KANSAS ELECTRIC POWER COOPERATIVE, INC.
600 S.W. CORPORATE VIEW
TOPEKA, KS 66615

INTEGRATED RESOURCE PLAN
FOR SUBMISSION TO THE
WESTERN AREA POWER ADMINISTRATION

May 2021

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Executive Summary

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

Overview of KEPCo

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

KEPCo provides the power requirements for 16 member cooperatives who, in turn, provide service to approximately 77,000 members and maintain 41,000 miles of electric distribution line.

The combined service territory of KEPCo's member cooperatives covers much of the rural area in the eastern two-thirds of Kansas and encompasses a wide range of physiographic regions.

KEPCo's power supply resources include a 6% ownership in the Wolf Creek Generating Station. Wolf Creek is a reliable nuclear power plant that has provided dependable base load power since it began commercial operation in 1985. The unit has a total rated nameplate capacity of 1170 megawatts (MW) of which KEPCo's share is 70 MW. The plant has a lifetime capacity factor of 85% and furnishes approximately 30% of KEPCo's energy requirements. KEPCo also owns a 3.5% ownership interest (30 MW) of Iatan 2, an 850-MW super-critical coal-fired generating facility located in Weston, Missouri. KEPCo solely owns the Sharpe Generating Station, a peaking facility that is comprised of 10 2-MW Caterpillar diesel generators that can be remotely operated from KEPCo headquarters. Most recently, KEPCo built and solely owns a 1-MW solar facility, Prairie Sky Solar Farm, located near Benton, Kansas. KEPCo has contracts with the U.S. Department of Energy Western Area Power Administration (WAPA) and the Southwestern Power Administration (SWPA). KEPCo has a 13-MW allocation of firm hydropower from WAPA and a 100-MW allocation of peaking and supplemental hydro power from SWPA.

In addition to its owned generation and long-term hydro allocations, KEPCo purchases its remaining requirements from Evergy, Inc. (Evergy) and Sunflower Electric Power Corporation (Sunflower) for base, intermediate, and peaking power supply. These contracts provide KEPCo with power from coal, nuclear, natural gas, and wind resources.

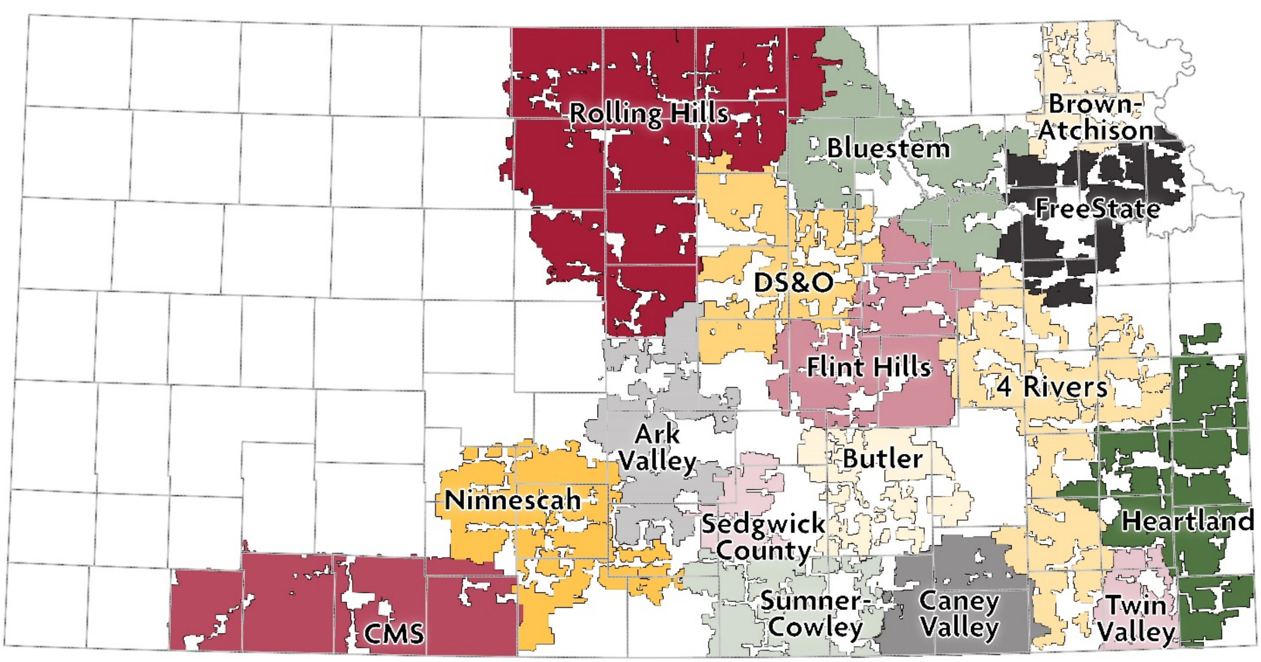
KEPCo does not own or operate any transmission facilities. KEPCo purchases transmission service from the Southwest Power Pool, Inc. (SPP) to deliver the power and energy from its resources to the KEPCo member load. KEPCo is a member of the SPP and participates in the planning and expansion of the system within Kansas and the region. Because KEPCo is a relatively small power supplier without a 24-hour dispatch desk and real-time scheduling capability, KEPCo obtains scheduling and balancing and other ancillary services from others via contract.

While the economy of the KEPCo members' service territories is primarily agricultural, there is considerable diversity in the type of agriculture and commercial load that each member cooperative serves. A number of KEPCo's members also serve a significant amount of residential load. Cumulatively, rural residential load accounts for more than 50% of KEPCo's annual energy requirements.

Prior to January 1, 2021, KEPCo provided power and energy to 18 member distribution cooperatives. Two members – Prairie Land Electric Cooperative, Inc. and The Victory Electric Cooperative Assn., Inc. – opted not to renew their respective all requirement power contracts; thus, their membership in KEPCo terminated when their respective initial all requirement power contracts expired on December 31, 2020. These two cooperatives accounted for approximately 29 MW of demand and 175,500 MWh of energy sales.

KEPCo Board of Trustees
KEPCo is governed by a Board of Trustees (Board) representing each of its 16 members. The KEPCo Board meets regularly to establish policies and act upon issues that often include recommendations from working committees of the Board and KEPCo staff. The Board also elects a seven-person executive committee, which includes the president, vice president, secretary, treasurer, and three additional executive committee members.

KEPCo Member Distribution Cooperatives
The following are the 16 member cooperatives that receive service from KEPCo and a map illustrating each of the 16 members' service territories.



4 Rivers Electric Cooperative, Inc.
2731 Milo Terr.
Lebo, KS 66856
Miles of Line: 4,020

Ark Valley Electric Cooperative Assn., Inc.
10 E. 10th Ave.
South Hutchinson, KS 67505
Miles of Line: 2,101

Bluestem Electric Cooperative, Inc.
1000 South Wind Dr.
Wamego, KS 66547
Miles of Line: 2,851

Brown-Atchison Electric Coop. Assn., Inc.
1712 Central
Horton, KS 66439
Miles of Line: 1,105

Butler Rural Electric Cooperative Assn., Inc.
216 S. Vine St.
El Dorado, KS 67042
Miles of Line: 2,188

Caney Valley Electric Cooperative Assn., Inc.
401 Lawrence
Cedar Vale, KS 67024
Miles of Line: 1,740

CMS Electric Cooperative, Inc.
509 E. Carthage
Meade, KS 67864
Miles of Line: 2,612

DSO Electric Cooperative Assn., Inc.
201 Dakota Dr.
Solomon, KS 67480
Miles of Line: 2,470

Flint Hills Rural Electric Cooperative Assn., Inc.
1564 S. 1000 Rd.
Council Grove, KS 66846
Miles of Line: 2,556

FreeState Electric Cooperative, Inc.
507 N. Union
McLouth, KS 66054
Miles of Line: 3,141

Heartland Rural Electric Cooperative, Inc.
110 N. Enterprise Dr.
Girard, KS 66743
Miles of Line: 3,805

Ninnescah Rural Electric Cooperative Assn., Inc.
275 N.E. 20th St.
Pratt, KS 67124
Miles of Line: 2,130

Rolling Hills Electric Cooperative, Inc.
3075 B U.S. Highway 24
Beloit, KS 67420
Miles of Line: 6,414

Sedgwick County Electric Cooperative Assn., Inc.
1355 S. 383rd St. West
Cheney, KS 67025
Miles of Line: 1,175

Sumner-Cowley Electric Cooperative, Inc.
2223 N. A St.
Wellington, KS 67152
Miles of Line: 1,774

Twin Valley Electric Cooperative, Inc.
1511 14,000 Rd.
Altamont, KS 67330
Miles of Line: 925

Wholesale Rate Competitiveness
Average annual wholesale rates for area/regional G&Ts include: Sunflower Electric Power Corporation, a G&T headquartered in Hays, Kansas, has an average rate of $0.05916/kWh; Western Farmers, a G&T headquartered in Anadarko, Oklahoma, has an average rate of $0.05212/kWh; and Central Electric Power, a G&T headquartered in Jefferson City, Missouri, has an average rate of $0.05730/kWh.

The following are KEPCo's average annual wholesale rates for the years 2016 thru 2020:

2016 – $0.0763/kWh
2017 – $0.0735/kWh
2018 – $0.0804/kWh
2019 – $0.0693/kWh
2020 – $0.0695/kWh

Load Growth
KEPCo's load forecast is based on a recent projection for KEPCo's demand and energy requirements through 2036. During this 15-year time period, KEPCo energy sales are projected to increase at 0.3% annually, based on normal weather conditions. The 15-year projection for demand increases at a rate of 0.5% annually.

KEPCo provided 2.13 million MWh of energy to its members in 2020 with a peak demand of 398 MW.

Load Forecast
KEPCo provided a 10-year long-range load forecast (LRLF) to Power System Engineering (PSE). PSE extended this forecast to the 15-year Resource Planning time horizon using a trending approach.

The 10-year LRLF was developed using a combination of linear regression and trending analysis to produce an aggregate forecast for each customer class at the member level of sales, and then a loss rate was applied to produce the KEPCo sales forecast for each member. Linear regression was used to develop econometric equations to predict energy sales for the residential and small commercial customer classes that relate variables such as weather, price of electricity, and economic indicators such as the price of oil to energy sales. A 10-year average of cooling and heating degree days, price of oil, per capital income, and population were found to be significant variables in predicting sales. The Woods & Poole Kansas State Profile was used to estimate future population growth and economic indicators, and trending analysis was used to predict the inflation-adjusted price of oil. Forecasts were also evaluated and adjusted based on recent sales and projected growth. Demand forecasts were produced for each member by a combination of linear regression modeling with energy and cooling degree days as predictive variables and trending analysis. The sales and demand projections for KEPCo as a whole are based on the summation of member forecasts. Projections for KEPCo's load in each transmission zone were based on the member's historic percentage of sales in each area and member forecasts.

The load forecast data will be made available to WAPA upon request.

Peak Reduction Programs
KEPCo operates a load management program designed to reduce peak load. In 1990, KEPCo adopted rates to encourage peak demand reduction and also began a load management program that involves issuing peak alert notifications to member

cooperatives who, in turn, have implemented rates and programs to reduce usage during peak demand periods.

In 2001, KEPCo implemented a state-of-the-art Energy Management and Supervisory Control and Data Acquisition (EMS/SCADA) system, which has enabled KEPCo to provide real-time monitoring of load data to its member cooperatives. KEPCo's current rate design defines the Billing Peak as a weekday, non-holiday Coincident Peak (CP). KEPCo and its members' load management efforts result in substantial financial savings for the KEPCo membership.

Summer 2020 was the first load management season under the new Schedule M-11C tariff. Prior to June 1, 2020, KEPCo's peak was set coincident with the aggregated member cooperatives' load. The tariff revision, applicable as of June 1, 2020, more closely aligns member billing mechanisms with the way KEPCo is billed by its suppliers, thereby motivating overall cost reduction initiatives and adding efficiencies for KEPCo's members.

KEPCo's ability to reduce demand has been influenced by three factors: several of KEPCo's member cooperatives have installed diesel-fired generators, which the members operate in response to KEPCo peak alerts; the cumulative effect of several years of energy efficiency measures, such as the installation of high-efficiency HVAC systems by cooperative members, promoted by KEPCo's high-efficiency HVAC rebate program; and the aggressive demand-side management program administered by KEPCo.

In 2020, 12 of KEPCo's member cooperatives joined together to enter into individual Power Purchase Agreements totaling 20 MW of solar generation to be installed in rural Kansas to reduce their carbon footprint and further reduce the peak demand on the KEPCo system. Most of these projects will become operational in 2021 with the balance in 2022.

Demand-Side Management

KEPCo completed a Demand Response Study (DR Study) in 2019. The DR Study summarizes modeling and analysis to assess the cost effectiveness of existing and potential new DR measures, to evaluate qualitative issues with respect to KEPCo's DR programs, and to provide guidance on how the current wholesale tariff flows benefit of DR from KEPCo through to the distribution member providing demand reductions.

Renewable Energy Considerations

Kansas has been identified as one of the highest wind areas in the United States and, thus, has a potential for substantial wind energy development. The state of Kansas was under a renewable portfolio standard for approximately six years. As a result of legislation passed in 2015, the mandatory renewable portfolio standard was repealed and replaced with a voluntary appeal to develop renewable resources totaling 20% nameplate capacity of each electric utility's peak load by 2020. This goal has been met and exceeded by KEPCo.

The most economical and reliable method for KEPCo to participate in developing wind resources is through the integrated mix of wind energy in its purchase power agreements. KEPCo's agreements with Evergy and Sunflower include wind generation as a part of the power supply mix. This partnering ensures that KEPCo is able to help contribute to the development of wind resources in Kansas in an economical and responsible manner.

Prairie Sky Solar Farm (Prairie Sky), a 1-MW solar facility in Benton, Kansas, began commercial operation in 2017. Since the time Prairie Sky was placed into service, it has operated and performed at the levels that were modeled during the design phase.

Regulatory Oversight

KEPCo was granted a limited certificate of convenience and necessity in 1980 to operate as a generation and transmission public utility in Kansas by the Kansas Corporation Commission (KCC). In 2009, KEPCo elected to be exempt from the jurisdiction, regulation, supervision, and control of the KCC as provided for in K.S.A. 66-104d. However, notwithstanding KEPCo's deregulated status, KEPCo's rates may be investigated by the KCC upon the filing of a petition by not less than 20% of KEPCo's members or 5% of the aggregate retail customers of such members within one year of a change in KEPCo's rates. Rate changes must be approved by KEPCo's Board.

KEPCo is subject to the rules and regulations of the U.S. Department of Agriculture's Rural Utilities Service (RUS). As KEPCo's primary lender and mortgage holder, RUS approves rate changes, purchase power contracts, generation projects, and loans, among other areas under RUS' supervision and control. KEPCo must also meet financial matrix thresholds to remain in compliance with RUS' mortgage requirements.

Plan Components

In April 2021, PSE completed KEPCo's Resource Planning Study (RPS). The RPS evaluates KEPCo's future power supply needs and satisfies the requirements set forth in the regulations regarding information to be included in the IRP. KEPCo has an all requirements contract with Evergy that credits KEPCo for the capacity and energy provided by certain KEPCo resources under the contract. About 90% of KEPCo's load requirements are met by the resources under this contract which has a term (2045) which is well beyond the planning horizon of this IRP. Therefore, the focus of the RPS and this IRP is on the balance of the KEPCo resource requirements. The RPS is included in its entirety under Tab 1.

Public Participation

KEPCo is soliciting public comment on the IRP by placing ads in 25 newspapers within and surrounding KEPCo's members' service territories. Please see Tab 2 for a copy of the ad and a list of the selected newspapers.

KEPCo presents recommendations to its Board regarding power supply and generation resources through a variety of mechanisms, such as the RPS associated with this IRP. KEPCo then acts on the Board's directives. KEPCo intends to present this IRP to its Board on May 19, 2021 for the Board's approval, pending potential changes due to public comment. KEPCo will seek Board approval via a Board resolution.

Goals and Implementation

Consistent with KEPCo's purpose statement, KEPCo's goal is to continue to provide the most safe, reliable, economical, and environmentally responsible power supply possible. To this end, KEPCo has opted to reduce market exposure and fuel volatility by securing long-term purchase power agreements with local and regional suppliers.

As a wholesale provider of electricity, with limited influence or relationship with the end consumer, KEPCo is restricted in the scope of programs that can be offered to influence energy conservation and energy efficiency. However, KEPCo works with its member cooperatives on an individual basis on the marketing of programs specific to the cooperative.

KEPCo's specific resource planning goals include:

- KEPCo will continue to offer rebates for air source heat pumps, ground source heat pumps, and electric water heaters. Given the analysis of historical data, a goal of 200 water heaters and 150 HVAC rebates annually has been established and subsequent years will be compared to the goals.

- KEPCo will continue to work with its members to fully implement the existing load management program.

- KEPCo will continue to work with its members to evaluate the efficacy of additional demand side management and energy efficiency opportunities relating to the goal of reducing peak demand and energy consumption.

- KEPCo will establish an energy hedging policy to put in place a framework to manage exposure to market energy price volatility.

- KEPCo will issue a Request for Proposals (RFP) seeking products to hedge market energy price volatility and for resources and/or power purchase agreements using the results of the Resource Planning Study as a guide.

- KEPCo will use the results of this RFP, the RPS, and additional analyses to address future resource adequacy requirements.

- KEPCo will continue to support initiatives introduced by the Kansas Legislature, KCC, or other appropriate body that promote energy efficiency, so long as the initiatives do not adversely affect the consumers in the rural areas of Kansas.

Power System Engineering

Resource Planning Study

Prepared for:

Kansas Electric Power Cooperative, Inc

KEPCo

Prepared by:

Power System Engineering, Inc.

First Board Presentation Draft – April 15, 2021

Resource Planning Study
for
Kansas Electric Power Cooperative, Inc.

Authors:

Tom Butz, P.E.

Jeff Laslie, CPA

Rich Macke, MBA

Contact: Tom Butz, P.E.

butzt@powersystem.org

Direct: 763-755-5122

Mobile: 612-961-9495

10710 Town Square Drive, NE, Suite 201
Blaine, MN 55449

www.powersystem.org

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Statement of Limitations

In the preparation of this Resource Planning Study, Power System Engineering (PSE) has been provided and has relied upon information and data provide by Kansas Electric Power Cooperative, Inc. (KEPCo). Such information and data were not, in all cases, independently verified by PSE, and while PSE has no reason to believe that the information and data provided is materially inaccurate or incomplete, PSE cannot guarantee its accuracy or completeness.

Further, in the completion of this Resource Planning Study, PSE necessarily developed and established estimates and projections pertaining to things such as resource costs, operating expenses, market performance, etc. based upon its experience and qualifications as a professional consultant. In all such cases where projections and estimates were developed, PSE advises that actual results are outside of its control and it cannot guarantee accuracy.

1 Executive Summary

The Resource Planning Study (Study) provides support to KEPCo in developing the KEPCo Integrated Resource Plan (IRP) that is required by the Western Area Power Administration (WAPA). The IRP is required to be submitted every five years. The Study is designed to inform KEPCo strategic plan decision makers on viable future resource options and utilizes previously developed load forecast and demand response studies as a basis for focusing on the range of supply-side resources that can complement the KEPCo resource portfolio.

Sections of this report are as follows:

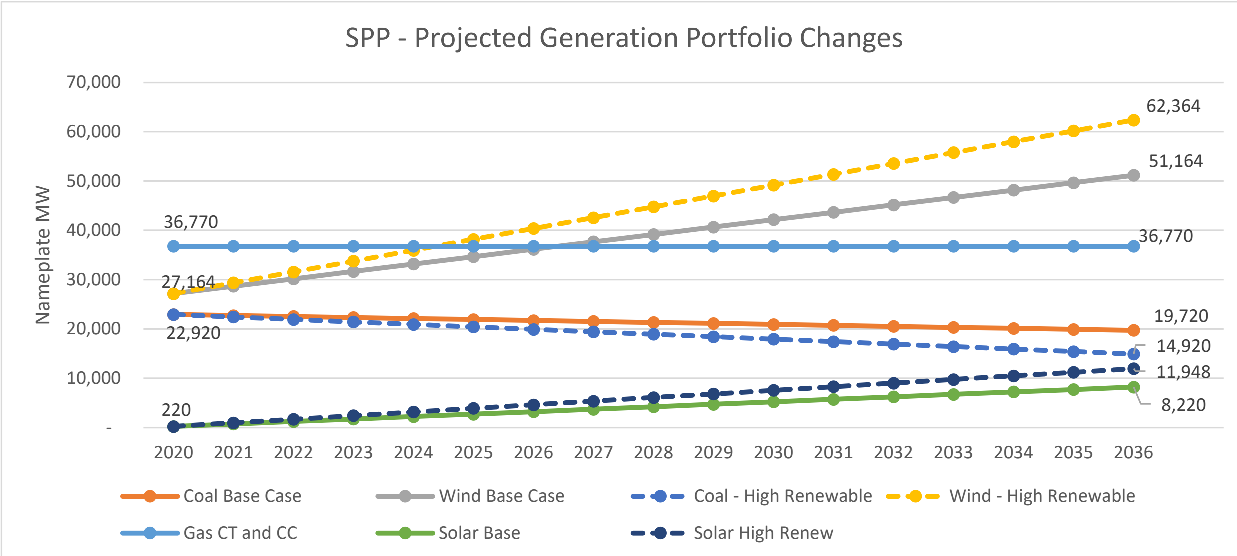
1. Executive Summary
2. Electric Power Industry Review
3. Regulatory Review
4. Demand Side Management Analysis
5. Technology Assessment
6. Economic Evaluation
7. Recommendations

Key objectives of the Study included meeting the WAPA IRP requirements and providing a range of resource portfolio alternatives to meet projected load obligations. Resource needs were focused on the KEP2 portion of the KEPCo system due to the resource for the KEPC portion being met from the combination of KEPCo owned resources and purchase power agreements that extend beyond the planning horizon. Resource portfolios evaluated in the Study are indicative of the costs and operational characteristics of the portfolio but are not intended to be definitive in what final resource portfolio will be developed.

Southwest Power Pool (SPP) resource portfolio transformation is expected to continue with the retirement of coal and gas generation facilities and the addition of renewable resources. The 2021 SPP Integrated Transmission Planning Assessment (ITP) provides a summary of assumptions in regard to resource retirements and additions.

The 2021 ITP projected a Base and High Renewable scenario projection of SPP nameplate capacity by fuel type as shown for 2022-2036 in Figure 1.

Figure 1: Projected SPP Nameplate Capacity by Fuel Type– Base and High Renewable



KEPCo owned and contracted resources include the following:

<u>Owned Resources</u>

- Wolf Creek Generation Station (nuclear) .... 70 MW
- Iatan 2 Generating Plant (coal) .... 30 MW
- Sharpe Generating Station (diesel) .... 20 MW
- Prairie Sky (solar) .... 1 MW

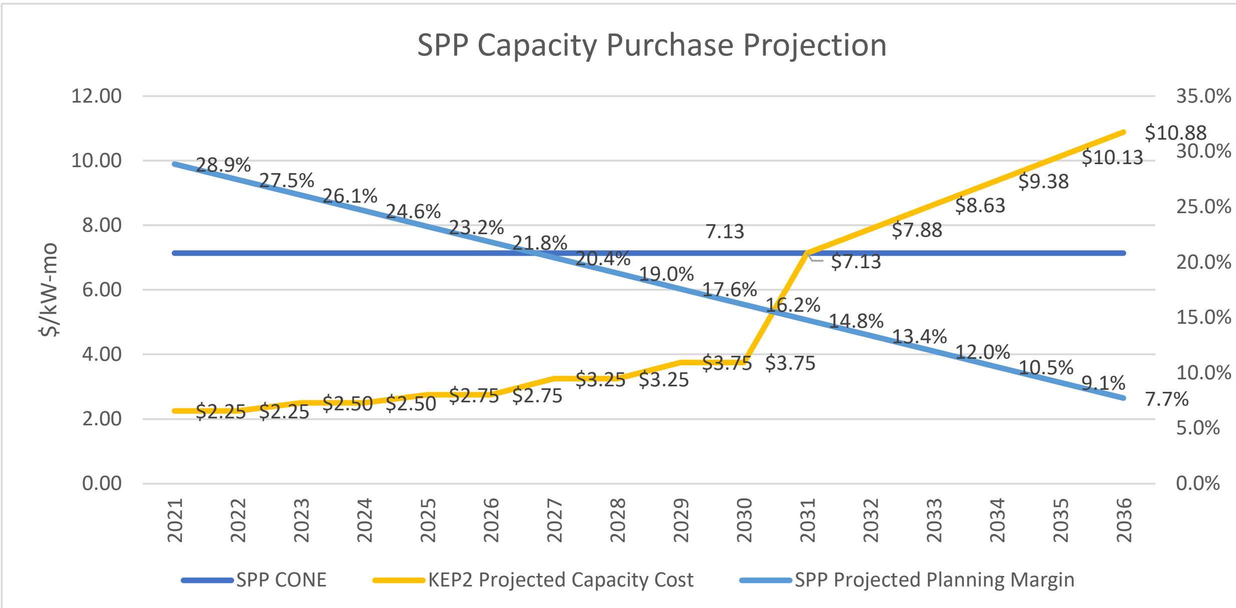
<u>Purchases</u>

- Southwestern Power Administration (hydroelectric)... 100 MW
- Western Area Power Administration (hydroelectric) .... 13 MW
- Evergy (KEP2 Capacity 2021-2026) .... 50 MW
- Evergy (KEPC Energy and Capacity expires 2045) .... Approx. 158 MW

The 2021-2026 Evergy capacity purchase provides an indication on bilateral capacity purchase prices for the early years of the Study, but there is a challenge to assess the cost of bilateral capacity for 2027-2036. SPP utilizes a Cost of New Entry (CONE) capacity price that is based on the cost of building a new peaking plant. CONE is currently set at \$7.73/kW-month.

The SPP planning reserves are trending lower and there is uncertainty regarding what new capacity resources will be developed to replace the expected plant retirements. As the projected planning reserves decrease, the cost of bilateral capacity is expected to increase. This study uses the current price trend through 2030 but in 2031 the cost increases to the current SPP CONE and then increases by $0.75/kW-mo. for each year thereafter. The cost of bilateral capacity used in the study for the 2022-2036 are shown in Figure 2.

Figure 2: Bilateral Capacity Purchase Projection



In addition to the Base and High Renewable scenarios for SPP generation changes, the Study also included two cases for natural gas prices, and a provision to evaluate a future carbon tax. This results in a total of eight combinations of the scenarios/sensitivities summarized by the following:

- SPP Generation Mix Changes – 2 (Base and High Renewables)
- Natural Gas Price Forecast – 2 (Base and High Gas)
- Carbon Tax - 2 (none and $15/ton)

The analysis also used three years of historic data to provide the overall baseline of the KEP2 load shapes and SPP underlying dispatch by fuel data used to create the Locational Marginal Price (LMP) hourly data.

KEP2 capacity requirements are 45 MW and projected to increase to nearly 47 MW by 2036. Energy requirements are 229 GWh in 2022 and projected to increase to 240 GWh by 2036. Resource portfolios for the Study have a rating of 50 MW with energy for each resource dependent on how it is expected to be dispatched in the SPP Integrated Market (IM).

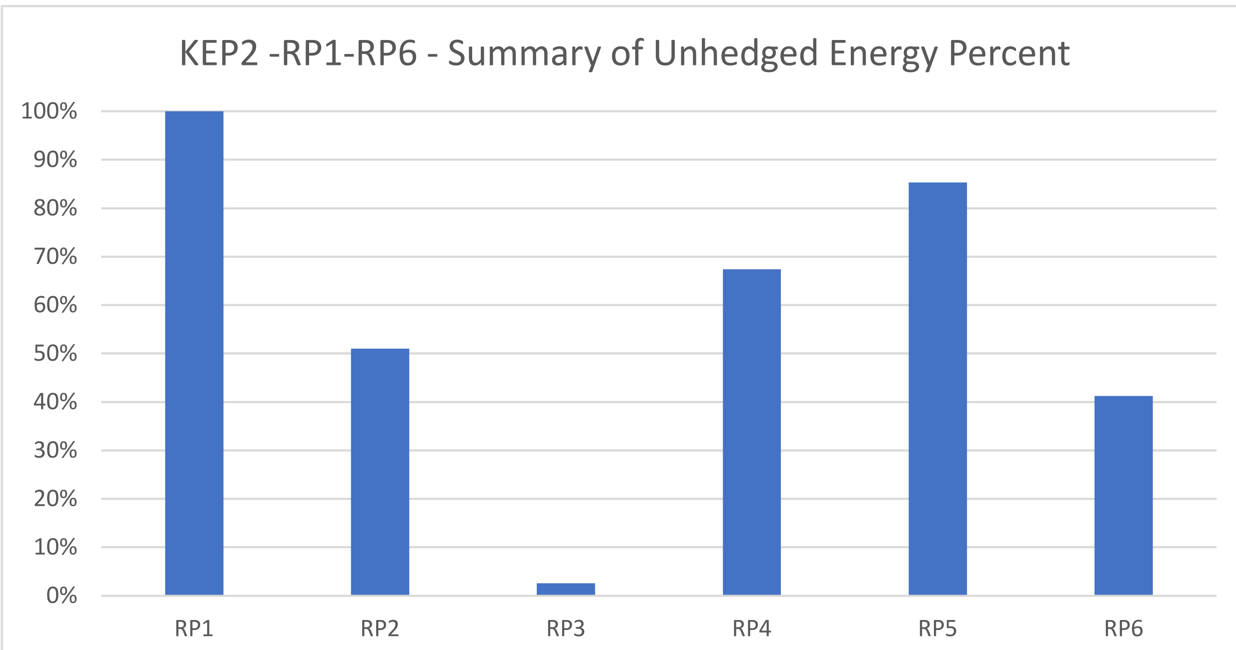
The following resource portfolios (RP) were evaluated in the Study:

- RP1 – Bilateral capacity purchase and SPP IM energy purchase
- RP2 – Bilateral capacity purchase and 5x16 (on-peak) block of energy purchase with balance of energy purchased from the SPP IM

- RP3 - 50 MW nameplate of wind and additional capacity from bilateral market[1]
- RP4 - 50 MW share of a CC baseload plant[1]
- RP5 - 50 MW share of a fast-ramping peaking plant[1]
- RP6 – 50 MW nameplate of solar and additional capacity from bilateral market[1]

Resource Portfolios were evaluated on the ability to hedge energy prices from the SPP IM, the 15 year Net Present Value (NPV) of the total cost for each of the scenarios/sensitivities (24 total cases), and the standard deviation of the 15 year NPV. The percentage of unhedged energy exposure for each RP is shown in Figure 3.

Figure 3: KEP2 - RP1-RP6 Summary of Unhedged Energy Percent



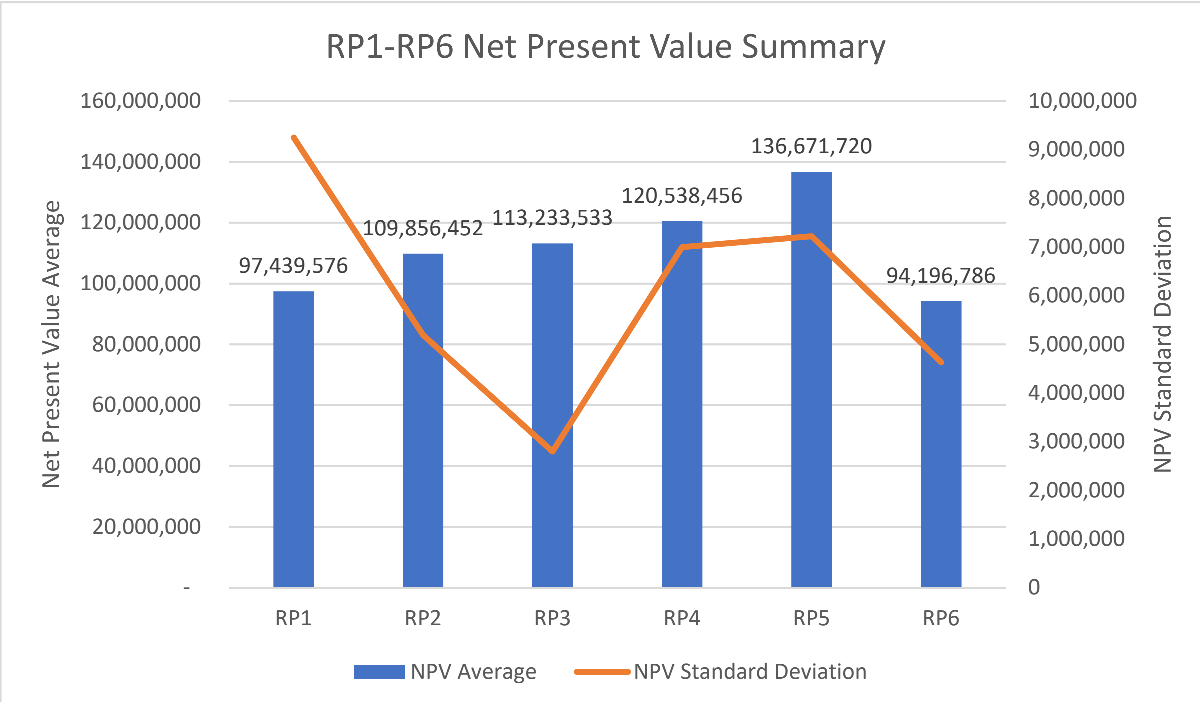
RP1 is completely unhedged from the SPP IM and RP3 has the lowest unhedged energy exposure. RP4 and RP5 are shown based upon how they were dispatched in the projected SPP IM but could vary depending on actual market conditions. The amount of unhedged energy for RP4 and RP5 will also depend in part on the cost of natural gas. RP6 includes 50 MW nameplate of solar and significantly reduces market energy exposure. Energy production from RP6 is also expected to align well with peak energy prices in the summer.

The 15-year NPV of total power costs for each RP are shown in Figure 4. These costs range from just under $95 million for RP6 to over 136 million for RP5. The volatility of the NPV across all of the scenarios/sensitivities is represented by the standard deviation which ranges from $3 million

[1] RP3-RP6 Assume RP2 for 2022-2026 due to Evergy Capacity Purchase

for RP3 to over $9.4 million for RP1. RP6 has both a low NPV and stable costs with a standard deviation value of $4.7 million.

Figure 4: RP1-RP6 Net Present Value Summary



The recommendations of this Study include performing a more detailed analysis to determine the amount of energy to be hedged from the SPP IM, and to issue a Request for Proposals (RFP) to determine the availability and pricing of wind and solar resource options. The information gathered from the RFP process will be useful to work out a more detailed and optimized resource portfolio.

2 Electric Power Industry Review

Most of the recent trends in the electric power industry are indicative of the industry's central role in the country's efforts to address climate change. The following discusses many of the trends apparent in today's electric power industry, the Southwest Power Pool (SPP) IM, and KEPCo's current power supply resources.

2.1 Industry Trends

2.1.1 Renewable and Emerging Technology Development

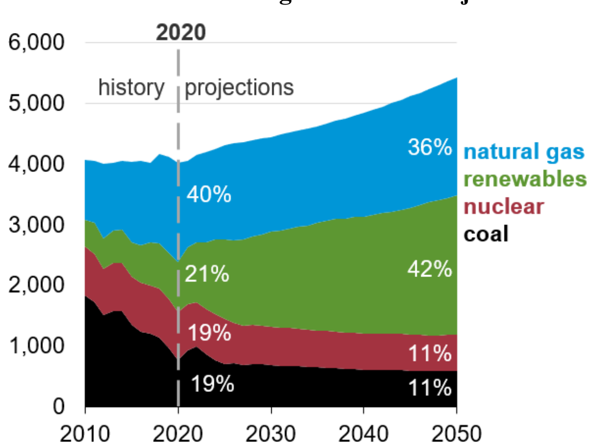
Spurred by regulation, and tax incentives, renewable resource additions are continuing at an increasing pace. About 81% of the 40 GW of generating capacity expected to become operational in 2021 will be renewable resources. Of the total renewable resource additions, 4.3 GW is battery storage, which more than quadruples the utility-scale battery storage capacity nationally. Further, it is estimated that roughly 30% of the solar capacity coming online in 2021 is to be paired with storage capacity.

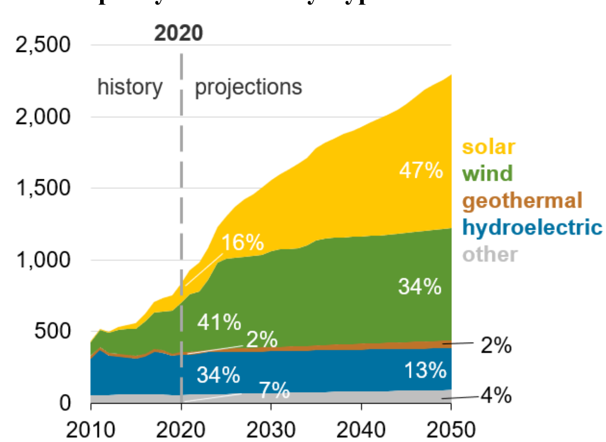
Green hydrogen storage is emerging as an alternative to natural gas for fueling generation. The hydrogen is produced by electrolysis using solar energy and stored for use, as needed, during system peaks or for balancing the grid. San Diego Gas and Electric is planning two hydrogen storage facilities to become operational in 2022, and other entities are researching the potential of the technology.

2.1.2 Solar and Wind Development

According to the Energy Information Administration (EIA) and consensus of the industry, the vast majority of new generation additions are expected to be renewable generating resources. Of the projected renewable generation capacity additions, the largest growth is expected from solar, followed by wind, which when combined are expected to represent over 80% of renewable generation capacity and approximately 34% of all generation capacity by 2050.

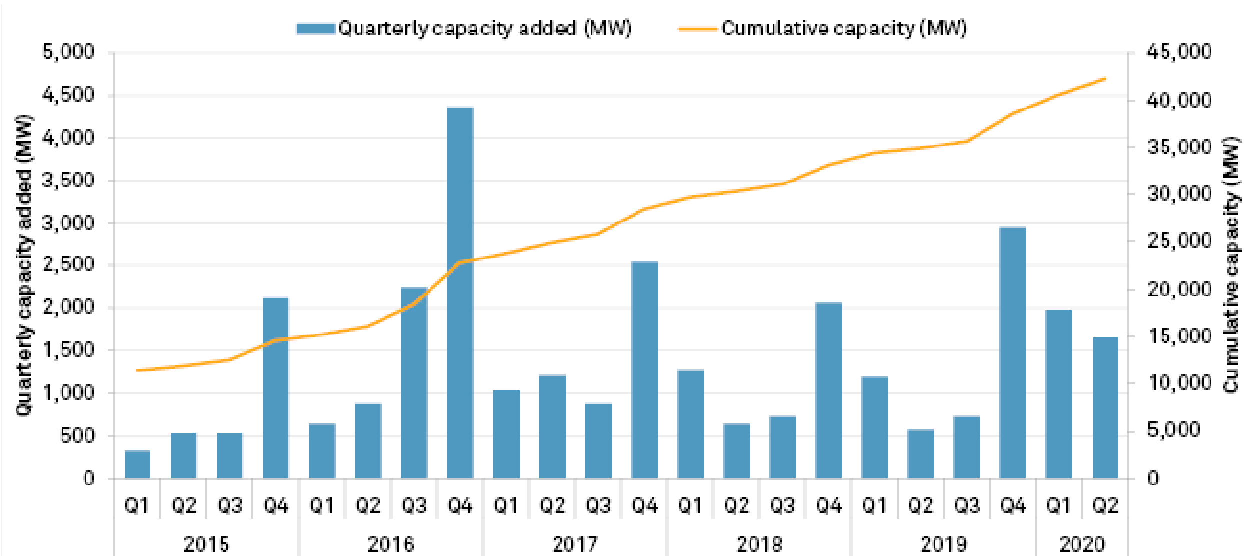
Figure 5: EIA Project of Generation Capacity Additions by Type





Reaching these levels will require a significant escalation in the rate of growth from historical levels, to say nothing of significant efforts and investment to reliably integrate them into the evolving grid. The EIA projections call for over 1,000 GW of installed solar capacity by 2050, whereas it reports just over 42 GW of solar installed as of Q2 of 2020. To meet EIA's projections, solar installations will need to grow by over 960 GW during the next 30 years, or about 30 GW each year on average. This forecast growth (per above) is not projected to be constant (i.e. ~ 30 GW per year) but is expected to proceed at a rapidly increasing rate, especially until the mid-2020s.

Figure 6: EIA History of Installed Solar Capacity by Quarter



The EIA states that in 2019, wind energy surpassed coal for the first time as the largest share of electricity in Kansas. Wind power increased to 41% of total energy and coal fell to 33%, giving Kansas the second-highest share of wind power generation after Iowa.

2.1.3 Policy and Public Influence on Renewable Development

Federal, state, and local governments and electric utilities encourage or, in some cases, require investing in and using renewable energy. There are hundreds of programs available nationally that generally fall into the following broad categories as identified by the EIA.

Government Financial Incentives

Several federal government tax credits, grants, and loan programs are available for qualifying renewable energy technologies and projects. The federal tax incentives, or credits, for qualifying renewable energy projects or equipment include the Renewable Electricity Production Tax Credit (PTC), the Investment Tax Credit (ITC), the Residential Energy Credit, and the Modified Accelerated Cost-Recovery System (MACRS). Grant and loan programs may be available from several government agencies, including the U.S. Department of Agriculture, the U.S. Department of Energy (DOE), and the U.S. Department of the Interior. It is likely that most or all federal programs will be reviewed and possibly revised, expanded, or extended by the Biden Administration.

Most states, including Kansas, have some financial incentives available to support or subsidize the installation of renewable energy equipment.[2]

Renewable portfolio standards and state mandates or goals

A renewable portfolio standard (RPS) typically requires that a percentage of electric power sales in a state comes from renewable energy sources. Some states have specific mandates for power generation from renewable energy, and some states have voluntary goals. Compliance with RPS policies will sometimes require or allow trading of Renewable Energy Certificates (RECs).

Renewable Energy Certificates or Credits (RECs)

There are financial products available for sale, purchase, or trade that allow a purchaser to pay for renewable energy production without directly obtaining the energy from renewable energy sources. The most widely available products are often (but not always) called renewable energy certificates or credits (RECs), which may be used by electric utilities to comply with state renewable energy portfolio standards.

Net metering

As of June 2020, 35 states and the District of Columbia have state-developed mandatory net metering for certain utilities, five states have statewide distributed generation compensation rules other than net metering, and five states are in transition to statewide distributed generation compensation rules other than net metering. Two states do not have statewide rules, but some utilities in those two states allow net metering. Most net metered systems are solar photovoltaic systems. Kansas requires all investor-owned utilities to offer net metering rates, and numerous electric cooperatives have voluntarily followed suit.

In 2010, the Kansas Corporation Commission promulgated rules to implement net metering standards. These rules are mandatory for the state's investor-owned utilities and provide for a credit for net excess generation equal to 100% of the utility's monthly system average energy cost per kWh. Since 2014, customer generation capability has been subject to the following limitations:

- Residential – 15 kW
- Non-Residential – 100 kW
- Schools – 150 kW

Many of the state's cooperative and municipal utilities have voluntarily implemented some form of net metering.[3]

[2] https://programs.dsireusa.org/system/program/ks
[3] https://kcc.ks.gov/electric/net-metering-in-kansas

Feed-in tariffs (FITs)

Several states and individual electric utilities in the United States have established special rates for purchasing electricity from certain types of renewable energy systems. These rates, sometimes known as feed-in tariffs (FITs), are generally higher than electricity rates otherwise available to the generator. FITs are intended to encourage new projects of specific types of renewable energy technologies.

Green power purchasing

Consumers in nearly every state can purchase green power, which represents electricity generated from specific types of renewable energy resources. Most of these voluntary programs generally involve the physical or contractual delivery of the electricity generation resource to the customer or utility.

Renewable research and development

DOE and other federal government agencies fund research and development of renewable energy technologies. Most of the research and development is carried out at the National Labs and in cooperation with academic institutions and private companies. The availability of these programs depends on annual appropriations from the U.S. Congress.

2.1.4 Natural Gas Prices

Natural gas prices have remained relatively low over the last few years and are projected to remain so. However, the Energy Information Administration estimates that the annual spot price to increase $0.98 per MMBtu during 2021-2022 from the 2021 average of $2.05 per MMBtu, their lowest level in years.

2.1.5 "Firm" Natural Gas Pipeline Capacity

With the increased reliance on natural gas generation, there has been increased interest in developing firm gas capacity as a lower cost alternative to gas transport contracts. With natural gas being neither carbon-free nor renewable, and pipeline construction being expensive and risky, interest may be waning in favor of more sustainable alternatives. Early examples of this are Dominion Energy and Duke Energy cancelling a joint pipeline project along the east coast. Dominion went a step further and has eliminated its gas transmission and storage operations altogether. Pricing in SPP does not typically include the additional costs of firm natural gas pipeline capacity, and this is an issue when it comes to a tight market condition during the winter and can impact natural gas pricing. This condition was a contributing factor for the February 2021 price spike.

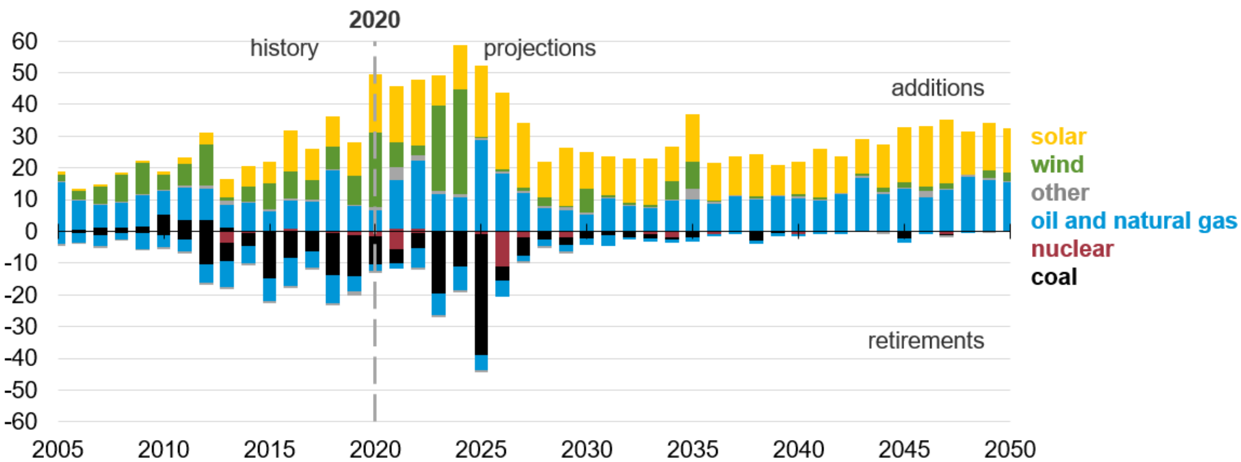
2.1.6 Wholesale Market Energy Prices

With low natural gas prices, increased renewable output, and low load growth, wholesale prices have been relatively low for several years when compared to historical averages. Although extreme weather in February 2021 caused volatility in market prices across parts of the country, prices have since returned to previous levels.

2.1.7 Coal Fired Generation Retirements

With increasing interest in green energy, regulatory mandates, and the high cost of compliance alternatives, coal-fired generation continues to be retired with no replacement coal-generation under construction or proposed. From 2014 to 2019, 66 GW of coal-fired generation was retired, and an additional 24 GW is planned to be retired through 2024.[4]

Figure 7: EIA History and Projection of Resource Additions and Retirements by Type



In early 2021, two bills were pending before the Kansas legislature (SB 202 and SB 245) that provide for securitization of the transition to renewable energy, including accelerated retirement of coal fire generating units. Similar legislation has failed in past years, but this year, the dynamics were different. Evergy, a regional investor owned utility with operations in Kansas, is the author of SB 245 and is a supporter of securitization. Evergy cites increasing demand for renewable energy and pressure to meet that demand as the reasons for its position. The need of Kansas Gas Service and others to securitize their exposure to extreme natural gas costs resulting from Winter Storm Uri also provided support for this bill. In addition, a consulting firm hired by the legislature to investigate ways to advise the state on lowering electric rates has recommended securitization with the caveat that, while monthly bills will be lower, the total cost paid by the ratepayers could be higher. The bill was approved by the legislature and signed into law by the governor.

2.1.8 Load Growth

While much of the U.S. has experienced economic growth over the past several years, it has not resulted in comparable growth in demand and energy consumption. This can be attributed, at least in part, to conservation and energy efficiency programs implemented across the nation. With natural gas and petroleum consumption being targeted in clean energy initiatives, there is potential for longer term impact on electricity consumption. The focus on electric vehicles (EVs) is well known, and the current administration has indicated its goal of removing the economic and practical barriers to their use. There are numerous communities across the nation that have already

[4] "America's Electric Generation Capacity, 2020 Update," APPA, pages 13 and 14

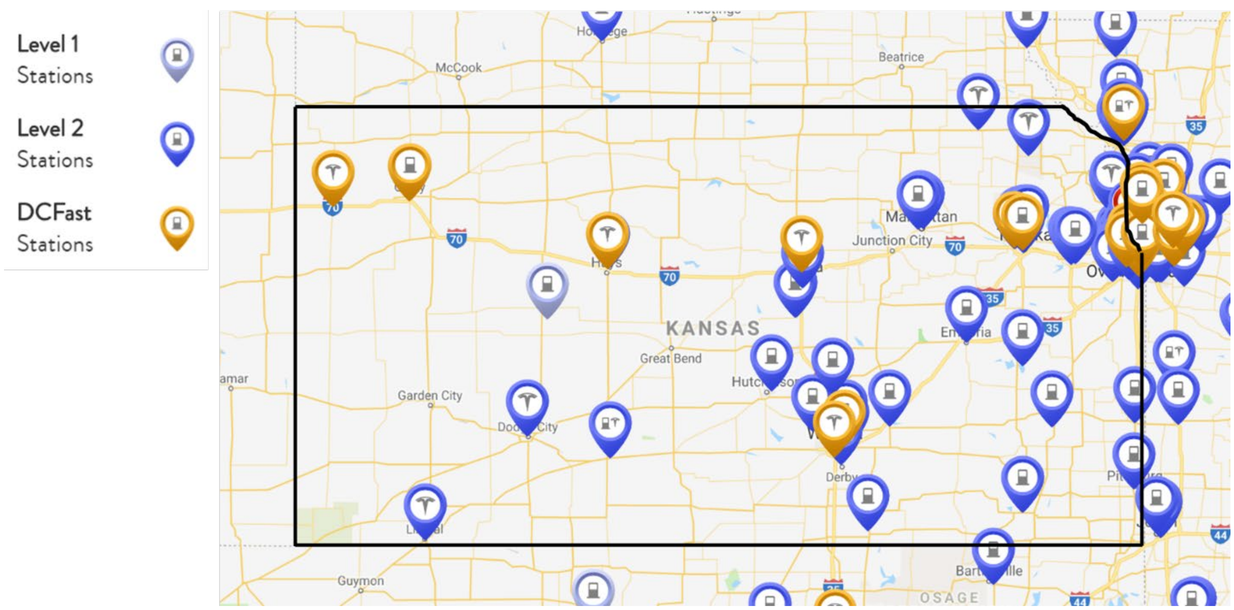
mandated that all new homes constructed be all electric. While it's too early to quantify the impact, electricity becoming the energy of choice has the potential to increase future consumption.

2.1.9 Electric Vehicles

Plug-in hybrid electric vehicles (PHEV) have been available since 2010, so they are not necessarily new technology. Battery electric vehicles (BEV) are a more recent development with continually evolving and improving technology and increasing sales and market share. Making EVs more desirable on a national level appears to be a key component of the national effort to reduce carbon emissions, which, in turn, is putting a priority on EV research and innovation. As of late 2020, over 1.4 million EVs have been sold nationally, comprising about 2% of new car sales in 2019.[5]

While this is still very low penetration, nearly all major car manufacturers have established goals around electrifying their models, and of course, new all-electric manufacturers continue to introduce their plans to enter the market. That, coupled with various public policies that go so far as banning the internal combustion engine (ICE), building out charging infrastructure, rebate incentives will certainly provide ongoing incentive for further development and market penetration of EVs.

Figure 8: KS EV Sales & Charging Stations[6]



EVs have two major drawbacks that limit their desirability: limited charging infrastructure and limited driving range times. Another drawback, much higher cost than ICE alternatives, is becoming less significant. There are also concerns regarding the time required to recharge batteries and battery safety.

EVs are currently powered by lithium-ion batteries, which sometimes have a characteristic of short circuiting and, in rare instances, causing fires when charged too quickly. Accordingly, there is a

[5] https://usafacts.org/articles/how-many-electric-cars-in-united-states/
[6] As of 2019 according to ChargeHub.

limit to how fast these batteries can charge, even with large capacity level 3 chargers. Typically, using such a charger for 30 minutes might provide about 80% of the battery's capacity. In late 2020, a new type of battery was announced that shows the potential to allow a much faster charge time, provide greater range, and be safer and cheaper than its lithium-ion counterparts. While it will be a few years before this is fully developed and commercially available, innovation like this will be helpful for expanding the EV market.

In early 2021, the US Department of Energy reported that there are 100,000 public charging outlets at 41,300 locations across the nation. Roughly 31% of both the chargers and locations are in California. Of the total charging outlets, just over 17,300 are DC Fast chargers. The Biden Administration has identified expanding current charging infrastructure as a priority.

In 2017, the US District Court approved a settlement with Volkswagen (VW) regarding the company's use of illegal methods to understate vehicle emissions. As part of the settlement, VW was required to establish a $2.7 billion environmental mitigation trust. The state of Kansas was allocated approximately $15.6 million of this trust. Per its report issued in 2018, the Kansas Department of Health and Environment (KDHE) anticipates working with various public and private entities, including electric companies to use 15% of its share or $2.3 million for increasing public EV charging infrastructure within the state. Examples include DC fast-charging stations located at rest areas along major highways or other appropriate areas and/or Level-2 stations located at public parking areas. KDHE proposes to provide up to 60 percent of the cost necessary for acquisition, installation, operation, and maintenance of the equipment.

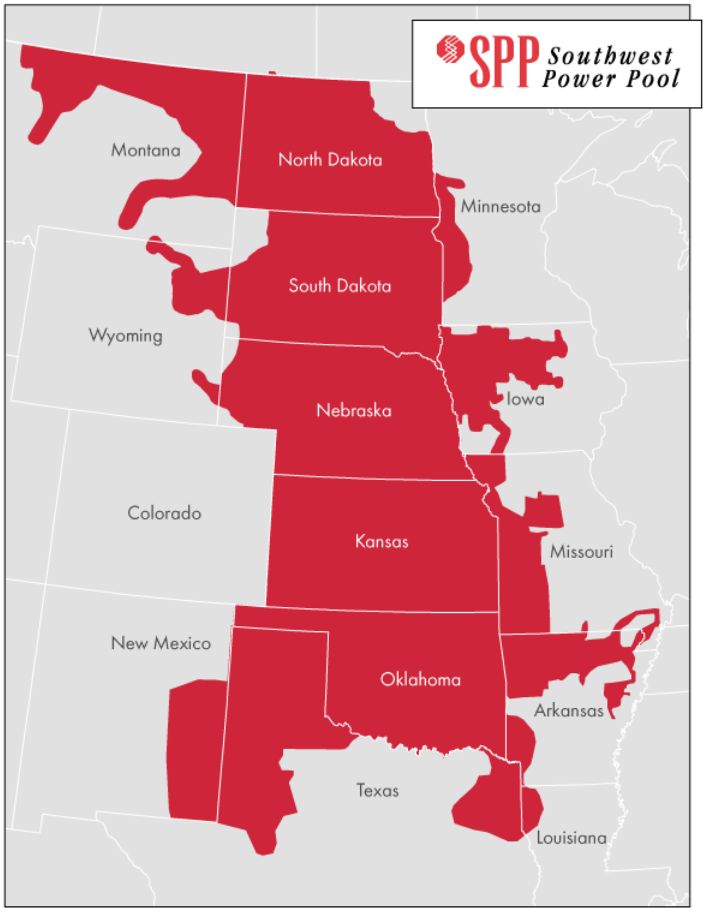
2.2 Southwest Power Pool

2.2.1 General

Southwest Power Pool (SPP) was first organized in 1941 by several regional power companies to help provide uninterrupted power to critical defense contractors during World War II. Since then, it has maintained its presence in maintaining electric reliability and coordination and, in 2004, was approved as a Regional Transmission Organization. In 2014, SPP initiated its Integrated Market. It serves numerous utilities and market participants located across 14 states.

SPP's service territory is shown in the figure below.

Figure 9: SPP Integrated Market Service Territory



SPP operations encompass the following markets:

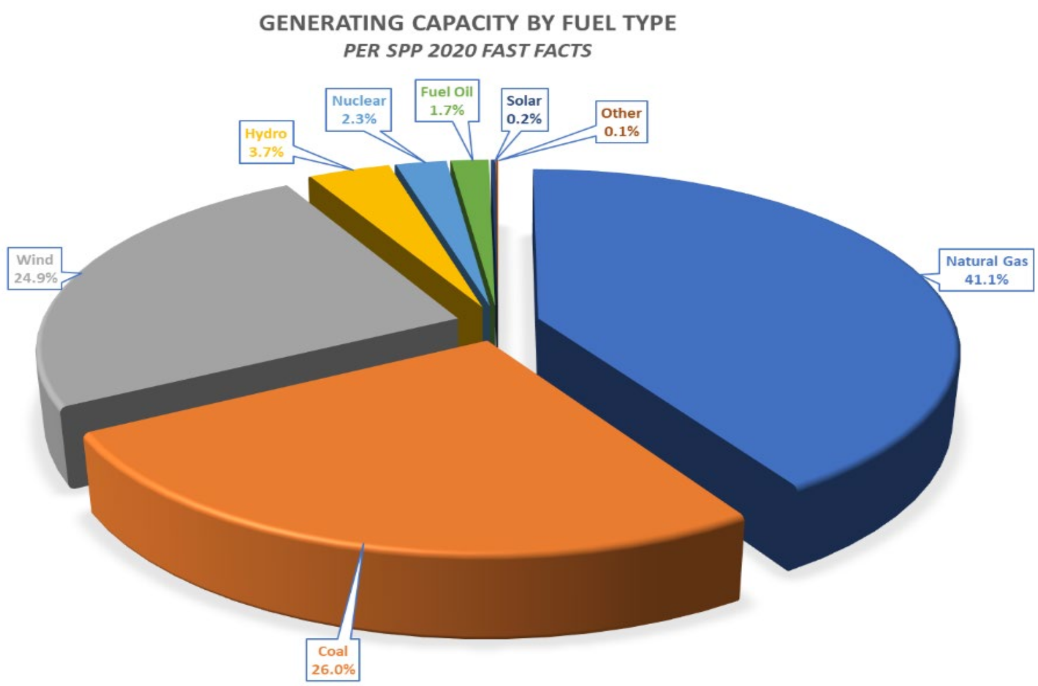
- Transmission Service: Participants buy and sell use of regional transmission lines that are owned by different parties.
- Integrated Marketplace: Participants buy and sell wholesale electricity in day-ahead and real-time.
- Day-Ahead Market: SPP commits the most cost-effective and reliable mix of generation for the region.
- Real-Time Balancing Market: SPP economically dispatches generation to balance real-time generation and load, while ensuring system reliability.

2.2.2 Current Generation Capacity and Production

SPP has a diverse array of capacity and energy resources, including fossil fuel, renewables, and nuclear generation. In the past 5 years, SPP power mix has shifted markedly from fossil fuel to renewables. While SPP's percentages of all fossil-fuel resources have decreased since 2015, coal stands out, having dropped over 7% of total generating capacity since 2015. Conversely, wind has increased from 14.9% to 26.0% of total capacity during the same period. While solar is still a minor component at 0.2% of SPP's current generating resources, it is likely to become far more significant based on SPP's proposed interconnections.

The chart below shows the makeup of SPP's current 90.4 GW of generating capacity.

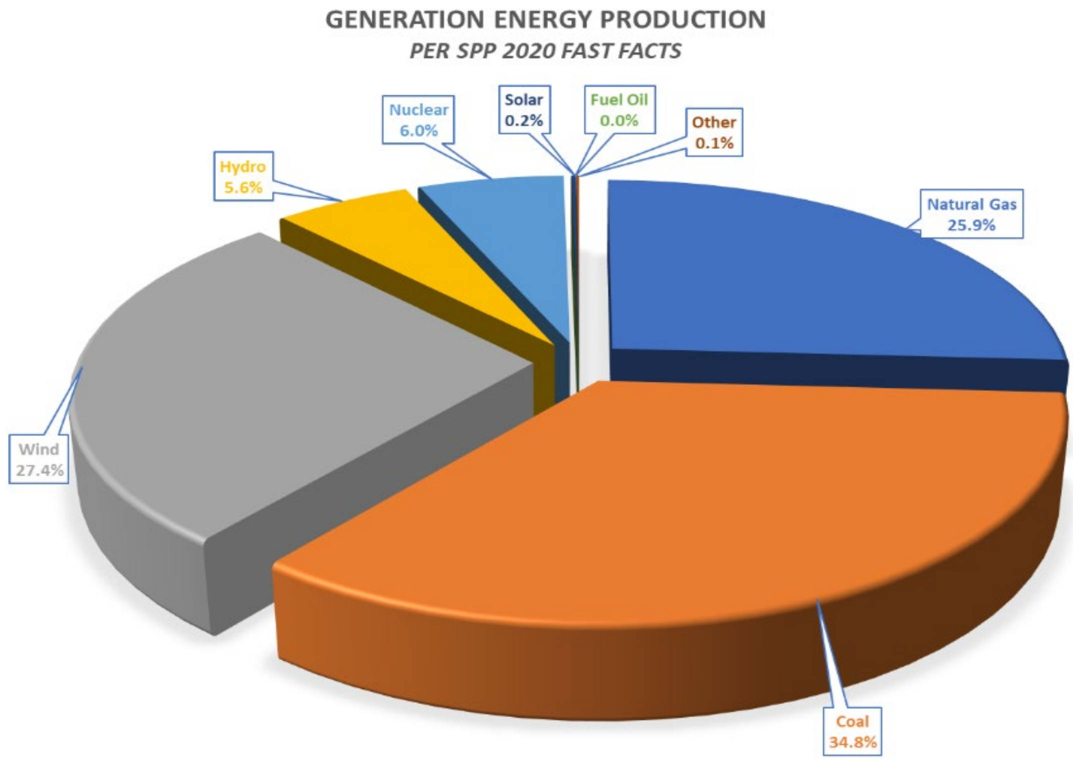
Figure 10: Generating Capacity by Fuel Type



As expected, SPP's main energy resources (coal, wind, hydro, and nuclear) account for the bulk of energy production, and natural gas is operated at a lower capacity factor than other significant resources. Since 2015, wind energy has doubled from 13.5% to 27.4% of SPP's total energy production, and, conversely, energy from coal resources has decreased from 55.1% to 34.8%.

SPP reported that its total 2020 energy output, 271,330 GWh, was produced as shown in the figure below.

Figure 11: Generation Energy Production



As of January 2020, SPP has 90,466 MW of generation nameplate capacity at its disposal. Its summer coincident peak load is 50,662 MW (August 2019), and winter coincident peak load is 43,584 MW (January 2018)[7].

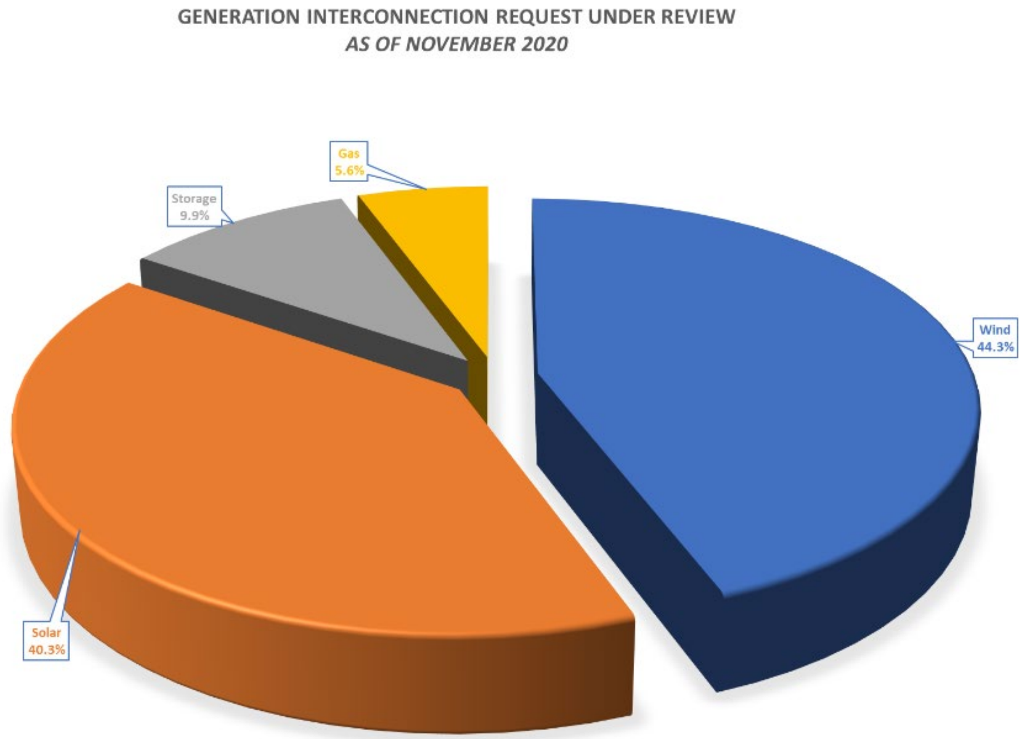
2.2.3 Generation Interconnection Requests

As of late 2020, SPP had Generation Interconnection Requests (GIR) in progress representing over 90 GW of capacity. The bulk of these resources are scheduled to become operational in the next 5 years. It is noteworthy that while solar and storage comprise an almost negligible portion of SPP's current generation mix (approximately 0.2%), they comprise one half of the GIR capacity or 45,000 MW currently under study.

[7] The Winter Peak set during Winter Storm Uri was slightly higher (43,611 MW on Feb. 15, 2021)

As shown on the following chart, renewables make up 94.4% of the GIR capacity, and natural gas makes up the remaining 5.6%.

Figure 12: Generation Interconnection Request Under Review



2.2.4 Generation Interconnection (GI) Policies

To address concerns expressed about the GI Queue process, FERC issued a Notice of Proposed Rule Making in late 2016 to address the possible shortcoming of the then existing interconnection processes. According to SPP, FERC sought to:

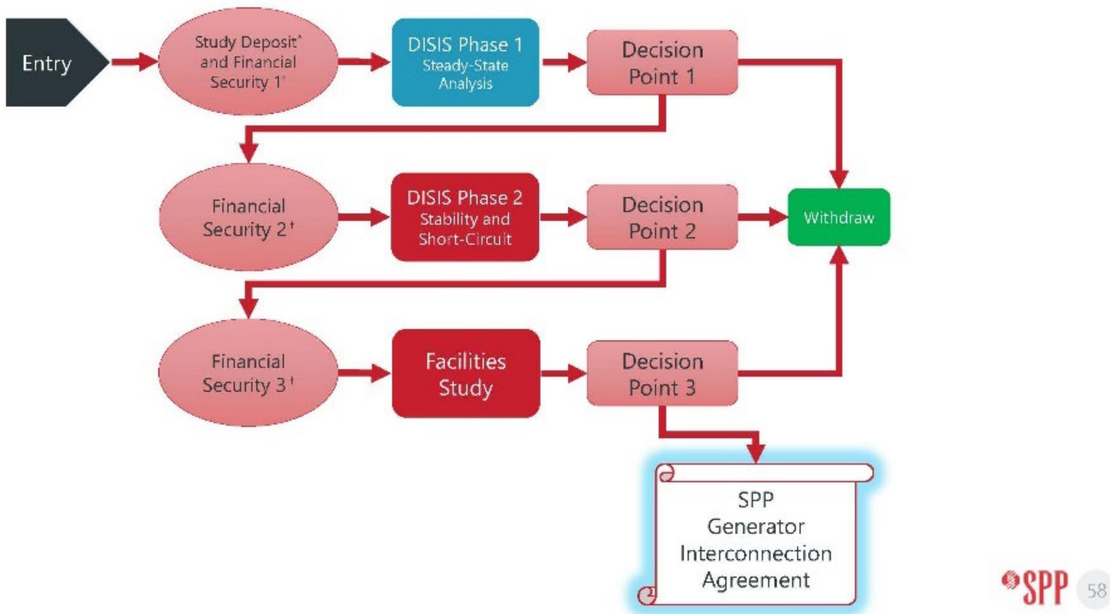
- Allow better decision making by improving the transparency of the process.
- Reduce cost uncertainty.
- Develop new generation on a timely basis.

SPP noted that FERC's main frustration was over "…repeated restudies and prolonged queue times resulting from the withdrawal of higher queued interconnection requests."

Following FERC's action, SPP initiated a GI Improvement Task Force in early 2017. The Task Force's efforts resulted in SPP's Three-Phase Interconnection Study Process, which became effective in mid-2019.

The following SPP flowchart provides a high-level illustration of the new process.

Figure 13: New SPP GI Study Process (Three-Phase)



SPP identifies the key attributes of the new process as:

- Streamlined, simplified, less confusing.
    - Easier for SPP to administer.
    - Easier for customers to understand and navigate.
- Majority of upgrades [to transmission resources] are identified in Stage 1, which permits customers to make an informed decision prior to committing to a lengthy and expensive stability analysis.
- Tying financial security to upgrade cost allocation encourages customers to weigh the risks of proceeding at an earlier stage.
- Reduce the number of requests withdrawing late in the process, which reduces re-studies and uncertainty.

2.2.5 Future Capacity Market

The SPP capacity market is not established as a Regional Transmission Organization (RTO), but the bilateral capacity market in SPP is vibrant and allows SPP Load Responsible Entities (LREs) to buy and sell capacity. Details on how the bilateral capacity market is being modeled for this Study are in Section 6.2.

2.3 KEPCo Power Supply

KEPCo provides energy and capacity to its members through owned resources and power supply contracts. KEPCo's total coincident peak demand is approximately 418 megawatts (MW) or 475 MW when including transmission losses and a 12% capacity margin.[8] KEPCo is currently forecasting long-term load growth around 0.3%, which is consistent with other utilities' load forecasts in the region.

The following summarizes KEPCo's existing power supply po1ifolio for meeting its load and energy requirements:

- Owned resources
  - Wolf Creek Generation Station (nuclear) 70 MW
  - Iatan 2 Generating Plant (coal) 30 MW
  - Sharpe Generating Station (diesel) 20 MW
  - Prairie Sky (solar) 1 MW
- Power purchase agreements
  - Southwestern Power Administration (hydroelectric) 100 MW
  - Western Area Power Administration (hydroelectric) 13 MW
  - Evergy Capacity (expires 12/31/2026) 50 MW
  - Evergy (expires 2045)[9] Approx. 158 MW

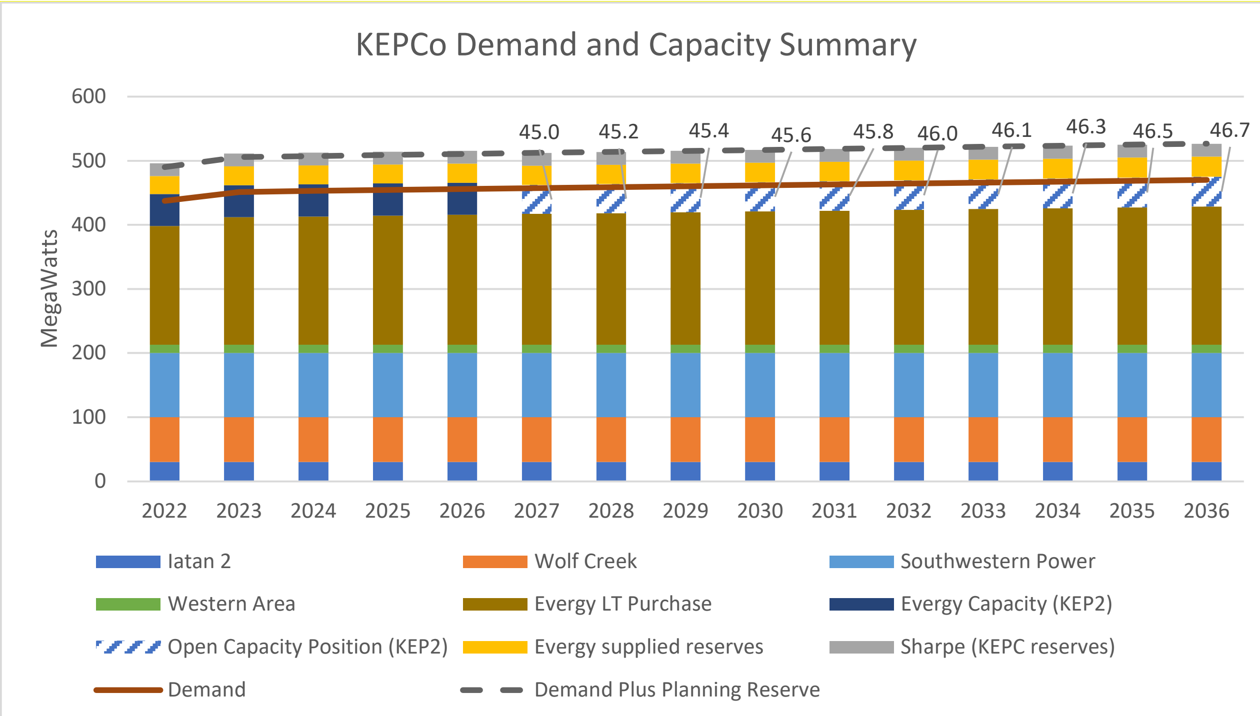
As illustrated by the list above, KEPCo has a diverse power supply portfolio consisting of nuclear, coal, peaking, and hydroelectric resources. Both the Southwestern Power Administration (SWPA) and Western Area Power Administration (WAPA) power purchase agreements (PPA) consist of hydroelectric resources, which are anticipated to operate through the current planning horizon. Furthermore, the Evergy PPA is sourced from energy from the utility fleet, which include coal, natural gas, and renewable sources.

A balance of loads and resources (BLR) based on the load forecast and resources that KEPCo will have available to meet its obligations is presented below. Based on existing resources and current load projections, KEPCo will require additional capacity in 2027, after the expiration of the Evergy capacity PPA.

A key objective of this Study is to determine the power supply alternatives available to KEPCo to meet capacity and energy requirements after the 2027 expiration of the Evergy capacity PPA.

[8] Appendix A-4, Page 9
[9] KEPCo has an "all requirements" contract with Evergy that credits KEPCo for the capacity and energy provided by KEPCo resources under the contract. About 90% of KEPCo's load requirements are met by this contract.

Figure 14: Balance of Loads and Resources



3 Regulatory Review

3.1 Environmental Protection Agency (EPA) Initiatives

The EPA has issued rules covering electric utilities in the areas listed below. Recent EPA actions are noted where appropriate.

- Cleaner Power Plants: In 2011, the EPA established national standards for reduction of toxic air pollution for coal and oil-fired power plants. These standards address toxins such as mercury, other metallic, acid, and organic.

- Cross State Air Protection Rule (CSAPR): In March 2021, a revised CSAPR was issued requiring power plants in 12 states, including Kansas, to further reduce nitrogen oxide emissions.

- Mercury and Air Toxic standards, including Final Mercury and Air Toxics Standards (MATS) for Power Plants finalized July 17, 2020: This action changes the format and methods for electronic reporting but does not change the information already required.

- National Emissions Standards for Hazardous Air Pollutants (NESHAP) Air Toxics Regulations:

  - Air Toxic Standards for Utilities: The key pollutants EPA regulates include particulate matter (PM), nitrogen oxides (NOx), and sulfur dioxide (SO_2).

  - Benzene Waste Operations: These standards apply to equipment and processes at certain chemical manufacturing plants, coke byproduct recovery plants, petroleum refineries, and facilities that treat, store, or dispose of waste generated by those facilities.

  - Stationary Internal Combustion Engines, including Reciprocating Internal Combustion Engines (RICE) regulations: This rule has been in effect since early 2013 and sets limits for several pollutants associated with internal combustion engines.

  - Stationary Combustion Turbines: This final rule, issued in March 2020, establishes national emission standards for hazardous air pollutants (NESHAP) for stationary combustion turbines. Stationary combustion turbines have been identified as major sources of hazardous air pollutants (HAP) emissions such as formaldehyde, toluene, benzene, and acetaldehyde.

- Greenhouse Gas Reporting Program: This program requires reporting of greenhouse gas (GHG) data and other relevant information from large GHG emission sources, including power plants. The first reporting year was 2019.

- Fossil Fuel Combustion Waste: Issued in early 2015, this rule establishes a comprehensive set of minimum requirements for the disposal of coal combustion residuals (CCRs or coal ash) in landfills and surface impoundments. This rule does not affect state regulations that are more stringent and, while they are not required to do so, the EPA encourages states to adopt at least the minimum federal criteria into their regulations.

- Cooling Water Intake Structures: This 2014 rule established regulations to reduce injury and death of fish and other aquatic life caused by cooling water intake structures at existing power plants and factories.

- Steam Electric Power Generating Effluent Guidelines, including the 2020 Steam Electric Reconsideration Rule finalized August 31, 2020: Generating effluent has been subject to EPA oversight since 1974 (40 CFR Part 423). In 2015, the rule was revised to limit the level of toxic metals that can be discharged from a power plant based on technological improvement in the industry. As a result of legal challenges, the 2015 rule was revised in 2020 to include new requirements for two specific waste streams, flue gas desulphurization water, and bottom ash transport water.

3.2 Clean Power and Regulatory Matters

In the past 5 years, the industry has faced two significant EPA environmental regulations: The Clean Power Plan (2015) and The Affordable Clean Energy Rule (2019). The Clean Power Plan was stalled in the courts before being repealed in 2019. The Affordable Clean Energy Rule also faced legal challenges before being vacated in federal court in early 2021. As a result, there is currently no overarching federal regulation addressing carbon emissions in the electric power industry. This situation is unlikely to last long as the current Administration in Washington, DC has advocated a carbon-free power sector by 2035, or roughly 15 years from now.

About three quarters of the states have implemented renewable energy regulations in some form. These vary from relatively modest targets for renewable energy as a percentage of each utility's power supply portfolio to the industry being 100% carbon-free or 100% renewable by a future date (2045 is typical). Some of these states, as well as some additional states, are considering new or updated clean energy regulations. The National Conference of State Legislatures attributes about one half of the growth in renewable energy in the last 15 plus years to state-level initiatives.

3.3 Carbon Pricing

Carbon pricing can take two forms. The first is a carbon tax on the distribution, sale, or use of fossil fuels, based on their carbon content. The second is a system called "cap-and-trade," where the total of allowable emissions is set, and companies are taxed if they produce a higher level of emissions than their permits allow. Companies that reduce their emissions can sell, or "trade," unused permits to other companies.

The current Biden Administration has, so far, sent mixed signals regarding its position on carbon pricing. However, there are strong proponents of carbon pricing among cabinet and senior staff members who are working on the Administration's climate policy recommendations due out later this year. Preliminary indications, for example from Treasury Secretary Janet Yellen, are that the Administration favors and will advocate for a carbon tax.

While the likelihood and form of a proposed carbon pricing mechanism is a question mark at the federal level, several states, including the Regional Greenhouse Gas Initiative in New England and along the west coast, have initiated cap and trade programs as of early 2020. During 2018 and 2019, there were unsuccessful attempts in several states to implement carbon taxes, which is considered a tougher sell.

In early 2021, the Administration estimated the cost of CO2 to be $51 per ton. This is over 6 times higher than the $8 per ton estimated by the prior administration. Without arguing the merits of either estimate, this difference indicates that the calculation of carbon cost is not universally defined and is likely to be controversial. Defining what constitutes a societal cost, how the cost is determine, and even what the appropriate discount rate is, to a large degree, a matter of opinion. Indeed, some estimate the cost to be far higher than $51 per ton.

The Energy Information Administration (EIA) estimates that, on average, generating 1 kWh of electricity produces 0.92 pounds of CO2. For purposes of this Resource Planning Study the following emissions rates (in tons per MWh) are used based upon the 2019 data for SPP. A carbon cost of $15 per short ton has been used.

Table 1: CO2 Emissions Rates Ton/MWh

Coal	Gas	Oil
1.12	0.525	1.0216

4 Demand Side Management Analysis

KEPCo completed a Demand Response Study (DR Study) in 2019. The DR Study summarizes modeling and analysis to assess the cost effectiveness of existing and potential new DR measures, to evaluate qualitative issues with respect to KEPCo's DR programs, and to provide guidance on how the current wholesale tariff flows benefit of DR from KEPCo through to the distribution member providing demand reductions.[10]

Below is a discussion of the demand-side management and Energy Efficiency (EE) programs that are currently in place at KEPCo, along with results of the DR Study in regard to potential for new DR measures. It should be noted that KEPCo does not currently operate a "centralized" Demand Side Management (DSM) program, but rather these programs and activities are independently pursued and implemented by KEPCo's distribution cooperative members. KEPCo does provide peak alert notifications and generation requests to the members who then make decisions about operating their DR resources/programs.

4.1 Existing DSM Programs

The DSM programs currently in place at certain KEPCo member cooperatives include the following:

- Air Conditioning Control: Using a load controller, the air conditioner compressor is cycled during a load control event, commonly for a duration of 3-4 hours. A limitation for the program is the duration of control that is possible before the indoor air temperature increases to an uncomfortable level.

- Water Heater Control: Using a load controller or timer, the heating element within the water heater is shut off during a load control event, commonly for a duration of 3-4 hours. Often the consumer will not realize that the control has happened, however, a lack of hot water may be noticed if the event lasts too long.

- Irrigation Pump and Oil Well Control: Using a load controller, the irrigation pump or oil well is shut off during a load control event. The shut-off typically requires a restart, which can either be manually visiting and re-starting each site or, in some cases, by remotely restarting.

- Distributed Generation: KEPCo allows its member cooperatives to own and self-supply a portion of their power supply requirements. Some member cooperatives own diesel generators that are operated during peak events to reduce load. KEPCo members are adding 20 MW solar to their systems in the 2021-2022 timeframe.

- Time-of-Use and Interruptible Rates: Some KEPCo members use Time-of-Use rates to encourage energy shifting or reduction during on-peak hours. They also use Interruptible

[10] "2019 Demand Response Study, Final Report", completed for Kansas Electric Power Cooperative by GDS Associates, Inc. November 4, 2019, page 1.

Rates to encourage commercial and industrial customers to reduce load during on peak hours.

- Voluntary Load Management: Many KEPCo members notify their customers about peak alert days and encourage them to voluntarily shift or reduce load as much as possible in the name of the "cooperative spirit" and to help control electric costs in general.

4.2 Potential New DSM Programs

Several potential or new DSM programs were identified and evaluated in the DR Study:

1. Electric Battery Storage
2. Smart Thermostats
3. Residential Demand Rate
4. Critical Peak Pricing ("CPP")
5. Critical Peak Rebate ("CPR")
6. Real Time Pricing ("RTP")

4.3 Benefit-Cost Modeling of DSM Programs

Each existing and new DSM program was evaluated utilizing the Total Resource Cost Test (TRCT), which is a common cost effectiveness test used for initial screening of EE and DR programs.[11] The TRCT considers whether the sum of the utility costs and participants' costs decrease with the program. In other words, the TRCT establishes whether there are adequate benefits when viewing KEPCo, the distribution cooperative, and the retail member consumer as one integrated system that exceed the costs.

The TRCT is expressed as a benefit-cost ratio, calculated as below:

$$TRCT = \frac{NPV\ of\ Benefits}{NPV\ of\ Costs}$$

[11] The five commonly used cost effectiveness tests used in the industry for the evaluation of EE and DR programs include: 1) Societal Cost, 2) Total Resource Cost, 3) Utility Cost, 4) Participant Cost, and 5) Rate Impact Measure.

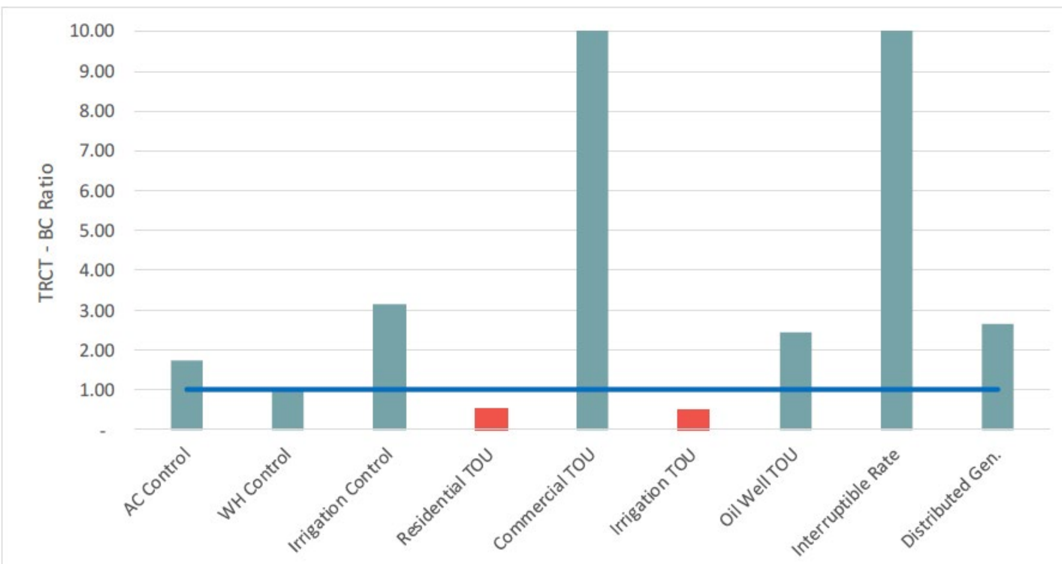
The benefits included in the DR Study for purposes of determining the TRC include those listed in the table below:

Table 2: TRCT Benefit and Cost Categories

Benefits	Costs
Avoided Capacity Costs	Program Administrator Expenses
Avoided Energy Costs	Program Administrator Capital Costs
Avoided Transmission & Distribution Costs	DR Measure Costs: Program Admin. Contribution
Avoided Ancillary Service Costs	DR Measure Costs: Participant Contribution
Revenue from Wholesale DR Programs	Participant Transaction Costs
Market Price Suppression Effects	Participant Value of Service Lost
Avoided Environmental Compliance Costs	Increased Energy Consumption
Tax Credits	Environmental Compliance Costs

Results of the benefit-cost tests under the expansion case for the existing DSM programs are summarized in the figure below, taken from page 5 of the DR Study.

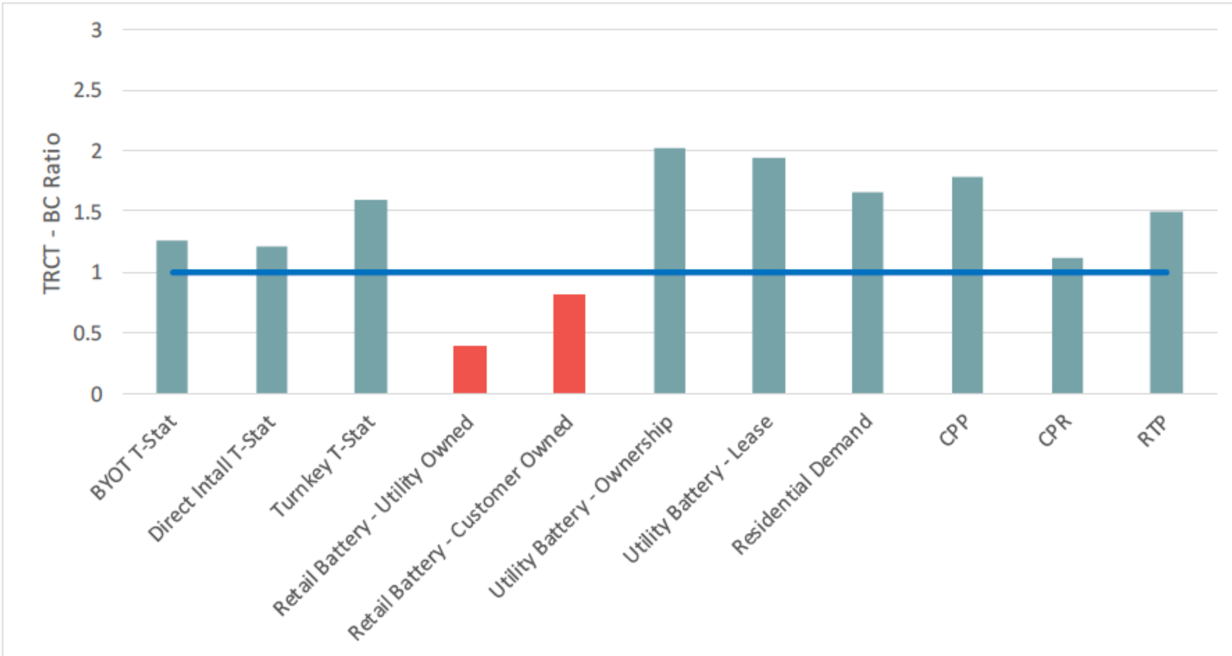
Figure 15: Benefit Cost Tests Results – Existing DSM Program



The DR Study concluded that, except for the Residential Time-of-Use (TOU) and Irrigation TOU programs, all the existing DSM programs are cost effective. In regard to those two programs, the DR Study advises that the TRCT is focused on evaluating the cost effectiveness of DR only and that there can be several other reasons to implement a TOU retail rate design that fall outside of what the TRCT measures.

Results of the benefit-cost tests under the expansion case for the new DSM programs are summarized in the figure below, taken from page 5 of the DR Study.

Figure 16: Benefit Cost Tests Results – Expansion Case DSM Program



Once again, the DR Study finds that, with two exceptions, the potential new programs pass the TRCT with benefit-cost ratios exceeding 1.0. It is advised that although many of the potential new programs pass the TRCT, KEPCo and/or its members should consider additional factors in more detail before deciding to implement new programs.

4.4 Qualitative Assessments and Operational Issues

The DR Study also evaluates other programs from a qualitative perspective because they are not as conducive to a TRCT analysis. A summary is provided below.

- Voluntary Load Management: A program such as "Beat the Peak" where the utility simply asks members to voluntarily conserve during peak hours. This type of program has somewhat unpredictable response and it does require some means of notification such as email, text, radio, social media, etc.

- Conservation Voltage Reduction ("CVR"): The increasing prevalence of SCADA and other smart grid equipment can help utilities pursue CVR more effectively than in the past. The program involves the reduction of voltage on a feeder in a way that reduces load yet does not result in flickers or brownouts. The reduction in load means that less demand and energy is required; however, it also means that less energy, and possible demand, is billed at retail. If targeted to only peak events, the demand cost benefits could more than offset the energy sales loss. CVR can be very feeder-specific (i.e. the types of loads on the feeder) and some feeders are not good candidates because of the presence of critical or sensitive loads such as hospitals or some industries.

Centralized Model of Distributed Generators: The KEPCo contract with its members allows the members to self-supply a portion of their capacity and energy requirements. Several KEPCo member cooperatives have installed distributed generation resources to decrease the peak demand on KEPCo's system. The number of member cooperatives utilizing distributed generation is expected to continue to increase over the next few years. Currently, KEPCo issues generation requests to its members as an attempt to reduce its billing demand, which generates an avoided cost benefit.

- Wholesale Billing Definition: The DR Study considered and provided comments and observations on the question of whether the wholesale billing demand should be changed to align with the Evergy peak. It acknowledges that while there is significant overlap between the Evergy and KEPCo peaks, there are some conflicting price signals or inefficiency to the extent they are not perfectly aligned.

- Number of Events Called by KEPCo: The implementation of DR programs in the KEPCo system depends on the calling of peak events by KEPCo. There is a tradeoff between calling too many events (resulting in loss of service, sales, satisfaction, etc.) and too few (resulting in missing the peak). The impacts and unpredictability of weather, a significant driver of load, can make balancing this a challenge. During the period evaluated in the DR Study, KEPCo called for DR in about 100 hours, which is not outside a typical range of expectation. Further, surveys indicated that DR participants are not complaining about too much control. Reducing the number of events could impact the effectiveness of calling events during the peak, and so a reduction in event hours was not recommended.

The DR Study concludes with the following summary recommendations for expanding DR:

1. Expand existing programs, in particular irrigation control, AC control, interruptible rates, and distributed generation programs.

2. Consider potential new programs, including thermostat programs, innovative rate designs, CVR, and voluntary load management programs.

3. Evaluate utility-scale battery options to enhance demand management.

4. Evaluate a centralized control model for distributed generation assets to improve the utilization/effectiveness of existing capacity resources at member locations.

5. Maintain current methods used to call generation requests and peak alerts.

4.4.1 Load Forecast

KEPCo provided a 10-year long-range load forecast (LRLF) that was utilized in the Resource Plan. The LRLF provided by KEPCo was developed internally and extended, using a trending approach, through the 15-year Resource Plan timeframe.

KEPCo developed the forecasted energy and demand using a combination of linear regression and trending analysis to produce an aggregate forecast for each customer class at the Member level of sales, and then a loss rate was applied to produce the KEPCo sales forecast for each Member.

Linear regression was used to develop econometric equations to predict energy sales for the residential and small commercial customer classes that relate variables such as weather, price of electricity, and economic indicators such as the price of oil to energy sales. A 10-year average of cooling and heating degree-days, price of oil, per capital income, and population were found to be significant variables in predicting sales. The Woods & Poole Kansas State Profile was used to estimate future population growth and economic indicators, and trending analysis was used to predict the inflation-adjusted price of oil. Forecasts were also evaluated and adjusted based on recent sales and projected growth. Demand forecasts were produced for each Member by a combination of linear regression modeling with energy and cooling degree days as predictive variables and trending analysis. The sales and demand projections for KEPCo as a whole is the summation of Member forecasts. Projections for each KEPCo control area were based on the Member's historic percentage of sales in each area and Member forecasts.

The forecasts for demand and energy are summarized on an annual basis over the study period in the figures below.

Figure 17: 15-Year Summer Peak Demand Forecast

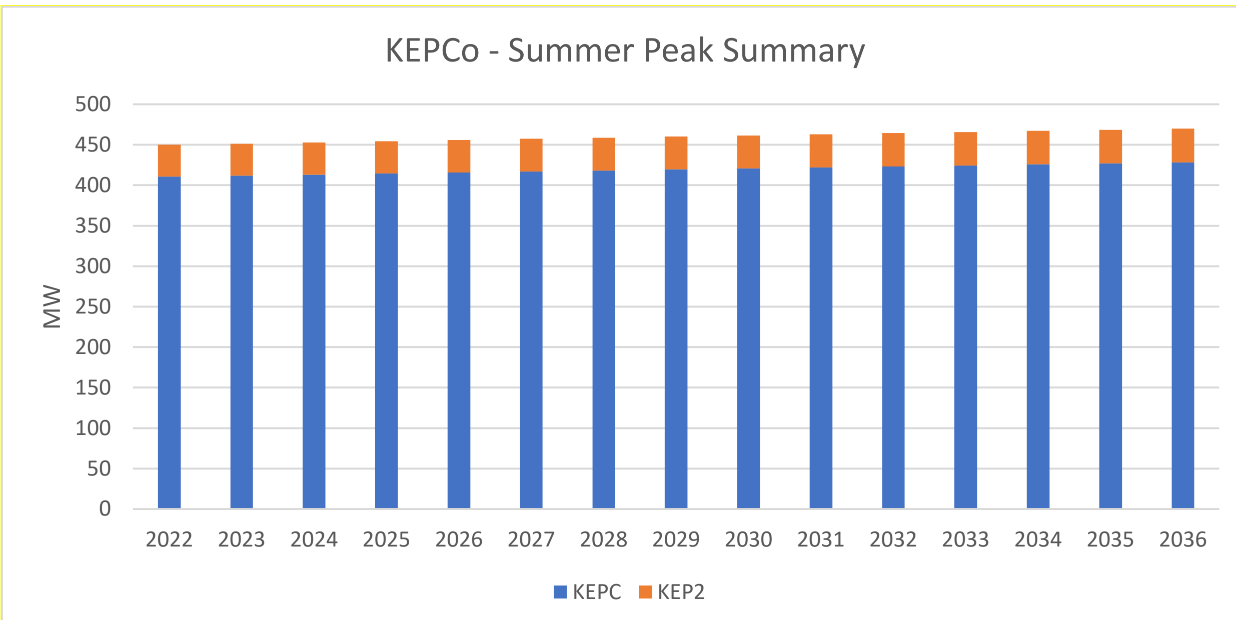
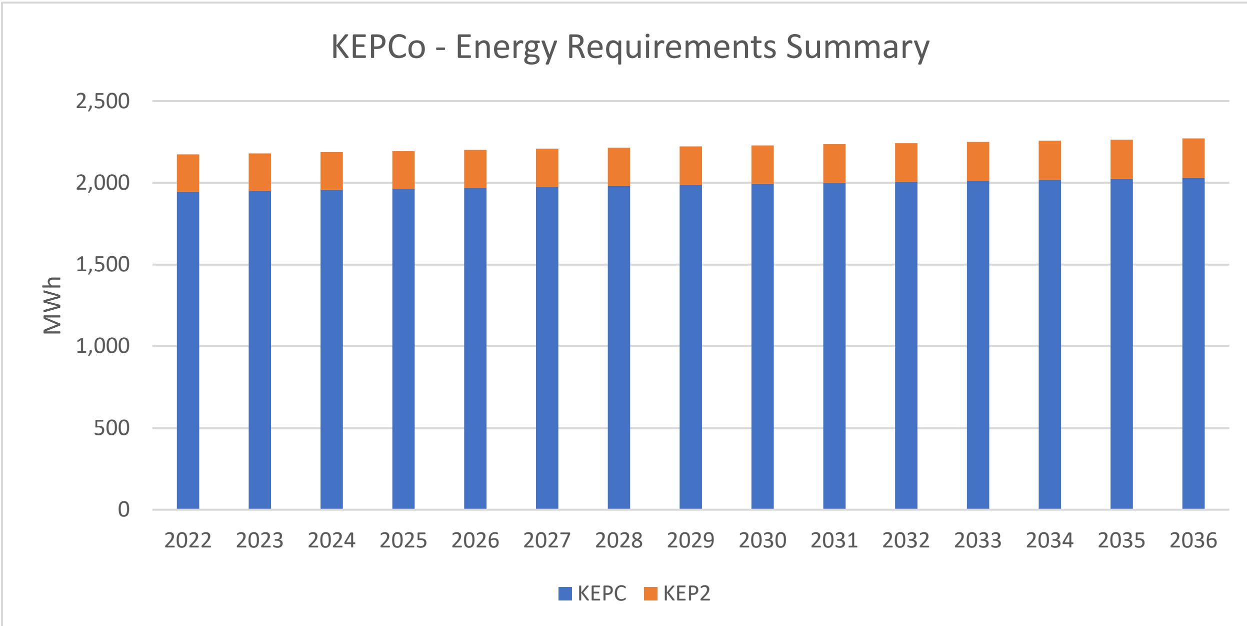


Figure 18: 15-Year Energy Forecast



5 Technology Assessment

There is a broad range of resources that are viable for meeting KEPCo energy and capacity requirements. As a LRE in SPP, KEPCo has the opportunity to secure a bilateral contract or participate in an ownership position for energy and/or capacity needs. The range of resource alternatives is broad, and the assessment of viable options is made based on the current context of resource portfolio transformation that is occurring.

Available technologies for meeting resource needs can be summarized under the categories of conventional technologies and renewable technologies:

1. Conventional Technologies
   i. Simple Cycle Peaking Generation
      1. Proven technology
      2. Dispatchable resource
      3. Natural gas fuel
      4. Likely need to consider a shared peaking plant, due to 50 MW targeted size
      5. More simple operation – no steam cycle

   ii. Fast Ramping Peaking Generation
      1. Proven technology
      2. Simple operation
      3. Natural gas or diesel fuel
      4. Distributed generation installation of this type of generation could be used
      5. Capability of quickly coming online and meeting unforeseen load requirements

   iii. Combined Cycle Peaking Generation
      1. Most efficient conventional generation capacity
      2. Natural gas fuel
      3. Proven technology
      4. More involved unit commitment and operations due to having both a simple cycle generation and heat recovery steam generator (HRSG) systems

   iv. Steam Cycle Natural Gas Generation
      1. Proven technology
      2. Less efficient generation than a combined cycle
      3. Longer start-up time for bringing boilers up to operating conditions
      4. Not typically considered a viable alternative, as it isn't as efficient as combined cycle

2. <u>Renewable Technologies</u>
   i. Solar PV – Utility Scale
      1. Proven technology
      2. Improved reliability with string inverter designs to allow for partial forced outages and maintenance outages
      3. Attractive costs as shown by historic PPA data
      4. Scalable to smaller footprints to lessen transmission interconnection impacts

   ii. Solar – Distributed or Solar Garden
      1. Proven technology
      2. Improved reliability with string inverter designs to allow for partial forced outages and maintenance outages
      3. Extremely scalable within the distribution system

   iii. Wind Generation
      1. Proven technology
      2. Significant levels of wind generation in SPP, and projected levels to more than double in the next 15 years
      3. Historically low SPP LMP values in areas of high wind development are an indication of inadequate transmission facilities for moving the generation to load centers. Evaluating wind generation interconnection requests involves making the assessment for transmission improvements on the system. If the wind project under consideration for KEPCo would require the need to make major transmission improvements, it could adversely impact the economic viability of the wind project.
      4. This results in wind generation additions having challenges in defining interconnection timing and costs due to the need to make transmission improvements needed on the system

   iv. Energy Storage
      1. Proven technologies
      2. Challenge for establishing an economic business case in the wholesale markets
      3. Capital costs in the range of $250/kWh

5.1.1 KEPCo Capacity and Energy Requirements

Capacity and energy requirements for KEPCo in the planning horizon of 2022-2036 are shown in Table 3. These requirements are net of expected impacts of DSM programs on the capacity and energy projections.

Table 3: KEPCo Total Capacity and Energy Requirements (2022-2036)

Year	Summer Demand	Winter Demand	Energy (GWh)
2022	437.54	364.04	2,173.53
2023	451.36	336.14	2,180.27
2024	452.82	337.20	2,187.35
2025	454.40	338.37	2,194.88
2026	455.80	339.40	2,201.53
2027	457.33	340.53	2,208.93
2028	458.69	341.54	2,215.43
2029	460.12	342.60	2,222.57
2030	461.50	343.62	2,229.65
2031	463.01	344.74	2,236.67
2032	464.42	345.78	2,243.71
2033	465.86	346.85	2,250.78
2034	467.30	347.91	2,257.86
2035	468.74	348.98	2,264.97
2036	470.18	350.04	2,272.10

KEPCo has a common tariff and a common rate for all Members and utilizes a blended power supply.

KEPCo's KEP2 capacity is provided through 12/31/2026 with an Evergy PPA. KEP2 energy supply is not committed to any contractual arrangement, and the Study is evaluating resource alternatives to avoid this power supply as being exposed to the SPP IM. KEPCo's KEPC energy and capacity is served through a combination of KEPCo owned resources, hydroelectric purchases from Southwestern Power Administration and Western Area Power Administration, and supplemental Cost Based Formula Rate Agreement with Evergy Kansas Central. The Evergy contract term is through 2045.

The KEPCo capacity and energy resources include the following:

- Owned resources
  - Wolf Creek Generation Station (nuclear) — 70 MW
  - Iatan 2 Generating Plant (coal) — 30 MW
  - Sharpe Generating Station (diesel) — 20 MW
  - Prairie Sky (solar) — 1 MW
- Power purchase agreements
  - Southwestern Power Administration (hydroelectric) — 100 MW
  - Western Area Power Administration (hydroelectric) — 13 MW
  - Evergy (KEP2 Capacity 2021-2026) — Approx. 50 MW
  - Evergy (KEPC Energy and Capacity expires 2045)[12] — Approx. 158 MW

[12] KEPCo has an "all requirements" contract with Evergy that credits KEPCo for the capacity and energy provided by KEPCo resources under the contract. About 90% of KEPCo's load requirements are met by this contract.

The summary of the demand and energy requirement for KEPC load is shown in the table below.

Table 4: KEPC Demand and Energy Requirements (2022-2036)

Year	Summer Demand	Winter Demand	Energy (GWh)
2022	398.1	331.6	1,944.1
2023	411.8	304.8	1,950.0
2024	413.1	305.7	1,956.2
2025	414.5	306.8	1,962.9
2026	415.7	307.6	1,968.6
2027	417.1	308.7	1,975.2
2028	418.3	309.5	1,980.8
2029	419.6	310.5	1,987.0
2030	420.8	311.4	1,993.2
2031	422.1	312.4	1,999.4
2032	423.4	313.3	2,005.6
2033	424.7	314.2	2,011.8
2034	425.9	315.2	2,018.0
2035	427.2	316.1	2,024.3
2036	428.5	317.1	2,030.6

Capacity and Energy requirements for KEP2 is based on the seasonal peak demands that have been submitted in the SPP Resource Adequacy Workbook. Capacity and energy resource requirements for KEP2 is the primary focus to evaluate for the KEPCo resource needs. The table below shows the KEP2 demand and energy requirements for the period of 2022-2036.

Table 5: KEP2 Demand & Energy Requirements (2022-2036)

Year	Summer Demand	Winter Demand	Energy (GWh)
2022	39.40	32.41	229.40
2023	39.53	31.38	230.31
2024	39.72	31.50	231.14
2025	39.87	31.61	231.96
2026	40.07	31.76	232.96
2027	40.21	31.87	233.78
2028	40.38	31.99	234.67
2029	40.52	32.09	235.54
2030	40.70	32.23	236.42
2031	40.87	32.35	237.27
2032	41.04	32.48	238.12
2033	41.20	32.60	238.97
2034	41.37	32.72	239.83
2035	41.54	32.85	240.68
2036	41.71	32.97	241.55

Planning reserves are defined in the workbook as 12%, and the total seasonal capacity requirement is calculated in the SPP Workbook. The table below shows the summary of the seasonal demands and SPP capacity obligation for KEP2 load.

Table 6: KEP2 Peak Load and Capacity Requirements (2022-2036)

Year	Summer Demand	Planning Reserves	Capacity Requirements
2022	39.40	4.73	44.13
2023	39.53	4.74	44.27
2024	39.72	4.77	44.49
2025	39.87	4.78	44.65
2026	40.07	4.81	44.88
2027	40.21	4.83	45.04
2028	40.38	4.85	45.23
2029	40.52	4.86	45.38
2030	40.70	4.88	45.58
2031	40.87	4.90	45.77
2032	41.04	4.92	45.96
2033	41.20	4.94	46.15
2034	41.37	4.96	46.34
2035	41.54	4.98	46.53
2036	41.71	5.01	46.72

5.1.2 Portfolio Design

There are a range of KEPCo resource alternatives to meet the projected capacity and energy requirements. The portfolio design is intended to provide a range of resources that can be evaluated over the defined sensitivities for the Study. The need for capacity for all portfolios begins on 1/1/2027 due to an existing contract in place to meet capacity needs from Evergy through 12/31/2026.

Specific Portfolio Designs are described below.

5.1.2.1 Resource Portfolio 1 (RP1) SPP IM Energy Purchase / Bilateral Capacity Purchase

RP1 is fully exposed to market volatility because all energy requirements are purchased from the SPP IM and the capacity requirements are met via a bilateral agreement with Evergy. RP1 results in having about 10% of KEPCo's total energy requirements exposed to the SPP IM. Other portfolios have a partial energy exposure to SPP IM when the portfolio resource is not being dispatched to serve the load.

The bilateral capacity purchase price is defined in Section 6.2, and this pricing was used for the capacity purchases required for RP1. The amount of capacity purchased is assumed to match the capacity requirements defined by the peak demand forecast.

5.1.2.2 Resource Portfolio 2 (RP2) 5x16 Energy Purchase/Bilateral Capacity Purchase

RP2 assumes that all future needs through 2036 will be met with a purchase for both capacity and energy. The energy purchase is assumed to be a block of energy for on-peak hours on the weekdays. This type of energy purchase is referred to as 5x16 purchase. Purchasing a 5x16 block of energy allows for price certainty and reduces energy market exposure. Typically, the pricing in the 5x16 hours is the most volatile, but the price excursion from February 14–19, 2021 has raised the concerns on what level of energy price exposure could occur during the balance of hours beyond the 5x16 block. The amount of capacity purchased is assumed to match the capacity requirements defined by the peak demand forecast. The pricing for the 5x16 block was arrived at by adding one standard deviation to the average annual prices from RP1 for each year of the Study.

KEPCo has a bilateral capacity purchase agreement through the end of 2026, and the cost attributes of RP2 is used for the annual costs for RP3-RP6 for the period of 2022-2026 to reflect the term of this existing capacity purchase agreement, and to allow a consistent timeframe to evaluate the other resource portfolios.

5.1.2.3 Resource Portfolio 3 (RP3) 2027 50 MW Nameplate Wind Addition

RP3 resource needs are met using the RP2 scenario for years 2022-2026 (a bilateral capacity purchase and a 5x16 energy purchase). RP3 then transitions into a 50 MW nameplate purchase of wind to be in service by 1/1/2027 and a bilateral capacity market purchase for the remaining capacity requirements. Wind is assumed to have a 17% accreditation value of the nameplate based on the current SPP accreditation standard. The hourly shape of the wind generation is assumed to be a scaled hourly shape of the SPP wind generation profile. All energy that is needed to serve load not hedged by wind generation is assumed to be purchased from the SPP IM at the LMP for the load node.

5.1.2.4 Resource Portfolio 4 (RP4) 2027 50 MW Combined Cycle Addition

RP4 resource needs are met using the RP2 scenario for years 2022-2026 (a bilateral capacity purchase and a 5x16 energy purchase). RP4 transitions into a 50 MW nameplate share of a natural gas combined cycle generation plant to be in service by 1/1/2027. The specific configuration of the combined cycle could vary depending on what opportunities are available.

Combined Cycle(CC) generation operation assumptions are to use a single heat rate point of 7,000 Btu/kWh, the monthly natural gas forecast, and a variable O&M value of $5.00/MWh that escalates in the planning horizon to create the energy price. The projected SPP hourly LMP is compared to the calculated hourly operating cost to determine if the combined cycle is dispatched.

The dispatch is simple, in that each hour that the LMP is higher than the calculated combined cycle operating cost, the unit is dispatched to the full 50 MW value. More robust production models consider start-up costs, minimum run times, and hourly ramp rates. The production model using this more simplified approach provides a screening level of clarity on the viability of developing a combined cycle resource for hedging the cost of serving load.

All energy that is needed to serve load not hedged by combined cycle generation is assumed to be purchased from the SPP IM at the LMP for the load node. A 5x16 purchase could be assumed to be purchased in more detailed analysis if a greater amount of price hedging is desired.

5.1.2.5 Resource Portfolio 5 (RP5) 2027 50 MW Simple Cycle Peaking Addition

RP5 resource needs are met using the RP2 scenario for years 2022-2026 (a bilateral capacity purchase and a 5x16 energy purchase). RP5 assumes a 50 MW nameplate share of a natural gas simple cycle generation plant starting on 1/1/2027. Simple cycle peaking generation is assumed to have a 98% accreditation value of the nameplate based on an estimated forced outage rate of 2%.

Simple cycle generation operation assumptions are to use a single heat rate point of 9,124 Btu/kWh, the monthly natural gas forecast, and a variable O&M value of $4.72/MWh that escalates in the planning horizon to create the energy price. The calculated hourly LMP is compared to the calculated hourly operating cost to determine if the combined cycle is dispatched.

The dispatch is simple in that each hour that the LMP is higher than the calculated operating cost, the unit is dispatched to the full 50 MW value. More robust production models consider start-up costs, minimum run times, and hourly ramp rates. The production model using this more simplified approach provides a screening level of clarity on the viability of developing a simple cycle resource for hedging the cost of serving load.

All energy that is needed to serve load not hedged by the peaking generation is assumed to be purchased from the SPP IM at the LMP for the load node. A 5x16 on-peak energy block could be purchased if a greater level of energy hedging is desired .

5.1.2.6 Resource Portfolio 6 (RP6) 2027 50 MW Nameplate Solar Generation Addition

RP6 resource needs are met using the RP2 scenario for years 2022-2026 (a bilateral capacity purchase and a 5x16 energy purchase). RP6 assumes the development of a 50 MW solar generation resource. The solar resource could either be a stand-alone utility grade installation or a share of a larger facility if a partial ownership option is available. The development of a 50 MW solar resource is viable in smaller increments if that would lower the impact of transmission interconnection requirements. Solar is assumed to have a 40% accreditation value of the nameplate based on the current Effective Load Carrying Capability (ELCC) SPP accreditation standard and an assumed total SPP installation of 15,000 MW.

Pricing for the solar resource was assumed to be a flat price Purchase Power Agreement (PPA) based on publicly available pricing data. The price was assumed to be $40/MWh for all hours of solar generation. The analysis is set up so that sensitivities on this PPA price can be looked at in more detail if this option is pursued. All energy that is needed to serve load not hedged by the solar generation is assumed to be purchased from the SPP IM at the LMP for the load node. A 5x16 on-peak energy block could be purchased if a greater level of energy hedging is desired.

6 Economic Evaluation

The economic evaluation provides the opportunity to evaluate the six portfolios across a range of scenarios and sensitivities. There are two defined scenarios, two fuel price cases, and two carbon price assumptions, creating eight combinations of these variables. This provides a total of 48 cases to evaluate each portfolio for the 2022-2036 planning horizon. Using the SPP IM LMP provides the ability to reflect the actual market conditions and load shapes for 2018, 2019, and 2020.

6.1 SPP Integrated Market Price Development

Developing an hourly price for the SPP IM is an essential element for the Study. The Study scope did not include the development of an hourly price model from a production model such as that provided by PROMOD software. There are a number of approaches to developing hourly RTO pricing data. One approach is to trend the average component(s) of the LMP and apply an hourly reference share to the projected averages. The challenge of this approach is using a reference shape when significant changes are expected in the generation portfolio. The expected changes are for more coal and natural gas generation retirements and more wind and solar additions. If the short-term variations in the independent variables have an adequate range to represent the expected longer-term variation in the variables, a regression approach can be applied. Regression model statistics show the dependency of each input variable on the dependent variable. The model can provide a reasonable level of confidence in applying the regression model for a future resource mix. Model results can be evaluated for changes in the independent variable assumptions to evaluate the model.

Elemental Pnode pricing information from SPP was needed to create the historic 2011-2020 KEP2 pricing data. The SPP Pnodes, used to create the KEP2 settlement node, are listed in the footnote.[13] In 2021 a portion of the KEP2 load continues to be served by an all requirements contract with Sunflower Electric Power Corporation (SEPC) and this load settles at the SEPC settlement location (SECI_SECI). Beginning in 2022 this load will be transferred to the KEP2 settlement location and served by the bilateral capacity purchase from Evergy Kansas Central.

The Study uses a regression model for the 2018-2020 period showing the relationship of the independent variables and the resulting KEP2 pricing node. Models were developed for summer and winter on and off-peak periods.[14] Models for each component of the LMP were also developed to spot check expected signs of the coefficients. As one example, increasing levels of wind generation have shown to result in a more negative Marginal Congestion Component (MCC), and this trend was verified in the modeling results.

[13] SECICUDAHY1LD2
SECICUDAHY1LDCUDAHY1LD1
SECIHASKEL2LD3
SECILIBERAL_LD2
SECIMOSCCMSLD2
SECIMOSCOW1LD2
SECIKISMETLD1
SECIPLAINV1LD2

[14] Summer – May-September, Winter October-April On/Off peak periods based on 5x16 on peak 7am-10pm M-F

The regression model evaluated data for each of the years from 2018-2020, as well as two-year periods covering 2018-2019 and 2019-2020. The 2020 data has the unique characteristic of being a period when over 9 months were impacted by the COVID-19 shutdowns that were occurring across the country. The regression variables for the history of 2018-2019 combined were used for the Study model.

Once the regression model is established, a new series of input variables can be used to simulate the hourly LMP. Yearly maximums were projected for wind, solar, and coal, and the maximums were applied to the per-unitized shapes. Specifically, the historic generation data from 2018, 2019, and 2020 was per-unitized and scaled to the projected annual nameplate values as described by the Scenario Definitions in Section 6.2. Other key inputs were established using the results of the natural gas price and the assumed level of carbon tax from the 6.1.2 Sensitivities section below.

The SPP IM LMP hourly prices were projected for the 2022-2036 period using the historic shapes of 2018, 2019, and 2020. The base development of the hourly pricing model was compared with the actual LMP prices to assess the modeling accuracy. Scenarios varying the SPP generation mix were then used on the model to create hourly LMP that reflects the expected changes in the SPP resource portfolio. This approach of using three years of history for each projected year results in a more robust representation of the future hourly projection.

6.1.1 Scenarios

Two (2) scenarios are included for the Study that are intended to show how various resource portfolios perform under a range of key changes in the assumptions.

The SPP resource mix is expected to change to higher levels of renewable generation and more retirements of existing coal and natural gas resources. The pace of these resource changes is assumed to change and is being characterized as either the Base Case or a higher level of renewable generation transformation referred to as the High Renewable Case.

The SPP summary of nameplate capacity by generation type is shown in the table below.

Table 7: Nameplate Capacity by Generation Type

Fuel Type	2017	2018	2019
Gas, simple cycle	23,847	22,596	23,297
Nuclear	2,061	2,061	2,061
Coal	25,717	25,064	22,920
Wind	17,596	20,589	22,482
Gas, Combined Cycle	12,868	13,498	13,473
Hydro	3,422	3,431	3,431
Oil	1,639	1,639	1,563
Solar	215	215	215

Source: SPP state of market 2020 Figure 2.13 Generation nameplate by Capacity by Technology Type

This provides the backdrop for generation, and the 2021 SPP Integrated Transmission Planning (ITP) Assessment provides guidance as to the expected rate of generation portfolio transformation. The 2021 ITP study provides two cases for resource transformation based on the expected age of conversional generation that will drive retirements. The Reference Case from the 2021 study includes the assumption that coal generation older than 56 years is viable for retirement. The Emerging Technologies case assumes a retirement for coal for units 50 years or older. When the plant data is summarized, it turns out that this distinction of 6 years is not a significant difference in retired MW. The assumption of all coal plants older than 50 years results in over 9,300 MW of coal retirements by 2036. It is difficult to assess whether other system studies or individual ownership decisions will result in that level of retirements.

Considering the number of uncertainties regarding system retirements, and additional hesitations that may come into play after seeing the extremely high gas price and market price excursion from the February 15-19, 2021 event, the coal retirements assumption was scaled down to a smoothed out annual assumption of 1200 MW per year for 15 years for a total of 5,600 MW retired by 2036 for the High Renewable case. The Base Case assumption is to use a value at approximately 60% of the High Renewable Case, or a total coal retirement of 3,200 MW.

The 2021 ITP Reference Case assumption for natural gas retirement is assumed to be 50 years or older to be viable for retirement. The assumption for the 2021 ITP Emerging Technologies Case is 48 years. The assumed retirements based on this approach would have a total of 3,000 MW assumed to be considered for retirement by 2021. This approach would target another 4,800 MW for retirement by 2036. This level of natural gas generation retirements is very difficult to view as viable, given the fact that gas CO2 emissions for the total SPP fleet is roughly half of coal emissions on a CO2 ton/MWh basis. The difference in retirements from 48 to 50 years is also insignificant. Given the concerns of what resource it will take to keep the real-time balance of electricity flowing to the load, and the generic nature of the natural gas retirement assumptions, the approach for the Study is to simply hold onto the current amount of natural gas generation and not assume any retirements for the 2022-2036 period.

The current level of nameplate wind generation is 27,164 MW. The expected wind additions from the 2021 ITP study are in the range of 29,000-32,000 MW. The Base Case projection is assuming total wind additions of 24,000 MW, and the High Renewable Case is assuming total wind additions through 2036 of 32,400 MW. Solar additions from the 2021 ITP study are projected to be in the range of 6,000 to 9,000 MW. This is a very aggressive amount of growth from the current levels of 230 MW of solar. The Base Case assumption for the Study is assuming a solar expansion to 8,220 MW, and the High Renewables Case is assuming a solar expansion to 12,000 MW. These are very drastic increases in the solar generation capacity.

The SPP IM LMP hourly regression model is based on the short-term variations of solar generation for the 2018, 2019, and 2020 historic data, and the coefficient for the solar generation output is shown as being correlated to the LMP value with a Pr(>|t|) value that is low enough to provide this support. With such a significant increase in solar generation output, there is a concern as to whether the SPP IM LMP model can accurately model the increasing solar generation to this significant magnitude. The average energy prices that are shown in RP1 are annual values that are escalating at 2.2 percent per year, which is reasonable for the 15-year planning horizon.

There is value in having a reasonable spread in two scenarios when performing a resource plan analysis, so the approach defined for this plan is to use the Emerging Technologies as a guide for the High Renewables Case but spreading expected levels of resource changes over a 15-year period for both retirements and additions. The other caveat is a hesitancy to implement any levels of natural gas generation retirements, as the level of resource transformation would be so drastic as to not have certainty on the viability of wind and solar to be able to adequately fill the 8760 hours of a year without having adequate dispatchable resources. Clearly, more studies are needed in this regard for SPP, and there are indications that these will be forthcoming.

The following provides the summary of how the Base Case and High Renewables Case are defined for this Study:

- Base Case: These benchmarks were considered meaningful, but they need to be looked at in comparison with the higher level of renewable generation transformation in order to lay out the overall approach to both the Base Case and the High Renewable Case for the Study. Generation scaling factors were developed for the Base Case that were reflective of being roughly 70% of the values used for the High Renewables case. This scaling is based on the value of having a planning process where a wider range of projections is included, so it can show how these projections impact the results. In the 2021 SPP ITP study, both projections are significant changes from the current system, and the desire for the Base Case design is to show a less extreme level of changes, as there could clearly be a trend that follows this pattern due to a number of factors, including needs for transmission infrastructure, value of fuel diversity for winter peaking conditions like what occurred February 15-19, 2021, supply chain realities in being able to procure such significant amounts of wind and solar, individual decisions on plant retirements vs. the generic assumptions of plant retirements based on the age, etc.

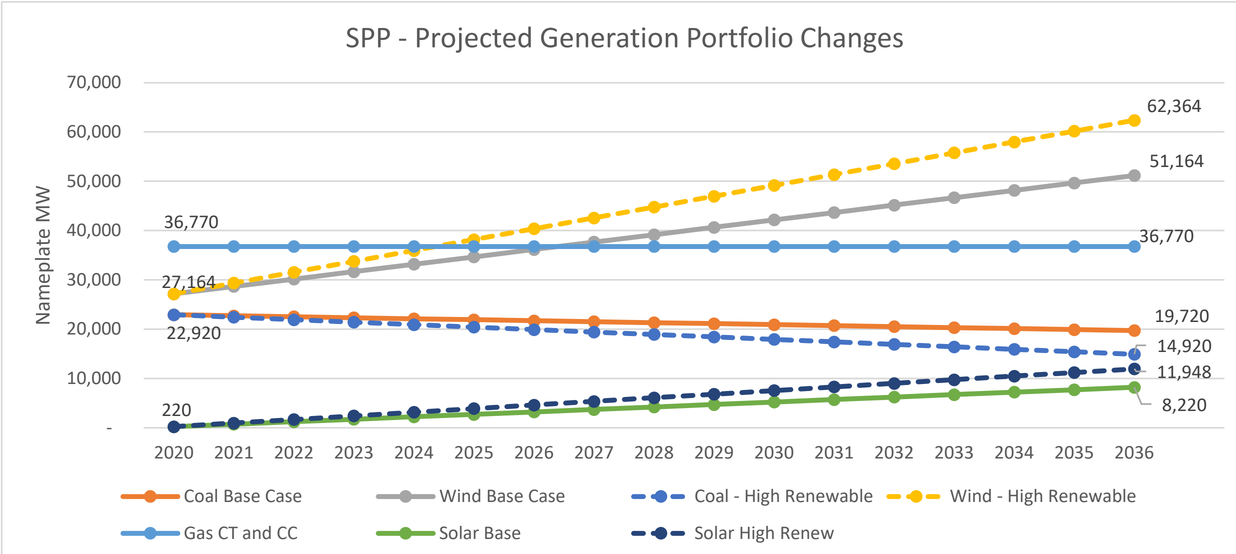
- High Renewables Case: Wind and solar additions to the system are assumed to be in the range of the 2021 ITP Emerging Technologies Case over a 15-year period. Coal retirements are also in line with the 2021 study, and natural gas generation is assumed to remain the same. The table below summarizes the High Renewables Case.

Table 8: Resource Nameplate Summary (MW)

Fuel Type	2019 Actual	Base Case 2036	High Renewables 2036
Gas, Simple and combined cycle	23,297+ 13,482	23,297+ 13,482	23,297+ 13,482
Nuclear	2,061	2,061	2,061
Coal	22,920	-3,200	-5,600
Wind	22,482	+24,000	+32,400
Hydro	3,431	3,431	3,431
Oil	1,563	1,563	1,563
Solar	215	+8,220	+11,948

Figure 19 shows the annual projected SPP generation nameplate by fuel type MW for 2022-2036.

Figure 19: Projected SPP Nameplate Capacity by Fuel Type– Base and High Renewable



6.1.2 Sensitivities

The Study includes two sensitivities that are viewed as being critical to KEPCo:

1. Gas Price Escalation: Two natural gas price forecasts for Henry Hub were used from the 2021 Annual Energy Outlook and were converted to the Short-term Annual Energy Outlook variable for natural gas that was used in the SPP IM LMP model. Monthly actual prices for the Short-term gas variable were brought into the analysis to reflect the gas prices monthly from the annual forecasted value.

   Natural gas prices were gathered using an Annual Energy Outlook (AEO) short-term energy outlook variable for Natural gas usage for electric generation in Kansas. Regression results show statistical variables for each type of generation by fuel type, and the natural gas variable was a very important variable to establish a calculated LMP.

2. Carbon Tax Adoption: Carbon tax evaluations have been included in planning studies for multiple decades to show the carbon emission cost impacts on existing and future resources. There are a wide range of proposed values from various studies and legislative proposals. The Study is using a value of $15/Ton that is not escalating in the study period. This is a fairly conservative approach and could be considered to be on the low side of legislative proposals in the next couple of years.

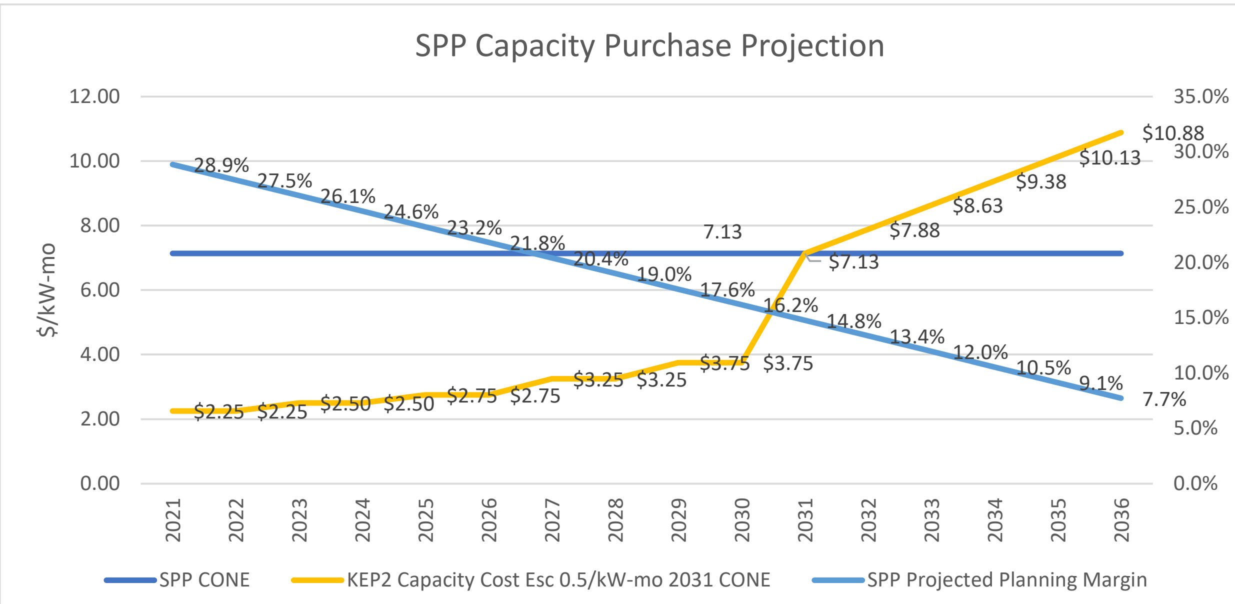
6.2 Bilateral Capacity Purchase Price Projection

KEPCo is purchasing capacity for KEP2 through 12/31/2026 at a bilateral market price that is low but not expected to continue to be available into the future. The levels of capacity retirements from resources that have a high accreditation to nameplate ratio such as coal units. The replacement capacity of wind and solar has a much lower accreditation value and there isn't a significant amount of additional generation that is known to be added to the system. This leads to a high level of uncertainty as to the price of bilateral capacity going forward.

One approach to projecting the bilateral capacity price is to trend the SPP planning reserve value into the future and declare a date when the margin gets down to a level where the CONE purchase price value is assumed to be the bilateral capacity price. The SPP planning margin was trended using the 2014-2019 accredited total generation by resource compared to the system peak. The planning reserve trend continued into the 2021-2036 period.

The years following that selected date can also be shown to go higher than CONE as the system would be expected to be in a period of significant deficit until a time when additional capacity is added to the system. This approach is a fairly pessimistic view of bilateral capacity purchase costs and can be updated when a better understanding is gained regarding what capacity additions are expected to be made on the system.

Figure 20: Bilateral Capacity Purchase Cost Projection



The combination of scenarios and sensitivities results in the following combinations that are used for the Study (shown in the order they are presented in Study Exhibits):

3. CTax – Base Generation – Base Gas Price
4. CTax – Base Generation – High Gas Price
5. CTax – High Renewable Generation – Base Gas Price
6. CTax – High Renewable Generation – High Gas Price
7. No CTax – Base Generation – Base Gas Price

8. No CTax – Base Generation – High Gas Price

9. No CTax – High Renewable Generation – Base Gas Price

10. No CTax – High Renewable Generation – High Gas Price

6.3 Resource Portfolio Results

Portfolio results are shown primarily for the cost projections for the KEP2 system in order to show the focus of the varying costs by Resource Portfolio (RP). Results include an annual load and resource summary chart, which shows the energy dispatch of the resource being evaluated and how much energy remains in the SPP IM.

Annual total costs for KEPCo will also be shown, but not for the full range of portfolios. Costs for each RP are shown for the full 24 combinations of the Scenarios (Base and High Renewable), Sensitivities (Base and High Natural gas, and No Carbon Tax & $15/Ton Carbon Tax) and the three historic years used to develop the various historic datasets for the analysis (2018, 2019, and 2020). Annual total costs are the most granular results that can be shown with any level of visual clarity. These results can show many trends that are observed across the range of variables. A net present value approach to the KEP2 costs is also provided for the 24 combinations of variables, with the average of those values being shown as the comparable number that allows the most direct comparison of all the RPs.

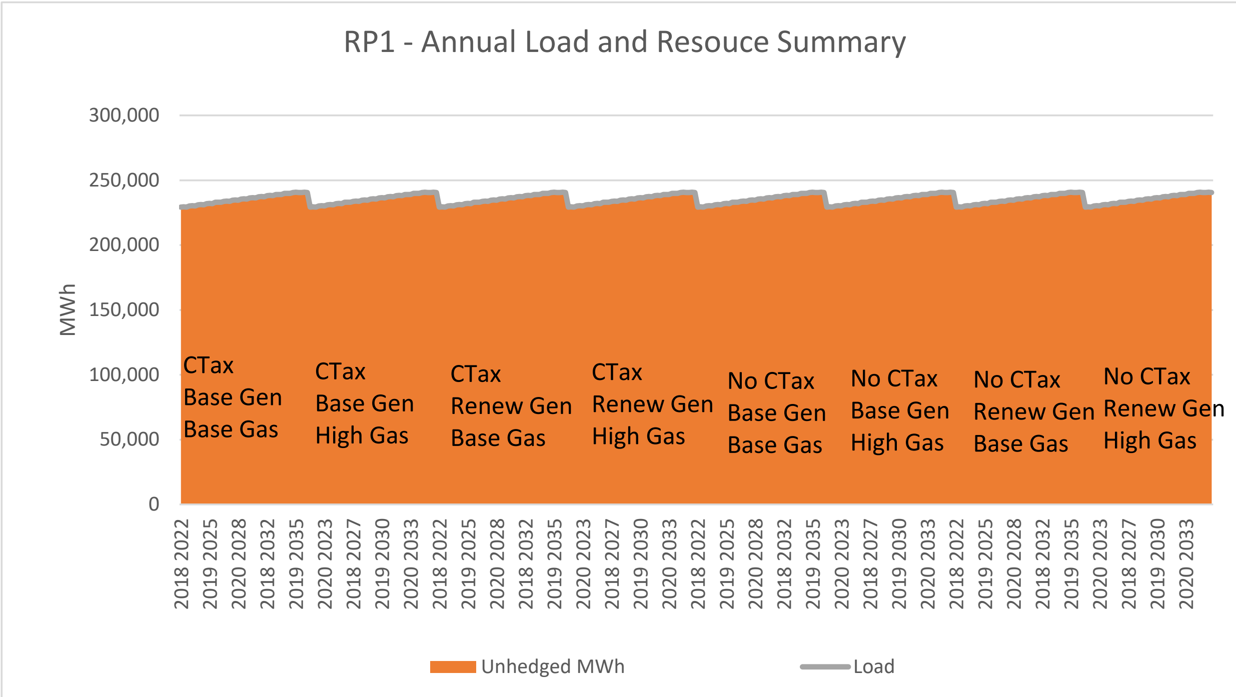
Results also include a net present value cost summary chart that shows the 15-year net present value of each of the 24 combinations of scenarios and the average of the 24 values. The standard deviation is also included in the discussion of the results in order to provide a metric on the cost variability of the RP for the 24 combinations.

6.3.1 RP1 Results

Results for RP1 are intended to show the average energy purchase price in the SPP IM and also to show the impact of bilateral capacity purchase costs on the total costs for the 15-year planning horizon across the entire range of the plan sensitivities.

The annual load and resource summary for RP1 shows that all energy is being purchased from the SPP IM for all combinations of scenarios and sensitivities.

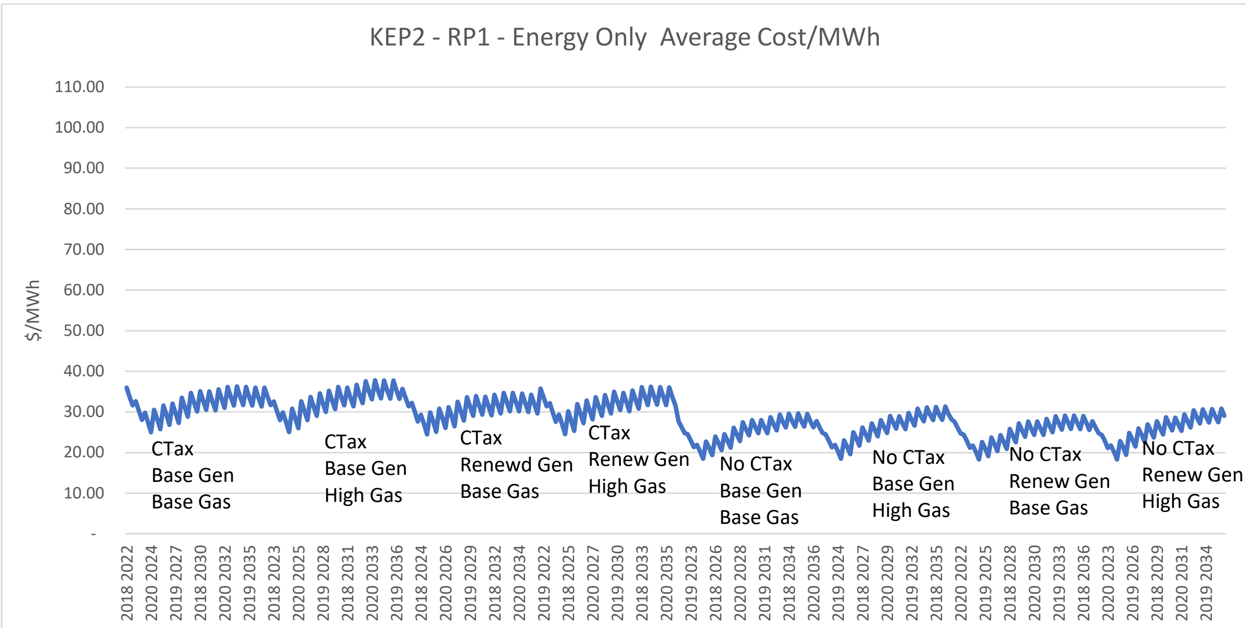
Figure 21: RP1 - Annual Load and Resource Summary



The annual results charts show the average annual cost for the analysis for each of the 24 cases, which shows a pattern of the annual results for each of the three historic years grouped for the eight combinations of the sensitivities of SPP portfolio (Base Gen vs. Renew Gen), natural gas prices, and the carbon tax. The labels on the charts show the grouping of 8 combinations. The X-axis below shows the planning year and the historic data year used for the case as 2022-2018, which means 2022 results using the 2018 historic dataset.

The following chart shows annual energy prices for the full range of scenarios and sensitivities.

Figure 22: RP1 – KEP2 Energy Only Average Cost/MWh



The short-term variations of plus or minus 1-2/MWh are driven by the variations of the historic datasets and are consistent throughout the entire range of cases. This reflects the level of pricing uncertainty due to the differences in market conditions, regardless of the more clearly defined forecast variables such as annual natural gas, carbon tax impacts, or ranges of SPP generation transformations.

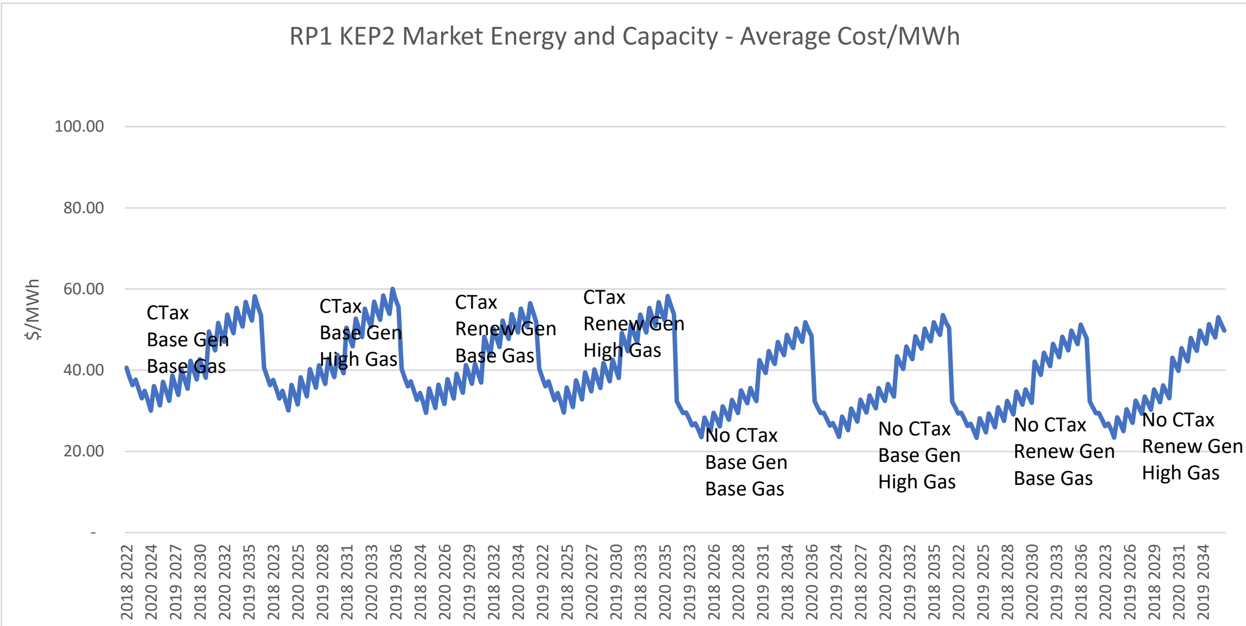
Comparing the group of four on the left to the group on the right indicates the impacts of the $15/ton carbon tax on the SPP IM price.

Comparing the cases with Base Gen to Renew Gen shows an increase in costs due to higher renewable generation. The mathematical basis for this is due to the Solar regression variable having a positive coefficient, but from a system marginal cost basis, the higher pricing is driven more by the need for additional generation production to provide energy when the higher levels of renewable (common to both Base Gen and Renew Gen) are implemented.

The energy-only annual cost summary for RP1 provides a means of showing the dispatch of other KEPCo resources in the SPP IM, as the resource will only be utilized when the operation costs of the resource are lower than the SPP IM.

The average cost of serving KEP2, including the cost of bilateral capacity, is shown in the chart below.

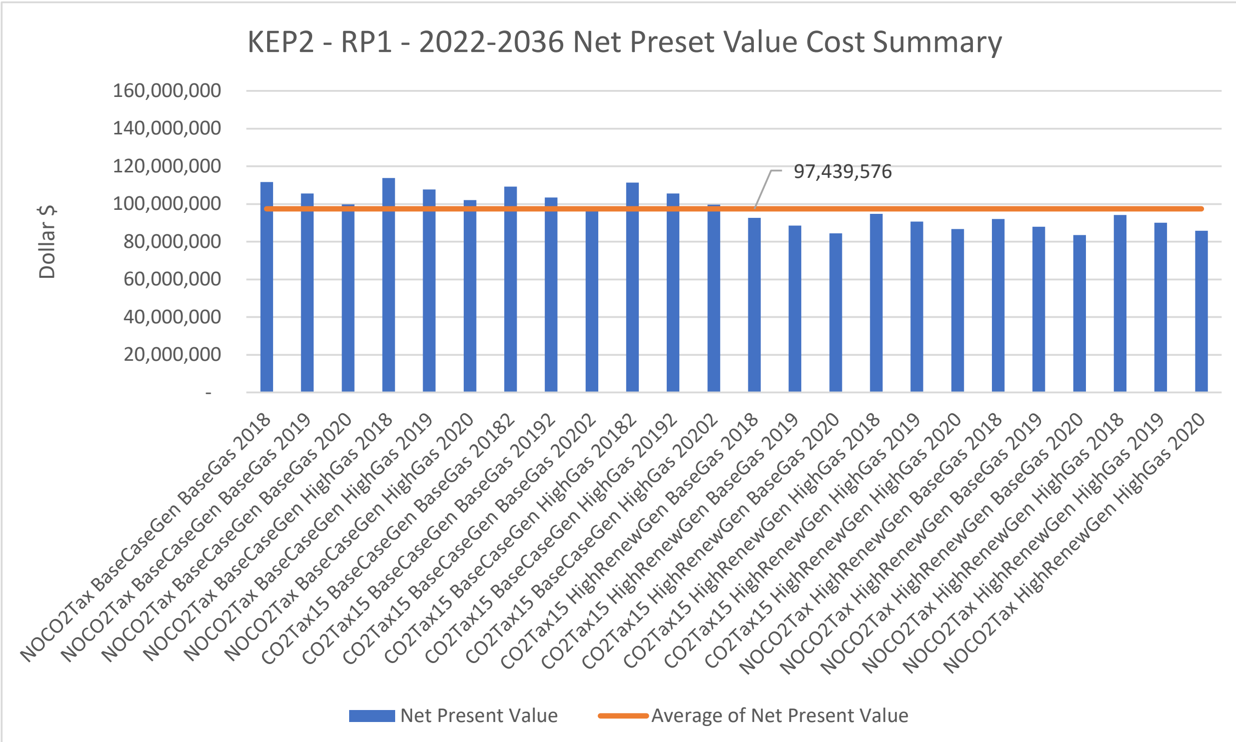
Figure 23: RP1 – KEP2 Market Energy and Bilateral Capacity – Average Cost/Mwh



The overall observation of the results is that the primary trend of increasing costs is year over year from 2022-2036 with slight variations driven by varying market conditions (2018, 2019, 2020) and some variations over the range of the eight combinations of scenarios and sensitivities.

The RP1 net present cost summary shows the 15-year cost summaries by scenario and sensitivity and the average value of $97.4 million. The standard deviation for RP1 net present value is the highest of all portfolios at $9.2 million.

Figure 24: KEP2 - RP1 – 2022-2036 Net Present Value Cost Summary

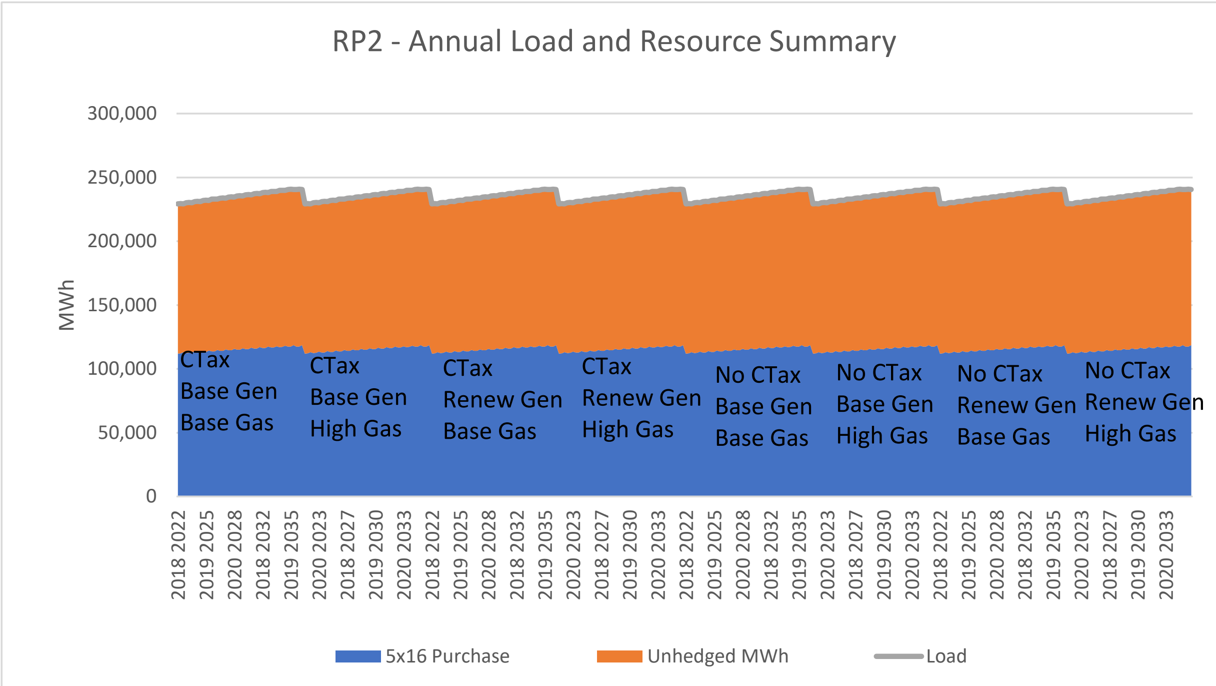


6.3.2 RP2 Results

Results for RP2 are an important milestone because they show the projected costs of purchasing a 5x16 energy block and bilateral capacity purchase.

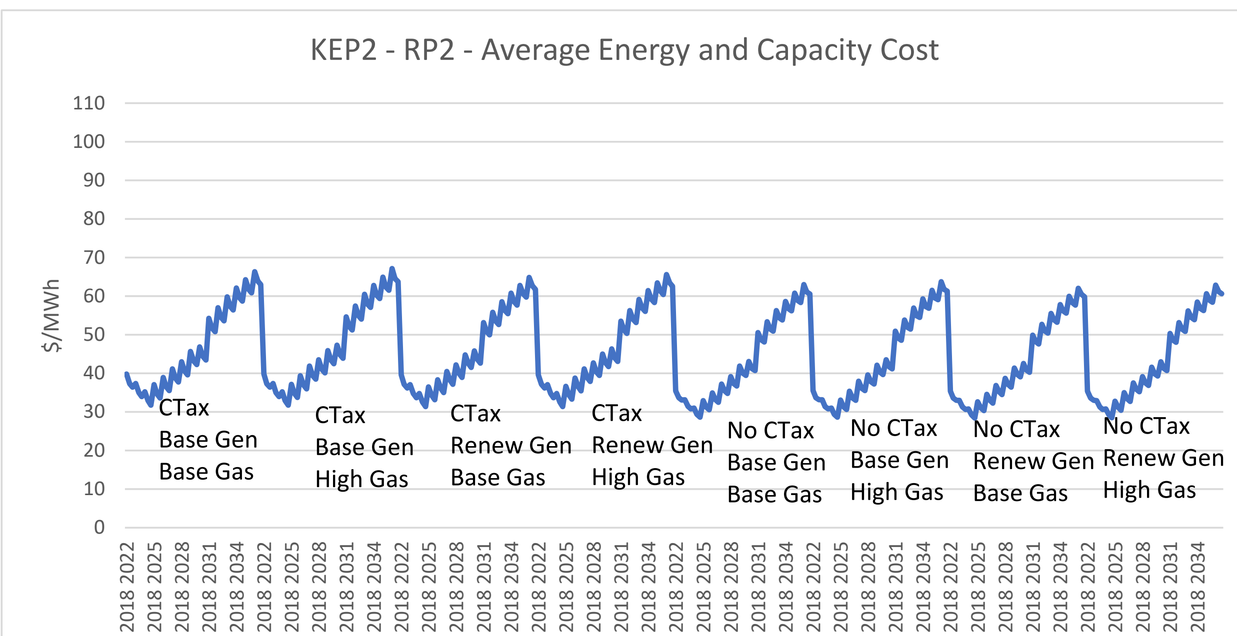
The 5x16 energy purchase provides about 50% of the energy as shown in the annual load and resource summary.

Figure 25: RP2 – Annual Load and Resource Summary



The results for 2022-2026 from RP2 are used for the annual results for all other resource portfolios for the 2022-2026 period.

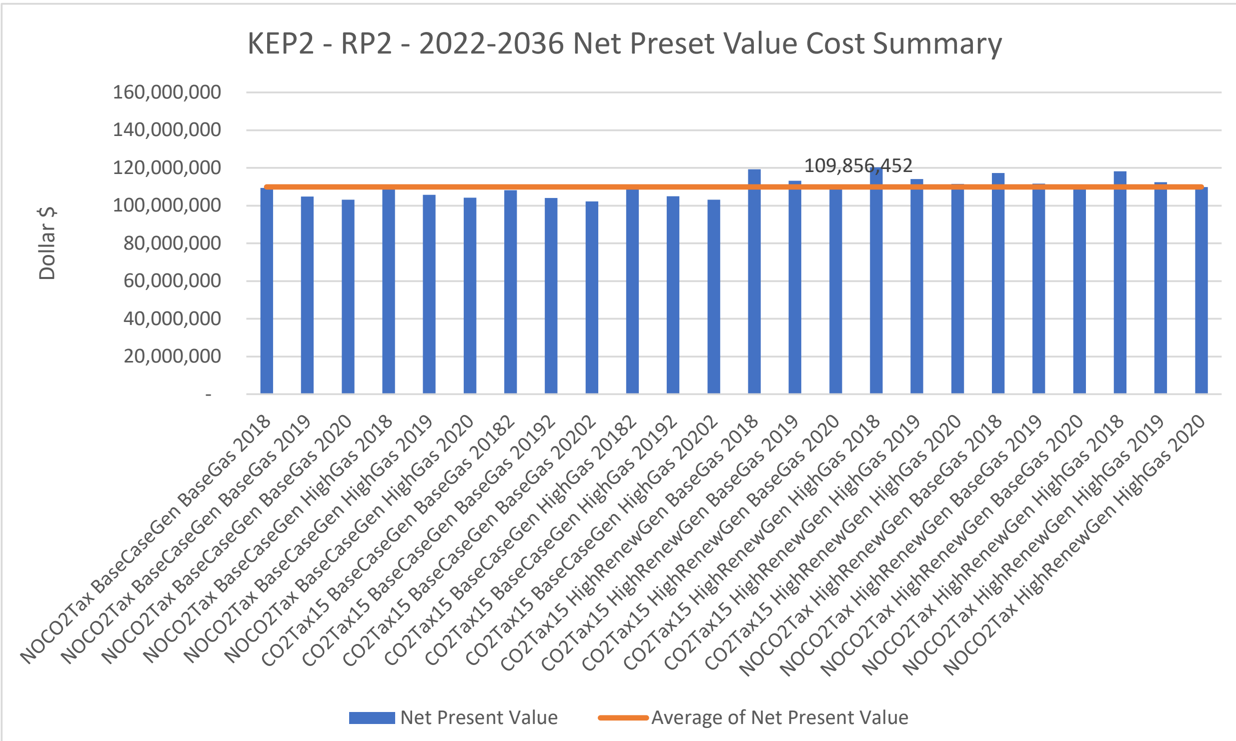
Figure 26: RP2 – KEP2 Average Energy and Capacity Cost



RP2 has a lower level of price variation from the 2018, 2019, and 2020 market conditions compared to RP1, due to the hedging capability of the 5x16 on-peak block energy purchase versus to the SPP IM exposure of RP1. The variations of cost within the groupings of having the carbon tax or not having the carbon tax is lower than RP1, thereby showing again the hedging of the load serving costs of having a 5x16 block purchase with a fixed cost in place.

Results shown on an annual Net Present Value basis provides a means of summarizing all 24 cases over the 15-year forecast period. The standard deviation and average of NPVs allows for a means of comparing the costs of each portfolio.

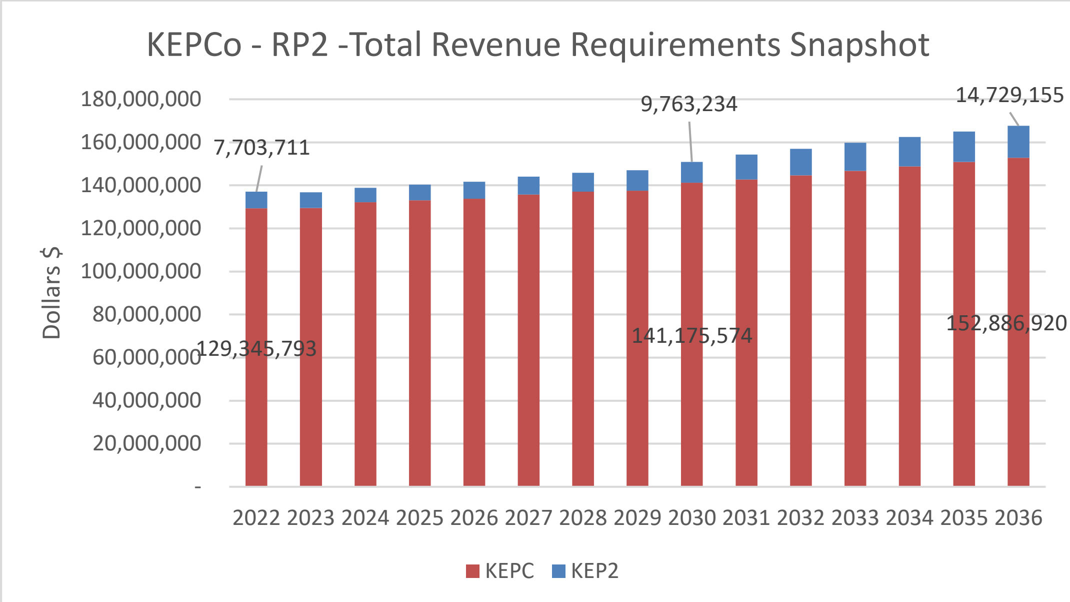
Figure 27: Case P2 – NPV Summary



The standard deviation of the NPVs for RP2 is $5.2 million, and this can be compared with other resource portfolio results.

In order to provide a perspective on how the amount of KEP2 costs compared to the KEPCo total revenue requirements, the annual costs of a sample scenario of the RP2 data and the KEPC revenue requirements is shown in the figure below for 2022-2036. The KEP2 share of the KEPCo increases at an annualized growth rate of over 4.4%, compared to the annual growth rate of KEPC of 1.1%.

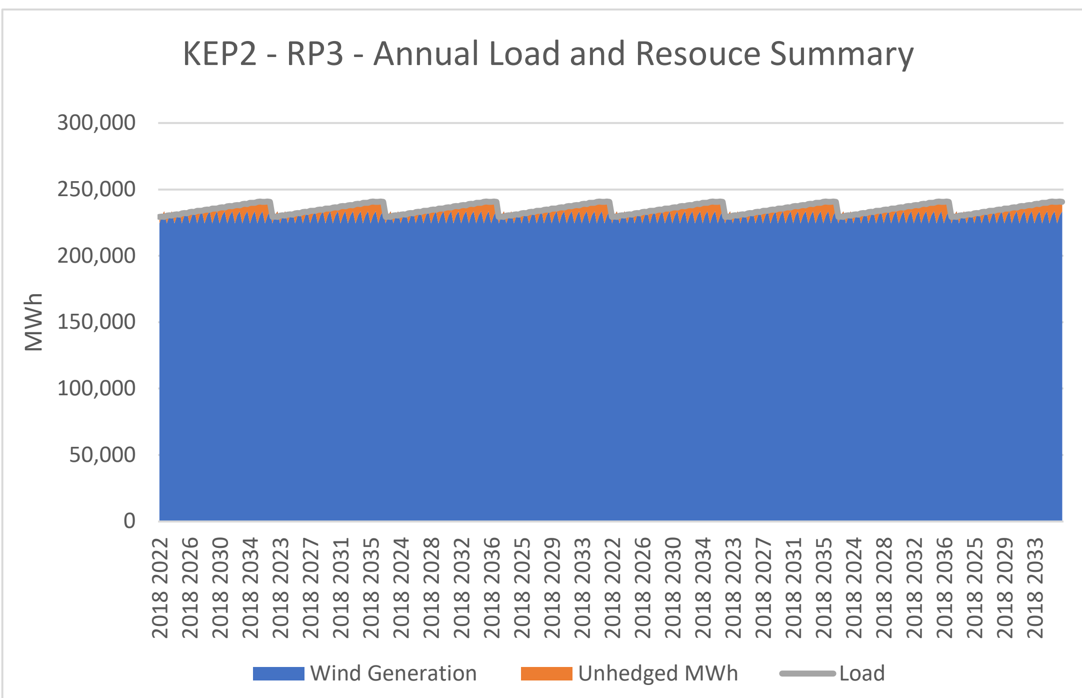
Figure 28: KEPCo - RP2 – Total Revenus Requirements Snapshot



6.3.3 RP3 Results

RP3 results shows the impact of a 50 MW wind purchase starting in 2027. The wind resource provides over 90% of the load serving energy.

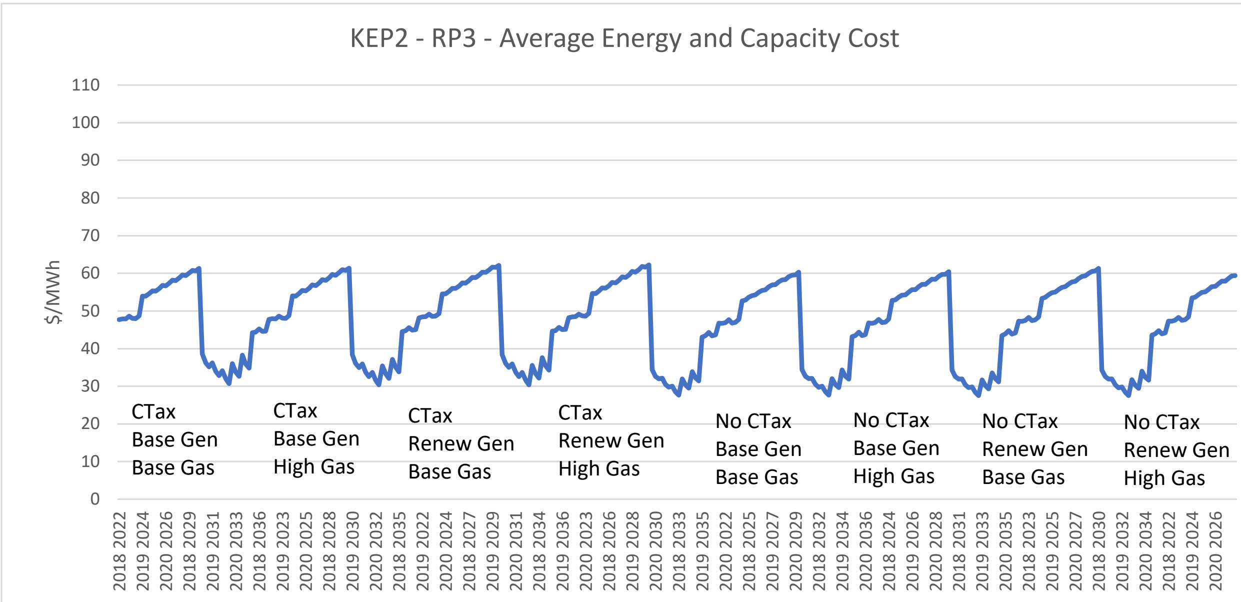
Figure 29: RP3 – Annual Load and Resource Summary



Wind Generation provides a significant energy market hedge for serving the KEP2 load, with the unhedged MWh values being slightly above and below zero across the cases.

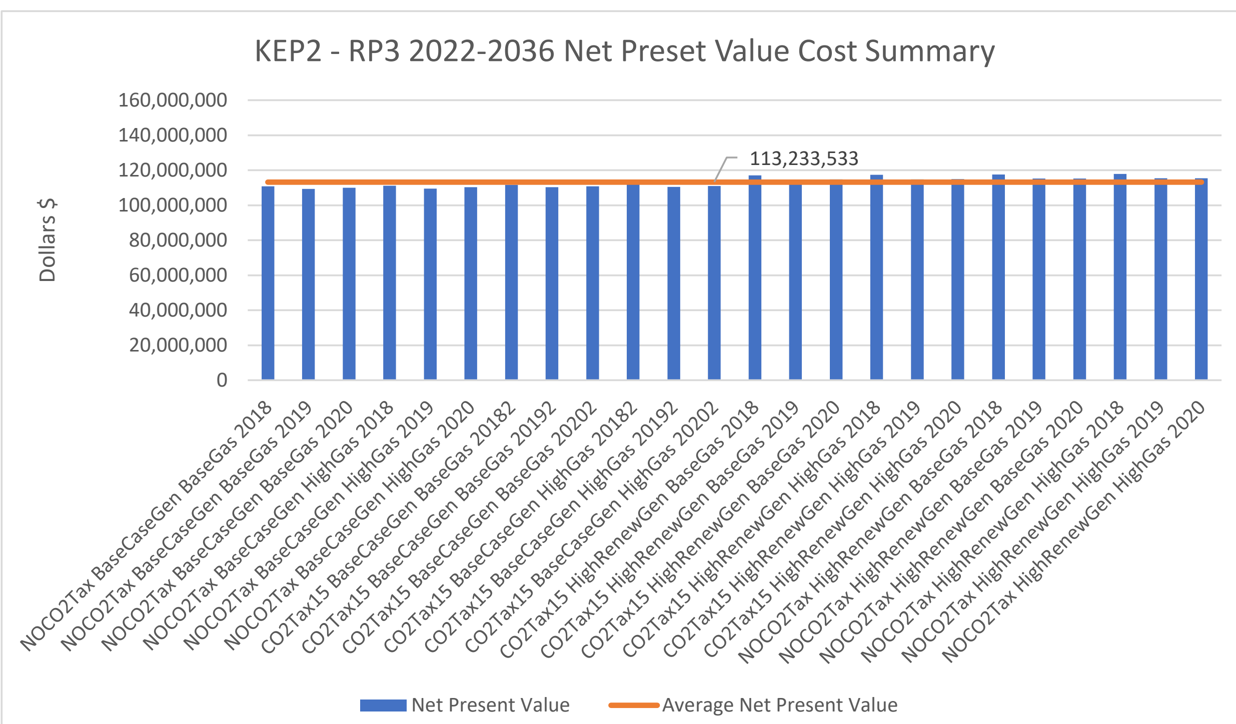
Annual average energy and capacity cost per MWh is shown across the scenarios and sensitivities. Annual average costs have a notably lower value in the later years of each case due to the wind resource providing the price certainty for a large percentage of load serving energy.

Figure 30: KEP2 - RP3 – Average Energy and Capacity Cost



RP3 net present value costs for 2022-2036 show the NPV for each scenario and sensitivity and an average of $113.2 million.

Figure 31: RP3 – 2022-2036 NPV Summary

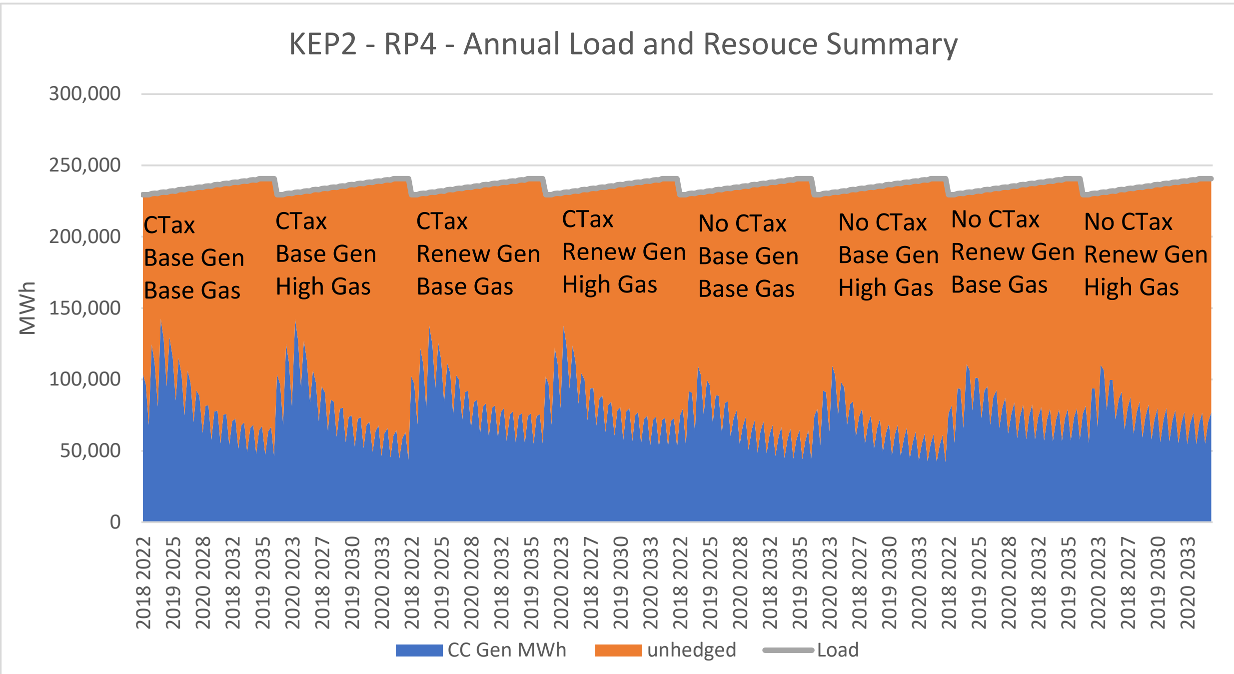


The average NPV value for RP3 is slightly higher than RP2, but the standard deviation of RP3 is lower than RP2 at $2.8 million.

6.3.4 RP4 Results

RP4 results shows the dispatch of a combined cycle plant into the SPP IM and hedging the KEP2 load serving costs. The energy balance of the cases is shown in the following chart.

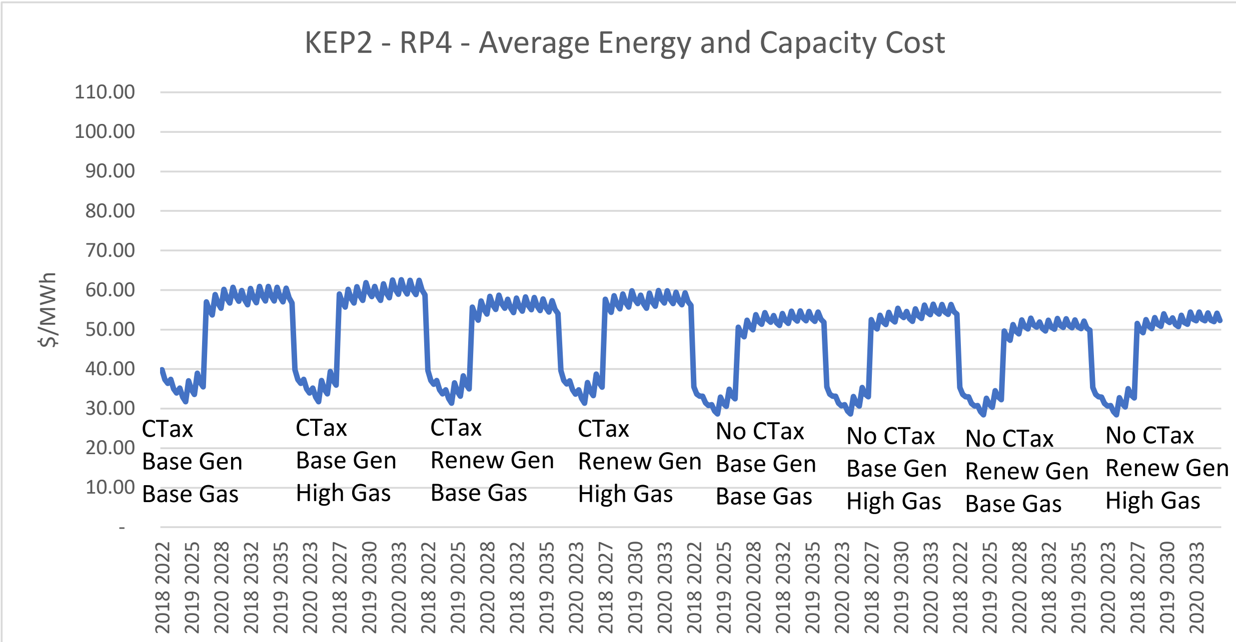
Figure 32: RP4 – Annual Load and Resource Summary



The dispatch of the combined cycle plant has a higher level of variance in the early years of most cases, which shows the crossovers of the combined cycle operating cost compared to the market price projection. The dispatch of the combined cycle provides about 1/3 of the KEP2 load.

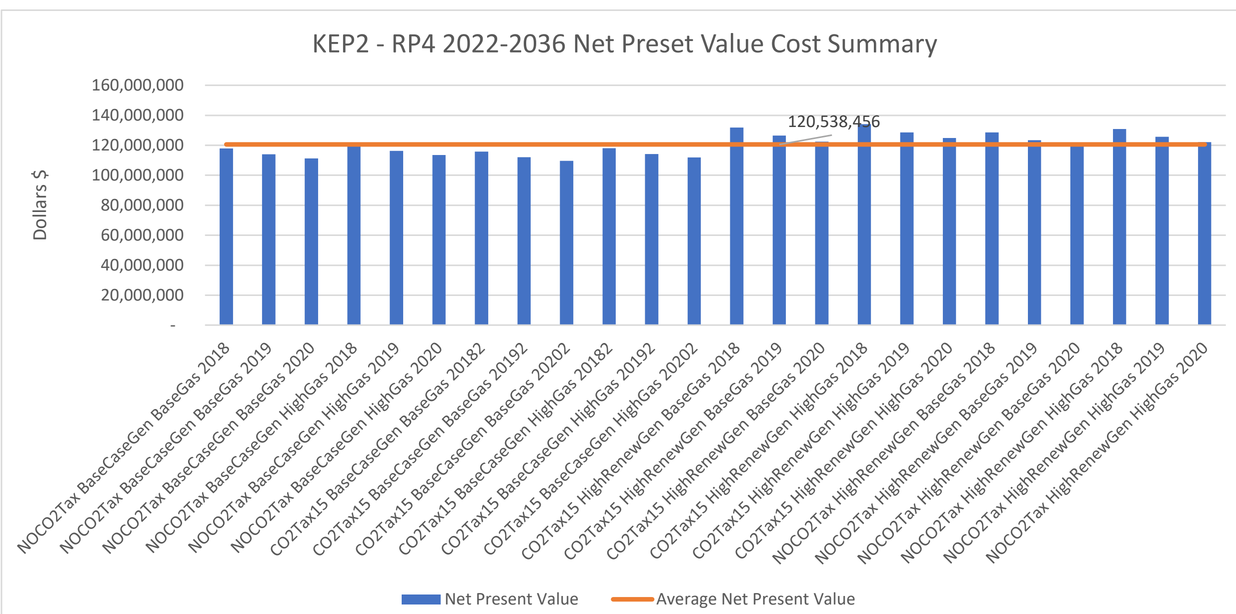
Annual average cost results are shown in the figure below and show a significant capability of hedging against the increasing energy and capacity costs in the later years of each series of annual costs. The average costs are much more like a block, with a higher cost than other portfolios in the early years due to paying the fixed combined cycle costs starting in 2027, where other portfolios have the bilateral capacity purchase, which starts out much lower but gets up to higher costs later in the planning horizon. There is some exposure to the carbon tax in RP4, but for a carbon tax of $15/ton, the exposure is not significant.

Figure 33: KEP2 - RP4– Average Energy and Capacity Cost



The NPV results or RP4 are pretty similar to other portfolios evaluated thus far and show an average NPV of $120.5 million.

Figure 34: KEP2 RP4 – 2022-2036 Net Present Value Cost Summary

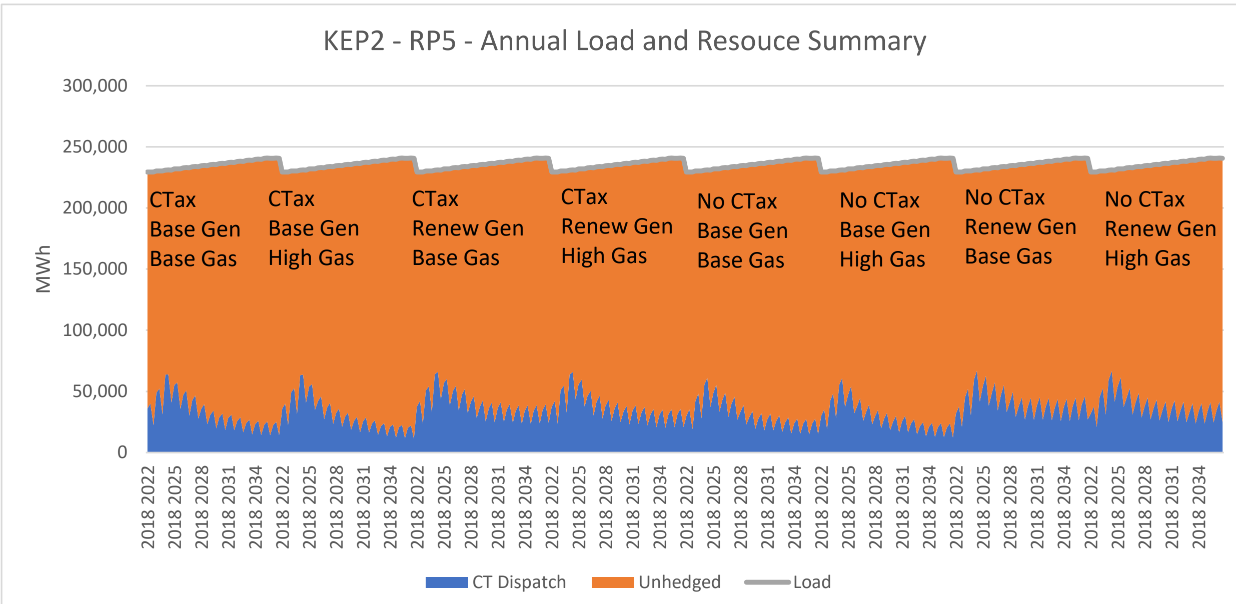


The NPV variance across the cases is higher than RP3 at $7.0 million, which shows a higher level of uncertainty across the range of defined scenarios and sensitivities.

6.3.5 RP5 Results

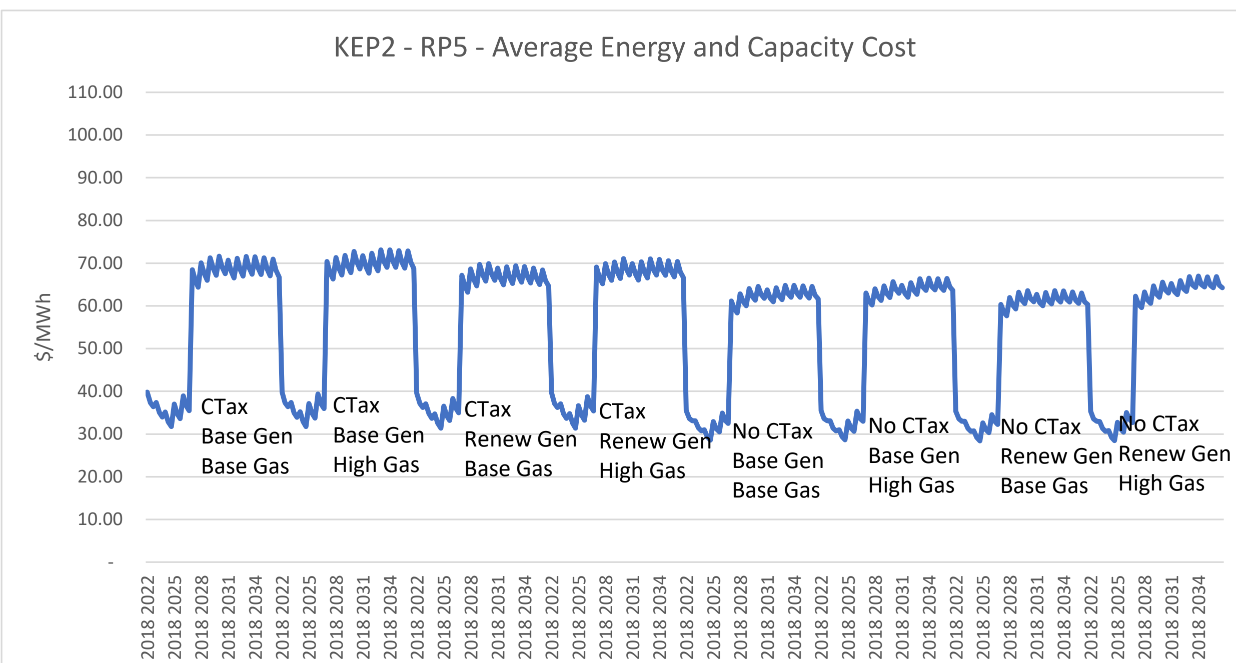
RP5 results show the dispatch of a peaking plant into the SPP IM and the ability to hedge against higher market prices. The amount of energy dispatched from the peaking plant is much lower than the combined cycled in RP4 due to the peaking unit having a higher operating cost.

Figure 35: KEP2 - RP5 – Annual Load and Resource Balance



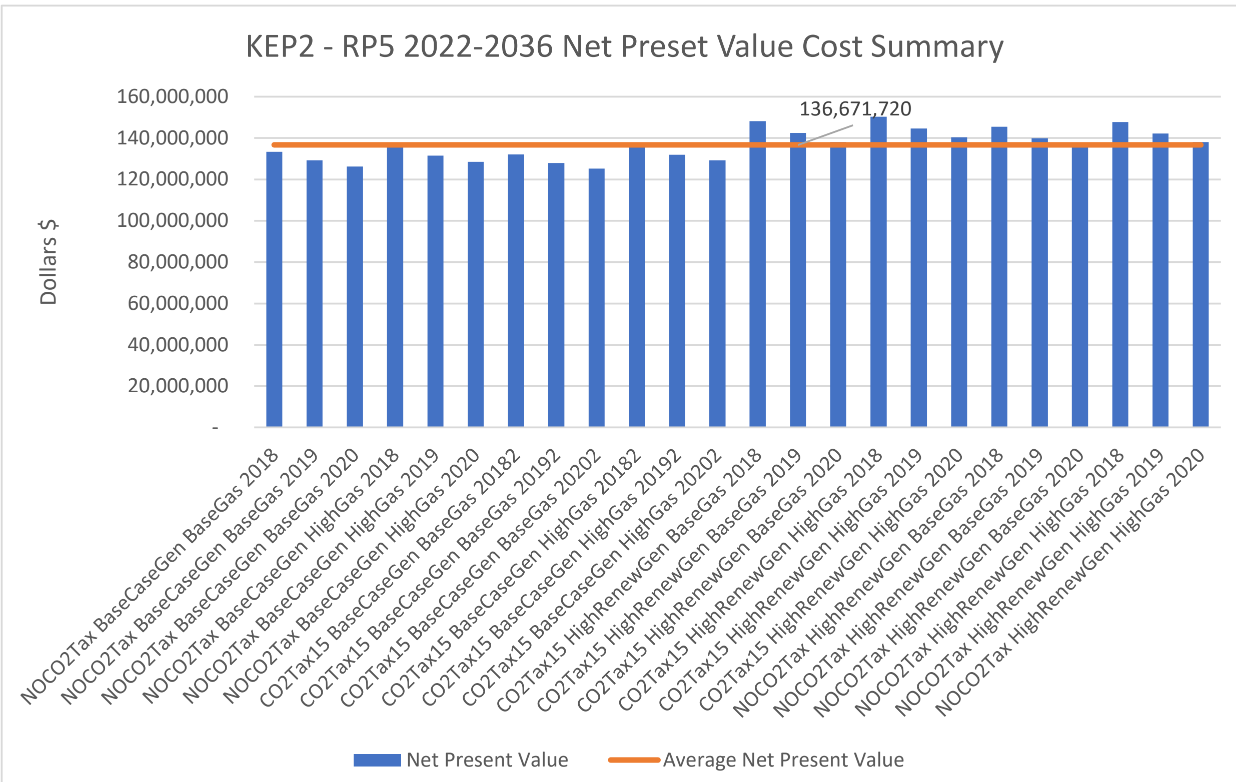
Annual average costs for RP5 are shown in the following chart across the 8 combinations of sensitivities and scenarios.

Figure 36: RP5 – Average Cost $/MWh



The NPV cost summary of RP5 is over $16 million higher than other cases and the standard deviation of the results is $7.2 million, which is comparable to RP4. The comparison of RP4 and RP5 is not just a matter of the reported costs, but there would likely be a higher cost for RP4 if the normal constraints of the combined cycle were modeled with a unit commitment logic and ramp rate limitations. The RP4 modeling is essentially getting the best of both worlds between combined cycle and peaking but being able to provide the most efficient heat rate in a burst of time, where the actual costs would be higher. The results of RP4 and RP5 can be essentially combined in a form to show that the expected costs of a natural gas fired unit would be somewhere between these two in a case where the amount of energy hedged is driven by the combined cycle having a more efficient heat rate, but the short-term flexibility of being able to generate power quickly for a sudden need in the market could be accomplished using the peaking unit.

Figure 37: RP5 – 2022-2036 NPV Summary

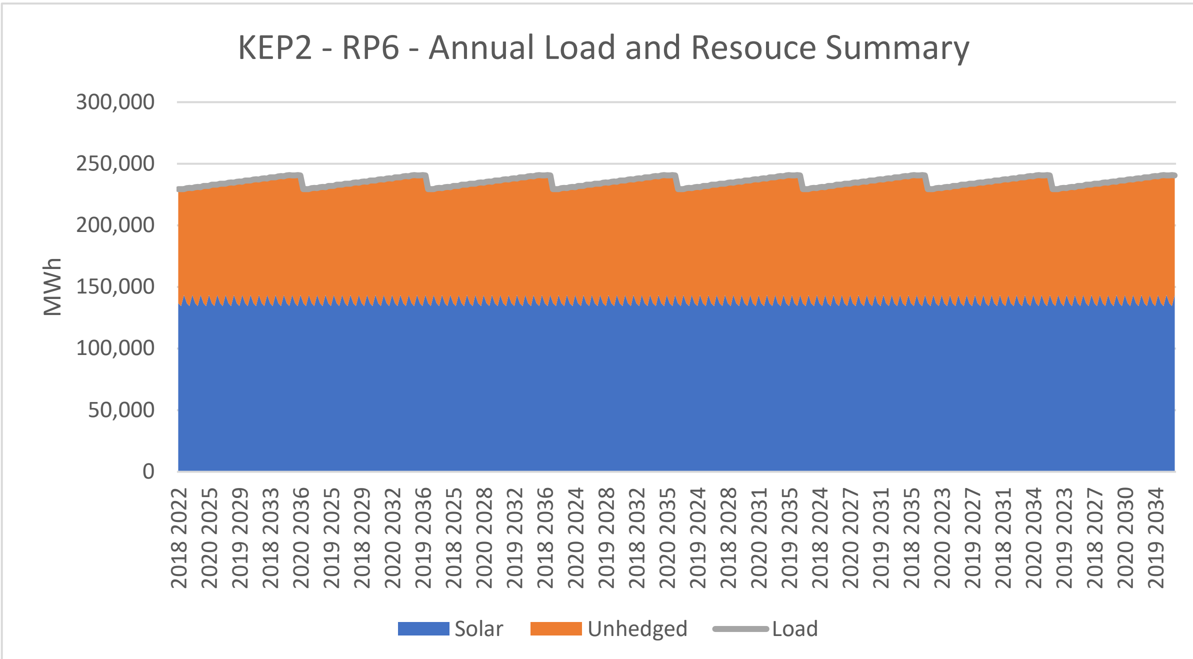


6.3.6 RP6 Results

RP6 results shows the dispatch of a 50 MW nameplate solar plant into the SPP IM and the ability to hedge against the load. This portfolio is showing a very strong capability to hedge against the market, but it is important to understand that the pricing model is using the extremely high levels of solar generation to derive the pricing, and this higher pricing during times of high solar activity is a key driver in the results.

Solar generation provides roughly 2/3 of the total energy requirements of the KEP2 load, as shown in the figure below.

Figure 38: RP6 – MWh Balance MWh



The cost of solar is assumed to be $40/MWh based on publicly available data for similar sized projects. The comparison of the $40/MWh cost and the average value of the SPP IM revenue when the solar is being dispatched shows how this revenue is driving the average costs of serving load to such a low value.

Figure 39: Case P6 – Solar Cost and Revenue $/MWh

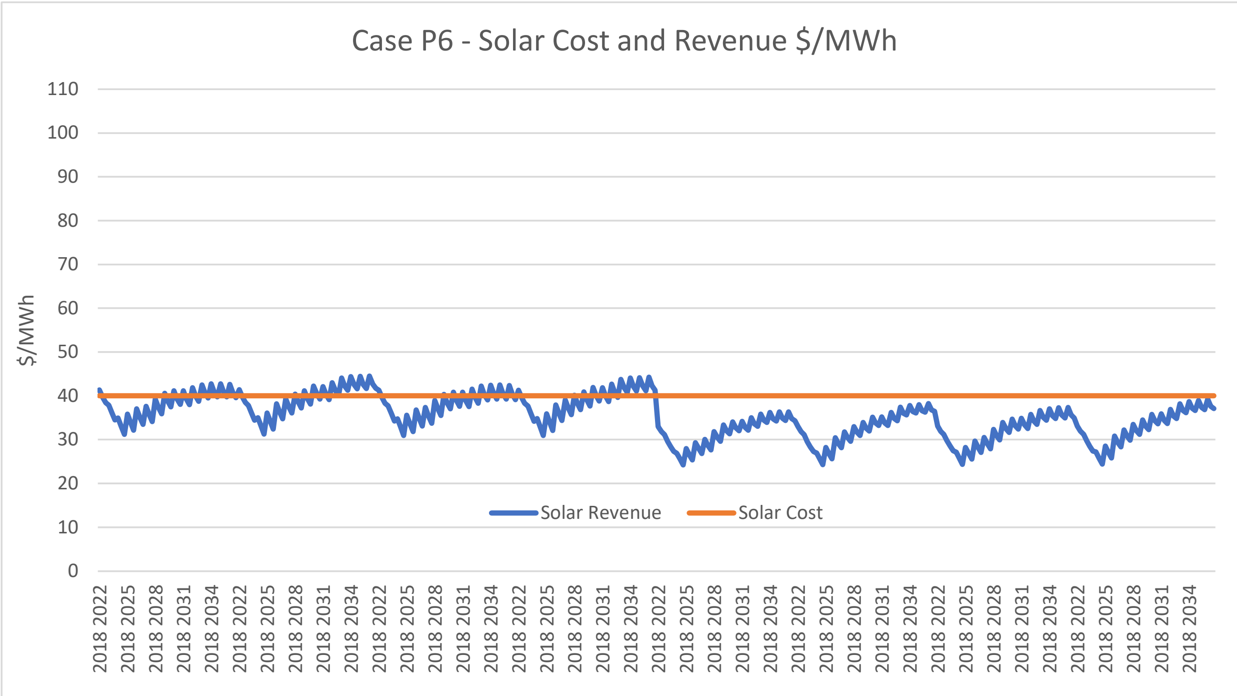


Figure 40: RP6 – Average Energy and Capacity Cost

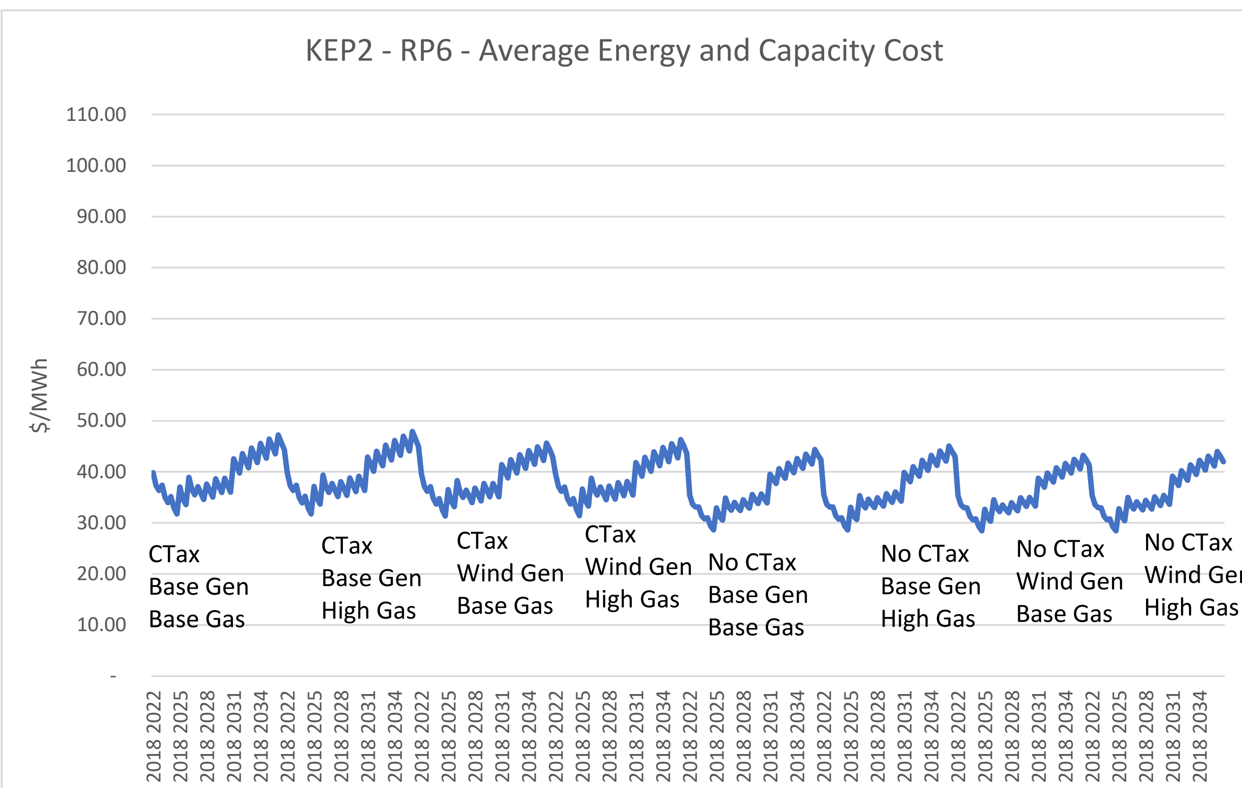
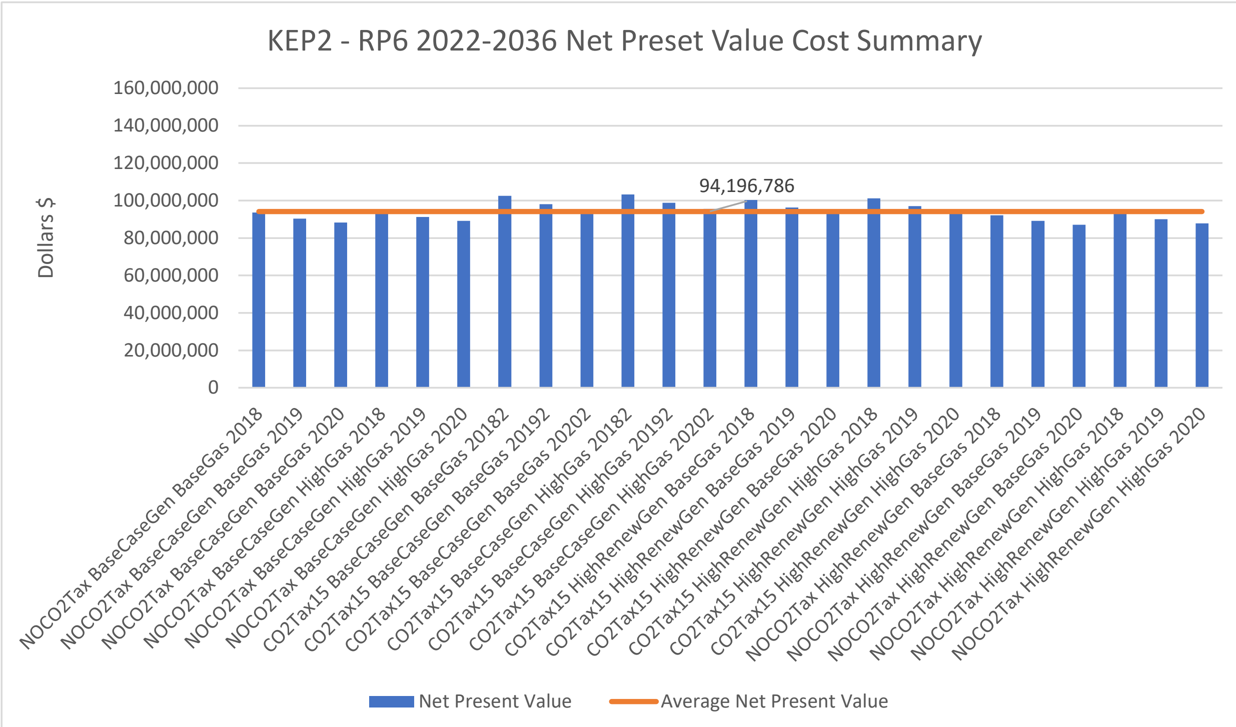


Figure 41: RP6 – 2022-2036 NPV Summary



The standard deviation of the NPV results is $4.6 million, so it has a higher level of cost uncertainty than RP3.

6.3.7 RP1-RP6 Summary

There are a number of points that can be summarized from the evaluation of the RP1, RP2, RP3, RP4, RP5, and RP6 results. RP2 does a very good job of hedging energy exposure to market prices because the on-peak energy block is not dependent on the output of a specific resource and therefore, is always available and dispatched on peak. It should also be noted that the resource simulation used in the economic evaluation of the various scenarios assumes perfect knowledge of the market price to the dispatch of resources, and the dispatch of the resources doesn't include a forced outage rate to account for the unavailability of the resource to hedge market energy.

The energy produced by RP3 (50 MW of wind) and RP6 (50 MW of solar) significantly reduce market energy exposure and the cost of that energy production is not impacted by a carbon tax.

The resource simulation considers energy on an annual basis rather than an hourly (SPP day ahead market) or 5-minute (SPP real time balancing market). This simplifying assumption in the simulation overstates the actual effectiveness of the resources to hedge market energy exposure. The best example of this is RP3. The wind resource is likely to produce significant energy during the shoulder months and off-peak when prices are lower rather than on-peak when prices are higher.

Figure 42: KEP2 - RP1-RP6 Summary of Unhedged Energy Percent

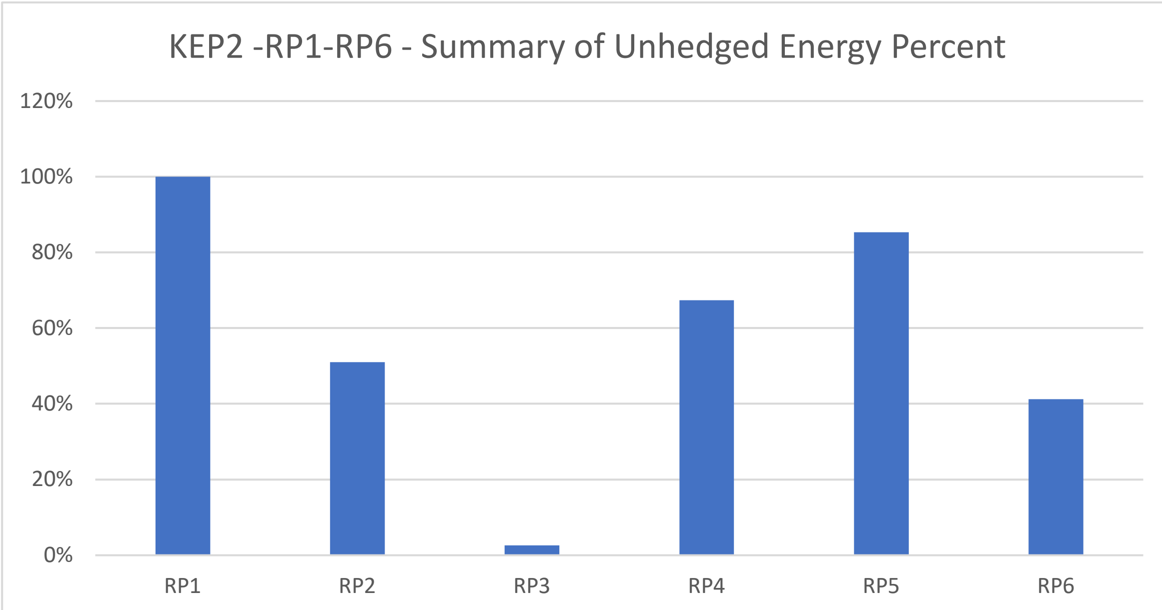
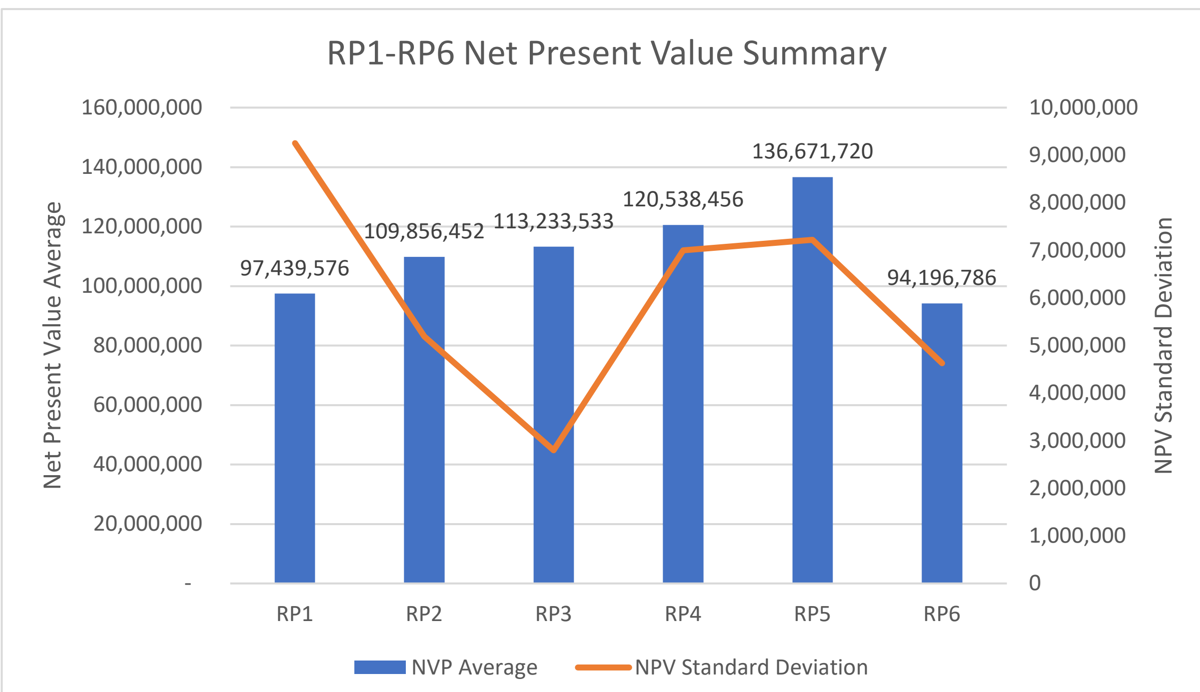


Figure 43: RP1-RP6 – Net Present Value Summary



The exposure to the variables defined in the balance of the KEPCo resource portfolio is something that is not defined in this Study, but the focus is on the part of the resource portfolio that can be defined in the next coming years.

The evaluation sets a timeframe for making a more substantive energy procurement decision by 2027, but details on the decision-making process and specific options will clearly have to play out based on available opportunities and KEPCo's desired strategic direction.

7 Recommendations

Recommendations for the Study are intended to provide a guide of next steps within the bounds of what is known at the time of the Study. There are a number of outside events that could change the needs and viable path of recommendations that will need to be continually monitored.

SPP is showing significant levels of wind and solar generation development in the next 10-15 years. Currently, there are over 24,000 MW of nameplate of wind generation, and this is expected to at least double the amount of wind in the next 15 years and may be as high as 32,000 MW more nameplate by 2036. Solar additions are also expected to be significant over the next 15 years, and the Study assumes a range of 8,200 MW to as high as 12,000 MW nameplate. The SPP interconnection queue and the SPP 2021 ITP study provide the basis for the renewable generation additions.

There is a concurrent need to evaluate the viability of an energy block purchase that could begin as early as 2022, and the viability of adding wind and/or solar by 2027. Wind and/or solar could be added earlier than 2027 if the project development or share of an existing project would create an opportunity. Wind development can provide a significant level of energy pricing protection, and solar development can also provide protection to what is expected to be the pricing with the higher price volatility. With the range of uncertainty in wind and solar project availability, and the uncertainty of the amount of hedging desired from contracts or resources, the RFP will be useful to evaluate the needs more closely and make decisions based on findings from the RFP.

Recommendations include the following:

- Based on the most recent information about any potential retirements and other market factors, conduct detailed analysis showing the targeted amount of energy that is protected from SPP IM volatility. Study results will be shown for purchase options, solar development, and wind development.

- Issue an RFP seeking proposals for the following resources:

    - Targeted block MW 5x16 energy purchase for 2022-2026 with options for extending the purchase from 2027 and beyond.

    - Targeted wind MW nameplate wind generation purchase as early as 2024 for a targeted 20-year term.

    - Targeted solar MW nameplate solar generation purchase as early as 2024 for a targeted 20-year term.

- Critical information from the RFP will include the following:

    - Specific interconnection milestones and cost projections for potential wind or solar resources in order to provide insights into the costs and schedule for generation development.

    - Level of development of the project in terms of business case, other parties involved if a joint project, other project development history.

    - Projected costs.

- Evaluate the results of the RFP and determine the mix of resources from the results that will provide guidance on the KEPCo portfolio expansion.

The next resource portfolio decisions for KEPCo will involve a number of factors that are not clearly understood at this point but will be more apparent in the next phases of evaluation in the months and years to come.