RESOLUTION NO: 5305

RESOLUTION APPROVING THE 2024 INTEGRATED RESOURCE PLAN OF THE KANSAS CITY BOARD OF PUBIC UTILITIES AN ADMINISTRATIVE AGENCY OF THE UNIFIED GOVERNMENT OF WYANDOTTE COUNTY/KANSAS CITY KANSAS PERTAINING TO PLANNING FOR NEW ENERGY SOURCES

WHEREAS, the Kansas City Board of Public Utilities (the "BPU") an administrative agency of the Unified Government of Wyandotte County/Kansas City ("Unified Government"), has prepared a 2024 Integrated Resource Plan in accordance with Department of Energy Regulations at 10 CFR Part 905, Subpart B for submittal to the Western Area Power Administration in accordance with the regulations; (attached is exhibit A) and

WHEREAS, the BPU reviewed the 2024 Integrated Resource Plan at numerous Work Session and Regular meetings, including accepting public comments; and

WHEREAS, the BPU has considered all matters it deemed necessary or appropriate to enable it to review, evaluate and reach an informed conclusion as to completeness and approval of the 2024 Integrated Resource Plan as supplemented and has determined that the 2024 Integrated Resource Plan as supplemented is complete to and in the best interests of the BPU.

BE IT RESOLVED BY THE KANSAS CITY BOARD OF PUBLIC UTILITIES AS FOLLOWS:

1. The 2024 Integrated Resource Plan as supplemented is determined complete and is authorized for submittal to the Western Area Power Administration pursuant to Department of Energy Regulations at 10 CFR Part 905, Subpart B, and provides for the overall direction of activities related to providing adequate and reliable electric service; and further

2. The General Manager of the BPU and other BPU staff as needed are authorized and directed to execute such planning activities as are necessary to provide reliable electric energy supply consistent with the 2024 Integrated Resource Plan as supplemented.

3. The Elected Board states its intent to review the IRP prior to the five year requirement.

ADOPTED BY THE GOVERNING BODY OF THE KANSAS CITY BOARD OF PUBLIC UTILITIES THIS 6th DAY OF NOVEMBER, 2024.

By: Thomas W. Groneman
Thomas W. Groneman, Board President

Approved as to form:

Attest: Stevie A. Wakes
Stevie A. Wakes, Board Secretary

2024 INTEGRATED RESOURCE PLAN

B&V PROJECT NO. 417702

PREPARED FOR

Kansas City Board of Public Utilities

30 AUGUST 2024

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1 Introduction and Background

1.1 INTRODUCTION

This 2024 Electric Integrated Resource Plan ("IRP") for the Kansas City Board of Public Utilities ("BPU") is intended to guide efforts to allow BPU to continue providing power to its customers for decades to come, while balancing the needs for affordability, reliability, and environmental sustainability. This 2024 IRP combines economics, engineering, and public engagement to chart a responsible course forward toward 2030 and beyond.

Long-term strategic planning is a continual and evolutionary process that calls for the re-analysis of utility system plans as market conditions, technologies, and power requirements change. One of the objectives of the IRP process is to find the lowest cost solution that will supply customers with the amount and quality of electric service desired while at the same time supporting the utility's long term financial health.

BPU is required by law to file an IRP with the Western Area Power Administration ("WAPA"), an Agency of the U.S. Department of Energy, and update the plan every five years. BPU is also required to submit annual progress reports on the status of its IRP. In return, BPU receives an annual allocation of approximately 4.8 megawatts ("MW") of capacity and about 14,900 megawatt-hours ("MWh") of hydroelectric power from WAPA.

1.2 BENEFITS OF IRP PLANNING

There are multiple benefits that can be gained through regular integrated resource planning. A good, practical plan manages risks and seeks to minimize long-term costs. It also encourages energy conservation and the use of renewable energy resources while also promoting the use of lower cost and more abundant fuels. Furthermore, it provides a forum for diverse interests and disciplines to communicate and develop a common goal to select acceptable resource options.

Among the benefits gained by BPU from integrated resource planning are:

- Deferral of the need for new generation capacity additions that has aided in stabilizing rates and keeping costs down for customers,
- Assistance in improving BPU's system load factor that allows better utilization of existing equipment,
- Increased use of more efficient generating equipment and thus lowering the per unit cost of power being generated,
- Reduction in energy consumption in certain situations by encouraging the use of more efficient appliances and building additions. Consequently, this has decreased load growth in peak periods, while at the same time increased off-peak energy usage, and
- Assistance in improving public relations with BPU customers and stakeholders.

1.3 BPU ELECTRIC UTILITY OVERVIEW

BPU was created in 1909 when Kansas City, Kansas purchased a privately-owned water system in order to provide the community with improved water service. In 1912, the BPU electric utility became operational, and the utility was officially established in 1929. BPU is a publicly owned administrative agency of the Unified Government of Wyandotte County/Kansas City, Kansas and is self-governed by an elected six-member board of directors. Since its inception, BPU's purpose has been to provide its customers with high quality electric and water services at the lowest possible cost.

BPU now serves 67,000 electric customers within a service territory of 155.9 square miles in Wyandotte County. The electricity needs of those customers are provided for with a combination of self-owned and jointly-owned thermal power plants along with purchased power agreements ("PPAs") for renewable energy. The energy generated and purchased by BPU reaches its customers through 29 substations and more than 3,000 miles of transmission and distribution lines.

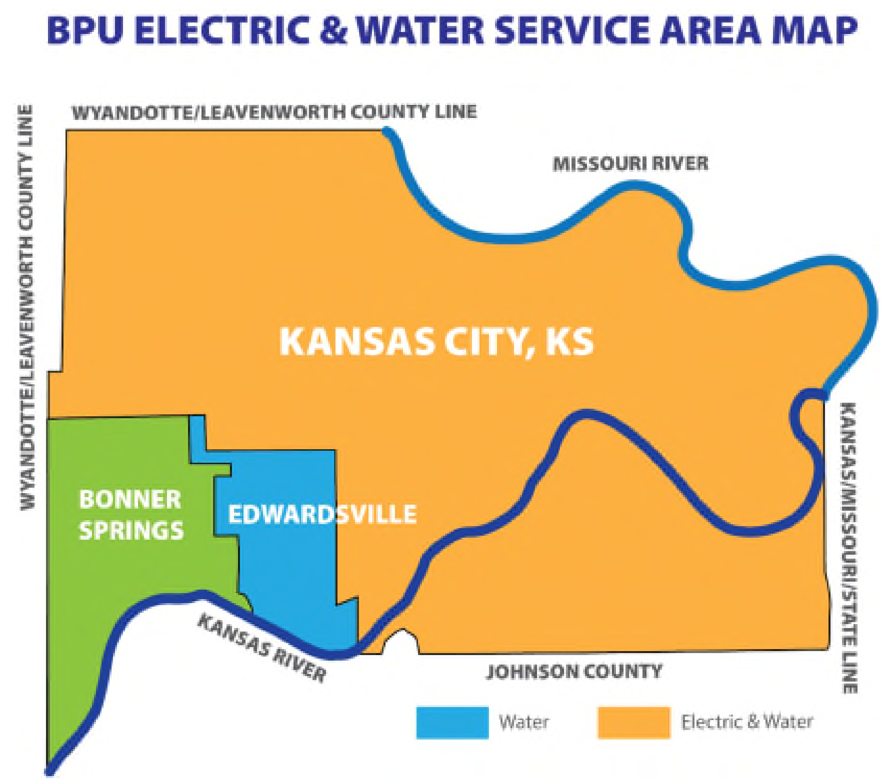

Figure 1-1 Kansas City BPU Service Area Map

1.4 INTEGRATED RESOURCE PLANNING PROCESS

Through the 2024 IRP process, BPU conducted an extensive study of customers' needs for the next 20 years based on currently available data. It did so by analyzing the costs and benefits of various supply alternatives to develop resource portfolio options that help meet BPU's planning objectives. The results of the IRP are not intended to represent static plans or pre-determined schedules for resource additions. Instead, the IRP results are best viewed as a range of possible future outcomes that BPU could experience. By analyzing multiple different scenarios with different sets of assumptions about the future, insights can be gained about the solutions that can best address the widest range of possible outcomes.

There are four phases to the IRP analysis that ultimately provided insights into BPUs strategy and near-term action plan to address its long-term resource needs. These phases are outlined in Figure 1-2 below. This report outlines the inputs, process, and outputs of each phase of this IRP.

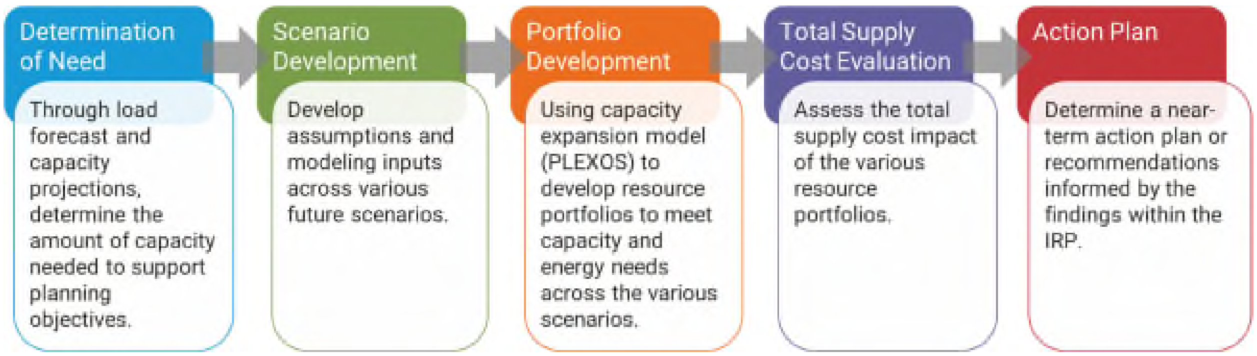

Figure 1-2 2024 IRP Analytical Framework

2 Determination of Need

A number of factors drive BPU's future capacity and energy requirements. These requirements over the next 20 years are driven by the magnitude of potential load growth, market-wide changes in planning reserve margin ("PRM") requirement, the expiration of existing purchased power agreements ("PPAs") for renewable energy, and the potential for the deactivation or retirement of BPU owned resources.

Section 2.1 of this IRP outlines the development of BPU's load forecast through the planning horizon, along with disposition and capacity contribution of BPU's existing resource mix. The resulting capacity position (i.e., peak load requirements, plus reserve requirements, minus BPU's available capacity) lays the foundation for the development of future portfolio options and evaluations.

Section 2.2 documents BPU's resource portfolio. There are the power plants and PPAs that are currently used to provide the electricity needed to meet customer needs. BPU has a diverse collection of energy generating facilities with multiple fuel types alongside a robust set of PPAs that provide large amounts of renewable energy.

Section 2.3 describes BPU's current set of demand side management ("DSM") and energy efficiency programs. These programs are designed to reduce the total amount of energy consumed by BPU's customers along with the peak load experienced by the system. In addition to saving customers money on their energy bills, these programs serve to reduce the cost to supply electricity during times of peak demand when market energy prices are at their highest.

2.1 LOAD ANALYSIS AND FORECAST

BPU's load forecast was developed by Black & Veatch covers the 20-year period of 2024 through 2043. This forecast used historical load data from BPU different load classes along with a series of econometric models to predict how customer's demands would change in the future.

The total net energy for load values listed in Table 2-1 represents the amount of energy that the utility would have to either generate or purchase to meet customer needs. These values include the additional load necessary to account for the losses inherent in all transmission systems. The annual peak loads in Table 2-1 represent the maximum coincident energy demand from BPU customers. Peak demand is an important consideration for future planning since it is tied to the calculation of BPU necessary planning reserve margin requirement within the Southwest Power Pool ("SPP").

The full analysis supporting the 2024 IRP load forecast is attached to this report in Appendix B.

Table 2-1 Annual Total Net Energy for Load and Peak Load Forecasts

Year	Total Net Energy for Load (MWh)	Annual Peak Demand (MW)
2024	2,663,548	486.6
2025	2,676,773	487.1
2026	2,690,106	487.6
2027	2,703,546	488.2
2028	2,717,094	488.7
2029	2,730,750	489.3
2030	2,744,515	489.9
2031	2,758,389	490.4
2032	2,772,373	491.0
2033	2,786,467	491.6
2034	2,800,671	492.2
2035	2,814,986	492.8
2036	2,829,413	493.4
2037	2,843,951	494.1
2038	2,858,602	494.7
2039	2,873,365	495.3
2040	2,888,241	496.0
2041	2,903,231	496.6
2042	2,918,336	497.3
2043	2,933,554	497.9

2.2 CURRENT RESOURCE PORTFOLIO

BPU currently serves its electric customers with a diverse portfolio of conventional thermal generation and renewable energy resources. BPU owns all or a portion of three active, traditional thermal generation sites: Nearman Creek Power Station, Quindaro Power Station, and Dogwood Energy Facility while its renewable energy comes from purchased power agreements. BPU's long-term purchased power agreements for renewable energy contribute to the diversity of the power supplied to customers and provide a hedge against fuel and wholesale energy price volatility. Table 2-2 provides a summary of BPU's current resource portfolio.

Table 2-2 BPU Existing Generation Resource Summary

Generator	Fuel Type	Resource Type	COD	Modeled Capacity (BPU Share)	Deactivation Assumption / Contract End Date
Nearman Creek Power Station					
Nearman Creek Unit 1	Coal	BPU Owned	1981	235 MW	--
Nearman Creek Unit 4	Gas/Oil	BPU Owned	2006	85 MW	--
Quindaro Power Station					
Quindaro CT 2	Oil	BPU Owned	1974	52 MW	--
Quindaro CT 3	Oil	BPU Owned	1977	55 MW	--
Dogwood Energy Facility[1]	Gas	Co-Owned	2002	116.3 MW	--
Smoky Hills Wind	Wind	Contracted	2008	25 MW	2027
Alexander Wind	Wind	Contracted	2015	25 MW	2035
Cimarron Bend Wind	Wind	Contracted	2017	200 MW	2037
Oak Grove					
Oak Grove Unit 1	Landfill Gas	Contracted	2010	1.6 MW	2029
Oak Grove Unit 2	Landfill Gas	Contracted	2013	1.95 MW	2029
SWPA Hydro	Hydro	Contracted	Various	38.6 MW	--
WAPA Hydro	Hydro	Contracted	Various	4.8 MW	--
Bowersock Hydro	Hydro	Contracted	1905	7 MW	2037
BPU Community Solar	Solar	Contracted	2017	1 MW	2042

[1] Dogwood is jointly owned. BPU has a 17% stake in the unit.

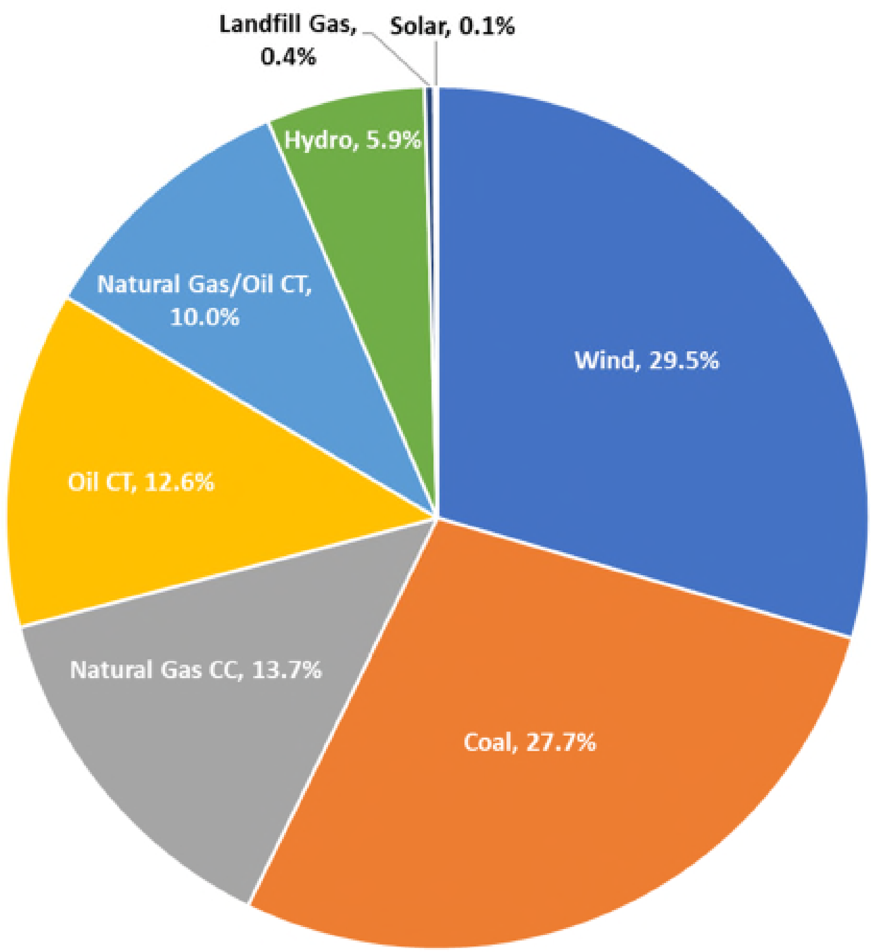

Figure 2-1 Existing BPU Capacity by Fuel and Power Plant Type

2.2.1 Thermal Generation

Thermal generating resources are power plants that use the heat energy released by burning fuel to generate electricity. BPU owns and operates thermal power plants in Wyandotte County at the Nearman Creek Power Station and the Quindaro Power Station. BPU also owns a portion of the Dogwood Energy Facility located in Pleasant Hill, Missouri. Together, these generating assets provide BPU with approximately 543 MW of generating capacity.

NEARMAN CREEK POWER STATION

The Nearman Creek Power Station is located on the south bank of the Missouri River at the northern end of 55th Street in Kansas City, Kansas. BPU owns and operates two units at Nearman Creek Power Station. Nearman Creek 1 is a coal-fired power plant that began operations in 1981 and has a modeled capacity of 235 MW. Nearman Creek CT 4 is a dual fuel natural gas and fuel oil simple cycle combustion turbine with a rated capacity of 85 MW that was commissioned in 2006.

QUINDARO POWER STATION

The Quindaro Power Station includes two simple cycle combustion turbines. Quindaro CT 2 came online in 1974 and has a modeled capacity of 52 MW. Quindaro CT 3 came online in 1977 and has a modeled capacity of 55 MW. Both of the Quindaro combustion turbine units use fuel oil as their primary energy source.

DOGWOOD ENERGY FACILITY

The Dogwood Energy Facility is a natural gas-fired, combined cycle power plant located in Cass County, Missouri, near the town of Pleasant Hill. Dogwood began commercial operations in February 2002. In May 2012, BPU purchased a 17% stake in Dogwood that gives it the rights to approximately 116 MW of generating capacity.

2.2.2 Wind Generation

BPU currently purchases a total of 250 MW of wind capacity from the Smoky Hills, Alexander, and Cimarron Bend wind farms. In a typical year BPU's three wind facilities produced approximately 1.1 million MWh or approximately 42% of BPU's total system energy needs.

SMOKY HILLS WIND

The 100 MW Smoky Hills wind facility located near Lincoln, Kansas achieved commercial operations in 2008. BPU has a purchased power agreement for a 25 MW share of the facility’s output and began receiving wind generated energy from Smoky Hills Wind Farm in early 2008. The contract is set to expire at the end of 2027.

ALEXANDER WIND

The Alexander Wind Project located in Rush County, Kansas has a total capacity of 48.3 MW and came online in 2015. The terms of BPU’s purchased power agreement give it a 25 MW share of the wind farm’s generating output through the scheduled end of the contract in 2035.

CIMARRON BEND WIND

BPU has a purchased power agreement for 200 MW of wind energy from the Cimarron Bend Wind Farm. This wind farm is located in Clark County, Kansas and has a total capacity of 599 MW. Per BPU’s long-term contract, it will continue to receive a share of the facility’s generation through the end of 2037.

2.2.3 Landfill Gas Generation

The methane gas produced in a landfill is a potent greenhouse gas that must be collected and flared off or used to produce heat or electricity in order to prevent it from migrating to the atmosphere where it contributes to local smog and global climate change. Using landfill gas to produce electricity results in beneficial use of the methane that would otherwise be wasted.

OAK GROVE

In 2008 BPU entered into a purchased power agreement with Oak Grove Power Producers, LLC. for capacity and energy from a landfill gas facility in Arcadia, Kansas. BPU currently receives a total of 3.55 MW of generation from the Oak Grove Landfill Gas and will continue to purchase that energy until the contract expires in 2029.

2.2.4 Hydroelectric Generation

BPU has existing contracts in place with three hydroelectric entities: the Southwest Power Administration ("SWPA"), the Western Area Power Administration ("WAPA"), and Bowersock. Hydroelectric generation is a cost-effective alternative to base load fossil fuel generation. BPU purchases a combined total of 50 MW of hydro capacity from its three hydro partners.

SWPA HYDRO

SWPA is one of four power marketing administrations within the U.S. Department of Energy whose role is to market and transmit electricity from 24 U.S. Army Corps of Engineers multipurpose dams. By law, SWPA's power is marketed and delivered primarily to public bodies such as rural electric cooperatives and municipal utilities. BPU's contract with SWPA entitles it to 38.6 MW of capacity. This contract is currently set to expire in 2035, but it is assumed that it will be renewed and will remain available through the end of the IRP planning period.

WAPA HYDRO

Like SWPA, WAPA is another of the four power marketing administrations within the U.S. Department of Energy. Under an agreement with WAPA, BPU is required by law to file an IRP with WAPA and update the plan every five years. The BPU is also required to submit annual progress reports on the status of its IRP. In return, the BPU receives an annual allocation of approximately 4.8 MW of capacity and about 14,900 MWh of hydroelectric power. This contract is scheduled to expire in 2034, but it is assumed that it will be renewed and will remain available through the end of the IRP planning period.

BOWERSOCK HYDRO

BPU has a purchased power agreement with the Bowersock Mills and Power Company to purchase the capacity and energy from a run-of-the-river hydroelectric facility on the Kansas River in Lawrence, Kansas. The Bowersock agreement provides 7 MW of power until its scheduled end in 2037.

2.2.5 Solar Generation

BPU COMMUNITY SOLAR

The BPU Community Solar Farm was constructed next to the Nearman Creek Power Station and became operational in September 2017 with a maximum output of 1 MW. Interested residential and commercial customers can lease panels at the solar farm and receive a credit for the energy output from their leased panels on their monthly energy bills.

2.3 CURRENT DEMAND SIDE MANAGEMENT PROGRAMS

The demand side management ("DSM") programs described in this section are either a continuation of those programs started as a result of a prior IRP or that were started in an effort to minimize costs and increase energy efficiency. DSM programs are used to incentivize customers to change the timing and amount of their energy use. By reducing the total amount of energy consumed and/or reducing energy usage during times of peak demand, customers can not only reduce their own utility bills, but also help to defer the need for additional new generating resources and minimize the costs borne by BPU to ensure that sufficient energy is always available to meet customer needs. The impact of these programs on both total annual load and peak load is reflected in the load forecast developed in support of this IRP.

2.3.1 System Load Factor Benefits

The DSM programs implemented by BPU contribute to improvement of the system load factor. The system load factor is a quotient of energy used (in kilowatt-hours or "kWh") divided by the product of the peak load (in kilowatts or "kW") and the number of hours in the year. Generally, an improvement in system load factor is desirable because it allows for the more efficient use of existing equipment and lowers the per unit cost of fuel. An improvement in system load factor occurs when the increase in total system energy requirements is greater than the increase in system peak demand.

Improvements in load factor associated with DSM result from the fact that some of the programs implemented have increased off-peak energy use, while others have encouraged energy conservation or the use of more efficient appliances at the time of peak loads. Reductions in peak demand also help BPU in reducing costs related to the purchase of off-system power.

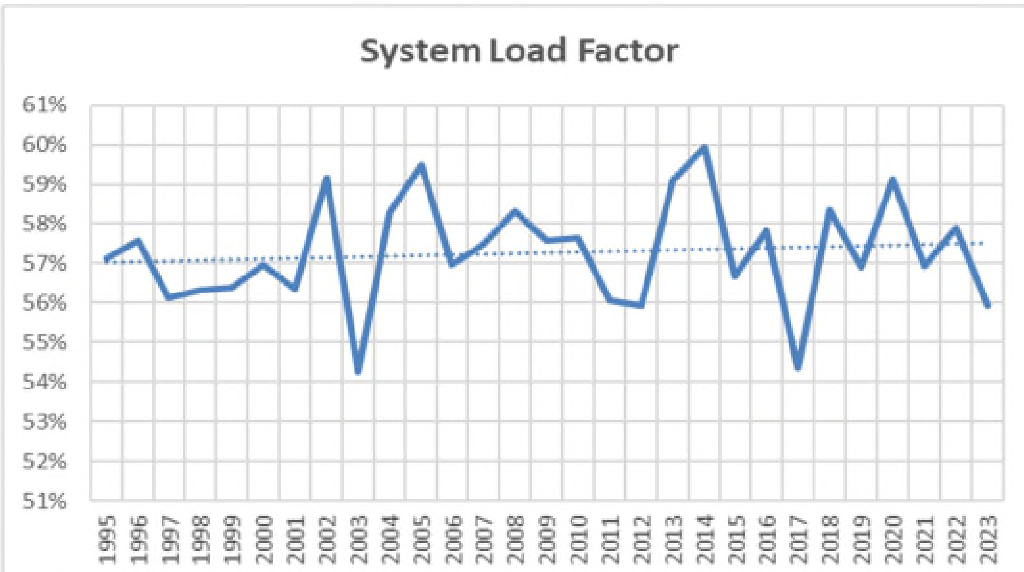

Figure 2-2 BPU System Load Factor

The apparent random variations in the load factor from year to year are due to a multitude of factors with the predominant reasons being shifting load dynamics and weather variations. The general trend of improvement in system load factor is attributed to the success of the DSM programs implemented by BPU. Some of the major contributors to this change in system load factor have been the following:

1. Electric heat pump and all electric home rebate program.
2. Changes in the electric rate structure lowering winter rates thus encouraging winter use and increasing summer rates making energy management programs economically viable.
3. Changes in the standards for the signal light and street light replacement program.
4. Implementation of construction standards emphasizing higher efficiency.

A discussion and documentation of each of these programs follows.

2.3.2 Heat Pump and Hot Water Heater Rebate Programs

The BPU Heat Pump and Hot Water Heater Rebate Programs began in 2001 and continue today. The program is designed for both residential and commercial customers and rebates are given to customers or builders who install or retrofit energy efficient heat pumps or hot water heaters. BPU partners with the Energy Star Program and rebates are consistent with Energy Star recommendations.

These programs are intended to incentivize residential and commercial customers to install highly efficient electric devices into their homes and businesses. These new efficient appliances allow customers to reducing the amount of energy being consumed, especially during those times when energy demand is at its highest. The programs also provide numerous benefits to the electrical system as a whole in a number of ways. They work to smooth energy consumption across the year to provide a more efficient load profile, reduce overall demand and energy consumption during those high demand periods that would likely require peaking resources to serve that incremental load, and lastly, by trimming the incremental peak it also helps extend the timeline and requirements associated with acquiring additional peaking generation.

These BPU rebate programs continue to drive demand for highly efficient electrical appliances especially from the residential development community. With the push to a cleaner resource mix and further electrification within the residential and commercial sector, it is anticipated that more consumers will consider participation in these programs.

Table 2-3 summarizes the incremental gains of the rebate programs over the last 6 years.

Energy Savings	2018	2019	2020	2021	2022	2023
Incremental Annual MWh Savings	203	210	61	232	43	198
Incremental Peak MW Demand Savings	0.41	0.44	0.12	0.43	0.09	0.4

Table 2-3 BPU Rebate Program Energy Savings

2.3.3 Utility Learning Center

BPU established an on-site Utility Learning Center to assist customers in the area of energy efficiency. Under this program, customers are able to meet with trained energy efficiency staff to review their bills and consumption patterns within the Energy Engage portal while also learning about energy efficiency methods that may be useful and cost-effective for their residence or business. This program is designed to inform customers about the tools and technologies that are currently available and to teach them how to best use those technologies to track and manage their energy consumption.

2.3.4 Reactive Adjustment Rider

Customers with low power factors impose a burden on the electrical system by causing a utility to increase its capacity for the generation, transmission, and distribution of energy. Power factors are functions of real power (kW) and the apparent power (kVA) that a utility must supply to the customer. For any given-metered load in kW, the lower the power factor, the greater the amount of apparent power (kVA) a utility must generate and deliver to the customer. For example, in order to supply a load of 100 kW having a power factor of 85% the utility would have to generate and deliver approximately 117.6 kVA. An 85%

power factor would require equipment with 17.6% more capacity to meet this demand. Further, since system losses vary as the square of the amperage required to serve the load, there is at the same time a 36% increase in system losses. BPU rates are designed to permit a customer to have a power factor greater than or equal to 90%. Customers with power factors less than 90% are penalized.

In August 2003, the power factor penalty provision was revised because the then current rate structure did not adequately address the cost of low power factors while customers with low power factors continued to impose a burden on the BPU system. A customer with a low power factor can correct its power factor by installing corrective equipment or by modifying the use of its equipment. When this new reactive adjustment penalty provision was enacted, customers were notified of the change and given a six-month grace period in which to take corrective action.

Currently, customers are notified if they have a low power factor and are given an opportunity to correct the problem. If corrective action is not taken within a reasonable period of time, then a penalty is added to their bill. The penalty is the difference between 90% and the actual power factor applied to the customer's total monthly electric billing. For example, if a customer has a power factor of 80% then a penalty of 10% is applied to the bill (90% minus 80% equals 10%).

BPU continues to review rate design and charges related to power factors to ensure that those customers that drive additional cost on the system are paying for their share of utilization of the system. Power factor data, much like many other customer specific details, are analyzed to determine their true cost to ensure subsidization between customers is mitigated as much as possible.

2.3.5 Net Metering

In May 2009, Kansas passed the Net Metering and Easy Connection Act which is applicable to Investor-Owned Utilities (IOU's) only. BPU, as a municipal utility, was not subject to that regulation. However, BPU did develop and adopt net metering and connection standards for Large, Medium, and Small Commercial and Residential customers to enable customer owned renewable generation sources. Although regulations surrounding net metering are now required, BPU was actively participating in net metering and providing customers a means to self-generate well before required to do so. Due to the falling prices surrounding photovoltaic solar installations and the robustness of the BPU net metering program, BPU has seen substantial growth in customer participation. In 2014, BPU only had 4 customers on the net metering program while at the end of 2018 the count of participating customers had increased to 39. By the end of 2023, BPU had a total of 301 net metering customers. BPU continues to monitor regulations and studies from around the country to ensure that the organization is actively pursuing best practices in self-generation while attempting to limit cross-subsidization.

2.3.6 Smart Meters

Over the past several years, BPU implemented Advanced Metering Infrastructure ("AMI") or "smart metering technology" to all BPU customers. The goal of the Advanced Metering Infrastructure is to improve customer service, lower BPU's expense structure, and provide consumers with the ability to monitor and drive efficiencies within their own systems. The new meters are more accurate, less prone to failure, and eliminate the potential for reader error that existed with the older electro-mechanical meters. In 2015, BPU rolled out the Energy Engage Portal which allowed customers the ability to access their own individualized data regarding energy usage. AMI meters are another tool that consumers can use that can have a direct impact on their energy usage and energy costs. BPU continues to explore new ways to make the data more accessible and more useful to both the customer and the utility.

2.3.7 FlexPay Program

In August 2017, BPU rolled out a new payment method called the FlexPay program. The FlexPay program was designed to allow customers more flexibility in the manner in which they view and manage their energy needs as well as when and what payments are made. FlexPay is a program that allows customers to monitor their electricity and water usage on an as-needed basis. This program also allows customers to receive service with no deposit or late fees while providing customers the ability to view their account balance, daily usage, payment history, and more through an App or an online portal. There are approximately 1,300 customers currently participating in the FlexPay program.

2.4 FUTURE RESOURCE REQUIREMENTS

A number of factors are considered and evaluated in order to understand and determine BPU's resource needs: Long-Term Capacity Requirements – BPU is projected to need new generating capacity over the course of the 20-year IRP period in order to reliably serve customers. Taking deactivation assumptions, contract expirations, and load growth into account, BPU is expected to see a capacity deficit beginning in 2030. Without action, this deficit is anticipated to continue an grow throughout the planning horizon. Table 2-4 below shows BPU's existing resource portfolio, as described above, compared to BPU's peak load-plus-reserve-margin target under the "Base Case" assumptions. The deficit expands over time as expected loads increase and older generating units reach an assumed end of useful life.

Table 2-4 Base Case Firm Capacity Forecast: 2024 – 2043

BASE CASE FIRM CAPACITY FORECAST (MW)																				
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
Nearman Creek 1	240.0	240.0	220.8	220.8	220.8	220.8	220.8	220.8	220.8	220.8	220.8	220.8	220.8	220.8	220.8	220.8	220.8	220.8	220.8	220.8
Nearman Creek CT4	81.0	81.0	74.5	74.5	74.5	74.5	74.5	74.5	74.5	74.5	74.5	74.5	74.5	74.5	74.5	74.5	74.5	74.5	74.5	74.5
Dogwood	105.0	105.0	99.8	99.8	99.8	99.8	99.8	99.8	99.8	99.8	99.8	99.8	99.8	99.8	99.8	99.8	99.8	99.8	99.8	99.8
Quindaro CT2	43.0	43.0	39.6	39.6	39.6	39.6	39.6	39.6	39.6	39.6	39.6	39.6	39.6	39.6	39.6	39.6	39.6	39.6	39.6	39.6
Quindaro CT3	48.0	48.0	44.2	44.2	44.2	44.2	44.2	44.2	44.2	44.2	44.2	44.2	44.2	44.2	44.2	44.2	44.2	44.2	44.2	44.2
SWPA Hydro	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6
WAPA Hydro	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Bowersock Hydro	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0						
Oak Grove Unit 1	1.6	1.6	1.6	1.6	1.6	1.6														
Oak Grove Unit 2	1.95	1.95	1.95	1.95	1.95	1.95														
Smoky Hills Wind	3.8	3.8	3.8	3.8																
Alexander Wind	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8								
Cimarron Bend Wind	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0						
BPU Solar	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	
Total Firm Capacity:	**604**	**604**	**566**	**566**	**562**	**562**	**559**	**559**	**559**	**559**	**559**	**559**	**555**	**555**	**523**	**523**	**523**	**523**	**523**	**522**
System Peak	487	487	488	488	489	489	490	490	491	492	492	493	493	494	495	495	496	497	497	498
System Peak + Capacity Margin (15%)	560.1	560.1	561.2	561.2	562.4	562.4	563.5	563.5	564.7	565.8	565.8	567.0	567.0	568.1	569.3	569.3	570.4	571.6	571.6	572.7
Firm Capacity Surplus/(Deficit)	**44.0**	**44.0**	**4.8**	**4.8**	**(0.1)**	**(0.1)**	**(4.8)**	**(4.8)**	**(6.0)**	**(7.1)**	**(7.2)**	**(8.3)**	**(12.1)**	**(13.2)**	**(46.4)**	**(46.4)**	**(47.6)**	**(48.7)**	**(48.7)**	**(50.4)**

2.5 EPA'S EMISSION GUIDELINES FOR GREENHOUSE GAS EMISSIONS FOR ELECTRIC UTILITY GENERATING UNITS

On May 11, 2023, US Environmental Protection Agency ("EPA") issued proposed Clean Air Act emission limits and guidelines for carbon dioxide ("CO2") from fossil fuel-fired power plants based on cost-effective and available control technologies ("EPA GHG Standards"). This rule, along with other environmental and sustainability initiatives at the federal and local levels, including customer-driven initiatives, increase the complexity and uncertainty within the long-term strategic planning considered by this IRP. These new standards and initiatives drive an increased need for proactive planning to replace aging and carbon-intensive infrastructure.

2.5.1 EPA GHG Standards – BPU Impact

In April 2024, the EPA finalized new rules relating to power plant carbon emissions, potentially impacting the future operation of existing coal-fired power plants, natural gas and oil-fired generating units, and new and reconstructed gas-fired combustion turbines. Below are summarized the key standards that could impact future capacity, energy needs, and the options available to meet those challenges. Each of the bulleted items below represent the actions prescribed by the new EPA rules that would be deemed acceptable methods to reduce the emission of CO2 from the energy generation sector.

- For new gas-fired baseload combustion turbines, with capacity factors above 40%, Phase One of the GHG Standards require best maintenance practices through December 2031. Phase Two of the GHG rules require 90% carbon capture and sequestration or co-firing with hydrogen, with a compliance deadline of January 1, 2032. If the combustion turbine's capacity factor stays below 40%, these additional modifications would not be required.

- Existing coal plants that intend to operate on or past January 1, 2039 need to meet a 90% capture of CO2 emissions by January 1, 2032. This would be accomplished by retrofitting the existing coal plant with a carbon capture and sequestration system.

- Existing coal plants that plan to operate on or past January 1, 2032 but retire before January 1, 2039 will need to make provisions to co-fire 40% natural gas by January 1, 2030.

- Existing coal plants that plan to retire prior to January 1, 2032 and commit to do so under the state plans submitted to the EPA are exempt from the new GHG Standards and will not have to make any modifications to control carbon emissions.

Within this IRP, Scenarios 2 and 3 were created to explores opportunities to reduce emissions at BPU's only coal facility, Nearman Creek 1, in accordance with the methods approved by the EPA.

3 Scenario Development

To address the uncertainty and risk inherent in long-term planning, including the uncertainty regarding existing and future environmental regulation, the IRP involves the modeling of multiple scenarios. The scenarios used within this IRP encompass a range of potential load and fuel forecasts, reserve margin requirements, environmental regulation requirements, the disposition of and investments in existing resources, and portfolio alternatives. Each scenario represents a possible future that BPU could experience. Because it is impossible to perfectly predict the future, it is not reasonable to merely select the results from one scenario or sensitivity case to determine which resource options to pursue. It is more reasonable to identify resource options that appeared most frequently in the results across all the scenarios. In this way, BPU can be more confident that the resource options it chooses to develop will become and remain valuable additions to its portfolio regardless of which future occurs.

Ten scenarios were developed for this IRP, blending reliability, economics, and societal considerations. Scenario 1 serves as the “business as usual” Base Case while Scenarios 2 through 4 assess the future disposition of Nearman Creek 1 in response to environmental regulation risk. Scenarios 5 through 7 assess the fuel price and load uncertainty. Scenarios 8 through 10 assess the impact of various resource plan strategies.

3.1 SCENARIO 1 - BASE CASE

Scenario 1 – *Base Case*

- All existing thermal resources continue to operate without changes to fuel or emissions controls.
- SWPA and WAPA hydro agreements continue through the end of the planning period.
- All other purchased power agreements expire at the end of their existing terms.

Scenario 1, or the “Base Case,” represents a future at BPU that maintains the status quo. The existing thermal power plants in the BPU portfolio are assumed to continue operating under the same basic operational parameters while still requiring continued capital investments to continue running reliably. The additional capital costs from the most recent “Life Assessment Report” for the Nearman Creek Power Station and Quindaro Power Station were included in the PLEXOS model as additional fixed operations and maintenance costs.

The intent of the Base Case is to generate operating cost estimates in the absence of any new environmental regulations. The Base Case uses the load forecast and existing units as defined in Table 2-4 with retirements and PPA expirations as indicated by the year of the first shaded gray cell for each line item.

In this scenario Nearman Creek 1 operates through the planning period and beyond with no changes to fuel use or new emissions controls.

3.2 SCENARIO 2 – CO-FIRING OF NATURAL GAS AT NEARMAN CREEK 1

Scenario 2 -
Co-Firing of Natural Gas at Nearman Creek 1

- Base Case with one modification:
- Nearman Creek 1 begins co-firing with 40% natural gas on January 1, 2030 and permanently cease operations before January 1, 2039.

To evaluate and understand the potential implications of the new EPA GHG Standards, the Base Case model was modified to convert Nearman Creek 1 to operate partially on natural gas. Starting in 2030 and running through the end of 2038, Nearman Creek 1's operating characteristics were changed to force it run 40% on natural gas. Co-firing with natural gas would allow for a 16% reduction in the emissions rate for Nearman Creek 1, allowing the unit to comply with the new CO2 emission standards through 2038. Within Scenario, by the requirements of the new EPA rules, Nearman Creek 1 would be forced to retire prior to January 1, 2039. All other inputs and assumptions from the Base Case were left unchanged.

3.3 SCENARIO 3 – NEARMAN CREEK 1 CARBON CAPTURE AND SEQUESTRATION

Scenario 3
Nearman Creek 1 Carbon Capture and Storage

- Base Case with one modification:
- Nearman Creek 1 implements carbon capture and sequestration on January 1, 2032.

Similar to Scenario 2, Scenario 3 was created to evaluate possible BPU responses to the new EPA GHG Standards. Under this scenario, Nearman Creek 1 was retrofitted to operate with a 90% effective carbon capture and sequestration ("CCS") system starting in 2032. This would allow the plant to continue to operate throughout the remainder of the planning period with no enforced retirement date. All other inputs and assumptions from the Base Case were left unchanged.

3.4 SCENARIO 4 – NEARMAN CREEK 1 NOX CONTROLS

Under Scenario 4, enhanced NOx controls at Nearman Creek 1 were assumed to be implemented to address the Cross-State Air Pollution Rule ("CSAPR") Good Neighbor Plan ("GNP"). Under this scenario, Nearman Creek 1 was required to operate during ozone season with a NOx emissions rate of 0.058 lb/MMBtu and at a rate of 0.155 lb/MMBtu for the remainder of the year. All other inputs and assumptions from the Base Case were left unchanged.

Scenario 4
Nearman Creek 1 NOx Controls

- Base Case with one modification:
- Enhanced NOx controls at Nearman Creek 1 starting in 2025 to meet the requirements of the Cross-State Air Pollution Rule Good Neighbor Plan.

3.5 SCENARIO 5 - HIGH FUEL PRICES SENSITIVITY

Scenario 5
High Fuel Price Sensitivity

Sensitivity case to examine the impact of higher fuel and market energy prices.

Scenario 5 examines the impact of higher fuel and market energy prices. For this scenario, the prices of coal, oil, and natural gas were modified with a year-over-year price increase that was 10% higher as compared to the Base Case. An associated adjustment to the SPP market prices was included as well. All other inputs and assumptions from the Base Case were left unchanged.

3.6 SCENARIO 6 - LOW FUEL PRICES SENSITIVITY

Scenario 6
Low Fuel Price Sensitivity

Sensitivity case to examine the impact of lower fuel and market energy prices.

Scenario 6 examines the impact of lower fuel and market energy prices. The prices of coal, oil, and natural gas were modified to assumes a year-over-year price increase that was 10% lower as compared to the Base Case. An associated adjustment to the SPP market prices was included as well. All other inputs and assumptions from the Base Case were left unchanged.

3.7 SCENARIO 7 – HIGH LOAD GROWTH SENSITIVITY

Scenario 7
High Load Growth Sensitivity

Sensitivity case to examine the impact of high load growth.

Scenario 7 includes higher load growth rates than assumed in the Base Case. In the Base Case, load growth is projected to be small. This sensitivity case examines the impact from higher than expected load growth. For this scenario, the forecasted year-over-year load growth is assumed to be 50% higher than the Base Case forecast.

3.8 SCENARIO 8 – HIGH RESERVE REQUIREMENT SENSITIVITY

Scenario 8
High Reserve Margin Sensitivity

Increases the constant 15% planning reserve margin ("PRM") assumed for the Base Case.

Scenario 8 evaluates the impact of higher reserve margin requirements than were assumed in the Base Case. The 15% planning reserve margin requirement from the Base Case will be assumed to continue from 2024 through 2030. For this scenario, the reserve margin increases to 18% in 2031. Then, in 2037, the planning reserve margin increases again to a maximum of 20% where it remains until the end of the planning period in 2043. All other inputs and assumptions from the Base Case were left unchanged.

3.9 SCENARIO 9 – NET ZERO SENSITIVITY

Scenario 9
Net Zero Target

Simulates a "Net Zero Carbon" option in which non-carbon emitting generation will be equal to BPU's native load by 2040.

Scenario 9 is focused on achieving a "net zero" portfolio by 2040. For this scenario, a net zero generating portfolio is one in which the total amount of zero carbon energy being generated over the course of a year is greater than or equal to the total annual load from customers.

Within this scenario, the total annual load is being offset on an annual basis by an equivalent amount of zero carbon energy. However, hourly capacity and energy requirements can be met by conventional resources (such as coal, oil, or natural gas-fired power plants) to support operational needs. All other inputs and assumptions from the Base Case were left unchanged.

3.10 SCENARIO 10 – 2028 COMBUSTION TURBINES

Scenario 10
2028 Quindaro CT2 & CT3 Deactivation

Forced deactivation of Quindaro CT2 and CT3 by 2028.

Scenario 10 forces the model to deactivate Quindaro CT2 and CT3 in 2028 and then assess the impact of the replacement capacity necessary to replace the firm capacity of that deactivated generation. All other inputs and assumptions from the Base Case were left unchanged.

4 Portfolio Development

The development of the 2024 IRP relied on the PLEXOS model to develop optimized portfolios for BPU under a range of possible scenarios. PLEXOS is a production cost and capacity expansion optimization tool that simulates the operations of utility generation using hourly demand and individual resource operating characteristics in a chronological dispatch algorithm and uses projected market economics to determine the optimal long-term resource portfolio under varying future conditions including: fuel prices, available generation technologies, environmental constraints, and future demand forecasts.

PLEXOS's optimization process identifies the set of future resources that most economically meets the identified requirements given the defined constraints.

4.1 FUTURE RESOURCE OPTIONS

As a part of the capacity expansion modeling, future needs will be met either through purchased capacity in the form of bi-lateral transactions with other market participants, or through the addition of new generating resources. Within the PLEXOS model, a set of options were selected to represent reasonable options that BPU might consider for future expansion. Unproven or speculative new generation technologies were not considered as viable expansion options at this time. Also, consideration was given to picking options that were suitable for the BPU region and for the SPP market as a whole.

4.1.1 Thermal Resource Expansion Options

Given current trends in environmental regulations, power plants that burn coal or oil as their primary fuel source were not considered as viable options for future expansion at BPU at this time. However, as the owners and operators of power plants at the Quindaro and Nearman Creek sites, BPU would be able to use its existing properties and connections to pipelines to construct new natural gas-fired power plants within its service territory to serve its customers. Alternately, BPU could contract with other market participants to buy energy from or co-own thermal assets within the larger footprint of the SPP market.

The modeled options for natural gas-fired generation in this IRP consisted of the units listed in Table 4-1.

Table 4-1 Natural Gas-Fired New Resource Options

Resource Type	Capacity [MW]
1x0 LM6000 PF+	54.8
1x1 LM6000 PF+ DF	93.3
2x1 LM6000 PF+ DF	189
3x1 LM6000 PF+ DF	284.1
Simple Cycle Combustion Turbine	237
Percentage of New Combined Cycle Facility	50
1x0 RICE	18.17

The LM6000 units are based on an aeroderivative gas turbine from GE in both simple cycle configuration (1x0) and in multiple combined cycle configurations (1x1, 1x2, etc.). In its combined cycle configuration, the heat from the exhaust of a gas turbine is captured and is used to make steam to power a separate steam turbine. This allowed the combined unit operations to use fuel more efficiently and to produce additional energy. The LM6000 options had maximum capacities ranging from around 55 MW up to more than 284 MW.

In addition to the LM6000 units modeled, two other gas turbine options were considered. The first was another simple cycle combustion turbine with a capacity significantly larger than a single LM6000 unit. The second was based on the partial ownership that BPU already has at the Dogwood Energy Facility. The resource titled, “Percentage of New Combined Cycle Facility,” was created to represent the possibility of entering into a similar agreement with a new combined cycle facility within SPP. In that option, BPU was modeled as being able to add additional the additional capacity and energy from a portion of such a facility and could be purchased in 50 MW capacity increments.

The final natural gas-fired generation option considered as an expansion candidate was a reciprocating internal combustion engine (“RICE”) with an individual unit capacity of slightly more than 18 MW. These smaller units can be built in groups to meet larger capacity needs if needed.

4.1.2 Renewable Energy and Energy Storage Options

BPU’s future energy and capacity needs could also be met with contributions from renewable energy and/or energy storage facilities. The options considered for this IRP are listed in Table 4-2.

Table 4-2 Renewable Energy and Energy Storage Options

Resource Type	Capacity [MW]
Biomass	5
Solar Farm with Production Tax Credits (PTCs)	25
Solar Farm with Investment Tax Credits (ITCs)	25
Wind Farm	25
Battery Storage (4-hr)	25

The biomass generation option represents a facility similar to the one in the existing contract with Oak Grove Power Producers where methane that is produced at a landfill is burned to generate electricity. By their nature, such facilities are generally small and cannot be used for large amounts of generation or capacity. For that reason, the total build-out of biomass capacity in the model was limited.

Currently, SPP has limited amounts of solar generating capacity, but it is anticipated that it will become an important part of capacity expansion for many load serving entities within the market in the years to come. Within the PLEXOS model, two options for building solar farms are provided. These options represent the same type of physical installation of photovoltaic solar panels, but account for the effects of either production tax credits (“PTCs”) or investment tax credits (“ITCs”). Solar resources can be built within the model in increments of 25 MW with no upper limit on the total amount of solar capacity that can be added.

Wind resources are already an important part of the BPU portfolio in form of the Smoky Hills, Cimarron Bend, and Alexander wind contracts. Like with the solar resources, the PLEXOS model allows additional wind capacity to be added in 25 MW increments with no upper limit on total wind capacity.

As the contributions from renewable energy increase, both across the nation and in the SPP market specifically, the need for energy storage resources is expected to grow. Energy storage, in the form of utility-scale battery energy storage systems (“BESS”) are not generators in the traditional sense, in that they do not produce any energy of their own. Instead, BESS facilities can be used to store energy during times of surplus and low prices and then discharge that energy during times of need and high prices. Energy storage can be an excellent complement to the intermittent generation from solar and wind energy. Within this IRP, energy storage was included in the PLEXOS model in the form of a 4-hour lithium-based battery system that could be built in 25 MW increments. In this context a 25 MW, 4-hour battery means that the facility could provide an output 25 MW for a total of 4 hours before its energy was exhausted and it would have to be recharged.

4.1.3 Purchased Capacity

Firm capacity needs can be met within SPP using bi-lateral contracts with other market participants that have excess firm capacity elsewhere in the market. When small amounts of firm capacity are needed, BPU can choose to enter into such an agreement to purchase the rights to that firm capacity for a set period at an agreed upon price. It is anticipated that in the near- to medium-term, the amount of firm capacity available to purchases in the SPP markets will likely decrease and, as a result, prices will increase. It is not desirable to become over-reliant on purchased capacity instead of maintaining firm capacity through long-term purchased power agreements or through the construction of utility-owned generating resources. However, purchased capacity can be a valuable option to dealing with small capacity needs.

For all scenarios within this IRP, purchased capacity is included as an option for meeting firm capacity needs. However, the PLEXOS model is configured to only be able to allow a maximum of 20 MW of capacity purchases to be made in any one year. Within the model, purchased capacity must first be bought in a single 10 MW block. Purchased capacity needs above 10 MW can then be bought in single MW increments. This means that if only 5 MW of purchased capacity were needed, 10 MW will have to be bought, while if 13 MW of purchased capacity were needed, exactly 13 MW could be bought. This was done to try to account for the realities of the purchased capacity market and the limited options for contracts of very small amounts of firm capacity.

During the modeling process it was found that the use of short term purchased capacity contracts in the near- to medium-term was of similar cost to procuring limited amounts of long term (30-year) solar capacity. After this observation was made, it was decided to give preference in the model to the use of purchased capacity in the early years of the planning period to capture BPU’s desire to maintain the greatest amount of flexibility when considering programs such as the Green Energy Rider, the possibility of new community solar projects, and energy savings from demand side management programs.

Table 4-3 Purchased Capacity Prices

Assumed Purchase Capacity Prices	
Year	2024$/kW-month
2024	$7.00
2025	$7.17
2026	$7.35
2027	$7.52
2028	$7.71
2029	$7.90
2030	$8.09
2031	$8.29
2032	$8.49
2033	$8.70
2034	$8.91
2035	$9.12
2036	$9.35
2037	$9.58
2038	$9.81
2039	$10.05
2040	$10.29
2041	$10.54
2042	$10.80
2043	$11.06

5 Total Supply Cost Evaluation

For each scenario evaluated in this IRP, a PLEXOS capacity expansion model was created and run to generate a 20-year simulation of the BPU generation portfolio. These models were used to generate capacity expansion plans along with the relative costs associated with each scenario. The different types and quantities of new generation selected in the different scenarios and the relative costs of different expansion options can be used to help inform future strategic planning decisions.

5.1 SCENARIO 1 – BASE CASE

5.1.1 Assumptions

Scenario 1, or the "Base Case," represents a future at BPU that maintains the status quo. The existing thermal power plants in the BPU portfolio are assumed to continue operating without changes to their fuel types or emissions controls while still requiring ongoing capital investments to continue running reliably. The additional capital costs from the most recent "Life Assessment Report" for the Nearman Creek and Quindaro Power Stations were included in the PLEXOS model as additional fixed operations and maintenance costs. Except for the SWPA and WAPA hydro contracts, the existing renewable energy contracts are assumed to expire at the end of their existing terms. The SWPA and WAPA hydro contracts are assumed to continue through the end of the IRP planning period.

As shown in Table 2-16, the firm capacity of the existing thermal units decreases starting in 2026. This was done to account for a change in the way that firm capacity will be calculated by SPP for all market participants and not just for BPU. This adjustment in firm capacity calculation in 2026 is included in every IRP scenario and not just in the Base Case.

The Base Case, along with every other scenario in this IRP, is modeled in such a way as to allow any or all of the existing thermal power plants to be retired at any point after 2028. If economic conditions warrant the retirement of an existing power plant, the model can retire that unit and replace it with new generation assets.

5.1.2 Capacity Expansion Planning Results

The capacity expansion planning results from the Base Case found that under status quo conditions, only limited amounts of firm capacity would be needed in the near- to medium term. The 20 MWs of available purchased capacity within the model were sufficient to meet BPU's firm capacity needs through the end of 2037. However, starting in 2038, due to the anticipated loss of the firm capacity from the expiration of the Cimarron Bend wind contract, the need for new generating resources results in solar capacity being added to the BPU portfolio. Combined with the continued contributions from small amounts of purchased capacity, a total of 75 MW of solar energy capacity was used to meet BPU's long-term firm capacity needs through the end of the planning period in 2043. None of BPU's existing power plants were retired in the Base Case scenario.

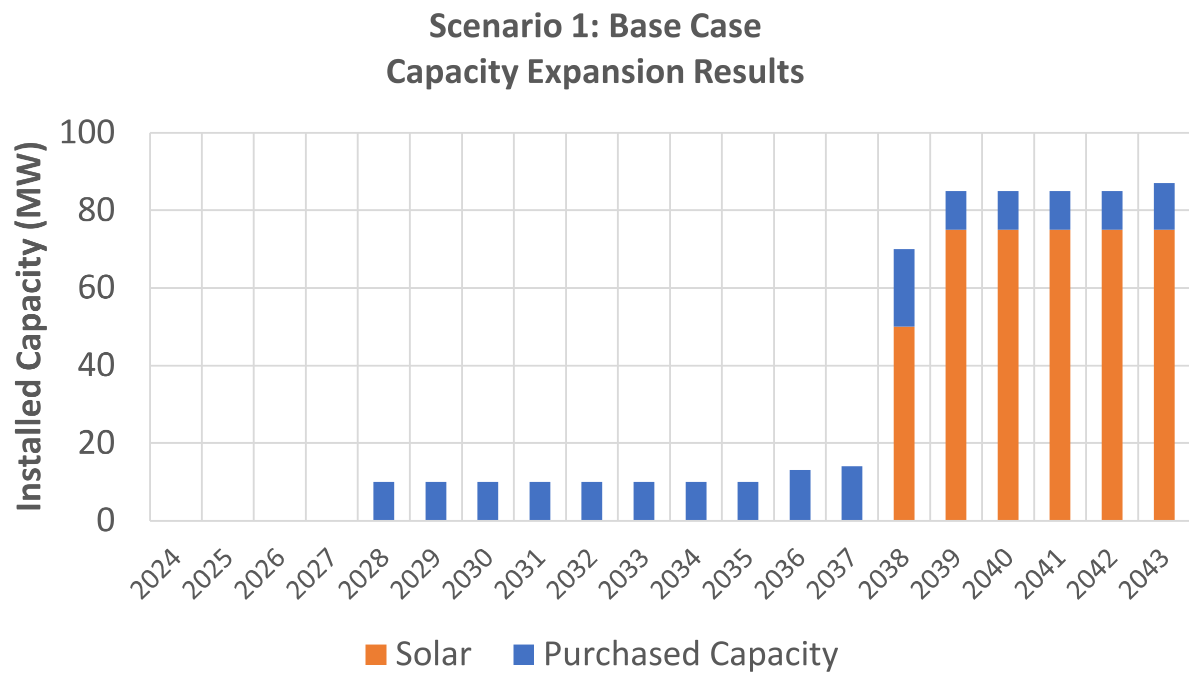

Figure 5-1 Scenario 1 Capacity Expansion Results

5.2 SCENARIO 2 – CO-FIRING OF NATURAL GAS AT NEARMAN CREEK 1

5.2.1 Assumptions

In response to the new carbon emission rules that were finalized by the EPA in April 2024, multiple options exist at Nearman Creek 1 that would allow the coal-fired power plant to continue operating past 2032 and remain in compliance with CO2 emissions reduction requirements. The first option would be to modify Nearman Creek 1 to burn natural gas in addition to coal. By modifying the plant to operate with a mixture of 40% natural gas and 60% coal (on a heat input basis) by 2030, Nearman Creek 1 would be allowed to operate until the end of 2038.

For Scenario 2, the Base Case model was modified to simulate just such a conversion at Nearman Creek 1. Starting in 2030 and running through the end of 2038, Nearman Creek 1's operating characteristics were changed to force it run on the prescribed natural gas/coal fuel mixture. All other inputs and assumptions from the Base Case were left unchanged.

5.2.2 Capacity Expansion Planning Results

Similar to the Base Case, all near- to medium-term firm capacity needs in Scenario 2 were met through the use of limited amounts of purchased capacity. Again, like the Base Case, solar farms were added starting in 2038 and a total of 75 MW of solar capacity was added by the end of the planning period. However, unlike the Base Case, the forced retirement of Nearman Creek 1 at the end of 2038 necessitated the addition of a significant amount of firm capacity in 2039. This was accomplished with the modeled construction of a 237 MW natural gas-fired simple cycle combustion turbine. Besides the forced retirement of Nearman Creek 1, no other power plant retirements were a part of the results for Scenario 2.

The new combustion turbine unit would not require any additional carbon emission reduction features beyond the use of a highly efficient design with best operating and maintenance practices. This is because, based on the model results, it would be classified as an “intermediate load” unit with a capacity factor of between 20% and 40%. Currently, the EPA has not finalized additional requirements for future carbon emissions reductions at such a power plant.

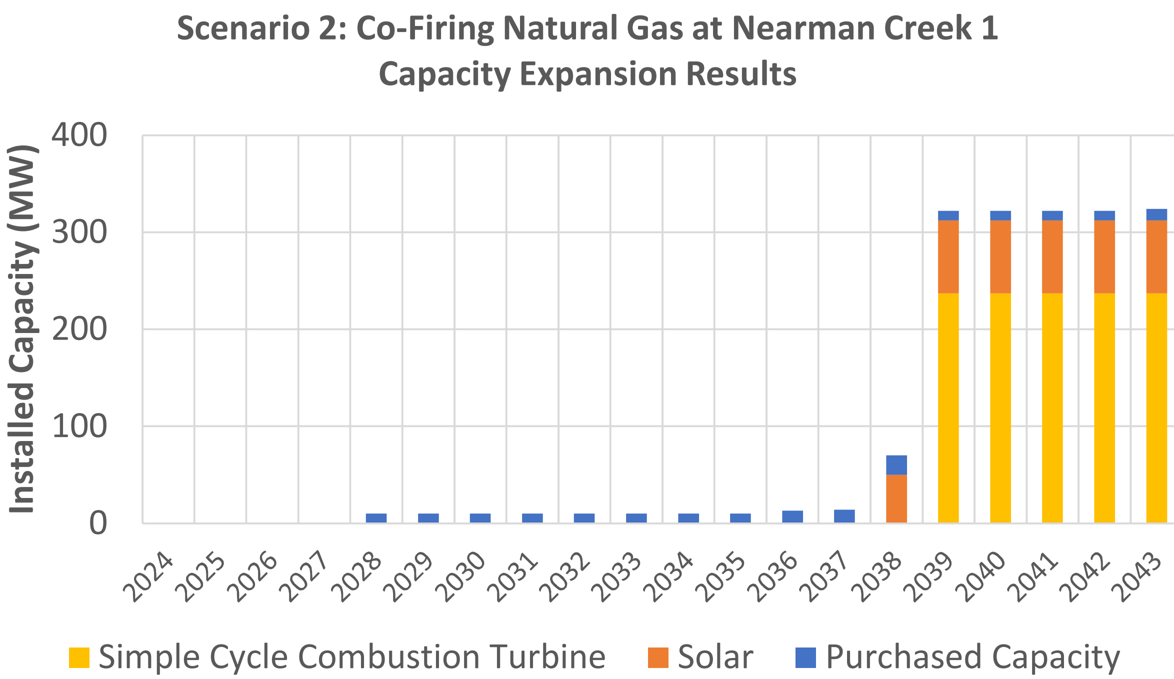

Figure 5-2 Scenario 2 Capacity Expansion Results

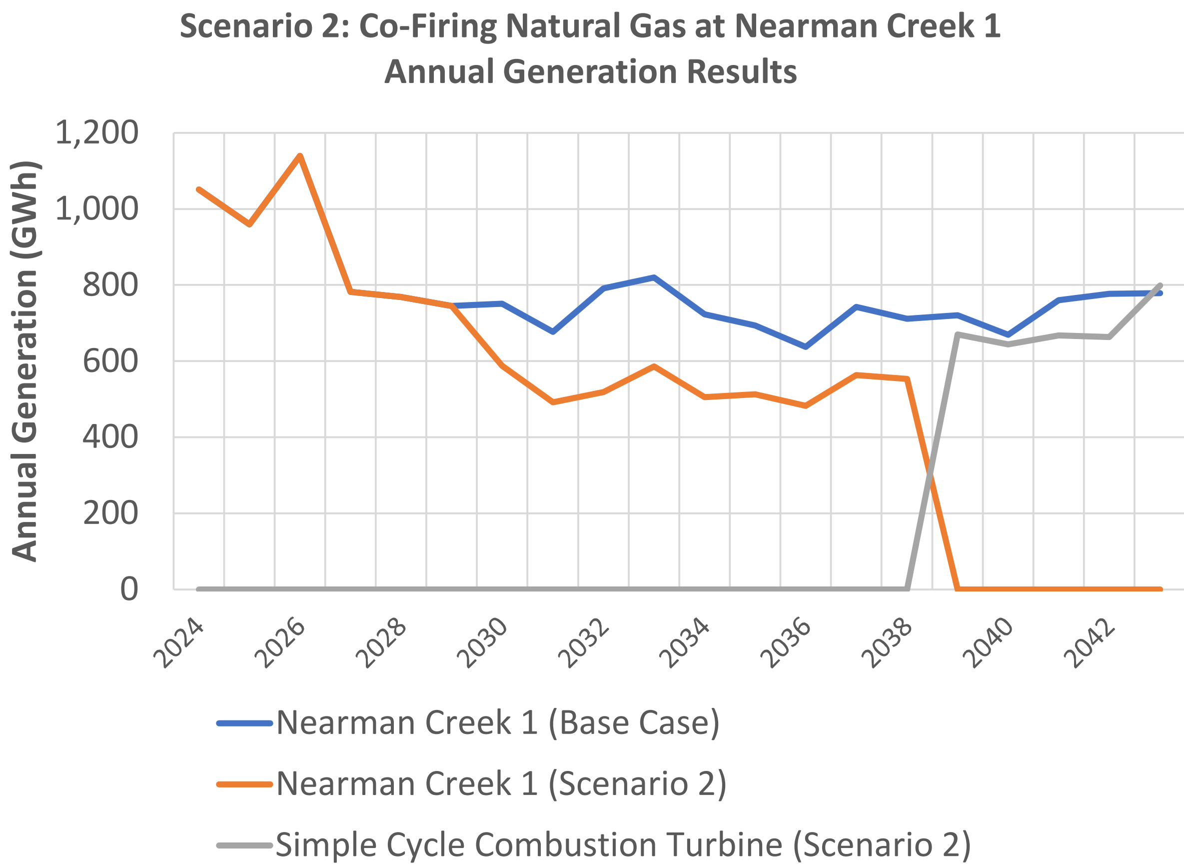

Figure 5-3 Scenario 2 Nearman Creek 1 Annual Generation Results

5.3 SCENARIO 3 – NEARMAN CREEK 1 CARBON CAPTURE AND SEQUESTRATION

5.3.1 Assumptions

Similar to Scenario 2, Scenario 3 was created to evaluate possible BPU responses to the carbon pollution rules finalized by the EPA in April 2024. Under those rules, if Nearman Creek 1 was retrofitted to operate with a 90% effective carbon capture and sequestration system by no later than 2032, it would be allowed to continue operating throughout the rest of the planning period with no enforced retirement date.

Retrofitting an existing coal-fired power plant to operate with CCS can be a financial and technological challenge. Beside the increased operating costs inherent to CCS systems, the large power requirements to run the new equipment would decrease the net generating capacity at a retrofitting unit, effectively decreasing its overall efficiency. Additionally, the carbon that is captured by a CCS system must also be transported off-site for permanent disposal via pipeline. At this time, no such pipeline exists near the Nearman Creek 1 power plant site. For the purposes of modeling, it was assumed that a third-party would construct the necessary pipeline to allow for CO2 sequestration at a remote site. The cost of such a pipeline was not specifically estimated for this project, but it could range up into the tens or hundreds of millions of dollars depending on its length and chosen construction path. Similarly, within the scope of this IRP no detailed evaluation of the capital costs for a potential CCS retrofit at Nearman Creek 1 was performed. A high-level estimate based on industry average values would place the cost of installing a CCS system at Nearman Creek 1 at approximately $700,000,000.

The 2022 Inflation Reduction Act contains provisions for tax credits related to CCS. The current law allows for a maximum tax credit of $85/tonne of CO2 that was successfully captured at a power plant and delivered for geologic sequestration. While this tax credit is substantial given the amount of CO2 that could be captured at a facility similar to Nearman Creek 1, it was estimated that it would not be sufficient to totally offset the costs of capturing, transporting, and permanently storing that carbon. The increased operating costs associated with a hypothetical CCS system at Nearman Creek 1, coupled with a decreased operating efficiency would likely cause difficulty in maintaining competitive bids within the SPP market and a decreased annual capacity factor.

5.3.2 Capacity Expansion Planning Results

The results of the PLEXOS modeling for Scenario 3 are shown below. Starting in 2032, 125 MW of solar capacity is added to the BPU portfolio. This is needed to offset the loss of firm capacity at Nearman Creek 1 associated with the decreased net output due to the power demand from the CCS system. In 2038, additional solar capacity similar to that found in the Base Case is added to offset the firm capacity loss from the expiration of renewable energy contracts. A total of 200 MW of solar capacity is built in this scenario. The results of Scenario 3 do not include the retirement of any of BPU's currently existing thermal power plants.

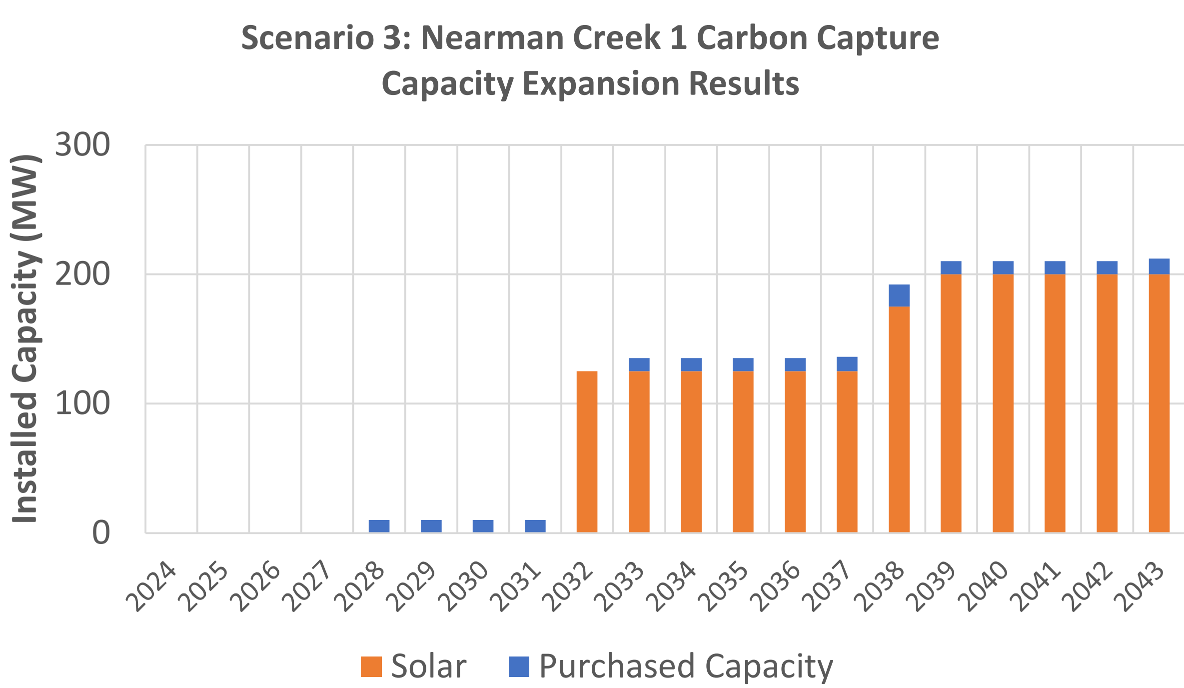

Figure 5-4 Scenario 3 Capacity Expansion Results

Also of note for this scenario was the observation that within the model, the cost of operating its new CCS system caused dramatic reductions in the annual capacity factor at Nearman Creek 1. In the years leading up to the retrofit within the model, the plant had a forecasted annual capacity factor of approximately 40%. After the retrofit, the annual capacity factor dropped to an average of less than 1%. This low level of dispatch within the market combined with the other high costs and uncertainty of carbon transportation and disposal options call into question the suitability of Nearman Creek 1 for future CCS retrofits.

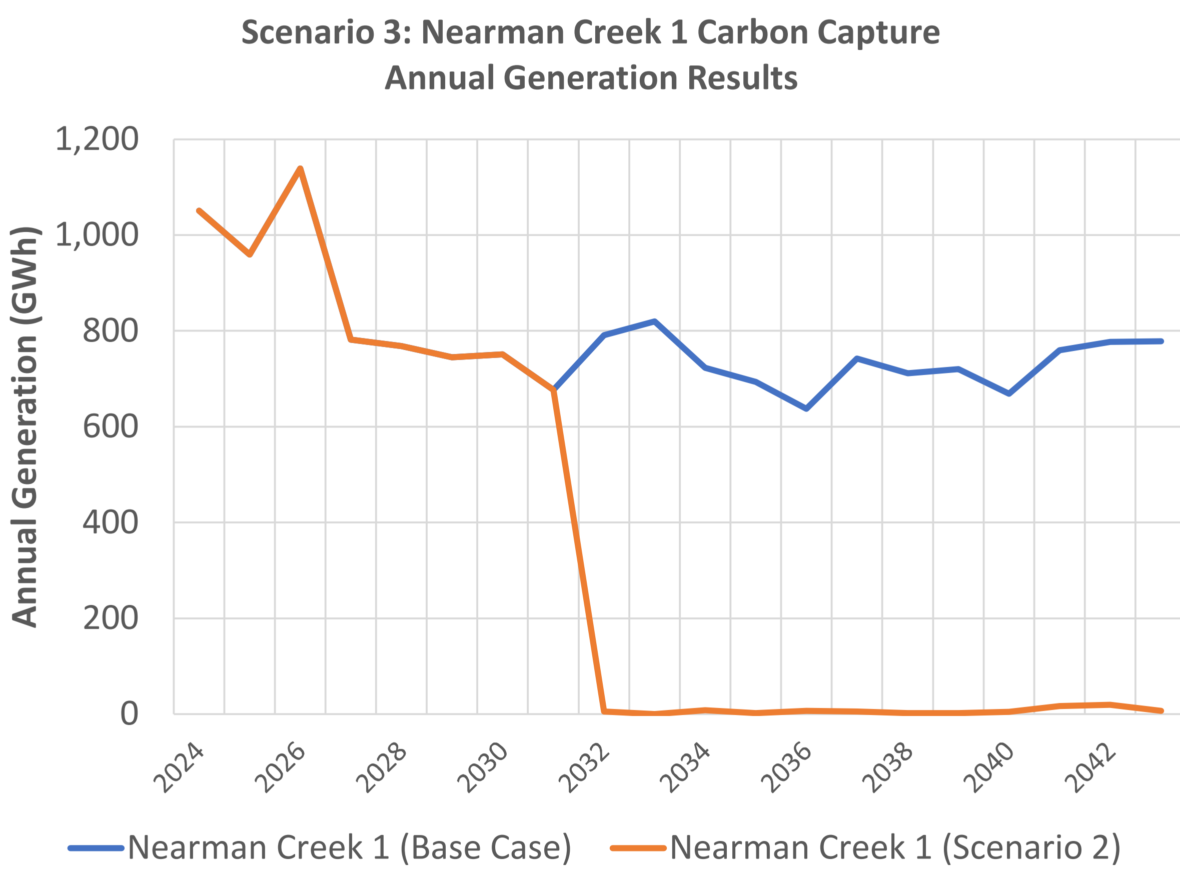

Figure 5-5 Scenario 3 Nearman Creek 1 Annual Generation Results

5.4 SCENARIO 4 – NEARMAN CREEK 1 NOX CONTROLS

5.4.1 Assumptions

Beyond the carbon pollution considerations that were the basis for Scenarios 2 and 3, consideration was also given to the impact from the potential tightening of particulate pollution regulations.

Within the PLEXOS model for Scenario 4, Nearman Creek 1 was operated with more stringent NOx controls than were accounted for in the Base Case. Starting in 2025, during "Ozone Season" (in the months of May – September), a NOx removal rate of 73% over the Base Case was modeled. Throughout the rest of the year (in the months of October – April), a removal rate of 27% was used. The costs associated with the enhanced NOx removal were also included in the model and were incorporated into the overall cost to run Nearman Creek 1.

5.4.2 Capacity Expansion Planning Results

The capacity expansion plan for Scenario 4 was found to be identical to that calculated for the Base Case. This is an expected result since Nearman Creek 1 continued to operate and contribute an identical amount of firm capacity for BPU's portfolio. Purchased capacity was sufficient to cover firm capacity needs in the near- to medium-term with a total of 75 MW of solar capacity being added starting in 2038. Also, as in the Base Case, no retirements of any currently operating BPU power plants are forecasted based on the results for Scenario 4.

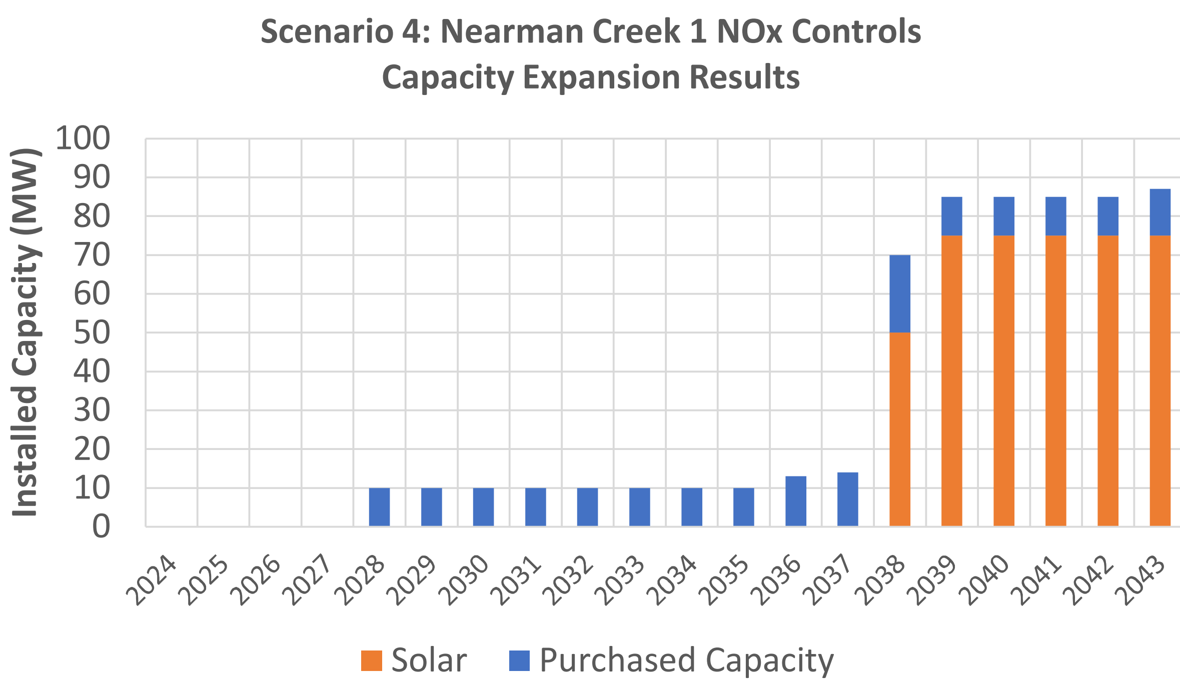

Figure 5-6 Scenario 4 Capacity Expansion Results

The costs attributable to the additional NOx removal in Scenario 4 were calculated to be an average of $1.3 million per year. These additional costs resulted in Nearman Creek 1 operating with a slightly reduced capacity factor. During the planning period, following the modeled implementation of the enhanced NOx controls, the Nearman Creek 1 power plant was calculated to have, on average, an annual capacity factor approximately 4.4% lower than was calculated in the Base Case. These results are presented in Figure 5-7 below.

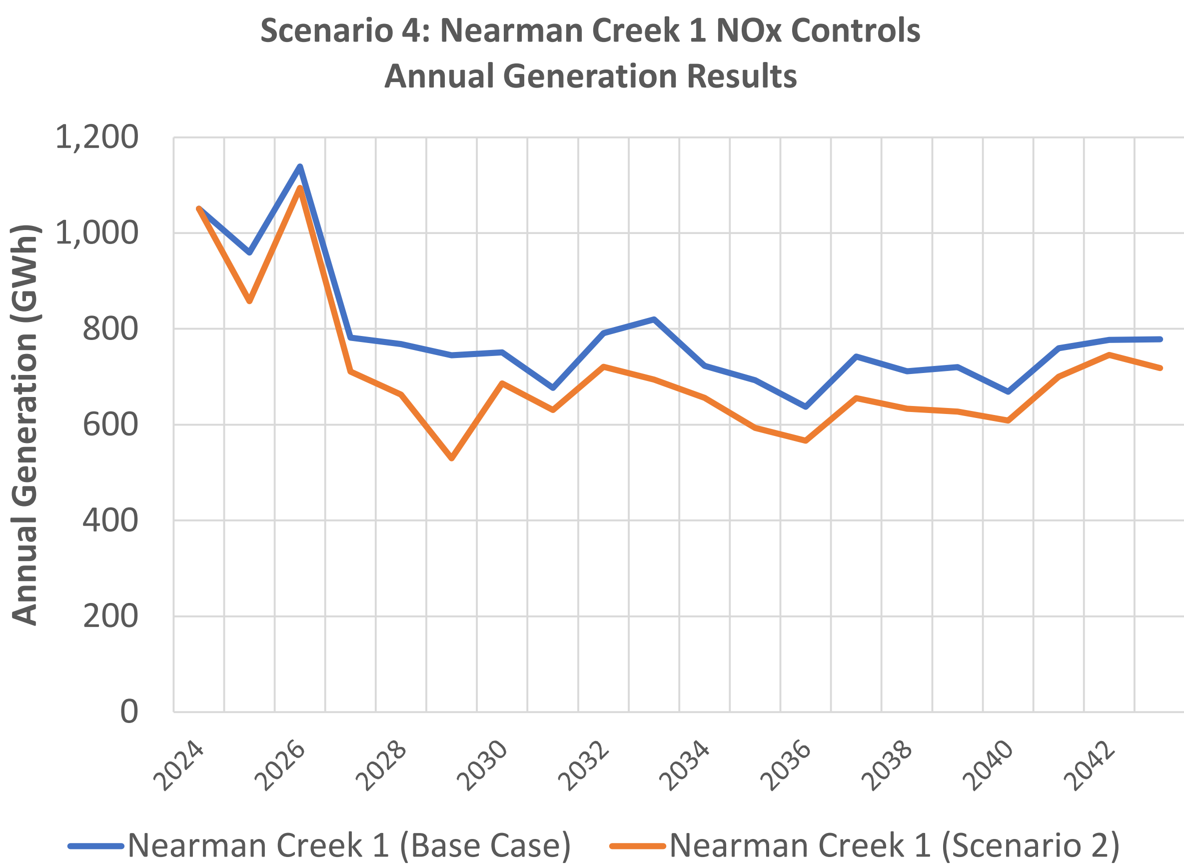

Figure 5-7 Scenario 4 Nearman Creek 1 Annual Generation Results

5.5 SCENARIO 5 – HIGH FUEL PRICES SENSITIVITY

5.5.1 Assumptions

Within Scenario 5, the PLEXOS model was rerun to evaluate a possible future in which fuel prices and market energy prices were higher than what were used in the Base Case. The prices of coal, oil, and natural gas were adjusted by assuming a year-over-year price increase of 10% as compared to the Base Case. Since the Scenario 5 fuel price increases were assumed to be a market-wide impact, rather than just a change to the costs borne by BPU, the price of energy in the SPP market as a whole was also adjusted. Even with the widespread growth of wind resources within SPP, the marginal cost of energy is still largely set by fossil-fuel based resources. Higher fuel prices directly impact the cost to operate those power plants and make the energy produced by the fossil-fuel based resources more expensive.

5.5.2 Capacity Expansion Planning Results

No changes were observed in Scenario 5's capacity expansion planning as compared to the Base Case and no retirements of existing power plants were determined to be economically viable. The near- to medium-term needs for firm capacity were met with capacity purchases until 2038. In 2038, the loss of the firm capacity from the expiration of renewable energy contracts created a firm capacity deficit that was greater than the assumed 20 MW purchased capacity limit. As a result, new solar generation resources were determined by the model to be the lowest cost option to fill the firm capacity need. A total of 75 MW of solar energy capacity in combination with limited amounts of purchased capacity was sufficient to meet BPU's firm capacity needs through 2043.

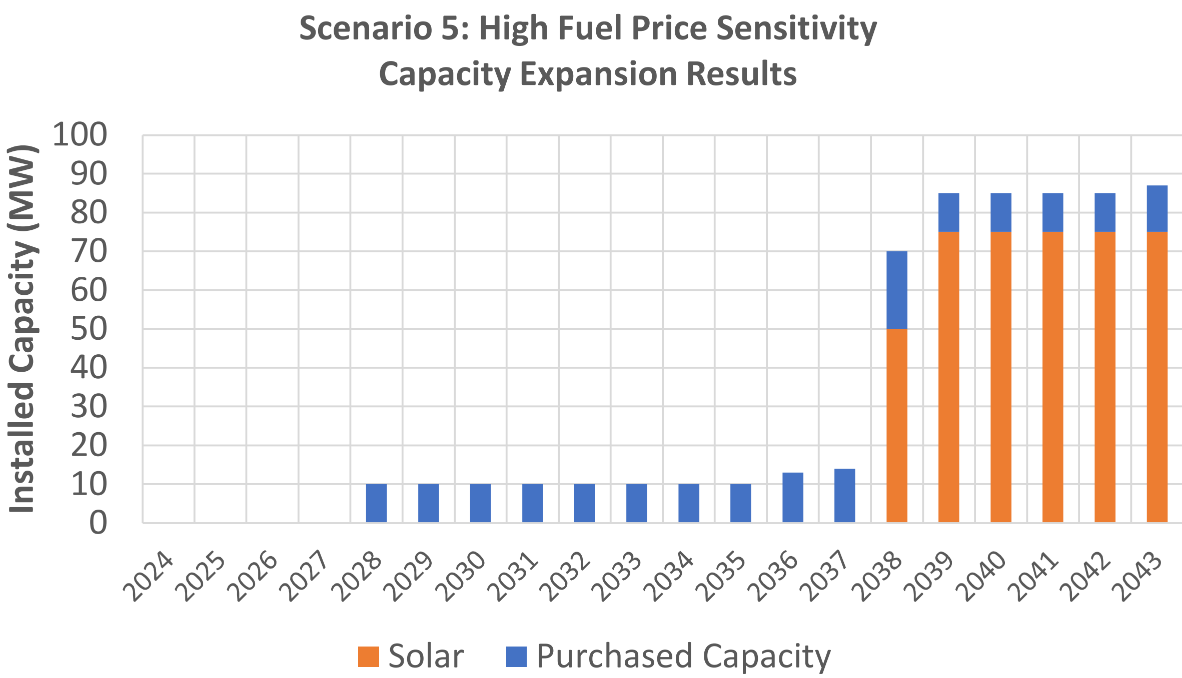

Figure 5-8 Scenario 5 Capacity Expansion Results

5.6 SCENARIO 6 – LOW FUEL PRICES SENSITIVITY

5.6.1 Assumptions

As a complement to Scenario 5 which assumed fuel and market prices were higher than those assumed in the Base Case, Scenario 6 was created to evaluate conditions in which fuel and market prices were lower than in the Base Case. Using similar methods as those employed in Scenario 5, fuel prices were adjusted by assuming a year-over-year price decrease of 10% as compared with the Base Case. Likewise, the SPP market prices were also changed to reflect the market-wide impacts of lower fuel costs.

5.6.2 Capacity Expansion Planning Results

The capacity expansion planning results from Scenario 6 were found to be the same as in Scenario 5 and the Base Case. Just like in Scenario 5, Scenario 6's results did not include the need for the economic retirement of any existing BPU power plants. Capacity purchases were sufficient to meet firm capacity needs until 2038. Starting in 2038, the firm capacity needs exceeded the 20 MW limit imposed on capacity purchases and so new generating resources were added to the BPU portfolio. A total of 75 MW of solar capacity was added and was, in combination with continued capacity purchases, able to meet all firm capacity obligations through 2043.

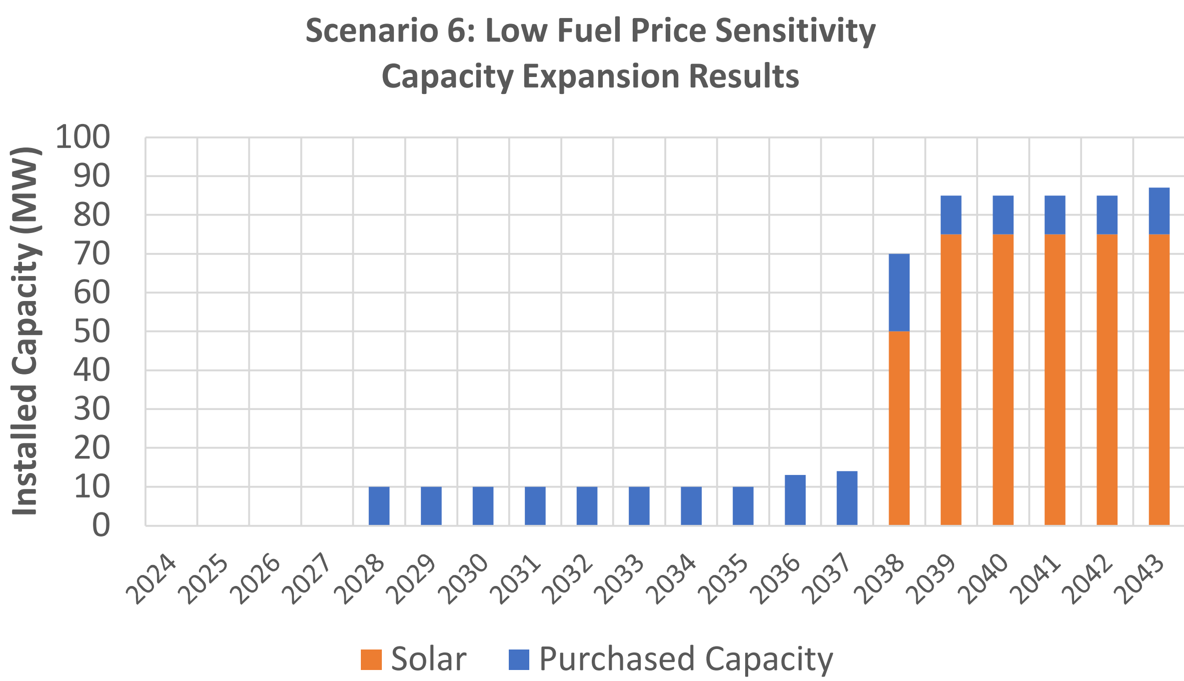

Figure 5-9 Scenario 6 Capacity Expansion Results

5.7 SCENARIO 7 – HIGH LOAD GROWTH SENSITIVITY

5.7.1 Assumptions

Under Scenario 7, changes were made regarding the future growth of BPU customer load. In the Base Case, load growth is assumed to be positive, but relatively small over the next twenty years. Scenario 7 examines the possible impacts from a future in which load growth accelerates. Such increased load growth could come from a more rapid electrification of loads that have been traditionally served by fuels such as oil, gasoline, and natural gas. Increased load growth could also come from the addition of new large commercial or industrial customers being served by BPU. For Scenario 7, the annual load growth rates were assumed to be 50% higher than the forecast used for the Base Case.

5.7.2 Capacity Expansion Planning Results

Firm capacity requirements are calculated as a percentage of peak load. The increased load growth assumptions Scenario 7 result in a firm capacity requirement that grows faster than in the Base Case. As in the Base Case, firm capacity needs are met in the near- to medium term with capacity purchases only. Starting in 2033, more purchased capacity is added as compared to the Base Case. The 20 MW limit on purchased capacity remains adequate to satisfy needs until 2038. A total of 75 MW of solar capacity is added starting in 2038 with increasing amounts of purchased capacity needed in each following year. No economic or forced retirements of BPU power plants were a part of the results for Scenario 7.

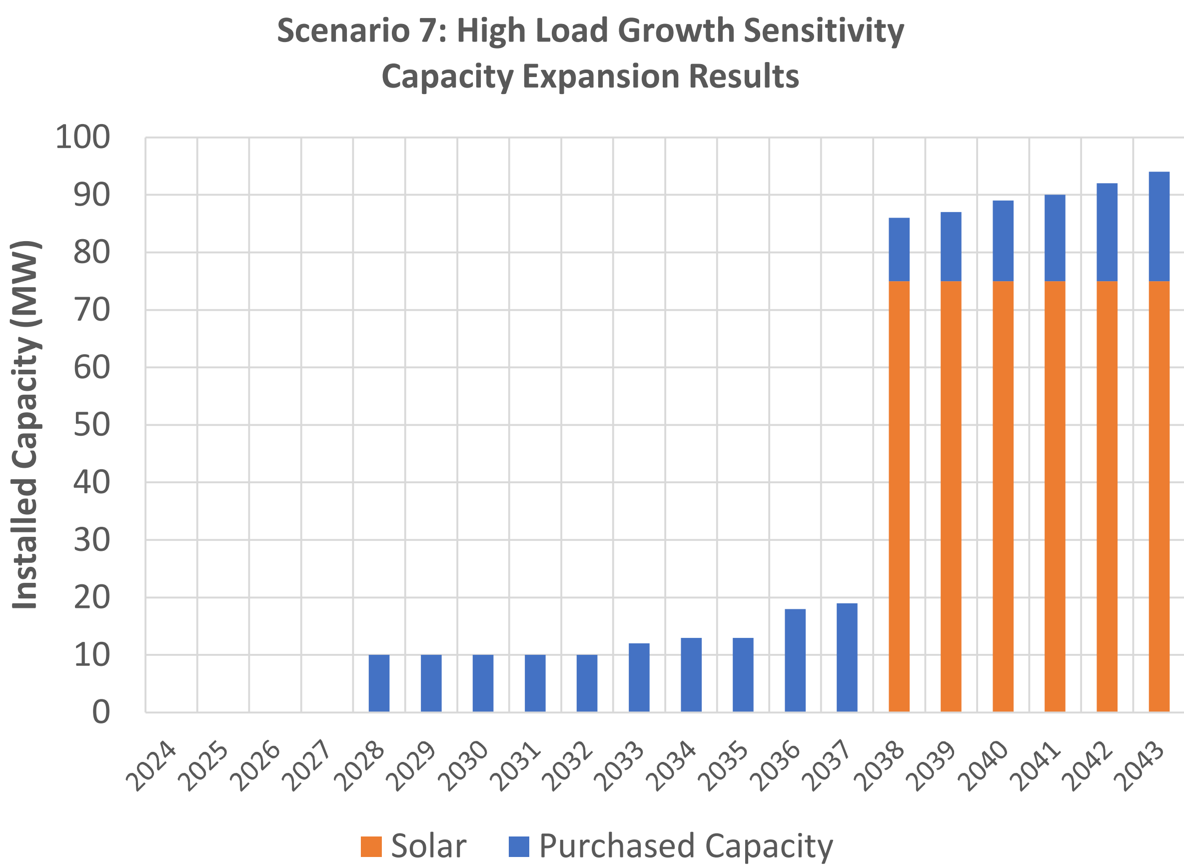

Figure 5-10 Scenario 7 Capacity Expansion Results

5.8 SCENARIO 8 – HIGH RESERVE REQUIREMENT SENSITIVITY

5.8.1 Assumptions

Scenario 8 considered a future in which the SPP planning reserve margin increases during the planning period. In all other scenarios, the planning reserve margin requirement is assumed to be constant and equal to BPU's annual peak load plus an additional 15%. For Scenario 8, that requirement was changed to increase from the Base Case value of 15% in 2024 up to 18% in 2031, and 20% in 2037.

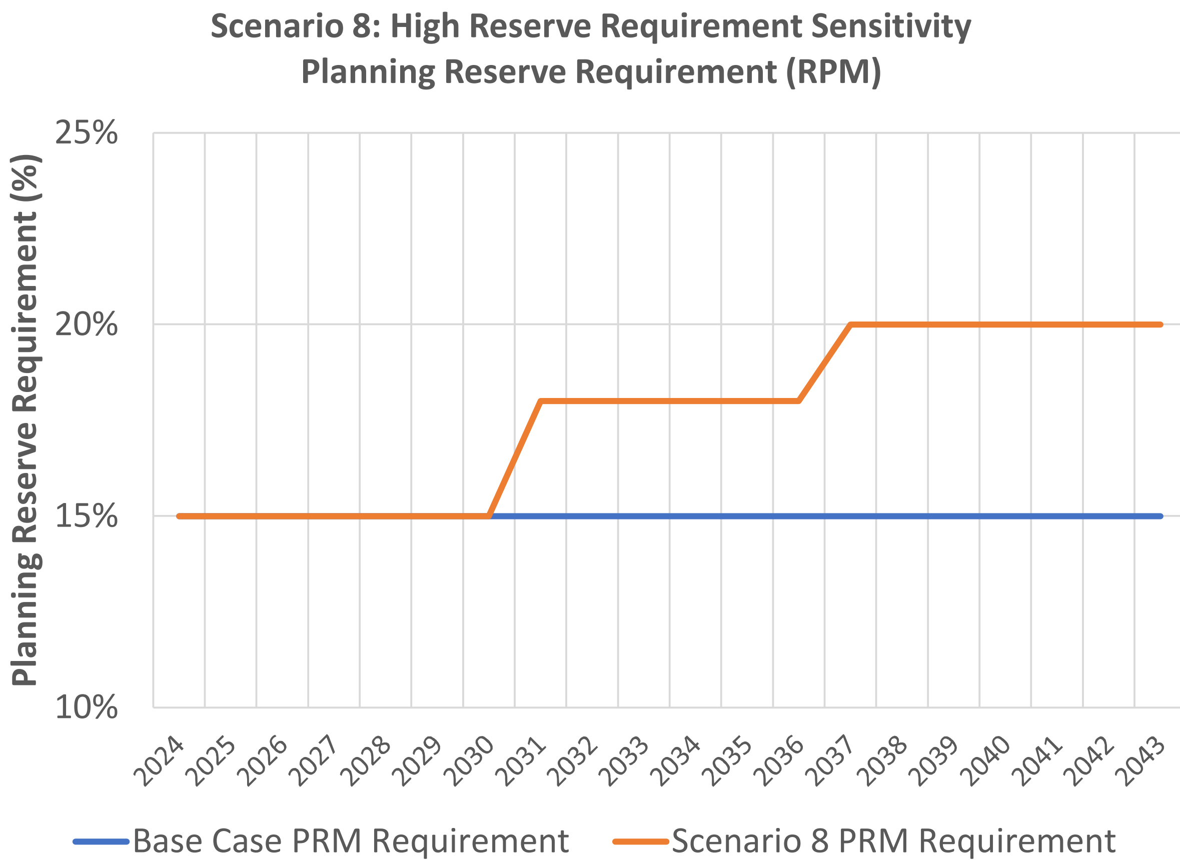

Figure 5-11 Scenario 8 Planning Reserve Requirement (PRM)

Changes in the SPP planning reserve margin have been made in recent years, with the current 15% requirement only coming into effect during the summer of 2023. That increase was driven by challenges to market reliability such as the retirement of thermal power plants, the effects of extreme weather events, and the expansion of intermittent renewable generation.

Following the completion of the modeling for this IRP, SPP announced new changes to its planning reserve margin requirements.[2] Starting in 2026, a summer planning reserve margin of 16% will be used and a new winter planning reserve margin will be set at 36%. The one percent increase over the current summer planning reserve margin requirement is relatively small and does not invalidate the overall results and conclusions from these IRP analyses. Given the forecast peak load used in this IRP, a 1% increase in firm capacity requirement is equivalent to approximately 5 MW. These changes to SPP's planning reserve margin requirements demonstrate the importance of evaluating the effects of additional future planning reserve margin increases like those assumed in Scenario 8.

[2] https://www.spp.org/news-list/spp-board-approves-new-planning-reserve-margins-to-protect-against-high-winter-summer-use/

5.8.2 Capacity Expansion Planning Results

The higher planning reserve margins contemplated in Scenario 8 drove the need for new generation resources from the year 2038 in the Base Case to as soon as 2032. It was in that year that the 20 MW limit on purchased capacity was exceeded and firm capacity from new resources was needed. 25 MW of solar capacity was added in 2032 with additional capacity added in 2037, 2038, and 2041 to reach a total solar generating capacity of 125 MW. Limited amounts of purchased capacity were also continued to be used to fulfill the need for small amounts of firm capacity throughout the planning period. None of the existing power plants in BPU's portfolio were retired in the capacity expansion model results for Scenario 8.

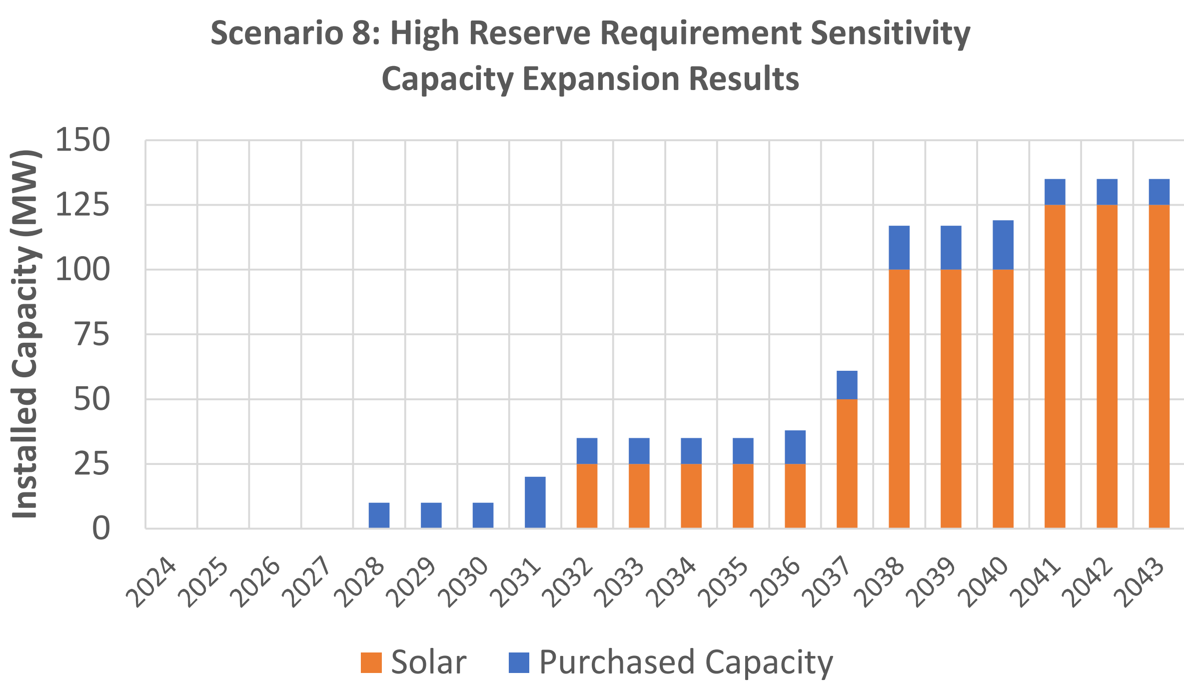

Figure 5-12 Scenario 8 Capacity Expansion Results

5.9 SCENARIO 9 – NET ZERO BY 2040

5.9.1 Assumptions

Unlike the other scenarios being evaluated in this IRP, Scenario 9 is not primarily constrained by meeting the SPP planning reserve margin requirements. Instead, Scenario 9 is focused on achieving a "net zero" portfolio by 2040. In this context, a net zero generating portfolio is one in which the total amount of zero carbon energy being generated over the course of a year is greater than or equal to the total annual load from customers. This means that while the total annual load is being offset on an annual basis by an equivalent amount of zero carbon energy, in any given hour, carbon producing resources (such as coal, oil, or natural gas-fired power plants) can still be operated to meet customer needs. Like in all other scenarios, the PLEXOS capacity expansion model can choose to retire existing resources if economic conditions warrant it. However, in Scenario 9, no retirements of existing resources were manually "forced" to occur outside of the expiration of some of the purchased power agreements that are already reflected in the Base Case.

Qualifying sources of zero carbon energy that were included in the net zero calculation within the PLEXOS model included both new and existing generation from wind, solar, biomass, and hydroelectric facilities. All other assumptions were the same as those used in the Base Case.

While Scenario 9 does not represent current BPU policies or goals concerning the use of renewable energy, it serves as an important look at the magnitude of the investments that may be required in the future to achieve similar results.

5.9.2 Capacity Expansion Planning Results

Beginning in 2031, solar capacity is added to the BPU portfolio resulting in a total of 250 MW being added by 2032. Beginning in 2036, significant amounts of solar are added each year, until 2040, when a total of 1,150 MW of solar capacity has been added. By the end of the planning period in 2043, 1,175 MW of solar capacity was added. The addition of such a large amount of solar capacity allowed for the economic retirement of Quindaro CT2 and Quindaro CT3 in 2031 and Nearman Creek 1 in 2038 while still meeting all firm capacity requirements.

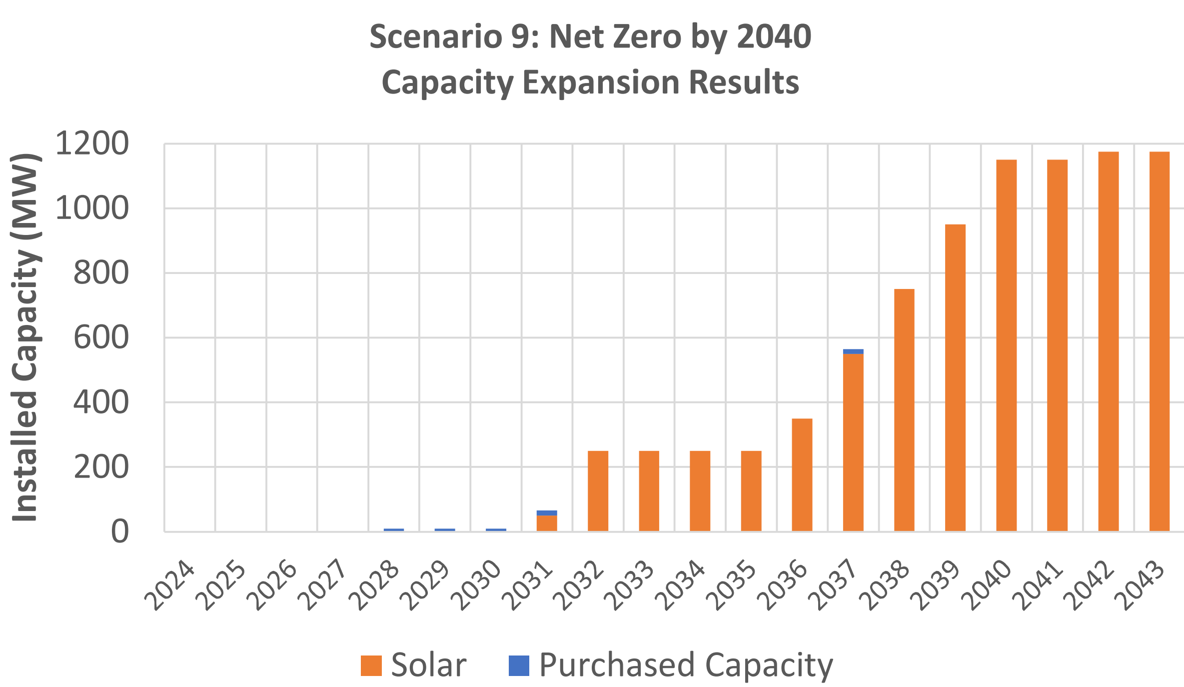

Figure 5-13 Scenario 9 Capacity Expansion Results

It is important to reflect on the nature of the PLEXOS model's outputs. No constraints were placed on the total amount of energy being generated by any one particular technology. The current BPU generating portfolio is a diverse mixture of different types of power plants with different fuel types for its thermal power plants combined with different forms of renewable energy. The results of Scenario 9 show a heavy dependance on solar energy to achieve the net zero goal. If a net zero goal is implemented by BPU, it would be recommended that BPU consider a more diverse set of renewable resource options to increase system reliability and decrease risk.

Another consideration relevant to the installation of large amounts of solar energy is land use. Within the PLEXOS model, solar capacity can be built in 25 MW increments. Each one of those 25 MW increments would require approximately 175 acres of land to be built. BPU does not currently possess enough free land to build the required amounts of solar energy locally. As a result, any large solar installations would likely have to be installed elsewhere in the SPP market footprint and arrangements for adequate transmission resources would have to be made. It is important to understand that the results of the capacity expansion model do not include the additional transmission system costs that would be associated with transporting that solar energy back to BPU. Depending on the sites chosen for new solar capacity, there could also be additional costs related to upgrades on the transmission system to ensure that reliability standards are maintained. While these transmission costs are not considered in the results for this IRP analysis, they are factors that should be considered during any detailed follow up analysis to support the decisions on new capacity additions to the BPU portfolio.

The large amounts of solar capacity contemplated in Scenario 9 would also be affected by the future capacity expansion plans of other market participants in SPP. As more solar capacity is added to the SPP market, it is expected that that effective load carrying capacity (“ELCC”) for solar resources will decrease. This trend is already account for within the PLEXOS model by using solar ELCC values that decrease over time. However, if buildouts of solar capacity are faster than expected, it could cause that trend to accelerate. The result of a decreased ELCC value would be an increase in the cost per MW of firm capacity from solar energy. That change could affect decisions about future capacity expansion plans.

It is noted that within the scope of this IRP, no dispatchable zero carbon options were considered as capacity expansion candidates. In the future, as technology develops and new resource options become available within the market, BPU may want to consider the availability of zero- or low-carbon options such as hydrogen-fired combustion turbines, natural gas-fired units with integrated carbon capture and sequestration, or even contributions from contracts with small modular nuclear reactors. While all of these technologies are currently either under design or testing, none of them are yet in widespread use within energy markets.

5.10 SCENARIO 10 – 2028 COMBUSTION TURBINES

5.10.1 Assumptions

Scenario 10 was used to evaluate the impact on capacity expansion planning from an early retirement of the Quindaro 2 and Quindaro 3 oil-fired combustion turbines in 2028. Within the PLEXOS model, those two existing power plants were manually “forced” to retire at the beginning of 2028. All other inputs and assumptions were the same as those used in the Base Case.

5.10.2 Capacity Expansion Planning Results

The early retirements of the Quindaro combustion turbines creates a shortfall in firm capacity that is greater than can be met with the 20 MW of purchased capacity that is assumed to be available within the model. Together, the two Quindaro units are modeled to have a total of 83.8 MW of firm capacity.

As a result, 125 MW of solar capacity is added in 2028. With an assumed ELCC value of 60% in 2028, this 125 MW of installed solar capacity represents 75 MW of firm capacity that can be used to meet BPU's planning reserve margin requirements. Purchased capacity is used to make up the remainder of the firm capacity shortfall. Another 25 MW of solar capacity is added in 2032 and an additional 75 MW added in 2038. At the end of the planning period, 225 MW of solar capacity has been added to the BPU portfolio. The forced retirements of the two Quindaro combustion turbines in 2028 are the only existing power plant retirements in the expansion plan results for Scenario 10.

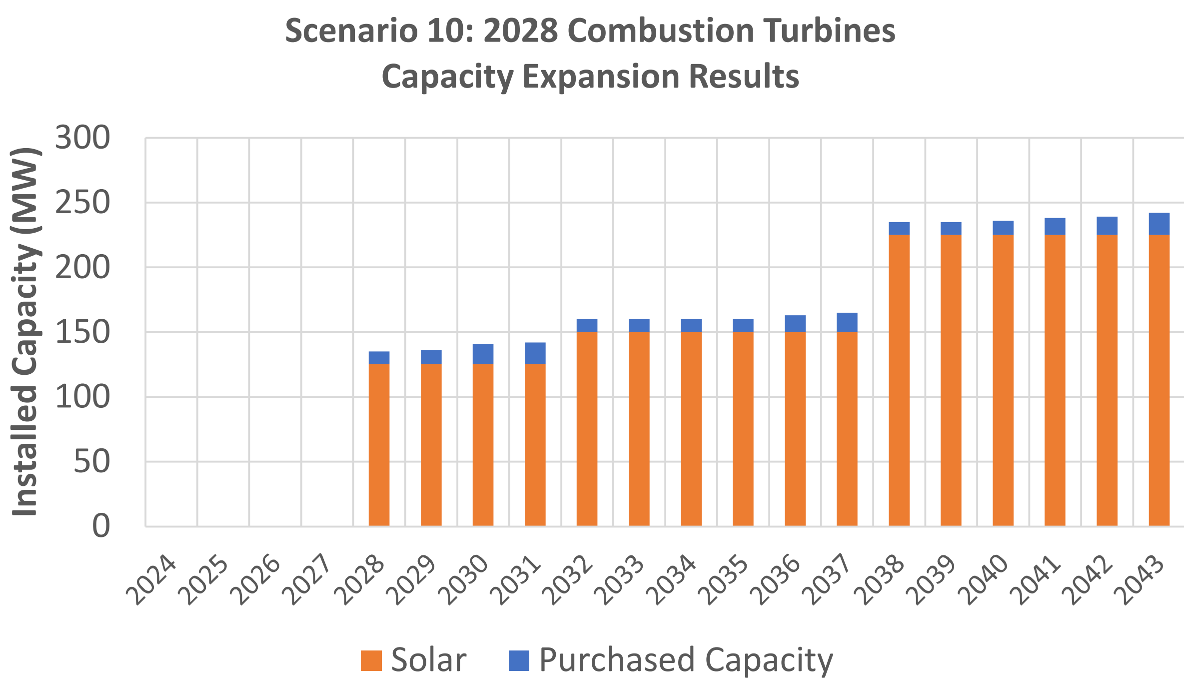

Figure 5-14 Scenario 10 Capacity Expansion Results

5.11 TOTAL SUPPLY COST BY SCENARIO

The cumulative present worth costs were calculated for the capacity expansion planning results described above for each scenario. The cost to build, operate, and maintain each scenario's portfolio during the twenty-year planning period was determined and combined with the projected costs and revenues that were generated by buying and selling energy in the modeled SPP market. A total net present value cost in 2024 dollars was calculated for each scenario.

The cumulative present worth costs for each scenario are summarized in Table 5-1 and are assigned a ranking (low to high). Additional commentary regarding the cost results is also provided below.

Table 5-1 Cumulative Present Worth Costs

Scenario		Cost (2024$)	Rank
Scenario 1	Base Case	$978,200,080	5
Scenario 2	Co-Firing Natural Gas at Nearman Creek 1	$1,009,371,992	9
Scenario 3	Nearman Creek 1 Carbon Capture and Sequestration	$1,232,292,216	10
Scenario 4	Nearman Creek 1 NOx Controls	$982,908,377	6
Scenario 5	High Fuel Prices Sensitivity	$1,002,109,754	8
Scenario 6	Low Fuel Prices Sensitivity	$959,647,405	3
Scenario 7	High Load Growth Sensitivity	$994,773,352	7
Scenario 8	High Reserve Requirement Sensitivity	$975,339,672	4
Scenario 9	Net Zero by 2040	$918,887,719	1
Scenario 10	2028 Combustion Turbines	$937,561,310	2

The scenario with the lowest costs calculated in this IRP was Scenario 9, the Net Zero by 2040 case. The relative low cost can be attributed to the very aggressive buildout within the model of solar resources and the resulting revenues generated by selling that solar energy back into the SPP market. The calculated market revenues for Scenario 9 are based on the market prices that are inputs into the capacity expansion model. In a competitive energy market such as SPP, if opportunities for revenues such as these are available in the future, other SPP market participants will likely choose to take advantage of the higher prices and add similar resources to their portfolios. If additional load serving entities in SPP also decide to implement a similar net zero policy and perform a similar analysis that results in a more aggressive buildout of solar energy from other parties in addition to BPU, the market prices would be expected to drop thereby reducing the revenues for each individual solar facility. This type of market behavior was not fully captured in the capacity expansion model. Any future plans that are dependent on building large amounts of generation and recovering costs through energy market revenues have inherently higher amounts of risk than portfolios that seek to more closely balance customer load and generation.

None of the scenarios evaluated in this IRP include the costs that will have to be incurred to secure the transmission rights to transmit the energy from distant solar farms back to BPU or the costs of any transmission upgrades that would be necessary to maintain system reliability. Those types of costs can be very site and situation specific and are difficult to estimate, especially in a region such as SPP that does not already have large amounts of solar capacity installed. Scenario 9 has the largest solar capacity buildout and so it would be expected to incur more of those types of transmission costs than any of the other IRP scenarios. This means that the total cost for Scenario 9 would be most impacted if those additional transmission costs were added in and its rank as the lowest cost scenario could change.

Scenario 10, the case that contemplates the early retirement of the Quindaro combustion turbines is the second lowest cost scenario. This lower cost is tied to the early retirement of the two Quindaro units and their replacement in 2028 with 125 MW of solar capacity. That new solar capacity was calculated to generate much more energy during the course of the planning period than the Quindaro units would have and as a result, reduced net market energy purchase costs and increased market sales revenues. Again, just as in Scenario 9, it should be noted that future market revenues, especially from sources of intermittent renewable energy, are uncertain. However, unlike Scenario 9 and its highly aggressive buildout of new solar capacity equal to 1,175 MW, Scenario 10 includes a much more modest series of solar additions totaling only 200 MW.

Scenarios 1, 4, 5, 6, 7, and 8 all have similar capacity expansion planning results and so it is expected that all of these scenarios have similar costs. Differences in the exact timing of resource buildouts along with individual scenario's assumptions about fuel prices and the market prices for energy are largely responsible for these relatively small differences.

The second highest cost scenario considered was Scenario 2 which examined the possibility of retrofitting Nearman Creek 1 to burn a combination of coal and natural gas starting in 2030. The cost of the retrofit was estimated to be fairly modest, but the scenario also included the forced retirement of Nearman Creek 1 at the end of 2038 and its replacement with a new 237 MW natural gas-fired simple cycle combustion turbine. The addition of that large new unit in 2039 is a significant driver of the total costs for Scenario 2.

As expected, the highest cost option examined was Scenario 3. The very high capital cost of installing a carbon capture system at Nearman Creek 1 combined with the lack of generation at that power plant following the retrofit and the large amount of necessary market energy purchases to make up for that lost generation all contribute to the high overall cost. As discussed previously in Section 5.3, the results of this IRP analysis along with the current uncertainties surrounding the availability of the necessary CO2 transportation and storage infrastructure, indicate that Nearman Creek 1 is not likely to be a good candidate for upgrading to use carbon capture and sequestration.

6 Action Plan and Future Initiatives

This IRP is intended to act as a comprehensive decision support tool and road map for BPU's objective of providing reliable and least-cost electric service to all its customers while addressing the substantial risks and uncertainties inherent in the electric utility business. Today's utilities are facing greater challenges than ever before with more challenges and opportunities on the horizon. The analyses and decisions that come from the IRP planning process can make lasting advancements in the development of the utility and in the services that it provides to its customers. As such, it is recommended that BPU continue to constantly evaluate its options with respect to capacity and energy additions or modifications considering the numerous changes ongoing within the electric utility industry.

6.1 ACTION PLAN

Each of the ten scenarios documented above represents a possible future that BPU could experience. Because it is not possible to predict the future with perfect accuracy, the use of multiple planning scenarios allows decision makers to identify future resource options or strategies that appear most often. This results in increased confidence that near-term strategies will allow BPU to meet its customer's needs over a wide range of possible outcomes.

As shown in Table 6-1, many of the IRP planning scenarios indicated that new generating capacity would not be needed until as late as 2038. This general timeline indicates BPU is well situated in the near- to medium-term to continue supplying reliable electricity to its customers with its existing resources.

Table 6-1 Year of Earliest New Generating Capacity Additions

Scenarios	Year of Earliest New Generating Capacity Additions
Scenario 1 - Base Case	2038
Scenario 2 - Co-firing of Natural Gas at Nearman Creek 1	2038
Scenario 3 - Nearman Creek 1 Carbon Capture and Sequestration	2032
Scenario 4 - Nearman Creek 1 NOx Controls	2038
Scenario 5 - High Fuel Prices Sensitivity	2038
Scenario 6 - Low Fuel Prices Sensitivity	2038
Scenario 7 - High Load Growth Sensitivity	2038
Scenario 8 - High Reserve Requirement Sensitivity	2032
Scenario 9 - Net Zero by 2040	2031
Scenario 10 - 2028 Combustion Turbines	2028

Based on the results of this 2024 IRP analysis, it is likely that BPU will be able to continue to meet all of its energy and capacity obligations over the next five years through the continued use of its existing generation resources and purchased power contracts. Prior to 2038, BPU's firm capacity needs are anticipated to remain small. However, it is recommended that BPU continue to evaluate opportunities in the near-term related to new sources of energy and capacity. As shown in the results from the cost analysis for Scenario 10 in Section 5.11, the construction, purchase, or acquisition of long-term contract rights for new sources of renewable energy in the near-term could be advantageous in the long-term management of total system costs. Such acquisitions could also reduce future needs for purchased capacity in a market where firm capacity is forecasted to become more expensive and more difficult to acquire in the years to come. Existing opportunities for managing the costs of new sources of renewable energy could come from the Green Rider Program and/or the expansion of locally based community solar facilities.

During the development of the IRP capacity expansion model, it was found that before 2038, the model was sensitive to the assumptions about the cost and availability of purchased capacity. Small variations in those assumptions could shift the date in which the model would choose to add new solar capacity. This indicates that the cost difference between those options can be small. In such a circumstance, purchased capacity could be used to preserve flexibility in future resource planning decisions with a cost that would be similar to other capacity expansion options.

New conventional thermal generation did not appear appreciably in the results of this IRP, but as needs for new energy generation and capacity develop, and the wider energy market continues to change, it is recommended that new and highly efficient natural gas-fired thermal power plants still be included as possible options to meet some of BPU's future needs. A well-balanced portfolio of generating resources, such as the one currently possessed by BPU, contains a mixture of different power plant technologies and fuel types.

It is also recommended that BPU continues to provide its customers with access to programs that help them optimize their energy usage schedule and to incentivize the installation of new, more efficient appliances. By reducing overall energy consumption and shifting demand away from peak times, BPU can help defer the need for new generating resources while reducing costs for both its customers and the utility.

6.1.1 Other Planning Considerations

As BPU continues to evaluate options for future new energy and capacity needs, several categories stand out as the potential largest drivers affecting those decisions. Additional commentary for each is provided below.

6.1.1.1 Environmental Regulations

The future of new environmental rules that could impact the operation and/or retirement of Nearman Creek 1 is uncertain. Legal challenges to these regulations are likely to continue for years to come. Additionally, possible changes to the political landscape at the federal level could have significant impacts on how those regulations are defended in court and how any possible new environmental rules are issued. It is important that BPU consider the possible impacts from the new EPA pollution standards and if it wants to examine in more detail the possibility of retrofitting Nearman Creek 1 to reduce its carbon emissions, action may need to be taken in the near-term. The deadlines for completing the retrofits contemplated in the new carbon pollution rules are in 2030 for operating with the co-firing of natural gas, and in 2032 for operating with carbon capture and sequestration equipment. Each of those projects would require years of preparation and therefore, if desired, preliminary studies should be started in the near-term.

6.1.1.2 Changes in Capacity Mix Within SPP

Over the next twenty years, the mix of generating resources within SPP may see significant changes. It is anticipated that existing coal power plants will continue to be retired and renewable resources will become a larger fraction of the total generation within the market. SPP is already rich with wind energy, but the potential exists for large amounts of solar energy to be added as well. Energy storage facilities may also become an increasingly important part of the SPP market to complement the increased use of intermittent renewable generation. Any of these possible changes will impact the future costs and firm capacity contributions from different energy resources. BPU will need to continue to monitor these market-wide changes to ensure that its future decisions remain in line with market realities. The use of the formal IRP planning process every five years ensures a fresh look at those market conditions while on-going operations and participation in the SPP market will provide BPU the ability to monitor those types of changes as they occur.

6.1.1.3 Wind Energy

Other considerations include the replacement of the energy being provided by the existing contracts with the Smoky Hills, Alexander, and Cimarron Bend wind farms. Within SPP, it is forecast that wind farms will continue to have lower ELCC values when compared with solar facilities, and as a result, will have lower contributions to firm capacity on a per MW of installed capacity basis. However, by their nature, wind farms can generate electricity both during the day and at night and can be important sources of energy to serve customer loads. Currently, BPU's three wind farms provide energy generation equal to more than 40% of BPU's total annual load. Energy from long-term contracts can provide BPU with a hedge against future market price volatility and help provide predictable energy costs for customers.

6.1.1.4 Firm Capacity Contracts

One of the major drivers in this IRP is the price and availability of firm capacity contracts that BPU will have access to over the next twenty years. The PLEXOS modeling allowed a maximum of 20 MW of firm capacity to be purchased at any one time. That limitation is not a hard limit, but rather the amount that at the time of this study was considered to likely be available at the costs assumed based on the current environment. BPU can choose to procure more firm capacity through bi-lateral contracts within SPP if the terms and price of a contract warrant. If firm capacity can be acquired at favorable terms, it could provide additional flexibility for BPU in the timing of future resource buildouts.

6.2 PUBLIC PARTICIPATION

During the IRP process, BPU solicited input from members of the pubic. Comments were provided both online via email and in person during a regularly scheduled meeting of the Board. Copies of all public comments provided to BPU in writing during the IRP process are attached in Appendix D.

7 Appendix A – List of Acronyms

AAGR	Average Annual Growth Rate
AMI	Advanced Metering Infrastructure
BESS	Battery Energy Storage System
BPU	Board of Public Utilities
CC	Combined Cycle
CCS	Carbon Capture and Sequestration
CDD	Cooling Degree Days
CSAPR	Cross-State Air Pollution Rule
CT	Combustion Turbine
DSM	Demand Side Management
EE	Energy Efficiency
EPA	Environmental Protection Agency
GHG	Greenhouse Gas
GNP	Good Neighbor Plan
HDD	Heating Degree Days
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
kVA	Kilovolt-amperes
kW	Kilowatts
kWh	Kilowatt-hours
MW	Megawatts
MWh	Megawatt-hours
NOAA	National Oceanic and Atmospheric Administration
NOx	Nitrogen Oxides
PPA	Purchased Power Agreement
PRM	Planning Reserve Margin
PTC	Production Tax Credit
PV	Photovoltaic
RICE	Rotating Internal Combustion Engine
SPP	Southwest Power Pool
SWPA	Southwest Power Administration
WAPA	Western Area Power Administration

8 Appendix B – Load Forecast Report

8.1 SUMMARY

An Integrated Resource Planning ("IRP") study requires a long-term load forecast, as utilities plan to meet long-term energy requirements and to have sufficient capacity installed to meet the system annual peak load plus the utility's reserve requirements.[3] In IRP studies, the long-term load forecast is an input into an expansion planning model, and various combinations of candidate future capacity resources are developed to evaluate the mix of resources that will result in the lowest reasonable costs, consistent with meeting reserve obligations and operating in an environmentally acceptable manner.

Black & Veatch Management Consulting, LLC ("Black & Veatch") was retained by the Kansas City Kansas Board of Public utilities ("BPU") to develop a long-term forecast (2024-2043) for the BPU electric system. The BPU forecast was prepared using an econometric model developed specifically for the utility's system. The load forecast consists of multiple econometric equations that tested various economic, socioeconomic, time trend, and weather data series as independent variables to forecast energy sales.

Total BPU energy sales projections were derived by summing up the individual end user classes (residential, commercial, industrial, and other) forecasts. The resulting total system energy sales forecast projects little change expected over the forecast period. Specifically, energy sales are projected to increase at an annual average growth rate of 0.50 percent, from 2,518 GWh to 2,766 GWh during the 2024 through 2043 forecast period. When adjusted to account for expected system losses, energy sales are projected to increase from 2,664 GWh in 2024 to 2,934 GWh in 2043.

[3] Reserves are an amount over and above the projected system peak that utilities will plan to maintain in the event that the actual demand is higher than anticipated due to extreme weather conditions or higher than expected load growth, or in the event that capacity resources are not available due to a forced outage, a transmission line failure, or due to other additional factors.

8.2 INTRODUCTION

8.2.1 General Discussion of Econometric Models

The BPU load forecast was prepared by developing econometric equations specifically for the utility's system. Econometric models are commonly used in the utility industry and have generally provided satisfactory results for long-range system planning purposes.

Econometric models use regression analysis whereby a dependent variable, such as energy sales, is modeled as a function of one (simple regression) or more (multiple regression) independent variables, also called explanatory variables. The objective is to predict the average value of a dependent variable given fixed values of the independent variable(s).[4] For example, energy sales may be modeled as a dependent variable and population may be selected as an independent variable. Graphically, the relationship between the dependent and independent variables follows the pattern shown in Figure 8-1, where energy sales are assumed to be the dependent variable and population is the independent variable. When expressing this relationship mathematically, the regression functional form can be written as follows:

$$Y = \alpha + \beta_1 X_i + u_i$$

Where: Y is the dependent variable, α is the intercept, β_1 is the slope coefficient, X_i is the independent variable and u_i is the residual term arising from other factors that are not part of the equation. Thus, in the example, β_1 measures the change in the mean value of Y (energy sales in this example) per unit change in X_i (population) and determines the slope seen in Figure 8-1. The coefficient can be positive or negative and should be reviewed for consistency with economic theory and power system operations. For example, if population is used as an independent variable to predict energy consumption, population would be expected to be positively related to energy consumption and would be expected to have a positive coefficient. For a winter peaking utility, on the other hand, if minimum winter temperature is used as an independent variable to project the system peak demand, the temperature variable would be expected to have a negative coefficient since a lower winter temperature would tend to produce a higher system peak demand.

A common technique to estimate coefficients is ordinary least squares regression analysis, so named because a regression line is selected that minimizes the sum of the squared residuals. This method is considered to be the best linear unbiased coefficients estimator.

[4] Regression analysis deals with the dependence of one variable on another, but does not necessarily imply causation, which arise from economic theory, observation, or other source.

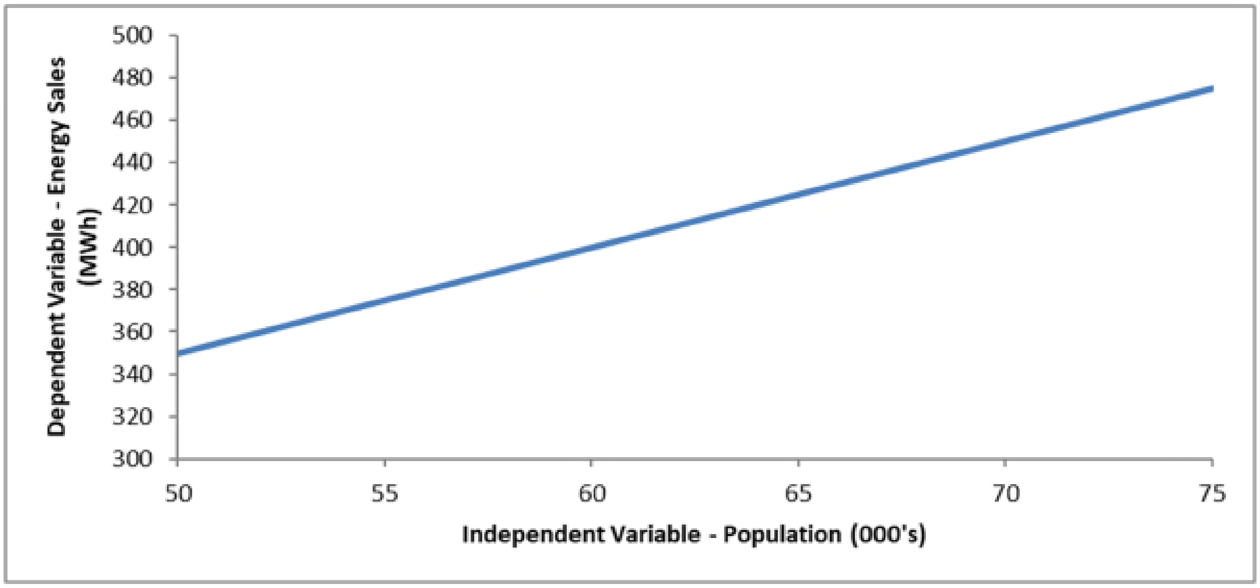

Figure 8-1 Basic Relation of Energy Sales and Population

Econometric models often contain multiple independent variables because a multi-variable model may provide greater explanatory power than a single variable model. For example, some utilities have also determined that temperature and the price of retail energy are key explanatory variables in predicting energy sales. A multi-variable econometric model reflecting this scenario would take the functional form:

$$Y = \alpha + \beta_1 X_{1i} + B_2 X_{2i} + u_i$$

One of the most important measures of how well the independent variables explain the variation in the dependent variable is called the coefficient of determination, r^2 (for simple regression, R^2 for a multiple regression)[5]. The coefficient of determination indicates the percentage of total variation in the dependent variable explained by the regression model. The value of r^2 will range from a high of 1.00 (100 percent of the variation is explained by the regression model) to a low of 0.00 (no variation in the dependent variable is explained by the model). Thus, if a regression analysis that modeled energy sales as a function of population produced an r^2 of 0.75, it would mean that 75 percent of the demand for energy is explained by the regression model. In load forecasting, R^2 values of 0.70 or more are commonly achieved for the peak demand and energy forecasts.

While the R^2 is a useful figure, the "adjusted R^2" is a better reflection of the explanatory power of a model as it adjusts for the number of independent variables, and reduced degrees of freedom, in the model. The adjusted R^2 should be less than the R^2.

Other statistical indicators that are routinely evaluated are the t-statistic for the independent variables (which is a measure of how strongly a particular independent variable explains variations in the

[5] Noted as r-square or R-square.

dependent variable; the larger the t-statistic, the better the independent variable's explanatory power) and the regression's F-statistic (which is similar to the t-statistic, but looks at the quality of the entire model, meaning with all independent variables included. By eliminating independent variables with a low t-statistic, the F-statistic will increase as will the overall quality of the model). Finally, the standard error is also helpful when choosing among competing forecast equations. The standard error is a measure of the average distance that observed values fall from the regression line. The standard error indicates how well the regression model fits a dataset, on average, using the units in the equation; thus, a smaller standard error is preferred as it is an indication that the observations are closer to the fitted line. These statistical results are routinely produced by econometric software packages such SAS, SPSS and by regression analysis functions in spreadsheet software such as Microsoft Excel. Microsoft Excel was used for the BPU forecast.

Once the functional form of an equation is selected, it is used to project the future value of the dependent variable given a forecast for the independent variables, based on the assumption that the coefficient estimate(s) will remain a good indicator of the relationship between the dependent and independent variables. In the present example, it is possible to forecast energy sales given a forecast of future population. It is common to develop a baseline forecast constructed on the most likely assumptions, and then to develop high and low forecasts based on alternative values of the independent variables.

8.3 LOAD FORECAST

BPU's 2023-2043 load forecast developed by Black & Veatch covers the 21-year period of 2023 through 2043 (note that historical 2023 data was not available and so the first forecast year was 2023 while the expansion plan period is the 20-year period: 2024-2043). The load forecast consists of multiple econometric equations that utilize various economic, socioeconomic, and weather data series as independent variables to project net energy requirements.

8.3.1 Data and General Approach

BPU provided historical utility data covering the period of 2011-2022 for energy sales. The historical energy sales data was used to develop the forecast. The historical data used in this forecast is shown in Table 8-1. The historical data shows that the total BPU energy sales decreased at an average annual rate of 0.03 percent from 2011 through 2022.

Table 8-1 Historical Annual Energy and Peak Demand Data Used for the BPU Load Forecast

Year	Residential Sales (kWh)	Commercial Sales (kWh)	Industrial Sales (kWh)	Other Sales (kWh)	Total Sales (kWh)	Sales Change from Previous Year	Annual System Peak Demand (MW)	Peak Change from Previous Year
2011	593,263	947,700	617,011	375,030	2,533,004		502	-1.39%
2012	575,632	1,002,860	558,121	209,451	2,346,064	-7.38%	495	-8.28%
2013	570,101	974,198	539,562	264,081	2,347,942	0.08%	454	1.10%
2014	570,452	972,782	554,090	397,970	2,495,294	6.28%	459	5.66%
2015	553,722	971,811	622,672	352,048	2,500,253	0.20%	485	-1.03%
2016	578,784	976,063	599,925	355,559	2,510,332	0.40%	480	2.92%
2017	565,191	963,303	558,583	265,561	2,352,638	-6.28%	494	0.40%
2018	615,850	1,031,360	594,720	432,377	2,674,307	13.67%	496	-2.62%
2019	585,779	964,951	569,704	496,464	2,616,897	-2.15%	483	-8.28%
2020	582,140	907,607	513,640	416,611	2,419,998	-7.52%	443	4.74%
2021	598,543	958,611	467,110	394,880	2,419,144	-0.04%	464	4.53%
2022	602,404	1,001,706	539,368	399,715	2,543,193	5.13%	485	-1.39%
Historical AAGR	0.14%	0.51%	-1.22%	0.58%	0.04%		-0.31%	

To forecast future peak and net energy requirements, several economic data series were collected and tested for use as independent variables in the forecast equations. The historical data was obtained from various sources and forecast values for these variables were either provided by the data source or developed by Black & Veatch from the historical data. Table 8-2 shows the data series obtained and tested for use in the econometric models.

Table 8-2 Data Obtained, Tested and Used for the BPU Forecast

Variable Tested	Source of Historical Data	Source of Forecast for the Independent Variable Tested	Used in Final Forecast
Total Residential Electric Customers	KCK BPU	Black & Veatch, based on 2011-2022 average annual growth rate (AAGR)	Residential
Total Commercial Electric Customers	KCK BPU	Black & Veatch, based on 2011-2022 AAGR	No
Total Industrial Electric Customers	KCK BPU	Black & Veatch, based on 2011-2022 AAGR	Industrial
Total Other Electric Customers*	KCK BPU	Black & Veatch, based on 2011-2022 AAGR	Other**
Residential Electric Price	S&P Global Market Intelligence	Not developed as it was not adopted as an explanatory variable	No
Commercial Electric Price	S&P Global Market Intelligence	Not developed as it was not adopted as an explanatory variable	No
Industrial Electric Price	S&P Global Market Intelligence	Not developed as it was not adopted as an explanatory variable	No
Cooling Degree Days*	National Oceanic and Atmospheric Administration (NOAA)	Black & Veatch, based on historical average CDD	Residential, Other
Heating Degree Days*	NOAA	Black & Veatch, based on historical average HDD	Residential, Commercial, Other
GDP Per Capita of the Wyandotte County	U.S. Bureau of Economic Analysis	Not developed as it was not adopted as an explanatory variable	No
GDP Per Capita of the State of Kansas	U.S. Bureau of Economic Analysis	Not developed as it was not adopted as an explanatory variable	No
GPD of Wyandotte County	U.S. Bureau of Economic Analysis	Black & Veatch, based on 2011-2022 AAGR	Commercial
GDP of Kansas	U.S. Bureau of Economic Analysis	Not developed as it was not adopted as an explanatory variable	No

Variable Tested	Source of Historical Data	Source of Forecast for the Independent Variable Tested	Used in Final Forecast
COVID-19 Years Indicator Variable	None	Black & Veatch, Applied to 2020 and 2021	Commercial, Industrial
Wyandotte County Population	U.S. Bureau of Economic Analysis	Black & Veatch, based on 2011-2022 AAGR	Other
Total Employment in Wyandotte County	U.S. Bureau of Economic Analysis	Black & Veatch, based on 2011-2022 AAGR	Commercial
Income Per Capita, Wyandotte County	U.S. Bureau of Economic Analysis	Black & Veatch, based on 2011-2022 AAGR	Industrial

*A cooling degree day ("CDD") refers to the number of degrees that the daily average temperature is above 65 degrees Fahrenheit, and a heating degree day ("HDD") refers to the number of degrees that the daily average temperature is below 65 degrees. The CDD measure is closely linked to energy requirements for summer peaking utilities as CDDs are usually highly correlated with the use of air conditioning in the summer months. For peak demand, temperature-driven measures can be used. To model peak demand absolute temperature during a year can be used, but peak demand generally occurs as the result of a prolonged temperature buildup and the days of the week that the temperature buildup occurs. CDD can be used as a variable for forecasting peak load and total energy requirements to at least partially account for heat buildup.

** Other Customer class includes Schools, Wholesale Sales, Highway Lighting and Public Authorities

8.3.2 Energy Sales

The general approach used to develop the net energy sales forecast by each customer class (residential, commercial, industrial, and other) was to test the explanatory variables individually and in combination with other possible independent variables through the creation of dozens of econometric equations. Equations were eliminated from further consideration if they were judged to be inferior to other equations, based on an evaluation of the regression results as calculated by Excel. Key result statistics evaluated included the R^2, the adjusted R^2, the standard error, the t-Stat of individual variables (or corresponding P-value), and the F-Test of the equation. The coefficient of the variable also needed to have a sign consistent with economic theory.

An equation was selected for use in the energy sales forecast for each individual customer class, and the equation coefficients were applied to the forecasted values of the independent variables to arrive at the energy sales forecasts for each class. Those individual customer class forecasts were added together to create the total energy sales forecast for the entire Kansas City, Kansas BPU System. The results of the net energy requirements forecast for each customer class are summarized in the following subsections.

8.3.2.1 Residential Energy Sales

The residential energy sales forecast for residential customers was derived by developing multiple possible equations in which energy sales were modeled as a function of several variables including the number of residential customers, the residential electric price, heating degree days, cooling degree days, Wyandotte County GDP per capita, population, total employment, and Wyandotte County GDP. In the end, the following equation was selected for use in the residential sales forecast:

$$Residential\ Sales = \alpha + \beta_1(\#ResCust) + \beta_3(HDD) + \beta_4(CDD)$$

where:

Residential Sales = the residential energy sales dependent variable
α = the equation constant or intercept term
β_n = independent variables' coefficients
#ResCust = the number of residential electric customers
HDD = Heating Degree Days
CDD = Cooling Degree Days

This equation was applied to historical residential energy sales data from 2011 through 2022. The key results of the equation are shown in Table 8-3. These results indicate that the equation explains approximately 80.63 percent, as indicated by R-Square value, (or 73.37 percent as indicated by the adjusted R-Square) of the historical variation in net residential energy requirements and the coefficients have the expected signs. Results for the adjusted R-Square, standard error, the t-Stat and the F-Test are also shown in the table.

Table 8-3 Primary Regression Result Statistics for Residential Sales Forecast Equation[6]

Coefficients	Value	t Stat	P-value
Intercept	-48,786.49	-0.3829	0.7118
Residential Customers	7.51	3.7485	0.0056
HDD	14.31	2.7436	0.0253
CDD	71.92	4.6820	0.0016
Statistic	**Value**		
Multiple R	0.8979		
R Square	0.8063		
Adjusted R Square	0.7337		
Standard Error	9046.2784		
Observations	12.0000		
Regression F-Test	11.1001		

Once the residential energy sales equation was selected, the equation coefficients were applied to the forecasted values of the independent variables to arrive at the residential energy sales figure. The forecast of the number of residential electric customers was estimated based on the year 2022 residential customer count of 60,117 residential customers and using the historical average annual

[6] Regression Result Statistics:
R-Square: measure of how much variation in the dependent variable is explained by the independent variables.
Adjusted R-Square: adjusts for the number of independent variables in the equation.
Standard Error: a measure of the precision of the parameter estimate.
Regression F Statistic: used to test the overall significance of the independent variables in a regression model.
T Statistic: used to measure the significance of the parameter estimate.

growth rate (“AAGR”) of 0.60 percent. The projected heating degree days and cooling degree days were based on historical average values. The historical average heating degree days used for the forecast is 4454.83; the historical average cooling degree days used for the forecast is 1830.75. The resulting energy sales forecast is shown in Table 8-4.

Table 8-4 indicates that residential energy sales are projected to increase at an AAGR of 0.46 percent between for the nineteen years from 2024 and 2043. During this period, energy sales are projected to increase from 603,636 MWh in 2024 to 658,512 MWh in 2043.

Table 8-4 Residential Energy Sales (MWh) Forecast

Year	Historical	Forecast	Year	Forecast
2011	593,263		2024	603,636
2012	575,632		2025	606,372
2013	570,101		2026	609,124
2014	570,452		2027	611,892
2015	553,722		2028	614,678
2016	578,784		2029	617,479
2017	565,191		2030	620,298
2018	615,850		2031	623,133
2019	585,779		2032	625,986
2020	582,140		2033	628,855
2021	598,543		2034	631,742
2022	602,404		2035	634,646
2023*		600,917	2036	637,567
			2037	640,506
			2038	643,463
			2039	646,437
			2040	649,429
			2041	652,438
			2042	655,466
*2023 Actuals were not available at the time of the forecast development.			2043	658,512
			AAGR: 2024-2043	0.46%

8.3.2.2 Commercial Energy Sales

The commercial energy sales forecast for commercial customers was derived by developing multiple possible equations in which energy sales were modeled as a function of several variables including the number of commercial customers, the commercial electric price, heating degree days, cooling degree days, total employment in Wyandotte County, Wyandotte County GDP, Wyandotte County GDP per

[7] Regression Result Statistics:
R-Square: measure of how much variation in the dependent variable is explained by the independent variables.
Adjusted R-Square: adjusts for the number of independent variables in the equation
Standard Error: a measure of the precision of the parameter estimate
Regression F Statistic: used to test the overall significance of the independent variables in a regression model.
T Statistic: used to measure the significance of the parameter estimate.

capita, and a COVID-19 indicator variable (sometimes called dummy variable in statistics literature) set equal to zero in years not impacted by COVID-19, and 1 for years where commercial sales significantly dropped due to impacts from COVID-19. In the end, the following equation was selected for use in the commercial sales forecast:

$$Commercial\ Sales = \alpha + \beta_1(Covid) + \beta_2(TotEmp) + \beta_3(GDP) + \beta_4(CDD)$$

where:

Commercial Sales = the commercial energy sales dependent variable
α = the equation constant or intercept term
β_{n} = independent variables' coefficients
Covid = COVID-19 Year indicator variable
TotEmp = Wyandotte County total number of jobs
GDP = GDP by County
CDD = Cooling Degree Days

This equation was applied to historical commercial energy sales data from 2011 through 2022. The key results of the equation are shown in Table 8-5. These results indicate that the equation explains approximately 76.04 percent, as indicated by R-Square value, (or 62.35 percent as indicated by the adjusted R-Square) of the historical variation in net commercial energy requirements and the coefficients have the expected signs. Results for the adjusted R-square, standard error, the t-Stat and the F-Test are also shown in the table.

Table 8-5 Primary Regression Result Statistics for Commercial Sales Forecast Equation

Coefficients	Value	t Stat	P-value
Intercept	438,255.1265	1.9861	0.0874
Indicator Variable for COVID years	-35,057.6492	-2.3054	0.0546
Total Employment	2.2292	1.3484	0.2195
GDP By County (thousands of chained 2012 dollars)	0.0143	0.9900	0.3552
CDD	79.1573	2.3894	0.0482
Statistic	**Value**		
Multiple R	0.8720		
R Square	0.7604		
Adjusted R Square	0.6235		
Standard Error	18881.18		
Observations	12		
Regression F-Test	18.57		

After the commercial energy sales equation was determined, the equation coefficients were applied to the forecasted values of the independent variables to arrive at the commercial energy sales forecast values. The indicator variable was forecasted as 0 as no further impacts by COVID-19 are expected in the base forecast. The forecast of total employment was estimated using the historical AAGR of 0.93 percent per year and with the year 2022 total employment value of 111,222. The forecast of GDP By

County (thousands of chained 2012 dollars) was estimated using the historical AAGR of 0.59 percent and with the year 2022 GDP By County value of 10,941,644. The projected cooling degree days were based on the historical average. The historical average cooling degree days used for the forecast is 1830.75. The resulting energy sales forecast is shown in Table 8-6.

Table 8-6 indicates that the commercial energy sales for the Kansas City BPU are projected to increase at an AAGR of 0.34 percent from 2024 and 2043. During this period, energy sales are projected to increase from 993,770 MWh in 2024 to 1,060,860 MWh in 2043.

Table 8-6 Commercial Energy Sales Forecast

Year	Historical	Forecast	Year	Forecast
2011	947,700		2024	993,770
2012	1,002,860		2025	997,044
2013	974,198		2026	1,000,345
2014	972,782		2027	1,003,673
2015	971,811		2028	1,007,029
2016	976,063		2029	1,010,413
2017	963,303		2030	1,013,826
2018	1,031,360		2031	1,017,266
2019	964,951		2032	1,020,735
2020	907,607		2033	1,024,233
2021	958,611		2034	1,027,761
2022	1,001,706		2035	1,031,317
2023*		990,524	2036	1,034,904
			2037	1,038,520
			2038	1,042,166
			2039	1,045,843
			2040	1,049,551
			2041	1,053,289
			2042	1,057,059
*2023 Actuals were not available at the time of the forecast development.			2043	1,060,860
			AAGR: 2024-2043	0.34%

8.3.2.3 Industrial Energy Sales

The industrial energy sales forecast for industrial customers was derived by developing multiple possible equations in which energy sales were modeled as a function of several variables including the number of industrial customers, number of residential customers, the industrial electric price, heating degree days, cooling degree days, GDP per capita of Wyandotte County, total jobs in Wyandotte County, and GDP of Wyandotte County. Upon completing a statistical analysis of the equations identified, the following equation was selected for use in the industrial sales forecast:

$$Industrial\ Sales = \alpha + \beta_1(\#IndCust) + \beta_2(Covid) + \beta_3(IncPerCap)$$

where:

Industrial Sales = the industrial energy sales dependent variable α = the equation constant or intercept term

β_n = independent variables' coefficients

#IndCust = the number of KCK BPU industrial electric customers

Covid = Indicator variable for years impacted by COVID-19

IncPerCap = Wyandotte County Income Per Capita

This equation was applied to historical industrial energy sales data from 2011 through 2022. The key results of the equation are shown in Table 8-7. These results indicate that the equation explains approximately 79.73 percent, as indicated by R-Square value, (or 72.14 percent as indicated by the adjusted R-Square) of the historical variation in net industrial energy requirements and the coefficients have the expected signs. Results for the adjusted R-Square, standard error, the t-Stat and the F-Test are also shown in the table.

Table 8-7 Primary Regression Result Statistics for Industrial Sales Forecast Equation

Coefficients	Value	t Stat	P-value
Intercept	200,264.1570	1.1351	0.2892
Industrial Customers	6,235.9045	2.6164	0.0308
Indicator Variable for COVID Years	-64,452.2784	-3.2123	0.0124
Income Per Capita (Wyandotte County)	-4.4568	-2.9632	0.0181
Statistic	**Value**		
Multiple R	0.8930		
R Square	0.7974		
Adjusted R Square	0.7214		
Standard Error	23452.3		
Observations	12		
Regression F-Test	10.49		

After the industrial energy sales equation to be used for the forecast was determined, the equation coefficients were applied to the forecasted values of the independent variables to arrive at the industrial energy sales forecast. The number of industrial customers has decreased from 94 industrial customers in 2011 to 82 industrial customers in 2022. This decrease represents an AAGR of negative 1.23 percent over the historical period analyzed. It is expected that the rate at which the number of industrial customers has decreased will slow going forward. For this study, it is assumed that going forward through the forecast period the number of industrial customers will decrease at an average annual rate of 0.62 percent per year. The indicator variable was forecasted as 0 as no further impact by COVID-19 was contemplated in the base forecast. The forecast of the income per capita of Wyandotte County was estimated using the historical AAGR of 0.08 percent per year applied to the year 2022 value of $38,253. These values and the resulting energy sales forecast are shown in Table 8-8.

The resulting industrial energy sales forecast is shown in Table 8-8. Table 8-8 shows that industrial energy sales for the Kansas City, Kansas BPU are projected to decrease at an AAGR of 0.61 percent between 2024 and 2043. During this period, energy sales are projected to decrease from 534,550 MWh in 2024 to 475,804 MWh in 2043.

Table 8-8 Industrial Energy Sales Forecast

Year	Historical	Forecast	Year	Forecast
2011	617,011		2024	534,550
2012	558,121		2025	531,292
2013	539,562		2026	528,053
2014	554,090		2027	524,833
2015	622,672		2028	521,632
2016	599,925		2029	518,450
2017	558,583		2030	515,287
2018	594,720		2031	512,141
2019	569,704		2032	509,015
2020	513,640		2033	505,906
2021	467,110		2034	502,816
2022	539,368		2035	499,744
2023*		537,827	2036	496,690
			2037	493,654
			2038	490,635
			2039	487,634
			2040	484,651
			2041	481,685
			2042	478,736
*2023 Actuals were not available at the time of the forecast development.			2043	475,804
			AAGR: 2024-2043	-0.61%

8.3.2.4 Other Energy Sales

The other energy sales forecast that includes sales to schools, wholesale buyers, highway lighting, and public authorities was derived by developing multiple possible equations in which energy sales were modeled as a function of several variables including the number of other customers, the population of Kansas City, Kansas, heating degree days, cooling degree days, and industrial electric prices. Upon completing a statistical analysis of the equations identified to determine the best predictor of other energy sales, the following equation was selected for use in the other sales forecast:

$$Other\ Sales = \alpha + \beta_1(Pop) + \beta_2(HDD) + \beta_3(CDD)$$

where:

Other Sales = the other energy sales dependent variable
α = the equation constant or intercept term
β_n = independent variables' coefficients
Pop = Kansas City, Kansas Population
HDD = Heating Degree Days
CDD = Cooling Degree Days

This equation was applied to historical other energy sales data from 2011 through 2022. The key results of the equation are shown in Table 8-9. These results indicate that the equation explains approximately 81.31 percent, as indicated by R-Square value, (or 74.3 percent as indicated by the adjusted R-Square) of the historical variation in net other energy requirements and the coefficients have the expected signs. Results for the adjusted R-square, standard error, the t-Stat and the F-Test are also shown in the table.

Table 8-9 Primary Regression Result Statistics for Other Sales Forecast Equation

Coefficients	Value	t Stat	P-value
Intercept	-2,619,860	-4.0470	0.0037
Population (persons) 1	13.7092	3.8768	0.0047
HDD	111.0731	4.6763	0.0016
CDD	120.3771	1.7116	0.1253
Statistic	**Value**		
Multiple R	0.9017		
R Square	0.8131		
Adjusted R Square	0.7430		
Standard Error	41085.7026		
Observations	12.0000		
Regression F-Test	11.6029		

Once the other energy sales equation was selected, the equation coefficients were applied to the forecasted values of the independent variables to arrive at the other energy sales figure. The forecast of the Kansas City, Kansas population was estimated using the historical AAGR of 0.41 percent and the year 2022 value of 165,746. The projected HDD and CDD were based on the historical average values of 4454.83 and 1830.75 for projected HDD and CDD, respectively. The resulting other sales forecast is shown in Table 8-10.

Table 8-10 indicates that the other sales for the Kansas City, Kansas BPU are projected to increase at an AAGR of 2.08 percent between 2024 and 2043. During this period, other energy sales are projected to increase from 386,220 MWh in 2024 to 571,138 MWh in 2043.

Table 8-10 Other Energy Sales

Year	Historical	Forecast	Year	Forecast
2011	375,030		2024	386,220
2012	209,451		2025	395,599
2013	264,081		2026	405,016
2014	397,970		2027	414,472
2015	352,048		2028	423,966
2016	355,559		2029	433,500
2017	265,561		2030	443,072
2018	432,377		2031	452,684
2019	496,464		2032	462,335
2020	416,611		2033	472,025
2021	394,880		2034	481,755
2022	399,715		2035	491,525
2023*		376,880	2036	501,335
			2037	511,185
			2038	521,075
			2039	531,006
			2040	540,978
			2041	550,990
			2042	561,044
*2023 Actuals were not available at the time of the forecast development.			2043	571,138
			AAGR: 2024-2043	2.08%

8.3.2.5 Total BPU Energy Sales

The total BPU energy sales forecast is the sum of the individual residential, commercial, industrial, and other energy sales. The total KCK BPU system energy sales forecast is shown in Table 8-11, which forecasts little expected growth. Energy sales are projected to increase at an annual average growth rate of 0.50% percent from 2,518,176 MWh to 2,766,315 MWh during the 2024 through 2043 forecast period.

Table 8-11 Customer Class and Total Energy Sales Forecast

Year	Residential Sales	Commercial Sales	Industrial Sales	Other Sales	Total Sales	Change from Previous Year
2024	603,636	993,770	534,550	386,220	2,518,176	0.48%
2025	606,372	997,044	531,292	395,599	2,530,307	0.48%
2026	609,124	1,000,345	528,053	405,016	2,542,538	0.48%
2027	611,892	1,003,673	524,833	414,472	2,554,871	0.49%
2028	614,678	1,007,029	521,632	423,966	2,567,306	0.49%
2029	617,479	1,010,413	518,450	433,500	2,579,843	0.49%
2030	620,298	1,013,826	515,287	443,072	2,592,482	0.49%
2031	623,133	1,017,266	512,141	452,684	2,605,225	0.49%
2032	625,986	1,020,735	509,015	462,335	2,618,071	0.49%
2033	628,855	1,024,233	505,906	472,025	2,631,020	0.49%
2034	631,742	1,027,761	502,816	481,755	2,644,074	0.50%
2035	634,646	1,031,317	499,744	491,525	2,657,233	0.50%
2036	637,567	1,034,904	496,690	501,335	2,670,496	0.50%
2037	640,506	1,038,520	493,654	511,185	2,683,865	0.50%
2038	643,463	1,042,166	490,635	521,075	2,697,340	0.50%
2039	646,437	1,045,843	487,634	531,006	2,710,920	0.50%
2040	649,429	1,049,551	484,651	540,978	2,724,608	0.50%
2041	652,438	1,053,289	481,685	550,990	2,738,403	0.51%
2042	655,466	1,057,059	478,736	561,044	2,752,305	0.51%
2043	658,512	1,060,860	475,804	571,138	2,766,315	0.51%
AAGR: 2024-43	0.46%	0.34%	-0.61%	2.08%	0.50%	-

8.3.3 Annual Peak Demand and Net Energy for Load Forecasts

The BPU annual peak demand forecast was determined by performing a regression analysis to develop the relationship between historic annual energy sales and historic annual peak demand. Using the historical relationship between annual energy sales, CDD, and peak demand, the system annual peaks were forecast using the forecast energy sales and CDD. Upon completing a statistical analysis of the equation identified to determine the best predictor of system annual peak load, the following equation was selected for use in the annual peak demand forecast:

$$Peak = \alpha + \beta_1(Year) + \beta_2(Residential\ Sales) + \beta_3(CDD) + \beta_4(Industrial\ Sales) \\ + \beta_5(Other\ Sales)$$

where:

Peak = the annual system peak demand

α = the equation constant or intercept term

β_n = independent variables' coefficients

Year = Year

Residential Sales = Annual Residential Sales

CDD = Cooling Degree Days

Industrial Sales = Annual Industrial Sales
Other Sales = Annual Other Sales

This equation was applied to historical peak data from 2011 through 2022. The key results of the equation are shown in Table 8-12. These results indicate that the equation explains approximately 71 percent, as indicated by R-Square value, (or 46.9 percent as indicated by the adjusted R-Square) of the historical variation in annual system peak demand. Results for the adjusted R-square, standard error, the t-Stat and the F-Test are also shown in Table 8-12.

Table 8-12 Primary Regression Result Statistics for Annual Peak Demand Equation

Coefficients	Value	t Stat	P-value
Intercept	-3445.9	-0.92116	0.3925
Year	1.7594	0.95133	0.37817
Residential Sales	0.00030208	0.65691	0.53561
CDD	0.026593	0.72849	0.49375
Industrial Sales	0.00033648	2.3829	0.05455
Other Sales	-0.00010205	-1.1678	0.2872
Statistic	**Value**		
Multiple R	0.84284		
R Square	0.71038		
Adjusted R Square	0.46903		
Standard Error	13.771		
Observations	12		
Regression F-Test	2.9434		

A load-serving entity's net energy for load is the total amount of energy that it must generate or purchase to meet its retail sales obligations. It includes retail consumption and transmission, distribution, storage, and other losses but excludes energy needed to meet wholesale sales obligations. For this IRP study, losses are estimated by customer class based on component losses for transmission losses and primary and secondary losses. The losses assumptions used to determine net energy for load are shown in Table 8-13.

Table 8-13 Loss Assumptions

Class	Transmission	Primary	Secondary	Total
Residential	0.44%	2.39%	4.38%	7.21%
Commercial	0.44%	2.39%	4.38%	7.21%
Industrial	0.44%	0%	0%	0.44%
Other	0.44%	2.39%	4.38%	7.21%

The resulting annual BPU total net energy for load forecast and the BPU system annual peak demands forecast are shown in Table 8-14. Also shown in Table 8-14 are the system annual load factors based on the forecast system annual net energies for load and forecast system annual peak demands. Total annual net energies for load are forecast to increase at an annual average growth rate ("AAGR") of about 0.51 percent. The total growth in forecast total net energy for load from the year 2024 through 2043 is about ten percent. The annual system peak demand is forecast to increase at a slower AAGR of about 0.12 percent resulting in a 2.34 percent increase from the year 2024 through 2043. The net effect of a slower growth rate in the system annual peak demand compared to the growth rate of total net energy for load is an increase in the system annual load factor over the forecast period of about 7.9 percent at an AAGR of about 0.40 percent. The forecasts of total annual net energy for load and system peak are shown graphically in Figure 8-2.

Table 8-14 Annual Total Net Energy for Load and Peak Load Forecasts

Year	Total Net Energy for Load (Annual Sales + Losses)	NEL Change from Previous Year	Annual Peak Demand	Peak Change from Previous Year	Annual Load Factor
2024	2,663,548		486.6		62.3%
2025	2,676,773	0.50%	487.1	0.11%	62.7%
2026	2,690,106	0.50%	487.6	0.11%	63.0%
2027	2,703,546	0.50%	488.2	0.11%	63.2%
2028	2,717,094	0.50%	488.7	0.11%	63.5%
2029	2,730,750	0.50%	489.3	0.12%	63.7%
2030	2,744,515	0.50%	489.9	0.12%	64.0%
2031	2,758,389	0.51%	490.4	0.12%	64.2%
2032	2,772,373	0.51%	491.0	0.12%	64.5%
2033	2,786,467	0.51%	491.6	0.12%	64.7%
2034	2,800,671	0.51%	492.2	0.12%	65.0%
2035	2,814,986	0.51%	492.8	0.12%	65.2%
2036	2,829,413	0.51%	493.4	0.12%	65.5%
2037	2,843,951	0.51%	494.1	0.13%	65.7%
2038	2,858,602	0.52%	494.7	0.13%	66.0%
2039	2,873,365	0.52%	495.3	0.13%	66.2%
2040	2,888,241	0.52%	496.0	0.13%	66.5%
2041	2,903,231	0.52%	496.6	0.13%	66.7%
2042	2,918,336	0.52%	497.3	0.13%	67.0%
2043	2,933,554	0.52%	497.9	0.13%	67.3%
AAGR: 2024-2043	0.51%		0.12%		0.40%

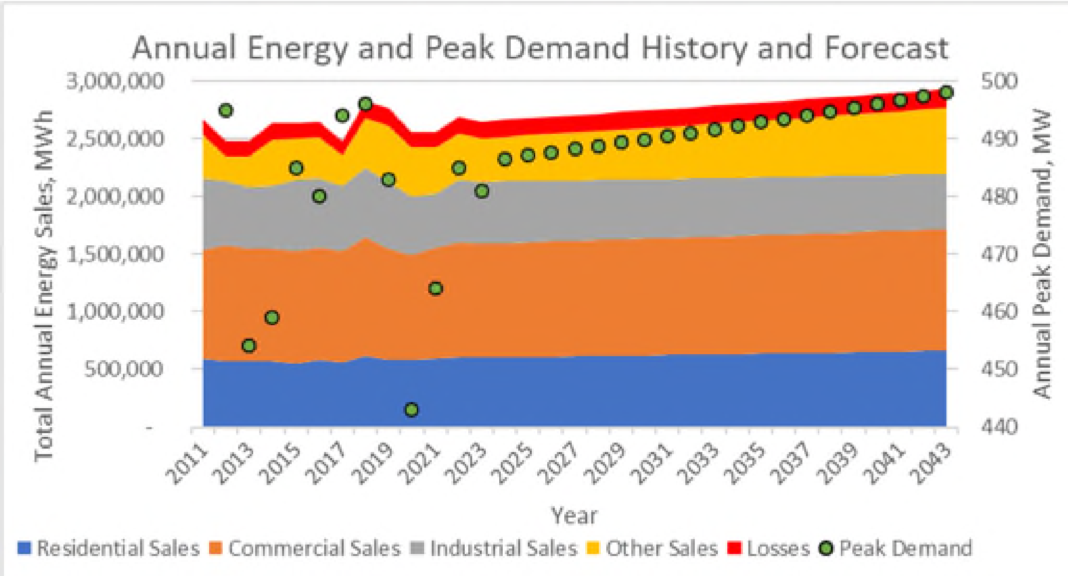

Figure 8-2 Annual Energy and Peak Demand History and Forecast

9 Appendix C – Cumulative Present Worth Cost Tables

BPU 1 Base Case 24-43

Economic Parameters	
CPW Real Discount Rate:	10.00%
Base Year for $	2024

Nearman ST1 Retrofit Costs	
Levelized Annual Costs, $1000/yr:	--
Beginning Yr:	--

Generation Additions and Capacity Purchases

Generator Addition or Capacity Purchase	Year	MW	Purchase or Installed Cost ($1,000)	Levelized Cost ($1,000)
Solar Farm with ITC	2038	50	39,419	3,154
Solar Farm with PTC	2039	25	22,856	1,828
Capacity Purchase	2028	10	925	
Capacity Purchase	2029	10	948	
Capacity Purchase	2030	10	971	
Capacity Purchase	2031	10	994	
Capacity Purchase	2032	10	1,019	
Capacity Purchase	2033	10	1,043	
Capacity Purchase	2034	10	1,069	

Capacity Purchase Year	MW	Purchase Cost ($1,000)
2035	10	1,095
2036	13	1,458
2037	14	1,609
2038	20	2,354
2039	10	1,206
2040	10	1,235
2041	10	1,265
2042	10	1,296
2043	12	1,593

	Energy Balance				SPP Market		Production Cost										
								Plant O&M									
Year	Load (GWh)	Generation (GWh)	Market Purchases Imports (GWh)	Market Sales Exports (GWh)	Market Purchases Cost ($1,000)	Market Sales Revenue ($1,000)	Fuel Cost ($1,000)	Variable[1] ($1,000)	FO&M Cost ($1,000)	Start & Shutdown Cost ($1,000)	Total Generation Cost ($1,000)	Total Generation Cost ($/MWh)	Capacity Purchases Costs ($1,000)	Unit Build Costs ($1,000)	Annualized Build and Retrofit Costs ($1,000)	Total System Cost ($1,000)	Cumulative Present Worth Cost (CPWC) ($1,000)
2024	2,663.6	2,817.3	444.1	597.7	14,345	26,900	39,085	32,238	23,984	3,221	98,528	34.97	0	0	0	85,973	85,973
2025	2,676.8	2,684.2	553.6	561.0	21,873	26,109	39,442	31,946	29,318	3,168	103,874	38.70	0	0	0	99,638	176,552
2026	2,690.0	2,833.7	446.6	590.3	18,188	27,351	42,903	32,317	36,293	3,188	114,702	40.48	0	0	0	105,539	263,775
2027	2,703.5	2,523.2	598.0	417.8	24,491	21,676	39,448	31,507	29,193	2,619	102,767	40.73	0	0	0	105,582	343,100
2028	2,717.1	2,395.1	698.5	376.5	28,626	19,757	39,495	27,667	27,067	2,723	96,953	40.48	925	0	0	106,747	416,010
2029	2,730.8	2,340.1	741.4	350.7	29,523	19,009	39,381	26,983	34,343	2,743	103,449	44.21	948	0	0	114,912	487,361
2030	2,744.5	2,331.4	760.6	347.5	28,354	20,068	42,598	25,660	23,643	3,174	95,075	40.78	971	0	0	104,331	546,253
2031	2,758.5	2,249.4	812.5	303.4	30,168	17,986	39,698	25,477	23,618	3,312	92,105	40.95	994	0	0	105,280	600,279
2032	2,772.4	2,366.4	755.7	349.8	25,694	20,763	42,425	25,815	24,184	3,488	95,912	40.53	1,019	0	0	101,862	647,798
2033	2,786.4	2,394.7	743.1	351.3	24,339	20,314	43,295	25,807	23,554	3,582	96,239	40.19	1,043	0	0	101,307	690,762
2034	2,800.6	2,278.4	842.3	320.1	27,930	19,305	39,134	25,568	23,554	2,934	91,190	40.02	1,069	0	0	100,884	729,657
2035	2,815.0	2,251.1	872.0	308.1	27,916	18,658	39,100	25,498	27,554	3,062	95,214	42.30	1,095	0	0	105,568	766,658
2036	2,829.5	2,114.4	960.4	245.3	29,715	15,796	37,930	22,272	23,619	3,739	87,560	41.41	1,458	0	0	102,938	799,457
2037	2,844.0	2,202.3	938.2	296.5	28,289	19,156	42,059	22,288	25,548	3,409	93,304	42.37	1,609	0	0	104,046	829,596
2038	2,858.6	1,394.1	1,613.9	149.4	41,844	10,724	42,896	3,234	32,306	3,851	82,286	59.03	2,354	39,419	3,154	118,914	860,909
2039	2,873.5	1,454.6	1,574.6	155.7	41,531	11,181	43,725	2,392	24,600	3,578	74,296	51.08	1,206	22,856	4,982	110,834	887,442
2040	2,888.3	1,404.6	1,634.4	150.8	45,770	11,320	43,034	3,135	24,661	3,051	73,881	52.60	1,235	0	4,982	114,548	912,371
2041	2,903.2	1,535.4	1,556.3	188.6	43,242	14,753	50,260	3,365	24,988	3,791	82,404	53.67	1,265	0	4,982	117,141	935,547
2042	2,918.3	1,575.5	1,516.6	173.8	43,793	14,882	54,691	3,401	24,982	3,459	86,533	54.92	1,296	0	4,982	121,722	957,439
2043	2,926.0	1,622.3	1,495.8	192.1	44,287	16,338	60,359	3,315	24,509	4,262	92,445	56.99	1,593	0	4,982	126,970	978,200
Levelized Cost($1000):					$26,925	$20,766	$41,418	$25,001	$27,334	$3,192	$96,945	$42.08	$731	$1,693	$620	$104,454	
NPV:					$252,150	$194,475	$387,872	$234,130	$255,985	$29,892	$907,878		$6,844	$15,852	$5,804	$978,200	
Levelized Cost($/MWh):					$12.89	$30.26	$9.07	$5.47	$5.99	$0.70	$21.23		$0.12	$0.28	$0.14	$17.50	
Load Based Levelized Cost($/MWh):					$4.51	$3.48	$6.94	$4.19	$4.58	$0.53	$16.24		$0.12	$0.28	$0.10	$17.50	

Notes:

[1] PPA energy purchase costs included in Variable O&M costs.

BPU 2 N1 Nat Gas 24-43

Economic Parameters	
CPW Real Discount Rate:	10.00%
Base Year for $	2024

Nearman ST1 Retrofit Costs	
Levelized Annual Costs, $1000/yr:	940
Beginning Yr:	2030

Generation Additions and Capacity Purchases

Generator Addition or Capacity Purchase	Year	MW	Purchase or Installed Cost ($1,000)	Levelized Cost ($1,000)	Capacity Purchase Year	MW	Purchase Cost ($1,000)
Solar Farm with ITC	2038	50	39,419	4,094	2035	10	1,095
Solar Farm with ITC	2039	25	242,682	1,554	2036	13	1,458
SCCT Adv	2039	237	1,206	17,860	2037	14	1,609
Capacity Purchase	2028	10	925		2038	20	2,354
Capacity Purchase	2029	10	948		2039	10	1,206
Capacity Purchase	2030	10	971		2040	10	1,235
Capacity Purchase	2031	10	994		2041	10	1,265
Capacity Purchase	2032	10	1,019		2042	10	1,296
Capacity Purchase	2033	10	1,043		2043	12	1,593
Capacity Purchase	2034	10	1,069				

	Energy Balance				SPP Market		Production Cost										
Year	Load (GWh)	Generation (GWh)	Market Purchases Imports (GWh)	Market Sales Exports (GWh)	Market Purchases Cost ($1,000)	Market Sales Revenue ($1,000)	Fuel Cost ($1,000)	Plant O&M Variable[1] ($1,000)	Plant O&M FO&M Cost ($1,000)	Start & Shutdown Cost ($1,000)	Total Generation Cost ($1,000)	Total Generation Cost ($/MWh)	Capacity Purchases Costs ($1,000)	Unit Build Costs ($1,000)	Annualized Build and Retrofit Costs ($1,000)	Total System Cost ($1,000)	Cumulative Present Worth Cost (CPWC) ($1,000)
2024	2,663.6	2,818.6	444.9	599.9	14,395	26,995	39,111	32,238	23,984	3,221	98,553	34.97	0	0	0	85,953	85,953
2025	2,676.8	2,684.2	553.6	561.0	21,873	26,109	39,442	31,946	29,318	3,168	103,874	38.70	0	0	0	99,638	176,533
2026	2,690.0	2,799.6	463.5	573.1	18,826	26,644	42,114	32,238	36,293	3,022	113,667	40.60	0	0	0	105,849	264,011
2027	2,703.5	2,523.2	597.8	417.5	24,466	21,656	39,450	31,507	29,193	2,619	102,769	40.73	0	0	0	105,579	343,334
2028	2,717.1	2,391.9	700.5	375.3	28,745	19,690	39,319	27,660	27,067	2,723	96,769	40.46	925	0	0	106,750	416,246
2029	2,730.8	2,340.1	741.4	350.7	29,523	19,009	39,381	26,983	34,343	2,743	103,449	44.21	948	0	0	114,912	487,597
2030	2,744.5	2,166.6	857.8	279.9	32,817	16,968	39,770	25,278	23,643	3,041	91,732	42.34	971	0	940	109,492	549,402
2031	2,758.5	2,064.6	934.1	240.2	35,549	15,068	35,890	25,046	23,618	3,277	87,831	42.54	994	0	940	110,247	605,976
2032	2,772.4	2,093.1	936.4	257.2	34,113	16,357	35,852	25,178	24,184	2,805	88,019	42.05	1,019	0	940	107,733	656,234
2033	2,786.4	2,160.3	900.5	274.4	31,543	16,742	38,469	25,264	23,554	3,191	90,477	41.88	1,043	0	940	107,261	701,724
2034	2,800.6	2,051.9	1,002.1	253.3	34,837	16,340	34,555	25,040	23,554	3,057	86,207	42.01	1,069	0	940	106,712	742,866
2035	2,815.0	2,071.2	991.7	247.9	33,397	15,936	35,216	25,079	27,554	3,057	90,906	43.89	1,095	0	940	110,402	781,561
2036	2,829.5	1,945.1	1,090.0	205.5	35,496	13,978	34,967	21,878	23,619	3,529	83,993	43.18	1,458	0	940	107,909	815,944
2037	2,844.0	2,022.3	1,068.0	246.3	34,107	16,647	39,006	21,872	25,548	3,095	89,520	44.27	1,609	0	940	109,529	847,671
2038	2,858.6	1,229.3	1,761.2	131.9	48,852	9,693	39,962	2,849	32,306	3,480	78,596	63.93	2,354	39,419	4,094	124,202	880,377
2039	2,873.5	1,402.0	1,647.2	175.6	42,267	12,824	48,672	5,055	14,454	1,013	69,194	49.36	1,206	242,682	23,508	123,352	909,906
2040	2,888.3	1,376.2	1,678.6	166.6	44,601	12,733	48,371	4,922	14,488	911	68,692	49.91	1,235	0	23,508	125,303	937,176
2041	2,903.2	1,441.5	1,659.6	197.9	45,368	15,829	54,000	5,067	14,443	1,076	74,586	51.74	1,265	0	23,508	128,899	962,678
2042	2,918.3	1,455.5	1,656.1	193.3	48,377	15,875	57,174	5,036	14,437	992	77,639	53.34	1,296	0	23,508	134,945	986,949
2043	2,926.0	1,644.1	1,517.4	235.5	41,363	20,321	69,740	5,666	14,392	1,197	90,994	55.34	1,593	0	23,508	137,138	1,009,372
				Levelized Cost($1000):	$29,439	$19,774	$40,342	$25,034	$26,237	$2,820	$94,432	$42.61	$731	$7,312	$2,953	$107,782	
				NPV:	$275,698	$185,178	$377,802	$234,438	$245,705	$26,405	$884,350		$6,844	$68,476	$27,658	$1,009,372	
				Levelized Cost($/MWh):	$13.00	$30.95	$9.29	$5.76	$6.04	$0.65	$21.74		$0.12	$1.22	$0.68	$18.06	
				Load Based Levelized Cost($/MWh):	$4.93	$3.31	$6.76	$4.19	$4.40	$0.47	$15.82		$0.12	$1.22	$0.49	$18.06	

Notes:

[1] PPA energy purchase costs included in Variable O&M costs.

BPU 3 Nearman CCS 24-43

Economic Parameters	
CPW Real Discount Rate:	10.00%
Base Year for $	2024

Nearman ST1 Retrofit Costs	
Levelized Annual Costs, $1000/yr:	56,000
Beginning Yr:	2032

Generation Additions and Capacity Purchases

Generator Addition or Capacity Purchase	Year	MW	Purchase or Installed Cost ($1,000)	Levelized Cost ($1,000)
Solar Farm with ITC	2032	125	91,609	63,329
Solar Farm with ITC	2038	50	39,419	3,154
Solar Farm with ITC	2041	25	22,358	1,789
Capacity Purchase	2028	10	925	
Capacity Purchase	2029	10	948	
Capacity Purchase	2030	10	971	
Capacity Purchase	2031	10	994	
Capacity Purchase	2032	0	0	
Capacity Purchase	2033	10	1,043	
Capacity Purchase	2034	10	1,069	

Capacity Purchase Year	MW	Purchase Cost ($1,000)
2035	10	1,095
2036	10	1,122
2037	11	1,264
2038	17	2,001
2039	18	2,170
2040	20	2,470
2041	10	1,265
2042	10	1,296
2043	12	1,593

	Energy Balance				SPP Market		Production Cost										
								Plant O&M									
Year	Load (GWh)	Generation (GWh)	Market Purchases Imports (GWh)	Market Sales Exports (GWh)	Market Purchases Cost ($1,000)	Market Sales Revenue ($1,000)	Fuel Cost ($1,000)	Variable[1] ($1,000)	FO&M Cost ($1,000)	Start & Shutdown Cost ($1,000)	Total Generation Cost ($1,000)	Total Generation Cost ($/MWh)	Capacity Purchases Costs ($1,000)	Unit Build Costs ($1,000)	Annualized Build and Retrofit Costs ($1,000)	Total System Cost ($1,000)	Cumulative Present Worth Cost (CPWC) ($1,000)
2024	2,663.6	2,817.7	443.9	598.0	14,340	26,908	39,097	32,239	23,984	3,221	98,541	34.97	0	0	0	85,973	85,973
2025	2,676.8	2,685.0	552.7	560.9	21,834	26,105	39,454	31,947	29,318	3,175	103,894	38.69	0	0	0	99,623	176,539
2026	2,690.0	2,834.8	448.3	593.1	18,161	27,539	43,111	32,320	36,293	3,189	114,913	40.54	0	0	0	105,536	263,759
2027	2,703.5	2,525.9	597.7	420.2	24,466	21,749	39,538	31,513	29,193	2,619	102,864	40.72	0	0	0	105,581	343,083
2028	2,717.1	2,395.2	698.3	376.4	28,621	19,757	39,500	27,667	27,067	2,723	96,958	40.48	925	0	0	106,747	415,992
2029	2,730.8	2,254.8	789.1	313.1	31,968	17,072	36,548	26,784	34,343	2,661	100,336	44.50	948	0	0	116,179	488,130
2030	2,744.5	2,331.4	760.6	347.5	28,356	20,068	42,596	25,660	23,643	3,174	95,073	40.78	971	0	0	104,331	547,023
2031	2,758.5	2,226.1	823.8	291.3	30,862	17,196	38,957	25,422	23,618	3,227	91,225	40.98	994	0	0	105,885	601,358
2032	2,772.4	1,884.4	914.5	26.6	37,209	1,527	15,926	24,020	32,569	1,140	73,655	39.09	0	91,609	63,329	172,665	681,908
2033	2,786.4	1,877.7	929.6	20.9	37,303	795	15,800	23,898	31,872	1,075	72,646	38.69	1,043	0	63,329	173,526	755,500
2034	2,800.6	1,867.1	960.2	26.6	37,314	1,816	15,712	23,950	31,845	1,146	72,654	38.91	1,069	0	63,329	172,549	822,025
2035	2,815.0	1,863.2	970.8	19.1	37,241	1,273	15,279	23,901	35,836	1,034	76,049	40.82	1,095	0	63,329	176,442	883,866
2036	2,829.5	1,772.7	1,071.1	14.3	39,930	1,532	16,139	20,810	31,913	1,344	70,206	39.60	1,122	0	63,329	173,055	939,007
2037	2,844.0	1,768.4	1,086.4	10.7	41,029	831	16,550	20,608	33,810	1,106	72,074	40.76	1,264	0	63,329	176,864	990,238
2038	2,858.6	987.1	1,873.6	2.1	62,477	347	17,201	1,596	40,558	1,190	60,544	61.34	2,001	39,419	66,482	191,156	1,040,576
2039	2,873.5	979.4	1,895.9	1.8	64,677	365	17,349	1,588	32,469	1,109	52,515	53.62	2,170	0	66,482	185,479	1,084,978
2040	2,888.3	981.7	1,910.2	3.7	66,381	722	17,650	1,608	32,545	1,102	52,904	53.89	2,470	0	66,482	187,516	1,125,787
2041	2,903.2	1,095.3	1,819.9	12.0	65,275	1,282	21,783	1,739	33,211	1,259	57,993	52.95	1,265	22,358	68,271	191,522	1,163,678
2042	2,918.3	1,116.1	1,816.4	14.2	69,438	1,739	23,876	1,752	33,196	1,092	59,915	53.68	1,296	0	68,271	197,182	1,199,143
2043	2,926.0	1,157.7	1,775.8	7.5	71,029	765	27,052	1,568	32,691	1,297	62,607	54.08	1,593	0	68,271	202,736	1,232,292
				Levelized Cost($1000):	$32,829	$14,729	$31,505	$24,383	$30,409	$2,316	$88,612	$41.82	$701	$6,144	$24,173	$131,586	
				NPV:	$307,444	$137,938	$295,037	$228,344	$284,774	$21,688	$829,843		$6,568	$57,540	$226,375	$1,232,292	
				Levelized Cost($/MWh):	$13.89	$37.69	$7.88	$6.10	$7.61	$0.58	$22.18		$0.12	$1.03	$6.05	$22.04	
				Load Based Levelized Cost($/MWh):	$5.50	$2.47	$5.28	$4.08	$5.09	$0.39	$14.85		$0.12	$1.03	$4.05	$22.04	

Notes:

[1] PPA energy purchase costs included in Variable O&M costs.

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Economic Parameters	
CPW Real Discount Rate:	10.00%
Base Year for $	2024

Nearman ST1 Retrofit Costs	
Levelized Annual Costs, $1000/yr:	--
Beginning Yr:	--

Generation Additions and Capacity Purchases

Generator Addition or Capacity Purchase	Year	MW	Purchase or Installed Cost ($1,000)	Levelized Cost ($1,000)
Solar Farm with ITC	2038	50	39,419	3,154
Solar Farm with ITC	2039	25	19,428	1,554
Capacity Purchase	2028	10	925	
Capacity Purchase	2029	10	948	
Capacity Purchase	2030	10	971	
Capacity Purchase	2031	10	994	
Capacity Purchase	2032	10	1,019	
Capacity Purchase	2033	10	1,043	
Capacity Purchase	2034	10	1,069	

Capacity Purchase Year	MW	Purchase Cost ($1,000)
2035	10	1,095
2036	13	1,458
2037	14	1,609
2038	20	2,354
2039	10	1,206
2040	10	1,235
2041	10	1,265
2042	10	1,296
2043	12	1,593

	Energy Balance				SPP Market		Production Cost										
								Plant O&M									
Year	Load (GWh)	Generation (GWh)	Market Purchases Imports (GWh)	Market Sales Exports (GWh)	Market Purchases Cost ($1,000)	Market Sales Revenue ($1,000)	Fuel Cost ($1,000)	Variable[1] ($1,000)	FO&M Cost ($1,000)	Start & Shutdown Cost ($1,000)	Total Generation Cost ($1,000)	Total Generation Cost ($/MWh)	Capacity Purchases Costs ($1,000)	Unit Build Costs ($1,000)	Annualized Build and Retrofit Costs ($1,000)	Total System Cost ($1,000)	Cumulative Present Worth Cost (CPWC) ($1,000)
2024	2,663.6	2,818.7	444.8	599.9	14,391	26,995	39,114	32,238	23,984	3,221	98,557	34.97	0	0	0	85,953	85,953
2025	2,676.8	2,582.3	599.9	505.5	23,686	24,013	36,325	31,709	29,318	3,124	100,476	38.91	0	0	0	100,149	176,997
2026	2,690.0	2,783.7	480.8	574.4	19,466	27,033	41,510	32,201	36,293	3,353	113,357	40.72	0	0	0	105,789	264,427
2027	2,703.5	2,455.8	636.2	388.5	25,978	20,486	37,229	31,350	29,193	2,697	100,469	40.91	0	0	0	105,960	344,036
2028	2,717.1	2,250.7	784.0	317.6	32,636	16,975	34,509	27,330	27,067	2,387	91,293	40.56	925	0	0	107,879	417,719
2029	2,730.8	2,307.2	759.8	336.2	30,334	18,449	38,296	26,906	34,343	2,741	102,285	44.33	948	0	0	115,118	489,199
2030	2,744.5	2,267.8	798.0	321.3	30,018	18,867	40,372	25,512	23,643	3,061	92,589	40.83	971	0	0	104,710	548,304
2031	2,758.5	2,203.7	841.3	286.5	31,368	17,194	38,004	25,370	23,618	3,369	90,361	41.00	994	0	0	105,529	602,458
2032	2,772.4	2,296.1	803.7	327.5	27,709	19,788	40,161	25,651	24,184	3,359	93,355	40.66	1,019	0	0	102,295	650,179
2033	2,786.4	2,264.3	819.2	297.0	28,216	17,261	39,169	25,514	23,554	3,520	91,757	40.52	1,043	0	0	103,755	694,181
2034	2,800.6	2,209.9	892.0	301.3	29,851	18,587	36,974	25,408	23,554	3,223	89,159	40.35	1,069	0	0	101,491	733,310
2035	2,815.0	2,151.0	936.7	272.7	30,866	17,085	35,354	25,264	27,554	3,116	91,288	42.44	1,095	0	0	106,164	770,520
2036	2,829.5	2,062.5	995.9	228.8	31,202	15,073	36,161	22,151	23,619	3,843	85,773	41.59	1,458	0	0	103,360	803,454
2037	2,844.0	2,116.2	1,000.2	272.4	30,965	17,971	38,998	22,090	25,548	3,501	90,137	42.59	1,609	0	0	104,740	833,793
2038	2,858.6	1,317.1	1,681.4	139.8	45,105	10,172	40,006	3,054	32,306	3,546	78,911	59.91	2,354	39,419	3,154	119,352	865,222
2039	2,873.5	1,363.1	1,657.1	146.7	45,344	10,673	40,282	3,032	24,600	3,376	71,290	52.30	1,206	19,428	4,708	111,874	892,004
2040	2,888.3	1,347.0	1,683.9	142.7	48,098	10,828	40,739	3,001	24,661	3,090	71,491	53.07	1,235	0	4,708	114,704	916,967
2041	2,903.2	1,465.2	1,624.2	186.2	46,408	14,587	47,593	3,201	24,988	4,155	79,937	54.56	1,265	0	4,708	117,732	940,260
2042	2,918.3	1,546.0	1,544.0	171.7	45,131	14,713	53,393	3,332	24,982	3,498	85,205	55.11	1,296	0	4,708	121,627	962,135
2043	2,926.0	1,564.6	1,546.3	184.8	47,033	15,805	57,756	3,179	24,509	4,073	89,517	57.22	1,593	0	4,708	127,046	982,908
Levelized Cost($1000):					$28,833	$19,701	$39,122	$24,864	$27,334	$3,183	$94,504	$42.30	$731	$1,605	$590	$104,956	
NPV:					$270,017	$184,503	$366,372	$232,853	$255,985	$29,811	$885,021		$6,844	$15,031	$5,530	$982,908	
Levelized Cost($/MWh):					$13.15	$30.74	$8.86	$5.63	$6.19	$0.72	$21.39		$0.12	$0.27	$0.13	$17.58	
Load Based Levelized Cost($/MWh):					$4.83	$3.30	$6.55	$4.17	$4.58	$0.53	$15.83		$0.12	$0.27	$0.10	$17.58	

Notes:

[1] PPA energy purchase costs included in Variable O&M costs.

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Economic Parameters	
CPW Real Discount Rate:	10.00%
Base Year for $	2024

Nearman ST1 Retrofit Costs	
Levelized Annual Costs, $1000/yr:	--
Beginning Yr:	--

Generation Additions and Capacity Purchases

Generator Addition or Capacity Purchase	Year	MW	Purchase or Installed Cost ($1,000)	Levelized Cost ($1,000)		Capacity Purchase Year	MW	Purchase Cost ($1,000)
Solar Farm with ITC	2038	50	39,419	3,154		2035	10	1,095
Solar Farm with ITC	2039	25	19,428	1,554		2036	13	1,458
						2037	14	1,609
Capacity Purchase	2028	10	925			2038	20	2,354
Capacity Purchase	2029	10	948			2039	10	1,206
Capacity Purchase	2030	10	971			2040	10	1,235
Capacity Purchase	2031	10	994			2041	10	1,265
Capacity Purchase	2032	10	1,019			2042	10	1,296
Capacity Purchase	2033	10	1,043			2043	12	1,593
Capacity Purchase	2034	10	1,069					

	Energy Balance				SPP Market		Production Cost										
								Plant O&M									
Year	Load (GWh)	Generation (GWh)	Market Purchases Imports (GWh)	Market Sales Exports (GWh)	Market Purchases Cost ($1,000)	Market Sales Revenue ($1,000)	Fuel Cost ($1,000)	Variable[1] ($1,000)	FO&M Cost ($1,000)	Start & Shutdown Cost ($1,000)	Total Generation Cost ($1,000)	Total Generation Cost ($/MWh)	Capacity Purchases Costs ($1,000)	Unit Build Costs ($1,000)	Annualized Build and Retrofit Costs ($1,000)	Total System Cost ($1,000)	Cumulative Present Worth Cost (CPWC) ($1,000)
2024	2,663.6	2,818.7	444.8	599.9	14,391	26,995	39,114	32,238	23,984	3,221	98,557	34.97	0	0	0	85,953	85,953
2025	2,676.8	2,724.0	537.4	584.6	21,644	27,650	41,386	32,006	29,318	3,098	105,808	38.84	0	0	0	99,802	176,682
2026	2,690.0	2,834.7	455.9	600.6	18,995	28,706	44,181	32,276	36,293	3,020	115,771	40.84	0	0	0	106,061	264,336
2027	2,703.5	2,426.1	652.4	375.1	28,651	19,898	37,940	31,247	29,193	2,685	101,065	41.66	0	0	0	109,818	346,843
2028	2,717.1	2,433.8	681.2	397.9	28,990	21,739	42,589	27,728	27,067	2,882	100,266	41.20	925	0	0	108,442	420,910
2029	2,730.8	2,387.0	711.0	367.2	29,456	20,755	43,104	27,063	34,343	2,901	107,410	45.00	948	0	0	117,058	493,594
2030	2,744.5	2,377.0	734.3	366.8	28,606	22,289	46,872	25,743	23,643	3,287	99,546	41.88	971	0	0	106,834	553,899
2031	2,758.5	2,273.3	796.1	311.0	31,084	18,953	43,342	25,511	23,618	3,698	96,169	42.30	994	0	0	109,293	609,984
2032	2,772.4	2,423.6	723.3	374.5	25,312	23,398	47,344	25,911	24,184	3,791	101,231	41.77	1,019	0	0	104,163	658,577
2033	2,786.4	2,305.1	804.8	323.5	29,283	19,612	43,195	25,574	23,554	3,510	95,833	41.57	1,043	0	0	106,547	703,763
2034	2,800.6	2,316.6	816.8	332.8	28,180	21,205	43,047	25,643	23,554	3,250	95,494	41.22	1,069	0	0	103,538	743,682
2035	2,815.0	2,263.8	856.0	304.8	28,641	19,438	42,052	25,520	27,554	3,161	98,287	43.42	1,095	0	0	108,584	781,740
2036	2,829.5	2,159.3	934.7	264.5	30,038	17,973	42,289	22,359	23,619	4,174	92,440	42.81	1,458	0	0	105,963	815,503
2037	2,844.0	2,231.0	916.4	303.4	29,034	20,716	45,898	22,331	25,548	3,339	97,117	43.53	1,609	0	0	107,044	846,510
2038	2,858.6	1,429.5	1,582.9	153.8	43,126	11,776	47,228	3,302	32,306	3,913	86,748	60.68	2,354	39,419	3,154	123,605	879,059
2039	2,873.5	1,474.9	1,561.7	163.0	43,632	12,439	47,751	3,263	24,600	3,661	79,275	53.75	1,206	19,428	4,708	116,381	906,919
2040	2,888.3	1,423.4	1,620.1	155.2	48,331	12,440	46,952	3,156	24,661	3,095	77,864	54.70	1,235	0	4,708	119,699	932,969
2041	2,903.2	1,597.7	1,506.6	201.1	43,357	16,834	57,444	3,482	24,988	4,223	90,137	56.42	1,265	0	4,708	122,633	957,231
2042	2,918.3	1,605.2	1,491.1	178.0	45,663	16,360	60,457	3,444	24,982	3,653	92,537	57.65	1,296	0	4,708	127,844	980,225
2043	2,926.0	1,682.8	1,448.0	204.7	44,901	18,734	68,743	3,421	24,509	4,701	101,375	60.24	1,593	0	4,708	133,843	1,002,110
				Levelized Cost($1000):	$27,875	$21,882	$44,035	$25,031	$27,334	$3,292	$99,692	$43.07	$731	$1,605	$590	$107,007	
				NPV:	$261,044	$204,919	$412,383	$234,413	$255,985	$30,830	$933,611		$6,844	$15,031	$5,530	$1,002,110	
				Levelized Cost($/MWh):	$13.54	$31.23	$9.55	$5.43	$5.93	$0.71	$21.62		$0.12	$0.27	$0.13	$17.93	
				Load Based Levelized Cost($/MWh):	$4.67	$3.67	$7.38	$4.19	$4.58	$0.55	$16.70		$0.12	$0.27	$0.10	$17.93	

Notes:

[1] PPA energy purchase costs included in Variable O&M costs.

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Economic Parameters	
CPW Real Discount Rate:	10.00%
Base Year for $	2024

Nearman ST1 Retrofit Costs	
Levelized Annual Costs, $1000/yr:	--
Beginning Yr:	--

Generation Additions and Capacity Purchases

Generator Addition or Capacity Purchase	Year	MW	Purchase or Installed Cost ($1,000)	Levelized Cost ($1,000)
Solar Farm with ITC	2038	50	39,419	3,154
Solar Farm with ITC	2040	25	22,524	1,802
Capacity Purchase	2028	10	925	
Capacity Purchase	2029	10	948	
Capacity Purchase	2030	10	971	
Capacity Purchase	2031	10	994	
Capacity Purchase	2032	10	1,019	
Capacity Purchase	2033	10	1,043	
Capacity Purchase	2034	10	1,069	

Capacity Purchase Year	MW	Purchase Cost ($1,000)
2035	10	1,095
2036	13	1,458
2037	14	1,609
2038	20	2,354
2039	20	2,412
2040	10	1,235
2041	10	1,265
2042	10	1,296
2043	12	1,593

	Energy Balance				SPP Market		Production Cost										
								Plant O&M									
Year	Load (GWh)	Generation (GWh)	Market Purchases Imports (GWh)	Market Sales Exports (GWh)	Market Purchases Cost ($1,000)	Market Sales Revenue ($1,000)	Fuel Cost ($1,000)	Variable[1] ($1,000)	FO&M Cost ($1,000)	Start & Shutdown Cost ($1,000)	Total Generation Cost ($1,000)	Total Generation Cost ($/MWh)	Capacity Purchases Costs ($1,000)	Unit Build Costs ($1,000)	Annualized Build and Retrofit Costs ($1,000)	Total System Cost ($1,000)	Cumulative Present Worth Cost (CPWC) ($1,000)
2024	2,663.6	2,818.7	444.8	599.9	14,391	26,995	39,114	32,238	23,984	3,221	98,557	34.97	0	0	0	85,953	85,953
2025	2,676.8	2,643.7	572.4	539.3	22,275	24,652	37,398	31,872	29,318	3,061	101,649	38.45	0	0	0	99,273	176,201
2026	2,690.0	2,794.1	469.9	574.0	18,778	25,901	40,582	32,280	36,293	3,096	112,251	40.17	0	0	0	105,129	263,085
2027	2,703.5	2,511.1	603.4	411.0	23,911	20,527	37,402	31,504	29,193	2,586	100,685	40.10	0	0	0	104,069	341,274
2028	2,717.1	2,344.8	727.1	354.8	28,727	17,922	36,124	27,587	27,067	2,724	93,503	39.88	925	0	0	105,233	413,149
2029	2,730.8	2,304.8	759.8	333.9	29,006	17,279	36,256	26,931	34,343	2,589	100,119	43.44	948	0	0	112,794	483,185
2030	2,744.5	2,285.9	787.7	329.1	28,077	18,109	38,805	25,576	23,643	3,005	91,030	39.82	971	0	0	101,969	540,744
2031	2,758.5	2,213.3	835.1	289.9	29,592	16,250	36,239	25,418	23,618	3,182	88,457	39.97	994	0	0	102,794	593,494
2032	2,772.4	2,319.3	788.3	335.2	25,711	19,027	38,701	25,707	24,184	3,167	91,759	39.56	1,019	0	0	99,461	639,893
2033	2,786.4	2,359.4	757.7	330.7	23,734	18,190	39,659	25,761	23,554	3,426	92,400	39.16	1,043	0	0	98,987	681,873
2034	2,800.6	2,239.5	868.8	307.8	27,626	17,616	35,564	25,507	23,554	2,903	87,528	39.08	1,069	0	0	98,607	719,890
2035	2,815.0	2,212.9	894.9	292.9	27,545	16,791	35,200	25,440	27,554	3,011	91,206	41.21	1,095	0	0	103,054	756,010
2036	2,829.5	2,088.5	976.4	235.4	28,781	14,366	34,767	22,234	23,619	3,537	84,156	40.30	1,458	0	0	100,029	787,882
2037	2,844.0	2,182.0	948.8	286.8	27,173	17,505	38,662	22,256	25,548	3,256	89,722	41.12	1,609	0	0	100,999	817,138
2038	2,858.6	1,368.8	1,635.9	146.1	40,340	9,902	39,321	3,197	32,306	3,714	78,537	57.38	2,354	39,419	3,154	114,483	847,285
2039	2,873.5	1,357.3	1,649.1	132.9	41,703	9,103	39,573	3,180	24,227	3,312	70,292	51.79	2,412	0	3,154	108,457	873,249
2040	2,888.3	1,380.5	1,650.4	142.7	43,554	10,067	39,078	3,102	24,661	3,077	69,919	50.65	1,235	22,524	4,956	109,597	897,101
2041	2,903.2	1,496.7	1,587.7	181.2	41,789	13,198	45,052	3,300	24,988	3,690	77,030	51.47	1,265	0	4,956	111,842	919,228
2042	2,918.3	1,555.7	1,528.9	166.3	41,345	13,291	49,546	3,379	24,982	3,273	81,180	52.18	1,296	0	4,956	115,487	939,999
2043	2,926.0	1,558.2	1,548.2	180.4	43,709	14,203	52,611	3,190	24,509	3,800	84,110	53.98	1,593	0	4,956	120,166	959,647

	Market Purchases Cost	Market Sales Revenue	Fuel Cost	Variable	FO&M Cost	Start & Shutdown Cost	Total Generation Cost	Total Generation Cost ($/MWh)	Capacity Purchases Costs	Unit Build Costs	Annualized Build and Retrofit Costs	Total System Cost
Levelized Cost($1000):	$26,603	$19,325	$38,484	$24,973	$27,325	$3,082	$93,863	$41.29	$762	$1,632	$571	$102,473
NPV:	$249,133	$180,981	$360,397	$233,866	$255,895	$28,859	$879,017		$7,133	$15,282	$5,346	$959,647
Levelized Cost($/MWh):	$12.43	$29.33	$8.57	$5.56	$6.09	$0.69	$20.91		$0.13	$0.27	$0.13	$17.17
Load Based Levelized Cost($/MWh):	$4.46	$3.24	$6.45	$4.18	$4.58	$0.52	$15.72		$0.13	$0.27	$0.10	$17.17

Notes:

[1] PPA energy purchase costs included in Variable O&M costs.

BPU 7 HLG 24-43

Economic Parameters	
CPW Real Discount Rate:	10.00%
Base Year for $	2024

Nearman ST1 Retrofit Costs	
Levelized Annual Costs, $1000/yr:	--
Beginning Yr:	--

Generation Additions and Capacity Purchases

Generator Addition or Capacity Purchase	Year	MW	Purchase or Installed Cost ($1,000)	Levelized Cost ($1,000)		Capacity Purchase Year	MW	Purchase Cost ($1,000)
Solar Farm with ITC	2038	75	59,129	4,730		2035	13	1,424
						2036	18	2,019
						2037	19	2,183
Capacity Purchase	2028	10	925			2038	11	1,295
Capacity Purchase	2029	10	948			2039	12	1,447
Capacity Purchase	2030	10	971			2040	14	1,729
Capacity Purchase	2031	10	994			2041	15	1,898
Capacity Purchase	2032	10	1,019			2042	17	2,203
Capacity Purchase	2033	12	1,252			2043	19	2,523
Capacity Purchase	2034	13	1,390					

	Energy Balance				SPP Market		Production Cost										
								Plant O&M									
Year	Load (GWh)	Generation (GWh)	Market Purchases Imports (GWh)	Market Sales Exports (GWh)	Market Purchases Cost ($1,000)	Market Sales Revenue ($1,000)	Fuel Cost ($1,000)	Variable[1] ($1,000)	FO&M Cost ($1,000)	Start & Shutdown Cost ($1,000)	Total Generation Cost ($1,000)	Total Generation Cost ($/MWh)	Capacity Purchases Costs ($1,000)	Unit Build Costs ($1,000)	Annualized Build and Retrofit Costs ($1,000)	Total System Cost ($1,000)	Cumulative Present Worth Cost (CPWC) ($1,000)
2024	2,663.6	2,818.7	444.8	599.9	14,391	26,995	39,114	32,238	23,984	3,221	98,557	34.97	0	0	0	85,953	85,953
2025	2,683.4	2,684.3	557.1	558.0	21,996	25,975	39,445	31,946	29,318	3,168	103,877	38.70	0	0	0	99,898	176,770
2026	2,703.1	2,848.4	446.6	591.9	17,907	27,553	43,706	32,354	36,293	3,265	115,618	40.59	0	0	0	105,972	264,350
2027	2,723.1	2,524.2	610.6	411.7	24,937	21,359	39,479	31,512	29,193	2,620	102,803	40.73	0	0	0	106,382	344,276
2028	2,743.3	2,394.7	716.3	367.7	29,278	19,337	39,485	27,666	27,067	2,724	96,942	40.48	925	0	0	107,808	417,911
2029	2,763.5	2,339.6	764.3	340.4	30,328	18,477	39,351	26,983	34,343	2,747	103,423	44.21	948	0	0	116,221	490,075
2030	2,784.2	2,331.3	787.5	334.7	29,195	19,364	42,592	25,661	23,643	3,181	95,077	40.78	971	0	0	105,879	549,841
2031	2,804.6	2,247.8	843.7	286.9	31,097	17,007	39,628	25,476	23,618	3,298	92,020	40.94	994	0	0	107,104	604,802
2032	2,825.5	2,348.5	810.2	333.2	27,521	19,880	41,917	25,768	24,184	3,376	95,245	40.56	1,019	0	0	103,905	653,275
2033	2,846.4	2,395.9	783.0	332.5	25,448	19,278	43,338	25,810	23,554	3,583	96,285	40.19	1,252	0	0	103,707	697,256
2034	2,867.4	2,274.5	890.4	297.5	29,283	18,027	38,990	25,560	23,554	2,931	91,035	40.02	1,390	0	0	103,679	737,229
2035	2,888.6	2,251.6	925.1	288.1	29,315	17,528	39,135	25,497	27,554	3,066	95,252	42.30	1,424	0	0	108,462	775,245
2036	2,909.9	2,113.0	1,022.3	225.4	31,504	14,630	37,893	22,267	23,619	3,732	87,511	41.42	2,019	0	0	106,404	809,148
2037	2,931.5	2,195.3	1,004.5	268.3	30,233	17,434	41,691	22,271	25,548	3,321	92,830	42.29	2,183	0	0	107,811	840,378
2038	2,953.2	1,454.9	1,645.0	146.6	42,617	10,514	42,937	3,234	32,681	3,820	82,671	56.82	1,295	59,129	4,730	120,799	872,188
2039	2,975.0	1,458.3	1,649.4	132.8	43,676	9,707	43,873	3,253	24,600	3,543	75,268	51.61	1,447	0	4,730	115,415	899,817
2040	2,997.0	1,405.4	1,719.8	128.2	48,348	9,760	43,067	3,138	24,661	3,047	73,913	52.59	1,729	0	4,730	118,961	925,706
2041	3,019.4	1,535.8	1,645.0	161.4	45,987	12,758	50,281	3,365	24,988	3,791	82,425	53.67	1,898	0	4,730	122,282	949,899
2042	3,041.5	1,567.8	1,616.8	143.1	47,343	12,430	54,272	3,394	24,982	3,490	86,139	54.94	2,203	0	4,730	127,985	972,919
2043	3,056.2	1,623.4	1,593.4	160.7	47,728	13,781	60,466	3,312	24,509	4,174	92,462	56.95	2,523	0	4,730	133,662	994,773
Levelized Cost($1000):					$27,848	$20,102	$41,447	$25,023	$27,345	$3,187	$97,002	$42.04	$837	$1,663	$637	$106,223	
NPV:					$260,797	$188,250	$388,147	$234,338	$256,083	$29,848	$908,416		$7,843	$15,571	$5,968	$994,773	
Levelized Cost($/MWh):					$12.74	$30.82	$9.07	$5.47	$5.98	$0.70	$21.22		$0.14	$0.27	$0.14	$17.40	
Load Based Levelized Cost($/MWh):					$4.56	$3.29	$6.79	$4.10	$4.48	$0.52	$15.89		$0.14	$0.27	$0.10	$17.40	

Notes:

[1] PPA energy purchase costs included in Variable O&M costs.

BPU 8 HRR 24-43

Economic Parameters	
CPW Real Discount Rate:	10.00%
Base Year for $	2024

Nearman ST1 Retrofit Costs	
Levelized Annual Costs, $1000/yr:	--
Beginning Yr:	--

Generation Additions and Capacity Purchases

Generator Addition or Capacity Purchase	Year	MW	Purchase or Installed Cost ($1,000)	Levelized Cost ($1,000)		Capacity Purchase Year	MW	Purchase Cost ($1,000)
Solar Farm with ITC	2032	25	18,322	1,466		2034	10	1,069
Solar Farm with ITC	2037	25	19,992	1,599		2035	10	1,095
Solar Farm with ITC	2038	50	39,419	3,154		2036	13	1,458
Solar Farm with ITC	2041	25	22,358	1,789		2037	11	1,264
Capacity Purchase	2028	10	925			2038	17	2,001
Capacity Purchase	2029	10	948			2039	17	2,050
Capacity Purchase	2030	10	971			2040	19	2,347
Capacity Purchase	2031	20	1,989			2041	10	1,265
Capacity Purchase	2032	10	1,019			2042	10	1,296
Capacity Purchase	2033	10	1,043			2043	10	1,328

	Energy Balance				SPP Market		Production Cost										
								Plant O&M									
Year	Load (GWh)	Generation (GWh)	Market Purchases Imports (GWh)	Market Sales Exports (GWh)	Market Purchases Cost ($1,000)	Market Sales Revenue ($1,000)	Fuel Cost ($1,000)	Variable[1] ($1,000)	FO&M Cost ($1,000)	Start & Shutdown Cost ($1,000)	Total Generation Cost ($1,000)	Total Generation Cost ($/MWh)	Capacity Purchases Costs ($1,000)	Unit Build Costs ($1,000)	Annualized Build and Retrofit Costs ($1,000)	Total System Cost ($1,000)	Cumulative Present Worth Cost (CPWC) ($1,000)
2024	2,663.6	2,818.7	444.8	599.9	14,391	26,995	39,114	32,238	23,984	3,221	98,557	34.97	0	0	0	85,953	85,953
2025	2,676.8	2,684.3	553.6	561.1	21,873	26,112	39,444	31,946	29,318	3,168	103,876	38.70	0	0	0	99,637	176,532
2026	2,690.0	2,819.8	458.1	587.9	18,563	27,347	42,699	32,285	36,293	3,106	114,383	40.56	0	0	0	105,599	263,804
2027	2,703.5	2,525.8	597.6	419.9	24,460	21,738	39,531	31,513	29,193	2,619	102,857	40.72	0	0	0	105,579	343,127
2028	2,717.1	2,395.2	698.3	376.5	28,621	19,757	39,501	27,668	27,067	2,723	96,959	40.48	925	0	0	106,747	416,037
2029	2,730.8	2,339.7	741.7	350.6	29,536	19,003	39,365	26,982	34,343	2,743	103,432	44.21	948	0	0	114,912	487,388
2030	2,744.5	2,331.7	760.3	347.5	28,345	20,069	42,607	25,661	23,643	3,174	95,085	40.78	971	0	0	104,332	546,281
2031	2,758.5	2,245.4	815.7	302.6	30,347	17,923	39,562	25,467	23,618	3,305	91,951	40.95	1,989	0	0	106,364	600,863
2032	2,772.4	2,405.6	736.7	369.9	25,242	21,969	41,762	25,765	24,582	3,361	95,471	39.69	1,019	18,322	1,466	101,228	648,086
2033	2,786.4	2,459.9	704.4	377.9	23,026	21,875	43,462	25,818	23,942	3,582	96,805	39.35	1,043	0	1,466	100,465	690,693
2034	2,800.6	2,350.2	797.0	346.6	26,301	20,909	39,496	25,592	23,937	2,942	91,967	39.13	1,069	0	1,466	99,893	729,206
2035	2,815.0	2,315.0	833.2	333.2	26,691	20,082	39,190	25,500	27,935	3,070	95,694	41.34	1,095	0	1,466	104,863	765,960
2036	2,829.5	2,156.4	935.8	262.7	29,142	16,965	37,288	22,228	23,998	3,652	87,167	40.42	1,458	0	1,466	102,268	798,545
2037	2,844.0	2,315.4	865.8	337.2	26,259	21,663	41,648	22,269	26,302	3,313	93,531	40.40	1,264	19,992	3,065	102,456	828,223
2038	2,858.6	1,515.4	1,531.6	188.4	39,285	13,247	42,936	3,235	33,056	3,842	83,068	54.81	2,001	39,419	6,219	117,326	859,119
2039	2,873.5	1,515.1	1,533.4	174.9	40,170	12,441	43,721	3,245	24,973	3,578	75,517	49.84	2,050	0	6,219	111,515	885,815
2040	2,888.3	1,465.9	1,592.2	169.8	44,347	12,593	43,065	3,137	25,033	3,051	74,286	50.68	2,347	0	6,219	114,605	910,756
2041	2,903.2	1,656.7	1,476.8	230.3	40,629	17,718	50,254	3,365	25,727	3,791	83,137	50.18	1,265	22,358	8,007	115,320	933,571
2042	2,918.3	1,710.2	1,425.6	217.6	40,216	18,217	55,287	3,428	25,717	3,564	87,996	51.45	1,296	0	8,007	119,298	955,028
2043	2,926.0	1,743.8	1,419.1	236.9	41,534	19,876	60,411	3,319	25,238	4,262	93,230	53.46	1,328	0	8,007	124,223	975,340
				Levelized Cost($1000):	$26,381	$21,466	$41,374	$25,017	$27,520	$3,174	$97,086	$41.44	$807	$3,112	$1,340	$104,148	
				NPV:	$247,057	$201,032	$387,468	$234,285	$257,721	$29,727	$909,200		$7,562	$29,142	$12,552	$975,340	
				Levelized Cost($/MWh):	$13.06	$29.60	$8.85	$5.35	$5.89	$0.68	$20.77		$0.14	$0.52	$0.29	$17.45	
				Load Based Levelized Cost($/MWh):	$4.42	$3.60	$6.93	$4.19	$4.61	$0.53	$16.26		$0.14	$0.52	$0.22	$17.45	

Notes:

[1] PPA energy purchase costs included in Variable O&M costs.

BPU 9 Net Zero 24-43

Economic Parameters	
CPW Real Discount Rate:	10.00%
Base Year for $	2024

Nearman ST1 Retrofit Costs	
Levelized Annual Costs, $1000/yr:	--
Beginning Yr:	--

Generation Additions and Capacity Purchases

Generator Addition or Capacity Purchase	Year	MW	Purchase or Installed Cost ($1,000)	Levelized Cost ($1,000)
Solar Farm with ITC	2030	25	19,251	1,540
Solar Farm with ITC	2031	100	75,145	6,012
Solar Farm with ITC	2032	200	146,574	11,726
Solar Farm with ITC	2036	25	20,274	1,622
Solar Farm with ITC	2037	200	159,934	12,795
Solar Farm with ITC	2038	200	157,678	12,614
Solar Farm with ITC	2039	200	155,422	12,434
Solar Farm with ITC	2040	200	180,195	14,416
Solar Farm with ITC	2042	25	22,193	1,775

Capacity Purchase Year	MW	Purchase Cost ($1,000)
2028	10	925
2029	10	948
2031	17	1,690

	Energy Balance				SPP Market		Production Cost										
								Plant O&M									
Year	Load (GWh)	Generation (GWh)	Market Purchases Imports (GWh)	Market Sales Exports (GWh)	Market Purchases Cost ($1,000)	Market Sales Revenue ($1,000)	Fuel Cost ($1,000)	Variable[1] ($1,000)	FO&M Cost ($1,000)	Start & Shutdown Cost ($1,000)	Total Generation Cost ($1,000)	Total Generation Cost ($/MWh)	Capacity Purchases Costs ($1,000)	Unit Build Costs ($1,000)	Annualized Build and Retrofit Costs ($1,000)	Total System Cost ($1,000)	Cumulative Present Worth Cost (CPWC) ($1,000)
2024	2,663.6	2,816.4	444.9	597.7	14,372	26,900	39,072	32,238	23,984	3,229	98,522	34.98	0	0	0	85,994	85,994
2025	2,676.8	2,684.2	553.6	561.0	21,873	26,109	39,442	31,946	29,318	3,168	103,874	38.70	0	0	0	99,637	176,574
2026	2,690.0	2,844.9	443.8	598.7	17,981	27,778	43,342	32,343	36,293	3,188	115,167	40.48	0	0	0	105,369	263,656
2027	2,703.5	2,523.5	597.6	417.6	24,461	21,660	39,458	31,507	29,193	2,619	102,778	40.73	0	0	0	105,579	342,979
2028	2,717.1	2,392.1	700.3	375.4	28,739	19,693	39,327	27,660	27,067	2,723	96,778	40.46	925	0	0	106,750	415,891
2029	2,730.8	2,340.2	741.3	350.7	29,522	19,008	39,381	26,983	34,343	2,743	103,450	44.21	948	0	0	114,911	487,242
2030	2,744.5	2,387.7	727.1	370.3	26,970	21,413	42,601	25,660	24,068	3,174	95,502	40.00	0	19,251	1,540	102,600	545,156
2031	2,758.5	2,530.7	639.7	411.9	22,726	23,654	39,599	25,496	22,830	3,373	91,298	36.08	1,690	75,145	7,552	99,613	596,273
2032	2,772.4	3,031.0	460.5	719.2	13,886	40,614	40,934	25,754	26,517	3,394	96,600	31.87	0	146,574	19,278	89,149	637,862
2033	2,786.4	3,053.4	475.2	742.2	13,544	41,423	42,199	25,753	25,767	3,400	97,120	31.81	0	0	19,278	88,519	675,403
2034	2,800.6	2,907.3	516.9	623.5	14,777	35,569	36,860	25,441	25,698	2,958	90,957	31.29	0	0	19,278	89,443	709,887
2035	2,815.0	2,918.8	554.8	658.6	15,690	37,460	37,918	25,460	29,672	3,008	96,059	32.91	0	0	19,278	93,567	742,682
2036	2,829.5	2,800.8	600.9	572.2	16,163	33,574	35,548	22,156	26,097	3,559	87,360	31.19	0	20,274	20,899	90,850	771,629
2037	2,844.0	3,180.6	575.1	911.8	16,196	49,463	33,559	21,939	29,007	2,915	87,421	27.49	0	159,934	33,694	87,848	797,076
2038	2,858.6	2,192.8	1,338.7	672.9	40,393	33,784	15,533	1,560	19,353	1,066	37,511	17.11	0	157,678	46,308	90,429	820,888
2039	2,873.5	2,477.7	1,359.1	958.1	43,783	46,615	10,444	1,441	22,279	1,168	35,333	14.26	0	155,422	58,742	91,243	842,731
2040	2,888.3	3,092.6	1,278.8	1,240.6	44,317	55,303	8,282	1,398	25,244	1,536	36,460	11.79	0	180,195	73,158	98,632	864,196
2041	2,903.2	3,140.8	1,259.5	1,239.0	46,075	58,123	10,268	1,421	25,086	1,777	38,552	12.27	0	0	73,158	99,661	883,914
2042	2,918.3	3,158.0	1,264.5	1,251.5	49,936	61,999	10,810	1,396	25,365	1,725	39,296	12.44	0	22,193	74,933	102,166	902,289
2043	2,926.0	3,213.2	1,236.9	1,254.0	50,961	66,243	13,149	1,322	25,206	2,186	41,862	13.03	0	0	74,933	101,514	918,888
Levelized Cost($1000):					$23,790	$31,319	$35,893	$24,751	$27,504	$2,873	$91,021	$33.91	$223	$31,237	$14,405	$98,120	
NPV:					$222,794	$293,299	$336,135	$231,787	$257,570	$26,910	$852,402		$2,088	$292,528	$134,903	$918,888	
Levelized Cost($/MWh):					$14.13	$20.19	$6.04	$4.16	$4.63	$0.48	$15.31		$0.04	$5.23	$2.42	$16.44	
Load Based Levelized Cost($/MWh):					$3.99	$5.25	$6.01	$4.15	$4.61	$0.48	$15.25		$0.04	$5.23	$2.41	$16.44	

Notes:

[1] PPA energy purchase costs included in Variable O&M costs.

BPU 10 2028 CTs 24-43

Economic Parameters	
CPW Real Discount Rate:	10.00%
Base Year for $	2024

Nearman ST1 Retrofit Costs	
Levelized Annual Costs, $1000/yr:	--
Beginning Yr:	--

Generation Additions and Capacity Purchases

Generator Addition or Capacity Purchase	Year	MW	Purchase or Installed Cost ($1,000)	Levelized Cost ($1,000)	Capacity Purchase Year	MW	Purchase Cost ($1,000)
Solar Farm with ITC	2028	125	100,899	8,072	2034	10	1,069
Solar Farm with ITC	2032	25	18,322	1,466	2035	10	1,095
Solar Farm with ITC	2038	75	59,129	4,730	2036	13	1,458
					2037	15	1,724
Capacity Purchase	2028	10	925		2038	10	1,177
Capacity Purchase	2029	11	1,042		2039	10	1,206
Capacity Purchase	2030	16	1,553		2040	11	1,359
Capacity Purchase	2031	17	1,690		2041	13	1,645
Capacity Purchase	2032	10	1,019		2042	14	1,815
Capacity Purchase	2033	10	1,043		2043	17	2,257

	Energy Balance				SPP Market		Production Cost										
								Plant O&M									
Year	Load (GWh)	Generation (GWh)	Market Purchases Imports (GWh)	Market Sales Exports (GWh)	Market Purchases Cost ($1,000)	Market Sales Revenue ($1,000)	Fuel Cost ($1,000)	Variable[1] ($1,000)	FO&M Cost ($1,000)	Start & Shutdown Cost ($1,000)	Total Generation Cost ($1,000)	Total Generation Cost ($/MWh)	Capacity Purchases Costs ($1,000)	Unit Build Costs ($1,000)	Annualized Build and Retrofit Costs ($1,000)	Total System Cost ($1,000)	Cumulative Present Worth Cost (CPWC) ($1,000)
2024	2,663.6	2,818.7	444.8	599.9	14,391	26,995	39,114	32,238	23,984	3,221	98,557	34.97	0	0	0	85,953	85,953
2025	2,676.8	2,684.3	553.6	561.1	21,873	26,112	39,444	31,946	29,318	3,168	103,876	38.70	0	0	0	99,637	176,532
2026	2,690.0	2,819.8	458.1	587.9	18,563	27,347	42,699	32,285	36,293	3,106	114,383	40.56	0	0	0	105,599	263,804
2027	2,703.5	2,525.8	597.6	419.9	24,460	21,738	39,531	31,513	29,193	2,619	102,857	40.72	0	0	0	105,579	343,127
2028	2,717.1	2,698.0	540.2	521.2	22,094	27,342	39,221	27,663	23,753	2,723	93,359	34.60	925	100,899	8,072	97,108	409,453
2029	2,730.8	2,647.8	561.1	478.2	22,203	25,882	39,225	26,988	33,710	2,744	102,667	38.77	1,042	0	8,072	108,101	476,575
2030	2,744.5	2,632.7	587.8	476.1	22,027	27,095	42,240	25,659	22,932	3,156	93,987	35.70	1,553	0	8,072	98,544	532,201
2031	2,758.5	2,558.1	616.1	415.7	22,730	23,647	39,590	25,495	22,830	3,373	91,288	35.69	1,690	0	8,072	100,134	583,585
2032	2,772.4	2,724.8	554.2	506.6	18,809	28,823	41,970	25,807	23,731	3,402	94,910	34.83	1,019	18,322	9,538	95,453	628,115
2033	2,786.4	2,694.8	569.2	477.6	18,852	26,781	41,151	25,664	23,050	3,418	93,283	34.62	1,043	0	9,538	95,935	668,801
2034	2,800.6	2,632.6	625.6	457.5	20,635	26,524	38,376	25,549	23,018	2,915	89,858	34.13	1,069	0	9,538	94,575	705,264
2035	2,815.0	2,614.3	659.9	459.2	21,264	26,787	38,797	25,497	27,006	3,047	94,347	36.09	1,095	0	9,538	99,456	740,122
2036	2,829.5	2,470.3	727.6	368.4	22,298	22,661	37,178	22,255	23,057	3,717	86,207	34.90	1,458	0	9,538	96,840	770,978
2037	2,844.0	2,557.8	725.5	439.4	22,098	27,462	41,516	22,274	22,976	3,312	90,079	35.22	1,724	0	9,538	95,976	798,779
2038	2,858.6	1,816.1	1,340.1	297.6	33,634	19,920	42,655	3,234	32,097	3,828	81,814	45.05	1,177	59,129	14,268	110,973	828,002
2039	2,873.5	1,816.3	1,340.4	283.2	34,176	19,177	43,285	3,245	24,005	3,568	74,104	40.80	1,206	0	14,268	104,577	853,037
2040	2,888.3	1,769.2	1,391.3	272.3	37,804	19,010	42,690	3,137	24,053	3,036	72,916	41.21	1,359	0	14,268	107,336	876,396
2041	2,903.2	1,897.5	1,330.2	324.5	36,226	23,919	49,640	3,365	24,370	3,768	81,143	42.76	1,645	0	14,268	109,363	898,033
2042	2,918.3	1,929.9	1,290.7	302.4	36,302	23,923	53,569	3,389	24,353	3,441	84,751	43.92	1,815	0	14,268	113,214	918,395
2043	2,926.0	1,994.3	1,262.7	330.9	36,290	26,902	59,919	3,348	23,870	4,167	91,304	45.78	2,257	0	14,268	117,216	937,561
Levelized Cost($1000):					$22,589	$25,504	$41,079	$25,013	$26,707	$3,166	$95,964	$37.69	$813	$9,934	$6,251	$100,114	
NPV:					$211,549	$238,842	$384,700	$234,243	$250,105	$29,652	$898,699		$7,616	$93,033	$58,540	$937,561	
Levelized Cost($/MWh):					$13.08	$27.84	$7.96	$4.85	$5.18	$0.61	$18.61		$0.14	$1.66	$1.21	$16.77	
Load Based Levelized Cost($/MWh):					$3.78	$4.27	$6.88	$4.19	$4.47	$0.53	$16.08		$0.14	$1.66	$1.05	$16.77	

Notes:

[1] PPA energy purchase costs included in Variable O&M costs.

10 Appendix D – Public Comments

IRP Comments

Doyle, Patrick H. <phdoyle@wycokck.org>
To: IRP

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You forwarded this message on 10/8/2024 5:19 PM.

1. Table 8-4 entry for year 2043 should be 658,000
2. Table 8-7Error! Reference source not found
3. Residential stock is presently replaced with higher efficiency and density units resulting in overall MWh decrease (Adopting the 2024 International Energy Conservation Code in 2026)
4. Population growth is 0.4% -vs. AAGR 0.6%*
5. Population is rapidly aging indicating lower consumption*

* Wyandotte County, KS population by year, race, & more | USAFacts

Patrick Doyle, PE
Engineering Supervisor/Project Manager
PHDoyle@wycokck.org
Department of Planning + Urban Design
Unified Government of Wyandotte County • Kansas City, Kansas

NOTE: All Board of Zoning Appeals, City Planning Commission, and Landmarks Commission hearings will be heard virtually with in-person availability in the City Hall lobby (701 North 7th Street, Kansas City, KS 66101). All meetings with Planning and Urban Design staff will continue to prioritize virtual meetings.

Our goal is to serve you with excellence! Please click the following link and take a moment to complete this short customer service survey to help us better help you: Planning & Urban Design Department Feedback Form (openforms.com)

IRP comment

Amber Adams <aadams@vibranthealthkc.org>

To: IRP

Reply | Reply All | Forward

Wed 8/7/2024

Good afternoon,

Thank you so much for the invitation to submit comment. I would however hope for there to be an opportunity for public input once the report has been released.

Best,

Amber Adams, MPH

Vibrant Health

Sent from my iPhone

Re: IRP and ECHO Recommendations for BPU Board and Staff

TG Ty Gorman <ty.gorman@sierraclub.org>

To: Thomas Groneman; David Haley; David.Haley@senate.ks.gov; Rose Mulvany-Henry; Rose M Henry; steve0835@sbcglobal.net; steve0835@sbcglobal.net; Steve Wakes; Brett Parker; brett@thedartcenter.org; kjohnson@bpu.org; Andrew Ferris; Patrice Townsend

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KCK groups with whom I volunteer continue to hope that an IRP process is a beginning to engagement with community organizations that can continue next year looking at ways to prioritize long term lower prices for customers through demand side management.

By relying more on virtual power plants (VPPs), utilities could save roughly $10 billion in annual spending. This playbook explores how next-gen VPPs will deliver greater value to grid operators, planners, DER owners and decarbonization efforts.

Download to learn how next-gen VPPs improve:

- Visibility
- Predictability
- Granular control

For these insights and more, **download the playbook.**
https://www.publicpower.org/periodical/article/virtual-power-plants-could-save-utilities-15-35b-capacity-investment-over-10-years-report

Ty Gorman
Sierra Club Sr. Campaign Organizing Strategist
Beyond Coal Campaign
Southwest Power Pool, Kansas
E-Mail: ty.gorman@sierraclub.org
Cell: 913 227 9310

IRP and ECHO Recommendations for BPU Board and Staff

Ty Gorman <ty.gorman@sierraclub.org>

To: Thomas Groneman; David Haley; [illegible]; Rose Mulvany Henry; Ricc M. Henry; [illegible]; Stevie Walker; [illegible]
Johnson@bpu.org; Andrew Ferris; Patrice Townsend

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BPU 2023 Synapse Testimony Sarah Shenstone-Harris.pdf
579 KB

BPU Recommendations June 2024 IRP.pdf
13 KB

Reply | Reply All | Forward

Dear General Manager Johnson and BPU Board,

Thank you for the offer during the last board meeting, Mr. Johnson; I would love to schedule a meeting with Andrew Ferris, Patrice Townsend (it can be 1:1 or with community volunteers).

As promised, here are the recommendations from our community groups requesting changes in BPU's planning process. Also attached in the addendum and pdf separately is Synapse's analysis submitted to BPU during the Rate Case last year. The community activists with whom I volunteer have been advocating for substantive changes in BPU policies for years, and are excited by some of the directions the Board and staff have taken since the last election. This summer, we are hopeful and ready for Board engagement to optimize assumptions and results in IRP modeling to benefit our diverse residential and small business stakeholders.

I look forward to discussing the recommendations with you and feel confident that we can work together for our community to create an excellent 2024 (and 2025) BPU IRP.

Thank you very much!

Ty Gorman
Sierra Club Sr. Campaign Organizing Strategist
E-Mail: ty.gorman@sierraclub.org
Cell: 913.207.3588
Kansas City, KS

IRP Recommendations for the Kansas City, KS Board of Public Utilities: June, 2024

IRP Recommendations for policy improvement summarized from sources submitted to the BPU from 2022-2024 by Ty Gorman: ty.gorman@sierraclub.org, 913-227-9310

As part of the 2024 Integrated Resource Plan ("IRP"), the BPU Board of Directors should:

1. Vote to conduct annual IRP capacity expansion modeling updates annually to identify the quickly evolving benefits and costs of a variety of new demand side and transmission policies and incentives.
2. Direct BPU staff and consultants to work with third party stakeholders to provide transparent modeling details and inputs to any outside organization that would like to conduct their own IRP analysis. Follow IRP best practices from industry leading resources in equitable utility planning, including Lawrence Berkeley National Laboratory (LBNL), Synapse Energy, and others linked below. Add to the IRP the following methodologies for **coalition building**, **inclusive stakeholder process**, and **intervenor or stakeholder compensation** to give input on IRP assumptions, rate design, customer assistance policies and economic opportunities for new demand and supply side resource options. IRPs should account for equity through best practice methodology on the Distribution of DER Benefits to Utility Customers (6/25/2024 https://emp.lbl.gov/publications/distributional-equity-analysis).
3. Detailed recommendations are listed below, followed by previously submitted community recommendations and Synapse rate case analysis documents in the appendix:
    a. Direct BPU staff to account for likely local policy changes in their capacity modeling assumptions, including SPP implementation of broad FERC capacity accreditation resource adequacy rules (including FERC 1920), and benefits from the Inflation Reduction Act investments that create energy efficiency and load-flattening, behind-the-meter value to BPU's grid resources under FERC

2222. BPU staff can use these tools with capacity models to better account for risks from fossil fuel market failures and opportunities from economies of scale under solar, storage and demand flexibility.

i. As part of guidance to staff, the BPU Board should utilize the stakeholder and generation-specific modeling recommendations explicitly outlined in the Synapse report submitted to the BPU Board and Staff in 2023's rate increase hearing.

- Include equity as a goal and identify strategies to improve equity as a resource planning scenario with higher investment metrics for strategies that improve equity and include differential treatment for overburdened customers and environmental justice communities in KCK. States that lead the country in addressing equity: (1) identify and prioritize the goal of equity; (2) define the meaning of equity; (3) cease inequitable practices and establish protections to ensure the inequities do not continue; (4) direct investments to remedy inequities and address gaps in services; (5) proactively identify and engage community members and partners who can drive equitable outcomes; (6) streamline and coordinate efforts to maximize the impact of limited available time and resources and provide clarity, consistency, and transparency; and (7) establish ways to evaluate progress on equity.
- Reduce costs and avoid risks for its ratepayers by minimizing losses from operating Nearman. This would require disallowing long-term and must-take-clause coal contracts, as well as self-commitment into the Southwest Power Pool ("SPP") without proof of operational requirement. Nearman should be retired as soon as capacity modeling indicates that is in the best interest of customers without consideration of sunk-cost fallacies. Nearman incurred costs in excess of its market energy and capacity value each year that gas prices weren't spiking ($16 million in losses per year during those years according to the Synapse analysis)
- Direct staff to work directly with KCK volunteers who want to improve customer assistance access and policies to avoid death and injury from dangerous involuntary power and water shut-offs, including medical equipment protections. lower fixed costs on bills, These demands should be achieved cooperative with the

BPU Board through staffed and resourced community working groups. In the last two years, hundreds of BPU customers have signed petitions demanding the following actions from the BPU Board

(1) Facilitate solutions with the UG and community groups to end all BPU water or electric shut offs that might put customers at health risk. No shut-off without first assessing risks from medical devices, hot and cold temperatures, and landlord disputes. No one should be put at risk of losing water or power because of regressive city charges (BPU should continue to advocate for removal of these fees and replacement of UG funding with a progressive tax structure).

(2) Facilitate solutions with the UG and community groups to lower fixed costs for BPU low income customers and small businesses long term. Set a goal eliminating Energy Burden (above 7% of income). Rich developers and corporations are getting reduced pricing from BPU and UG staff to keep their costs low, while the residents and small businesses that are the lifeblood of the county have no representation to lower bills. Follow Board President Groneman's suggestion to hire full time residential and small business customer advocates to attend to those customers' needs in the same way large users are treated.

Appendix I

BPU Customer Demand Details (2022-23):

1. BPU Board members should vote to create and fund two community peer learning working groups to develop solutions. Community-chosen leaders would report directly to Board representatives, who can then bring solutions to management. Staff liaisons and other resources should be provided to the working groups as needed.

    a. Customer Shut-offs Working Group (bill assistance access, United Way, and customer protections)

    b. Customer Bill Reduction (identifying opportunities for BPU savings throughout operations and Integrated Resource Planning)

2. No water or electric shut-offs for amounts owed less than $50)

3. Two written notices delivered 8 weeks before any shutoff, verified as received; proactive connections to energy efficiency, health, other assistance

4. Provide explanations in various languages/formats for simple, free procedures for appeal

5. Charge no late/disconnection/reconnection fees for low income customers.

6. Disconnect no customer at end of day or before weekends/holidays

7. No low-income customer disconnects without transparent, pro-active outreach to connect customers to available United Way assistance funding (customers have gotten cut off when they thought they paid, and then are charged extra fees because of misunderstandings and customer service mistakes).

BPU is still shutting customers off in the winter even there is $250 thousand extra for bill assistance in the new year. The Shut off moratorium should continue throughout the winter, and all customers who can't pay should be guided by staff (BPU or United Way) through the dozen local agencies listed here directed by the board to not shut anyone off. If anyone gets shut off, or needs money for bills and can't access it this winter, reporters are asking me to connect with them and raise the alarm. We'll shame and pressure BPU leadership if any BPU customer in need is shut off because they can't access assistance.

In the December 2022 Board meeting, members Mulvaney-Henry, Haley, Groneman, and Bryant promised to bring the community to the decision making table to address our demands in 2023. Mulvaney-Henry committed to propose a working group bringing meaningful community engagement to the BPU decision making process in 2023-2024. Bryan and Groneman also stressed that just because something is in the budget that passed, doesn't mean it can't be changed by the board at any time.

UG Commissioners: BPU Board members agreed to support the community by pressuring the UG Commissioners to remove fees from BPU bills in 2023. There are many options to replace these regressive fees: Read the full report here (CAP Action). PILOT fees are intended to remove taxation from residents by charging "non-profits" like Hospitals that own property valued at millions of dollars. The UG Commission is wrong when they call regressive fees extorted from low income customers monthly so that they can maintain healthy power and water a "PILOT program." BPU acts as bill collector for the UG general fund forcing the most vulnerable BPU customers to pay a much higher percentage of their income every month than well off community members or industrial/commercial entities for UG services, threatening BPU customers with medical risk from shut-offs and poverty every month. Medically dangerous energy burden is exacerbated by the UG misuse of PILOT and other fees: using the BPU as a regressive tax collection agency is terrible public finance, it's damaging our most vulnerable community members, and the community is angry enough, especially with the orchestrated removal of power from the elected mayor last month, to hold all UG commissioners accountable for the PILOT fee. It's also wrong for the UG to be getting free utilities and giving discounts without conditions to gentrifying investors as part of economic development. This forces the poorest KCK residents to pay the highest percentage of their income for utilities. BPU board members should set a goal of stopping shutoffs and eliminating Energy Burden above 7% of income/month using federal dollars, then bring the community into the planning process for how to implement necessary changes.

Working Groups Under BPU Board Member Control:

1. Community Planning best practices: Community members are the experts on how BPU has affected our lives and how it needs to change; other organizations (like Groundwork NRG, Clean Air Now, Sierra Club, Cross-lines, etc.) are experts on community engagement, IRP processes, and how BPU affects community health. The first step BPU Board members need to make to stop doing us harm is to bring the community substantively into the decision making process. BPU only needs to follow processes from other municipal utilities in the Midwest; (NARUC, ICLEI, RMI, Regulatory Assistance Project, etc...just google) other regional utility leaders invest resources not in marketing, but in responsive staff who build coalitions to:

- Engage stakeholders early and often throughout a well-publicized, facilitated planning process.
- Ensure trust and respect are built through transparent sharing of information, consensus building around the meaningful goals that community members set.
- Evaluate barriers to access that potential stakeholders may face and eliminate these barriers to participation.

Working Group 1: Planning Goals for which customers and organizations representing community interests should be included: affordability and reliability planning to access federal dollars to lower customer bills and keep customers safe in 2023.

BPU staff must be directed to listen and create a community plan in collaboration with the Integrated Resource Plan (IRP) process to proactively solicit community solutions. It's up to the BPU Board to give a framework based on the following resources, assign staff to plan with the community to attain goals of lowering bills and keeping customers safe from disconnects, and holding staff accountable to transparent documentation of that process. Elected officials should facilitate and fund transparent public participation in community planning as part of IRP processes. Organizations throughout the county should be part of the effort to secure federal funding and loans for everything from job training and bill assistance to efficiency installations, related determinates of health, and retirement plans for Nearman Coal Plant within the next 4 years to access hundreds of millions in federal resources.

Working Group 2: Improve customer service/assistance, and end all water or electric shut offs that might put customers at health risk (work with KCK community to cover costs using federal and state funding sources). BPU just needs to follow what other utilities have done by making sure there is no risk of health or short term eviction before involuntarily disconnecting anyone. The BPU Board should instruct staff to do this by

· Prohibiting any involuntary shut-offs when customer assistance funding is available.

· Collecting data on reasons for nonpayment, household's current energy usage, possible cost effective efficiency investments, hot and cold temps in upcoming weeks, ages of occupants (the very young and very old are at heightened risk), medical needs, and household income.

· Providing detailed data of those factors to relevant community assistance groups, reporting all risks of disconnection to energy efficiency, health, social service, and state/local authorities to engage with pro-active assistance at least 8 weeks before shut-off.

· Providing two written notices delivered 8 weeks before any shutoff, verified as received by resident, written notice of simple, free procedures for appeal (disconnecting no customers in appeal process attempting to access assistance.

· Charging no late fees or disconnection/reconnection fees.
· Disconnect no customer that has disputed bill payment or assistance program paperwork.
· Prohibiting termination at end of day or before weekends or holidays when customers can't immediately address the problem with customer service.
· Negotiating a reasonable installment plan with no fees: if the customer cannot make payments, the payment plan should be renegotiated (protecting BPU from liability for adhesion contracts).

It's in the utility and public's interest to provide power to customers even when they can't pay on time, and to pursue payment retroactively through available federal and state assistance programs, including energy efficiency services, loans, grants, and refunds through community action agencies (policy details available through Low Income Home Energy Assistance Program (LIHEAP), Clearinghouse National Energy Assistance Referral (NEAR) and Lifeline Across America (LAA).

On February 28th in KANSAS CITY, KS - Concerned community members are coming together to demand that the Kansas City Board of Public Utilities (BPU) stop utility disconnections and UG Commissioners remove regressive fees and taxes from BPU utility bills. Community members are also demanding transparency and accountability for BPU efforts to lower customer prices using federal dollars for home health, clean energy and other efforts consistent with the KC Regional Climate Action Plan. BPU disconnected over 10,000 accounts in 2021, including over 1000 accounts per month during some of the coldest winter months in 2021-

2022 Communication from the The Economic Community Health Organization

(ECHO) committed itself to advocate for the environmental health of formerly redlined neighborhoods in NE KCK. Residents and organizations active in the NE KCK community can sign onto a letter to BPU and UG leaders demanding (1) no BPU shut offs that may put customers at high health risk, there should be no shut offs from December through March annually, and during the hottest months of the year (2) separation of electric and water charges from unrelated fees and fixed costs - no one should be at risk of utility shut off due to inappropriate city taxation practices, (3) transparency around opportunities for bill and pollution reduction, including community access to billions of dollars in federal funding for municipal utility clean energy transition grants in the IRA and IIJA.

· Basic Rights: Minimum Protections Relating to utilities often include: (a) that the service will be terminated after receival of various rights that the consumer has to prevent termination and notice date has been verified received by resident along with procedures for appeal. Often, written notice must be given more than once.

· Rules should also prohibit disconnections when there is a dispute over the bill or the implementation of any assistance programs on which residents are relying. Special Protections and Moratoria on Terminations exist in most hot and cold-weather states.

· Other common prohibitions against terminations apply after a certain time of day and before weekends or holidays. The customer should always have a right to appeal to both the utility and to their regulator before termination moves forward. In many states, informal appeals can be made by telephone before the termination, and the utility service will be maintained or reconnected during the appeals process.

· In many states, prior to termination, a consumer must be informed of the option to pay the old bills through a negotiated reasonable installment (Right to Deferred Payment Plan) with no fees. If the consumer's circumstances have not changed since the plan was created, but the consumer still could not make the payments, the plan may not have been reasonable in the first place. Many state regulations require that the utility take into consideration a number of factors, such as the reasons for nonpayment, the household's current energy usage (leading to cost effective efficiency investment), and the household's income. If there was a change in circumstances (job loss, illness) an advocate should have the time to argue that the plan needs to be revised (preferably before the breach). Utilities will always say that the customer agreed to the payment plan in a contract, and thus cannot come back and say that the terms are unfair. However, there is often an absence of equal bargaining power when a customer deals with a utility. These types of agreements could fall into the category of "adhesion contracts" and courts may refuse to enforce them.

· It's in the utility and public's interest to provide power to customers and pursue payment through federal dollars when possible, including energy efficiency services through on-bill loans or grants in instances where customers are unable to pay. Community action agencies, utility companies and state utility commissions should be able to provide consumers with means of maintaining continuous electricity, gas, telecommunications, and water service. Payment assistance information for water service is paramount, then Customer service can guide customers through the LIHEAP Clearinghouse National Energy Assistance Referral (NEAR) project -toll free number for NEAR is 1- 866-674-6327. Lifeline Across America, www.lifeline.gov Link-up and Lifeline, which are discounts applied to telephone installation and monthly payments for low-income customers.

Gas and coal are the most expensive sources of energy, primary drivers of climate change, tend to fail more often in extreme heat and cold, just when customers need power the most, and their cost volatility make these fuel sources significantly more unreliable than clean energy and transmitted market energy. We need to invest in cheap energy efficiency and renewable energy that invests in Wyandotte County homes and communities. A study showed that incorporating renewable energy into the grid bolsters its resilience against extreme weather and heat waves. Solar and wind notably "bailed out" the Texas grid", and IRA policies can cover 50-70% of the cost of transition away from coal to clean energy.

These programs create historic clean energy transition cost savings and low income assistance opportunities for BPU, especially in the next four years, that need to be fully modeled in the IRP next year. Given 40% direct payment, economically disadvantaged community grants, low income housing efficiency and solar project cost, and low-to-no interest loans for public entities, BPU governors should, and many customers will, demand a transition to clean energy and low prices in the next few years. Biden's executive order requires that 40% of these funds go to "disadvantaged communities," and Wyandotte qualifies. The opportunity couldn't be clearer for KCK.

Loss of utility service is a particularly serious problem for older Americans, who can face serious illness or death from extreme weather conditions. The most frequent reason utility service is disconnected is for nonpayment of the bill. As we've shared with BPU and the board for over two years, Common limits and procedural requirements placed on the ability of a utility to disconnect a customer include measures that advocate for the elderly, infants, those with serious illnesses, extreme temperatures, and poverty conditions where reduced rates and weatherization can be connected with customers instead of shut-offs. We have shared policies and programs of this nature that far exceed BPU's protections in person and in writing after Mr. Johnson said in a meeting with advocates that he "challenged anybody to find a utility offering more services than [BPU] - comparing apples to apples." He also said that it was "not our role to solve social and economic challenges in the community." We provided customer safety programs for utilities in NM, MN, WI, and MI that far outstripped BPU's protections. At a minimum, written notice of the utility's intention to disconnect service and the customer's right to a hearing are generally required.
Even within BPU's existing medical exceptions, there are huge gaps in equipment that qualifies, and, as Jeanette who leads the program put it with General Manager Johnson's support: "even in our life support program - you have to have a backup system - we say we can't provide service - so you have to have a backup system...if a bill does not get paid in our life support program, your power will still get turned off. It just means we will provide you notification and continue to work with you to try to make sure the service does get turned on, but once we provide you that notification, we will turn your service off even if you're on our life support system" "we cannot provide you with service and the service continues to not get paid. we try to give you an opportunity to work with us, but if you continue not to pay, even if you're on life support, you just can't go without paying."

Appendix II

Public Power Utilities and the Inflation Reduction Act (2023)

The Inflation Reduction Act of 2022 (IRA) provides powerful new tools for public power utilities to tap low cost clean energy. Under the IRA public power entities like municipal and state-owned utilities have new opportunities to lead the clean energy transition, reducing costs for ratepayers and constituents, and driving a new, local clean energy economy. Under the IRA, towns and cities can support local investments in residential and commercial efficiency, electrification, and distributed generation, build and own clean energy, and improve public infrastructure. Forward-thinking public power agencies can use these programs in concert to reduce costs, increase resiliency, bring new economic opportunities and tax base, and keep their communities competitive in the new energy economy. For municipal utilities, every dollar of savings that can be harnessed through IRA programs frees up critical dollars for education, fire and police services, critical infrastructure, and other municipal programs.

IRA factsheet: Kansas Sustainability Board IIJA / IRA planning

Appendix III

Recommendations by Synapse: filed electronically on May 15, 2023 BEFORE THE KANSAS CITY BOARD OF PUBLIC UTILITIES (Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power. Synapse's clients include state consumer advocates, public utilities commission, staff, attorneys general, environmental organizations, federal government, agencies, and utilities).

BPU Rate Case: Nearman

1 **Q Please describe the avoided O&M and sustaining capital costs associated 2 with an earlier Nearman retirement.**

3 A On a per MW basis, Nearman is expensive to own and operate, relative to other 4 BPU resources and industry averages (as discussed in Section 4(iv), above). 5 These are costs that are passed on to ratepayers. Protecting ratepayers from 6 unnecessary costs is especially important given Nearman's age. Total spending on 7 sustaining capital expenses is likely to increase with the need for additional 8 refurbishment of aging equipment, replacement of older parts, etc.

For wind and solar, O&M and sustaining capital costs are relatively low.[59] 9 If 10 Nearman is replaced with more renewable resources, BPU's O&M spending 11 should decline. This in turn will lower revenue requirements and reduce costs 12 passed on to ratepayers.

13 **Q Please describe the forced outage risks associated with operating a 41-year** 14 **old**

plant that will be mitigated with an earlier Nearman retirement.

A The risk of forced outages is also a concern, especially given that Nearman is over 40 years old. As generators age, the likelihood and frequency of forced outages increases. For instance, CenterPoint Indiana South's Culley Unit 3 in Indiana was shut down unexpectedly for nearly six months due to a turbine failure. Not only did this put reliability at risk, but it also led to a rate hike for CenterPoint customers to cover the cost of replacement energy.[60] Similarly, as Nearman

[57] U.S. Environmental Protection Agency. Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants, Docket No. EPA-HQ-OAR-2023-0072. *Available at:* https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and guidelines-fossil-fuel-fired-power.

[58] U.S. Environmental Protection Agency. Fact Sheet: Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants Proposed Rule. *Available at:* https://www.epa.gov/system/files/documents/2023-05/FS-OVERVIEW-GHG for%20Power%20Plants%20FINAL%20CLEAN.pdf.

[59] National Renewable Energy Laboratory, "Annual Technology Baseline: 2022 Electricity ATB Technologies and Data Overview: Summary of Minimum and Maximum Values of CAPEX, Capacity Factor, O&M and LCOE," 2022, *available at:* https://atb.nrel.gov/electricity/2022/index.

[60] Schneider, K., "CenterPoint Energy request 3-month rate hike for 2023 following coal plant failure," Indianapolis Star, (November 25, 2022), *available at:* https://www.indystar.com/story/news/2022/11/25/centerpoint-files-for-rate-hike following-coal-plant-malfunction/69670232007/.

continues to age, total spending on replacement parts and maintenance will continue to grow, increasing costs to BPU and its ratepayers and increasing the likelihood of more forced outages.

Q What do you conclude about the risks posed by continuing to operate Nearman and producing a large portion of energy from coal generation?

A As of 2022, BPU generates more than 40 percent of its energy from coal. Given the risks of derates, outages, escalating costs, and reliability issues associated with coal generation that are summarized above, BPU should commit to retiring Nearman early and start replacing its energy and capacity with lower-risk and lower-cost resources. In other words, maintaining the status quo is no longer the lowest-risk option.

6. BPU SHOULD START BUILDING OR PROCURING REPLACEMENT RESOURCES FOR NEARMAN SOONER RATHER THAN LATER, AND TAKE ADVANTAGE OF THE TAX BENEFITS OFFERED THROUGH THE *INFLATION REDUCTION ACT*

Q What alternatives has BPU considered for future energy supply?

A BPU has not indicated that it is planning for Nearman's retirement or considering replacement resources or PPAs. Its most recent IRP from 2019 says nothing specifically about future energy supply. BPU conducted a study in 2014 to evaluate the feasibility of converting Nearman to a gas-fired unit.[61]

As part of its next IRP, the Board of Directors should request that BPU staff conduct a full analysis to determine Nearman's most economic retirement date and the least-cost set of replacement resources. Specially, BPU should consider

[61] Kansas City Board of Public Utilities. Nearman Creek Station. Natural Gas Firing Feasibility Study. June 26, 2014. BPU response to Sierra Club data request 3-3.

building out or procuring from the marketplace renewables and other low-cost resources that minimize the risks and costs I summarize above.

Q Should BPU wait before starting to procure or build replacement resources?

A No, BPU should begin building or procuring replacement resources for Nearman as soon as possible after completing the robust analysis I am recommending.

As I have shown in my analysis, Nearman is expected to operate at a loss every year going forward; it appears to be becoming too uneconomic to justify further investment and operations. Additionally, as I discussed, the electricity market is changing, and Nearman will likely be outcompeted over time and with greater frequency by renewables. The plant is also aging and exposed to risks that include extreme weather and fuel supply constraints. Nearman may be placed on reserve shutdown more frequently, experience more forced outages and derates, or be forced to retire early. Preparing now to avoid expensive replacement energy purchases in the future will benefit ratepayers.

Furthermore, the build-out or procurement of new resources can take years. There are multiple implementation barriers, including interconnection queue backlogs. Starting early improves BPU's preparedness for Nearman's retirement.

Lastly, there are numerous tax benefits available that BPU should act on now. The IRA increased the tax credits available for solar and wind and introduced new tax credits for batteries. However, many of these incentives could expire within the next 10 years; acting now ensures that BPU and its customers can still benefit.

Q Please describe the IRA tax benefits for solar, wind, and batteries in more detail.

Through the IRA, utility-scale wind and solar are now both eligible for a 30 percent investment tax credit ("ITC"), which increases to 40 percent if the facility

is located in an 'energy community,' as defined in the IRA.[62] Stand-alone battery storage is also newly eligible for a 30 percent ITC. The IRA also increased production tax credits

("PTC"): it increased wind and solar PTCs to \$26/MWh (\$2022). When the ITC and PTC are applied to new renewable and battery storage projects, cost savings can be considerable. However, the new ITC and PTC options could be phased out by 2032.[63]

Q What are some other examples of IRA tax options available?

A Additional examples of tax options available through the IRA are summarized in Table 5. The table includes funding for refinancing undepreciated assets and reinvesting in renewables, which could be particularly advantageous for BPU considering Nearman's large undepreciated balance.

[62] Parts of Kansas City would qualify as an energy community. Energy communities include census tracts where a coal-fired electric generating unit has been retired since 2009, statistical areas with 0.17% or greater fossil fuel employment since 2010, or 25% or greater local tax revenues related to fossil fuel extraction, processing, or transport.

[63] The later of 2032 or the first year that greenhouse gas emissions from U.S. electricity production are less than or equal to 25 percent of 2022 levels. Congress.gov. "Text - H.R.5376 - 117th Congress (2021-2022): Inflation Reduction Act of 2022." August 16, 2022. *Available at:* https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

Table 5. Examples of tax benefits available through the *Inflation Reduction Act*

Funding for refinancing undepreciated assets and reinvesting in renewables	
Sec. 50141. Funding for DOE Loan Programs Office	Loans to retool, repower, repurpose, or replace energy infrastructure that has retired or to improve efficiency and reliability of existing resources ($40 billion of authority through FY2026)
Sec. 50144. Energy Infrastructure Reinvestment Financing	Loans to retool, repower, repurpose, or replace energy infrastructure no longer in operation or enable operating energy infrastructure to avoid greenhouse gas emissions ($5 billion to guarantee up to $250 billion in loans through FY2026)
Sec. 60103. Greenhouse Gas Reduction Fund	Financial assistance for projects that reduce greenhouse gas emissions or deploy zero-emission technology ($27 billion available through FY2024)
Transmission development	
Sec. 50151. Transmission facility financing	Loans supporting the construction and modification of national interest electric transmission facilities ($2 billion through FY 2030)
Sec 50152. Grants to Facilitate the Siting of Interstate Electricity Transmission Lines	Grants to study impacts of transmission projects, hosting negotiations, participating in regulatory proceedings and economic development for communities affected by construction and operation ($760 million)

3 *Source: Congress.gov. "Text - H.R.5376 - 117th Congress (2021-2022): Inflation* 4 *Reduction Act of 2022." August 16, 2022. Available at:*
5 *https://www.congress.gov/bill/117th-congress/house-bill/5376/text.*

6 BPU can access some of these tax benefits to enable the early retirement of 7 Nearman and adoption of lower cost, lower risk resources to the ultimate benefit 8 of ratepayers and

Kansas City, Kansas community members.

Quick synopsis of the remaining analysis:

1. Between 2018 and 2020, Nearman incurred costs in excess of its market energy revenue and capacity value. These excess costs were passed on to BPU ratepayers, and that pattern of low gas (then low battery storage) prices is repeating.

2. My analysis, based on BPU's projections and assuming capacity value based on BPU's existing contracts, shows that Nearman is not expected to be economic going forward and is expected to incur total net losses of $47 million between 2023 and 2027 (on a net present value ("NPV") basis).

3. BPU's projections of the future costs required to operate and maintain Nearman are unusually high compared to plants of similar size across the country.

4. BPU and its ratepayers can avoid capital expenditures and O&M costs and mitigate the risks associated with continuing to operate Nearman by retiring the plant as soon as possible and replacing its energy and capacity with less expensive alternatives.

3. AN OVERVIEW OF THE NEARMAN COAL PLANT

Q Please provide some background on BPU's Nearman Creek Power Station (Unit 1).

A Nearman Creek Power Station (Unit 1) is a 245 MW (net rating) coal-fired unit located along the Missouri River in Kansas City, Kansas. BPU is the sole owner of the plant.[2] The plant was commissioned in 1981[3] and is currently 42 years old.

Q What is BPU's generation mix?

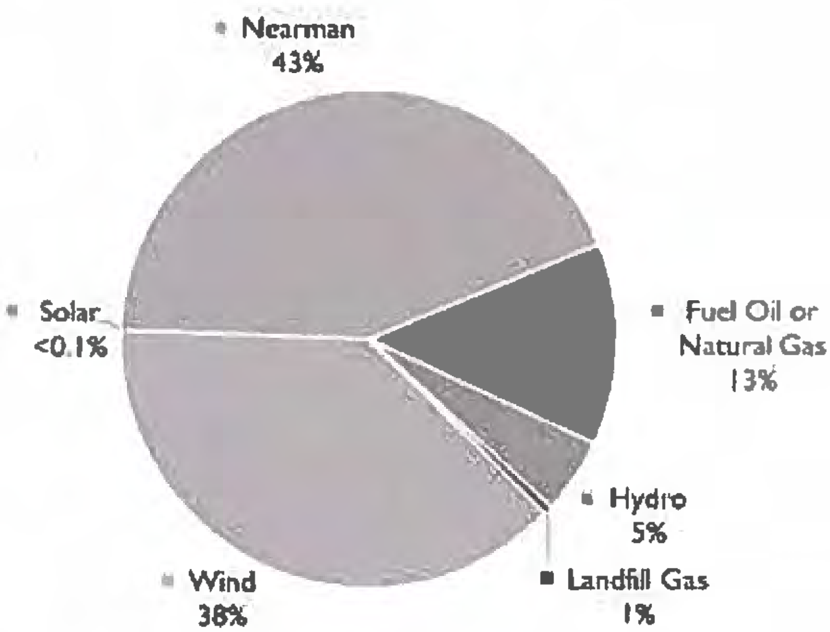
A Nearman Unit 1 provided 43 percent of the BPU's energy generation in 2022 (Figure 1).

[2] Kansas Corporation Commission. Electric Supply & Demand Biennial Report. 2023. *Available at* https://kcc.ks.gov/images/PDFs/legislative reports/2023_Electric_Supply_and_Demand_Report.pdf.

[3] Kansas Corporation Commission. Electric Supply & Demand Biennial Report. 2023. *Available at* https://kcc.ks.gov/images/PDFs/legislative reports/2023_Electric_Supply_and_Demand_Report.pdf.

8

Figure 1. BPU's generation mix in 2022



Source: BPU response to Sierra Club data request 1-22(c).

In 2015, coal represented 73 percent of BPU's energy.[4] But in recent years, BPU's coal reliance has declined due to the improving economics of renewable energy power purchase agreements ("PPA"), the conversion of Quindaro from coal to gas, and Nearman's declining operations.[5] However, going forward, BPU is not expecting any major changes to its energy portfolio. The Smoky Hill wind PPA is expiring in 2027,[6] and BPU currently plans to retire Quindaro CT2 and CT3 also in 2027.[7] Smoky Hills, Quindaro CT2, and Quindaro CT3 together generated 4 percent of BPU's energy in 2022.[8] In summary, BPU is planning to

[4] "Fitch Affirms Kansas City (KS) BPU Bonds 'A'; Outlook Stable." July 25, 2022. Fitch Ratings. *Available at*: https://www.fitchratings.com/research/us-public-finance/fitch affirms-kansas-city-ks-bpu-bonds-a-outlook-stable-25-07-2022.

[5] Ibid.

[6] Kansas City, Kansas, Board of Public Utilities Integrated Resource Plan 2019, pg. 19.

[7] Kansas City, Kansas, Board of Public Utilities Integrated Resource Plan 2019, pg. 10.

[8] BPU response to Sierra Club data request 1-22(c).

continue producing a large portion of its energy from coal generation for the foreseeable future.

Q What years does this rate application cover?

A BPU is proposing to increase electric operating base rate revenues, on an annualized basis, for two 12-month periods starting July 1, 2023, and July 1, 2024.

Q What is BPU requesting in this rate case relating to Nearman?

A BPU seeks to include O&M, capital, and fuel costs in this rate application to continue operating Nearman in 2023 and 2024. These costs total $51.9 million and $52.3 million in 2023 and 2024,respectively (Table 1).[9]

[9] Costs also include common expenses for Nearman Unit 1 and CT4, "Nearman Common." BPU response to Sierra Club data request 1-3.

Table 1. Requested expenses for Nearman Creek Power Station in the current

rate application, by fiscal year

Category	**July 1, 2023 – June 30, 2024 ($millions)**	**July 1, 2024 – June 30, 2025 ($millions)**
Nearman Common $0.8 $0.8		
Unit 1 Maintenance $9.7 $9.9		
Unit 1 Operations $9.9 $10.1		
Unit 1 Engineering $3.9 $3.9		
Unit 1 Fuel $27.7 $27.7		
Total $51.9 $52.3		

Source: BPU response to Sierra Club data request 1-3. Costs also include common expenses for Nearman Unit 1 and CT4, referred to as "Nearman Common."

Q What is the undepreciated balance of Nearman as of 2022?

A As of December 31, 2022, the Net Book Value for the Nearman coal unit was $305 million.[10]

Q When does BPU expect Nearman to be fully depreciated? A BPU is projecting that Nearman will be fully depreciated by 2050.[11] **Q When does BPU currently plan on retiring Nearman?**

A BPU's has estimated that Nearman will retire in 2040.[12] This means that Nearman will be online for another 17 years, until the plant is 59 years old.

[10] BPU response to Sierra Club data request 1-1.
[11] BPU response to Sierra Club data request 1-19.
[12] BPU response to Sierra Club data request 1-18.

Q Has BPU committed to this retirement date?

A No, BPU has not committed to 2040 as a retirement date; rather, it is an estimate.

Q What is BPU's rationale for estimating 2040 as a retirement date for Nearman?

A BPU is estimating the retirement date of 2040 to align roughly with the year that Nearman's bonds will be paid off, which is 2045.[13]

Q Is it reasonable to include sunk costs, such as debt costs, in selecting a unit's retirement date?

A No. Retirement decisions should be based on the economics of the generator relative to the economics of alternatives and based on minimizing costs and risks for ratepayers.

Q Has BPU conducted an economic or resource plan evaluation assessing Nearman retirement dates that are earlier than 2040?

A No, BPU has not conducted any recent analyses to evaluate the economic effect on ratepayers of an earlier retirement date than 2040 for Nearman.[14]

[13] BPU response to Sierra Club data request 4-3a.

[14] BPU response to Sierra Club data request 1-19.

4. NEARMAN UNIT 1'S COSTS HAVE EXCEEDED ITS REVENUE IN RECENT YEARS, AND THE COAL PLANT IS NOT EXPECTED TO BE ECONOMIC GOING FORWARD

i. BPU market-commits and self-commits Nearman into the SPP energy market

Q How can generators participate in the SPP energy market?

A Generator owners such as BPU have five options for generators in the SPP energy market: (1) market-commitment, (2) self-commitment, (3) reliability, (4) outage, and (5) not participating.[15]

Market-committed generators are offered into the market at a price that covers their marginal costs, which includes fuel and operating costs. SPP schedules the resource if its offer price is equal to or lower than the other generators selected to meet demand. The generator will then be paid for its generation at the market clearing price. Additionally, if a generator does not recover all of its costs (including its opportunity costs of providing operating reserve in lieu of energy), SPP will provide a make-whole payment that covers the remainder (a payment only available to market-committed resources). In this way, market commitment insulates a generator from energy-market risk.

Self-committed resources choose to generate regardless of whether the market clearing price will cover their marginal cost and the costs of startup and operating stably at minimally required output levels (though they can then be dispatched

[15] Reliability status is defined as "the resource is off-line and is only available for centralized unit commitment if there is an anticipated reliability issue," outage status is defined as "the resource is unavailable due to a planned, forced, maintenance, or other approved outage," and the not participating status is defined as "the resource is otherwise available but has elected not to participate in the day-ahead market." SPP Market Monitoring Unit: Self-committing SPP markets: overview, impacts, recommendations. December 2019. *Available at:* https://spp.org/documents/61118/spp%20mmu%20self-commit%20whitepaper.pdf.

economically at higher output levels). Self-commitment is typical for solar and wind, which have variable costs of zero or near-zero. Some coal generators choose to self-commit, despite the risk of operating at a loss. For example, coal generators with must-take coal supply agreements may self-commit so they can burn down their coal inventories to make room for a new delivery. Self commitment exposes generators to energy-market risk.

Q How does BPU commit Nearman into the SPP energy market?

A BPU prefers to market-commit Nearman,[16] but it did self-commit the generator for more than half of its operating time in 2018 through 2020 (Table 2).

Table 2. Percentage of time Nearman Unit 1 self committed into the SPP energy market

Year	% Self-Committed
2018	54%
2019	73%
2020	71%

2021	4%
2022	5%

Source: BPU response to Sierra Club data request 3-1(a)ii.

BPU self-commits Nearman for a few reasons, including:

- Environmental and performance testing,
- Managing its Air Quality Control System ("AQCS")—BPU runs Nearman every 21 days to manage reagents in its AQCS,

[16] Kansas City Board of Public Utilities BPU. March 1, 2023 – Regular Session, at 1:17. *Available at:* https://www.youtube.com/watch?v=Nz6uXy0NW3E.

- Coal silo management—BPU periodically burns coal to avoid self-ignition of the fuel, and
- Managing coal inventories—BPU is charged $5 per ton if it is unable to receive coal shipments.[17]

BPU states that it intends to market-commit Nearman most of the time going forward.[18]

Q What are the risks associated with self-commitment?

A Self-committed resources choose to generate regardless of whether the market clearing price will cover their marginal cost. Given the high cost of operating Nearman (outlined below), self-commitment increases the risk and likelihood that BPU will not be able to recoup its marginal costs. Nearman is also ineligible for SPP make-whole payments when self-committed, further adding to potential losses. While each of the specific reasons offered by BPU for self-committing Nearman may seem reasonable in isolation—e.g., BPU must comply with its air permit—the list as a whole highlights the inflexibility of the unit and the risk it poses to ratepayers.

Losses during self-commitment are likely going to get worse. Wind already makes up over 35 percent of SPP's energy generation,[19] meaning that some hours of the day have very low-priced electricity. Since wind and solar resources have a dispatch price of zero, they displace the marginally priced resources, which are typically expensive coal plants or higher running-cost gas-fired peaking generation. The presence of more wind generation depresses locational marginal

[17] Kansas City Board of Public Utilities BPU. March 1, 2023 – Regular Session, at 1:20. *Available at:* https://www.youtube.com/watch?v=Nz6uXy0NW3E.

[18] BPU response to Sierra Club data request 3-1.

[19] Southwest Power Pool. Fast Facts: Energy production by fuel type (as of 1/19/2023). *Available at*: https://www.spp.org/about-us/fast-facts/.

prices ("LMP"). Coal units in general, and Nearman in particular, do not "follow" energy prices well. Nearman has a long start time and is an inflexible resource; it cannot turn on and off easily as LMPs go up and down over the course of a day. As SPP members continue to add more resources to the grid that cost nothing to dispatch, such as wind, solar, and battery storage, the number of hours with low priced energy is only going to increase. Ultimately, this means that BPU will have fewer chances to recoup Nearman's costs when self-committed.

ii. BPU is forecasting unrealistically high utilization rates for Nearman

Q Describe Nearman's historical utilization rate.

A Between 2018 and 2022, Nearman's utilization rate ranged from 45 percent to 59 percent (Figure 2, below).[20]

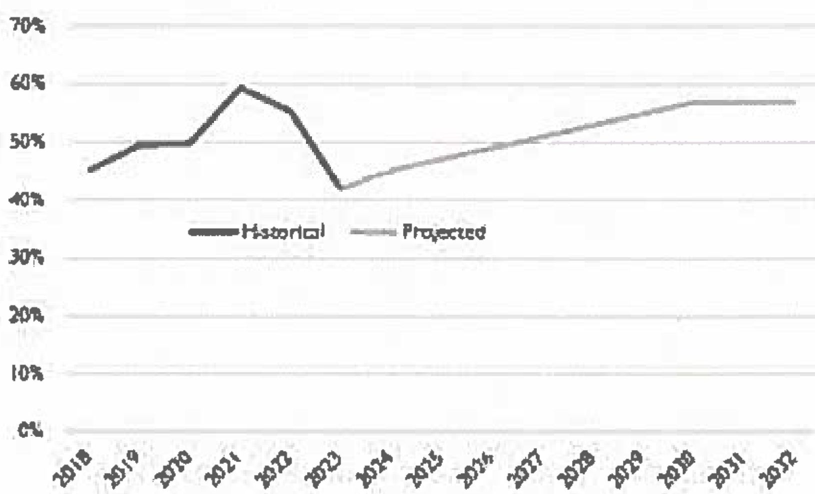
Q What is BPU projecting for Nearman's utilization rate going forward?

A BPU is projecting capacity factors that steadily increase from 42 percent in 2023 to 57 percent in 2032 (Figure 2).[21]

[20] BPU response to Sierra Club data request 1-6.

[21] BPU response to Sierra Club data request 1-7.

Figure 2. Historical and projected capacity factors for Nearman Unit 1



Source: BPU response to Sierra Club data requests 1-6 and 1-7.

Q How does BPU explain its capacity factor projections for Nearman?

A BPU predicts that plant retirements in SPP territory, transmission congestion, natural gas prices, and growth in demand from electrification will drive the increase in BPU's utilization rate.[22]

Q Do you have concerns about BPU's utilization rate projections for Nearman?

A Yes. BPU's projections that a coal plant will increase its capacity factors going forward deviates markedly from other utilities' projections of similar plants in recent years. Even if Nearman is well maintained, it is unreasonable to assume that the 42-year-old plant is immune from the forced outages and breakdowns that accompany an aging generator. Plus, when one considers the likelihood of increasing environmental regulation (discussed in Section 5), rising capacity factors seem especially unrealistic.

[22] BPU response to Sierra Club data request 1-7.

Further, BPU's assumption is at odds with market shifts already underway. As I noted, increasing amounts of wind and solar tend to drive down LMPs and displace expensive fossil fuel generators such as Nearman. In addition to Nearman becoming less cost-competitive and being dispatched less frequently in the coming decade, its energy margin will fall.

Barring my already stated concerns about forced outrages and environmental regulation, the only way Nearman could achieve these capacity factors by 2032 is through self-commitment. If BPU chose to rely on self-scheduling, given Nearman's operational inflexibility and high operating costs going forward, Nearman would operate at an increasingly large loss, which would detrimentally affect its ratepayers.

Q What evidence exists in support of increasing amounts of wind, solar, and battery energy storage coming to the SPP energy marketplace, and reducing the need for energy from Nearman?

A The SPP interconnection queue for new generation shows a dramatic leap upward in 2023 (compared to prior years) for solar, wind, and battery storage resources applying for interconnection to the SPP grid. As of May 9, 2023, there are more than 77,000 MW of solar and wind generation applying for interconnection, and more than 21,000 MW of battery energy.[23] While the entirety of these requests is

[23] At the DISIS ("Definitive Interconnection System Impact Studies") or Facility Study Stage. Additional wind and solar resources of more than 14,000 MW have signed interconnection agreements and are indicated on being "on schedule" in the queue data. *See, e.g.*, SPP interconnection queue data available at: https://opsportal.spp.org/Studies/GIActive, and the interconnection queue dashboard at https://app.powerbi.com/view?r=eyJrIjoiNWRlMjYyN2EtOTA2Ny00NTE0LWI2M2QtMGE3MTAxZTAxOGE0IiwidCI6IjA2NjVkY2EyLTExNDEtNDYyNS1hMmI1LTY3NTY0NjNlMWVlMSIsImMiOjF9.

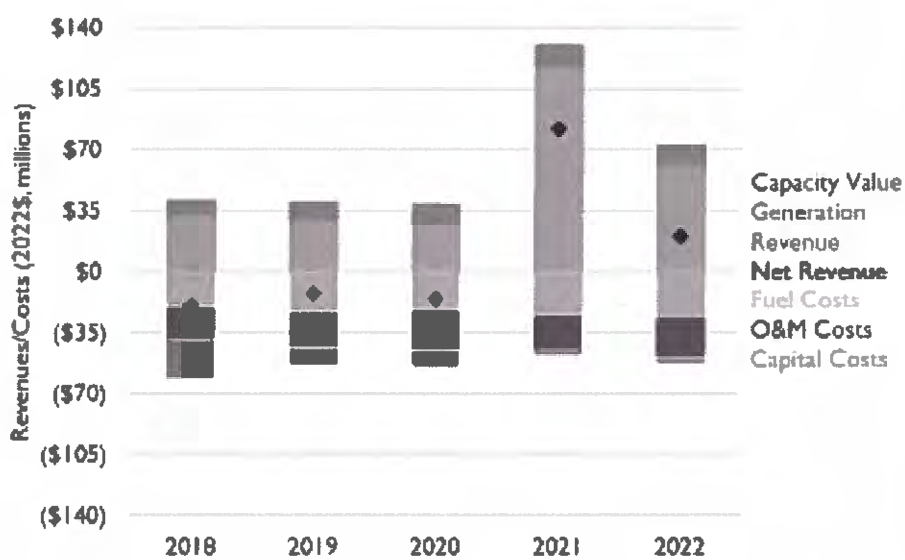
not likely to proceed to market development, the data indicate market responsiveness to the overall economics of these renewable resources. Further, as just one example, Evergy's 2021 IRP offers its plan to shift from a generation fleet in 2020 that is 27 percent wind and 0 percent solar to one that by 2030 would be 33 percent wind and 7 percent solar (on a capacity basis).[24]

iii. Nearman's costs have exceeded its revenue and value in recent years

Q Describe Nearman's financial performance in recent years.

A Based on BPU's own data, I find that Nearman incurred costs in excess of its market energy and capacity value each year from 2018 to 2020, losing on average $16 million (2022$) per year (Figure 3).

Figure 3. Nearman's historical costs and revenues

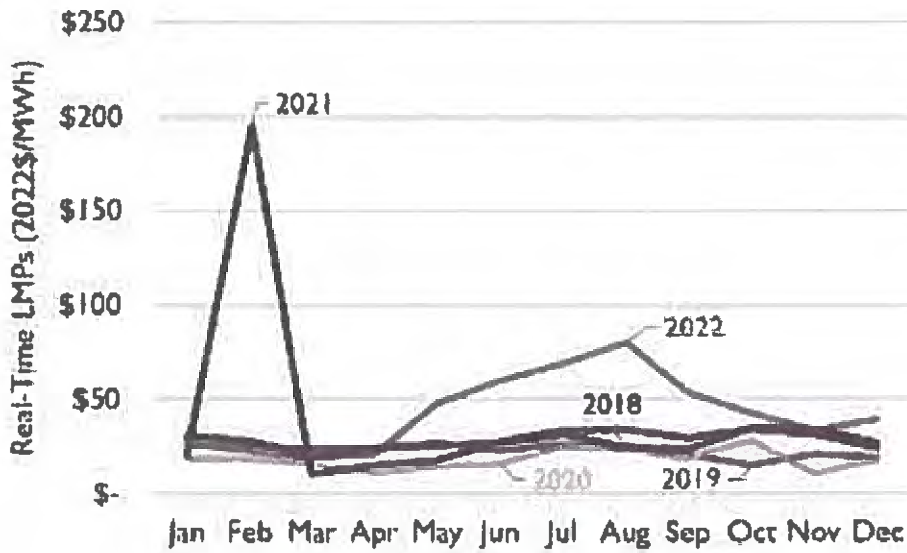


Source: see description in text.

[24] Evergy 2021 Integrated Resource Plan Overview, Figure 3, Generation Type By Fuel Type, *available at:* https://www.evergy.com/-/media/documents/smart-energy/evergy 2021-irp-overview.pdf.

As depicted above in Figure 3, for the years 2021 and 2022, Nearman's generation revenues were particularly high. Although average generation was roughly the same for all five years, LMPs were extremely high in February 2021 and greatly elevated for much of 2022 (Figure 4). These high LMP prices were responsible for uniquely high generation revenue in both 2021 and 2022 and should be viewed as an anomaly.

Figure 4. Average monthly SPP real-time energy market locational marginal prices, 2018–2022



Source: Figure 4-1 in SPP State of the Market Reports, available at https://www.spp.org/spp-documents-filings/?id=1859.

The high LMPs and associated energy revenues can be explained by two discrete factors: (1) a major cold weather event in February 2021, and (2) high gas and energy market prices in 2022 due to the war in Ukraine and other global market forces.

From February 6 to February 22, 2021, the Central United States experienced an extreme cold weather event that brought record-low temperatures and set record high winter demand. SPP cited the event as its greatest operational challenge in its

80-year history.[25] Record-high electricity use drastically increased LMPs across the SPP region (Figure 4). This event was the greatest driver for Nearman's energy revenues in 2021. It appears that Nearman made nearly as much in the energy market in February 2021 as it did for the rest of year. Similarly, SPP, and the United States as a whole, experienced unusually high LMPs for much of 2022 (Figure 4). They were driven by numerous global factors, including changes in demand following COVID-19 pandemic lockdowns, fossil fuel constraints as a result of the war in Ukraine, and various compounding global energy market dynamics.

It may be tempting to view these extreme weather events and global crises as benefits for Nearman and BPU's ratepayers, but relying on extraordinary events to achieve profitability is a risky proposition. These types of events may not repeat themselves and/or have the same results. They are also typically associated with major risks to coal generation (I discuss the risk of extreme weather and volatile energy markets in Section 5, below).

Q Describe your methodology for evaluating the historical economic performance of Nearman.

A I relied on data BPU provided in its rate application and through discovery. I summed annual historical Nearman fuel costs,[26] O&M costs,[27] and capital

[25] Southwest Power Pool. 2021 Winter Storm Review. *Available at:* https://www.spp.org/2021-winter-storm-review#:~:text=In%20February%202021%2C%20SPP%20experienced,exceptions%20(approximately%20four%20hours).

[26] BPU response to Sierra Club data request 1-6.

[27] BPU response to Sierra Club data request 1-6.

expenditures[28] to determine total historical costs for each year. I estimated Nearman's historical capacity value based on the capacity value from BPU's fixed capacity contracts and Nearman's historical unforced capacity.[29] I summed this capacity value with Nearman's annual energy revenues in the SPP marketplace[30] to find the total historical value per year. I netted the annual costs and values to find Nearman's historical net value (or cost) for each year.

iv. My analysis shows that Nearman's projected costs exceed its projected energy

revenues and capacity value, and these excess costs will be passed on to ratepayers

Q What do your findings show about the future financial performance of Nearman?

A My analysis finds that Nearman's costs exceed its revenues in each year going forward (Figure 5), incurring average net losses of $11 million (2022$) per year. On an NPV basis, Nearman is expected to incur total net losses of $47 million from 2023 to 2027, which will be passed on to ratepayers. Furthermore, given that Nearman's capacity factor forecasts are unrealistically high, and energy revenue forecasts are in part a function of utilization rates, Nearman's energy revenues are likely overestimated. As a result, annual net losses could be even higher than $11 million.

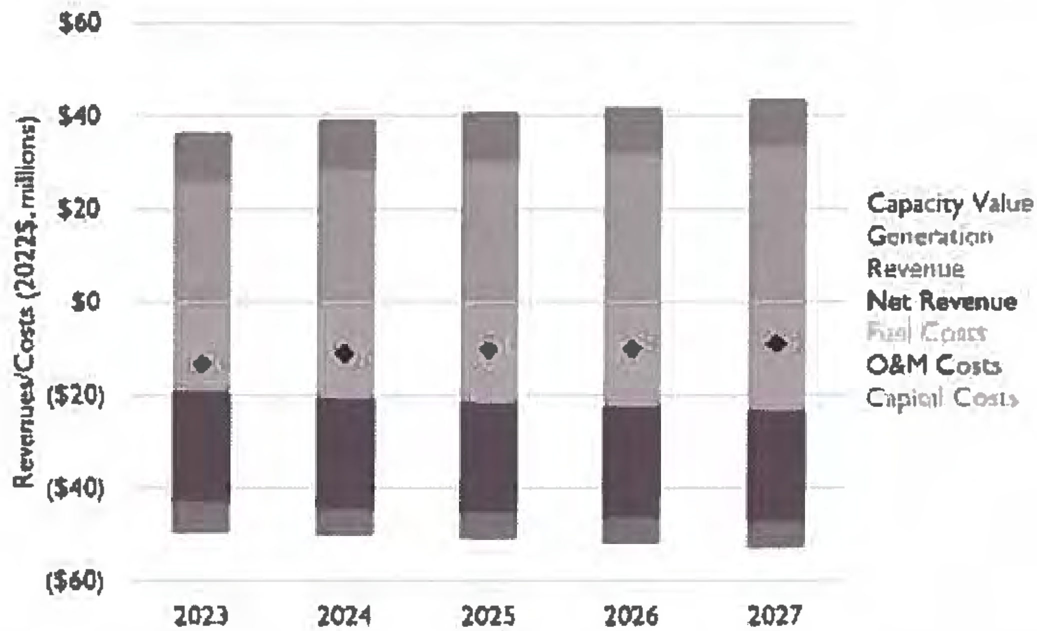
[28] I scaled Nearman Common expenses to Nearman Unit 1, proportionally based on relative capacities of Unit 1 and CT4. Values from BPU response to Sierra Club data request 1-10(a).

[29] Using a weighted average of capacity prices from BPU's fixed capacity contracts. Values from BPU response to Sierra Club data request 2-1. Unforced capacity projects from BPU response to Sierra Club data request 1-6.

[30] BPU response to Sierra Club data request 1-8.

BPU presently expects to retire Nearman 17 years from now, in 2040. With annual losses of at least $11 million, or possibly higher, Nearman's 5-year net costs of $47 million could balloon considerably over the course of its lifetime. If the Board of Directors does not act swiftly, these escalating costs will burden BPU ratepayers for the foreseeable future.

Figure 5. Projected net revenues for Nearman



Source: see description in text.

Q Why did you only look at Nearman's forward-going economics from 2023 to 2027?

A BPU only provided annual capital expenditures to 2027, so my analysis was necessarily limited to the period of 2023 to 2027. Nonetheless, the trend is clear; Nearman has been, and likely will continue to be, operating at a loss.

Q Describe your methodology for forecasting the economic performance of Nearman.

A I evaluated Nearman's forward-going economics using data provided by BPU in discovery and its rate application, as well as publicly available documents. Similar to my methodology for evaluating Nearman's historical economic performance, I summed BPU's own annual projected fuel costs,[31] O&M costs,[32] and capital expenditures[33] for Nearman to determine total projected costs per year. I estimated Nearman's capacity value based on its projected unforced capacity and its firm capacity contract prices.[34] I summed this capacity value with BPU's annual projected energy revenues[35] for Nearman to find the total value per year. I netted the annual costs and values to find Nearman's projected net value (or cost) for each year. To determine NPV, I used BPU's weighted average cost of capital[36] as a discount rate.

My analysis is not intended to calculate Nearman's full revenue requirements. Instead, it looks at Nearman spending relative to what it is earning, on a forward going basis, and it identifies the costs that can be avoided for ratepayers if BPU retires Nearman in the nearer term.

[31] BPU response to Sierra Club data request 1-7.

[32] BPU response to Sierra Club data request 1-7.

[33] I scaled Nearman Common capital expenses to Nearman Unit 1, proportionally based on relative capacities of Unit 1 and CT4. Values from BPU response to Sierra Club data request 1-10(b).

[34] Using a weighted average of capacity prices from BPU's fixed capacity contracts. Values from BPU response to Sierra Club data request 2-1. Unforced capacity values from BPU response to Sierra Club data request 1-7.

[35] BPU response to Sierra Club data request 1-9.

[36] BPU response to Sierra Club data request 1-5.

Q Explain why you added the full cost of each expenditure in the year it was incurred instead of annualizing the costs over the remaining life of the plant.

A I expensed the full cost of each capital expenditure in the year it was incurred because this approach is more fitting if earlier retirements are a possibility. In years where BPU undertakes large projects, capital expenditures will likely exceed the resources' total revenues and value; but the reverse is also true. And over a multi-year timeframe, if the plant is operating economically, the total costs incurred and total energy revenues earned, plus capacity value, should at the very least net out. If they do not, meaning that the plant's total fixed and variable costs consistently sum to more than its total energy market revenues plus capacity value, then continuing to invest in the plant is not in ratepayers' interest on a forward-going basis.

In contrast, most utilities typically annualize capital expenditures (based on the utility's cost of capital) and spread the costs out over the remaining economic life of the plant. This approach is reasonable with expenditures for capital projects where there is a reasonable degree of certainty that the plant will operate through its planned retirement date. But it is a dangerous assumption with aging resources such as coal plants that are likely to retire early. A project might look economic when spread out over a long time with many years of energy market revenues and capacity value to balance it out. But if a project must be recovered over a shorter time frame instead, it suddenly becomes clear how expensive and uneconomic it was to expend capital on the plant.

Q How do the forward-going costs for Nearman compare to alternative generation types?

A Nearman's forward-going levelized cost of energy ("LCOE") is $54 per MWh (on an NPV basis),[37] which is higher than many alternatives (Table 3). Accordingly, ratepayers should benefit if BPU replaces Nearman with a portfolio of more economic resources, including natural gas-fired generation, solar, and wind resources.

Table 3. LCOE of alternatives and BPU's PPA estimates ($/MWh), by generation type

Resource Type	BPU PPA Estimates $/MWh	Alternative LCOE Estimates $/MWh	Alternative Source
Wind	$24–$30	$17–$67	NREL (2022)
		$38	EIA (2022)
Solar (standalone)	$48–$58	$19–$33	NREL (2022)
		$33	EIA (2022)
Solar + 4-hour Battery		$55	EIA (2022)
Combined Cycle (natural gas)		$37	EIA (2022)

Source: BPU estimates from BPU response to Sierra Club data requests 2-3. National Renewable Energy Laboratory, "Annual Technology Baseline: 2022 Electricity ATB Technologies and Data Overview: Summary of Minimum and Maximum Values of CAPEX, Capacity Factor, O&M and LCOE," 2022, available at: https://atb.nrel.gov/electricity/2022/index. EIA estimates assume capacity weighted LCOE, from U.S. Energy Information Administration, "Levelized Costs of New Generation Resources in the Annual Energy Outlook

[37] LCOE based on projected generation and costs for 2023 to 2027, in NPV terms. Generation values from BPU response to Sierra Club data request 2-2(d). Costs include capital costs (BPU response to Sierra Club data request 1-10(b)), O&M costs and fuel costs (BPU response to Sierra Club data request 1-7).

2022," March 2022, available at: https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.

Q How does O&M spending at Nearman compare to industry averages for comparable coal plants?

A BPU's O&M spending is concerningly high for Nearman. From 2023 to 2028, BPU is forecasting an average of $24 million (2022$) per year on O&M expenses, which equates to $95/kW-year (2022$). This is well above the industry average for similarly sized coal plants (Table 4). In fact, projected O&M spending at Nearman is 1.5 times greater than the industry average.

Overspending at O&M is not only an issue going forward; BPU's O&M costs for Nearman were also above average over the last five years. This indicates that BPU ratepayers have been overpaying to keep Nearman operating and will increasingly do so in the coming years.

Table 4. U.S. EIA (Sargent & Lundy) industry averages and Nearman historical and projected average annual O&M costs

	Average Annual O&M Costs (2022)$/kW-year
Industry Average (Sargent & Lundy estimates)	$62
Nearman historical (2018–2022)	$85
Nearman projected (2023–2028)	$95

Source: BPU response to Sierra Club data requests 1-6 and 1-7, and U.S. EIA, *Generating Unit Annual Capital and Life Extension Costs Analysis (December 2019), available at https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf. Sargent & Lundy O&M costs are specific to coal plants smaller than 500 MW.*[27]

Q How does capital spending at Nearman compare to other resources in BPU's portfolio?

A Coal-burning power plants generally have high capital costs relative to other generating resources.[38] Plants such as Nearman with flue gas desulfurization ("FGD") are particularly cost-intensive for capital maintenance. Chemicals and reagents corrode equipment such as pumps, valves, etc., and parts need replacement more frequently compared to plants without FGD.[39]

Nearman represented 65 percent of capital spending for BPU between 2023– 2027[40] (relative to Nearman representing 41% of generation).[41] On a per MW basis, Nearman will cost BPU and its ratepayers $127,000 per MW,[42] which is double the cost of the Quindaro Power Plant CT2 and CT3,[43] and six times the cost of the Dogwood Energy Facility.[44,45]

The capital costs to sustain Nearman Unit 1 are much higher than for other generators in BPU's portfolio. Furthermore, when considering future

[38] National Renewable Energy Laboratory, "Annual Technology Baseline: 2022 Electricity ATB Technologies and Data Overview: Summary of Minimum and Maximum Values of CAPEX, Capacity Factor, O&M and LCOE," 2022, *available at:* https://atb.nrel.gov/electricity/2022/index.

[39] U.S. EIA, Generating Unit Annual Capital and Life Extension Costs Analysis (December 2019), *available at*: https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf.

[40] Direct testimony of BPU witness Glen Brendel, pg. 2-4.

[41] Annual average for 2019-2022. Values from BPU response to Sierra Club data request 1-22c.

[42] I scaled Nearman Common capital expenses to Nearman Unit 1, proportionally based on relative capacities of Unit 1 and CT4.

[43] Quindaro Power Plant CT2 and CT3 are peaking oil-fired units.

[44] Costs and MWs scaled to BPU's 17 percent share in Dogwood Energy Facility. Dogwood is a gas-fired combined cycle facility.

[45] Capital expenditure data from direct testimony of BPU witness Glen Brendel, pg. 2-4.

environmental regulation for coal generators, costly capital upgrades are a near certainty that will further drive-up spending.

v. To avoid unnecessary costs for ratepayers, BPU should commit to retiring Nearman in the near term

Q What do your findings suggest about continuing to operate and expend capital for Nearman Unit 1?

A My analysis shows that Nearman has been operating at a loss in recent years and is expected to do so continuously going forward. In addition, the O&M costs to keep Nearman running are markedly high compared to the industry average. To avoid locking in spending on fuel, O&M, and capital expenditures for the long term, and continuing to harm ratepayers by operating at a loss, BPU must consider an earlier retirement date. This date should be well before the current date of 2040.

Q Are you suggesting a specific retirement date for Nearman?

A Based on my findings that Nearman is expected to continue operating at a loss, I recommend that BPU commit to an earlier retirement date for Nearman and take the plant offline as soon as possible. However, I do not suggest a specific retirement date. Instead, BPU must conduct a robust study to determine a Nearman retirement date that is in the best interest of ratepayers.

Specifically, BPU must conduct detailed technical analyses using electricity production-cost and capacity expansion models. These types of analyses are considered best practice in the industry. If done properly, the analyses identify the most economic retirement date for Nearman and the least-cost set of replacement options. As a public utility, Nearman's top priority should be providing reliable energy to ratepayers while minimizing costs and risks.

Q Should BPU wait to retire Nearman until more of its balance depreciates?

A No. Nearman's undepreciated balance is already a sunk cost (ratepayers will pay for it regardless). Continuing to operate Nearman at a loss will only add to Nearman's debt. However, retiring Nearman will save money for ratepayers by not adding to the existing capital balance, and by no longer operating the plant at a loss. Plus, if the BPU replaces the plant with resources that have high energy margins (such as with wind and solar resources, which have minimal variable costs), BPU can pay off that balance ahead of schedule.

5. <u>THERE ARE MOUNTING RISKS AND COSTS ASSOCIATED WITH OPERATING NEARMAN THAT CAN BE AVOIDED WITH AN EARLY RETIREMENT</u>

Q Are there avoidable costs and risks associated with continuing to operate Nearman as a generating asset?

A Yes. There are numerous risks and costs for BPU ratepayers, who receive over 40 percent of their energy from a single coal plant with negative going-forward value. Many of these can be mitigated with early retirement. They include (1) issues with coal supply and delivery, (2) coal supply contract risks, (3) fuel price volatility, (4) reliability risks posed by extreme weather, (5) future environmental compliance costs, (6) operational costs associated with running an aging fossil fuel resource, and (7) forced outage risks associated with operating an aging plant.

Q Please describe the risks posed by coal delivery, supply, and transportation issues that would be mitigated with an earlier Nearman retirement.

A BPU has experienced issues with coal supply and delivery over the last few years. Specifically, from mid-April to the end of June 2022, BPU's coal supplier was not able to deliver the contracted amount of coal as a result of coal car maintenance

delays and Union Pacific labor disputes.[46] During this period, coal deliveries fell from 45–60 kilotons per month down to 27 kilotons, resulting in a derate (reduction in available capacity) for Nearman that burdened ratepayers with $960,000 in replacement power costs.[47]

Coal supply and delivery issues are not limited to BPU; they are occurring across the country. For instance, the coal supplier for the San Juan Power Station in New Mexico was unable to supply the contracted amount of coal to that plant in 2022, resulting in a derate.[48] In Arizona, labor shortages in 2022 prevented Burlington Northern Santa Fe Railroad from delivering all the coal it was contracted to provide to Tucson Electric Power Company in 2022.[49] More generally in 2022, rail labor shortages—with employment down 20.4 percent since January 2019— inhibited the movement of coal throughout the country and contributed to soaring prices.[50] Similarly, the potential but avoided rail strike in the fall of 2022 was a major threat to the coal industry. In fact, the coal industry is largely dependent on railways, further exposing vulnerabilities of the coal supply chain.[51]

[46] BPU response to Sierra Club data requests 1-15(a) and 1-15(b).
[47] BPU response to Sierra Club data request 1-15(c), 1-15(d), and 1-15(e). [48] Direct Testimony of Devi Glick, pg. 32. Docket No. E-01933A-22-0107. Arizona Corporation Commission (January 11, 2023).
[49] Ibid.
[50] Kuykendall, T., "Rail service 'meltdown' constraining US coal sector in hot market,"

S&P Global Market Intelligence (May 9, 2022). *Available at* https://www.spglobal.com/marketintelligence/en/news-insights/latest-news headlines/rail-service-meltdown-constraining-us-coal-sector-in-hot-market 70189190#:~:text=During%20an%20April%20conference%20hosted,the%20second% 2 0half%20of%202021.

[51] Bittle, J., "Railroad strike threatens power in coal-dependent states," Grist, (September 14, 2022), *available at* https://grist.org/energy/railroad-strike-coal-power-shortage/.

BPU's continued operation of the Nearman coal plant exposes ratepayers to the risk of fuel supply constraints as a result of these kinds of transportation and delivery issues, which could translate to high costs for replacement energy— potentially for a lengthy period of time.

Q Please describe the risks posed by coal supply contracts.

A Currently, BPU purchases coal through the Western Fuels Association ("WFA"), which in turn contracts with coal producers and railroads.[52] WFA's current coal supply contract extends to 2024, and its coal transportation contract is set to expire at the end 2025. As part of these contracts, BPU must pay a penalty of $5 per ton if it is unable to accept coal shipments. This penalty poses a major risk to BPU and its ratepayers and presents BPU with only lose-lose options. On one hand, BPU can pay exorbitant penalties if it cannot accept the coal. On the other hand, BPU can self-commit Nearman so it can burn coal unnecessarily to make room for more fuel. If LMPs are below Nearman's marginal costs during this self commitment, BPU will not recoup Nearman's marginal costs, thereby burdening ratepayers.

Additionally, to avoid paying must-take penalties, BPU staff indicated that they attempt to sell unwanted coal shipments to other utilities.[53] Given the issues with coal transportation that I outlined above, this strategy is in itself risky. Further, with more coal retirements planned for this decade, the number of willing off takers is only expected to decline.

During BPU's next contract renewal with WFA or other coal suppliers or brokers, the Board of Directors should ensure that future coal contracts minimize risks for

[52] BPU response to Sierra Club data request 3-4.

[53] Kansas City Board of Public Utilities BPU. March 1, 2023 – Regular Session, at 1:32. *Available at*: https://www.youtube.com/watch?v=Nz6uXy0NW3E.

ratepayers. In particular, BPU should avoid long-term contracts to prevent contractual issues if Nearman retires early. This is especially important considering Nearman's age and the risk of future environmental regulation, discussed below. To avoid unnecessary fuel consumption, must-take clauses should not be considered.

Q Please describe the avoided fuel costs associated with an earlier Nearman retirement.

A With such a significant portion of BPU's energy coming from coal, ratepayers have high exposure to fuel price volatility. Coal, natural gas, and oil prices are determined in large part by global markets and are influenced by numerous factors including rail and pipeline access, natural gas reserves in Europe, volume of exports and imports, extreme weather, etc. When fuel prices are high, ratepayers are on the hook to pay for high-cost electricity.

If BPU retires Nearman early and adds more solar and wind resources to its portfolio, ratepayers will have a buffer from potential coal price volatility. If BPU continues to operate Nearman to generate a substantial share of its energy, its ratepayers will bear the full burden of high and volatile fuel prices. One alternative to address volatility—entering into long-term coal contracts—presents long-term risks that likely outweigh the hedge benefit.

Q Please describe the risks posed by extreme weather that will be mitigated with an earlier Nearman retirement.

A Nearman may not be adequately designed for extreme weather such as winter storms and prolonged cold weather snaps. During these types of events, Nearman can suffer from equipment failures, resulting in derates or even complete shutdowns. LMPs can be very high during extreme weather events, as multiple

generators fail and demand peaks. When this occurs, BPU and its ratepayers are forced to pay for very expensive replacement energy; or worse, reliability suffers.

For instance, Nearman experienced a derate during Winter Storm Elliot in December 2022. After equipment froze, Nearman was limited to 150 MW from 6:30pm on December 22 to 9pm on December 24.[54] During this period, BPU purchased replacement power from the energy market, where LMPs averaged over $230/MWh, with one hour reaching as high as $1,391/MWh.[55] In total, replacement power during the derate event cost ratepayers an estimated $900,000.[56]

Q Please describe the risks and costs from environmental regulation that can be avoided with an earlier Nearman retirement.

A Based on current trends, most experts in the industry agree that there is a potential for greater regulation for coal-fired power plants going forward. Though nobody can predict exactly what future regulations will be, such regulation would most likely increase the cost to operate coal-fired power plants. Relative to other energy resource types, coal-fired power plants have numerous environmental compliance costs and regulatory risks. These include (1) carbon emissions, (2) air emissions (e.g., particulate matter), (3) water emissions (e.g., wastewater), (4) by products and waste (e.g., coal ash), and (5) plant inputs (e.g., coal mining). Even if Nearman is fully compliant with all finalized environmental regulations now,

[54] BPU responses to Sierra Club data request 1-17(c).

[55] BPU responses to Sierra Club data request 1-17(f).

[56] BPU responses to Sierra Club data request 1-17. I assumed Nearman would have been operating at 230 MW through the period of December 22-24, 2021.

the risk of future regulation touching on at least one, or even more than one, of these inputs and outputs is likely.

As an example, on May 11, 2023, the U.S. Environmental Protection Agency ("EPA") announced a proposed Clean Air Act rule limiting carbon dioxide ("CO_2") emissions from fossil fuel-fired power plants.[57] Specifically, the newly proposed Clean Air Act rule would require BPU to either commit to retiring Nearman by 2032, reduce its utilization factor to 20 percent and commit to retiring Nearman by 2035, or install expensive technology such as carbon capture and storage technology ("CCS") or equipment to enable natural gas co-firing.[58]

BEFORE THE

KANSAS CITY BOARD OF PUBLIC UTILITIES

DIRECT TESTIMONY OF

SARAH SHENSTONE-HARRIS

ON BEHALF OF SIERRA CLUB

Issue:

Electric Revenue Requirements and Risks
for Nearman Creek Power Station (Unit 1)

Filed Electronically On
May 15, 2023

BEFORE THE

KANSAS CITY BOARD OF PUBLIC UTILITIES

2023 RATE HEARING

AFFIDAVIT

Pursuant to Kansas City, Kansas Board of Public Utilities Rules of Procedure for Public Hearing on Rate Increases I, Sarah Shenstone-Harris, hereby state:

1. My name is Sarah Shenstone-Harris. I am a Senior Associate at Synapse Energy Economics, Inc. My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

2. Attached hereto and made part hereof for all purposes is my Direct Testimony on behalf of Sierra Club, including exhibits, which has been prepared in written form for introduction into evidence in the above-referenced rate case.

3. I hereby swear and affirm that based upon my personal knowledge, the facts stated in the Direct Testimony are true. In addition, my judgement is based on my professional experience, and the opinions and conclusions stated in the testimony are true, valid, and accurate.

Under penalty of perjury, I declare that the preceding to be true and correct to the best of my knowledge and belief.

Date: May 15, 2023

____

Sarah Shenstone-Harris

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1. INTRODUCTION AND SUMMARY

Q Please state your name and occupation.

A My name is Sarah Shenstone-Harris. I am a Senior Associate at Synapse Energy Economics, Inc. ("Synapse"). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q Please summarize your work experience and educational background.

A I provide research, analysis, and consulting services on various electricity-sector issues, including integrated resource planning and clean energy project evaluation. Before joining Synapse, I worked at Reading Municipal Light Department, one of Massachusetts's largest municipally owned utilities, as an Integrated Resource Analyst. I helped manage Reading Light's energy portfolio and secured reliable and cost-competitive long-term power contracts. I was also involved in rate design, and in the development and administration of energy efficiency and electrification programs.

I received a Master of Science in Environmental Sustainability from the University of Ottawa's Institute for the Environment, as well as a Bachelor of Science in Biology from Queen's University in Kingston, Ontario, Canada.

A copy of my current resume is attached as Exhibit SSH-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q Have you testified previously before the Kansas City Board of Public Utilities ("BPU" or the "Board")?

A No.

Q What is the purpose of your testimony in this proceeding?

A I review BPU's proposal to increase its electric rates, and the specific requests therein for the operations of, and required capital expenditures for, Nearman Creek Power Station Unit 1 ("Nearman").[1] I evaluate Nearman's recent historical economic performance and its likely economic performance going forward. To minimize risks and costs for ratepayers, I recommend BPU commit to a retirement date for Nearman ahead of the 2040 estimate. I also provide a brief summary of options BPU should consider for replacement resources.

Q How is your testimony structured?

A This Section 1 provides my introduction. In Section 2, I summarize my findings and recommendations for the Board.

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[1] Nearman Creek Power Station also includes a natural gas combustion turbine, "CT4". All references herein to Nearman refer specifically to Unit 1, the coal-burning unit, unless specified otherwise.

In Section 3, I contextualize Nearman and BPU's proposed operations and maintenance ("O&M") spending and capital expenditures ("Capex") included in the rate application.

In Section 4, I review Nearman's historical and future economic performance based on BPU's own data. I evaluate the assumptions BPU relies on for its own assessment of Nearman's ongoing and future operations, and I outline costs BPU can avoid if it retires Nearman and replaces it with alternatives.

In Section 5, I summarize the risks BPU is subjecting ratepayers to by continuing to operate Nearman.

In Section 6, I discuss the need to begin building or procuring replacement resources for Nearman immediately. I summarize the tax benefit options currently available through the federal *Inflation Reduction Act* ("IRA").

Q What documents did you rely on for your analysis, findings, and observations?

A My analysis relies primarily on the testimony and discovery responses of BPU staff in this rate case. I also rely on information from publicly available documents, including BPU publications.

2. <u>Findings and Recommendations</u>

Q Please summarize your findings.

A My primary findings are:

1. Between 2018 and 2020, Nearman incurred costs in excess of its market energy revenue and capacity value. These excess costs were passed on to BPU ratepayers.

2. My analysis, based on BPU's projections and assuming capacity value based on BPU's existing contracts, shows that Nearman is not expected to be economic going forward and is expected to incur total net losses of $47 million between 2023 and 2027 (on a net present value ("NPV") basis).

3. BPU's projections of the future costs required to operate and maintain Nearman are unusually high compared to plants of similar size across the country.

4. BPU does not fully account for the economic risks associated with using coal for electricity production. The electricity system is changing; maintaining the status quo is no longer the lowest-risk and lowest-cost option.

5. BPU and its ratepayers can avoid capital expenditures and O&M costs and mitigate the risks associated with continuing to operate Nearman by retiring the plant as soon as possible and replacing its energy and capacity with less expensive alternatives.

Q Please summarize your recommendations.

A Based on my findings, I recommend the following:

1. To reduce costs and avoid risks for its ratepayers, BPU should commit to retiring Nearman Unit 1 well ahead of the current 2040 estimate.

2. As part of its next Integrated Resource Plan ("IRP"), the Board of Directors should require BPU staff to conduct an assessment determining the most economic retirement date for Nearman using electricity production-cost and capacity expansion modeling. The analysis should also identify Nearman's replacement resources and determine the least-cost pathway forward for ratepayers.

3. To minimize losses from operating Nearman, BPU should avoid self-commitment into the Southwest Power Pool ("SPP") market as much as possible.

4. To protect ratepayers, the Board of Directors should direct BPU staff to avoid long-term coal contracts and contracts with must-take clauses.

5. To reduce exposure to the risks associated with BPU's continued operation of Nearman, BPU should take advantage of the tax benefits available through the IRA and build or procure more renewable energy and battery storage.

3. AN OVERVIEW OF THE NEARMAN COAL PLANT

Q Please provide some background on BPU's Nearman Creek Power Station (Unit 1).

A Nearman Creek Power Station (Unit 1) is a 245 MW (net rating) coal-fired unit located along the Missouri River in Kansas City, Kansas. BPU is the sole owner of the plant.[2] The plant was commissioned in 1981[3] and is currently 42 years old.

Q What is BPU's generation mix?

A Nearman Unit 1 provided 43 percent of the BPU's energy generation in 2022 (Figure 1).

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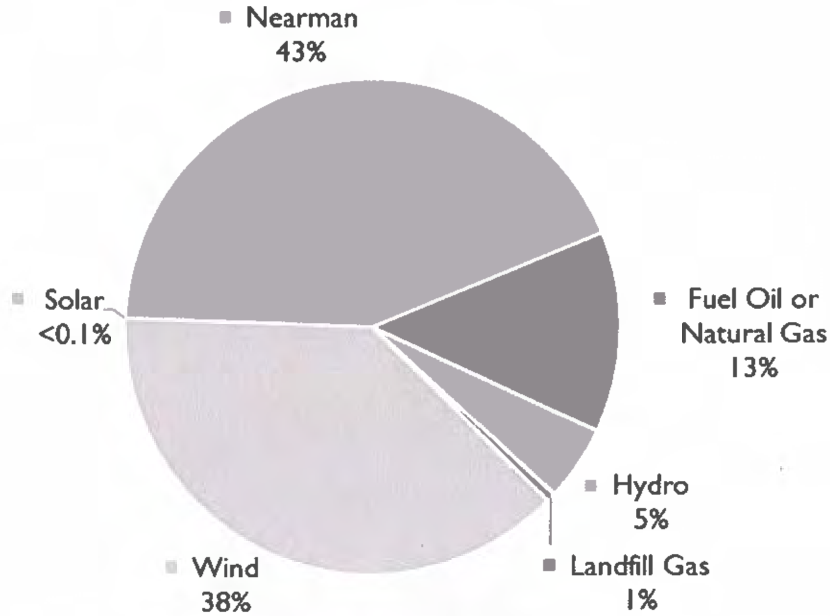
[2] Kansas Corporation Commission. Electric Supply & Demand Biennial Report. 2023. *Available at* https://kcc.ks.gov/images/PDFs/legislative-reports/2023_Electric_Supply_and_Demand_Report.pdf.

[3] Kansas Corporation Commission. Electric Supply & Demand Biennial Report. 2023. *Available at* https://kcc.ks.gov/images/PDFs/legislative-reports/2023_Electric_Supply_and_Demand_Report.pdf.

Figure 1. BPU's generation mix in 2022



Source: BPU response to Sierra Club data request 1-22(c).

In 2015, coal represented 73 percent of BPU's energy.[4] But in recent years, BPU's coal reliance has declined due to the improving economics of renewable energy power purchase agreements ("PPA"), the conversion of Quindaro from coal to gas, and Nearman's declining operations.[5] However, going forward, BPU is not expecting any major changes to its energy portfolio. The Smoky Hill wind PPA is expiring in 2027,[6] and BPU currently plans to retire Quindaro CT2 and CT3 also in 2027.[7] Smoky Hills, Quindaro CT2, and Quindaro CT3 together generated 4 percent of BPU's energy in 2022.[8] In summary, BPU is planning to

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[4] "Fitch Affirms Kansas City (KS) BPU Bonds 'A'; Outlook Stable." July 25, 2022. Fitch Ratings. *Available at*: https://www.fitchratings.com/research/us-public-finance/fitch-affirms-kansas-city-ks-bpu-bonds-a-outlook-stable-25-07-2022.

[5] Ibid.

[6] Kansas City, Kansas, Board of Public Utilities Integrated Resource Plan 2019, pg. 19.

[7] Kansas City, Kansas, Board of Public Utilities Integrated Resource Plan 2019, pg. 10.

[8] BPU response to Sierra Club data request 1-22(c).

continue producing a large portion of its energy from coal generation for the foreseeable future.

Q What years does this rate application cover?

A BPU is proposing to increase electric operating base rate revenues, on an annualized basis, for two 12-month periods starting July 1, 2023, and July 1, 2024.

Q What is BPU requesting in this rate case relating to Nearman?

A BPU seeks to include O&M, capital, and fuel costs in this rate application to continue operating Nearman in 2023 and 2024. These costs total $51.9 million and $52.3 million in 2023 and 2024, respectively (Table 1).[9]

[9] Costs also include common expenses for Nearman Unit 1 and CT4, "Nearman Common." BPU response to Sierra Club data request 1-3.

Table 1. Requested expenses for Nearman Creek Power Station in the current rate application, by fiscal year

Category	July 1, 2023 – June 30, 2024 ($millions)	July 1, 2024 – June 30, 2025 ($millions)
Nearman Common	$0.8	$0.8
Unit 1 Maintenance	$9.7	$9.9
Unit 1 Operations	$9.9	$10.1
Unit 1 Engineering	$3.9	$3.9
Unit 1 Fuel	$27.7	$27.7
Total	**$51.9**	**$52.3**

Source: BPU response to Sierra Club data request 1-3. Costs also include common expenses for Nearman Unit 1 and CT4, referred to as "Nearman Common."

Q What is the undepreciated balance of Nearman as of 2022?

A As of December 31, 2022, the Net Book Value for the Nearman coal unit was $305 million.[10]

Q When does BPU expect Nearman to be fully depreciated?

A BPU is projecting that Nearman will be fully depreciated by 2050.[11]

Q When does BPU currently plan on retiring Nearman?

A BPU's has estimated that Nearman will retire in 2040.[12] This means that Nearman will be online for another 17 years, until the plant is 59 years old.

[10] BPU response to Sierra Club data request 1-1.

[11] BPU response to Sierra Club data request 1-19.

[12] BPU response to Sierra Club data request 1-18.

Q Has BPU committed to this retirement date?

A No, BPU has not committed to 2040 as a retirement date; rather, it is an estimate.

Q What is BPU's rationale for estimating 2040 as a retirement date for Nearman?

A BPU is estimating the retirement date of 2040 to align roughly with the year that Nearman's bonds will be paid off, which is 2045.[13]

Q Is it reasonable to include sunk costs, such as debt costs, in selecting a unit's retirement date?

A No. Retirement decisions should be based on the economics of the generator relative to the economics of alternatives and based on minimizing costs and risks for ratepayers.

Q Has BPU conducted an economic or resource plan evaluation assessing Nearman retirement dates that are earlier than 2040?

A No, BPU has not conducted any recent analyses to evaluate the economic effect on ratepayers of an earlier retirement date than 2040 for Nearman.[14]

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[13] BPU response to Sierra Club data request 4-3a.

[14] BPU response to Sierra Club data request 1-19.

4. NEARMAN UNIT 1'S COSTS HAVE EXCEEDED ITS REVENUE IN RECENT YEARS, AND THE COAL PLANT IS NOT EXPECTED TO BE ECONOMIC GOING FORWARD

i. BPU market-commits and self-commits Nearman into the SPP energy market

Q How can generators participate in the SPP energy market?

A Generator owners such as BPU have five options for generators in the SPP energy market: (1) market-commitment, (2) self-commitment, (3) reliability, (4) outage, and (5) not participating.[15]

Market-committed generators are offered into the market at a price that covers their marginal costs, which includes fuel and operating costs. SPP schedules the resource if its offer price is equal to or lower than the other generators selected to meet demand. The generator will then be paid for its generation at the market clearing price. Additionally, if a generator does not recover all of its costs (including its opportunity costs of providing operating reserve in lieu of energy), SPP will provide a make-whole payment that covers the remainder (a payment only available to market-committed resources). In this way, market commitment insulates a generator from energy-market risk.

Self-committed resources choose to generate regardless of whether the market clearing price will cover their marginal cost and the costs of startup and operating stably at minimally required output levels (though they can then be dispatched

[15] Reliability status is defined as "the resource is off-line and is only available for centralized unit commitment if there is an anticipated reliability issue," outage status is defined as "the resource is unavailable due to a planned, forced, maintenance, or other approved outage," and the not participating status is defined as "the resource is otherwise available but has elected not to participate in the day-ahead market." SPP Market Monitoring Unit: Self-committing SPP markets: overview, impacts, recommendations. December 2019. *Available at:* https://spp.org/documents/61118/spp%20mmu%20self-commit%20whitepaper.pdf.

economically at higher output levels). Self-commitment is typical for solar and wind, which have variable costs of zero or near-zero. Some coal generators choose to self-commit, despite the risk of operating at a loss. For example, coal generators with must-take coal supply agreements may self-commit so they can burn down their coal inventories to make room for a new delivery. Self-commitment exposes generators to energy-market risk.

Q How does BPU commit Nearman into the SPP energy market?

A BPU prefers to market-commit Nearman,[16] but it did self-commit the generator for more than half of its operating time in 2018 through 2020 (Table 2).

Table 2. Percentage of time Nearman Unit 1 self-committed into the SPP energy market

Year	% Self-Committed
2018	54%
2019	73%
2020	71%
2021	4%
2022	5%

Source: BPU response to Sierra Club data request 3-1(a)ii.

BPU self-commits Nearman for a few reasons, including:

- Environmental and performance testing,
- Managing its Air Quality Control System ("AQCS")—BPU runs Nearman every 21 days to manage reagents in its AQCS,

[16] Kansas City Board of Public Utilities BPU. March 1, 2023 – Regular Session, at 1:17. *Available at:* https://www.youtube.com/watch?v=Nz6uXy0NW3E.

- Coal silo management—BPU periodically burns coal to avoid self-ignition of the fuel, and
- Managing coal inventories—BPU is charged $5 per ton if it is unable to receive coal shipments.[17]

BPU states that it intends to market-commit Nearman most of the time going forward.[18]

Q What are the risks associated with self-commitment?

A Self-committed resources choose to generate regardless of whether the market clearing price will cover their marginal cost. Given the high cost of operating Nearman (outlined below), self-commitment increases the risk and likelihood that BPU will not be able to recoup its marginal costs. Nearman is also ineligible for SPP make-whole payments when self-committed, further adding to potential losses. While each of the specific reasons offered by BPU for self-committing Nearman may seem reasonable in isolation—e.g., BPU must comply with its air permit—the list as a whole highlights the inflexibility of the unit and the risk it poses to ratepayers.

Losses during self-commitment are likely going to get worse. Wind already makes up over 35 percent of SPP's energy generation,[19] meaning that some hours of the day have very low-priced electricity. Since wind and solar resources have a dispatch price of zero, they displace the marginally priced resources, which are typically expensive coal plants or higher running-cost gas-fired peaking generation. The presence of more wind generation depresses locational marginal

[17] Kansas City Board of Public Utilities BPU. March 1, 2023 – Regular Session, at 1:20. *Available at:* https://www.youtube.com/watch?v=Nz6uXy0NW3E.

[18] BPU response to Sierra Club data request 3-1.

[19] Southwest Power Pool. Fast Facts: Energy production by fuel type (as of 1/19/2023). *Available at*: https://www.spp.org/about-us/fast-facts/.

prices ("LMP"). Coal units in general, and Nearman in particular, do not "follow" energy prices well. Nearman has a long start time and is an inflexible resource; it cannot turn on and off easily as LMPs go up and down over the course of a day. As SPP members continue to add more resources to the grid that cost nothing to dispatch, such as wind, solar, and battery storage, the number of hours with low-priced energy is only going to increase. Ultimately, this means that BPU will have fewer chances to recoup Nearman's costs when self-committed.

ii. __BPU is forecasting unrealistically high utilization rates for Nearman__

Q Describe Nearman's historical utilization rate.

A Between 2018 and 2022, Nearman's utilization rate ranged from 45 percent to 59 percent (Figure 2, below).[20]

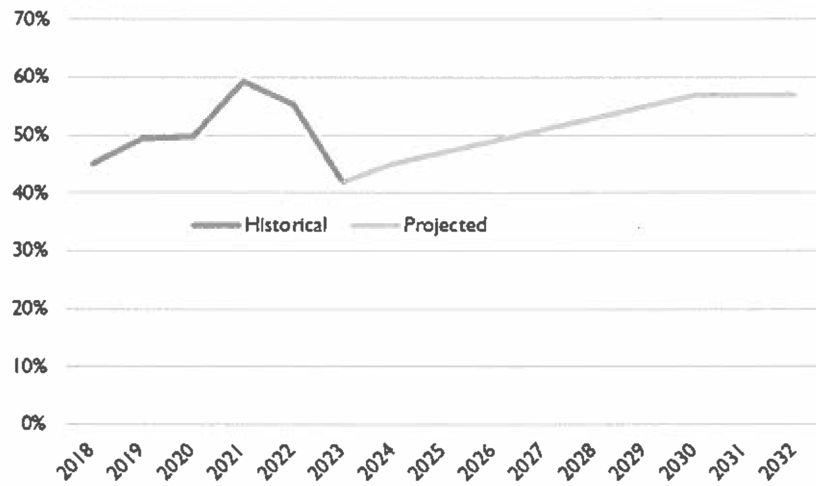
Q What is BPU projecting for Nearman's utilization rate going forward?

A BPU is projecting capacity factors that steadily increase from 42 percent in 2023 to 57 percent in 2032 (Figure 2).[21]

[20] BPU response to Sierra Club data request 1-6.

[21] BPU response to Sierra Club data request 1-7.

Figure 2. Historical and projected capacity factors for Nearman Unit 1



Source: BPU response to Sierra Club data requests 1-6 and 1-7.

Q How does BPU explain its capacity factor projections for Nearman?

A BPU predicts that plant retirements in SPP territory, transmission congestion, natural gas prices, and growth in demand from electrification will drive the increase in BPU's utilization rate.[22]

Q Do you have concerns about BPU's utilization rate projections for Nearman?

A Yes. BPU's projections that a coal plant will increase its capacity factors going forward deviates markedly from other utilities' projections of similar plants in recent years. Even if Nearman is well maintained, it is unreasonable to assume that the 42-year-old plant is immune from the forced outages and breakdowns that accompany an aging generator. Plus, when one considers the likelihood of increasing environmental regulation (discussed in Section 5), rising capacity factors seem especially unrealistic.

[22] BPU response to Sierra Club data request 1-7.

Further, BPU's assumption is at odds with market shifts already underway. As I noted, increasing amounts of wind and solar tend to drive down LMPs and displace expensive fossil fuel generators such as Nearman. In addition to Nearman becoming less cost-competitive and being dispatched less frequently in the coming decade, its energy margin will fall.

Barring my already stated concerns about forced outrages and environmental regulation, the only way Nearman could achieve these capacity factors by 2032 is through self-commitment. If BPU chose to rely on self-scheduling, given Nearman's operational inflexibility and high operating costs going forward, Nearman would operate at an increasingly large loss, which would detrimentally affect its ratepayers.

Q What evidence exists in support of increasing amounts of wind, solar, and battery energy storage coming to the SPP energy marketplace, and reducing the need for energy from Nearman?

A The SPP interconnection queue for new generation shows a dramatic leap upward in 2023 (compared to prior years) for solar, wind, and battery storage resources applying for interconnection to the SPP grid. As of May 9, 2023, there are more than 77,000 MW of solar and wind generation applying for interconnection, and more than 21,000 MW of battery energy.[23] While the entirety of these requests is

[23] At the DISIS ("Definitive Interconnection System Impact Studies") or Facility Study Stage. Additional wind and solar resources of more than 14,000 MW have signed interconnection agreements and are indicated on being "on schedule" in the queue data. *See, e.g.*, SPP interconnection queue data available at: https://opsportal.spp.org/Studies/GIActive, and the interconnection queue dashboard at https://app.powerbi.com/view?r=eyJrIjoiNWRlMjYyN2EtOTA2Ny00NTE0LWI2M2QtMGE3MTAxZTAxOGE0IiwidCI6IjA2NjVkY2EyLTExNDEtNDYyNS1hMmI1LTY3NTY0NjNlMWVlMSIsImMiOjF9.

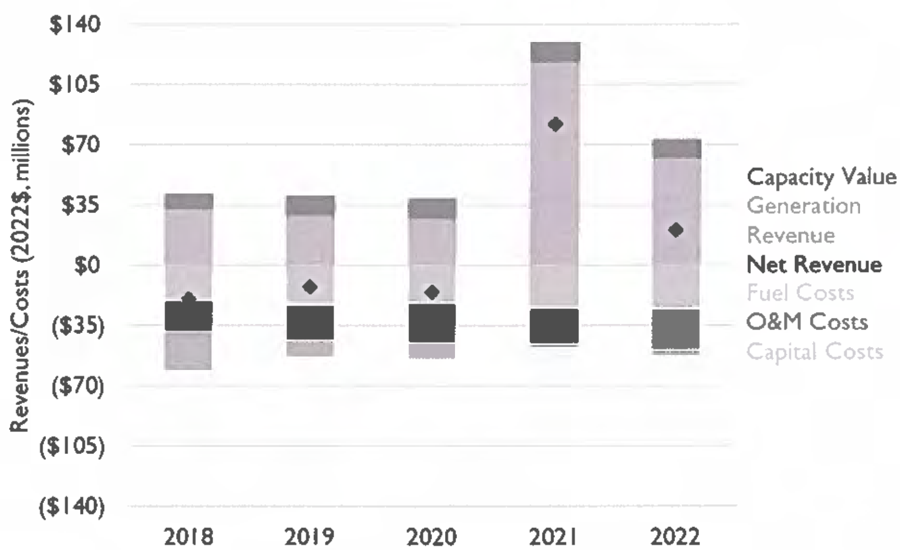
not likely to proceed to market development, the data indicate market responsiveness to the overall economics of these renewable resources. Further, as just one example, Evergy's 2021 IRP offers its plan to shift from a generation fleet in 2020 that is 27 percent wind and 0 percent solar to one that by 2030 would be 33 percent wind and 7 percent solar (on a capacity basis).[24]

iii. <u>Nearman's costs have exceeded its revenue and value in recent years</u>

Q Describe Nearman's financial performance in recent years.

A Based on BPU's own data, I find that Nearman incurred costs in excess of its market energy and capacity value each year from 2018 to 2020, losing on average $16 million (2022$) per year (Figure 3).

Figure 3. Nearman's historical costs and revenues

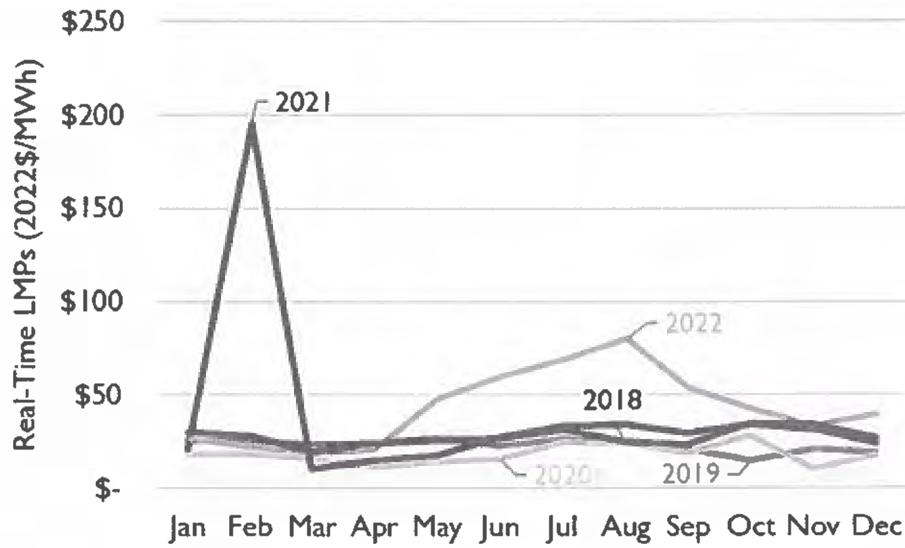


Source: see description in text.

[24] Evergy 2021 Integrated Resource Plan Overview, Figure 3, Generation Type By Fuel Type, *available at:* https://www.evergy.com/-/media/documents/smart-energy/evergy-2021-irp-overview.pdf.

As depicted above in Figure 3, for the years 2021 and 2022, Nearman's generation revenues were particularly high. Although average generation was roughly the same for all five years, LMPs were extremely high in February 2021 and greatly elevated for much of 2022 (Figure 4). These high LMP prices were responsible for uniquely high generation revenue in both 2021 and 2022 and should be viewed as an anomaly.

Figure 4. Average monthly SPP real-time energy market locational marginal prices, 2018–2022



Source: Figure 4-1 in SPP State of the Market Reports, available at https://www.spp.org/spp-documents-filings/?id=1859.

The high LMPs and associated energy revenues can be explained by two discrete factors: (1) a major cold weather event in February 2021, and (2) high gas and energy market prices in 2022 due to the war in Ukraine and other global market forces.

From February 6 to February 22, 2021, the Central United States experienced an extreme cold weather event that brought record-low temperatures and set record-high winter demand. SPP cited the event as its greatest operational challenge in its

80-year history.[25] Record-high electricity use drastically increased LMPs across the SPP region (Figure 4). This event was the greatest driver for Nearman's energy revenues in 2021. It appears that Nearman made nearly as much in the energy market in February 2021 as it did for the rest of year. Similarly, SPP, and the United States as a whole, experienced unusually high LMPs for much of 2022 (Figure 4). They were driven by numerous global factors, including changes in demand following COVID-19 pandemic lockdowns, fossil fuel constraints as a result of the war in Ukraine, and various compounding global energy market dynamics.

It may be tempting to view these extreme weather events and global crises as benefits for Nearman and BPU's ratepayers, but relying on extraordinary events to achieve profitability is a risky proposition. These types of events may not repeat themselves and/or have the same results. They are also typically associated with major risks to coal generation (I discuss the risk of extreme weather and volatile energy markets in Section 5, below).

Q Describe your methodology for evaluating the historical economic performance of Nearman.

A I relied on data BPU provided in its rate application and through discovery. I summed annual historical Nearman fuel costs,[26] O&M costs,[27] and capital

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[25] Southwest Power Pool. 2021 Winter Storm Review. *Available at:* https://www.spp.org/2021-winter-storm-review#:~:text=In%20February%202021%2C%20SPP%20experienced,exceptions%20(approximately%20four%20hours).

[26] BPU response to Sierra Club data request 1-6.

[27] BPU response to Sierra Club data request 1-6.

expenditures[28] to determine total historical costs for each year. I estimated Nearman's historical capacity value based on the capacity value from BPU's fixed capacity contracts and Nearman's historical unforced capacity.[29] I summed this capacity value with Nearman's annual energy revenues in the SPP marketplace[30] to find the total historical value per year. I netted the annual costs and values to find Nearman's historical net value (or cost) for each year.

iv. ***My analysis shows that Nearman's projected costs exceed its projected energy revenues and capacity value, and these excess costs will be passed on to ratepayers***

Q What do your findings show about the future financial performance of Nearman?

A My analysis finds that Nearman's costs exceed its revenues in each year going forward (Figure 5), incurring average net losses of $11 million (2022$) per year. On an NPV basis, Nearman is expected to incur total net losses of $47 million from 2023 to 2027, which will be passed on to ratepayers. Furthermore, given that Nearman's capacity factor forecasts are unrealistically high, and energy revenue forecasts are in part a function of utilization rates, Nearman's energy revenues are likely overestimated. As a result, annual net losses could be even higher than $11 million.

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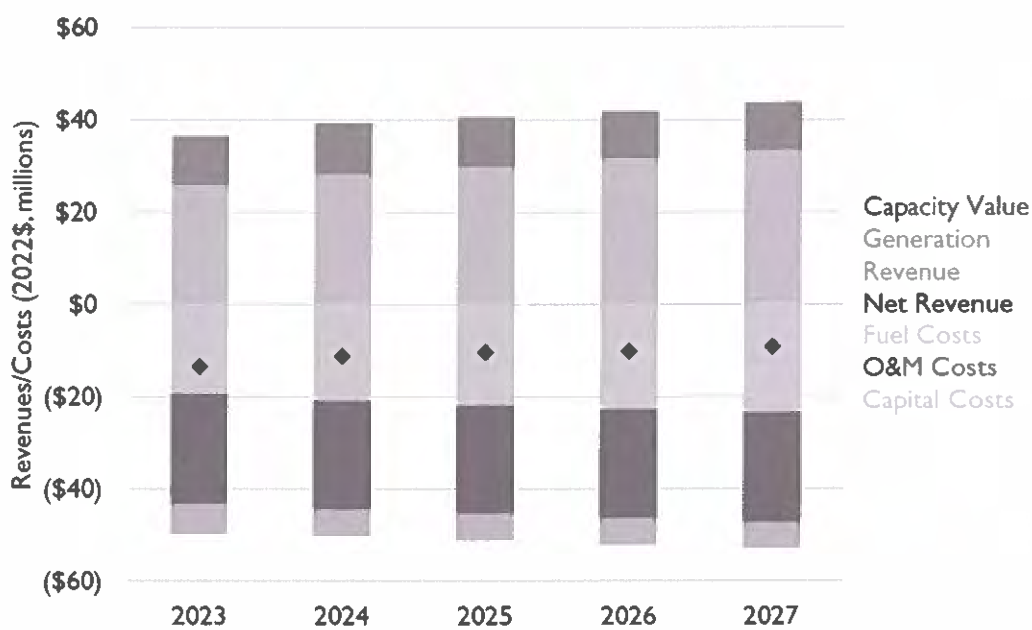
[28] I scaled Nearman Common expenses to Nearman Unit 1, proportionally based on relative capacities of Unit 1 and CT4. Values from BPU response to Sierra Club data request 1-10(a).

[29] Using a weighted average of capacity prices from BPU's fixed capacity contracts. Values from BPU response to Sierra Club data request 2-1. Unforced capacity projects from BPU response to Sierra Club data request 1-6.

[30] BPU response to Sierra Club data request 1-8.

BPU presently expects to retire Nearman 17 years from now, in 2040. With annual losses of at least $11 million, or possibly higher, Nearman's 5-year net costs of $47 million could balloon considerably over the course of its lifetime. If the Board of Directors does not act swiftly, these escalating costs will burden BPU ratepayers for the foreseeable future.

Figure 5. Projected net revenues for Nearman



Source: see description in text.

Q Why did you only look at Nearman's forward-going economics from 2023 to 2027?

A BPU only provided annual capital expenditures to 2027, so my analysis was necessarily limited to the period of 2023 to 2027. Nonetheless, the trend is clear; Nearman has been, and likely will continue to be, operating at a loss.

Q Describe your methodology for forecasting the economic performance of Nearman.

A I evaluated Nearman's forward-going economics using data provided by BPU in discovery and its rate application, as well as publicly available documents. Similar to my methodology for evaluating Nearman's historical economic performance, I summed BPU's own annual projected fuel costs,[31] O&M costs,[32] and capital expenditures[33] for Nearman to determine total projected costs per year. I estimated Nearman's capacity value based on its projected unforced capacity and its firm capacity contract prices.[34] I summed this capacity value with BPU's annual projected energy revenues[35] for Nearman to find the total value per year. I netted the annual costs and values to find Nearman's projected net value (or cost) for each year. To determine NPV, I used BPU's weighted average cost of capital[36] as a discount rate.

My analysis is not intended to calculate Nearman's full revenue requirements. Instead, it looks at Nearman spending relative to what it is earning, on a forward-going basis, and it identifies the costs that can be avoided for ratepayers if BPU retires Nearman in the nearer term.

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[31] BPU response to Sierra Club data request 1-7.

[32] BPU response to Sierra Club data request 1-7.

[33] I scaled Nearman Common capital expenses to Nearman Unit 1, proportionally based on relative capacities of Unit 1 and CT4. Values from BPU response to Sierra Club data request 1-10(b).

[34] Using a weighted average of capacity prices from BPU's fixed capacity contracts. Values from BPU response to Sierra Club data request 2-1. Unforced capacity values from BPU response to Sierra Club data request 1-7.

[35] BPU response to Sierra Club data request 1-9.

[36] BPU response to Sierra Club data request 1-5.

Q Explain why you added the full cost of each expenditure in the year it was incurred instead of annualizing the costs over the remaining life of the plant.

A I expensed the full cost of each capital expenditure in the year it was incurred because this approach is more fitting if earlier retirements are a possibility. In years where BPU undertakes large projects, capital expenditures will likely exceed the resources' total revenues and value; but the reverse is also true. And over a multi-year timeframe, if the plant is operating economically, the total costs incurred and total energy revenues earned, plus capacity value, should at the very least net out. If they do not, meaning that the plant's total fixed and variable costs consistently sum to more than its total energy market revenues plus capacity value, then continuing to invest in the plant is not in ratepayers' interest on a forward-going basis.

In contrast, most utilities typically annualize capital expenditures (based on the utility's cost of capital) and spread the costs out over the remaining economic life of the plant. This approach is reasonable with expenditures for capital projects where there is a reasonable degree of certainty that the plant will operate through its planned retirement date. But it is a dangerous assumption with aging resources such as coal plants that are likely to retire early. A project might look economic when spread out over a long time with many years of energy market revenues and capacity value to balance it out. But if a project must be recovered over a shorter time frame instead, it suddenly becomes clear how expensive and uneconomic it was to expend capital on the plant.

Q How do the forward-going costs for Nearman compare to alternative generation types?

A Nearman's forward-going levelized cost of energy ("LCOE") is $54 per MWh (on an NPV basis),[37] which is higher than many alternatives (Table 3). Accordingly, ratepayers should benefit if BPU replaces Nearman with a portfolio of more economic resources, including natural gas-fired generation, solar, and wind resources.

Table 3. LCOE of alternatives and BPU's PPA estimates ($/MWh), by generation type

Resource Type	BPU PPA Estimates $/MWh	Alternative LCOE Estimates $/MWh	Alternative Source
Wind	$24–$30	$17–$67	NREL (2022)
		$38	EIA (2022)
Solar (standalone)	$48–$58	$19–$33	NREL (2022)
		$33	EIA (2022)
Solar + 4-hour Battery		$55	EIA (2022)
Combined Cycle (natural gas)		$37	EIA (2022)

Source: BPU estimates from BPU response to Sierra Club data requests 2-3. National Renewable Energy Laboratory, "Annual Technology Baseline: 2022 Electricity ATB Technologies and Data Overview: Summary of Minimum and Maximum Values of CAPEX, Capacity Factor, O&M and LCOE," 2022, available at: https://atb.nrel.gov/electricity/2022/index. EIA estimates assume capacity weighted LCOE, from U.S. Energy Information Administration, "Levelized Costs of New Generation Resources in the Annual Energy Outlook

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[37] LCOE based on projected generation and costs for 2023 to 2027, in NPV terms. Generation values from BPU response to Sierra Club data request 2-2(d). Costs include capital costs (BPU response to Sierra Club data request 1-10(b)), O&M costs and fuel costs (BPU response to Sierra Club data request 1-7).

2022," March 2022, available at: https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.

Q How does O&M spending at Nearman compare to industry averages for comparable coal plants?

A BPU's O&M spending is concerningly high for Nearman. From 2023 to 2028, BPU is forecasting an average of $24 million (2022$) per year on O&M expenses, which equates to $95/kW-year (2022$). This is well above the industry average for similarly sized coal plants (Table 4). In fact, projected O&M spending at Nearman is 1.5 times greater than the industry average.

Overspending at O&M is not only an issue going forward; BPU's O&M costs for Nearman were also above average over the last five years. This indicates that BPU ratepayers have been overpaying to keep Nearman operating and will increasingly do so in the coming years.

Table 4. U.S. EIA (Sargent & Lundy) industry averages and Nearman historical and projected average annual O&M costs

	Average Annual O&M Costs (2022)$/kW-year
Industry Average (Sargent & Lundy estimates)	$62
Nearman historical (2018–2022)	$85
Nearman projected (2023–2028)	$95

Source: BPU response to Sierra Club data requests 1-6 and 1-7, and U.S. EIA, Generating Unit Annual Capital and Life Extension Costs Analysis (December 2019), available at https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf. Sargent & Lundy O&M costs are specific to coal plants smaller than 500 MW.

Q How does capital spending at Nearman compare to other resources in BPU's portfolio?

A Coal-burning power plants generally have high capital costs relative to other generating resources.[38] Plants such as Nearman with flue gas desulfurization ("FGD") are particularly cost-intensive for capital maintenance. Chemicals and reagents corrode equipment such as pumps, valves, etc., and parts need replacement more frequently compared to plants without FGD.[39]

Nearman represented 65 percent of capital spending for BPU between 2023–2027[40] (relative to Nearman representing 41% of generation).[41] On a per MW basis, Nearman will cost BPU and its ratepayers $127,000 per MW,[42] which is double the cost of the Quindaro Power Plant CT2 and CT3,[43] and six times the cost of the Dogwood Energy Facility.[44,45]

The capital costs to sustain Nearman Unit 1 are much higher than for other generators in BPU's portfolio. Furthermore, when considering future

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[38] National Renewable Energy Laboratory, "Annual Technology Baseline: 2022 Electricity ATB Technologies and Data Overview: Summary of Minimum and Maximum Values of CAPEX, Capacity Factor, O&M and LCOE," 2022, *available at:* https://atb.nrel.gov/electricity/2022/index.

[39] U.S. EIA, Generating Unit Annual Capital and Life Extension Costs Analysis (December 2019), *available at*: https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf.

[40] Direct testimony of BPU witness Glen Brendel, pg. 2-4.

[41] Annual average for 2019-2022. Values from BPU response to Sierra Club data request 1-22c.

[42] I scaled Nearman Common capital expenses to Nearman Unit 1, proportionally based on relative capacities of Unit 1 and CT4.

[43] Quindaro Power Plant CT2 and CT3 are peaking oil-fired units.

[44] Costs and MWs scaled to BPU's 17 percent share in Dogwood Energy Facility. Dogwood is a gas-fired combined cycle facility.

[45] Capital expenditure data from direct testimony of BPU witness Glen Brendel, pg. 2-4.

environmental regulation for coal generators, costly capital upgrades are a near certainty that will further drive-up spending.

v. ***<u>To avoid unnecessary costs for ratepayers, BPU should commit to retiring Nearman in the near term</u>***

Q What do your findings suggest about continuing to operate and expend capital for Nearman Unit 1?

A My analysis shows that Nearman has been operating at a loss in recent years and is expected to do so continuously going forward. In addition, the O&M costs to keep Nearman running are markedly high compared to the industry average. To avoid locking in spending on fuel, O&M, and capital expenditures for the long term, and continuing to harm ratepayers by operating at a loss, BPU must consider an earlier retirement date. This date should be well before the current date of 2040.

Q Are you suggesting a specific retirement date for Nearman?

A Based on my findings that Nearman is expected to continue operating at a loss, I recommend that BPU commit to an earlier retirement date for Nearman and take the plant offline as soon as possible. However, I do not suggest a specific retirement date. Instead, BPU must conduct a robust study to determine a Nearman retirement date that is in the best interest of ratepayers.

Specifically, BPU must conduct detailed technical analyses using electricity production-cost and capacity expansion models. These types of analyses are considered best practice in the industry. If done properly, the analyses identify the most economic retirement date for Nearman and the least-cost set of replacement options. As a public utility, Nearman's top priority should be providing reliable energy to ratepayers while minimizing costs and risks.

Q Should BPU wait to retire Nearman until more of its balance depreciates?

A No. Nearman's undepreciated balance is already a sunk cost (ratepayers will pay for it regardless). Continuing to operate Nearman at a loss will only add to Nearman's debt. However, retiring Nearman will save money for ratepayers by not adding to the existing capital balance, and by no longer operating the plant at a loss. Plus, if the BPU replaces the plant with resources that have high energy margins (such as with wind and solar resources, which have minimal variable costs), BPU can pay off that balance ahead of schedule.

5. <u>THERE ARE MOUNTING RISKS AND COSTS ASSOCIATED WITH OPERATING NEARMAN THAT CAN BE AVOIDED WITH AN EARLY RETIREMENT</u>

Q Are there avoidable costs and risks associated with continuing to operate Nearman as a generating asset?

A Yes. There are numerous risks and costs for BPU ratepayers, who receive over 40 percent of their energy from a single coal plant with negative going-forward value. Many of these can be mitigated with early retirement. They include (1) issues with coal supply and delivery, (2) coal supply contract risks, (3) fuel price volatility, (4) reliability risks posed by extreme weather, (5) future environmental compliance costs, (6) operational costs associated with running an aging fossil fuel resource, and (7) forced outage risks associated with operating an aging plant.

Q Please describe the risks posed by coal delivery, supply, and transportation issues that would be mitigated with an earlier Nearman retirement.

A BPU has experienced issues with coal supply and delivery over the last few years. Specifically, from mid-April to the end of June 2022, BPU's coal supplier was not able to deliver the contracted amount of coal as a result of coal car maintenance delays and Union Pacific labor disputes.[46] During this period, coal deliveries fell from 45–60 kilotons per month down to 27 kilotons, resulting in a derate (reduction in available capacity) for Nearman that burdened ratepayers with $960,000 in replacement power costs.[47]

Coal supply and delivery issues are not limited to BPU; they are occurring across the country. For instance, the coal supplier for the San Juan Power Station in New Mexico was unable to supply the contracted amount of coal to that plant in 2022, resulting in a derate.[48] In Arizona, labor shortages in 2022 prevented Burlington Northern Santa Fe Railroad from delivering all the coal it was contracted to provide to Tucson Electric Power Company in 2022.[49] More generally in 2022, rail labor shortages—with employment down 20.4 percent since January 2019—inhibited the movement of coal throughout the country and contributed to soaring prices.[50] Similarly, the potential but avoided rail strike in the fall of 2022 was a major threat to the coal industry. In fact, the coal industry is largely dependent on railways, further exposing vulnerabilities of the coal supply chain.[51]

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[46] BPU response to Sierra Club data requests 1-15(a) and 1-15(b).

[47] BPU response to Sierra Club data request 1-15(c), 1-15(d), and 1-15(e).

[48] Direct Testimony of Devi Glick, pg. 32. Docket No. E-01933A-22-0107. Arizona Corporation Commission (January 11, 2023).

[49] Ibid.

[50] Kuykendall, T., "Rail service 'meltdown' constraining US coal sector in hot market," S&P Global Market Intelligence (May 9, 2022). *Available at* https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/rail-service-meltdown-constraining-us-coal-sector-in-hot-market-70189190#:~:text=During%20an%20April%20conference%20hosted,the%20second%20half%20of%202021.

[51] Bittle, J., "Railroad strike threatens power in coal-dependent states," Grist, (September 14, 2022), *available at* https://grist.org/energy/railroad-strike-coal-power-shortage/.

BPU's continued operation of the Nearman coal plant exposes ratepayers to the risk of fuel supply constraints as a result of these kinds of transportation and delivery issues, which could translate to high costs for replacement energy—potentially for a lengthy period of time.

Q Please describe the risks posed by coal supply contracts.

A Currently, BPU purchases coal through the Western Fuels Association ("WFA"), which in turn contracts with coal producers and railroads.[52] WFA's current coal supply contract extends to 2024, and its coal transportation contract is set to expire at the end 2025. As part of these contracts, BPU must pay a penalty of $5 per ton if it is unable to accept coal shipments. This penalty poses a major risk to BPU and its ratepayers and presents BPU with only lose-lose options. On one hand, BPU can pay exorbitant penalties if it cannot accept the coal. On the other hand, BPU can self-commit Nearman so it can burn coal unnecessarily to make room for more fuel. If LMPs are below Nearman's marginal costs during this self-commitment, BPU will not recoup Nearman's marginal costs, thereby burdening ratepayers.

Additionally, to avoid paying must-take penalties, BPU staff indicated that they attempt to sell unwanted coal shipments to other utilities.[53] Given the issues with coal transportation that I outlined above, this strategy is in itself risky. Further, with more coal retirements planned for this decade, the number of willing off-takers is only expected to decline.

During BPU's next contract renewal with WFA or other coal suppliers or brokers, the Board of Directors should ensure that future coal contracts minimize risks for

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[52] BPU response to Sierra Club data request 3-4.

[53] Kansas City Board of Public Utilities BPU. March 1, 2023 – Regular Session, at 1:32. *Available at*: https://www.youtube.com/watch?v=Nz6uXy0NW3E.

ratepayers. In particular, BPU should avoid long-term contracts to prevent contractual issues if Nearman retires early. This is especially important considering Nearman's age and the risk of future environmental regulation, discussed below. To avoid unnecessary fuel consumption, must-take clauses should not be considered.

Q **Please describe the avoided fuel costs associated with an earlier Nearman retirement.**

A With such a significant portion of BPU's energy coming from coal, ratepayers have high exposure to fuel price volatility. Coal, natural gas, and oil prices are determined in large part by global markets and are influenced by numerous factors including rail and pipeline access, natural gas reserves in Europe, volume of exports and imports, extreme weather, etc. When fuel prices are high, ratepayers are on the hook to pay for high-cost electricity.

If BPU retires Nearman early and adds more solar and wind resources to its portfolio, ratepayers will have a buffer from potential coal price volatility. If BPU continues to operate Nearman to generate a substantial share of its energy, its ratepayers will bear the full burden of high and volatile fuel prices. One alternative to address volatility—entering into long-term coal contracts—presents long-term risks that likely outweigh the hedge benefit.

Q **Please describe the risks posed by extreme weather that will be mitigated with an earlier Nearman retirement.**

A Nearman may not be adequately designed for extreme weather such as winter storms and prolonged cold weather snaps. During these types of events, Nearman can suffer from equipment failures, resulting in derates or even complete shutdowns. LMPs can be very high during extreme weather events, as multiple generators fail and demand peaks. When this occurs, BPU and its ratepayers are forced to pay for very expensive replacement energy; or worse, reliability suffers.

For instance, Nearman experienced a derate during Winter Storm Elliot in December 2022. After equipment froze, Nearman was limited to 150 MW from 6:30pm on December 22 to 9pm on December 24.[54] During this period, BPU purchased replacement power from the energy market, where LMPs averaged over $230/MWh, with one hour reaching as high as $1,391/MWh.[55] In total, replacement power during the derate event cost ratepayers an estimated $900,000.[56]

Q Please describe the risks and costs from environmental regulation that can be avoided with an earlier Nearman retirement.

A Based on current trends, most experts in the industry agree that there is a potential for greater regulation for coal-fired power plants going forward. Though nobody can predict exactly what future regulations will be, such regulation would most likely increase the cost to operate coal-fired power plants. Relative to other energy resource types, coal-fired power plants have numerous environmental compliance costs and regulatory risks. These include (1) carbon emissions, (2) air emissions (e.g., particulate matter), (3) water emissions (e.g., wastewater), (4) by-products and waste (e.g., coal ash), and (5) plant inputs (e.g., coal mining). Even if Nearman is fully compliant with all finalized environmental regulations now,

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[54] BPU responses to Sierra Club data request 1-17(c).

[55] BPU responses to Sierra Club data request 1-17(f).

[56] BPU responses to Sierra Club data request 1-17. I assumed Nearman would have been operating at 230 MW through the period of December 22-24, 2021.

the risk of future regulation touching on at least one, or even more than one, of these inputs and outputs is likely.

As an example, on May 11, 2023, the U.S. Environmental Protection Agency ("EPA") announced a proposed Clean Air Act rule limiting carbon dioxide ("CO_2") emissions from fossil fuel-fired power plants.[57] Specifically, the newly proposed Clean Air Act rule would require BPU to either commit to retiring Nearman by 2032, reduce its utilization factor to 20 percent and commit to retiring Nearman by 2035, or install expensive technology such as carbon capture and storage technology ("CCS") or equipment to enable natural gas co-firing.[58] Although not yet finalized, this rule is an example of the risk of environmental regulation.

Additionally, BPU only looks at capital costs five years into the future. The costs from environmental regulations go well beyond 2027. To make prudent economic decisions about Nearman and the rest of BPU's resource portfolio, BPU should consider capital expenditures, including potential environmental costs, beyond 2027. As part of BPU's next IRP, the Board of Directors should require BPU staff to consider long-term costs beyond 2027 that include potential environmental compliance costs.

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[57] U.S. Environmental Protection Agency. Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants, Docket No. EPA-HQ-OAR-2023-0072. *Available at:* https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power.

[58] U.S. Environmental Protection Agency. Fact Sheet: Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants Proposed Rule. *Available at:* https://www.epa.gov/system/files/documents/2023-05/FS-OVERVIEW-GHG-for%20Power%20Plants%20FINAL%20CLEAN.pdf.

Q Please describe the avoided O&M and sustaining capital costs associated with an earlier Nearman retirement.

A On a per MW basis, Nearman is expensive to own and operate, relative to other BPU resources and industry averages (as discussed in Section 4(iv), above). These are costs that are passed on to ratepayers. Protecting ratepayers from unnecessary costs is especially important given Nearman's age. Total spending on sustaining capital expenses is likely to increase with the need for additional refurbishment of aging equipment, replacement of older parts, etc.

For wind and solar, O&M and sustaining capital costs are relatively low.[59] If Nearman is replaced with more renewable resources, BPU's O&M spending should decline. This in turn will lower revenue requirements and reduce costs passed on to ratepayers.

Q Please describe the forced outage risks associated with operating a 41-year-old plant that will be mitigated with an earlier Nearman retirement.

A The risk of forced outages is also a concern, especially given that Nearman is over 40 years old. As generators age, the likelihood and frequency of forced outages increases. For instance, CenterPoint Indiana South's Culley Unit 3 in Indiana was shut down unexpectedly for nearly six months due to a turbine failure. Not only did this put reliability at risk, but it also led to a rate hike for CenterPoint customers to cover the cost of replacement energy.[60] Similarly, as Nearman

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[59] National Renewable Energy Laboratory, "Annual Technology Baseline: 2022 Electricity ATB Technologies and Data Overview: Summary of Minimum and Maximum Values of CAPEX, Capacity Factor, O&M and LCOE," 2022, *available at:* https://atb.nrel.gov/electricity/2022/index.

[60] Schneider, K., "CenterPoint Energy request 3-month rate hike for 2023 following coal plant failure," Indianapolis Star, (November 25, 2022), *available at:* https://www.indystar.com/story/news/2022/11/25/centerpoint-files-for-rate-hike-following-coal-plant-malfunction/69670232007/.

continues to age, total spending on replacement parts and maintenance will continue to grow, increasing costs to BPU and its ratepayers and increasing the likelihood of more forced outages.

Q What do you conclude about the risks posed by continuing to operate Nearman and producing a large portion of energy from coal generation?

A As of 2022, BPU generates more than 40 percent of its energy from coal. Given the risks of derates, outages, escalating costs, and reliability issues associated with coal generation that are summarized above, BPU should commit to retiring Nearman early and start replacing its energy and capacity with lower-risk and lower-cost resources. In other words, maintaining the status quo is no longer the lowest-risk option.

6. BPU SHOULD START BUILDING OR PROCURING REPLACEMENT RESOURCES FOR NEARMAN SOONER RATHER THAN LATER, AND TAKE ADVANTAGE OF THE TAX BENEFITS OFFERED THROUGH THE *INFLATION REDUCTION ACT*

Q What alternatives has BPU considered for future energy supply?

A BPU has not indicated that it is planning for Nearman's retirement or considering replacement resources or PPAs. Its most recent IRP from 2019 says nothing specifically about future energy supply. BPU conducted a study in 2014 to evaluate the feasibility of converting Nearman to a gas-fired unit.[61]

As part of its next IRP, the Board of Directors should request that BPU staff conduct a full analysis to determine Nearman's most economic retirement date and the least-cost set of replacement resources. Specially, BPU should consider

[61] Kansas City Board of Public Utilities. Nearman Creek Station. Natural Gas Firing Feasibility Study. June 26, 2014. BPU response to Sierra Club data request 3-3.

building out or procuring from the marketplace renewables and other low-cost resources that minimize the risks and costs I summarize above.

Q Should BPU wait before starting to procure or build replacement resources?

A No, BPU should begin building or procuring replacement resources for Nearman as soon as possible after completing the robust analysis I am recommending.

As I have shown in my analysis, Nearman is expected to operate at a loss every year going forward; it appears to be becoming too uneconomic to justify further investment and operations. Additionally, as I discussed, the electricity market is changing, and Nearman will likely be outcompeted over time and with greater frequency by renewables. The plant is also aging and exposed to risks that include extreme weather and fuel supply constraints. Nearman may be placed on reserve shutdown more frequently, experience more forced outages and derates, or be forced to retire early. Preparing now to avoid expensive replacement energy purchases in the future will benefit ratepayers.

Furthermore, the build-out or procurement of new resources can take years. There are multiple implementation barriers, including interconnection queue backlogs. Starting early improves BPU's preparedness for Nearman's retirement.

Lastly, there are numerous tax benefits available that BPU should act on now. The IRA increased the tax credits available for solar and wind and introduced new tax credits for batteries. However, many of these incentives could expire within the next 10 years; acting now ensures that BPU and its customers can still benefit.

Q Please describe the IRA tax benefits for solar, wind, and batteries in more detail.

Through the IRA, utility-scale wind and solar are now both eligible for a 30 percent investment tax credit ("ITC"), which increases to 40 percent if the facility is located in an 'energy community,' as defined in the IRA.[62] Stand-alone battery storage is also newly eligible for a 30 percent ITC. The IRA also increased production tax credits ("PTC"): it increased wind and solar PTCs to \$26/MWh (\$2022). When the ITC and PTC are applied to new renewable and battery storage projects, cost savings can be considerable. However, the new ITC and PTC options could be phased out by 2032.[63]

Q What are some other examples of IRA tax options available?

A Additional examples of tax options available through the IRA are summarized in Table 5. The table includes funding for refinancing undepreciated assets and reinvesting in renewables, which could be particularly advantageous for BPU considering Nearman's large undepreciated balance.

[62] Parts of Kansas City would qualify as an energy community. Energy communities include census tracts where a coal-fired electric generating unit has been retired since 2009, statistical areas with 0.17% or greater fossil fuel employment since 2010, or 25% or greater local tax revenues related to fossil fuel extraction, processing, or transport.

[63] The later of 2032 or the first year that greenhouse gas emissions from U.S. electricity production are less than or equal to 25 percent of 2022 levels. Congress.gov. "Text - H.R.5376 - 117th Congress (2021-2022): Inflation Reduction Act of 2022." August 16, 2022. *Available at:* https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

Table 5. Examples of tax benefits available through the *Inflation Reduction Act*

Funding for refinancing undepreciated assets and reinvesting in renewables	
Sec. 50141. Funding for DOE Loan Programs Office	Loans to retool, repower, repurpose, or replace energy infrastructure that has retired or to improve efficiency and reliability of existing resources ($40 billion of authority through FY2026)
Sec. 50144. Energy Infrastructure Reinvestment Financing	Loans to retool, repower, repurpose, or replace energy infrastructure no longer in operation or enable operating energy infrastructure to avoid greenhouse gas emissions ($5 billion to guarantee up to $250 billion in loans through FY2026)
Sec. 60103. Greenhouse Gas Reduction Fund	Financial assistance for projects that reduce greenhouse gas emissions or deploy zero-emission technology ($27 billion available through FY2024)
Transmission development	
Sec. 50151. Transmission facility financing	Loans supporting the construction and modification of national interest electric transmission facilities ($2 billion through FY 2030)
Sec 50152. Grants to Facilitate the Siting of Interstate Electricity Transmission Lines	Grants to study impacts of transmission projects, hosting negotiations, participating in regulatory proceedings and economic development for communities affected by construction and operation ($760 million)

Source: Congress.gov. "Text - H.R.5376 - 117th Congress (2021-2022): Inflation Reduction Act of 2022." August 16, 2022. Available at: https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

BPU can access some of these tax benefits to enable the early retirement of Nearman and adoption of lower cost, lower risk resources to the ultimate benefit of ratepayers and Kansas City, Kansas community members.

Q Does this conclude your testimony?

A Yes.

From: Dorothy McField (dorothymcfield4401@gmail.com) Sent You a Personal Message <kwautomail@phone2action.com>
Sent: Friday, October 25, 2024 8:12 PM
To: IRP
Subject: Kansans need a long-term energy plan that reduces bills by investing in clean energy.

Dear Kansas City Board of Public Utilities (BPU),

I personally hope that all the persons making the decisions will do the right thing and make the necesary changes which will reflect the public's desire for clean, efficient energy at reasonable cost. A consideration the upper paid employees might consider is taking a 1 to 2 % pay cut and adding the money for funds to reduce costs for tax payers..

To Whom it May Concern:

As a resident of Kansas, the recent actions of the Unified Government (UG) concern me. BPU's elected board has made clear that the UG has no right to increase fees on our bills in one of the most energy burdened communities in the country. The UG can't be allowed to hold our water and power hostage unless fixed income customers pay tens of millions of dollars in taxes.

This elected BPU board has fought for its customers, demanding the fees be taken off BPU bills. I ask the board to step up efforts to educate the public on the UG's political actions, hire a new General Manager that will lower the energy burden in Wyandotte County by replacing BPU's expensive coal plant with cheap clean energy, and push staff to facilitate sign-ups for energy efficiency and other federal and state assistance programs for all low income BPU customers.

The Integrated Resource Plan (IRP) should be an opportunity for the board and staff to proactively engage the community, especially low income customers, to create long term improvement plans for generation and demand side management of BPU resources. Customers should be able to bring all concerns forward during an IRP public hearing so that the Board and staff can address all customer concerns within the longer term BPU clean energy transition.

As a BPU customer, I ask that the BPU add the following goals in their long term plan (IRP) by 2025:
-Reduce Utility Burden in Wyandotte County in the short term by reducing BPU costs and continuing to fight for removal of flat fees such that no customers pay more than 8 percent of their annual income for BPU bills.
-Reduce regulatory risk, customer costs and pollution by closing the Nearman coal plant and replacing it with clean energy (solar, demand side and storage) by 2030.
-Reduce low income customer customer bills, improve health, and increase BPU revenue by facilitating investments by landlords and homeowners in home and multifamily energy efficiency and demand flexibility programs.

Thank you.

Sincerely,

Dorothy McField
3058 Parkwood Blvd
Kansas City, KS 66104
dorothymcfield4401@gmail.com
(913) 342-6760

From:	Emily Ho (coolcat3.14@gmail.com) Sent You a Personal Message <kwautomail@phone2action.com>
Sent:	Friday, October 25, 2024 6:59 PM
To:	IRP
Subject:	Kansans need a long-term energy plan that reduces bills by investing in clean energy.

Dear Kansas City Board of Public Utilities (BPU),

To Whom it May Concern:

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-Reduce low income customer customer bills, improve health, and increase BPU revenue by facilitating investments by landlords and homeowners in home and multifamily energy efficiency and demand flexibility programs.

Thank you.

Sincerely,

Emily Ho
3219 N 110th St
Kansas City, KS 66109
coolcat3.14@gmail.com
(913) 749-6113

From:	Joan Nickum (dogcopilot@fastmail.com) Sent You a Personal Message <kwautomail@phone2action.com>
Sent:	Thursday, October 24, 2024 5:01 PM
To:	IRP
Subject:	Kansans need a long-term energy plan that reduces bills by investing in clean energy.

Dear Kansas City Board of Public Utilities (BPU),

Taxes are killing homeowners and making home ownership even more out of reach for many. But reducing taxes alone won't matter if we don't start taking steps to save our planet. You have an important responsibility here.

To Whom it May Concern:

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-Reduce low income customer customer bills, improve health, and increase BPU revenue by facilitating investments by landlords and homeowners in home and multifamily energy efficiency and demand flexibility programs.

Thank you.

Sincerely,

Joan Nickum
1838 Freeman Ave
Kansas City, KS 66102
dogcopilot@fastmail.com
(913) 909-6496

From: Carol Carley (cac744@aol.com) Sent You a Personal Message <kwautomail@phone2action.com>
Sent: Thursday, October 24, 2024 4:23 PM
To: IRP
Subject: Kansans need a long-term energy plan that reduces bills by investing in clean energy.

Dear Kansas City Board of Public Utilities (BPU),

It is very hard to live without energy then it becomes almost impossible to live when you can't pay to keep it on without help, so BPU must take the fees off for those folks so they can have some dignity!

To Whom it May Concern:

As a resident of Kansas, the recent actions of the Unified Government (UG) concern me. BPU's elected board has made clear that the UG has no right to increase fees on our bills in one of the most energy burdened communities in the country. The UG can't be allowed to hold our water and power hostage unless fixed income customers pay tens of millions of dollars in taxes.

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Thank you.

Sincerely,

Carol Carley
1831 N. 19th St.
Kansas City, KS 66104
cac744@aol.com
(913) 342-8748

From: Christmas Burns (christmasb30@yahoo.com) Sent You a Personal Message <kwautomail@phone2action.com>
Sent: Thursday, October 17, 2024 8:05 AM
To: IRP
Subject: Kansans need a long-term energy plan that reduces bills by investing in clean energy.

Dear Kansas City Board of Public Utilities (BPU),

I'm really surprised to find out out the pilot is going anywhere. Also. If it was known that it would not discontinue in October why wasn't he notified. The BPU could have sent out a notice with our bill.

To Whom it May Concern:

As a resident of Kansas, the recent actions of the Unified Government (UG) concern me. BPU's elected board has made clear that the UG has no right to increase fees on our bills in one of the most energy burdened communities in the country. The UG can't be allowed to hold our water and power hostage unless fixed income customers pay tens of millions of dollars in taxes.

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Thank you.

Sincerely,

Christmas Burns
1715 S 31st. Apt A
Kansas city, KS 66106
christmasb30@yahoo.com
(913) 645-0432

From: Brook Anthony WILLIAMS (brook2be@yahoo.com) Sent You a Personal Message <kwautomail@phone2action.com>
Sent: Wednesday, October 16, 2024 6:37 PM
To: IRP
Subject: Kansans need a long-term energy plan that reduces bills by investing in clean energy.

Dear Kansas City Board of Public Utilities (BPU),

The reason why people who have researched this even a little bit can understand the difference between oil cold natural gas and a renewable energy like solar power

All of the former mentioned need to be renewed daily I have to put more coal in my fireplace daily I have to renew and put more oil kerosene gasoline natural gas in my furnace or for cooking DAILY......
WE DO NOT HAVE TO DO THAT FOR SOLAR EVEN IF THERE ARE SOME DRAWBACKS OF SOLAR FOR INSTANCE THERE IS SOME BYPRODUCT POLLUTION WHILE MAKING THE SOLAR PANEL.... BUT ONCE THE SOLAR PANEL IS BUILT AND MADE AND PUT ON THE HOUSE YOU DO NOT HAVE TO RENEW THE SOLAR PANEL EVERYDAY OR EVERY MONTH OR EVEN EVERY YEAR IF ANYTHING CLEAN IT OFF ONCE A YEAR... AND THE ENERGY IS THE SUN SO A BIG PUSH FOR SOLAR PANELS WOULD BE GREAT..... AND ONE SOLUTION IS BUILDING A SOLAR TOWER NOT A SOLAR FARM.
THERE IS A DIFFERENCE IN THE TWO..
SO LET'S DO SOLAR TOWERS SO WE DON'T NEED TO USE SOLAR PANELS FOR EACH HOUSE SOLAR TOWER GIVES ENERGY TO ALL

To Whom it May Concern:

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Thank you.

Sincerely,

Brook Anthony WILLIAMS
1040 Orville Avenue, Apt #103
Kansas City, KS 66102
brook2be@yahoo.com
(913) 284-2841

From: Kimberly Weaver (kimaweaver76@gmail.com) Sent You a Personal Message <kwautomail@phone2action.com>
Sent: Wednesday, October 16, 2024 4:44 PM
To: IRP
Subject: Kansans need a long-term energy plan that reduces bills by investing in clean energy.

Dear Kansas City Board of Public Utilities (BPU),

Literally today, I received a phone call from someone asking for a source that could help people with utility assistance. Wyandotte county residents deserve relief. We deserve a publicly owned utility company that works for and with the people. We deserve a company that priorities renewable, clean resources.

To Whom it May Concern:

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Thank you.

Sincerely,

Kimberly Weaver
5216 Rowland Avenue
Kansas City, KS 66104
kimaweaver76@gmail.com
(913) 735-7543

From: Barbara Ikerd (b2baybee@yahoo.com) Sent You a Personal Message <kwautomail@phone2action.com>
Sent: Wednesday, October 16, 2024 12:15 PM
To: IRP
Subject: Kansans need a long-term energy plan that reduces bills by investing in clean energy.

Dear Kansas City Board of Public Utilities (BPU),

I have received a charge for storm water (one item bill) and I see a storm water charge on my regular BPU bill ... what's up with that?

To Whom it May Concern:

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-Reduce low income customer customer bills, improve health, and increase BPU revenue by facilitating investments by landlords and homeowners in home and multifamily energy efficiency and demand flexibility programs.

Thank you.

Sincerely,

Barbara Ikerd
2738 N 88th Terrace
Kansas City, KS 66109
b2baybee@yahoo.com
(913) 522-2512

From:	Robert Ewing (roewing2617@aol.com) Sent You a Personal Message <kwautomail@phone2action.com>
Sent:	Wednesday, October 16, 2024 10:53 AM
To:	IRP
Subject:	Kansans need a long-term energy plan that reduces bills by investing in clean energy.

Dear Kansas City Board of Public Utilities (BPU),

To Whom it May Concern:

As a resident of Kansas, the recent actions of the Unified Government (UG) concern me. BPU's elected board has made clear that the UG has no right to increase fees on our bills in one of the most energy burdened communities in the country. The UG can't be allowed to hold our water and power hostage unless fixed income customers pay tens of millions of dollars in taxes.

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Thank you.

Sincerely,

Robert Ewing
2617 N. 45th Ter.
Kansas City, KS 66104
roewing2617@aol.com
(913) 515-3053

From: Randal Werdel (rjwerdel@gmail.com) Sent You a Personal Message <kwautomail@phone2action.com>
Sent: Wednesday, October 16, 2024 10:44 AM
To: IRP
Subject: Kansans need a long-term energy plan that reduces bills by investing in clean energy.

Dear Kansas City Board of Public Utilities (BPU),

Even if I invest in energy efficiency, my bill is still too high because most of it is from flat fees.

To Whom it May Concern:

As a resident of Kansas, the recent actions of the Unified Government (UG) concern me. BPU's elected board has made clear that the UG has no right to increase fees on our bills in one of the most energy burdened communities in the country. The UG can't be allowed to hold our water and power hostage unless fixed income customers pay tens of millions of dollars in taxes.

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Thank you.

Sincerely,

Randal Werdel
7126 Parallel Parkway
Kansas city, KS 66112
rjwerdel@gmail.com
(727) 509-2178

From: Daniarely Loma Jasso (daniarelylomajasso@gmail.com) Sent You a Personal Message <kwautomail@phone2action.com>
Sent: Wednesday, October 16, 2024 10:41 AM
To: IRP
Subject: Kansans need a long-term energy plan that reduces bills by investing in clean energy.

Dear Kansas City Board of Public Utilities (BPU),

Half of my bill shouldn't come from flat fees. It's a shame that UG would allow this to continue happening.

To Whom it May Concern:

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Thank you.

Sincerely,

Daniarely Loma Jasso
7126 Parallel Parkway
Kansas city, KS 66112
daniarelylomajasso@gmail.com
(727) 509-2178

From: Ana Pacheco (apach1400@gmail.com) Sent You a Personal Message <kwautomail@phone2action.com>
Sent: Monday, October 14, 2024 1:01 PM
To: IRP
Subject: Kansans need a long-term energy plan that reduces bills by investing in clean energy.

Dear Kansas City Board of Public Utilities (BPU),

I am a low income working adult and live paycheck to paycheck. Increasing fees on an already difficult to keep up with energy and water bill will only burden me and my family further, having to either sacrifice food or other necessities to make up for it. You have to think of us who are financially strained and how you are furthering making our lives difficult. You're digging the hole deeper when we're already so deep underground.

To Whom it May Concern:

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Thank you.

Sincerely,

Ana Pacheco
522 Elizabeth Ave
Kansas City, KS 66101
apach1400@gmail.com
(816) 726-5622

From: F J (feltonja@hotmail.com) Sent You a Personal Message <kwautomail@phone2action.com>
Sent: Saturday, October 12, 2024 12:00 PM
To: IRP
Subject: Kansans need a long-term energy plan that reduces bills by investing in clean energy.

Dear Kansas City Board of Public Utilities (BPU),

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Thank you.

Sincerely,

F J
13119 Delaware Ct
Kansas City, KS 66109
feltonja@hotmail.com
(816) 699-3791

From: Christian Johnson (christiancaj13johnson@gmail.com) Sent You a Personal Message <kwautomail@phone2action.com>
Sent: Friday, October 11, 2024 4:11 PM
To: IRP
Subject: Kansans need a long-term energy plan that reduces bills by investing in clean energy.

Dear Kansas City Board of Public Utilities (BPU),

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Thank you.

Sincerely,

Christian Johnson
805 N 6th St Apt 1
Kansas City, KS 66101
christiancaj13johnson@gmail.com
(913) 283-2333

From: Marisa Martinez (mariska2013@live.com) Sent You a Personal Message <kwautomail@phone2action.com>
Sent: Friday, October 11, 2024 3:43 PM
To: IRP
Subject: Kansans need a long-term energy plan that reduces bills by investing in clean energy.

Dear Kansas City Board of Public Utilities (BPU),

I have lived in this community my entire life. It is my hope that a long term energy plan would be implemented and benefit those of the community.

To Whom it May Concern:

As a resident of Kansas, the recent actions of the Unified Government (UG) concern me. BPU's elected board has made clear that the UG has no right to increase fees on our bills in one of the most energy burdened communities in the country. The UG can't be allowed to hold our water and power hostage unless fixed income customers pay tens of millions of dollars in taxes.

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Thank you.

Sincerely,

Marisa Martinez
2715 S 46th St
Kansas City, KS 66106
mariska2013@live.com
(913) 602-4316

From: Carol Carley (cac744@aol.com) Sent You a Personal Message <kwautomail@phone2action.com>
Sent: Friday, October 11, 2024 3:40 PM
To: IRP
Subject: Kansans need a long-term energy plan that reduces bills by investing in clean energy.

Dear Kansas City Board of Public Utilities (BPU),

Please continue working on getting more solar and wind into our energy investment instead investing in fossil fuels which harms our planet!

To Whom it May Concern:

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Thank you.

Sincerely,

Carol Carley
1831 N 19th St
Kansas City, KS 66104
cac744@aol.com
(913) 342-8748

From: Sylvia Williams (1brook1g@gmail.com) Sent You a Personal Message <kwautomail@phone2action.com>
Sent: Friday, October 11, 2024 2:22 PM
To: IRP
Subject: Kansans need a long-term energy plan that reduces bills by investing in clean energy.

Dear Kansas City Board of Public Utilities (BPU),

Hello I'm in the 66102 ZIP code . My name is Sylvia Williams, We as a community absolutely need clean water and a cleaner source of energy for me it's solar I've learned recently even solar panels can have some harmful side effects because of the materials that is made of.... I think even then it's sustainable cuz we only have to make them once as opposed to coal and oil once you use it it's still polluting the air and water... So please try your best to continue to give us clean water and a cleaner way of giving customers which are people and people are human beings. And we live on the planet Earth and we want the earth to live forever. And for the board members specifically please do not give yourself a raise just cuz you had record profits reinvest in the community add more parks give price cuts to the customers not charges for fees that are not necessary.
That's all I have to say I'm an 85-year-old woman and I have seen a lot and I would like to continue to see a lot ... thank you

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Thank you.

Sincerely,

Sylvia Williams
1040 Orville Ave Apt 107
Kansas City, KS 66102
1brook1g@gmail.com
(913) 284-2841

This message was sent by KnowWho, as a service provider, on behalf of an individual associated with Sierra Club. If you need more information, please contact Member Care at Sierra Club at member.care@sierraclub.org or (415) 977-5673.

From: G. Dale Mathey (g.dalemathey@gmail.com) Sent You a Personal Message <kwautomail@phone2action.com>
Sent: Friday, October 11, 2024 1:55 PM
To: IRP
Subject: Kansans need a long-term energy plan that reduces bills by investing in clean energy.

Dear Kansas City Board of Public Utilities (BPU),

We are overdue in utilizing clean energy. Global warming is real. Regressive taxing is wrong. Please take care of thr PILOT controversy. All of this should not be partisan.

To Whom it May Concern:

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Thank you.

Sincerely,

G. Dale Mathey
109 S Tremont St
Kansas City, KS 66101
g.dalemathey@gmail.com
(913) 321-8979

From: Kerry Gooch <kerry@goochstrategies.com>
Sent: Friday, October 11, 2024 4:45 PM
To: IRP; Thomas Groneman
Cc: Norine Spears
Subject: Kansas For An Affordable Future - IRP Memo
Attachments: RMI_BPU_IRP_Review_Memo.pdf

Dear President Groneman,

My name is Kerry Gooch, and I represent Kansans for an Affordable Future (KAF). I am excited to bring forth an IRP analysis that we have prepared to the Board of Public Utilities during your meeting on October 16th. The presentation will take approximately 15 minutes and we are happy to stay for questions. If the agenda for October 16 does not allow for our full presentation we are happy to schedule it at a later date when the BPU meets.

Sincerely,

Kerry Gooch

Review of the Board of Public Utilities' 2024 Integrated Resource Plan

Prepared for Kansas City Board of Public Utilities
October 16, 2024

RMI's Role

- RMI partnered with Sierra Club and Kansans for an Affordable Future to review Kansas City Bureau of Public Utilities' (BPU) 2024 Integrated Resources Plan (IRP)
- RMI's review is based on the Black & Veatch's full IRP as filed to the Board on August 30, 2024.
- This non-exhaustive review focuses on high-impact opportunities to perform best-practice resource planning.

RMI's Approach: Critical Topics

We focus on three critical topics for BPU's Integrated Resources Plan:

Key Topic	Summary of RMI's Approach
Overall Best Pratices	• Review BPU's IRP process in light of resource planning best practices
Demand-Side Resources	• Survey relevant IRA provisions that are shifting the economics of distributed energy resources • Evaluate how IRA provisions were integrated into load forecasts • We also review DER-related actions proposed in the 2024 IRP Update and provide additional recommendations to best take advantage of cost-effective DERs for the benefit of ratepayers.
Evaluating BPU's existing fleet	• Evaluate the economic position of Nearman 1, a key element of BPU's existing fleet • Explore options for managing costs associated with existing units

I. Integrated Resource Planning Best Practices

IRPs must maintain three core qualities to be effective tools for utilities and regulators to evaluate resource decisions

IRP quality	*Definition*
Trusted	The IRP is **transparent and well vetted**, with stakeholder input.
Comprehensive	The IRP can **accurately represent the costs, capabilities, system impacts, and values of resources** that might be available within the planning time horizon; the IRP can **consider actions across the transmission and distribution systems** as portfolio options.
Aligned	It is clear how the plan evaluates options to meet traditional planning requirements such as **reliability, affordability, and safety,** as well as **state and federal policies and customer or company priorities**, such as reducing emissions and advancing environmental justice.

Trusted IRPs are transparent and provide high-quality opportunities for input across stakeholder groups.

IRP quality	*Recommendations*
Trusted	• Take steps toward transparency for model and input data and documentation. • In partnership with local stakeholders, develop a stakeholder advisory or working group to provide key ongoing input on resource planning issues. • Conduct baseline economic optimization scenarios to set a transparent baseline for least-cost planning.

Trusted: The IRP should confirm economic optimization as a foundational method for developing portfolios

- The IRP isn't clear on the role that economic optimization takes in developing its scenarios and portfolios
  - As an example, the net-zero scenario shows significantly lower costs than the "baseline" portfolio.
- Economic optimization provides multiple benefits as a foundational planning method:

Cost-Effectiveness.

Economic optimization ensures that portfolios and decisions are as cost-effective as possible for ratepayers.

Transparency.

Economic optimization provides a replicable, clear process for assembling resource portfolios.

Analytical Rigor.

Economic optimization evaluates many permutations of portfolios and decisions and integrates insights across many datasets & objectives.

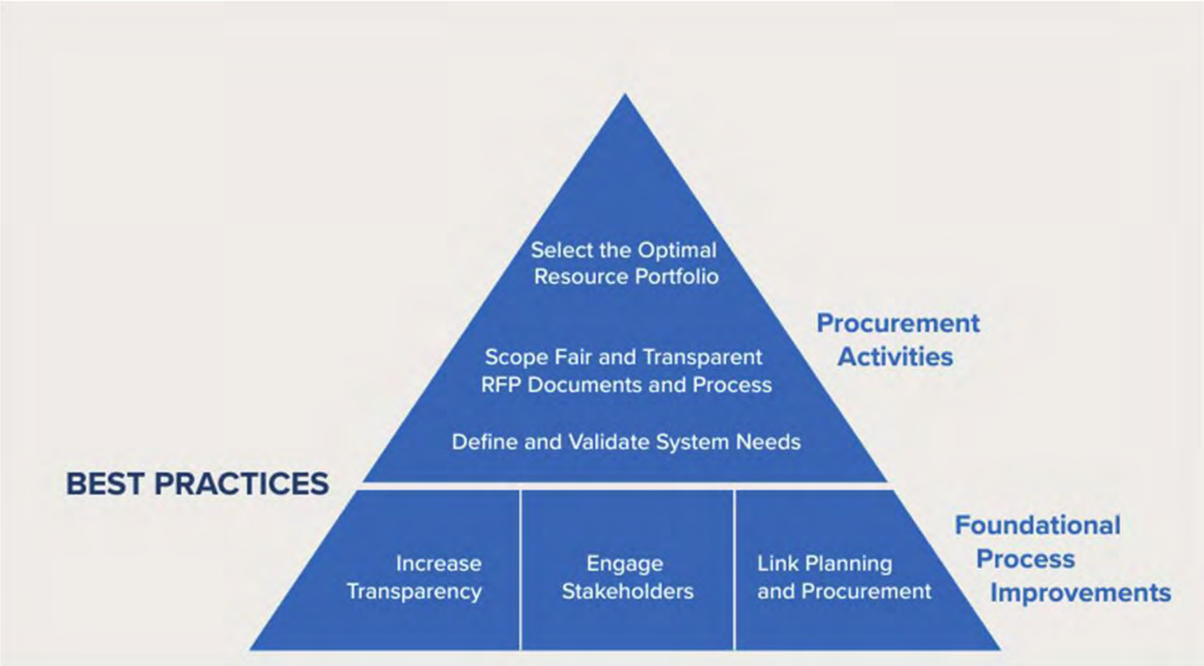
Comprehensive IRPs accurately represent capabilities, system impacts and resources that might be available within the planning time horizon

IRP quality	*Recommendations*
Comprehensive	• Expand consideration of available resources to include hybrid resources and clean repowering. • Develop an all-source request for proposals (RFP) that surfaces economic opportunities across a variety of resource technologies. • Take initial steps toward integrated distribution system planning into the IRP process.

Comprehensive: Developing a linked all-source RFP process

- All-source request for procurement (RFP) processes surface up-to-date prices and potential opportunities for BPU to procure resources
- When linked with resource planning processes, they can ensure that IRPs are evidence-based while providing a clear pathway to implementing IRP recommendations

Process Improvements for Next-Generation Procurement Principles



Aligned IRPs evaluate options in light of multiple priorities and objectives across stakeholders and jurisdictions

IRP quality	*Recommendation*
Aligned	• Update IRP inputs to integrate IRA policies. • Integrate regional, city, and stakeholder objectives into IRP stakeholder processes, inputs, and decision-making processes.

Aligned: BPU's IRP takes place within an overlapping landscape of objectives and priorities

Federal

Inflation Reduction Act

State & Regional

State policies; RTO policies; regional priorities

City & Stakeholders

City targets and objectives (e.g., air quality, econ development

BPU 2024 IRP

For more information, check out:

- RMI, **Reimagining Resource Planning** (2023)
- RMI, **How to Build Clean Energy Portfolios** (2020)

II. Demand-Side Resources

Evaluating Demand-Side Resources in BPU's IRP

- When integrated resource plans include demand-side resources into their resource plans, they can realize multiple co-benefits:

Energy Value

- Avoided operating costs, including air pollution, from BPU's existing fleet

Capacity Value

- Avoided costs and risks from market procurement of capacity
- Potentially, avoided capital and fixed O&M costs by retiring or avoiding new generation investments

Distribution-Level Value

- Avoided costs and investments on BPU's distribution system

Resilience Value

- Potential improvements to resilience during reliability evets

RMI's Review

- We provide recommendations across three elements of integrating demand-side resources into the BPU IRP:
  - Forecasting DERs
  - Expanding utility EE/DSM programs
  - Enabling and preparing for virtual power plants

Overview of IRA Provisions for Demand-Side Resources

IRA provisions support a variety of distributed energy resources…

- **Behind-the-meter generation and storage:**
  - Residential Clean Energy Credit
  - 48(e) tax credit for clean energy in low-income communities
  - Solar for All
- **Energy Efficiency & Demand-side Management:**
  - New efficient homes (45L)
  - Tax incentives for resi & commercial retrofits (25C & 179D)
  - Home electrification & efficiency rebates
  - Commercial efficiency rebates
- **Transport Electrification:**
  - Clean Vehicle tax credits (residential & commercial)
  - Tax credits for refueling infrastructure

…which have implications for resource planning.

- **Load Forecasting:**
  - Customer-led deployment of efficiency and electrification has offsetting impacts on load forecasts
- **Customer DER & EV Forecasts:**
  - DER and EV deployment has distribution-scale and bulk-scale impacts
- **Utility EE/DSM Program Forecasts:**
  - IRA reduces incremental costs, which reduces payback period and drives up adoption

See RMI Comments Attachment A: Summary of Key Inflation Reduction Act Provisions for Demand-Side Resources

Utility EE/DSM Programs

- Advancements in technology and policy support are opening pathways for innovative utility EE/DSM programs:

Utility	Fort Collins Utilities	Arizona Public Service
Program Name	Home Efficiency Loan & Epic Homes Program	CoolRewards
Customers Enrolled	Targeting 10,000	78,000
Description and Benefits	Finances accessible, clean energy projects, including solar and energy efficiency Leverages over $6 million of third-party capital	Smart thermostat programs that began in 2018 Program currently provides 278 MW of capacity to APS

- Utility EE/DSM programs could potentially ***avoid capacity market purchases altogether.***

Virtual Power Plants

- 500 virtual power plant programs provide up to 60 GW of capacity across the country.
- VPPs provide multiple potential services by linking together smart devices like solar, battery storage, and smart devices.
- BPU can prepare for VPP deployment by:
  - Working to provide value streams for distributed energy resources
  - Integrate demand-side resources into resource planning and operations

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Demand-Side Resources: Recommendations

Short- and long-term recommendations:

Short-Term

- **Update load and EE/DSM forecasts** to account for IRA provisions
- **Analyze potential for expanded utility EE/DSM programs** (e.g., thermostat DR, distributed storage)
- **Consider applications to time-limited federal financing programs** such as Energy Infrastructure Reinvestment (EIR)

Long-Term

- **Expand utility EE/DSM programs**
- **Prepare for VPPs** by encouraging DER adoption and supporting demand-side resources in utility planning and operations
- **Leverage innovative financing mechanisms** to lower costs of demand-side resource
  - On-bill financing for customers
  - Borrowing from city and state government
  - Collaborating with other public sector organizations eligible for preferential federal financing

III. Evaluating BPU's Existing Fleet

RMI's Review

- We focus our review on Nearman Creek Power Plant's Unit 1, which represents a significant amount of the energy and costs of BPU's existing portfolio.

- We focus on three major topics:
  - BPU's IRP as an opportunity to evaluate near-term options for the Nearman Creek unit, including economic retirement
  - Evaluating likely costs and capacity factors moving forward
  - Integrating air pollution costs into BPU's resource planning practice

Considerations for Economic Retirement Analysis

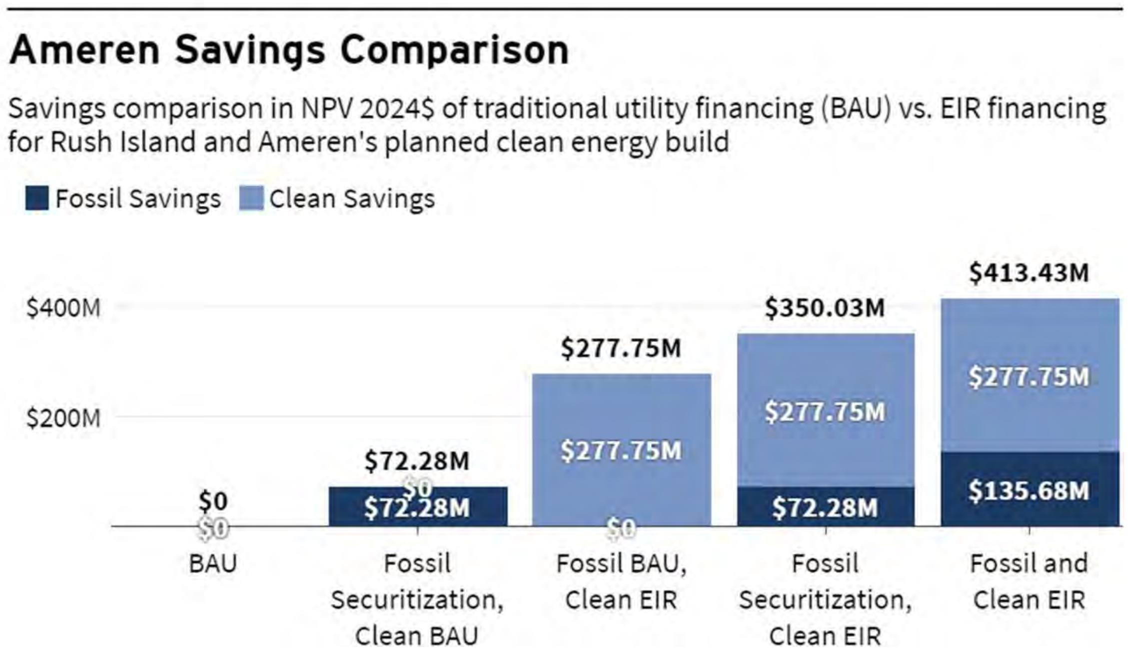
Option to Consider	Description	Potential Benefits
Economic retirement & replacement	Retire the Nearman Creek unit and replace with clean resources	Manages regulatory risk; Could reduce NPV portfolio costs
Clean repowering	Interconnect additional resources at the Nearman Creek interconnection to replace or supplement Nearman generation	Leverages cost benefits from re-use of interconnection infrastructure
Seasonal operation	Run Nearman Creek during peak seasons only	Maintains option value and reduces O&M costs

BPU's 2024 IRP represents a ***critical*** opportunity to evaluate these options, and it should seize the opportunity to do rigorous, objective, and quantitative analysis that determines the best path forward for BPU ratepayers.

Case Study: Ameren Missouri

Ameren is using US DOE LPO's Energy Infrastructure Reinvestment (EIR) program to finance retirement of its Rush Island coal plant and a buildout of clean energy

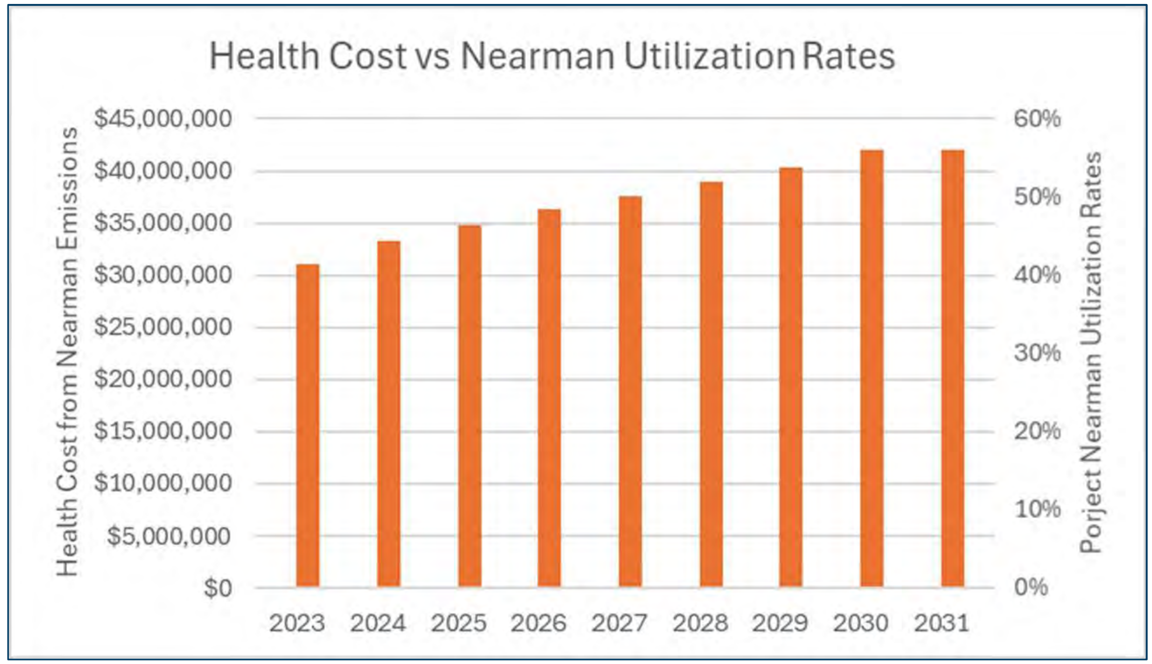
- EIR provides access to capital and reduces financing costs
- Retiring Rush Island early and financing with EIR allows Ameren to "recycle" capital into new assets



Evaluating Nearman Creek 1's Air Pollution Health Impacts

BPU can consider health costs borne by the community due to Nearman Creek's emissions.

- Based on BPU's projections, Nearman's local air pollutant emissions are projected to generate $347M in health costs and an additional 22 mortalities between 2024 and 2032.
- Adjusting cumulative present worth of the BPU base scenario to include health costs would raise this at least by 26% up to $1.3 billion.
- As agencies like the EPA tighten regulations on emissions, failing to account for these impacts could result in future liabilities, penalties, and increased costs of compliance



Existing Fleet Options: Recommendations

Short- and long-term recommendations:

Short-Term

- **Evaluate potential financing options** for retiring Nearman Creek 1, including the US Department of Energy's Energy Infrastructure Reinvestment (EIR) program.
- **Evaluate the potential to interconnect additional resources** at Nearman Creak 1's interconnection point, leveraging the Inflation Reduction Act incentives.
- **Conduct an updated set of capacity expansion analyses that can assist decision making around Nearman 1's retirement, replacement capacity, conversion to seasonal operation, economic dispatch, and coal contracts.** This can be as an update to the 2024 IRP, using the same underlying data.

Long-Term

- Convene a stakeholder group to consider methods for **integrating local air pollution costs into IRP analyses**.

BPU IRP Recommendations: Summary

	IRP Best Practices	Demand-Side Resources	Existing Fleet Options
Short-term (this IRP cycle)	• Transparent model inputs and stakeholder engagement • Comprehensive evaluation of resource options • Resource Planning Aligned with Policy Priorities	• Update load and EE/DSM forecasts • Analyze potential for expanded utility EE/DSM programs • Consider applications to time-limited federal financing programs	• Use PLEXOS capacity expansion to evaluate economic retirement of the Nearman Creek Power Plant, including economic retirement and conversion to seasonal operation. • Evaluate dispatch and coal contracts strategy for Nearman Creek.
Long-term (next IRP cycle)		• Expand utility EE/DSM programs • Prepare for VPPs • Leverage innovative financing mechanisms	• Convene a stakeholder group to consider methods for integrating local air pollution costs into IRP analyses.

Questions & Next Steps

- RMI has prepared a memo that covers these topics in greater detail, and plans to submit formally
- RMI staff are happy to participate in follow-up conversations with BPU members and staff

Thank you! Please don’t hesitate to reach out:

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Review and Recommendations for Best-Practices Planning: Kansas City Board of Public Utilities' 2024 IRP

October 10, 2024

Executive Summary

In this memo, RMI reviews the Kansas City Board of Public Utilities' (BPU) 2024 Integrated Resource Plan with an eye toward integrating best practices and producing trusted, comprehensive, and aligned integrated resource plans. We draw on emerging practices and case studies across the country to make recommendations that can help to drive prudent resource planning and least costs for Kansas City ratepayers.

Our review evaluates BPU's IRP across three categories:

- Overall resource planning practices;
- Demand-side resources; and
- BPU's treatment of its existing generation fleet, with special attention paid toward Nearman 1.

In our review, we make the following recommendations, spanning immediate actions after this IRP and recommendations for BPU's next IRP.

Overall Resource Planning Practices

Based on our review, we identify the following actions that BPU could engage in to ensure their integrated resource planning process is trusted, comprehensive, and aligned.

- **Transparent model inputs and stakeholder engagement:**
    - Take steps toward transparency for model and input data and documentation.
    - In partnership with local stakeholders, develop a stakeholder advisory or working group to provide key ongoing input on resource planning issues.
    - Conduct baseline economic optimization scenarios to set a transparent baseline for least-cost planning.
- **Comprehensive evaluation of resource options:**
    - Expand consideration of available resources to include hybrid resources and clean repowering.
    - Develop an all-source request for proposals (RFP) that surfaces economic opportunities across a variety of resource technologies.
    - Take initial steps toward integrated distribution system planning into the IRP process.
- **Resource Planning Aligned with Policy Priorities:**
    - Update IRP inputs to integrate IRA policies.
    - Integrate regional, city, and stakeholder objectives into IRP stakeholder processes, inputs, and decision-making processes.

Demand-Side Resources

To maximize the cost saving and risk mitigation potential of demand-side resources, we recommend BPU take the following actions:

- Update load and energy efficiency, demand-side management, and distributed energy resources (DER) forecasts (including forecasts of utility energy efficiency programs) to fully incorporate the impact of Inflation Reduction Act provisions on distributed resource economics.
- Analyze the potential for cost-effective expansion of utility demand-side resource programs (e.g., residential thermostat demand response, or "bring your own device" battery storage programs).
- Consider opportunities to advance cost-effective demand-side programs by leveraging innovative financial structures.
- Enable virtual power plants (VPPs) by encouraging distributed resource adoption and supporting demand-side resources in utility planning and operations.

BPU's Existing Resource Fleet

To ensure that the treatment of its existing fleet is consistent with BPU's long-term planning objectives of minimizing rate impacts, system reliability, environmental stewardship, and regulatory compliance, BPU can take the following steps:

- We strongly recommend that BPU conduct a supplemental resource planning analysis that uses the existing PLEXOS capacity expansion and production cost modeling to evaluate a variety of options for Nearman Creek Power Station, including economic retirement and conversion to seasonal operation.
- Based on this supplemental analysis, BPU should evaluate its dispatch and coal contracts strategy for Nearman Creek and consider minimizing cost risk associated with self-commitment and long-term, high-volume coal contracts.
- In line with its long-term planning objectives, BPU should consider integrating local air pollution costs into its resource planning analyses. As appropriate, it can collaborate with the contemplated stakeholder advisory group recommended above to do so.

Background

The Kansas City Board of Public Utilities filed its 2024 Integrated Resource Plan (IRP) on August 30, 2024.[1] This document outlines BPU's vision of the future energy landscape, evaluates any future resource needs to serve Kansas City ratepayers' energy needs, contemplates future resources that could cost-effectively, sustainably, and reliably meet those needs, and sets an action plan for how the Board can take immediate steps toward securing a least-cost future. The plan intends to evaluate portfolios in line with BPU's long-term planning objectives, which are system reliability, minimizing rate impacts, environmental stewardship, and regulatory compliance.[2]

In partnership with Kansans for an Affordable Future and the Sierra Club, RMI reviewed the 2024 BPU IRP with the goal of identifying opportunities for achieving resource planning best practices and achieving better outcomes for Kansas City ratepayers. Our review focuses on three areas:

- Overall Resource Planning Practices;
- Demand-Side Resources; and
- Evaluating BPU's Existing Fleet

While our review is not intended to be comprehensive, we identified the above as areas where a changed approach could drive substantial benefits for Kansas City ratepayers. We review BPU's IRP according to the elements below and provide recommendations to BPU to implement in this and future integrated resource plans.

I. Overall Resource Planning Practices

Integrated resource plans represent crucial opportunities for utilities, regulators, and stakeholders to:

- Understand the energy needs of the households, communities, and businesses a utility serves, as well as how they will change over time, and translate them into system needs;
- Establish a common set of assumptions and evidence that can be used to assess which near- and long-term options can meet system needs and achieve desired utility performance across multiple objectives; and
- Identify longer-term risks and opportunities and strategies to navigate them.

Highly effective integrated resource plans make their objectives clear, pull together the best available data, present an understandable picture of what future needs and available resources look like, and transparently set out a plan for meeting those needs while achieving those stated objectives. When executed well, integrated resource plans manage risks and deliver affordable, reliable, and clean power while building confidence across a range of stakeholders.

To accomplish those objectives, IRPs must maintain three core qualities to be effective tools for utilities and regulators to evaluate resource decisions:

- **Trusted:** The IRP is transparent and well-vetted, with stakeholder input.
- **Comprehensive:** The IRP can accurately represent the costs, capabilities, system impacts, and values of resources that might be available within the planning time horizon; the IRP can consider actions across the transmission and distribution systems as portfolio options.
- **Aligned:** It is clear how the plan evaluates options to meet traditional planning requirements such as reliability, affordability, and safety as well as state and federal policies and customer priorities, such as reducing emissions and advancing environmental justice.

These qualities don't refer to any specific analytical element of integrated resource plans, but instead represent a goal for the integrated resource plans to achieve as a whole.

In this document, we review the Kansas City Board of Public Utilities' (BPU) 2024 Integrated Resource Plan (IRP) considering these objectives. This review is not intended to be exhaustive, but instead to highlight high-priority opportunities for more effective resource planning.

A Fundamental for Best-Practices Resource Planning: Software-Driven Economic Optimization

For 21st-century integrated resource planning, software-driven economic optimization is a prerequisite for trusted, comprehensive, or aligned resource planning. Economic optimization uses integrated resource planning software (also called a capacity expansion model) and a powerful optimization algorithm to identify the set of investment, retirement, and operations decisions that minimize costs while meeting other relevant power system requirements like reserve margin and reliability standards. BPU's IRP uses PLEXOS, which is an industry-standard capacity expansion modeling software and is capable of economic optimization.

As grid planning has become more complex over the last quarter-century, use of software-driven economic optimization has become an industry standard for high-quality resource planning. They are also key for conducting trusted, comprehensive, and aligned planning:

- **Trusted:** Capacity expansion modeling provides a transparent and replicable process for selecting portfolios, which builds confidence across stakeholders.
- **Comprehensive:** Capacity expansion modeling can integrate a wide variety of resource options and high-quality datasets while testing thousands of potential resources and operating decisions, ensuring that all options have been adequately considered.

- **Aligned:** When objectives (such as a planning reserve margin) are represented in capacity expansion, they can ensure objectives are always fulfilled.

Based on our review of BPU's IRP, it is not clear that BPU used an economic optimization approach for identifying its portfolios. For example, the IRP's finding that the net-zero scenario would result in the least costs to ratepayers, for example, indicates that the baseline scenarios may not represent true least-cost scenarios for BPU's ratepayers. This is because an economically optimized baseline portfolio should be the least cost and any deviation from that scenario should, by definition, deviate from the least cost and increase costs. A baseline scenario that is not the least cost suggests that it wasn't optimized. To facilitate a trusted, comprehensive, and aligned IRP, BPU should consider using economic optimization as a primary strategy for identifying its preferred portfolio.

Trusted Resource Planning

Trusted IRPs are transparent and provide high-quality opportunities for input across a variety of groups and entities that have a meaningful stake in BPU's energy future. Stakeholders and regulators can trust an integrated resource plan when they are consulted throughout the process, have confidence in the inputs used in the plan, and understand the methods used to create the plan.

BPU can take the following actions to ensure that its IRP is trusted:

- **Lead a high-quality stakeholder process.** High-quality stakeholder processes present clear expectations about how stakeholders' input will be used and provide the time, data, and opportunities that stakeholders need to contribute meaningful input into the resource plan.
- **Identify sources of key inputs and provide data where possible.** While BPU's IRP provides data sources for some key inputs (e.g., the load forecast), it does not make input data public or share inputs comprehensively. As an example, BPU's IRP does not state the projected capital costs or data sources for future resource options.

  Even while maintaining non-disclosure where appropriate for competition and procurement reasons, BPU could provide more of this data to provide additional transparency to stakeholders. In its IRP guidelines, the Oregon Public Utilities Commission states that "While confidential information must be protected, the utility should make public in its plan any nonconfidential information that is relevant to its resource evaluation and action plan."[3]
- **Document and share methods and assumptions used during IRP development.** While the narrative of BPU's IRP helps to explain the analytical framework used to conduct the IRP's analysis, it does not clarify how economic optimization was used in conjunction with these scenarios. BPU's IRP also does not describe, for example, whether retirement dates for its existing fleet were fixed in its resource planning analysis, or what the parameters around economic retirement. BPU can directly

share model inputs, outputs, and assumptions to clarify the methods and assumptions that underlie its results.

- **Provide clarity and guidance on a regular cadence of IRP updates, or institute a permanent stakeholder advisory group.** Given the pace of changes to the energy economy, it may be appropriate to invite stakeholder input and update plans at a more frequent cadence than every five years; BPU could consider instituting a permanent stakeholder advisory group for ongoing input into resource planning decisions. Austin Energy's Resource Plan Working Group has provided input to the municipal utility since 2019.[4]

For more information on practices that support trusted integrated resource planning, RMI's Reimagining Resource Planning provides a number of best practices and case studies from across the United States.[5]

Comprehensive Resource Planning

Comprehensive IRPs accurately represent the capabilities, system impacts, and values of resources that might be available within the planning time horizon; the IRP can consider actions across the transmission and distribution systems as portfolio options.

BPU can take the following actions to ensure that its IRP is comprehensive:

- **Consider the full range of available resource technologies, including innovative solutions.** BPU could expand the range of available resources to its integrated resource plan to be consistent with available technologies and solutions today. These include hybrid resources that co-locate renewables and energy storage resources, procurement of demand-side resources for meeting bulk-scale energy needs, and a variety of durations of battery energy storage. Data sources like the National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB) provide an industry-standard, high-quality benchmark for a variety of potential resources.[6] Additionally, BPU could consider solutions like clean repowering, which use existing points of interconnection to cost-effectively interconnect renewables and energy storage.[7] Expanding the variety of technologies they consider, including demand-side technologies, renewables co-located with storage, and clean repowering. We will discuss the role of demand-side technologies more in a later section.
- **Evaluate the retirement and operations decisions of BPU's existing fleet.** Integrated resource plans represent an ideal venue for evaluating retirement and operational decisions for existing units because of their focus on economic optimization, clear link to procuring replacement resources if needed, and long time horizon of analysis. BPU should take the opportunity within this IRP to evaluate the long-term viability of its existing fleet and use IRP analysis to evaluate the cost-optimal retirement date for the Nearman Creek coal unit. We discuss this recommendation further in a section below.

- **Use an all-source request for procurement process to surface information about available technologies.** BPU can ground-truth its planning through the use of a linked all-source procurement process, which can surface other available resources and provide information on available market prices. Then, in the next iteration of BPU's IRP, it can use these prices as a guide for future resource cost and availability. Especially given BPU's relatively small size, identifying the set of actionable resource opportunities will provide valuable information for least-cost planning. Nothern Indiana Public Service Company (NIPSCO) uses this approach for their IRP and RFPs.[8]
- **Integrating the distribution-level system.** BPU can also make initial steps to integrate distribution-level and bulk-system planning, which can synchronize investments and enable distributed energy resources to provide bulk system needs. The Lawrence Berkeley National Laboratory provides guidance and technical assistance on how utilities can better integrate distribution planning into their plans for bulk power supply.[9]

For more information on comprehensive resource planning, see NREL's Annual Technology Baseline,[10] RMI's Clean Repowering,[11] and RMI's How to Build Clean Energy Portfolios,[12] and LBNL's portal for integrated distribution system planning.[13]

Aligned Resource Planning

In aligned resource plans, it's clear how the plan evaluates options to meet traditional planning requirements such as reliability, affordability, and safety, as well as state and federal policies and customer priorities, such as reducing emissions and advancing environmental justice.

Below, we identify policy objectives and goals across multiple stakeholders and the steps that BPU can take to ensure its IRP is aligned with these objectives:

- **Federal policy, including the Inflation Reduction Act.**
  - The Inflation Reduction Act's policies have shifted the US energy landscape, and planners should ensure that IRA policies are included across the plan's inputs and outputs. Key IRP components affected by the Inflation Reduction Act include:
    - Load forecasts, which could change due to more affordable energy efficiency and electrification;
    - Resource costs, which may be eligible for the investment and production tax credits and their bonus adders; and
    - Financing costs for projects such as plant retirement that may be eligible for the Energy Infrastructure Reinvestment (EIR) program.
- **Regional goals, including regional Kansas City programs.** The Kansas City Regional Climate Action Plan, for example, identify actions and priorities that entities across the region can take to deliver on environmental commitments.[14]

BPU's IRP should ensure that it integrates these actions and objectives into its plans.

  - **City & stakeholder objectives and priorities.** Finally, BPU's IRP should be crafted with Kansas City and stakeholder objectives in mind. At a minimum, this should include BPU's stated long-term planning goals of system reliability, minimizing rate impacts, environmental stewardship, and regulatory compliance.[15] This could also include objectives raised by stakeholders, including, for instance, an objective to improve environmental equity, reduce air pollution, or aid economic development.

Recommendations to BPU

Based on our review, we identify the following actions that BPU could engage in to ensure their integrated resource planning process is trusted, comprehensive, and aligned.

- **Transparent model inputs and stakeholder engagement:**
  - Take steps toward transparency for model and input data and documentation.
  - In partnership with local stakeholders, develop a stakeholder advisory or working group to provide key ongoing input on resource planning issues.
  - Conduct baseline economic optimization scenarios to set a transparent baseline for least-cost planning.
- **Comprehensive evaluation of resource options:**
  - Expand consideration of available resources to include hybrid resources and clean repowering.
  - Develop an all-source request for proposals (RFP) that surfaces economic opportunities across a variety of resource technologies.
  - Take initial steps toward integrated distribution system planning into the IRP process.
- **Resource Planning Aligned with Policy Priorities:**
  - Update IRP inputs to integrate IRA policies.
  - Integrate regional, city, and stakeholder objectives into IRP stakeholder processes, inputs, and decision-making processes.

II. Demand-Side Resources

Trends including growing electrification, cost declines for distributed energy resources (DERs), support for demand-side technologies through the Inflation Reduction Act (IRA), and the development of virtual power plants (VPPs) have primed demand-side resources to play a greater role in power sector operations. Opportunities are emerging for integrated resources planners to incorporate these new, cost-effective resources into their least-cost resource plans. To recognize the full value of demand-side resources in its forthcoming IRP, BPU can:

- Account for the impact of IRA incentives for demand-side resources in net load forecasts.
- Consider the impact of IRA incentives on existing utility program economics and adjust utility programs accordingly.
- Plan for participation of virtual power plants (VPPs) in resource forecasts, and concurrently work to develop enabling programs for VPPs.

In its draft IRP, BPU outlines the benefits of existing utility demand-side resource programs to its system: improvement of system load factor, deferral of new generation resource needs, and cost savings for customers. BPU describes energy efficiency (EE) programs for streetlighting and construction, as well as six demand-side management (DSM) programs: Heat Pump and Hot Water Heater Rebate Programs, Utility Learning Center, Reactive Adjustment Rider, Net Metering, Smart Metering, and the FlexPay program.[16] While BPU touts the benefits of historical programs, it makes no mention of plans for additional future programs.

Savings Opportunities from Leveraging Demand-Side Resources

New demand-side resources could potentially reduce costs and mitigate risk for BPU ratepayers. Savings could come from:

1) **Avoided operating costs:** Much of BPU's existing fleet incurs high operating expenses. For instance, using data provided by BPU, Synapse estimates that Nearman Creek—which provides over 40% of BPU's generation[17]—incurs operation and maintenance costs nearly 50% higher than the industry average for similar plants.[18] Reducing required generation from Nearman Creek can save customers money, and insulate them from risks associated with fuel price volatility and costs of compliance with future environmental regulations.
2) **Avoided investment and contract costs:** In the draft IRP's Base Case, BPU would invest in 75 MW of solar and purchase 10-20 MW of annual bilateral capacity contracts between now and 2039. This comes at a present worth cost of $62 million for the solar, and $20 million for the capacity contracts. Expanding cost-effective demand-side programs could obviate some of these expenditures. It is especially prudent for BPU to consider the potential to avoid entering capacity contracts, given the substantial uncertainty around future resource adequacy regulations in SPP.
3) **Avoided ongoing capital costs and fixed operating costs:** Expanded demand-side program participation could also help accelerate economic retirements of existing resources. Accelerated retirement could prove especially beneficial in the case of

Nearman Creek, which has been shown to be operating at a loss and is expected to continue to be uneconomic moving forward—costing BPU's customers as much as $47 million in net losses through 2027.[19]

Risk Mitigation Opportunities from Forecasting Customer-Driven Demand-Side Resources

Both under- and over-forecasting the demand-side opportunity carry risks. Some IRA provisions, such as rebates on energy-efficient retrofits, encourage accelerated adoption of demand-side resources.[20] Failing to account for these will lead BPU to overestimate resource needs, potentially leading to over procurement and saddling customers with unnecessarily high costs. Other IRA provisions encourage electrification of fossil-fueled end-uses. Failing to account for these could lead to under-procurement, threatening reliability or burdening customers with additional wholesale energy and bilateral capacity purchases. BPU can mitigate these risks by forecasting the impacts of IRA provisions on customer-driven adoption of demand-side resources. Attachment A: Summary of Key Inflation Reduction Act Provisions for Demand-Side Resources describes the key provisions that BPU should consider in its forecasts.

Best Practices for Implementing Demand-Side Opportunities

BPU can improve its resource planning process by incorporating the impacts of IRA provisions in demand-side resource forecasts, expanding traditional demand-side resource programs, and preparing for next-generation virtual power plants.

Incorporating the impacts of IRA provisions in load forecasts

In its IRP, BPU makes no mention of planned future demand-side programs. Nor does it include the impact of the IRA in its load forecast. Table 8-2 of the IRP lists explanatory variables tested in developing BPU's regression-based load forecast. The table indicates that future demand is formulated based on functional relationships observed between past demand and number of customers, the price of electricity, weather, economic growth, and demographics. An adjustment is made to consider the effects of Covid-19. But the IRA is not considered.[21]

Other utilities have begun to update their load forecasts to reflect the impact of the IRA on customer-driven EE, DSM, and DER adoption. One example is Pacificorp, which in its 2023 IRP incorporated IRA incentives into its Private Generation Resource Assessment (a measure of behind-the-meter generation) and its assessment of EE/DSM conservation potential.[22] In the absence of detailed analysis of the IRA's impacts on conservation potential, Pacificorp recommended use of the "high" conservation potential estimate to approximate IRA impacts. Another is Arizona Public Service (APS), which updated its load and DER forecast in its 2023 IRP to account for IRA impacts and uses an EE/DSM forecast from Guidehouse, which analyzes the impacts of IRA incentives on future utility EE/DSM program cost-effectiveness.[23]

Expand traditional utility demand-side programs

BPU can build off its successes with demand-side programs by expanding its utility program offerings. One leading example among municipal utilities is Fort Collins Utilities, which serves 66,000 customers in northern Colorado. Supported by over $6 million in capital from the Colorado Clean Energy Fund (a Colorado green bank), US Bank, and the Colorado Energy Office, Fort Collins Utilities has been able to issue over $2 million in demand-side resource[24] loans via on-bill financing, with zero defaults.[25] By coordinating with local governments and financial institutions to leverage federal incentives such as those described in Attachment A, BPU could similarly expand the breadth and uptake of its demand-side programs.

The cumulative impact of utility-sponsored demand-side resource programs can be substantial. Consider the total savings made possible by just one type of program: residential thermostat control programs. Arizona Public Service (APS) offers a leading example. In 2018, APS introduced a residential thermostat demand response program called Cool Rewards. By summer 2023, 78,000 customers were enrolled (6.5% of residential customers).[26] In its latest IRP, APS projects cost-effective, achievable program participation could triple to over 20% of residential customers by 2025.[27] If BPU enrolled 5% of its approximately 60,000 residential customers in a similar program,[28] peak demand savings could reach over 4 MW per year, [29] obviating the need for a substantial portion of BPU's planned capacity purchases. Combined with additional demand-side programs, BPU could entirely avoid the 10-20 MW per year of capacity purchases envisioned in its draft IRP.

Prepare for virtual power plants

Virtual power plants (VPPs)—grid-integrated aggregations of distributed energy resources, such as batteries, electric vehicles, smart thermostats, and other connected devices—are emerging as a growing solution to meet the needs of power system across the US. The Department of Energy estimates that 30-60 GW of VPPs are deployed across the US today, with the potential to grow to up to 160 GW by 2030.[30]

RMI's latest research shows that incorporating VPPs into the utility planning process could offer substantial cost savings by replacing conventional thermal and utility-scale battery storage resources and integrating additional quantities of low-cost renewable energy. In a case study of a representative Mountain West utility, RMI found that VPPs serving over 40% of peak demand could be economically added by 2035, yielding 20% savings in annual generation costs ($140 per household per year) compared to a business-as-usual planning scenario without VPPs available for resource selection.[31]

Already today we're seeing the impacts of VPPs in action. For example, Green Mountain Power, a 270,000-customer utility in Vermont, has a VPP of about 50 MW, saving customers $3 million per year.[32] A DOE-estimated 30-60 GW of additional VPPs are operating across the country, delivering a wide range of benefits.[33] Many of these programs are documented in depth in RMI's "Virtual Power Plant Flipbook."[34] BPU can prepare for VPPs by ensuring that distributed devices are interoperable, enabling infrastructure is installed, and the utility has high levels of visibility into distribution-system constraints and resource operations.

Recommendations:

To maximize the cost saving and risk mitigation potential of demand-side resources, we recommend BPU take the following actions:

- Update load and energy efficiency, demand-side management, and DER forecasts (including forecasts of utility energy efficiency programs) to fully incorporate the impact of Inflation Reduction Act provisions on distributed resource economics.
- Analyze the potential for cost-effective expansion of utility demand-side resource programs (e.g., residential thermostat demand response, or "bring your own device" battery storage programs).
- Consider opportunities to advance cost-effective demand-side programs by leveraging innovative financial structures. These include but are not limited to establishing on-bill financing for customer programs, borrowing from city and state government, applying directly for federal financing through programs such as Energy Infrastructure Reinvestment (EIR)[35], and collaborating with other public sector organizations eligible for additional preferential financing from federal programs.[36]
- Enable virtual power plants (VPPs) by encouraging distributed resource adoption and supporting demand-side resources in utility planning and operations.[37]

III. Evaluation of BPU's Existing Fleet

Because of its relative size within BPU's existing fleet, we focus our analysis on . We focused on these three issues – this isn't exhaustive but covers major priorities.

- **Evaluating economic retirement for Nearman Creek:** BPU can model various retirement scenarios for Nearman Creek Power Station, leveraging opportunities for clean repowering, IRA incentives, and loan guarantees from the Energy Infrastructure Reinvestment (EIR) program. BPU can potentially minimize costs and emissions by operating Nearman Creek seasonally or by retiring it from the generation fleet.

- **Consistency in Nearman's Operation and Economic Characteristics:** Recent analysis shows that Nearman has historically operated at a loss and is projected to continue operating at a loss. BPU's updated strategy to minimize self-commitment has improved its economic viability. Nearman has an opportunity to operate under economic dispatch or consider seasonal operations to avoid further economic losses, especially after current coal contracts expire.
- **Integrating Health Costs from Nearman's Emissions:** Emissions from Nearman Creek have caused significant health-related economic costs, including mortality and exacerbated health issues like asthma. Projected health costs from future emissions, as calculated using EPA's COBRA tool, emphasize the need for BPU to factor in these community impacts in its planning. The EPA is also further scrutinizing coal pollution health impacts and taking them into account when optimizing portfolios can help mitigate regulatory risk.

These points highlight critical areas for BPU to address in its IRP to align with economic and environmental best practices.

The IRP does not appear to use capacity expansion to optimize Nearman 1's retirement date

Based on BPU's IRP and load and resources table, it is not clear that BPU is evaluating economic retirement of its Nearman Creek coal unit.[38] This represents a significant potential risk for BPU, as the coal plant is already operating uneconomically.[39] While removing a plant from generation while it still has asset value may be counter-intuitive, it may save money overall if replacement generation and capacity can be procured at a power cost. Economic pressures of this kind of driven early retirements of coal units across the country.[40] By contrast, failure to address this could lead to greater financial strain and higher costs for BPU and its ratepayers.

In its 2024 IRP, BPU has the opportunity to use its IRP capacity expansion model to evaluate various options for Nearman Creek, including retirement or conversion to seasonal operation. Investigating the most economic retirement date for an asset can help minimize costs, improve reliability, and mitigate risk. By evaluating economic retirement for Nearman Creek, simulating economic dispatch, and evaluating replacement capacity options, BPU can comprehensively understand its options for managing costs related to Nearman Creek 1. Evaluating multiple scenarios for Nearman Creek's continued operation can help BPU prepare for potential future and reduce the risk of uncertainty such as regulatory changes, technology advancements, and fuel price spikes that can impact the overall IRP strategy.

This is a relatively common use of integrated resource planning. In their 2023 IRP, APS modeled different exit scenarios for its Four Corners coal plant to identify the least cost portfolios and identify which replacement capacity to begin building. APS also modeled Four Corners with economic dispatch to minimize potential costs in the portfolios.[41]

BPU can also explore the unique opportunities available to replacement or supplemental generation capacity at the Nearman Creek site. Clean repowering—siting clean energy alongside existing fossil generators to leverage their grid connections—allows these projects to take advantage of specific IRA incentives and to potentially pursue a streamlined interconnection process.[42] Given that clean repowering projects are in close proximity to existing energy infrastructure, they are likely eligible for IRA incentives and funding that is specifically targeted toward energy communities. The energy community tax credit bonus provides 10 percent adders on the Investment Tax Credit and Production Tax Credit for projects on a brownfield site, in an MSA or non-MSA meeting fossil employment and unemployment criteria or located in or adjoining a coal closure community. Combined with a comprehensive view of potential generation technologies and taking advantage of Nearman 1's interconnection with clean repowering, it could be possible for BPU to retire Nearman or operate it seasonally to avoid costly energy bills and air pollution.

The US Department of Energy's Energy Infrastructure Reinvestment (EIR) program could also be leveraged for clean repowering projects. BPU can use the EIR program, which offers lower borrowing costs compared to even top-tier corporate issuers. The EIR program offers up to $250 billion in loan guarantees for projects that replace energy infrastructure or enable existing energy infrastructure to reduce emissions. Examples show that Midwest utilities can retire their coal facilities, invest in clean generation, and save money by utilizing EIR.[43] Although a municipal utility has access to cheaper loans than a typical utility, it is still worth exploring if EIR financing can provide economic benefits or if additional access to financing would be beneficial for BPU. Funds for the EIR program must be committed by 2026, so if BPU were to pursue this financing it would need to begin developing its application in the coming months.

Projected Operations and Economic Characteristics of Nearman 1 are Not Consistent with Best Available Evidence

BPU's IRP can address Nearman's historical and projected financial losses by emphasizing strategies like shifting to economic dispatch, or reevaluating coal contracts.

Recent analysis of Nearman 1's economic operations indicates that operating decisions may not be consistent with economic factors like operating costs. Synapse's economic dispatch analysis indicates that the Nearman plant has historically operated at a loss between (2018-2020). This period of loss was paired with high levels of self-commitment ranging from 54%-73% of time Nearman Unit 1 self-committed into the SPP energy market. Nearman's economics in 2021 and 2022 improved when BPU decided to minimize self-commitment and self-commitment rates dropped to 4%-5% (2024 IRP). BPU has acknowledged that self-commitment is less effective as SPP continues adding wind power, though low gas prices have also played a role, and will instead continue to focus on market commitments only commit to SPP when it is economic to do so. BPU has the opportunity to use recent analyses to inform how it represents Nearman in its IRP and in future operating decisions.

According to the Synapse report, "Nearman is not expected to be economic going forward and is expected to incur total net losses of $47 million between 2023 and 2027".[44] To minimize rate payer costs and operation losses, BPU can operate Nearman Creek through economic dispatch, meeting load through market purchases when Nearman would otherwise generate losses. Alternatively, BPU can convert Nearman Creek to seasonal operations to minimize avoidable operations and maintenance costs at the plant. Importantly, the IRP's economic analysis can inform the appropriate dispatch of Nearman Creek assist in decision-making around dispatch strategy and seasonal operations.

BPU also can minimize costs by reevaluating its coal contracts. According to the filed public comments, BPU purchases coal through the Western Fuels Association which has a current coal supply contract that extends to 2024, and a coal transportation contract set to expire in 2025.[45] These coal contracts come with penalties if BPU is unable to accept the coal shipments which may push BPU to operate uneconomically to make room for more fuel and unnecessarily increase pollutants. Depending on the timeline for renewal for these contracts, the 2024 IRP could be an ideal analytical venue for evaluating these coal contracts and identifying the most cost-effective and least-risk contracting option moving forward. This could include conversion to short-term contracts to allow flexibility to adapt to market trends.

The IRP does not evaluate Costs from Nearman 1's Emissions of Air Pollutants.

In line with BPU's planning objectives of environmental stewardship and minimizing cost impacts to ratepayers, BPU could also consider health costs borne by the community due to Nearman Creek's local air emissions. Although health impacts are not currently included in the IRP, BPU factoring in these health costs can mitigate the direct financial burden on the community and align with evolving regulatory pressures.

When utilities don't consider health consequences of different portfolios on communities, they are leaving their customers vulnerable to harmful pollutants and increased costs in the form of medical bills, lost income, and other costs.

To assess Nearman Creek 1's local air pollution impacts, we used the US Environmental Protection Agency's Co- Benefit Risk Assessment Analysis (COBRA) tool, which evaluates the health impacts of power plant air pollutants (such as SO2 and NOx) at county-level granularity, based on power plant type and emissions factors.[46] Using Nearman Creek coal plant EPA CEMS emissions data,[47] our analysis shows that from 2015-2023, Nearman Creek emissions $619 million in health costs, with $101 million specifically impacting low-income communities. Using the expected 2024 – 2032 utilization rate projected in BPU's 2024 IRP, we also projected future emissions and health costs and found an expected $347 million in health costs and an additional 22 mortalities.

BPU's base case scenario has a cumulative present worth cost of $978 million. Adjusting cumulative present worth of the BPU base scenario to include health costs would raise this at least by 26% up to $1.3 billion. These costs are substantial compared to BPU's assessment of future production costs for its contemplated IRP scenarios. If air pollution costs were integrated into resource portfolio development, they could generate portfolios that were least-cost in terms of both ratepayer bills and health impacts. We include estimated costs and other health outcomes from Nearman 1's operations below in Table 1.

	Health Cost ($)	Mortality	Total Asthma Symptoms	ER Visits	Work Loss Days	School Loss Days
Historic 2016-2023	$619,387,813	45	24,981	58	2449	9739
Projected 2024-2032	$347,310,475	22	13,746	33	1038	6002

Table 1. Historic & Projected Health Costs Associated with Nearman 1

Recommendations for BPU

To ensure that treatment of its existing fleet is consistent with BPU's long-term planning objectives of minimizing rate impacts, system reliability, environmental stewardship, and regulatory compliance, BPU can take the following steps:

- We strongly recommend that BPU conduct a supplemental resource planning analysis that uses the existing PLEXOS capacity expansion and production cost modeling to evaluate a variety of options for Nearman Creek Power Station, including economic retirement and conversion to seasonal operation. Especially considering the need to evaluate long-term viability in light of expiring coal contracts, this is a critical opportunity to perform a robust, holistic evaluation of Nearman Creek's economic position and manage costs to ratepayers. Additionally, the supplemental analysis should consider:
  - Connecting additional resources at Nearman Creak 1's interconnection point, leveraging the Inflation Reduction Act incentives;
  - Leveraging financing available through the US Department of Energy's Energy Infrastructure Reinvestment (EIR) program.
- Based on this supplemental analysis, BPU should evaluate its dispatch and coal contracts strategy for Nearman Creek and consider minimizing cost risk associated with self-commitment and long-term, high-volume coal contracts.
- In line with its long-term planning objectives, BPU should consider integrating local air pollution costs into its resource planning analyses. As appropriate, it can work with the contemplated stakeholder advisory group recommended above to do so.

Conclusion

In its 2024 IRP, BPU has an opportunity to chart a least-cost, most prudent resource path for its ratepayers and citizens. The recommendations identified in this memo represent steps toward a comprehensive, trusted, and aligned resource plan.

RMI is grateful for the opportunity to provide this review and recommendations. Our team is available to discuss implementation of any of the above.

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Review of the Board of Public Utilities' 2024 Integrated Resource Plan

Prepared for Kansas City Board of Public Utilities

November 6, 2024

RMI's Role

- RMI partnered with Sierra Club and Kansans for an Affordable Future to review Kansas City Bureau of Public Utilities' (BPU) 2024 Integrated Resources Plan (IRP)
- RMI's review is based on the Black & Veatch's full IRP as filed to the Board on August 30, 2024.
- This non-exhaustive review focuses on high-impact opportunities to perform best-practice resource planning.

RMI's Approach: Critical Topics

We focus on three critical topics for BPU's Integrated Resources Plan:

Key Topic	Summary of RMI's Approach
Overall Best Pratices	• Review BPU's IRP process in light of resource planning best practices
Demand-Side Resources	• Survey relevant IRA provisions that are shifting the economics of distributed energy resources • Evaluate how IRA provisions were integrated into load forecasts • We also review DER-related actions proposed in the 2024 IRP Update and provide additional recommendations to best take advantage of cost-effective DERs for the benefit of ratepayers.
Evaluating BPU's existing fleet	• Evaluate the economic position of Nearman 1, a key element of BPU's existing fleet • Explore options for managing costs associated with existing units

I. Integrated Resource Planning Best Practices

IRPs must maintain three core qualities to be effective tools for utilities and regulators to evaluate resource decisions

IRP quality	*Definition*
Trusted	The IRP is **transparent and well vetted**, with stakeholder input.
Comprehensive	The IRP can **accurately represent the costs, capabilities, system impacts, and values of resources** that might be available within the planning time horizon; the IRP can **consider actions across the transmission and distribution systems** as portfolio options.
Aligned	It is clear how the plan evaluates options to meet traditional planning requirements such as **reliability, affordability, and safety,** as well as **state and federal policies and customer or company priorities**, such as reducing emissions and advancing environmental justice.

II. Demand-Side Resources

Evaluating Demand-Side Resources in BPU's IRP

- When integrated resource plans include demand-side resources into their resource plans, they can realize multiple co-benefits:

Energy Value

- Avoided operating costs, including air pollution, from BPU's existing fleet

Distribution-Level Value

- Avoided costs and investments on BPU's distribution system
- Better integration of electrifying loads

Capacity Value

- Avoided costs and risks from market procurement of capacity
- Potentially, avoided capital and fixed O&M costs by retiring or avoiding new generation investments

Resilience Value

- Potential improvements to resilience during reliability evets

Demand-Side Resources: Recommendations

Short- and long-term recommendations:

Short-Term

- **Update load and EE/DSM forecasts.**
- **Analyze potential for expanded utility EE/DSM programs.**
- **Consider applications to time-limited federal financing programs.**

Long-Term

- **Expand utility EE/DSM programs.**
- **Prepare for VPPs** by encouraging DER adoption and supporting demand-side resources in utility planning and operations.
- **Leverage innovative financing mechanisms** to lower costs of demand-side resources for customers.

III. Evaluating BPU's Existing Fleet

RMI’s Review

- We focus our review on Nearman Creek Power Plant’s Unit 1, which represents a significant amount of the energy and costs of BPU’s existing portfolio.

- We focus on three major topics:
  - BPU’s IRP as an opportunity to evaluate near-term options for the Nearman Creek unit, including economic retirement
  - Integrating air pollution costs into BPU’s resource planning practice

Considerations for Economic Retirement Analysis

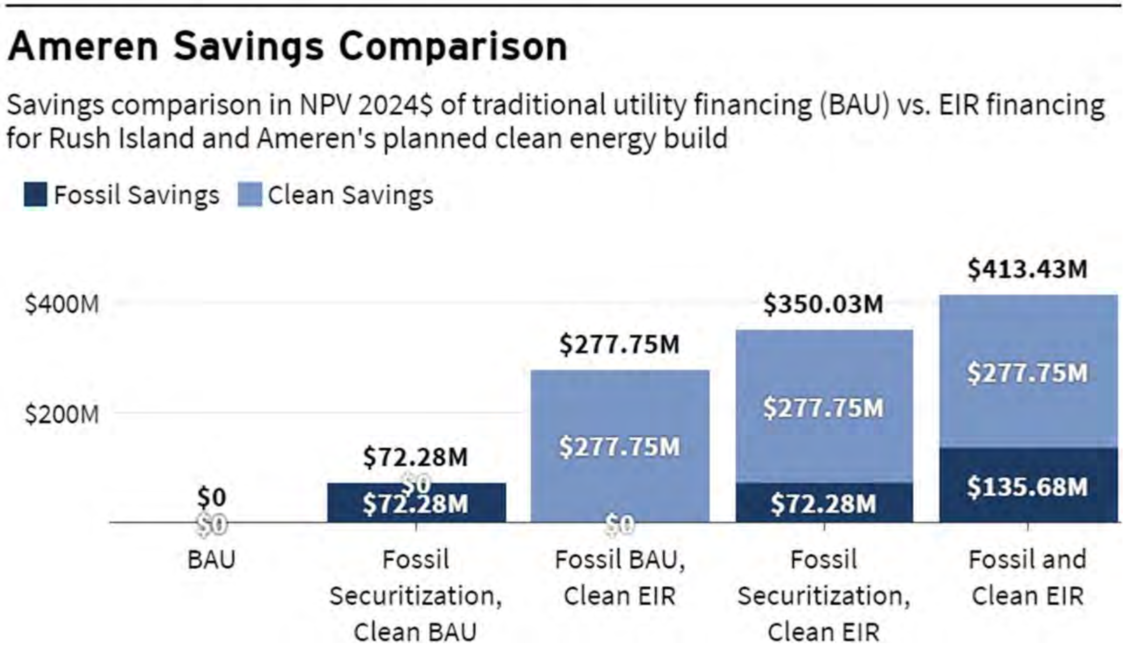
Option to Consider	Description	Potential Benefits
Economic retirement & replacement	Retire the Nearman Creek unit and replace with clean resources	Manages regulatory risk; Could reduce NPV portfolio costs
Clean repowering	Interconnect additional resources at the Nearman Creek interconnection to replace or supplement Nearman generation	Leverages cost benefits from re-use of interconnection infrastructure
Seasonal operation	Run Nearman Creek during peak seasons only	Maintains option value and reduces O&M costs

BPU's 2024 IRP represents a ***critical*** opportunity to evaluate these options, and it should seize the opportunity to do rigorous, objective, and quantitative analysis that determines the best path forward for BPU ratepayers.

Case Study: Ameren Missouri

Ameren is using US DOE LPO's Energy Infrastructure Reinvestment (EIR) program to finance retirement of its Rush Island coal plant and a buildout of clean energy

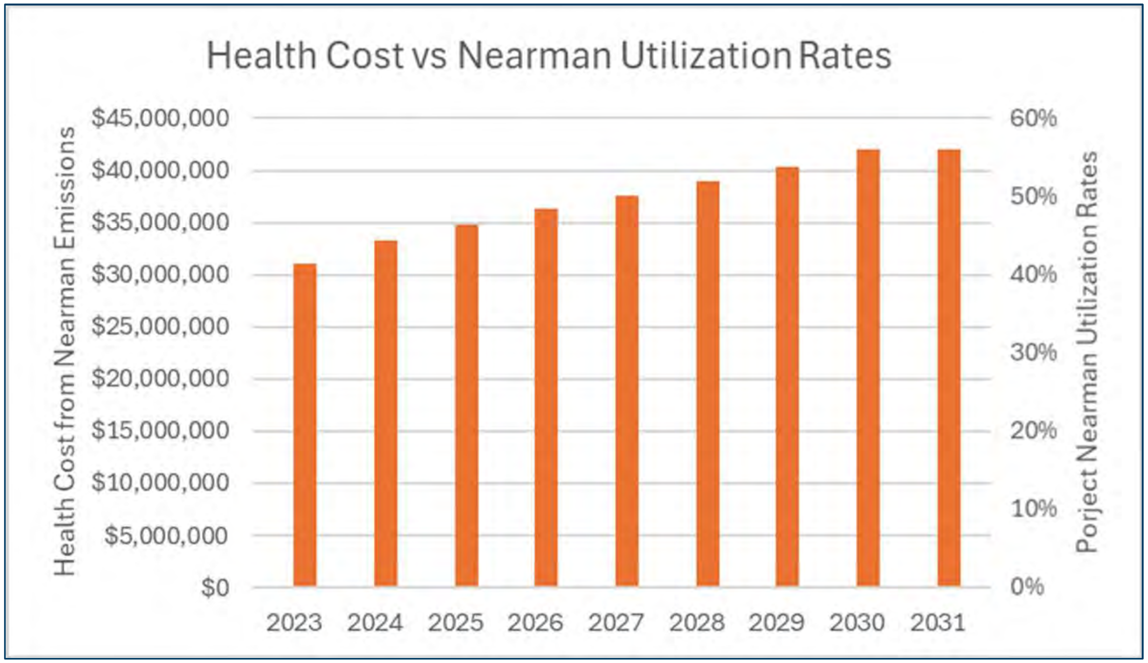
- EIR provides access to capital and reduces financing costs
- Retiring Rush Island early and financing with EIR allows Ameren to "recycle" capital into new assets



Evaluating Nearman Creek 1's Air Pollution Health Impacts

BPU can consider health costs borne by the community due to Nearman Creek's emissions.

- Based on BPU's projections, Nearman's local air pollutant emissions are projected to generate $347M in health costs and an additional 22 mortalities between 2024 and 2032.
- Adjusting cumulative present worth of the BPU base scenario to include health costs would raise this at least by 26% up to $1.3 billion.
- As agencies like the EPA tighten regulations on emissions, failing to account for these impacts could result in future liabilities, penalties, and increased costs of compliance



Thinking through federal policy uncertainty

- Given Trump's win in the 2024 presidential election, there is some uncertainty about implementation of existing policy and regulations

- These changes in policy are not likely to change fundamental coal economics

- Clarity on the durability of these policy elements will likely emerge in coming months

- BPU could consider an updated IRP that evaluates a wider set of options (including testing several retirement dates for Nearman Creek 1) in the near future

What’s the bottom line and what can BPU do?

- We present a playbook of options that BPU could take to ensure its IRP works for ratepayers, including:
  - Setting ground rules and procedure for a transparent and generative stakeholder consultation
  - Integrating its IRP with an all-source procurement process to get up-to-date costs and technologies
  - Taking inspiration from other energy efficiency programs, including from peer co-op utilities
  - Evaluating the best economic option for Nearman 1’s remaining lifetime
  - Clarifying how it uses PLEXOS’s economic optimization

What's the bottom line and what can BPU do?

- Actions that the Board could take today:
  - **Run supplemental scenarios using Black & Veatch's existing IRP model**:
    - A baseline "economic optimization" scenario that sets a common foundation for least-cost planning
    - Examine options at Nearman Creek 1 including
    - Integrating local air pollution costs into its cost evaluations
  - **Evaluate options to deploy clean resources at Nearman Creek 1's point of interconnection**
  - **Develop a working group or contract with a consultant to explore innovative energy efficiency & demand-side management programs**

Questions & Next Steps

- RMI has prepared a memo that covers these topics in greater detail and can share with the Board pending interest.
- RMI staff are happy to participate in follow-up conversations with BPU members and staff, and may be able to provide additional technical assistance.

Thank you! Please don't hesitate to reach out:

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