Final - PROPOSED

Nebraska Public Power District

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2023 Integrated Resource Plan

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LIST OF EXHIBITS

LIST OF ABBREVIATIONS

(AWEF) - Ainsworth Wind Energy Facility
(BPS) - Beatrice Power Station
(BWR) - Boiling Water Reactor
(CC) - Combined Cycle
(CCS) - Carbon Caputure and Sequestration
(CE) - Capacity Expansion
(CF) - Capacity Factor
(CNPPID) - Central Nebraska Public Power & Irrigation District
(CO_2) - Carbon Dioxide
(CT) - Combustion Turbine
(CNS) - Cooper Nuclear Station
(DA) - Day-Ahead
(DR) - Demand Response
(DRR) - Demand Response Resource
(EETS) - Energy Efficiency Tracking System
(ELCC) - Effective Load Carrying Capacity
(ELG) - Effluent Limitation Guideline
(EPRI) - Electric Power Research Institute
(EE) - Energy Efficiency
(EIA)- Energy Information Administration
(EMC) - Electric Membership Corporation
(ES) - Energy Storage
(ESR) - Energy Storage Resources
(G&T) - Generation and Transmission
(GI) - Generation Interconnection
(GGS) - Gerald Gentleman Station
(GW) - Gigawatt
(IIJA) - Infrastructure Investment and Jobs Act
(IRA) - Inflation Reduction Act
(IRP) - Integrated Resource Plan
(kV) - Kilovolt
(LCOE) - Levelized Cost of Energy
(MMU) - Market Monitoring Unit
(MEAN) - Municipal Energy Agency of Nebraska
(MEEA) - Midwest Energy Efficiency Alliance
(MW) - Megawatt
(MWh) - Megawatt-hour
(NC2) - Nebraska City Unit 2
(NPV) - Net Present Value
(NPPD) - Nebraska Public Power District
(OPPD) - Omaha Public Power District
(PBA) - Performance Based Accreditation
(PO) - Portfolio Optimization
(PPA) - Power Purchase Agreement
(PPD) - Public Power District
(PRAB) - Power Resource Advisory Board

(PRM) - Planning Reserve Margin
(PRO) - Professional Retail Operations
(PTC) - Production Tax Credit
(QLG) - Qualifying Local Generation
(RT) - Real-Time
(RICE) - Reciprocating Internal Combustion Engines
(RAR) - Resource Adequacy Requirement
(RPPD) - Rural Public Power District
(RRC) - Rate Review Committee
(SMR) - Small Modular Reactor
(SPP) - Southwest Power Pool
(SD) - Strategic Directive
(TEA) - The Energy Authority
(WAPA) - Western Area Power Administration

EXECUTIVE SUMMARY

The following integrated resource plan report details the analyses of electricity supply options and demand side management options (efficiency, conservation, and demand response) resulting in the least-cost options for providing energy services to NPPD's customers over the study period 2023-2052. This least-cost approach to resource planning includes cost, reliability, resiliency, and environmental considerations, and provides insight as to the most favorable approach for adding resources to meet future native load requirements while minimizing cost and risk.

The IRP does not provide an exact expansion plan to be followed for the next 30 years, nor does it evaluate every possible combination of resources to meet future native load requirements. The IRP is intended to provide a "directionally correct" vision of the future for decision making. While the modeling employed is intended to be accurate and comprehensive, it is intended to support, and not replace, the judgment of NPPD's decision makers.

Furthermore, the assumptions contained herein regarding potential CO_2 reduction scenarios, and other assumptions about future public policy provisions are for planning purposes only and are intended to provide credible planning scenarios, but are neither an endorsement of any particular regulatory regime or an attempt to predict the specific requirements of any regulatory regime that may be established. Costs for various alternatives are based on numerous assumptions and could increase or decrease under more detailed analysis involving specific projects. The assumptions and modeling scenarios and results described are hypothetical.

NPPD's Vision, Mission, Strategic Directives, and Strategic Plan guide the IRP. The Board-adopted Strategic Directives establish a requirement for NPPD to maintain a reliable and resilient generation portfolio to meet the needs of NPPD's customers with the ability to mitigate, survive, and/or recover from high impact events (BP-SD-03). The Board Strategic Directive on cost competitiveness (BP-SD-04) also establishes requirements for the District to meet certain cost competitiveness goals when measured against established benchmark standards. Additionally, the Strategic Directive for Carbon Emissions Reductions (BP-SD-05) recognizes the business risk of carbon emissions and emissions regulations, and establishes the goal of achieving "net zero" carbon emissions from NPPD's generation resources by 2050**.** NPPD's Board of Directors may evaluate and reconsider the District's Carbon Emissions Goal if it is determined that meeting or progressing toward the goal will adversely impact the District's ability to continue to meet the strategic directives concerning reliability (BP-SD-03) or cost competitiveness (BP-SD-04).

Process

Starting from NPPD's existing and committed generation resources, (Appendix B lists all of NPPD's existing generation resources, including in-state hydro purchases and capacity purchases), early work on the IRP necessitated the development of long-term assumptions around major uncertainties such as NPPD's load forecast, fuel and market pricing (Section 3.3), and plausible environmental regulations or regimes. Additionally, the IRP studies the potential addition of numerous candidate resources, either supply or demand, such as conventional, renewable, energy storage, and energy efficiency/demand response resources, as well as options to either continue operating, modify, or retire existing units in NPPD's portfolio.

By studying various combinations of major uncertainties, the IRP develops the lowest cost resource plan under each particular combination of inputs, using Hitachi Energy's Enterprise Software Capacity Expansion (CE) model. CE is a mid- to long-term portfolio optimization model. It provides automated screening and evaluation of decisions for generation capacity expansion, retirement options and contract transactions. CE includes both investment (capital) and operational (production) cost variables. The model analyzes using Linear Programming and Mixed Integer Programming. CE is fully integrated with Portfolio Optimization (PO), which NPPD uses for production cost modeling for our Rate Outlook and budgeting processes.

Results

NPPD ran 54 cases using the CE software. The NPV of 30-year Wholesale Revenue Requirements for all of the runs are shown in Exhibit 4.1.1-1. The first 27 cases examined combinations of low, base, and high scenarios for CO_2 restrictions, load, and market. After reviewing these results, various sensitivities were run to measure the impact of changing the resource plan.

The NPVs in this exhibit and elsewhere do not include credits from the Inflation Reduction Act (IRA). NPPD is still waiting on guidance from the federal government to fully understand its impact. A high-level estimate was undertaken to help in understanding the order of magnitude this act can have on NPPD. These estimated impacts can be found in Section 4.1.1.

Exhibit 4.1.1-4 shows annual projected emissions using a representative case for each CO_2 restriction scenario. All of the resulting resource plans were generally able to meet the modeled CO_2 reduction scenarios.

Although load was the greatest uncertainty as measured by NPV and shown in Exhibit 4.1.1-2 in the Results Section, the CO_2 restriction variable had a greater impact on the types of resource selected. Coal plants without CO_2 controls operated longer with the least restricted CO_2 restriction scenario, while NPPD's nuclear facility fared better under the most restricted CO_2 restriction scenarios.

Nuclear and coal units fared better under higher market prices. A major reason for this is due to the fuel costs being relatively uncorrelated to market prices, while natural gas fuel tends to be positively correlated with the market. Coal and nuclear units also tend to fare well under severe conditions, such as Winter Storm Uri. Their onsite fuel and robust design allows them to reliably respond to customer needs during severe weather conditions.

NPPD tries to maintain a diverse resource mix, in alignment with our Vision, Mission, Strategic Directives, and Strategic Plan. We believe this provides our customers with low cost, reliable, resilient, and sustainable energy, and reaffirms the need to maintain fuel diversity in our resources. In examining the lowest-cost resource plans for each case, the following conclusions were drawn:

- CNS is presently the least risky nuclear or coal with CCS option under a restrictive CO_2 scenario. Continued operation will also allow NPPD to maintain a diverse resource mix.

- The GGS units are presently a cost effective resource for NPPD's customers. With the potential availability of 45Q credits under the Inflation Reduction Act, it could also remain a cost effective solution under a restrictive CO_2 scenario, if retrofitted with CCS equipment.

This technology is not yet widely proven, so it is considered more risky than a relicense of CNS.

- Sheldon Station is a very good location for a generation resource. The results suggest restoring natural gas as the primary fuel at Sheldon can be in NPPD and its customers' best interest.

- Additional EE and DR can provide value to our customers, especially in high load and/or restrictive CO2 scenarios. NPPD will need to work with our customers to find programs that works best for all parties.

- Installation of new renewables tended to occur if a unit is retired or new load is added. Earlier installation of renewables can make sense with the Inflation Reduction Act credits and CO_2 restrictions and should be investigated.

- The amount of capital required for new resources and/or retrofit/extensions of existing facilities are quite large and some of these decisions will need to be made within the next few years. The capital requirements for a representative sample of resource plans are shown in Exhibit 4.1.1-3.

  NOTE: NPPD's current Wholesale Power Contract (WPC) expires at the end of 2035. While not part of the IRP discussion, it is understood that financing the capital requirements noted above will require revisiting the terms & conditions of the WPC with our customers.

Action Plan

The resulting IRP action plan includes minimum items NPPD feels it needs to better understand and position us for the future. It is not meant to be an all inclusive list of work items. The IRP can be updated as business conditions and available technologies change. Therefore, the action plan will also be periodically reviewed and updated to align with the changing business environment. The action plan items listed in Section 5 and summarized below are expected to be completed by the next IRP report.

Action Item 5.1 – Start proceeding with the second relicense renewal process at CNS, as well as further refine the capital costs needed for the relicense. Also continue to monitor CNS operating costs and reevaluate relicensing if projected costs are significantly higher than assumptions in the IRP.

Action Item 5.2 - Continue to operate GGS on coal, while monitoring potential risks to continued GGS operation. NPPD should also continue to investigate CCS for potentially lower cost options and impacts from the IRA credits, as well as other options for the GGS site in the event of a low carbon future.

Action Item 5.3 - Continue to pursue required modifications at Sheldon for compliance with ELG rule requirements, while also investigating potential restoration of the site to natural gas operation. NPPD should also obtain better estimates for natural gas restoration vs. a dual-fuel CT or RICE facility before making a final decision on any modifications.

Action Item 5.4 – Continue to monitor SMR progress and complete preliminary siting studies.

Action Item 5.5 - Evaluate the potential for increased funding of the EnergyWise[SM] program, in order to facilitate further discussion with our customers regarding the most mutually advantageous level of EE for NPPD to pursue in the future.

Action Item 5.6 - Work with customers to identify mutually beneficial opportunities to increase NPPD's use of DR. NPPD should also continue to participate in on-going review of SPP's requirements for DR to ensure its existing DR programs remain compliant and continue to provide a resource adequacy benefit.

Action Item 5.7 - Explore the possibility of early renewable installation utilizing IRA credits. The exact size and type and the value will depend on what is available to interconnect to the transmission system within a few years.

Action Item 5.8 - Investigate resource options due to the higher near-term projected loads.

Public Interface

The 2023 IRP Draft Report was presented to the Board of Directors during its January 2023 Board Meeting. This presentation officially began the process to gather input from the public concerning their comments and feedback. A variety of methods were used to gather feedback, including both virtual and face-to-face meetings.

Overall, there was not as much interest in the IRP vs. the public outreach during the development of BP-SD-05 based on the responses and feedback. One may surmise by this that the results of the IRP generally matched the expectation of NPPD's customers. A more detailed summary of the methods used to interface with the public and comments received can be found in Section 6.

1. INTRODUCTION

Nebraska Public Power District (NPPD) is Nebraska's largest electric utility, serving all or parts of 84 of Nebraska's 93 counties. NPPD supplies the total wholesale power requirements of 38 municipalities and 23 public power districts and cooperatives. NPPD also serves 79 entities at retail with Professional Retail Operations (PRO) Agreements as well as others, that combined, add up to almost 93,000 customers. NPPD’s electrical system, including transmission and subtransmission grids, comprises nearly 5,400 miles of power lines.

NPPD uses a diverse mix of fuel resources, including nuclear, coal, oil, and natural gas to generate electric power. NPPD also generates energy from renewable resources utilizing wind, solar and water (hydroelectric power). In addition, NPPD purchases energy from the Western Area Power Administration (WAPA), which is a Federal marketing and transmission agency for, primarily, Federal hydropower.

This report meets NPPD’s 2023 Integrated Resource Plan (IRP) cooperative filing requirement under WAPA’s regulations for a five-year report. A complete list of entities covered under the NPPD IRP is provided in Appendix A. This IRP is being prepared on behalf of:

> NPPD’s Wholesale Requirements Customers receiving WAPA power benefits through NPPD’s purchases from WAPA, and the following direct purchasers of WAPA power (those receiving their own allocation):
>
> > Auburn, Cambridge, David City, Deshler, DeWitt, Emerson, Franklin, Indianola, Laurel, Lodgepole, Lyons, Madison, Norfolk Regional Treatment Center, Oglala Sioux Tribe, Omaha Tribe, Ord, Randolph, Santee Sioux Tribe, Schuyler, Spalding, Wahoo, Wilber, Winnebago Tribe, and Winside

This report also meets the requirements of Nebraska Revised Statutes Section 66-1060 and NPPD’s Wholesale Power Contracts.

Integrated resource planning includes the analysis of electricity supply options and demand side management options (efficiency, conservation, and demand response) resulting in a least-cost plan for providing energy services to NPPD’s customers over the study period (2023-2052). This least-cost approach to resource planning includes cost, reliability, resiliency, and environmental considerations. Integrated resource planning is an ongoing process that must be flexible to respond to changes in the business environment.

An Integrated Resource Plan (IRP) provides insight as to the most favorable approach for adding resources to meet future native load requirements while minimizing cost and risk. The IRP does not provide an exact expansion plan to be followed for the next 30 years, nor does it evaluate every possible combination of resources to meet future native load requirements. The IRP is intended to provide a “directionally correct” vision of the future for decision making. While the modeling employed is intended to be accurate and comprehensive, it is intended to support, and not replace, the judgment of NPPD’s decision makers.

1.1 Disclaimer

Assumptions contained herein regarding potential CO_2 reduction scenarios, and other assumptions about future public policy provisions are for planning purposes only and are intended to provide credible planning scenarios, but are neither an endorsement of any particular regulatory regime or an attempt to predict the specific requirements of any regulatory regime that may be established. Costs for various alternatives are based on numerous assumptions and could increase or decrease under more detailed analysis involving specific projects. The assumptions and modeling scenarios and results described are hypothetical.

1.2 IRP Planning Principles

The IRP must align with NPPD's Vision, Mission, Strategic Directives, and Strategic Plan. The Board-adopted Strategic Directives establish a requirement for NPPD to maintain a reliable and resilient generation portfolio to meet the needs of NPPD's customers with the ability to mitigate, survive, and/or recover from high impact events (BP-SD-03). The Board Strategic Directive on cost competitiveness (BP-SD-04) also establishes requirements for the District to meet certain cost competitiveness goals when measured against established benchmark standards. Additionally, the Strategic Directive for Carbon Emissions Reductions (BP-SD-05) recognizes the business risk of carbon emissions and emissions regulations, and establishes the goal of achieving "net zero" carbon emissions from NPPD's generation resources by 2050**.** NPPD's Board of Directors may evaluate and reconsider the District's Carbon Emissions Goal if it is determined that meeting or progressing toward the goal will adversely impact the District's ability to continue to meet the strategic directives concerning reliability (BP-SD-03) or cost competitiveness (BP-SD-04).

Key language from NPPD's Strategic Directives and Strategic Plan that serve as guiding principles for the IRP process include:

- Balance affordability, reliability/resilience, and sustainability when addressing the business risks related to carbon emissions and emissions regulations.
- Continue the use of proven, reliable generation until alternative, reliable sources of generation are developed.
- Use certified offsets, energy efficiency projects, lower or zero carbon emission generation resources, beneficial electrification projects, or other economic and practical technologies that help NPPD meet the adopted goal at costs that are equal to, or lower than, current resources.
- Strive to increase energy efficiency, support effective economic development that enhances NPPD's load profile, and provide services in alignment with NPPD's core business to broaden NPPD's revenue base and reduce overall overhead costs to our customers.

Some general guidelines used to help focus the IRP analysis process are:

- Resource expansion plans evaluated and selected in the IRP must meet future native load plus Planning Reserve Margin (PRM) requirements.
- Resource expansion plans evaluated and selected in the IRP should minimize cost on a long-term basis after considering the effects of various risk factors.

- Resource expansion plans evaluated and selected in the IRP should meet the requirements of NPPD’s carbon emissions reduction directive BP-SD-05.
- The IRP should focus attention to resources that function well under a range of future planning scenarios.
- The IRP should address near term resource needs and position NPPD for the future.

2. EXISTING SYSTEM & COMMITTED RESOURCES

2.1 Existing

NPPD uses a diverse mix of generation resources such as coal, nuclear, natural gas, hydro, wind and solar to meet the needs of its customers. Appendix B lists all of NPPD's existing generation resources, including in-state hydro purchases and capacity purchases. NPPD typically calculates the non-carbon portion of its resource portfolio as either a percent of native load energy, or as a percent of NPPD's share, defined as native load plus non-firm energy sales, for various purposes. Non-carbon resources generated energy equal to approximately 61% of native load energy, based on an average of 2021 and 2022. Exhibit 2.1-1 shows NPPD's share of Energy Resources in 2021-22, where Exhibit 2.1-2 presents the capacity breakdown. An average of 2021-22 was used to smooth out the annual variation in energy numbers associated with the biennial refueling outage of NPPD's nuclear facility, CNS.

Exhibit 2.1-1 – NPPD's Share of 2021/22 Actual Energy Resources

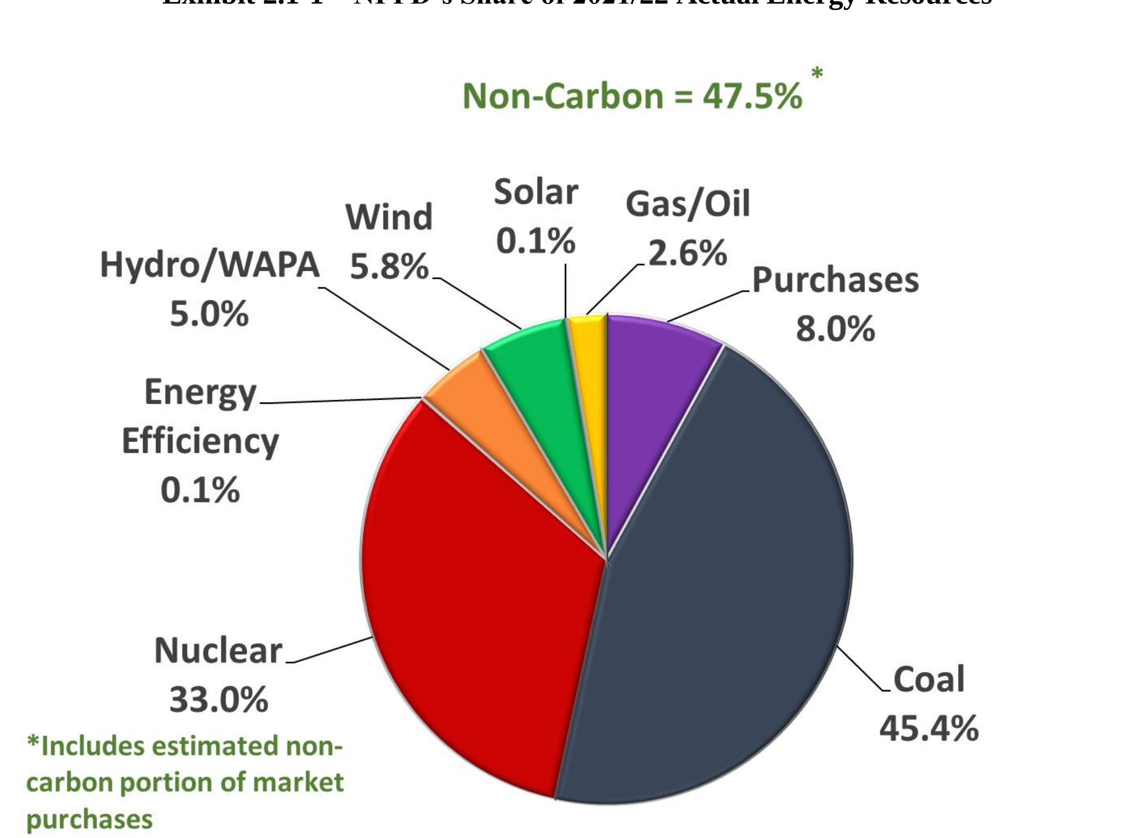
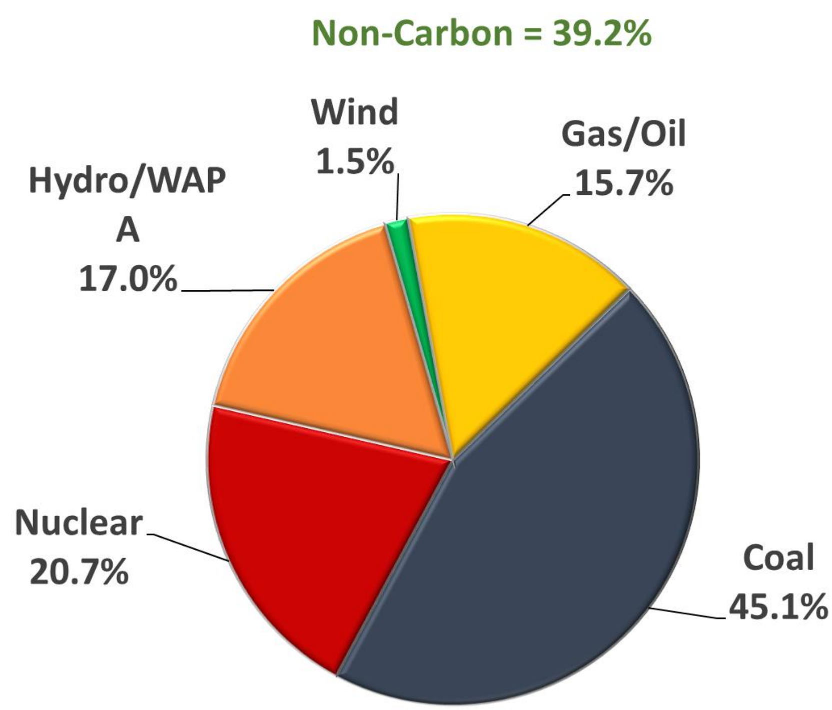


Exhibit 2.1-2 – NPPD's Share of 2021/22 Actual Capacity Resources



In 2021/22, 45% of NPPD's native load energy and non-firm sales obligation was met with coal generation. GGS, a coal plant located near Sutherland, is Nebraska's largest generating plant. GGS consists of two generating units which have the capability of generating 1,365 MW of power. GGS Unit 1 which has been in-service since May, 1979 has a net generation capability of 665 MW. GGS Unit 2, the larger unit at 700 MW net, has been commercial since January, 1982. GGS is fueled using sub-bituminous low sulfur coal from Wyoming's Powder River Basin. Participation sales with other utilities amount to approximately 133 MW of GGS' output in 2021.

Sheldon, a coal fired plant near Hallam, consists of two boilers that can generate 219 MW of electricity. Sheldon Unit 1, a 104 MW unit, was commissioned in 1961 while Unit 2, a 115 MW unit, was added in 1968. Sheldon also burns Powder River Basin low-sulfur coal.

Nebraska City Unit 2 (NC2) is an approximate 690 MW coal-fired generating unit that Omaha Public Power District (OPPD) constructed adjacent to its Nebraska City Unit 1 plant. NPPD has a life of plant power agreement with OPPD to receive 23.67%, or approximately 164 MW, of NC2's output. Commercial production of electricity commenced May 2009.

NPPD's second largest source of generation, and largest single generation unit, is CNS. CNS was put into operation in July 1974. In 2021/22, CNS accounted for approximately 33% of NPPD's native load energy and non-firm sales obligation, as shown in Exhibit 1.1-1. CNS, which has a net summer capacity of approximately 770 MW, is a Boiling Water Reactor (BWR) unit. In 2021, participation contracts accounted for 97 MW of the capacity. NPPD's operating license for CNS expires in 2034.

BPS, a combined cycle gas fired unit, came on-line in January 2005. BPS uses two combustion turbines and one steam unit to generate up to 220 MW. Canaday Station is a 99 MW gas fired unit. Canaday, constructed in 1958, was originally owned by Central Nebraska Public Power & Irrigation District (CNPPID). In 1995 NPPD acquired the "mothballed" plant and had it accredited in June 1998.

NPPD also owns three gas turbine units. The Hallam unit can generate 42 MW and can run on natural gas or distillate oil. The Hebron and McCook units are 42 and 40 MWs respectively, and run on distillate oil.

NPPD owns and operates two hydroelectric generation facilities. The largest is a two unit hydro located near North Platte. The North Platte hydro consists of two 12 MW units for a total of 24 MW capacity. This hydro, operating since 1937, uses water from the North and South Platte rivers. After flowing through the hydro, the water reenters the South Platte River and powers other hydros and irrigation needs downstream. The Kearney Hydro, the oldest in the state, has been operational since 1921. This hydro was rehabilitated in 1997 and generates about 1 MW.

In addition to NPPD owned hydro facilities, NPPD also purchases hydro capacity owned by Loup Power District and CNPPID. Loup owns and operates two facilities along the Loup canal system which in 2012 had an accredited capacity of approximately 45 MW. CNPPID owns and operates Kingsley Hydro, which is directly below Kingsley dam on Lake McConaughy and is accredited at 42 MW.

The Ainsworth Wind Energy Facility (AWEF) was built by NPPD in 2005. The facility consists of 36 1.65 MW turbines for a total nameplate capacity of approximately 60 MW. OPPD, Municipal Energy Agency of Nebraska (MEAN), and the City of Grand Island participate in 30% of AWEF's generation.

In addition to AWEF, NPPD has Power Purchase Agreements (PPAs) for the purchase of energy from seven other wind facilities across Nebraska.

1) The Elkhorn Ridge Wind facility, an 80 MW site, became operational in 2009. NPPD takes 40 MW of this facility's production and sells the remaining 40 MW to four other Nebraska utilities.
2) The Laredo Ridge Wind facility, an 80 MW site, became operational in 2010. NPPD takes 61 MW of this facility's production and sells the remaining 19 MW to three Nebraska utilities.
3) The Crofton Bluffs Wind facility, a 42 MW site, became operational in late 2012. NPPD takes 21 MW of this facility's production and sells the remaining 21 MW to three Nebraska utilities.
4) The Broken Bow Wind facility, an 80 MW site, became operational in late 2012. NPPD takes 51 MW of this facility's production and sells the remaining 29 MW to three Nebraska utilities.
5) The Broken Bow II Wind facility, a 73 MW site, became operational in late 2014. NPPD takes 29 MW of this facility's production and sells the remaining 44 MW to one Nebraska utility.
6) The Steele Flats Wind facility, a 75 MW site, became operational in late 2013 with NPPD taking the entire output.
7) The Springview II Wind facility became operational in 2011 which is a 3 MW site with NPPD taking the entire output.

Several of NPPD’s wholesale municipal customers own internal combustion generators. NPPD has capacity purchase agreements with these municipals for an additional 69 MW generation capacity. These smaller units are generally dispatched only at peak usage times, as emergency generation or to stabilize local transmission constraints.

In addition to the above generation facilities, NPPD purchases approximately 444 MW of firm power from WAPA and other capacity or energy on both a short-term and non-firm basis in the wholesale energy market. WAPA purchases make up over half of NPPD’s total energy purchases. Of the capacity purchases, 287 MW are a WAPA Firm Peaking Power Service product available in summer months.

Wholesale and retail customers, alongside the general public, continue to gain interest in solar and battery storage projects. NPPD's 2016 Wholesale power contract and Retail Professional Operating agreements allow customers and communities to install qualifying local generation (QLG) based on certain load criteria. As of December 2021, approximately 62 MW of QLG have been installed, including approximately 11 MW of retail community solar.

2.2 Committed

Committed resources are future resources that have been approved by NPPD’s Board of Directors to proceed. Presently, there are no committed resources.

Summary of Existing & Committed Resources

A projected load and capability graph with only existing/committed resources operating throughout the study period is included in Appendix C for the summer season. This graph generally confirms NPPD has sufficient resources to meet its seasonal capacity obligations in the near future under the base and low load forecast scenarios. If the high load forecast scenario were to occur, 360 – 400 MW of additional capacity would be necessary by 2026.

3. MAJOR ASSUMPTIONS

This section summarizes the main assumptions that were used in the IRP analysis.

3.1 Load Forecast

NPPD employs both top-down and bottom-up forecasting methods. The top-down econometric forecast uses service area socioeconomic "drivers" to project loads based on overall service area economic and demographic trends. The top-down econometric forecast includes models for NPPD system level demand and energy at the busbar, or system inlet. The top-down econometric forecast also develops customer class energy forecasts at the end-use meter level. The bottom-up or distributor level forecast consists of producing monthly demand and energy forecasts for all of NPPD's wholesale distributors, including NPPD Retail. The distributor level forecast uses data at Bus A, the metering point for wholesale billing. The two methods are reconciled by losses so that busbar, Bus A, and meter level forecasts are consistent with each other.

The base case load forecast used in the IRP analysis assumes that NPPD's summer demand requirements will grow at an average rate of 4.9% annually between 2023 and 2025, and the demand requirements are forecasted to grow at an average rate of 0.18% annually between 2025 and 2052 (see Exhibit 3.1-1). NPPD's base case energy requirements are forecasted to grow at an average rate of 7.3% annually between 2023 and 2025, and the energy requirements are forecasted to grow at an average rate of 0.26% annually between 2025 and 2052 (Exhibit 3.1-2). The larger annual growth at the front end of the forecast is due to a large step increase from an anticipated new large industrial customer. These growth rates reflect the moderate level of energy efficiency.

In addition to this base forecast, the IRP also considered two alternative load forecast scenarios. The high forecast assumes the addition of 450 MW of load above the base forecast beginning in 2026. This forecast is intended to represent uncertainty regarding potential new large facilities that are considering locating in NPPD's service territory. The low forecast assumes the loss of 20% of the base forecast beginning in 2036. Exhibits 3.1-1 and 3.1-2 compare the annual peak demand and energy, respectively for the three scenarios.

Since completing the load forecast used in the IRP, NPPD's Economic Development efforts and incentives in the IRA and IIJA have attracted a considerable amount of prospective new load. This additional load growth includes data centers, crypto mining, food and hydrogen processing. The original forecast included one large step load from an anticipated new large industrial customer. The updated forecast includes several anticipated new large and medium sized industrial customers. The resulting new base case forecast in 2030 is more than 200 MW higher than the high scenario used in the IRP. This could result in NPPD adding more capacity sooner than originally identified in the IRP. It is recommended to investigate resource options due to the higher near-term projected loads.

Exhibit 3.1-1 – Peak Demand Forecast

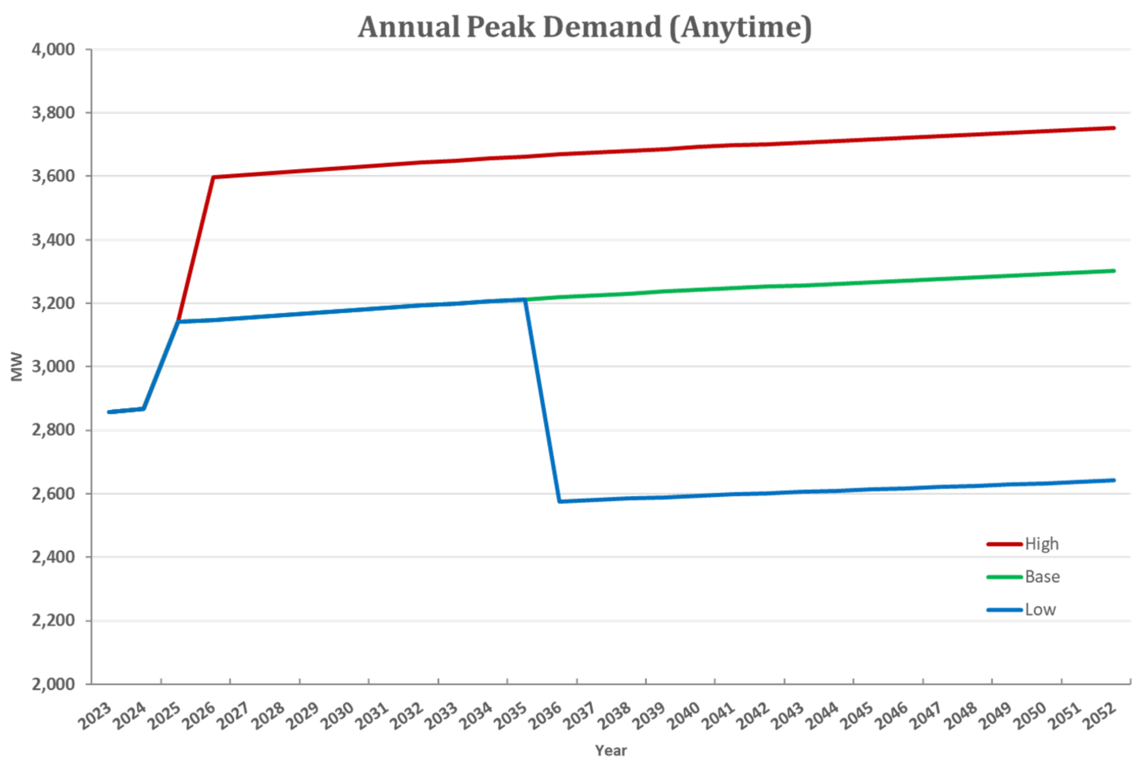
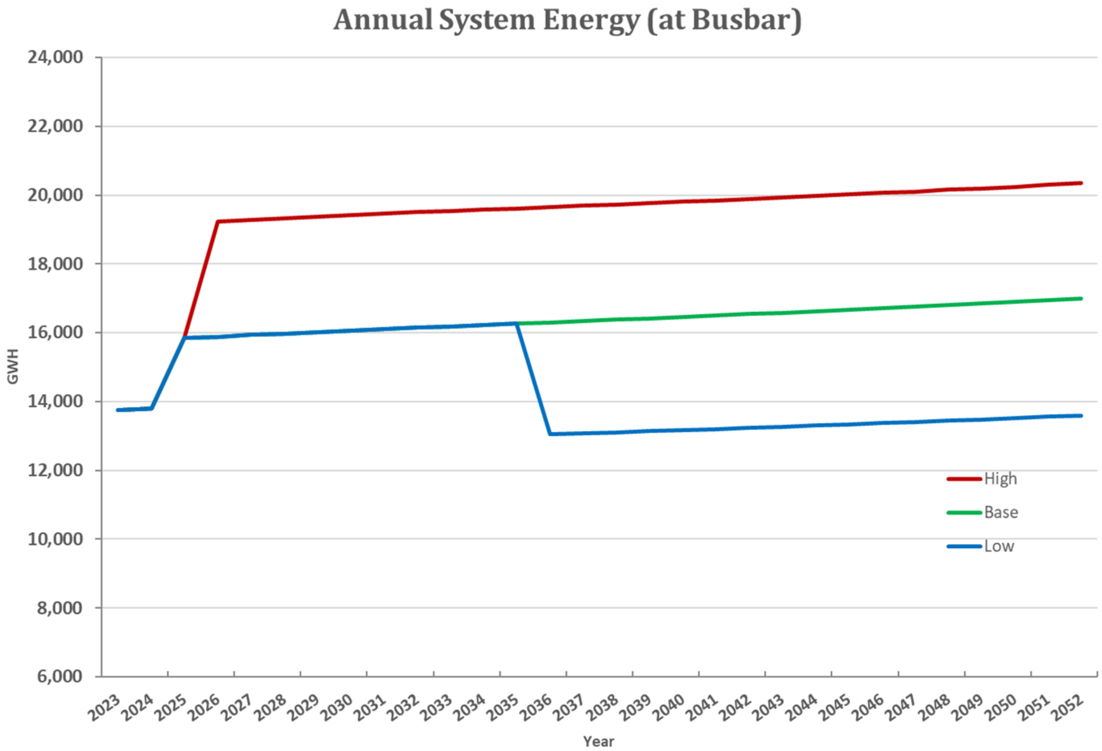


Exhibit 3.1-2 – Annual Energy Forecast



3.2 Potential Carbon Regulation or Legislation

Uncertainty surrounding carbon emissions and emissions regulation are a significant business risk for NPPD and its customers. NPPD recognizes the importance of balancing affordability, reliability/resilience, and sustainability when addressing the business risks related to carbon emissions and emissions regulations. In light of this risk, NPPD's Board of Directors approved Strategic Directive BP-SD-05 on December 9, 2021. BP-SD-05 adopts the goal of achieving "net zero" carbon emissions from NPPD's generation resources by 2050.

Three different scenarios were modeled.

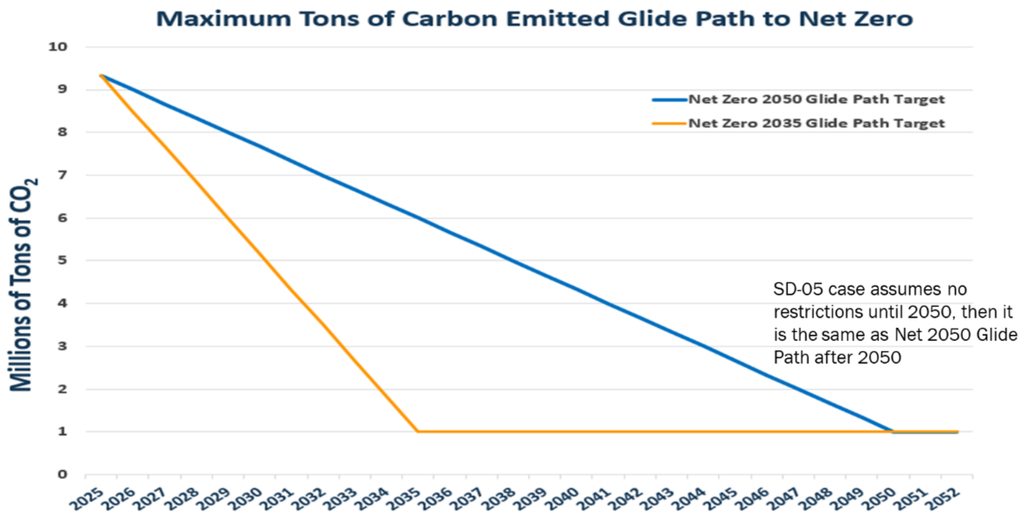
- SD-05 – This scenario, which incorporates the requirements of BP-SD-05, assumes a limit on CO_2 emissions of 1 million ton maximum[1] starting in 2050. No limits were assumed before 2050 since no intermediate goals are listed in BP-SD-05. It reflects a future in which minimal business risks associated with carbon emissions occur over the majority of the study period.
- Net Zero 2050 Glide Path – This scenario assumes the same CO_2 emission limit in 2050, but with a linear reduction beginning from a starting point of 9.3 million tons[2] in 2025. It is intended to represent a future with increased carbon emission related business risks occurring, that adversely impact NPPD's fossil fuel resources between now and 2050.

[1] This assumption for "net zero" reflects an NPPD load of approximately 17 million MWh in 2050, of which 10% is provided from carbon emitting resources with a carbon intensitiy of approximately 0.6 short tons/MWh.
[2] This is approximately equal to NPPD's actual 2021emissions for Native Load plus Non-firm Sales.

- Net Zero 2035 Glide Path – This scenario assumes a more aggressive linear reduction, from 2025, achieving a 1 million ton maximum in 2035. Like the Net Zero 2050 Glide Path, this scenario also reflects a future with increased carbon emission related business risks, including a potential federal mandate/restriction on carbon emissions by 2035, as has been discussed by current administration.

The three emission reduction scenarios are shown graphically in Exhibit 3.2-1

Exhibit 3.2-1 – Emission Reduction Scenarios



- 2025 value based on 2021 actual emissions

3.3 Fuel and Energy Market Prices

In general, fuel prices used assumptions from the 2021 Rate Outlook version, which extends to 2027, were used. The Fuel Department provided the natural gas price forecast through 2034.

NPPD fuel price forecasts are proprietary and confidential business information and therefore not included in this report. However, coal and uranium fuel costs were assumed to escalate 2.2% and 2.1% respectively, through 2053. Natural gas fuel costs were assumed to escalate approximately 2.2% over the 30-year period.

The electricity market is tied to the fuel market. The base energy market forecast for the IRP model was provided by NPPD's Energy Management and TEA. In general, the electricity market was correlated to the natural gas market forward curves through 2032. Prices are expected to decline on average 4.3% through 2029, then escalate about 3.5% through 2032. After 2032, market prices are assumed to escalate 1% annually, consistent with market projections provided by NPPD's "Plan B" consultants. TEA also provided 75th and 25th percentile projections for the high and low scenarios. Post 2032, the high scenario is assumed to escalate 1.5% annually while the low scenario escalates 0.5% annually. NPPD also considered a higher market sensitivity in which the price was approximately $10/MWh higher than the high market scenario.

3.4 Resources Studied

3.4.1 Energy Efficiency and Demand Response

NPPD presently has a successful demand waiver program, to reduce summer billable peaks. The demand waiver program is not controllable by NPPD. Customers are provided with a price signal, through the wholesale rate, and determine the appropriate level of control. The majority of savings in this program is due to irrigation load control by various wholesale customers, which accounted for approximately 620 MW of demand reduction from NPPD's billable peak during the summer of 2021. Another 2 MW of demand reduction was realized in 2021 from other sources. These demand reductions usually occur on weekdays from the hours of 4:00-6:00 p.m. Interestingly, due to the success of the irrigation load control program and the shifting of energy usage from "on-peak" periods to "off-peak" periods, NPPD's system peak during "off-peak" periods is now typically higher than its "on-peak" peak. For example, in 2021, the official "off-peak" peak was 489 MW higher than the "on-peak" peak.

In addition, NPPD currently offers the EnergyWise^{SM} Energy Efficiency program to its retail and wholesale customers. NPPD is committed to maximizing the value of customer energy purchases in a cost effective manner in order to improve customer bottom lines, reduce the cost to serve load during peak usage times, and delay or even eliminate the need to build additional resources. NPPD also provides a Beneficial Electrification program that encourages the continued electrification of large sectors of the economy such as transportation, industry, and residential heating under the EnergyWise^{SM} umbrella.

NPPD's Energy Efficiency Tracking System (EETS) is used to measure and verify annual energy savings, impact on summer peak electrical demand, and energy savings anticipated to be saved over the lifetime of the energy efficiency measures. NPPD uses values that are generally agreed-upon industry standards, or they may also be values that have been derived from extensive measurement and verification efforts that were previously conducted and demonstrated little variance to estimate energy savings.

The Base EE assumption for the IRP assumed continued funding of the EnergyWise^{SM} program at the current level of approximately $2.6 million annually over the study period. Given the historic performance of the program, delivering energy savings at a cost of 1¢/kWh or less, would result in annual savings of approximately 3 MW and 24 GWh annually. Cumulative savings by 2050 are projected to be 86 MW and 682 GWh[3].

An alternate High EE scenario was also examined, as part of the IRP analysis. NPPD's Energy Efficiency Department provided estimated impacts for an increase in budgeted spending of $1.3 million annually, beginning in 2025, and assuming the energy saving could be delivered at a cost of about 1.5¢/kWh, resulting in incremental annual savings of about 1 MW and 8 GWh. Cumulative savings by 2050 under this scenario are projected to be 27 MW and 215 GWh higher than under the Base assumptions.

[3] These Base EE savings are reflected in the load forecast scenarios, discussed in Section 3.1.

Exhibits 3.4.1-1 and 3.4.1-2 summarize the projected Demand & Energy EE savings assumptions, respectively.

Exhibit 3.4.1-1 – EE Demand Reduction Assumptions

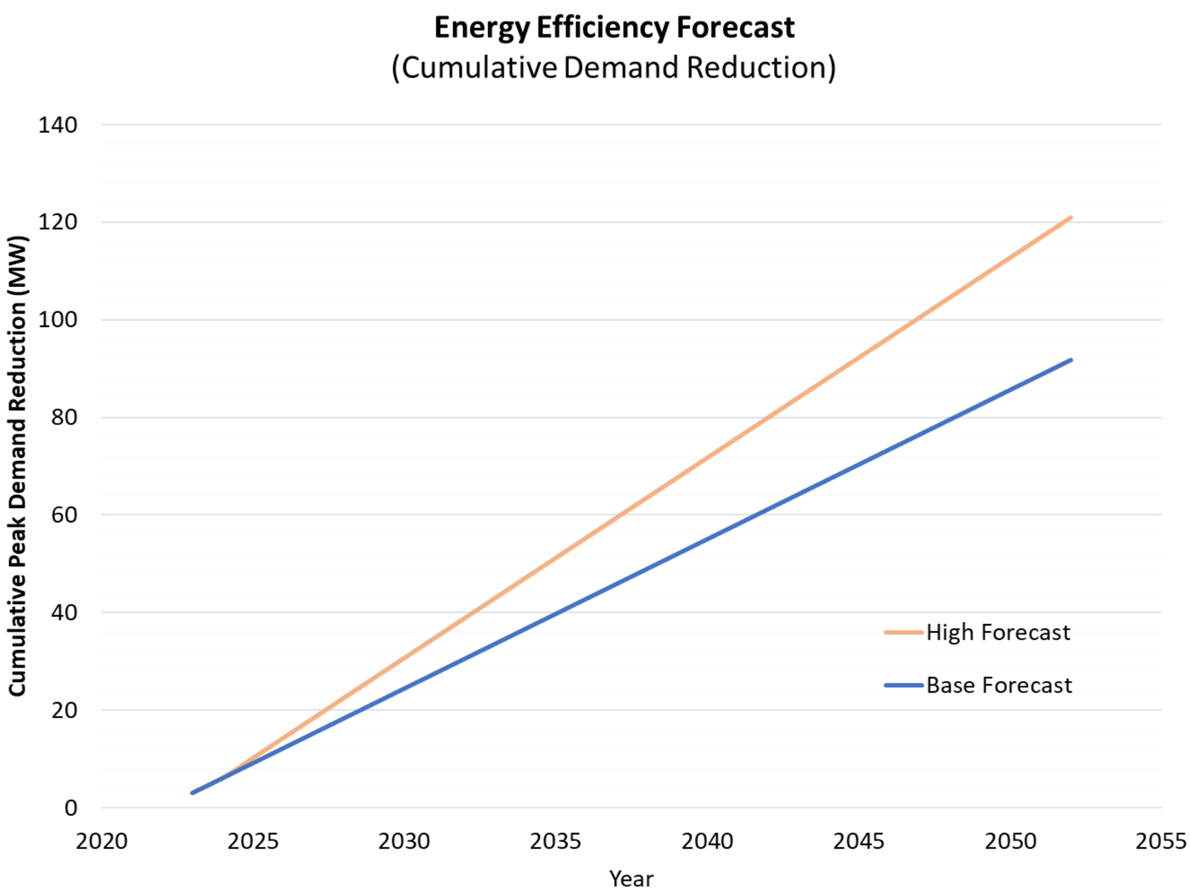
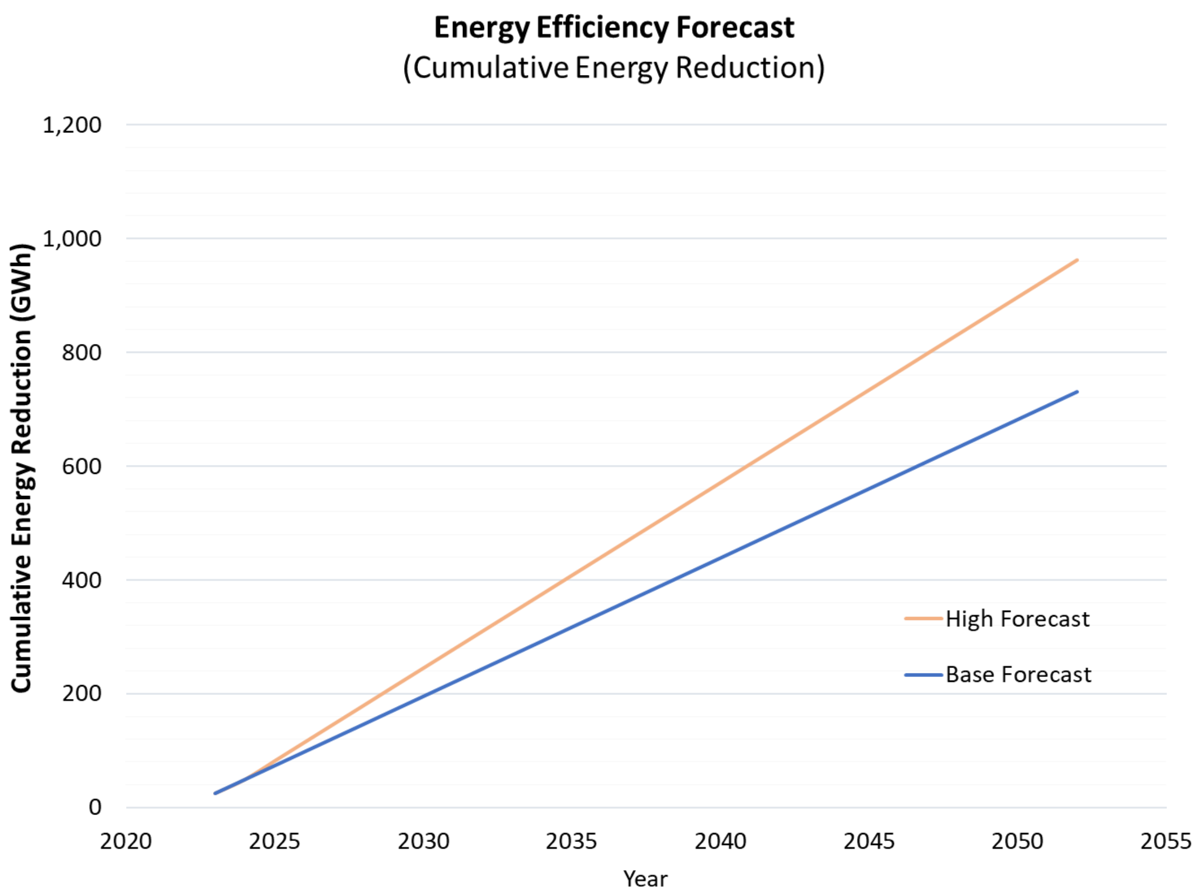


Exhibit 3.4.1-2 – EE Energy Reduction Assumptions

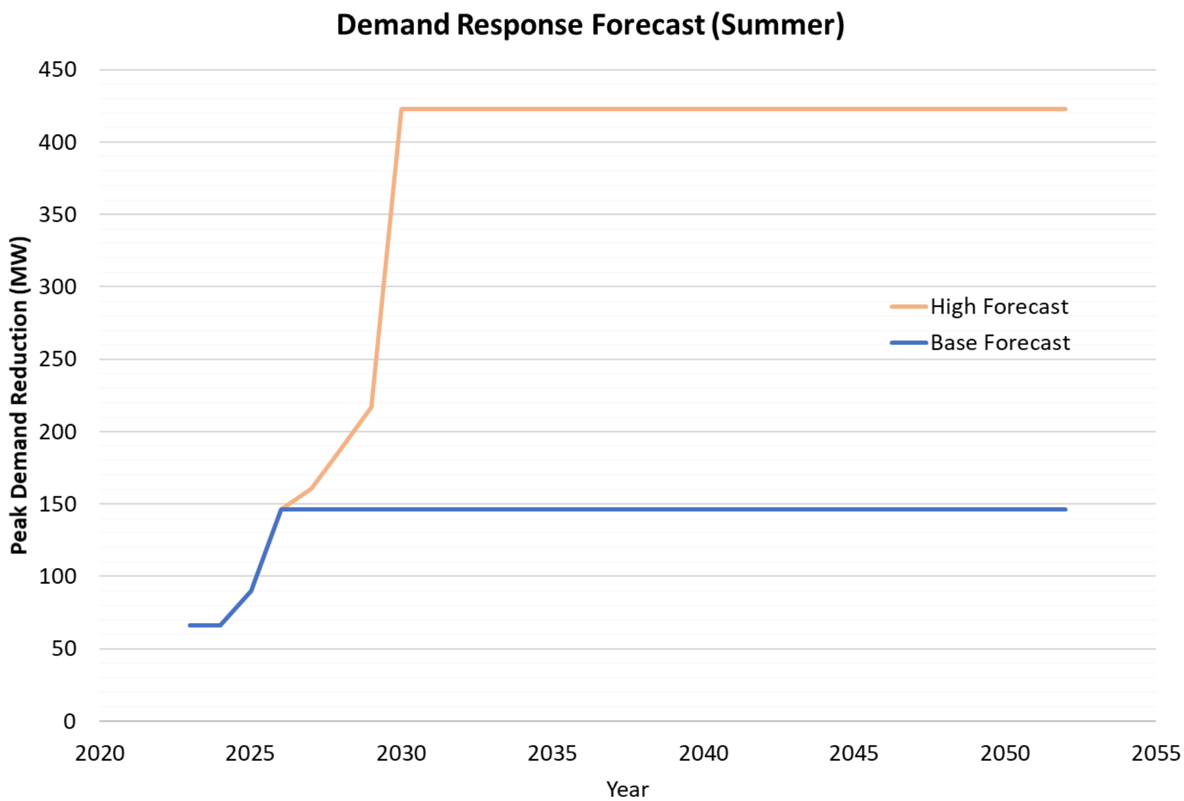


In 2018, NPPD implemented a Large Customer Interruptible Rate Schedule (Special Power Product No. 8), which is available to eligible wholesale customers, as well as an Interruptible Service Rider Rate Schedule (INT Rider), which is available to retail customers. Under these rate schedules, NPPD may call for curtailment of a portion of the customer's load (i.e., Non-Firm Service) under certain defined conditions (i.e., SPP System Emergency, High SPP Energy Prices, & Management of NPPD's Annual Peak Demand). NPPD is able to claim this non-firm, or interruptible load as a reduction in Net Peak Demand for purposes of establishing its annual Resource Adequacy Requirement (RAR) with SPP. NPPD currently has one customer taking service under the interruptible rate schedule. NPPD has also worked with another customer to offer its interruptible load into the Integrated Market as a Demand Response Resource (DRR) and NPPD could claim this load as a reduction to its annual RAR in our base assumptions. While the current number of customers taking service under the interruptible rate is small, NPPD anticipates more customers will take advantage of this rate schedule in the future.

For purposes of the IRP, the base forecast assumes demand response is essentially limited to growth from these existing customers. Under this forecast, the demand response reduction is assumed to grow to approximately 150 MW by 2026. Alternatively, the high forecast assumes several new customers with large incremental loads eventually take service under the interruptible rate schedule. The demand response reduction, under this forecast, grows to approximately 420 MW by 2030. Figure 2.4.1-3 displays the modeled forecasts.

SPP presently allows the use of demand response programs to reduce the load and associated planning reserves which need to be served by generating resources. This use of demand response is currently under investigation as to whether the requirements for these types of programs need to be better defined, along with the possibility of providing less resource adequacy credit. Any changes to SPP requirements will be reviewed by NPPD.

Exhibit 3.4.1-3 – Demand Response Forecast Assumptions



3.4.2 New Resource Alternatives

The IRP used a number of sources in developing cost and performance assumptions for future resource alternatives, including: the Electric Power Research Institute (EPRI), the U.S. Energy Information Administration (EIA), and recently completed studies from NPPD-contracted consultants as a part of NPPD's 2020 "Plan B" Carbon Reduction Impacts Study. Nine resources with detailed cost estimates from each of NPPD's sources were selected to be modeled in the IRP. These new resources were selected to provide a diverse resource mix, a range of options in capital and operating costs, and to include the new generation sources identified in the Plan B study. Regional adjustments for capital and operating costs were applied to better reflect the costs of building these resources in Nebraska. A general long-term escalation of 2% was applied to bring the costs from all sources into 2023 dollars.[4] The final assumptions for the nine new resources in the IRP model are summarized in Exhibit 3.4.2-1.

Exhibit 3.4.2-1 – New Resource Alternative Assumptions

Resource	Capacity (MW)	Economic Life (years)	Capital ($/kW)	Capital Escalation	1st Year $/MWh	Assumed CF
Combined Cycle (CC) – 1x1	386	30	$1,174	2%	$46	50%
CC – 2x1	1,000	30	$1,032	2%	$43	50%
CC - C02 Capture	348	30	$2,822	2%	$78	50%
Combustion Turbine	207	30	$809	2%	$104	10%
RICE	216	30	$1,464	2%	$111	15%
Small Modular Reactor	600	30	$8,220	1.5%	$82	90%
Wind	200	20	$1,336	1%	$30	50%
Solar	125	20	$1,130	(0.5%)	$45	25%
Battery (4 hour)	50	10	$1,233	(0.5%)	$160	12.5%

The capacity value shown reflects the estimated summer accredited capacity, except for wind, solar, and battery, where nameplate is listed. Capital cost escalation for most units is set to NPPD's standard assumption of a 2% long-term general escalation rate. For emerging technologies (SMR, Wind, Solar, and Battery) escalation rates were cited from NPPD's Plan B consultants and verified by NPPD's Sustainable Energy department. First year $/MWh costs, which are included for comparative purposes, are estimated by adding one year of amortized equal payments of capital costs across the resource's entire economic life, plus fixed O&M costs, variable O&M costs, and fuel costs. Variable O&M and fuel costs are derived from an average years' worth of generation based on capacity factor and heat rate. Assumed CF is based on the typical capacity factor for existing resources most like the new resources and is used for the first year cost calculations.[5] The battery

[4] The IRP also assumed an interest rate of 4% on long-term debt.
[5] In the Capacity Expansion model, resources are not constrained to operate at an assumed capacity factor, but dispatched economically to serve load.

resource was assumed to only charge and discharge three hours of its capacity daily to preserve its economic life.

Several assumptions were made to improve the resiliency of new units. Building one unit of wind required the model to also build one unit of solar and vice versa to diversify energy mix. The natural gas resources (CCs, CT, and RICE) are assumed to be built with dual fuel capabilities. Specific alternate fuels were not modeled due to not being readily available presently and dual fuel capabilities plus procurement and storage adding minimal cost to operating the resource.

Wind has historically had the greatest potential for development of large amounts of renewable generation in the Southwest Power Pool (SPP), including NPPD's service territory, along with being the most cost effective. Per SPP's Market Monitoring Unit (MMU) State of the Market 2022 Report, wind nameplate capacity of over 32 gigawatts (GW) was registered in the region. Average wind generation as a percent of load was 40% in 2022, and the maximum value for any five-minute interval reached a value of just over 88% in 2021. There is 27.4 GW of wind in the SPP's Generation Interconnection (GI) queue[6].

There are many hours in the year when wind dominates the energy landscape in SPP. When wind is the incremental cost of energy in the market, it tends to drive the wholesale energy rate low and even negative. Roughly seven (7) percent of all hours in the Day-Ahead (DA) Market were negative in 2022[7]. The percent of negative pricing hours over the last two (2) years are higher than previous years. In 2019, two (2) percent of the DA hours were negative, in 2020 five (5) percent, and in 2021 eight (8) percent of DA hours were negative. The Real-Time (RT) market has more negative pricing. Negative pricing occurs almost two times more frequently than in the DA Market. Spring and fall tend to have the most negative hours.

Solar facilities have not yet been as fully developed as wind in SPP. There is only approximately 245 MW of solar installed, but there is 47.4 GW in the SPP's GI queue.

3.4.2.1 ELCC for New Resource Alternatives

Effective October 1, 2022 for the 2023 Summer Peak Resource Adequacy process, SPP will use Effective Load Carrying Capability (ELCC) to calculate the SPP system-wide capacity value for all wind, solar and energy storage resources (ESRs) in the footprint[8]. ELCC is defined as the amount of incremental load a resource can reliably serve, while also considering probabilistic parameters of unserved load caused by forced outages, load uncertainty, and other factors. Using ELCC practices, a facility's accreditation (measured in MW) is a fractional probabilistic measure of the facility's nameplate rating that can be relied on to serve load. ELCC can express the value that generation contributes to a system as penetration of the specific resource type increases.

[6] Per SPP GI Queue Dashboard (SPP Generation Interconnection Queue
, as of 6/6/2023

[7] SPP 2022 annual state of the market report.pdf

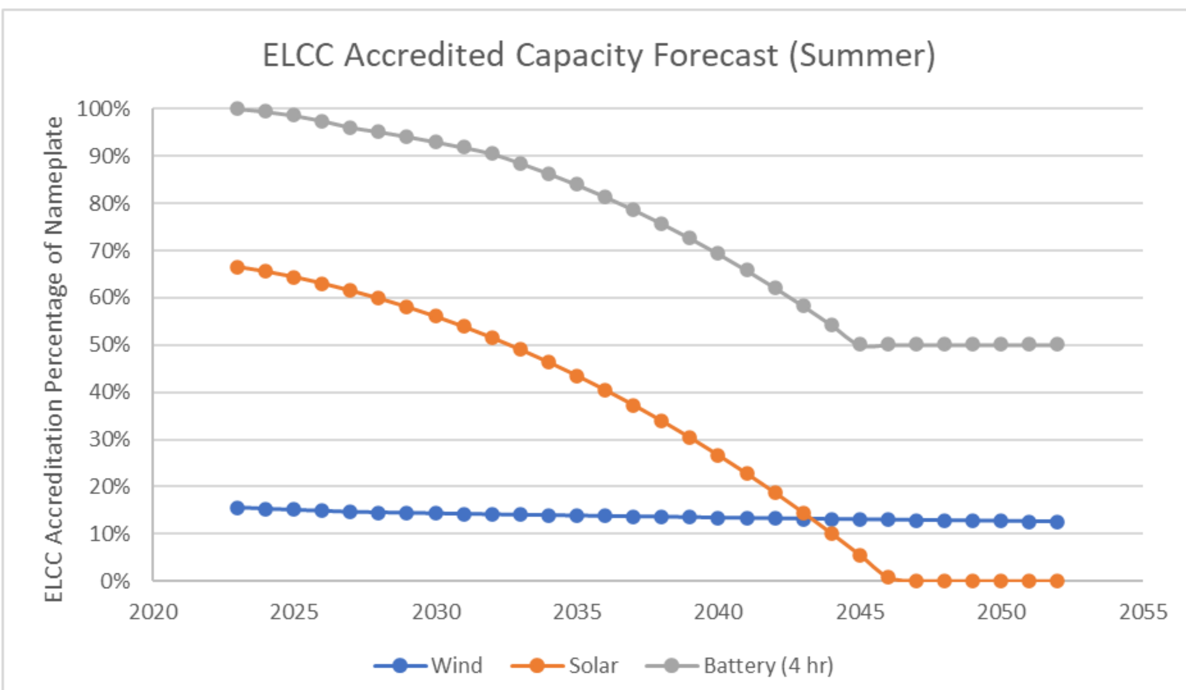
[8] On March 3, 2023 FERC rejected SPP's compliance tariff filing for use of the ELCC methodology, temporarily reverting accreditation of wind & solar resources to the previous Planning Criteria methodology. SPP is planning an expedited process to prepare and approve a Revision Request (RR) addressing issues raised by FERC no later than October 2023, with subsequent refiling at FERC.

Although the exact accreditation adjustments, resulting from the application of SPP's ELCC methodology couldn't be determined, it was important to try and estimate those adjustments in the IRP in order to account for the accredited capability which could be claimed for new wind, solar, and ESR alternatives.

NPPD started with an advance copy of the 2020 wind & solar ELCC study results, along with the 2019 ELCC results for battery storage from SPP[9]. These study results were in the form three separate graphs displaying the ELCC accreditation percentage of nameplate capacity verses the resource penetration.[10] A regression analysis was performed to develop a curve fit equation for the graphical data which could be more easily used to estimate the future accreditation percentage. To forecast the regional buildout of wind, solar, and battery storage resources, NPPD relied on assumptions from SPP's 2022 Integrated Transmission Planning (ITP) & 20-yr assessments, linearly interpolating between the year 5, 10, and 20 amounts. Combining this information, resulted in annual accreditation percentage of nameplate assumptions used in the IRP and shown graphically in Exhibit 3.4.2.1-1.

These assumptions suggest that the accredited capacity of new wind resources, while starting off much lower than solar and batteries, is expected to remain relatively constant, as a percentage of nameplate, over the IRP study period. In contrast, the accredited capacity of new solar and batteries starts off much higher but is anticipated to drop off more quickly over the study period.

Exhibit 3.4.2.1-1 – Accredited Capacity for new Wind, Solar, and Battery Alternatives



[9] Updated ELCC study results for all three resources types are expected from SPP by October 1, 2022, but were not available in time for use in the IRP.
[10] Penetration was displayed as installed namplate as a percentage of SPP peak load.

3.4.3 Existing Resource Options

Gerald Gentleman Station (GGS)

Three options were analyzed for GGS: Continue to operate on coal; Allow installation of Carbon Capture & Sequestration (CCS) equipment on Unit 2, starting in 2028; Early shutdown, no sooner than 2030. Forecasts of future operating costs for each option were developed by the Financial Planning Management Department, while assumptions associated with CCS were provided by the Generation Strategies Department and include capital and incremental Operation and Maintenance (O&M) costs. Installation of CCS would add a significant amount of auxiliary load. It is important to note, no additional emission control equipment was assumed to be required for continued operation on coal over the study period. Installation of CCS equipment for Unit 1 was not studied since its costs were not known.

Sheldon Station

For Sheldon, three options were considered: Continue to operate on coal; Restore natural gas as the primary fuel, beginning in 2028; Early shutdown in 2028. Forecasts of future operating costs for the three options were developed by the financial area. For continued operation on coal, this included estimated capital and incremental O&M costs for compliance with Effluent Limitation Guideline (ELG) requirements. The restoration option reflected high level capital cost assumptions to return Sheldon to natural gas-fired operation.

Cooper Nuclear Station (CNS)

Two options for CNS were analyzed in the IRP: Pursue a second license extension, with operation until 2054; and Shutdown at the end of the current operating license in January of 2034. Forecasts of future operating costs for each option were developed by the CNS Finance Cost & Procurement Department. In addition, costs associated with a second license extension, including direct licensing and expected additional capital equipment, were provided by Nuclear Strategic Asset Management.

Nebraska City 2 Unit 2 (NC2)

As mentioned in Section 2.1, NPPD has a life of plant power agreement to receive approximately 164 MW from OPPD's Nebraska City Unit 2 (NC2). In OPPD's most recent IRP and other studies, it found converting NC2 to natural gas was a cost effective option in the 2035-2045 time period. For purposes of this IRP, NPPD assumed OPPD converts NC2 to run on natural gas in 2040.[11] This is subject to change. OPPD is continuing its investigation and as more information is known, NPPD will revise the assumptions for NC2.

Other Existing Resources

Other existing resources, as described in Section 2.1, are assumed to continue operation through the 30-year study period, for purposes of the IRP.

[11] The costs associated with converting NC2 to natural gas operation are not included in the IRP analysis, as they are continuing to be developed by OPPD. Since the IRP assumed NC2 conversion would occur in all of the modeled resource plans, including the conversion cost would not affect the relative economics of those plans.

3.4.4 SPP Resource Adequacy Initiatives

SPP has implemented several initiatives intended to strengthen the current Resource Adequacy Requirements (RARs) for the region. Some, such as ELCC and Performance Based Accreditation (PBA) have been under development for several years, while others, for example increasing the Planning Reserve Margin (PRM) from 12% to 15%, have occurred since work began on the IRP in 2021. A number of these initiatives are not currently developed sufficiently for them to be incorporated into this IRP. NPPD will continue to monitor these initiatives and apply the resulting changes to RARs in future IRPs, as appropriate. Several of the more significant initiatives are summarized briefly below.

In July of 2022, the SPP Board of Directors approved an increase to the PRM from 12% to 15% effective for the 2023 summer season. The IRP assumed a stepped increase in the PRM (13%/14%/15% in 2023/24/25), based on an earlier recommendation from the Supply Adequacy Working Group. NPPD is expected to have sufficient resources to meet the RAR, including the higher 15% PRM, during the intervening years (i.e., 2023 – 2025).

SPP has approved changes to the Planning Criteria and Business Practice documents to implement an ELCC process for the determination of accredited capacity for all wind, solar and Energy Storage resources, effective October 1, 2023. As described in section 3.4.2.1, the IRP did apply estimated ELCC accredited capacity values for new wind, solar, and storage alternatives.[12]

The SPP Board of Directors, also approved the implementation of Performance-Based Accreditation (PBA) for conventional resources during its July 2022 meeting.[13] PBA would adjust the tested capability of conventional resources based on actual performance. Implementation of PBA would require the collection of performance data over several years and is not anticipated to become fully effective until 2028. For the IRP, NPPD assumed its units' performance will be similar to the region as a whole. As such, the accredited capability of conventional resources were not adjusted.

SPP has also begun discussions regarding the implementation of an enforceable Resource Adequacy Obligation for the Winter Season, similar to the current Summer Season Obligation, as well as a separate PRM for the winter season. These potential changes are not yet well enough defined for inclusion in the IRP. Although a minimum PRM requirement for the winter season was not applied in the development of future resource plans, it is possible to monitor the winter season reserve margin. The resulting resource plans, as discussed in the Section 3, are expected to meet or exceed a 15% PRM during the winter season.

3.4.5 Resiliency

Board approved Strategic Directive BP-SD-03, includes the statement "Resilience means that the critical parts of the electric supply system can mitigate, survive, and/or recover from high impact events. …" There is presently no standard industry metric for resiliency.

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[12] The IRP did not adjust the capability for existing wind resources to reflect the ELCC methodology, as SPP has not yet provided the results from the 2022 ELCC study to impacted generation owners. It is anticipated the ELCC capability values will be somewhat lower than the current capability assumptions.

[13] SPP is currently developing language changes to its applicable governing documents to implement PBA. SPP's current plan anticipates approval of the required language changes by October 2023, with subsequent filing at FERC.

NPPD incorporated resiliency in the model by:

1. Representing all new natural gas resources as capable of also being fired with liquid fuels
2. Not allowing only one type of renewable resource to be selected. New renewable resources will be a mixture of wind & solar to allow for energy to more closely match NPPD's load profile.
3. Maintaining the minimum SPP planning reserve margin for each year
4. Not purchasing more than 20-30% of native load requirements on an annual basis

In addition to the above, NPPD will consider the fuel diversity of the resource mix as well as on-site storage (e.g., nuclear, coal). We estimated the economic impacts of "shock" events such as Winter Storm Uri and high priced market years on nuclear and coal units vs. their replacements, based on historical data, and added the value of these resiliency impacts to the NPV of selected sensitivity cases.

4. RESULTS

4.1.1 General Results

NPPD ran 54 cases using the Capacity Expansion software. The NPV of 30-year Wholesale Revenue Requirements for all of the runs are shown in Exhibit 4.1.1-1. The first 27 cases examined combinations of low, base, and high scenarios for CO_2 restrictions, load, and market. After reviewing these results, various sensitivities were run to measure the impact of changing the resource plan. These results are discussed in later subsections.

Exhibit 4.1.1-1 – Capacity Expansion Case List

Case #	Case Name	30-Yr NPV (2023$B)*	CO2 Case	Load	Market Price	EE Forecast	DR Forecast	Comments
1	CE22001a	15.594	Net Zero 2050 (BP-SD-05)	Base Forecast	Base Forecast	Base Forecast	Base Forecast	
2	CE22001b	16.629	Net Zero 2050 w/ glide path	Base Forecast	Base Forecast	Base Forecast	Base Forecast	
3	CE22001c	17.519	Net Zero 2035 w/ glide path	Base Forecast	Base Forecast	Base Forecast	Base Forecast	
4	CE22001d	17.621	Net Zero 2050 (BP-SD-05)	Additional Load	Base Forecast	Base Forecast	Base Forecast	
5	CE22001e	18.696	Net Zero 2050 w/ glide path	Additional Load	Base Forecast	Base Forecast	Base Forecast	
6	CE22001f	19.491	Net Zero 2035 w/ glide path	Additional Load	Base Forecast	Base Forecast	Base Forecast	
7	CE22001g	14.654	Net Zero 2050 (BP-SD-05)	Lower Load	Base Forecast	Base Forecast	Base Forecast	
8	CE22001h	15.253	Net Zero 2050 w/ glide path	Lower Load	Base Forecast	Base Forecast	Base Forecast	
9	CE22001i	16.676	Net Zero 2035 w/ glide path	Lower Load	Base Forecast	Base Forecast	Base Forecast	
10	CE22002a	15.817	Net Zero 2050 (BP-SD-05)	Base Forecast	High Forecast	Base Forecast	Base Forecast	
11	CE22002b	16.753	Net Zero 2050 w/ glide path	Base Forecast	High Forecast	Base Forecast	Base Forecast	
12	CE22002c	17.591	Net Zero 2035 w/ glide path	Base Forecast	High Forecast	Base Forecast	Base Forecast	
13	CE22002d	17.816	Net Zero 2050 (BP-SD-05)	Additional Load	High Forecast	Base Forecast	Base Forecast	
14	CE22002e	18.930	Net Zero 2050 w/ glide path	Additional Load	High Forecast	Base Forecast	Base Forecast	
15	CE22002f	19.640	Net Zero 2035 w/ glide path	Additional Load	High Forecast	Base Forecast	Base Forecast	
16	CE22002g	14.877	Net Zero 2050 (BP-SD-05)	Lower Load	High Forecast	Base Forecast	Base Forecast	
17	CE22002h	15.443	Net Zero 2050 w/ glide path	Lower Load	High Forecast	Base Forecast	Base Forecast	
18	CE22002i	16.441	Net Zero 2035 w/ glide path	Lower Load	High Forecast	Base Forecast	Base Forecast	
19	CE22003a	15.370	Net Zero 2050 (BP-SD-05)	Base Forecast	Low Forecast	Base Forecast	Base Forecast	
20	CE22003b	16.238	Net Zero 2050 w/ glide path	Base Forecast	Low Forecast	Base Forecast	Base Forecast	
21	CE22003c	17.051	Net Zero 2035 w/ glide path	Base Forecast	Low Forecast	Base Forecast	Base Forecast	
22	CE22003d	17.231	Net Zero 2050 (BP-SD-05)	Additional Load	Low Forecast	Base Forecast	Base Forecast	
23	CE22003e	18.308	Net Zero 2050 w/ glide path	Additional Load	Low Forecast	Base Forecast	Base Forecast	
24	CE22003f	19.010	Net Zero 2035 w/ glide path	Additional Load	Low Forecast	Base Forecast	Base Forecast	
25	CE22003g	14.261	Net Zero 2050 (BP-SD-05)	Lower Load	Low Forecast	Base Forecast	Base Forecast	
26	CE22003h	14.903	Net Zero 2050 w/ glide path	Lower Load	Low Forecast	Base Forecast	Base Forecast	
27	CE22003i	16.400	Net Zero 2035 w/ glide path	Lower Load	Low Forecast	Base Forecast	Base Forecast	
28	CE22004a	14.214	Net Zero 2050 (BP-SD-05)	Lower Load	Low Forecast	High Forecast	Base Forecast	High EE Sensitivity
29	CE22004b	16.584	Net Zero 2050 w/ glide path	Base Forecast	Base Forecast	High Forecast	Base Forecast	High EE Sensitivity
30	CE22004c	19.562	Net Zero 2035 w/ glide path	Additional Load	High Forecast	High Forecast	Base Forecast	High EE Sensitivity
31	CE22004d	14.028	Net Zero 2050 (BP-SD-05)	Lower Load	Low Forecast	Base Forecast	High Forecast	High DR Sensitivity
32	CE22004e	16.412	Net Zero 2050 w/ glide path	Base Forecast	Base Forecast	Base Forecast	High Forecast	High DR Sensitivity
33	CE22005a	14.941	Net Zero 2050 (BP-SD-05)	Lower Load	Low Forecast	Base Forecast	Base Forecast	Select CNS 2nd relicense - 2034
34	CE22005b	16.783	Net Zero 2050 w/ glide path	Base Forecast	Base Forecast	Base Forecast	Base Forecast	Select CNS 2nd relicense - 2034
35	CE22005b1	17.370	Net Zero 2035 w/ glide path	Base Forecast	Base Forecast	Base Forecast	Base Forecast	Select CNS 2nd relicense - 2034
36	CE22005b2	16.436	Net Zero 2050 w/ glide path	Base Forecast	Low Forecast	Base Forecast	Base Forecast	Select CNS 2nd relicense - 2034
37	CE22005c	19.480	Net Zero 2035 w/ glide path	Additional Load	High Forecast	Base Forecast	Base Forecast	Select CNS 2nd relicense - 2034
38	CE22005c1	19.020	Net Zero 2050 w/ glide path	Additional Load	High Forecast	Base Forecast	Base Forecast	Select CNS 2nd relicense - 2034
39	CE22005d	16.824	Net Zero 2050 (BP-SD-05)	Lower Load	Low Forecast	Base Forecast	Base Forecast	Select SMR - 2034
40	CE22005e	18.851	Net Zero 2050 w/ glide path	Base Forecast	Base Forecast	Base Forecast	Base Forecast	Select SMR - 2034
41	CE22005f	22.370	Net Zero 2035 w/ glide path	Additional Load	High Forecast	Base Forecast	Base Forecast	Select SMR - 2030
42	CE22005g	20.097	Net Zero 2035 w/ glide path	Additional Load	High Forecast	Base Forecast	Base Forecast	Do not select CNS 2nd relicense
43	CE22006a	14.560	Net Zero 2050 (BP-SD-05)	Lower Load	Low Forecast	Base Forecast	Base Forecast	Select CCS for GGS2 - 2050
44	CE22006b	18.890	Net Zero 2050 w/ glide path	Base Forecast	Base Forecast	Base Forecast	Base Forecast	Select CCS for GGS2 -2034
45	CE22006c	22.089	Net Zero 2035 w/ glide path	Additional Load	High Forecast	Base Forecast	Base Forecast	Select CCS for GGS2 - 2030
46	CE22007a	14.328	Net Zero 2050 (BP-SD-05)	Lower Load	Low Forecast	Base Forecast	Base Forecast	Select Sheldon Shutdown in 2028
47	CE22007b	16.780	Net Zero 2050 w/ glide path	Base Forecast	Base Forecast	Base Forecast	Base Forecast	Select Sheldon Shutdown in 2028
48	CE22007c	19.755	Net Zero 2035 w/ glide path	Additional Load	High Forecast	Base Forecast	Base Forecast	Select Sheldon Shutdown in 2028
49	CE22007d	17.815	Net Zero 2050 (BP-SD-05)	Additional Load	High Forecast	Base Forecast	Base Forecast	Operate Sheldon on coal till 2050
50	CE22008a	14.814	Net Zero 2050 (BP-SD-05)	Lower Load	Low Forecast	Base Forecast	Base Forecast	Select Wind/Solar in 2026
51	CE22008b	16.798	Net Zero 2050 w/ glide path	Base Forecast	Base Forecast	Base Forecast	Base Forecast	Select Wind/Solar in 2026
52	CE22008c	19.611	Net Zero 2035 w/ glide path	Additional Load	High Forecast	Base Forecast	Base Forecast	Select Wind/Solar in 2026
53	CE22009b	16.984	Net Zero 2050 w/ glide path	Base Forecast	Alt High Forecast	Base Forecast	Base Forecast	
54	CE22009b2	16.816	Net Zero 2050 w/ glide path	Base Forecast	Alt High Forecast	Base Forecast	Base Forecast	Select CNS 2nd relicense - 2034

*30-Yr Net Present Value of Wholesale Revenue Requirements

The NPVs in the above exhibit do not include any credits due to the IRA. NPPD is waiting on guidance from the federal government to better explain the nuances of the act. NPPD did perform a very high level estimate of the act to provide a range of estimated benefits to NPPD and its customers. The values below are in NPV dollars.

- Existing Nuclear Credits – CNS may be eligible for existing nuclear credits from 2024 to 2032. NPPD is waiting for clarification on prevailing wages and gross receipts requirements. These credits range in NPV from $0 to $700 million and would offset operating costs in all cases since the model assumes CNS operates during this time frame. The second relicense wouldn't start until after these credits expire.

- Carbon Capture and Sequestration – The IRA credit is $85/tonne[14], escalated for inflation, over 12 years. If NPPD decides to add CCS equipment to a GGS unit no later than the early 2030s, the NPV could be above $2.6 billion assuming high availability and capacity factor.

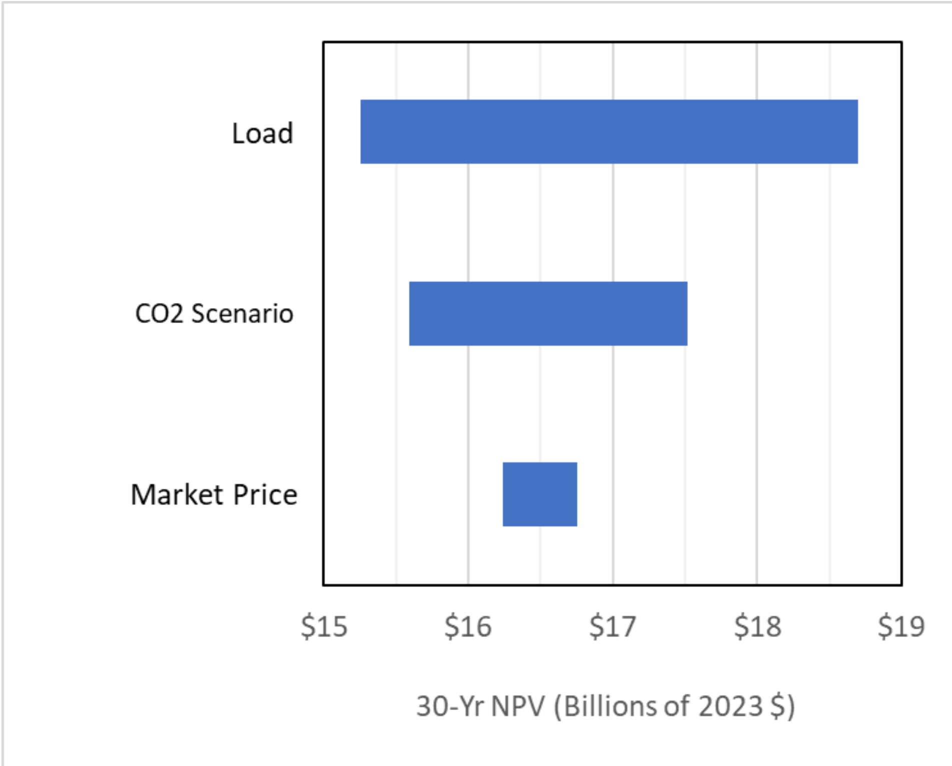
- Small Module Reactor – The IRA PTC is similar to the PTC for renewables, around $26/MWh in today's dollars and escalated for inflation in future years, for a period of 10 years. A 600 MW SMR installed by the early 2030s and operating with high capacity factors could have a NPV around $700 million.

- Renewables - In the scenario where early installation (2026) of renewables is installed, the NPV was estimated to be around $200 million for 125 MW of solar and 200 MW of wind. The highest amount of early renewable installation are selected in cases with high load and a CO_2 scenario of Net Zero by 2035 with a glide path. In these cases, the NPV is on the order of $850 million.

Exhibit 4.1.1-2 was developed to help understand the relative impact of the three (3) variables described earlier. As one can see, load created the most variation in NPV results, followed by CO_2 restriction, and finally market price. The order of the relative uncertainty of the variables has not changed from previous IRPs.

[14] The effective benefit associated with IRA credits for CCS would also need to consider the cost to store the captured CO_2. The IRP analysis assumed a cost of $15/tonne for carbon storage. Recent estimates range from $20-$30/tonne.

Exhibit 4.1.1-2 – NPV Variation by Load, CO_2 Restriction, and Market Price Assumption



The results generally found CCS and SMR to be too expensive, as modeled. The analysis did not take IRA credits into account[15]. The potential magnitude of IRA credits was addressed earlier in the report. Additional discussion can also be found in the applicable Results section.

Since CCS and SMR are currently too expensive, and coal generation output with unabated CO_2 emissions are restricted when CO_2 is restricted, the model generally selects renewables for energy and dual fuel natural gas/fuel oil generation for capacity when needed. These dual fuel units would generate at times when needed for reliability or when cost effective. They are limited in the amount of energy they can generate, since they also produce CO_2. NPPD becomes a net purchaser of energy when its large existing units no longer operate.

A review of the results showed energy storage (i.e., battery) was installed in six of the initial 27 modeled cases. Installation of either one facility (50 M) or two facilities (100 MW) was part of the resource mix in these cases. The installation of batteries typically occurs when a large existing unit is assumed retired. Under the SD-05 CO_2 and low load cases, batteries are mainly installed for capacity. The other cases where batteries were installed occurred when the 2035 glide path CO_2 scenario was modeled. When installed in these situations, batteries appear to be needed to transfer energy during times of peak production to peak consumption. These results indicate energy storage can play a role in NPPD's future resource mix, although CT or RICE resources are still required. Fast acting energy storage may also provide value vs. CT or RICE resources in the real-time market. This has not been fully explored. NPPD will continue to monitor industry trends to see if the real cost of these storage resources continue to drop over time.

[15] The IRA became effective on August 16, 2022.

The amount of capital required for new resources and/or retrofit/extensions of existing facilities is quite large and some of these decisions will need to be made within the next few years. The capital requirements for a representative sample of resource plans are shown below to indicate the relative size of these requirements. The size and timing of capital requirements are mainly driven by load and the operational decisions for the CNS & GGS units. The capital requirements below are shown in billions of nominal dollars (debt, not debt service dollars).

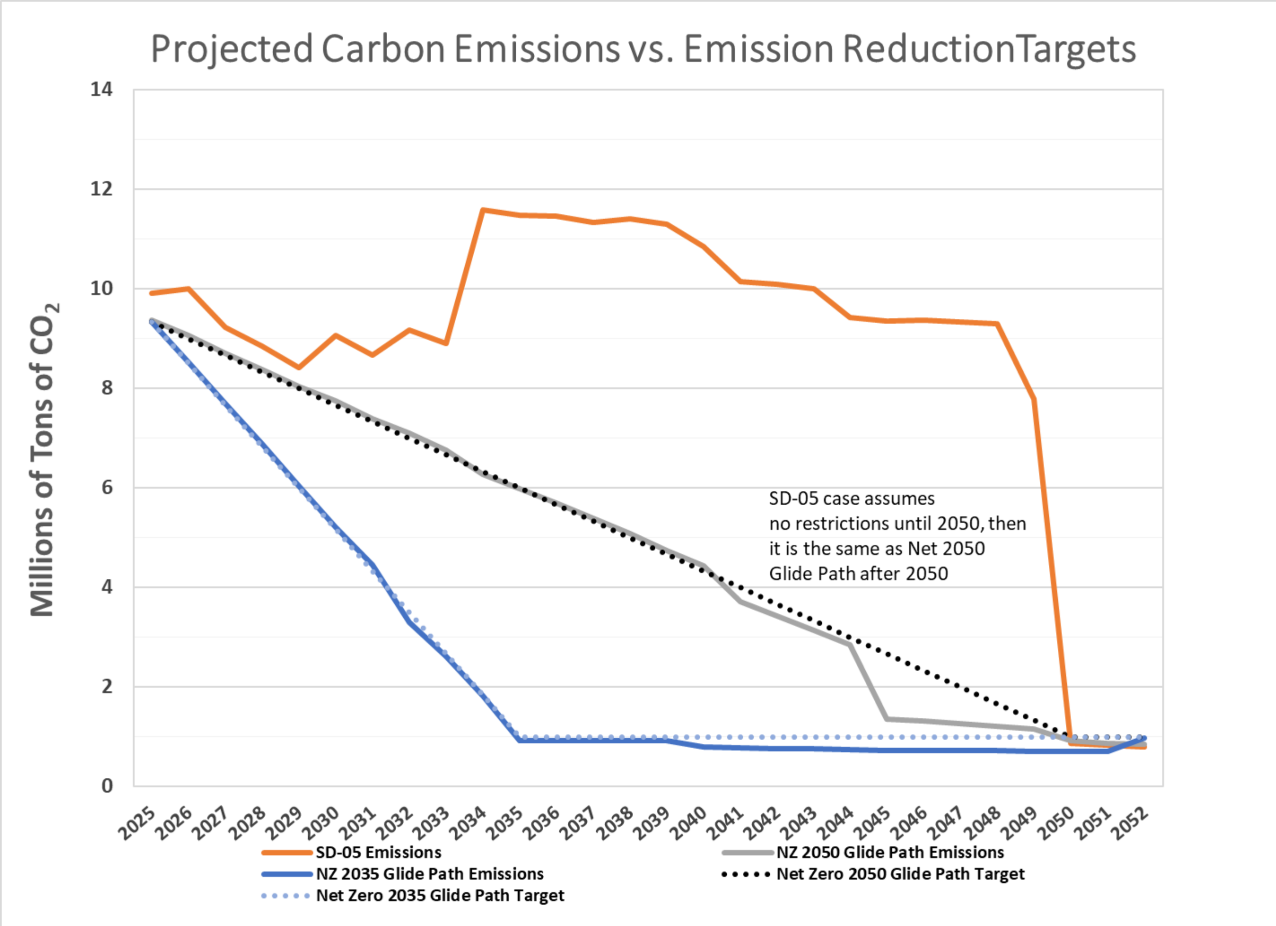
Exhibit 4.1.1-3 – Capital Requirements for Selected Cases

Case	CO_2 Scenario	Load Scenario	Other	Capital Requirements (Billions of Dollars)[16]	
				Through 2035	Through 2052
CE22001a	SD-05	Base		$0.9	$7.4
CE22001b	2050 Glide Path	Base		$3.5	$6.2
CE22001c	2035 Glide Path	Base		$6.4	$6.9
CE22003e	2050 Glide Path	High		$4.5	$8.8
CE22003h	2050 Glide Path	Low		$2.8	$3.7
CE22005b	2050 Glide Path	Base	2nd Relicense at CNS	$0.2	$4.1
CE22006b	2050 Glide Path	Base	CCS at GGS 2	$4.8	$9.9

A summary of new resources and retirements for all of the CE cases can be found in Appendix E. The cumulative additions, through 2035 and for the entire 30-year study period are shown. All of the resource plans were generally able to meet the modeled CO_2 reduction scenarios. Exhibit 4.1.1-4 graphically compares projected annual CO_2 emissions to the CO_2 reduction targets, for three representative resource plans. Under the SD-05 scenario, CO_2 emissions are unconstrained until 2050 and vary from year to year, before the restriction is applied.

[16] This table reflects estimated capital costs for new resources and major upgrades/changes to existing facilities only. Annual on-going capital expenses to maintain existing resources are not included.

Exhibit 4.1.1-4 – Annual CO_2 Emissions for selected Resource Plans

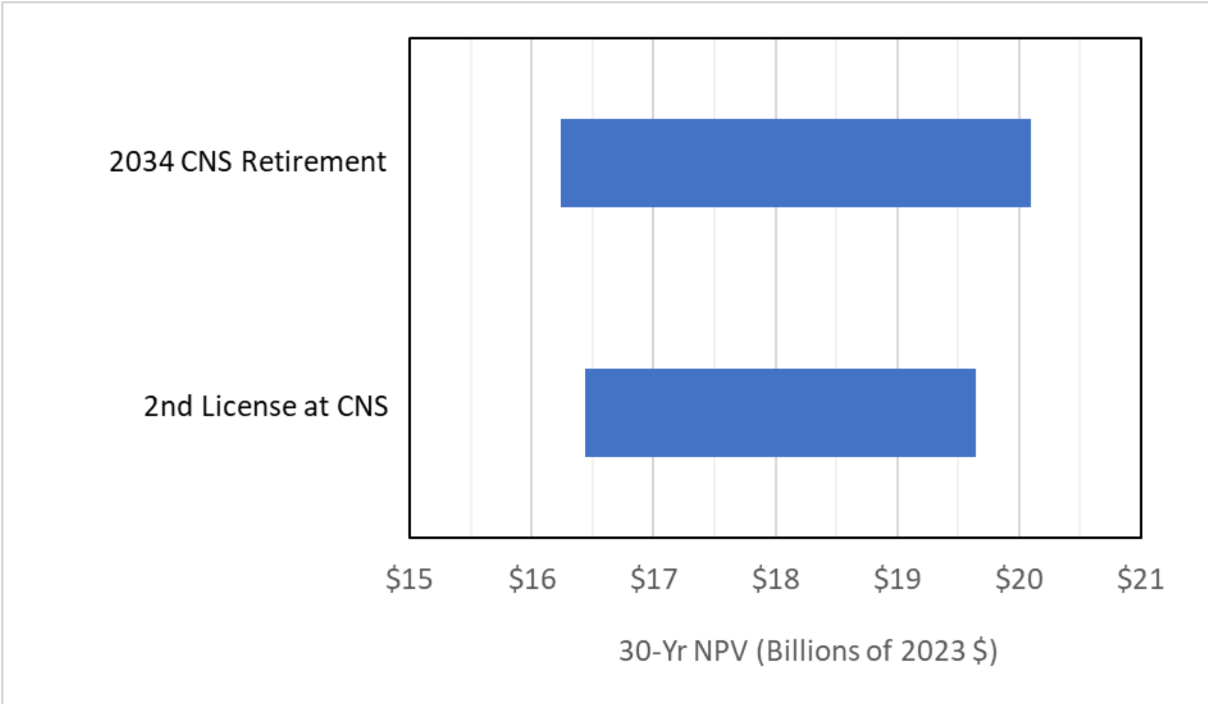


4.1.2 Cooper Nuclear Station (CNS) Sensitivity

When comparing a second relicense at CNS vs. the next lowest cost resource plan, the second relicense was more economical for the more restrictive CO_2 scenario as long as there wasn't a reduction in load in 2036 (i.e., low load scenario). In-lieu of CNS, the resources the model picked are CTs & CCs for capacity and some energy, and renewables, mostly for energy. The model also relied more on market purchases when CNS ceased operation.

Due to the uncertainty surrounding CO_2 restrictions, Exhibit 4.1.2-1 shows the NPV cost with and without the second relicense of CNS, under the 2050 glide path and 2035 glide path CO_2 scenarios. This shows the range of costs and highest risk under a second relicense is less than a resource plan without CNS operating past 2034.

Exhibit 4.1.2-1 – NPV variation with and without CNS License Extension

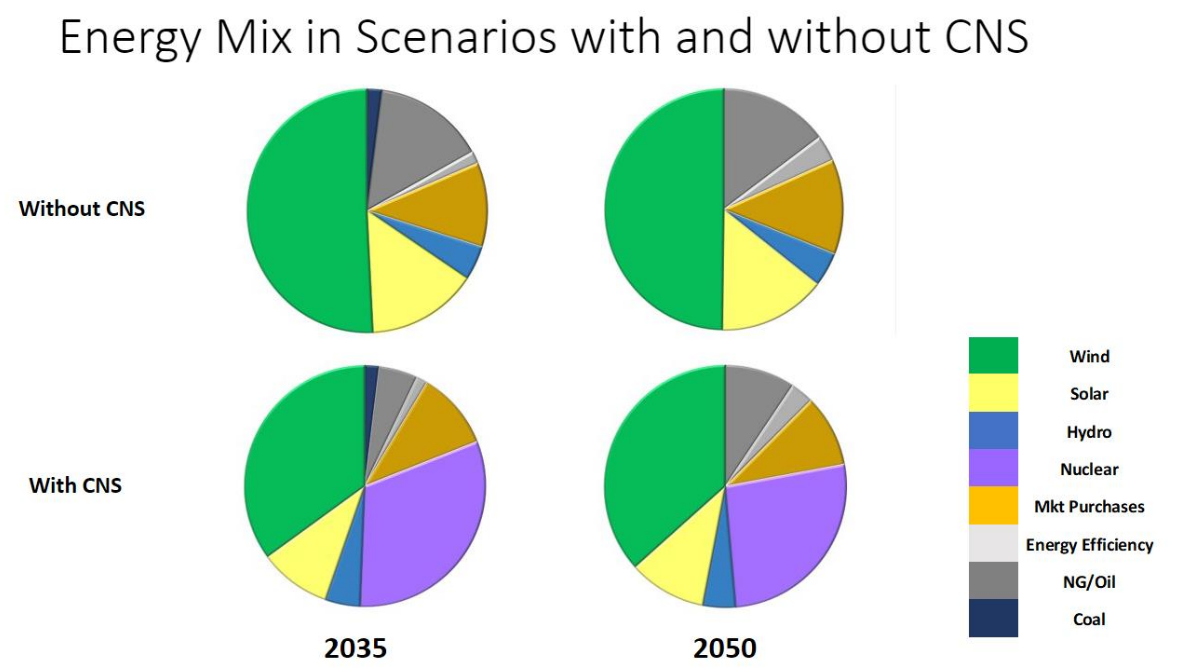


A second license extension at CNS was not shown as economical for a scenario with no CO_2 restrictions before 2050 and when projected load is reduced in 2036 (i.e., low load scenario).

The Nuclear Power Production Credit (45U) provisions of the IRA was not modeled for CNS. As currently defined, this credit ends before the start of the second relicense, so the differential NPV based on the existing nuclear 45U credits for a second relicense vs. ceasing operation in 2034 is zero. The 45U credits may have an impact on how the cash flow of a second relicense will occur, but was not investigated in this IRP.

As stated in the Assumptions Resiliency section, NPPD will look at the fuel diversity of the resource mix as part of the criteria when selecting the best resource plan. Exhibit 4.1.2-2 is a graph showing the resource mix with and without CNS under the 2035 glide path CO_2 restriction scenario. Fuel diversity is more robust with the second license at CNS.

Exhibit 4.1.2-2 – Energy Mix with and without CNS License Extension



CNS has a lower risk profile than SMR or coal with CCS resource options. Although CNS has its risks, the other options, SMR & CCS, are nascent technologies and have not yet proven themselves at grid scale and at high capacity factor and/or reliability levels.

Based on the above, it is recommended to proceed with the second relicense renewal process and further refine the capital costs needed for the relicense, as well as continue to monitor CNS operating costs.

4.1.3 Gerald Gentlemen Station Sensitivity

Results from the initial 27 runs indicate variation in the future operation of Gerald Gentleman Station (GGS) is primarily driven by the three CO_2 restriction scenarios studied. Under the SD-05 scenario, GGS continues to operate on coal until carbon constraints begin in 2050.

With the increasing CO_2 reduction constraints of the Net Zero 2050 Glide Path scenario, the first unit retires in the 2030s and total GGS generation is in the range of 5.5 million MWh/year, before retirement. Replacement resources selected include a combination of a large CC, usually in combination with CNS retirement, CTs and renewables.[17] The second unit retires in the late 2030s to mid 2040s, when total generation is in the 2.2 million MWh/year range prior to retirement. Replacement resources include CTs and/or renewables.

Under the more aggressive CO_2 reduction constraints of the Net Zero 2035 Glide path scenario, the first unit retires in 2030, with total GGS generation in the range of 4.3 million MWh/year. The second unit retires in the 2030 – 2034 timeframe when total generation is in the 2.2 million MWh/year range. Replacement resources selected are similar to the 2050 glide path scenario.

[17] In the lower load scenarios, a small CC plus CTs, or only CTs are substituted for the large CC.

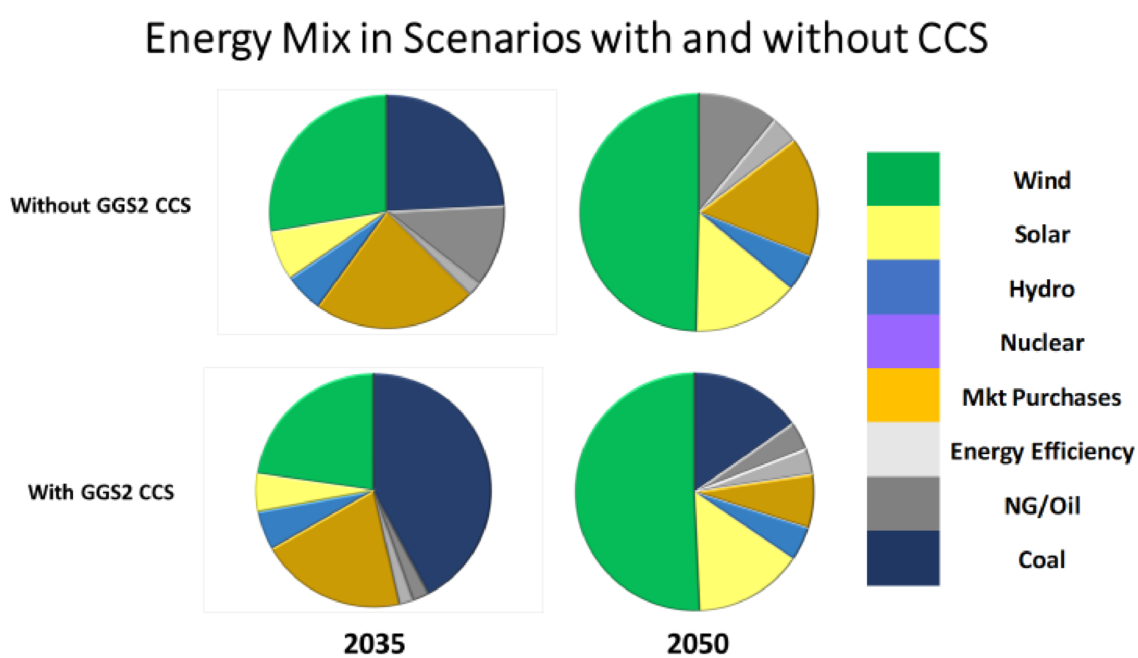
As discussed in the previous section on CNS, increasing CO_2 reduction constraints will impact the fuel diversity of NPPD's resource mix.

The installation of Carbon Capture & Sequestration (CCS) equipment on GGS2 was not selected in the initial 27 runs varying CO_2 restrictions, load, or market. Three (3) sensitivity cases were modeled to capture a range of costs and situations: 1) SD-05 CO_2 restriction, low load and market, 2) 2050 Net Zero with Glide Path CO_2 restriction, base load and market, and 3) 2035 Net Zero with Glide Path CO_2 restriction, high load and market. The operational date assumed for CCS varied from as early as 2030 for sensitivity case 3 to as late as 2050 for sensitivity case 1. The NPV cost with CCS installed was \$2.3 - \$2.5 billion higher than the lowest NPV resource plan.

The previous results do not reflect Carbon Capture & Sequestration Credit (45Q) provisions of the IRA. Assuming GGS2 with CCS is operated at a high capacity factor to maximize the amount of CO_2 sequestered, these 45Q credits could be enough to eliminate the gap or show a small benefit.

Exhibit 4.1.3-1 shows the resource mix with and without GGS2 CCS under the 2050 glide path CO_2 restriction scenario. Fuel diversity is more robust with the CCS.

Exhibit 4.1.3-1 – Energy Mix with and without GGS2 CCS



There are significant risks for NPPD associated with the CCS option. Large upfront capital outlays would be required, as would the successful development of necessary CO_2 pipeline and storage infrastructure. The majority of benefit comes from generating 45Q credits. If CCS equipment proves to be less reliable than expected and 45Q revenue is reduced or credits are rescinded in the future, NPPD could be left with insufficient revenue to support the required investment.

It is recommended to continue to operate GGS on coal, while monitoring potential risks to continued GGS operation. NPPD should also continue to investigate CCS for potentially lower cost options and impacts from the IRA credits, as well as other options for the GGS site in the event of a low carbon future.

4.1.4 Sheldon Sensitivity

Restoration of natural gas as the primary fuel at Sheldon beginning in 2028 was selected in almost all of the initial 27 runs varying CO_2 restrictions, load, or market. Three (3) sensitivity cases were modeled to compare retirement to natural gas operation 1) SD-05 CO_2 restriction, low load and market, 2) 2050 Net Zero with Glide Path CO_2 restriction, base load and market, and 3) 2035 Net Zero with Glide Path CO_2 restriction, high load and market, with a CT selected in-lieu of gas operation. The NPV cost with Sheldon retired in 2028 was within $70 – 150 million of the resource plans with gas operation, which may fall within the accuracy of the current assumptions. Other questions associated with these sensitivity cases include: 1) Would a new CT have better availability, compared to a restored natural gas steam generator? and 2) Could new equipment be installed by 2028?

One additional sensitivity case was modeled comparing continued operation on coal through 2050 to retirement in 2028 under the most favorable assumptions for coal (i.e., SD-05 CO_2 restriction, high load and market). The NPV cost for this case is within $50 million of the resource plan with gas operation and when resiliency considerations are included may be equal to gas operation. The likelihood of carbon constraints being enacted before 2050 is a risk associated with continued coal operation.

Based on these results, it is recommended to continue to pursue required modifications at Sheldon for compliance with ELG rule requirements, while also investigating potential restoration of the site to natural gas operation. Continuing on this dual track will afford NPPD the greatest flexibility to respond to our customers' needs in the future. NPPD should also obtain better estimates for natural gas restoration vs. a dual-fuel CT or RICE facility before making a final decision on any modifications.

4.1.5 Small Modular Reactor (SMR) Sensitivity

A SMR facility was not chosen as a resource in the initial 27 runs varying CO_2 restrictions, load, or market. Three (3) sensitivity cases were modeled to capture a range of costs and situations: 1) SD-05 CO_2 restriction, low load and market, 2) 2050 Net Zero with Glide Path CO_2 restriction, base load and market, and 3) 2035 Net Zero with Glide Path CO_2 restriction, high load and market. The SMR was assumed to be operational by 2034 for these sensitivities. The NPV cost with the SMR installed was $2.2-2.6 billion higher than the lowest NPV resource plan. The SMR cost was over $50/MWh higher than the alternative on a nominal basis. This value was calculated taking the difference in costs between the two cases and dividing by the SMR's generation.

IRA credits for new nuclear facilities are not included in the above numbers. As previously noted, these types of units have not yet been proven at grid scale and although manufacturers publicize the cost based on the "n" manufactured unit, these costs have not yet materialized. These two factors make a SMR facility more risky than a second license at CNS.

It is recommended to continue to monitor SMR's progress and complete preliminary siting studies. NPPD will also need to further define the potential benefits from the IRA for these types of units. To make sense for NPPD, the cost of SMR will need to rapidly de-escalate and NPPD will need to be able to use the IRA credits.

4.1.6 High Energy Efficiency Sensitivity

The initial 27 runs included the base Energy Efficiency (EE) assumption of continued funding of the EnergyWise^{SM} program at the current level of approximately $2.6 million annually over the study period. Three (3) sensitivity cases were modeled using the high EE assumption, as described in section 3.4.1, to capture the range of impacts: 1) SD-05 CO_2 restriction, low load and market, 2) 2050 Net Zero with Glide Path CO_2 restriction, base load and market, and 3) 2035 Net Zero with Glide Path CO_2 restriction, high load and market. The NPV costs, with the high EE assumption, ranged from $45 -78 million less than equivalent cases with base EE[18]. Additional EE was most beneficial in the high load/most restrictive CO_2 case and least beneficial in the low load/least restrictive CO_2 case. Although energy efficiency will reduce the amount of energy sold and thus might result in a slightly higher rate, the total dollars expended by a customer utilizing energy efficiency should be less, as long as the energy efficiency programs are less costly than the incremental cost to serve the load.

These results suggest additional EE could provide a beneficial reduction in costs. It is recommended to evaluate the potential for increased funding of the EnergyWise^{SM} program, in order to facilitate further discussion with our customers regarding the most mutually advantageous level of EE for NPPD to pursue in the future.

4.1.7 High Demand Response Sensitivity

The base assumption for Demand Response (DR), as discussed in section 3.4.1, was used for the initial 27 CE runs. Two (2) sensitivity cases were run with the high DR assumption: 1) SD-05 CO_2 restriction, low load and market, 2) 2050 Net Zero with Glide Path CO_2 restriction, base load and market. The NPV costs, with the high DR assumption was $217 – 233 million lower than the equivalent cases with base DR.

Under current SPP rules, DR has the ability to reduce the peak load plus planning reserve requirement NPPD must have generating resources to supply. It is recommended to continue to work with customers to identify mutually beneficial opportunities to increase NPPD's use of DR. NPPD should also continue to participate in on-going review of SPP's requirements for DR to ensure its existing DR programs remain compliant and continue to provide a resource adequacy benefit. Any adjustments to the SPP's requirements will need to be addressed and incorporated into NPPD's demand response program.

4.1.8 Early Renewable Sensitivity

The earliest renewable generation was installed in the initial 27 runs was 2030 in the 2035 glide path CO_2 restriction scenario, and 2034 in the SD-05 and 2050 glide path CO_2 restriction scenarios. To understand the additional costs of early installation of renewables, NPPD modeled adding 125 MW

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[18] The net savings listed includes the assumed incremental cost of approximately $20 million (NPV), associated with the additional EE, over the study period.

solar and 200 MW of wind in 2026 under the following three (3) cases: 1) SD-05 CO_2 restriction, low load and market, 2) 2050 Net Zero with Glide Path CO_2 restriction, base load and market, and 3) 2035 Net Zero with Glide Path CO_2 restriction, high load and market.

The additional NPV costs for the early renewable sensitivity ranged from $0-600 million higher. Earlier installation was most beneficial in the most restrictive CO_2 case, and least beneficial in the least restrictive CO_2 case. For the "middle" CO_2 case, the additional cost was $170 million. The early renewable cost was approximately $7/MWh higher than the alternative on a nominal basis. This value was calculated taking the difference in costs between the two cases and dividing by the early renewable generation.

These results did not include IRA credits. It appears if NPPD is able to fully use the IRA credits, early installation can make economic sense in the CO_2 glide path cases. Early installation will have a higher NPV cost even with IRA credits in the SD-05 CO_2 Restriction case. The cost to install renewable units have increased due to inflation, etc., that may further reduce their attractiveness.

It is recommended to explore the possibility of early renewable installation. The exact size and type and the value will depend on what is available to interconnect to the transmission system within a few years.

4.1.9 Higher Market Scenario

Market price and volatility have increased since the original assumptions were finalized. Therefore, two cases were run with market prices higher than the high market scenario assumptions. NPPD assumed prices in this Higher Market Scenario on average were approximately $10/MWh higher than the high market scenario. The two cases assumed a net zero 2050 glide path for CO_2 restrictions and base load. One case included a second relicense at CNS. The other one retired CNS in 2034.

The NPV for these sensitivity cases were higher when compared to the analogous original high market scenario assumptions. The NPV differences were in the $0-200 million range. One cause for the increase in NPV of the higher market scenarios is the more expensive energy mix needed. In all high and higher market price scenarios NPPD moves closer toward being a net purchaser from the market, so a higher market price will increase costs to serve load. These higher market prices also make the economics of building a different generation mix more attractive. In the higher market cases more solar, wind, and CT units are built than in the analogous original high market forecast cases, where a combined cycle was built with fewer wind, solar, and CT units.

The GGS units may operate a few more years in the higher market scenarios, since their economics are better than natural gas resource alternatives. Under these higher priced scenarios, combined cycles were not part of the resource plan. As noted in the previous paragraph, the model picked significantly more renewables, for energy and combustion turbines, mainly for capacity. The Sheldon units were still selected for restoration of natural gas as the primary fuel. The second relicense for CNS was more attractive under higher prices.

4.2 Summary

Although load was the greatest uncertainty as measured by NPV, the CO_2 restriction variable had a greater impact on the types of resource selected. Coal plants without CO_2 controls operated longer with the least restricted CO_2 restriction scenario, while NPPD's nuclear facility fared better under the most restricted CO_2 scenarios.

Nuclear and coal units fared better under higher market prices. A major reason for this is due to their fuel costs being relatively uncorrelated to market prices, while natural gas fuel tends to be positively correlated with the market. Coal and nuclear units also tend to fare well under severe conditions, such as Winter Storm Uri. Their onsite fuel and robust design allow them to reliably respond to customer needs during severe weather conditions.

NPPD maintains a diverse resource mix, in alignment with our Vision, Mission, Strategic Directives, and Strategic Plan, to reduce risk. and reaffirms the value and risk reduction benefits for our customers to ensure ongoing fuel diversity in our resources over the IRP planning horizon.

CNS is presently the least risky nuclear or coal with CCS option under a restrictive CO_2 scenario. Continued operation will also allow NPPD to maintain a diverse resource mix. As such, it is recommended to proceed with the second relicense renewal process and further refine the capital costs needed for the relicense, as well as continue to monitor CNS operating costs.

The GGS units are presently a cost effective resource for NPPD's customers. With the potential availability of 45Q credits under the Inflation Reduction Act, it could also remain a cost effective solution under a restrictive CO_2 scenario if retrofitted with CCS equipment. This technology is not yet widely proven so it is considered more risky than a relicense of CNS. As such, it is recommended to continue to operate GGS on coal, while continuing to investigate CCS for potentially lower cost options and impacts of the IRA.

Sheldon Station is a very good location for a generation resource. The results suggest restoring natural gas as the primary fuel at Sheldon can be in NPPD and its customers' best interest. It is recommended to continue to pursue required modifications at Sheldon for compliance with ELG rule requirements, while also investigating potential restoration of the site to natural gas operation. Continuing on this dual track will afford NPPD the greatest flexibility to respond to our customers' needs in the future.

SMRs are currently too expensive to be a cost effective resource. NPPD should continue to monitor the development of SMRs and complete preliminary siting studies. NPPD should also further define the potential benefits of the IRA for these types of units.

Energy efficiency and demand response can also provide value. It is recommended to discuss additional energy efficiency funding with NPPD's wholesale contract customers and retail to develop a program that works best for all parties. Demand response programs can provide a faster way to serve new load, but only if a customer is willing to curtail load when required. Demand response program requirements are also under review by SPP. Any adjustments to the requirements will need to be addressed and incorporated into NPPD's demand response programs.

Installation of new renewables tends to occur if a unit is retired or new load is added. Earlier installation of renewables can make sense with the Inflation Reduction Act credits and CO_2 restrictions and should be investigated. The exact size and type will depend on what is available to interconnect to the transmission system within a few years and its costs.

5. NEXT STEPS / ACTION ITEMS

All action items listed in this section are expected to be worked on by the next IRP report. A status update for all action items will be periodically prepared & will include a short description of work completed for each action item.

5.1 CNS

Action Item 5.1 – Start proceeding with the second relicense renewal process, as well as further refine the capital costs needed for the relicense. Also continue to monitor CNS operating costs and reevaluate relicensing if projected costs are significantly higher than assumptions in the IRP.

5.2 GGS

Action Item 5.2 - Continue to operate GGS on coal, while monitoring potential risks to continued GGS operation. NPPD should also continue to investigate CCS for potentially lower cost options and impacts from the IRA credits, as well as other options for the GGS site in the event of a low carbon future.

5.3 Sheldon

Action Item 5.3 - Continue to pursue required modifications at Sheldon for compliance with ELG rule requirements, while also investigating potential restoration of the site to natural gas operation. NPPD should also obtain better estimates for natural gas restoration vs. a dual-fuel CT or RICE facility before making a final decision on any modifications.

5.4 Small Modular Reactors

Action Item 5.4 - Continue to monitor SMR progress and complete preliminary siting studies.

5.5 Energy Efficiency

Action Item 5.5 - Evaluate the potential for increased funding of the EnergyWise^{SM} program, in order to facilitate further discussion with our customers regarding the most mutually advantageous level of EE for NPPD to pursue in the future.

5.6 Demand Response Resources

Action Item 5.6 - Work with customers to identify mutually beneficial opportunities to increase NPPD's use of DR. NPPD should also continue to participate in on-going review of SPP's requirements for DR to ensure its existing DR programs remain compliant and continue to provide a resource adequacy benefit.

5.7 Early Installation of Renewables

Action Item 5.7 - Explore the possibility of early renewable installation using IRA credits. The exact size and type and the value will depend on what is available to interconnect to the transmission system within a few years.

5.8 Investigate Near-Term Resource Options

Action Item 5.8 - Investigate resource options due to the higher near-term projected loads.

6. PUBLIC INTERFACE

6.1 Overview

The 2023 IRP Draft Report was presented to the Board of Directors during its January 2023 Board Meeting. Part of the presentation described the methods NPPD was planning to use to gather input from the public. A summary of these methods follow:

- There is a public comment agenda item on the monthly Board meetings for the public to address the Board concerning the IRP or any other topic of interest. These meetings are live streamed.
  - No one addressed the Board at these meetings concerning the IRP.
- A rotator on the front page of www.nppd.com directing them to the IRP website, www.nppd.com/irp.
  - The website included the draft IRP report, IRP presentations to the Board, and other IRP material.
  - There were more than 2,600 views of the IRP page on nppd.com. The IRP page was the third most-visited page during the scheduled advertising.
- There was a feedback comment form for interested parties to provide written feedback on the website.
- A special email address (irp@nppd.com) was created and shown on the website in case the public wished to address NPPD in this manner.
- Customer outreach meetings with our wholesale & retail customers where we explained what an IRP is, principles that guide the IRP approach, major inputs that impact the results, initial results and next steps.
- Four (4) in-person stakeholder meetings and one (1) virtual stakeholder meeting that included statewide screening locations were held in March.
- Ad placement in the Quarter 1, *Energy Insight* publication to wholesale customers, teammates and retirees.
- 116 newspaper ad insertions were placed with a total circulation of more than 21,000, 11 radio stations with a total of 415 spots, and digital display advertising with 749,000+ impressions to inform the public of the stakeholder meetings.
- A wholesale advertising toolkit was available for wholesale customers to promote the events as well.

The five (5) stakeholder meetings were attended by 95 members of the public. At the end of these sessions, there was time for members of the public to provide comments or ask questions of the draft IRP report and process. NPPD received 44 comments via the feedback form on the website.

We received two (2) written comments from our wholesale customers, one (1) from an end user of a wholesale customer, and two (2) comments submitted to the email address. Overall, there was not as much interest in the IRP vs. the Board's Strategic Directive 05, Carbon Reduction Strategy based on the responses and feedback. One may surmise by this that the results of the IRP generally matched the expectation of NPPD's customers.

6.2 Customer Input

NPPD representatives participated in four (4) customer meetings during the months of January through April to present and answer questions about the IRP. These meetings were either part of regularly-scheduled events or at the request of individual customers. These customer-specific meetings were held as follows, showing the meeting type, locations, and dates.

~ IRP Meetings with Customers~

RRC/PRAB Customer Meeting – Virtual, January 19, 2023
Nebraska G&T Managers Meeting – Columbus, NE, February 24, 2023
RRC/PRAB Customer Meeting – York, NE, March 23, 2023
Dawson PPD Board of Directors Meeting – Lexington, NE, April 5, 2023

NPPD received a written communication from the Southern Public Power District. Some of their comments are listed below, along with NPPD's responses in the sub-bullets.

- They indicated a plan that provides a low-cost power supply with the highest degree of reliability is the most important expectation they have with their partnership with NPPD. They stated, "We would generally agree that NPPD has recognized those obligations in the IRP through the continued use of a diverse mix of generation resources primarily using coal and nuclear …"
- They felt justification for expanding the energy efficiency program is weak.
    - The action item is to investigate the potential for increased funding of the EnergyWise℠ program, then facilitate further discussion with our customers regarding the most mutually advantageous level of EE for NPPD to pursue in the future.
- They did not understand why energy market costs escalated less than fuel costs.
    - One reason is the expected continued expansion of low variable cost renewable resources can keep energy market prices low. NPPD did perform sensitivities around market prices to gauge its impact.
- They prefer NPPD continue to own resources vs. relying on the energy market.
    - NPPD agrees overreliance on the energy market can lead to risks and price uncertainty. NPPD restricted the amount we could buy from the market based on this risk.
- They noted the IRP recognizes the value of demand-side management and they encourage NPPD to continue to do so.
- They indicated NPPD should carefully evaluate renewable resources to serve our demand and energy needs.
    - There is an action item to evaluate early installation of wind and/or solar to see if the addition of IRA credits provides value to NPPD and its customers.
- They stated, "Overall, we would agree that the proposed IRP has the appropriate action items and the appropriate time frame to continue without jeopardizing reliability and contain costs."

NPPD also received a written communication from the Nebraska Electric Generation and Transmission Cooperative, Inc. Some of their specific comments are listed below, along with NPPD's responses in the sub-bullets.

- They agreed with start proceeding with the second relicense process at CNS, continue to operate GGS, along with investigating CCS, continue operation of Sheldon on coal while studying potential to restore it to natural gas operation, and investigate SMR.
    - Their comments generally align with NPPD's action plan items for CNS, GGS, Sheldon, & SMR.
- They agreed with continuing to collaborate with customers on DR programs and explore possibility of renewable generation additions using IRA credits.
    - Their comments generally align with NPPD's action plan items for CNS, GGS, & SMR.
- They are skeptical NPPD can achieve the EE cumulative savings and additional funding could provide a favorable reduction in costs to our customers. We are not in favor at this time to increase EE funding.
    - As stated in a response to Southern, the action item is to investigate the potential for increased funding of the EnergyWise^{SM} program, then facilitate further discussion with our customers regarding the most mutually advantageous level of EE for NPPD to pursue in the future. We will review the cumulative savings and report our findings to our customers as we facilitate EE discussions.
- They were supportive of the IRP. They stated, "It is the opinion of NEG&T management that NPPD has thoroughly and thoughtfully considered all the various uncertainties that may hypothetically affect its long-term power and energy requirements. Moreover, NPPD has appropriately considered and identified numerous variables likely to impact NPPD's resource requirements for the IRP study period of 2023-2052 and has made assumptions that are generally in line with board directives and wholesale customer requests. NEG&T concludes that NPPD's IRP contains no apparent deficiencies that would adversely impact the NEG&T membership adversely and appears to be a 'directionally correct' future vision in an increasingly competitive and complex industry."

6.3 Public Stakeholder Meetings

NPPD held four (4) in-person stakeholder meetings across the state of Nebraska. The first was held in Kearney on March 21, 2023. A meeting in North Platte was on March 24th, York on March 25th, and Norfolk on March 28th. On March 29th, NPPD held a hybrid/virtual meeting which could also be attended in-person at the following satellite locations: Ainsworth, Auburn, Broken Bow, Chadron, Columbus, Hartington, McCook, Plattsmouth, and Scottsbluff. The length of each meeting was two (2) hours. All meetings started at 6 p.m.

A total of 95 members of the public attended these stakeholder presentations. At the end of each presentation, there was a chance for the public to comment or ask questions about the IRP. Most of the questions or feedback were in regard to better understanding modeling assumptions, although there were some comments concerning carbon. The District provided a response at the meetings for the questions. Below is a summary of these comments/questions:

- Carbon – There were questions in regard to the business risk of carbon, as well as how the carbon scenarios were chosen. Some were dissatisfied the District approved BP-SD-05, which set a goal of being net zero for carbon emissions by 2050. One business indicated their customers were asking about their carbon footprint.

- Load – There were questions concerning the cost benefit of new load. Another asked about our net metering policy, while others wondered how electric vehicle load may impact the District's Demand Waiver program, which incorporates a significant amount of irrigation load.
- Resources
    - Renewables – There were questions asking whether renewables are really lower cost than other resources, their impact on negative prices, the percent of renewables as a portion of the District's resource mix, and the accredited capacity of solar vs. wind. There were also questions concerning the amount of storage in batteries, and the battery material used for the modeling assumptions.
    - Question concerning the cost of Cooper Nuclear Station vs. Carbon Capture & Sequestration at Gerald Gentlemen Station.
    - Will there be additional federal regulation for natural gas due to Winter Storm Uri.
- Other Questions – Someone asked who developed the software used for the IRP modeling. There was a question concerning when hydrogen or ammonia for use in electric generation will be reliable. There were comments about keeping cost and reliability in mind for the future resource mix. One person asked if there are any metrics available to measure resiliency.

6.4 BP-SD-05 Interfaces

In 2021, NPPD's Board of Directors was developing a strategic directive concerning carbon emissions reductions. When developing this strategic directive, NPPD wanted to ensure we had input from our customers. In addition to receiving feedback from the Board of Directors and contract customer meetings, NPPD hosted a series of information forums during the month of August, focused on gathering customer thoughts. Topics concentrated on during these sessions included: 1. The risks of being a carbon-emitting utility 2. How NPPD's carbon reduction goal(s) should be structured 3. What principles (reliability, resiliency, affordability, environmental impact, etc.) are most important to maintain as NPPD works to reduce its carbon emissions. The forums included high-level educational presentations from the Electric Power Research Institute (EPRI) about the basics of electricity, what NPPD's current generation mix looks like, what decarbonization is and is not, and what factors to consider when decarbonizing. The forums were held in Norfolk, Seward, North Platte, Scottsbluff, and Kearney. Customers who couldn't attend one of these forums had the opportunity to review the materials presented on NPPD.com. We encouraged all to participate in an online survey from August to September to provide their thoughts, perceptions, and preferences.

A total of 545 individuals attended these forums. General themes from the feedback included:

- Support for decarbonization and alternative energy is mixed
- Climate change is an urgent matter for NPPD to address
- Participants expect NPPD to take the lead in energy policy
- Satisfaction with NPPD's energy management and leadership
- Meeting polling showed that 30% or more (30-52%) of those who participated are not concerned about decarbonization

The information above was provided to the Board of Directors at their November 3, 2021 retreat.

6.5 Public Survey

To gather comments about the IRP from the public who did not attend the stakeholder meetings or other avenues discussing the IRP, or that did not want to speak at these meetings, a comment form was available on the website. The comment form consisted of three (3) questions; their location, their electrical provider, and an open-ended question asking their opinion of the draft IRP report.

A total of 54 comments were received. NPPD engaged The MSR Group to help gather the data and categorize the comments. The MSR Group stressed one could not conclude the sample was representative of NPPD's customers due to the small sample size and they were not from a scientific sample.

The top two (2) themes centered around reliability and affordability. The next two (2) were in regard to early deployment of renewables and supported decarbonization efforts. Unlike previous IRPs, the themes were similar between those identified as end use customers in NPPD's or our wholesale customers' service territories vs. those outside of our service territories. The MSR Group stated the IRP results are generally consistent with the results from NPPD scientific surveys, where customers expressed a preference and expectation that NPPD balance providing affordable and reliable energy with concern for the environment including support for decarbonization efforts. These themes tie closely to the IRP principles and NPPD's Board strategic directives of having affordable, reliable, resilient, and sustainable energy. The themes and their frequency can be found in Appendix D.

6.6 Other Interested Parties

In addition to the feedback and responses described above, NPPD received three (3) responses from parties interested in the IRP.

The first of these responses was from the Midwest Energy Efficiency Alliance (MEEA). The MEEA response indicated support for NPPD's IRP process to include energy efficiency (EE) to help meet the net-zero carbon emissions directive described in BP-SD-05. MEEA went on to describe the benefits of additional investments in energy efficiency and encouraged NPPD to model EE as a candidate resource during capacity expansion modeling in future IRPs.

The second response was received from Wärtsilä, a global manufacturer of reciprocating internal combustion engines (RICE) used in many industries, including the power sector. Among the recommendations contained in their response, Wärtsilä suggested NPPD's IRP model may undervalue RICE units because the model did not have the capability to perform sub-hourly dispatch. While it is true NPPD's Capacity Expansion model did not perform sub-hourly dispatch, in future analyses where detailed examination of various generation resources is necessary for comparison and/or decision support, NPPD will take this recommendation into consideration.

Finally, a third response was received from an end-use customer of one of NPPD's wholesale customers. In this response, the interested party offered a recent analysis of the Levelized Cost of Energy (LCOE) and suggested ways in which NPPD could use the information to compare conventional resources with renewable resources by updating the assumptions used in the IRP. As this reference resource was received after the requisite modeling had been completed, NPPD does not intend to rerun the IRP cases using updated assumptions, but appreciates the information provided for potential future use.

APPENDICES

Appendix A – Customer Listing

NPPD WHOLESALE REQUIREMENTS CUSTOMERS
PUBLIC POWER DISTRICTS AND COOPERATIVES

Utility Name	City, State	G&T Member
Burt County PPD	Tekamah, NE	Yes
Butler PPD	David City, NE	Yes
Cedar-Knox PPD	Hartington, NE	Yes
Cornhusker PPD	Columbus, NE	Yes
Cuming County PPD	West Point, NE	Yes
Custer PPD	Broken Bow, NE	Yes
Dawson PPD	Lexington, NE	Yes
Elkhorn RPPD	Battle Creek, NE	Yes
Howard Greeley RPPD	St. Paul, NE	Yes
KBR RPPD	Ainsworth, NE	Yes
Loup Power District	Columbus, NE	No
Loup Valleys RPPD	Ord, NE	Yes
McCook PPD	McCook, NE	Yes
Niobrara Valley EMC	O'Neill, NE	Yes
Norris PPD	Beatrice, NE	No
North Central PPD	Creighton, NE	Yes
Perennial PPD	York, NE	Yes
Polk County RPPD	Stromsburg, NE	Yes
South Central PPD	Nelson, NE	Yes
Southern PD	Grand Island, NE	No
Southwest PPD	Palisade, NE	Yes
Stanton County PPD	Stanton, NE	Yes
Twin Valleys PPD	Cambridge, NE	Yes

NPPD WHOLESALE REQUIREMENTS CUSTOMERS

MUNICIPAL UTILITIES:

Utility Name	City, State	Direct WAPA
City of Arapahoe	Arapahoe, NE	
City of Auburn	Auburn, NE	Yes
City of Battle Creek	Battle Creek, NE	
Village of Bradshaw	Bradshaw, NE	
Village of Brainard	Brainard, NE	
City of Central City	Central City, NE	
Village of Chester	Chester, NE	
City of Cozad	Cozad, NE	
Village of Davenport	Davenport, NE	
City of David City	David City, NE	Yes
City of Deshler	Deshler, NE	Yes
Village of DeWitt	DeWitt, NE	Yes
Village of Dorchester	Dorchester, NE	
Village of Fairmont	Fairmont, NE	
City of Friend	Friend, NE	
City of Gothenburg	Gothenburg, NE	
Village of Hampton	Hampton, NE	
Village of Hemingford	Hemingford, NE	
Village of Hildreth	Hildreth, NE	
City of Holdrege	Holdrege	
City of Lexington	Lexington, NE	
Village of Lodgepole	Lodgepole, NE	Yes
City of Lyons	Lyons, NE	Yes
City of Madison	Madison, NE	Yes
City of Minden	Minden, NE	
City of Nelson	Nelson, NE	
City of North Platte	North Platte, NE	
City of Ord	Ord, NE	Yes
Village of Prague	Prague, NE	
City of Randolph	Randolph, NE	Yes
City of Seward	Seward, NE	
Village of Summerfield	Summerfield, KS	
City of Sutton	Sutton, NE	
City of Wahoo	Wahoo, NE	Yes
Village of Wauneta	Wauneta, NE	Yes
City of Webber	Webber, KS	
Village of Wilcox	Wilcox, NE	
City of Wymore	Wymore, NE	

* Although these municipals currently purchase primarily non-firm energy from NPPD, there is in place an agreement which provides for the municipal to purchase and NPPD to provide firm power and energy to serve any load growth above the municipal's WAPA allocation plus existing generating capacity.

REQUIREMENTS CUSTOMERS OF
NPPD'S WHOLESALE CUSTOMERS

Requirements Customer	Associated NPPD Wholesale Customer	Direct WAPA Allocation
Bartley, NE	Twin Valleys PPD	
Belleville, KS	Norris PPD	
Cambridge, NE	Twin Valleys PPD	Yes
Campbell, NE	Southern Power District	
Clarkson, NE	Loup PPD	
Decatur, NE	Burt County PPD	
Edgar, NE	South Central PPD	
Filley, NE	Norris PPD	
Franklin, NE	Southern Power District	Yes
Giltner, NE	Southern Power District	
Hebron, NE	Norris PPD	
Hickman, NE	Norris PPD	
Holbrook, NE	Twin Valleys PPD	
Hubbell, NE	Norris PPD	
Indianola, NE	McCook PPD	Yes
Laurel, NE	Cedar Knox PPD	Yes
Leigh, NE	Loup PPD	
Mullen, NE	Custer PPD	
Polk, NE	Polk County RPPD	
Sargent, NE	Custer PPD	Yes
Schuyler, NE	Loup PPD	Yes
Spalding, NE	Cornhusker PPD	Yes
St. Paul, NE	Howard Greeley RPPD	
Stanton, NE	Stanton County PPD	
Stratton, NE	Southwest PPD	
Stromsburg, NE	Polk County RPPD	
Weston, NE	City of Wahoo	
Wilber, NE	Norris PPD	Yes
Santee Sioux Tribe	North Central PPD	Yes
Omaha Tribe	Burt County PPD	Yes

NPPD Retail Customers with WAPA Allocation

Norfolk Regional Center	Direct WAPA Allocation - Yes
Winnebago Tribe	Direct WAPA Allocation - Yes
Oglala Sioux Tribe	Direct WAPA Allocation - Yes

NPPD Retail Entities with Professional Retail Operations (PRO) Agreement

Ainsworth	Gibbon	O'Neill
Alma	Gordon	Oshkosh
Ashton	Hartington	Pawnee City
Atkinson	Hay Springs	Plattsmouth
Aurora	Homer	Ravenna
Barada	Humboldt	Rushville
Bassett	Inman	Scottsbluff
Big Springs	Kearney	Shelton
Bloomfield	Lewellen	Shubert
Bristow	Lewiston	Steinauer
Broadwater	Long Pine	Stella
Brule	Loup City	Sterling
Burchard	Lynch	Sutherland
Butte	Madrid	Table Rock
Chadron	McCook	Tekamah
Clinton	McGrew	Terrytown
Crab Orchard	Meadow Grove	Tilden
Craig	Melbeta	Union
Crawford	Merriman	Venango
Creighton	Milford	Verdon
Dakota City	Minatare	Whitney
Dawson	Murray	Winnebago
DuBois	Nehawka	York
Elm Creek	Norfolk	
Elsie	Oakdale	
Emmet	Oakland	
Geneva	Ogallala	
Oglala Sioux Housing Authority	Oglala Sioux Tribal Council	

NPPD Retail Customers without Direct WAPA Allocation or PRO Agreement

Anoka	Lisco	Pine Ridge, SD
Brandon	Mynard	St. Mary
Crystal Lake	Northport	Whiteclay
Fort Robinson		

Appendix B – Existing Generating Unit Data

The following table lists the accredited capacity units (in MW) in the Southwest Power Pool, and does NOT include Qualifying Local Generation.
Unit Types: IC = Internal Combustion, CC – Combined Cycle, ST – Steam, HY – Hydro, NB – Nuclear, GT – Gas Turbine, WD – Wind
Fuel Type: NG – natural gas, FO2 – Fuel Oil #2, WAT – Water, UR – Uranium, BITW – Bituminous Western Coal

Nebraska Public Power District

Generating Capability Data
2023 Existing Megawatts

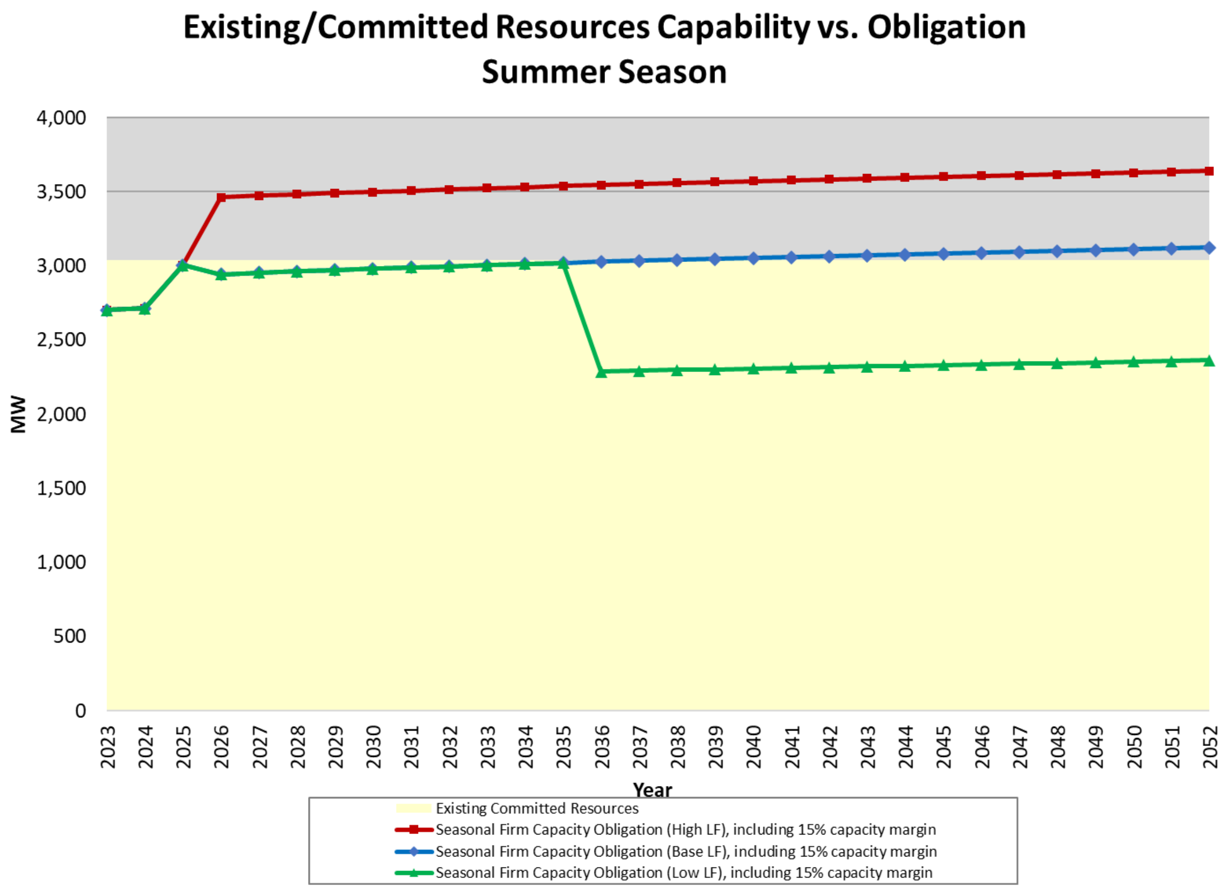
Unit Name	Location	Unit Type	Fuel Type	Summer Rating	Winter Rating	Commercial Start Date
Auburn 1	Auburn, NE	IC	NG,FO2	2.00	2.00	1982
Auburn 2	Auburn, NE	IC	NG,FO2	1.00	1.00	1949
Auburn 4	Auburn, NE	IC	NG,FO2	3.00	3.00	1993
Auburn 5	Auburn, NE	IC	NG,FO2	3.00	3.00	1973
Auburn 6	Auburn, NE	IC	NG,FO2	2.00	2.00	1967
Auburn 7	Auburn, NE	IC	NG,FO2	5.00	5.00	1987
BPS	Beatrice, NE	CC	NG	219.50	219.50	2005
Belleville 5	Belleville, KS	IC	NG,FO2	1.30	1.30	1961
Belleville 6	Belleville, KS	IC	NG,FO2	2.60	2.60	1966
Belleville 7	Belleville, KS	IC	NG,FO2	3.30	3.30	1971
Belleville 8	Belleville, KS	IC	NG,FO2	2.80	2.80	2005
Cambridge	Cambridge, NE	IC	FO2	3.00	3.00	1958
Canaday	Lexington, NE	ST	NG, FO6	99.30	99.30	1958
Columbus 1	Columbus, NE	HY	WAT	15.00	15.00	1936
Columbus 2	Columbus, NE	HY	WAT	15.00	15.00	1936
Columbus 3	Columbus, NE	HY	WAT	15.00	15.00	1936
Cooper	Brownville, NE	NB	UR	768.51	768.51	1974
David City 1	David City, NE	IC	NG, FO2	1.30	1.30	1960
David City 2	David City, NE	IC	FO2	0.80	0.80	1949
David City 3	David City, NE	IC	NG, FO2	0.90	0.90	1955
David City 4	David City, NE	IC	NG, FO2	1.80	1.80	1966
David City 5	David City, NE	IC	FO2	1.33	1.33	1996
David City 6	David City, NE	IC	FO2	0.00	0.00	1996
David City 7	David City, NE	IC	FO2	1.34	1.34	1996
Franklin 1	Franklin, NE	IC	NG, FO2	0.92	0.92	1963
Franklin 2	Franklin, NE	IC	NG, FO2	1.00	1.00	1974
Franklin 3	Franklin, NE	IC	NG, FO2	1.00	1.00	1968
Franklin 4	Franklin, NE	IC	NG, FO2	0.83	0.83	1955
Gentleman 1	Sutherland, NE	ST	BITW	665.00	665.00	1979
Gentleman 2	Sutherland, NE	ST	BITW	700.00	700.00	1982
Hallam	Hallam, NE	GT	NG, FO2	42.90	42.90	1973
Hebron	Hebron, NE	GT	FO2	42.05	42.05	1973
Kearney	Kearney, NE	HY	WAT	0.00	0.00	1921
Kingsley	Ogallala, NE	HY	WAT	41.67	41.67	1985

Unit Name	Location	Unit Type	Fuel Type	Summer Rating	Winter Rating	Commercial Start Date
Madison 1	Madison, NE	IC	NG, FO2	1.00	1.00	1969
Madison 2	Madison, NE	IC	NG, FO2	1.00	1.00	1959
Madison 3	Madison, NE	IC	NG, FO2	1.00	1.00	1953
Madison 4	Madison, NE	IC	FO2	0.70	0.70	1946
McCook	McCook, NE	GT	FO2	40.90	40.90	1973
Monroe	Monroe, NE	HY	WAT	3.00	3.00	1936
North Platte 1	North Platte, NE	HY	WAT	12.00	12.00	1937
North Platte 2	North Platte, NE	HY	WAT	12.00	12.00	1937
Ord 1	Ord, NE	IC	NG, FO2	5.00	5.00	1973
Ord 2	Ord, NE	IC	NG, FO2	1.00	1.00	1966
Ord 3	Ord, NE	IC	NG, FO2	2.00	2.00	1963
Ord 4	Ord, NE	IC	FO2	1.40	1.40	1997
Ord 5	Ord, NE	IC	FO2	1.40	1.40	1997
Sheldon 1	Hallam, NE	ST	BITW	104.00	104.00	1961
Sheldon 2	Hallam, NE	ST	BITW	112.00	112.00	1968
Wahoo_1	Wahoo, NE	IC	NG,FO2	1.70	1.70	1960
Wahoo_3	Wahoo, NE	IC	NG,FO2	3.60	3.60	1973
Wahoo_5	Wahoo, NE	IC	NG,FO2	1.80	1.80	1952
Wahoo_6	Wahoo, NE	IC	NG,FO2	2.90	2.90	1969
Wilber	Wilber, NE	IC	FO2	2.90	2.90	1949
Total				2975.45	2975.45	
				Nameplate Rating	Summer Rating [(1)]	
Ainsworth Wind	Ainsworth, NE	WD	WD	59.4	4.17	2005
Elkhorn Ridge Wind	Bloomfield, NE	WD	WD	80.0	4.50	2009
Laredo Ridge Wind	Petersburg, NE	WD	WD	80.0	10.89	2011
Springview Wind	Springview, NE	WD	WD	3.0	0.34	2011
Crofton Bluffs Wind	Crofton, NE	WD	WD	42.0	3.63	2012
Broken Bow Wind	Broken Bow, NE	WD	WD	80.0	8.29	2012
Steele Flats	Diller, NE	WD	WD	75.0	22.20	2013
Broken Bow Wind II	Broken Bow, NE	WD	WD	73.0	4.48	2014

[(1)] The values are NPPD's share of the 2023 SPP summer accredation values. These values can change on an annual basis as determined by SPP's accredation criteria.

Appendix C – Projected Load & Capability Graphs

Exhibit C-1 – Load & Capability with Only Existing/Committed Resources, Summer Season



Appendix D – Summary of Public Comments

Southern Public Power District Written Comments

SOUTHERN
public power district

4550 West Husker Hwy • PO Box 1687 • Grand Island, NE 68802-1687
308-384-2350 • 800-579-3019

April 12, 2023

Ms. Courtney Dentlinger
Vice President, Customer Services and External Affairs
& Chief Customer Officer
Nebraska Public Power District
1414 15th Street
Columbus, Nebraska 68602-0499

RE: NPPD 2023 Integrated Resource Plan

Dear Courtney,

We have reviewed your draft of the 2023 Integrated Resource Plan and would offer the following comments.

The quality of life and the economic viability of our area depends upon a plan that will provide a low-cost supply of wholesale power with the highest degree of reliability. These two elements are the most important expectations that we have in our partnership with NPPD. We would generally agree that NPPD has recognized those obligations in the IRP through the continued use of a diverse mix of generation resources primarily using coal and nuclear baseload generation to insure reliability. NPPD should be commended for recognizing the sufficiency of their current generation fleet to meet the demands of its wholesale customers and is demonstrating patience in not following the trends of closing baseload coal generation resources in favor of intermittent renewable resources such as wind and solar. Baseload generation will be even more valuable in this decade of projected growth.

NPPD has been successful in containing costs and ensuring reliability while diversifying its mix of generation resources. With the current mix of generation now over 50% carbon-free, NPPD has been able to provide a high percentage of non-carbon resources to its native load customers and will be able to continue to provide that level of non-carbon resources through the renewal of the Cooper Nuclear Station operating license through 2054 which we support.

The IRP forecasts an average rate of summer demand growth of 4.9% annually between 2023 and 2025 and 7.3% annually for energy growth during the same period. The IRP indicates NPPD is confident of a new large industrial load that will drive that growth in this short time period. For reliability purposes we agree with NPPD's need to provide additional baseload capacity, most likely a natural gas unit, in this short time period.

Powering A Brighter Future

The IRP forecasts an average rate of summer demand growth of only .18% between 2025 and 2052 and .26% annually for energy growth during the same period. The IRP indicates those low growth rates reflect the moderate level of energy efficiency. While extremely hard to predict, we believe those low growth rates are reflective of the general economy. Energy efficiency programs will have minimal impact on load growth and justification for expanding the energy efficiency program is weak. We would recommend that Action Item 4.5 for increased funding of the energy efficiency program be delayed until the program is reviewed for its impact on reducing the need for future generation.

In reviewing the section on Fuel and Market Prices we would question the IRP assumptions for the SPP energy market. While the IRP assumes future cost increases of 2.1 to 2.2% for coal, nuclear and natural gas, the IRP assumes the energy market costs will only escalate .2% to 1% annually. It is difficult for us to understand why the market is forecasted to increase less than half of the typical baseload resources. Underestimating market rates in the forecast may lead NPPD towards depending on the market for future needs versus constructing, owning and operating baseload plants to maintain reliability and control costs.

We would recommend NPPD continue with their longstanding successful approach of owning assets rather than relying on the uncertainty of the energy market. Let's not be quick to forget the success NPPD has derived in the energy market creating surpluses that have been passed to the wholesale customers due to low-cost resources such as Gerald Gentleman Station.

The IRP recognizes the value of demand-side management as it reduces NPPD's load obligation by up to 620 MW's by shifting NPPD's peak demands from on-peak hours to off-peak hours. Our District continues to experience customer confidence and acceptability of the successful demand waiver program as 75% of our irrigation operators representing over 310,000 horsepower of pumping capacity are participating in the program. We encourage NPPD to continue to recognize the importance of this program, as well as the benefits of the newly issued Large Power Interruptible Rate Schedule and other demand response programs as a generation resource throughout the IRP planning period.

The IRP also speaks to the possibility of early renewable installations utilizing IRA credits. While there may be some short-term financial benefits using Federal incentives, we would caution NPPD to evaluate wind and solar resources for their shortcomings in being able to serve both our demand and energy needs. We believe there will be deficiencies going forward in NPPD's ability to serve load 24-hours around the clock with these types of resources. NPPD will need to have additional investments in either baseload generation or technologies that are not available today such as batteries and small modular nuclear to support renewable installations.

Overall, we would agree that the proposed IRP has the appropriate action items and the appropriate time frame to continue without jeopardizing reliability and contain costs. Thank you for allowing us to comment on the IRP and be part of the planning process.

Sincerely,

Neal F. Niedfeldt
President and CEO

Powering A Brighter Future

Nebraska Electric Generation & Transmission Written Comments

NEGT

Nebraska Electric Generation and Transmission Cooperative, Inc.

402-564-8142 • 2472 18th Avenue • Columbus, NE 68601 • www.negt.coop

July 21, 2023

Mr. Tom Kent, President and CEO
Nebraska Public Power District
P.O. Box 499
Columbus, Nebraska 68602-0499

Dear Tom:

On behalf of Nebraska Electric Generation and Transmission Cooperative, Inc. (NEG&T) and our twenty members (listing attached), we would like to give comment on the 2023 NPPD Integrated Resource Plan (IRP). Our members, through NEG&T member contracts, in aggregate are NPPD's largest wholesale customer and have a massive, vested interest in future resource planning.

NEG&T agrees an IRP offers an understanding on favorable approaches for adding resources to meet future native load requirements while minimizing cost and risk exposure over the studied time frame of 2023-2052. It would be impossible to arrive at an exact plan to be followed for the next 30 years, but it does however provide framework that NPPD can use to thoroughly examine future resource options with all customers to hold robust discussions about the directionally correct path for the state's largest utility to meet all statutory obligations while balancing the must haves of reliability and affordability.

In 2021, NPPD's Board of Directors established a strategic directive (SD-05) to achieve net zero carbon emissions from generation resources by 2050 at costs that are equal to, or lower than, then current resources. The draft report on page 6 states "NPPD's Board of Directors may evaluate and reconsider the District's Carbon Emissions Goal if it is determined that meeting or progressing toward the goal will adversely impact the District's ability to continue to meet the strategic directives concerning reliability (BP-SD-03) or cost competitiveness (BP-SD-04)." NEG&T agrees that BP-SD-03 and BP-SD-04 are directives that should be eminently considered in any directional resource path forward and should be weighted equally to the tenants of BP-SD-05.

Specific comments for the 2023 IRP are as follows:

1. NEG&T concurs with the recommendation made by NPPD to start proceeding with the second relicense renewal process at Cooper Nuclear Station along as well as further refine the capital costs needed for completion of the relicense process.
2. NEG&T concurs with the recommendation made by NPPD for the continuation of Gerald Gentleman Station (GGS) to continue to operate as a coal-fired generating facility without an end date of ceasing operations. We also support monitoring and reporting

the potential risks of continuing GGS as a coal-fired generating facility and investigating a constrained CO2 scenario if GGS were retrofitted with Carbon Capture and Sequestration equipment to reduce emissions.

3. NEG&T concurs with the recommendation made by NPPD to continue to operate Sheldon Station (SS) as a coal-fired generating facility without an end date of ceasing operations. Also preferable is to pursue the required modifications at SS for compliance with Effluent Limitation Guideline rule requirements while also studying the potential restoration of SS to natural gas fired operations.
4. NEG&T concurs with the recommendation made by NPPD to continue to investigate Small Modular Reactors (SMR) as a resource future option and complete preliminary siting studies currently in progress.
5. NEG&T has skepticisms about the modeling of Energy Efficiency (EE) on exhibits 2.4.1-1 and 2.4.1-2 could actually achieve the cumulative savings by 2050 and that future additional funding to EE could provide a favorable reduction in costs to NPPD customers. Hence, at this time NEG&T would not be in favor of an increase in funding level for EE as a bundled charge in the General Firm Power Service rate schedule.
6. NEG&T concurs with the recommendation made by NPPD to continue to collaborate with customers to identify beneficial opportunities to increase the use of demand response programs, when applicable, that may provide a quicker way to serve new loads. NPPD should also continue to monitor and participate in on-going demand response reviews by the Southwest Power Pool.
7. NEG&T concurs with the recommendation made by NPPD to continue to explore the possibility of renewable generation additions that leverage the use of Inflation Reduction Act credits.

It is the opinion of NEG&T management that NPPD has thoroughly and thoughtfully considered all the various uncertainties that may hypothetically affect its long-term power and energy requirements. Moreover, NPPD has appropriately considered and identified numerous variables likely to impact NPPD's resource requirements for the IRP study period of 2023-2052 and has made assumptions that are generally in line with board directives and wholesale customer requests. NEG&T concludes that NPPD's IRP contains no apparent deficiencies that would adversely impact the NEG&T membership adversely and appears to be a 'directionally correct' future vision in an increasingly competitive and complex industry.

Thank you for taking the time to consider our thoughts and concerns on the 2023 IRP.

Sincerely,

Darin Bloomquist

Darin L. Bloomquist
General Manager

cc: Mick Spencer, Courtney Dentlinger, Laura Kapustka & Jim Fehr of NPPD

Midwest Energy Efficiency Alliance Written Comments

MEEA
MIDWEST ENERGY EFFICIENCY ALLIANCE

20 N. Wacker Drive, Suite 1301
Chicago, Illinois 60606
312.587.8390 Main Line
312.587.8391 Fax
www.mwalliance.org

April 12, 2023

Nebraska Public Power District (NPPD)

RE: 2023 Draft Integrated Resource Plan Stakeholder Input

Dear NPPD's Resource Planning and Risk Managers,

Thank you for the opportunity to comment on NPPD's draft 2023 Integrated Resource Plan (IRP). The Midwest Energy Efficiency Alliance (MEEA) is a member-based, nonprofit collaborative network, promoting energy efficiency (EE) to optimize energy generation, reduce consumption, create jobs and decrease carbon emissions in all Midwest communities, including Nebraska, where 54 of our 160+ members are headquartered or operating. At MEEA, we leverage our expertise to be the Midwest's leading resource for our members, allies, policymakers and the broader sector to promote energy efficiency as the essential pathway to achieve a clean, affordable, equitable and sustainable future.

We see energy efficiency as the least-cost foundation of the clean energy economy, creating immediate energy savings, providing career pathways, reducing emissions, improving new and existing buildings and boosting Midwest business and industries. MEEA develops connections and engagement opportunities for a diverse group of organizations to collaboratively create practical solutions. MEEA serves as a technical resource and promotes program and policy best practices and emerging technologies, all to maximize energy savings, reduce costs, improve resiliency and lower energy burden.

MEEA supports NPPD's IRP process to include and increase energy efficiency projects to help NPPD meet its goal of achieving net-zero carbon emissions from its generation resources by 2050. We are glad to see the alternate "High Energy Efficiency" sensitivity included in NPDD's IRP analysis and support further evaluation of enlarging the district's EE portfolio to reduce system costs, enhance resilience efforts and reduce carbon and other emissions. We commend the District for committing to a carbon reduction goal but would note that such a goal can only be achieved by including energy efficiency efforts in the mix of solutions. While NPPD already runs on 62% carbon-free, achieving that final 38% of carbon reduction will bring challenges. Energy efficiency can help right-size the grid, especially as demand is expected to increase with electrification and electric vehicles. Increasing energy efficiency can also help reduce the amount of power the District must purchase and decrease its reliance on additional energy production to meet the District's needs.

We encourage the District to look for ways to model EE as a selectable resource for capacity expansion modeling in future IRPs, rather than continuing the current practice of treating EE as a load reduction before implementing supply-side resource optimization. We have seen this change successfully implemented by utilities in Indiana and Michigan.

One of the best resources in the Midwest for learning about advancements in IRPs is the Indiana Utility Regulatory Commission's annual IRP Contemporary Issues Technical

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Conference. Some notable presentations on the integration of demand-side management into IRPs include:

- Dr. Fredrich Kahrl, *The Future of Electricity Resource Planning* (2017)
- Anna Sommer, *Using IRPs to Develop Avoided Costs for Energy Efficiency* (2018)
- Sydney Forrester and Andy Satchwell, *DERs in Indiana IRPs* (2020)

In Michigan, the Energy Waste Reduction Potential Study working group provides some additional useful materials including:

- Tom Eckman, Natalie Mims and Andy Satchwell, *Berkeley Labs Presentation to IRP Stakeholder Group Meeting* (2017), slides (p. 42, 75+), recording

Including all cost-effective EE as a selectable resource in optimization modeling lets the demand side compete fairly against supply-side options and helps demonstrate the system value of expanding energy efficiency to customers and decision makers. Energy efficiency is a valuable investment in Nebraska's communities, businesses and homes.

We also support efforts to expand demand response to help mitigate the need for transmission and distribution upgrades to meet customer peaks. Finally, future IRPs should consider federal funds, particularly from the Bipartisan Infrastructure Law and the Inflation Reduction Act as full details of their programs and funding streams become available. These federal funds could be used to further reduce the costs of demand-side energy resources for NPPD, making them an even more cost-effective part of the utility portfolio.

We appreciate the opportunity to comment on this important proceeding. An integrated resource plan is a critical document, outlining accessible supply and forecasted demand. This IRP is especially critical for NPPD as the District develops strategies to reach its carbon reduction targets. We believe energy efficiency can and should be a part of the solution, and we encourage the District to consider how increased energy efficiency can bring environmental and economic benefits to NPPD's customers.

We are prepared to provide support to the NPPD in any way we can. If you have any questions or need additional information, please contact Policy Manager Arlinda Bajrami at abajrami@mwalliance.org. Thank you.

Sincerely,

William Angelos

William Angelos, Interim Executive Director
Midwest Energy Efficiency Alliance

These comments reflect the views of the Midwest Energy Efficiency Alliance – a Regional Energy Efficiency Organization as designated by the U.S. Department of Energy – and not the organization's members or individual entities represented on our board of directors.

Wärtsilä Written Comments

Wärtsilä Energy Comments for Nebraska Public Power District

2023 Integrated Resource Plan

April 13, 2023

Wärtsilä is a global energy and marine technology company based in Helsinki Finland, with its North American headquarters in Houston, Texas. Wärtsilä's mission is to supply the power generation technology needed to enable a transition to a reliable, flexible, and affordable clean energy future. Wärtsilä's offerings include utility-scale reciprocating internal combustion engine (RICE) power plants, hybrid solar and battery storage power plants, and stand-alone battery energy storage systems (BESS). To date, Wärtsilä has deployed 76 GW of RICE and over 2 GW of BESS globally. Both RICE and BESS can provide NPPD with the capacity and renewable balancing capabilities it needs to construct a reliable, cost-effective, risk-managed, and clean portfolio that meets the Net Zero goal by 2050. Wärtsilä's RICE technology is significantly more efficient compared to similarly sized gas open cycle units with regards to both fuel and water consumption. They are the most flexible gas-fired technology, tolerating frequent starts and stops, no minimum run times, as well as ultra-fast ramping. In addition to natural gas or diesel (with seamless transitioning dual fuel capabilities for added resiliency), RICE are also capable of using a variety of alternative fuels, including hydrogen blends, biodiesel, synthetic methane, methanol, and green ammonia. By 2025, Wärtsilä will offer a 100% hydrogen capable generator to enable deep decarbonization.

Wärtsilä appreciates the chance to review and provide the following comments on NPPD's draft 2023 Integrated Resource Plan. As a summary, Wärtsilä recommends:

1) To minimize climate impacts as well as financial and regulatory risk, NPPD should "Front Load" Net Zero. This means taking steps now to build the low carbon portfolio and not waiting until the last minute.
2) Now is a good time to plan the retirement of Gerald Gentleman Station (GGS) with a cost-effective portfolio of renewables, battery storage, and reciprocating engines
3) NPPD's modeling software is biased towards less flexible legacy resources because it does not account for sub-hourly value, and hence under values RICE and battery storage.
4) Clean fuels should be contemplated in more detail, especially in light of the incentives included in the Inflation Reduction Act.

5) When issuing RFPs for new resource procurement, NPPD should a) Specify that RICE and batteries as viable technology options and b) Add the sub-hourly valuation to the resource evaluation.

Note: The above is the summary of Wärtsilä's feedback and recommendations. Only a portion of the entire response is included for reference.

Monolith's Written Comments

From: Akhil Chhabra >
Sent on: Thursday, April 13, 2023 2:08:22 PM
To: Sunneberg, Jon M. Rich, David Fehr, James R. Rosenkranz, Jason D. Swanson, John H.
Subject: Lazard LCOE Analysis
Attachments: lazards-lcoeplus-april-2023.pdf (1.01 MB)

Caution! External Sender, Stop, Check, and Verify. DO NOT click on links or open attachments unless you were expecting the email, recognize the sender, and know the content is safe! The email is from akhil.chhabra@monolith-corp.com.

NPPD Team –
Please find the attached LCOE analysis released by Lazard yesterday. It provides good context on how renewable energy compares with conventional resources. They took the added step to compare LCOE of new build renewables to marginal unit cost of running conventional resources (pg. 10).
They also provide color on regional LCOE of renewable energy and what it costs to firm it with CT's (pg 11). You can replace the CT cost with other technologies (Receps) by putting in your assumptions.
I haven't gone through all the assumptions in the appendix, but this information provides good color as you continue to consider your generation mix for the IRP.
Hope it helps.
Regards,
Akhil

Akhil Chhabra
Clean Energy Lead

monolith

Lincoln Office
134 S. 13th Street, Suite 700, Lincoln, NE 68508
monolith-corp.com

Note: The above is the feedback from Monolith providing an attachment (not included here) regarding the Levelized Cost of Energy for NPPD's consideration.

IRP Public Stakeholder Survey

Nebraska Public Power District
Always there when you need us

Integrated Resource Plan Study: Talking Points

- The IRP survey consisted of three questions:
  - Please enter your zip code.
  - What company provides your electrical service?
  - Please provide comments or suggestions, as it related to NPPD's Integrated Resource Plan (IRP).
- The IRP survey results are not representative of any NPPD customer group for the following reasons:
  - NPPD customers were informed through general media channels that the survey was available online, but no scientific sampling method was used
  - A very small number of customers from the NPPD service area completed the survey (n=30)
  - Given the outreach effort, the small number of completed surveys may indicate the public feels their opinions have been heard by NPPD
- The IRP results are generally consistent with the results from NPPD scientific surveys:
  - Customers express a preference and expectation that NPPD balance providing affordable and reliable energy with concern for the environment including support for decarbonization efforts.

MSR GROUP

NPPD IRP Study 2023

1

<u>IRP Public Stakeholder Survey Continued</u>

Nebraska Public Power District
Always there when you need us

Integrated Resource Plan Study: Frequency of Themes

All Mentions (n=44*)	Frequency	Percent
Reliability	14	16.9
Affordability	10	12.0
Support early expansion of renewable energies	9	10.8
Support of decarbonization efforts	9	10.8
Support increased investment in the EnergyWise Energy Efficiency Program	6	7.2
Increase the use of solar	4	4.8
Wind/solar energy, unsightly, take up valuable land, habitat, noise, etc.	4	4.8
Renewables must be compensated by our power plants	4	4.8
Presentation was good and seems to be on target	4	4.8
Explore all the incentive opportunities provided by the inflation reduction act	3	3.6
Continue using nuclear	3	3.6
Keep Cooper Nuclear Station open and proceed with a second relicense	2	2.4
Promote research and development of power sources that are proven to meet load requirements	1	1.2
Continue using coal	1	1.2
Power should only be provided by locally owned and controlled sources	1	1.2
Renewables are unreliable	1	1.2
Energy efficiency is important	1	1.2
Best technology for the future is Compressed Air Energy Storage (CAES)	1	1.2
Focus on using methane digesters for hog, cattle, and dairy confinement operations	1	1.2
Incentive program for renewables, like solar on roofs	1	1.2
Carbon credits and Inflation Reduction Act could turn out to be a myth	1	1.2
No comment	2	2.4
Total	83	100.0

All NPPD Mentions (n=30*)	Frequency	Percent
Reliability	10	17.9
Affordability	7	12.5
Support early expansion of renewable energies	6	10.7
Support of decarbonization efforts	5	8.9
Support increased investment in the EnergyWise Energy Efficiency Program	5	8.9
Renewables must be compensated by our power plants	4	7.1
Increase the use of solar	3	5.4
Presentation was good and seems to be on target	3	5.4
Keep Cooper Nuclear Station open and proceed with a second relicense	2	3.6
Wind/solar energy, unsightly, take up valuable land, habitat, noise, etc.	2	3.6
Continue using nuclear	2	3.6
Explore all the incentive opportunities provided by the inflation reduction act	1	1.8
Promote research and development of power sources that are proven to meet load requirements	1	1.8
Best technology for the future is Compressed Air Energy Storage (CAES)	1	1.8
Focus on using methane digesters for hog, cattle, and dairy confinement operations	1	1.8
Incentive program for renewables, like solar on roofs	1	1.8
Carbon credits and Inflation Reduction Act could turn out to be a myth	1	1.8
No comment	1	1.8
Total	56	100.0

Outside NPPD Mentions (n=14*)	Frequency	Percent
Reliability	4	14.8
Support of decarbonization efforts	4	14.8
Affordability	3	11.1
Support early expansion of renewable energies	3	11.1
Explore all the incentive opportunities provided by the inflation reduction act	2	7.4
Wind/solar energy, unsightly, take up valuable land, habitat, noise, etc.	2	7.4
Increase the use of solar	1	3.7
Support increased investment in the EnergyWise Energy Efficiency Program	1	3.7
Continue using nuclear	1	3.7
Presentation was good and seems to be on target	1	3.7
Continue using coal	1	3.7
Power should only be provided by locally owned and controlled sources	1	3.7
Renewables are unreliable	1	3.7
Energy efficiency is important	1	3.7
No comment	1	3.7
Total	27	100.0

***Caution: Small sample size**
Base: Total sample, coded up to 3 mentions per response
Reference: 1) Which company provides your electrical service? 2) Please provide comments or suggestions, as it relates to NPPD's Integrated Resource Plan (IRP).

Appendix E – Resource Plan Summary (Through 2035)

Legend (row colour)
Base Market Forecast
High Market Forecast
Low Market Forecast
EE Sensitivity
DR Sensitivity
CNS Sensitivity
SMR Sensitivity
GGS CCS Sensitivity
Sheldon Sensitivity
Early Renewable Sensitivity
Higher Market Scenario

R YYYY	Retirement
LE YYYY	CNS 2nd Relicense Extension
NG	Sheldon Natural Gas
CCS	GGS2 Carbon Capture Addition

								Cumulative Additions through 2035 (MW)									
Case #	Case Name	CO2	Load	Market	GGS	CNS	Sheldon	CC – 1x1	CC – 2x1	CC - CCUS	CT	RICE	SMR	Wind	Solar	Battery	Total Additions
1	CE22001a	NZ 2050	Base	Base	R 2050/50	R 2034	NG 2028				826						826
2	CE22001b	NZ 2050 GP	Base	Base	R 2034/45	R 2034	NG 2028		1,000		413			800	500		2,713
3	CE22001c	NZ 2035 GP	Base	Base	R 2030/34	R 2034	NG 2028		1,000		826			2,000	1,250		5,076
4	CE22001d	NZ 2050	High	Base	R 2050/50	R 2034	NG 2028	386			413			400	250		1,449
5	CE22001e	NZ 2050 GP	High	Base	R 2031/43	R 2034	NG 2028		1,000		826			1,000	625		3,451
6	CE22001f	NZ 2035 GP	High	Base	R 2030/32	LE 2034	NG 2028		1,000		207			1,400	875		3,482
7	CE22001g	NZ 2050	Low	Base	R 2048/50	R 2034	NG 2028				620					100	720
8	CE22001h	NZ 2050 GP	Low	Base	R 2037/45	R 2034	NG 2028				826			800	500		2,126
9	CE22001i	NZ 2035 GP	Low	Base	R 2030/34	R 2034	NG 2028		1,000		826			1,800	1,125	50	4,801
10	CE22002a	NZ 2050	Base	High	R 2050/50	R 2034	NG 2028		1,000								1,000
11	CE22002b	NZ 2050 GP	Base	High	R 2034/43	R 2034	NG 2028		1,000		413			1,000	625		3,038
12	CE22002c	NZ 2035 GP	Base	High	R 2030/30	R 2034	NG 2028	386	1,000		413			2,000	1,250		5,049
13	CE22002d	NZ 2050	High	High	R 2050/50	R 2034	R 2028		1,000		207			200	125		1,532
14	CE22002e	NZ 2050 GP	High	High	R 2035/41	R 2034	NG 2028		1,000		413			1,600	1,000		4,013
15	CE22002f	NZ 2035 GP	High	High	R 2030/30	LE2034	NG 2028		1,000		413			1,400	875		3,688
16	CE22002g	NZ 2050	Low	High	R 2050/50	R 2034	NG 2028		1,000		207						1,207
17	CE22002h	NZ 2050 GP	Low	High	R 2036/48	R 2034	NG 2028	386			207			800	500		1,893
18	CE22002i	NZ 2035 GP	Low	High	R 2030/32	R 2034	NG 2028		1,000		620			1,800	1,125	50	4,595
19	CE22003a	NZ 2050	Base	Low	R 2050/50	R 2034	NG 2028				826						826
20	CE22003b	NZ 2050 GP	Base	Low	R 2034/39	R 2034	NG 2028		1,000		207			600	375		2,182
21	CE22003c	NZ 2035 GP	Base	Low	R 2030/30	R 2034	NG 2028		1,000		826			2,000	1,250		5,076
22	CE22003d	NZ 2050	High	Low	R 2050/50	R 2034	R 2028		1,000		207			200	125		1,532
23	CE22003e	NZ 2050 GP	High	Low	R 2034/38	R 2034	NG 2028		1,000		413			1,200	750		3,363
24	CE22003f	NZ 2035 GP	High	Low	R 2030/31	LE 2034	NG 2028		1,000	348				1,000	625	50	3,023
25	CE22003g	NZ 2050	Low	Low	R 2050/50	R 2034	NG 2028				620					100	720
26	CE22003h	NZ 2050 GP	Low	Low	R 2036/46	R 2034	NG 2028		1,000		207			600	375		2,182
27	CE22003i	NZ 2035 GP	Low	Low	R 2030/31	R 2034	NG 2028		1,000	348	413			1,400	875	100	4,136
28	CE22004a	NZ 2050	Low	Low	R 2050/50	R 2034	NG 2028				620					100	720
29	CE22004b	NZ 2050 GP	Base	Base	R 2034/45	R 2034	NG 2028		1,000		413			800	500		2,713
30	CE22004c	NZ 2035 GP	High	High	R 2030/30	LE 2034	NG 2028		1,000		413			1,400	875		3,688
31	CE22004d	NZ 2050	Low	Low	R 2050/50	R 2034	NG 2028				413						413
32	CE22004e	NZ 2050 GP	Base	Base	R 2038/45	R 2034	NG 2028				207			1,000	625		1,832
33	CE22005a	NZ 2050	Low	Low	R 2036/50	LE 2034	NG 2028										0
34	CE22005b	NZ 2050 GP	Base	Base	R 2038/47	LE 2034	NG 2028										0
35	CE22005b1	NZ 2035 GP	Base	Base	R 2030/33	LE 2034	NG 2028				1,240			800	500		2,540
36	CE22005b2	NZ 2050 GP	Base	Low	R 2035/46	LE 2034	NG 2028		1,000								1,000
37	CE22005c	NZ 2035 GP	High	High	R 2030/30	LE 2034	NG 2028		1,000		413			1,400	875		3,688
38	CE22005c1	NZ 2050 GP	High	High	R 2036/47	LE 2034	NG 2028				620			800	500		1,920
39	CE22005d	NZ 2050	Low	Low	R 2036/50	R 2034	NG 2028				206		600				806
40	CE22005e	NZ 2050 GP	Base	Base	R 2032/45	R 2034	NG 2028				826		600	200	125		1,751
41	CE22005f	NZ 2035 GP	High	High	R 2030/30	R 2034	NG 2028	386	1,000		413		600	1,800	1,125		5,324
42	CE22005g	NZ 2035 GP	High	High	R 2030/30	R 2034	NG 2028		1,000	348	413			2,400	1,500	50	5,711
43	CE22006a	NZ 2050	Low	Low	R 2050 CCS 2050	R 2034	NG2028				826						826
44	CE22006b	NZ 2050 GP	Base	Base	CCS 2034 R 2044	R 2034	NG2028				826			600	375		1,801
45	CE22006c	NZ 2035 GP	High	High	R 2030 CCS 2030	LE 2034	NG2028		1,000		207			1,200	750		3,157
46	CE22007a	NZ 2050	Low	Low	R 2050/50	R 2034	R 2028				1,033						1,033
47	CE22007b	NZ 2050 GP	Base	Base	R 2038/47	R 2034	R 2028		1,000		620			800	500		2,920
48	CE22007c	NZ 2035 GP	High	High	R 2030/33	LE 2034	R 2028		1,000		620			1,800	1,125		4,545
49	CE22007d	NZ 2050	High	High	R 2050/50	R 2034	R 2050				826			400	250		1,476
50	CE22008a	NZ 2050	Low	Low	R 2050/50	R 2034	NG 2028				826			200	125		1,151
51	CE22008b	NZ 2050 GP	Base	Base	R 2038/47	R 2034	NG 2028		1,000		413			800	500		2,713
52	CE22008c	NZ 2035 GP	High	High	R 2030/30	LE 2034	NG 2028	386	1,000					1,400	875		3,661
53	CE22009b	NZ 2050 GP	Base	Alt High	R 2037/46	R 2034	NG 2028				620			1,600	1,000		3,220
54	CE22009b2	NZ 2050 GP	Base	Alt High	R 2038/47	LE 2034	NG 2028				207			1,000	625		1,832

Resource Plan Summary Continued (cumulative through 2052)

	Base Market Forecast
	High Market Forecast
	Low Market Forecast
	EE Sensitivity
	DR Sensitivity
	CNS Sensitivity
	SMR Sensitivity
	GGS CCS Sensitivity
	Sheldon Sensitivity
	Early Renewable Sensitivity
	Higher Market Scenario

R YYYY	Retirement
LE YYYY	CNS 2nd Relicense Extension
NG	Sheldon Natural Gas
CCS	GGS2 Carbon Capture Addition

								Cumulative Additions through 2052 (MW)									
Case #	Case Name	CO2	Load	Market	GGS	CNS	Sheldon	CC – 1x1	CC – 2x1	CC - CCUS	CT	RICE	SMR	Wind	Solar	Battery	Total Additions
1	CE22001a	NZ 2050	Base	Base	R 2050/50	R 2034	NG 2028		1,000		1,240			1,800	1,125		5,165
2	CE22001b	NZ 2050 GP	Base	Base	R 2034/45	R 2034	NG 2028		1,000		826			1,800	1,125		4,751
3	CE22001c	NZ 2035 GP	Base	Base	R 2030/34	R 2034	NG 2028		1,000		1,240			2,000	1,250		5,490
4	CE22001d	NZ 2050	High	Base	R 2050/50	R 2034	NG 2028	386	1,000		620			2,400	1,500		5,906
5	CE22001e	NZ 2050 GP	High	Base	R 2031/43	R 2034	NG 2028		1,000		1,033			2,600	1,625		6,258
6	CE22001f	NZ 2035 GP	High	Base	R 2030/32	LE 2034	NG 2028		1,000		413			2,200	1,375		4,988
7	CE22001g	NZ 2050	Low	Base	R 2048/50	R 2034	NG 2028		1,000		620			1,000	625	100	3,345
8	CE22001h	NZ 2050 GP	Low	Base	R 2037/45	R 2034	NG 2028				1,446			1,600	1,000		4,046
9	CE22001i	NZ 2035 GP	Low	Base	R 2030/34	R 2034	NG 2028		1,000		826			1,800	1,125	50	4,801
10	CE22002a	NZ 2050	Base	High	R 2050/50	R 2034	NG 2028		1,000		826			1,800	1,125		4,751
11	CE22002b	NZ 2050 GP	Base	High	R 2034/43	R 2034	NG 2028		1,000		826			1,800	1,125		4,751
12	CE22002c	NZ 2035 GP	Base	High	R 2030/30	R 2034	NG 2028	386	1,000		413			2,200	1,375		5,374
13	CE22002d	NZ 2050	High	High	R 2050/50	R 2034	R 2028		1,000		1,240			2,800	1,750		6,790
14	CE22002e	NZ 2050 GP	High	High	R 2035/41	R 2034	NG 2028		1,000		1,033			2,800	1,750		6,583
15	CE22002f	NZ 2035 GP	High	High	R 2030/30	LE2034	NG 2028		1,000		413			2,400	1,500		5,313
16	CE22002g	NZ 2050	Low	High	R 2050/50	R 2034	NG 2028		1,000		207			1,200	750		3,157
17	CE22002h	NZ 2050 GP	Low	High	R 2036/48	R 2034	NG 2028	386			826			2,000	1,250		4,462
18	CE22002i	NZ 2035 GP	Low	High	R 2030/32	R 2034	NG 2028		1,000		620			1,800	1,125	50	4,595
19	CE22003a	NZ 2050	Base	Low	R 2050/50	R 2034	NG 2028		1,000		1,240			1,600	1,000		4,840
20	CE22003b	NZ 2050 GP	Base	Low	R 2034/39	R 2034	NG 2028		1,000		826			2,000	1,250		5,076
21	CE22003c	NZ 2035 GP	Base	Low	R 2030/30	R 2034	NG 2028		1,000		826			2,400	1,500		5,726
22	CE22003d	NZ 2050	High	Low	R 2050/50	R 2034	R 2028		1,000	348	826			2,400	1,500		6,074
23	CE22003e	NZ 2050 GP	High	Low	R 2034/38	R 2034	NG 2028		1,000		1,240			2,800	1,750		6,790
24	CE22003f	NZ 2035 GP	High	Low	R 2030/31	LE 2034	NG 2028		1,000	348				1,200	750	100	3,398
25	CE22003g	NZ 2050	Low	Low	R 2050/50	R 2034	NG 2028		1,000		620			1,000	625	100	3,345
26	CE22003h	NZ 2050 GP	Low	Low	R 2036/46	R 2034	NG 2028		1,000		207			1,000	625		2,832
27	CE22003i	NZ 2035 GP	Low	Low	R 2030/31	R 2034	NG 2028		1,000	348	413			1,400	875	100	4,136
28	CE22004a	NZ 2050	Low	Low	R 2050/50	R 2034	NG 2028		1,000		620			1,000	625	100	3,345
29	CE22004b	NZ 2050 GP	Base	Base	R 2034/45	R 2034	NG 2028		1,000		826			1,800	1,125		4,751
30	CE22004c	NZ 2035 GP	High	High	R 2030/30	LE 2034	NG 2028		1,000		413			2,400	1,500		5,313
31	CE22004d	NZ 2050	Low	Low	R 2050/50	R 2034	NG 2028	386	1,000		413			1,000	625		3,424
32	CE22004e	NZ 2050 GP	Base	Base	R 2038/45	R 2034	NG 2028				1,446			2,400	1,500		5,346
33	CE22005a	NZ 2050	Low	Low	R 2036/50	LE 2034	NG 2028		1,000		413			200	125		1,738
34	CE22005b	NZ 2050 GP	Base	Base	R 2038/47	LE 2034	NG 2028		1,000		207			1,000	625		2,832
35	CE22005b1	NZ 2035 GP	Base	Base	R 2030/33	LE 2034	NG 2028		1,000		1,446				625		3,071
36	CE22005b2	NZ 2050 GP	Base	Low	R 2035/46	LE 2034	NG 2028		1,000		207			800	500		2,507
37	CE22005c	NZ 2035 GP	High	High	R 2030/30	LE 2034	NG 2028		1,000		413			2,200	1,375		4,988
38	CE22005c1	NZ 2050 GP	High	High	R 2036/47	LE 2034	NG 2028		1,000		620			1,800	1,125		4,545
39	CE22005d	NZ 2050	Low	Low	R 2036/50	R 2034	NG 2028		1,000		413		600				2,013
40	CE22005e	NZ 2050 GP	Base	Base	R 2032/45	R 2034	NG 2028		1,000		826		600	1,400	875		4,701
41	CE22005f	NZ 2035 GP	High	High	R 2030/30	R 2034	NG 2028	386	1,000		413		600	1,800	1,125		5,324
42	CE22005g	NZ 2035 GP	High	High	R 2030/30	R 2034	NG 2028		1,000	348	620			2,600	1,625	50	6,243
43	CE22006a	NZ 2050	Low	Low	R 2050 CCS 2050	R 2034	NG2028	386	1,000		826			800	500		3,512
44	CE22006b	NZ 2050 GP	Base	Base	CCS 2034 R 2044	R 2034	NG2028		1,000		1,033			2,000	1,250		5,283
45	CE22006c	NZ 2035 GP	High	High	R 2030 CCS 2030	LE 2034	NG2028		1,000		620			1,800	1,125		4,545
46	CE22007a	NZ 2050	Low	Low	R 2050/50	R 2034	R 2028		1,000		1,033			1,000	625		3,658
47	CE22007b	NZ 2050 GP	Base	Base	R 2038/47	R 2034	R 2028		1,000		1,653			1,800	1,125		5,578
48	CE22007c	NZ 2035 GP	High	High	R 2030/33	LE 2034	R 2028		1,000		620			2,000	1,250		4,870
49	CE22007d	NZ 2050	High	High	R 2050/50	R 2034	R 2050		1,000		1,653			2,600	1,625		6,878
50	CE22008a	NZ 2050	Low	Low	R 2050/50	R 2034	NG 2028		1,000		826			1,200	750		3,776
51	CE22008b	NZ 2050 GP	Base	Base	R 2038/47	R 2034	NG 2028		1,000		1,033			2,000	1,250		5,283
52	CE22008c	NZ 2035 GP	High	High	R 2030/30	LE 2034	NG 2028	386	1,000					2,200	1,375	50	5,011
53	CE22009b	NZ 2050 GP	Base	Alt High	R 2037/46	R 2034	NG 2028				1,859			3,200	2,000		7,059
54	CE22009b2	NZ 2050 GP	Base	Alt High	R 2038/47	LE 2034	NG 2028				1,240			2,400	1,500		5,140