

Hanover News
200 North Railroad
Hanover, KS 66945

Sedan Times-Star
226 East Main
Sedan, KS 67361

Hillsboro Free Press
116 South Main
Hillsboro, KS 67063

Parsons Sun
220 South 18th St
Parsons, KS 67357

Leavenworth Times
422 Seneca Street
Leavenworth, KS 66048

Montgomery County Chronicle
202 West 4th Street
Caney, KS 67333

Marion Co. Record
117 South 3rd
Marion, KS 66861

Marysville Advocate
107 South 9th St.
Marysville, KS 66508

Lindsborg News-Record
114 South Main
Lindsborg, KS 67456

Coffeyville Journal
302 West 8th Street
Coffeyville, KS 67337

Winfield Daily Courier
201 E. 9th Ave
Winfield, KS 67156

Moundridge Ledger
135 South Christian
Moundridge, KS 67017

McPherson Sentinel
301 South Main
McPherson, KS 67460

Wamego Times
416 Lincoln
Wamego, KS 66547

Ninnescah Valley News
201 Maple
Pretty Prairie, KS 67570

Hutchinson News
300 West 2nd
Hutchinson, KS 67504

Yates Center News
113 Main
Yates Center, KS 66783

Clifton News-Tribune
105 West Parallel
Clifton, KS 66937

Wilson Co. Citizen
406 N. 7th
Fredonia, KS 66736

CERTIFICATION

I, William G. Riggins, do hereby certify that I am the duly appointed and qualified Assistant Secretary of Kansas Electric Power Cooperative, Inc. and that the following is a true and correct copy of the Resolution duly adopted by the Board of Trustees of Kansas Electric Power Cooperative, Inc. at its Board of Trustees meeting on August 17, 2016:

RESOLUTION NO. 16-8

APPROVING INTEGRATED RESOURCE PLAN

WHEREAS, pursuant to Section 114 of the Energy Policy Act of 1992, KEPCo is required to prepare and submit an Integrated Resource Plan (IRP) to the Western Area Power Administration (WAPA) under Subpart B – Integrated Resource Planning – Sections §905.10 thru §905.24 every fifth year; and,

WHEREAS, KEPCo has prepared its IRP, consisting of a written evaluation of KEPCo's range of power supply alternatives, including new generation capacity, power purchases, energy conservation and efficiency, environmental impacts, and renewable energy resources, to provide economical and reliable service to KEPCo's nineteen member cooperatives; and,

WHEREAS the IRP was presented to the KEPCo Board of Trustees;

NOW, THEREFORE, BE IT RESOLVED that the IRP presented to the Board of Trustees be adopted and approved for submission to the Western Area Power Administration.

BE IT FURTHER RESOLVED, that the officers of KEPCo are authorized to sign and transmit such IRP to the Western Area Power Administration in the form and in the manner required by the Western Area Power Administration.

And that the action taken and Resolution adopted as above set out has never been rescinded, altered, modified or repealed, and is on this date in full force and effect.

IN WITNESS WHEREOF, I hereby set my hand and attached the seal of the Corporation this 18th day of August, 2016.

William G. Riggins, Assistant Secretary